SECTION V

POWER SYSTEM ANALYSIS, INTERCONNECTION AND POWER SYSTEM CONTROL SCADA SYSTEMS

44

Power System Stability, Auto-Reclosing Schemes, Methods of Analysis and Improvement of Transient Stability

PART A : CONCEPT OF POWER SYSTEM

44.1. POWER SYSTEM STABILITY

Power System Stability has been the area of study from early days of electrical power generation and transmission. The subject has gained more importance in today's interconnected power system having high capacity generating stations and Network of long EHV/HVDC transmission lines. The term *Power System Stability* refers to ability of the power system and the synchronous machines to run in synchronism. This applies to A C system.

The tendency to loose synchronism is called *Unstable* condition. Thus the subject matter of 'Power System Stability' refers to maintaining synchronism of synchronous generators, generating stations, Regional Grids and the National Grid.

Steady State Stability refers to the conditions of stability in response to small and gradual changes of load.

Transient Stability refers to the conditions of stability in response to *sudden changes of load of large magnitude.* Steady state stability limit is simple for analysis and can be calculated accurately. Transient stability limit is *lesser* than the *steady stability limit* and is, therefore, the deciding factor for normal power transfer.

The loading of a generator generating station, transmission line, Regional Grids and National Grid is based on respective Transient Stability Limits. By adopting appropriate protection schemes, auto-reclosing schemes and automatic fast excitation systems ; HVDC links, etc., the transient stability limit can be increased. Thereby the same installed capacity can deliver higher power.

The generation should match the load to maintain constant frequency. (Refer Ch. 45). The voltage should be maintained within specified limits. The synchronous machines and generating stations should maintain synchronism with the grid. Synchronism should be maintained between the Regional Grids connected together by the tie-lines or interconnectors. These tasks are covered under stability studies.

In traditional stability studies, the reactive power flow (Q), load power factor ($\cos \phi$) and bus voltage variation is *ignored*. These factors are very important and are covered separately under the topic 'Voltage Stability' — Ch. 45-C.

The following two unique cases are usually analysed as representative cases for stability studies :

1. Single synchronous machine operating against Infinite Bus. (Single Machine System).
2. Two synchronous Machines connected by a Tie-line (Two Machine System).

Both these systems have a similar set of equations and similar behaviour. The basic equation of power system stability applied to a tie-line is

$$P = \frac{|V_1| \cdot |V_2|}{X} \sin \delta$$

where $|V_1|$ and $|V_2|$ are sending end and receiving end voltage-magnitudes of transmission line, X is the series reactance of transmission line ; angle δ is called power angle, *i.e.* the angle between V_1 and V_2 vectors ; P is the power transfer.

Similar equation applied to a synchronous machine connected to Infinite Bus is

$$P = \frac{|V| \cdot |E|}{X} \sin \delta$$

where $|E|$ is the e.m.f. magnitude, $|V|$ is the terminal voltage-magnitude, X is the synchronous reactance, δ is the angle between V and E vectors, P is the power transfer.

Power angle diagram is a curve of power transfer (P) versus power angle (δ). It is a sine-curve.

Swing curve is a graph of angle (δ) versus time (t). If the angle δ reduces after attaining maxima corresponding to $d\delta/dt = 0$; the condition indicates stability.

Alternatively, *Equal Area Criterion is a graphical method of determining transient stability from Power Angle Diagram.*

For study of Voltage Stability, graph of receiving end voltage $|V_R|$ versus power transfer P is drawn. The point of maximum power P_m is reached at $dV/dP = 0$. This is covered in Ch. 45-C.

Swing Equation of a synchronous machine is,

$$M \frac{d^2 \delta}{dt^2} = P_s - P_e$$

where M is angular Momentum, P_s is mechanical shaft power and P_e is electrical power given by $VE \sin \delta/X$. Solution of swing equation (step by step method) gives values of δ for various values of time t.

Power System Stability *is closely associated with Switchgear and Protection. Today's power system are large interconnected grids having high fault levels at station buses.* **Transient Stability Limit of a transmission system or the network can be increased by following means :**

- Rapid fault clearing by circuit-breakers at both ends of the faulty transmission lines.
- Fast and selective protection, stable during the conditions of power swings.
- Autoreclosing of circuit-breakers for transmission lines. The transient stability can be increased by automatic reclosing of circuit-breakers which have opened under temporary fault condition.
- Single Pole Tripping for Single-line to ground faults. Single Pole auto-reclosing.
- Higher transmission voltages and better voltage control.
- Faster protection by static relays and carrier aided distance protection of transmission lines.

Other methods of improving transient stability limits include :

- Reducing series reactance of the tie-lines by using series capacitors or by adding parallel lines.

- Asynchronous HVDC Links for transmission of bulk power or for Tie Lines. (HVDC tie lines provide a link between two a.c. systems which need not be in synchronism, since they are connected by HVDC link).
- Using rapid-response excitation system for synchronous generators. (Ch. 45-D)
- HVDC transmission with damping control.
- Increasing steady state voltage stability and transient voltage stability of transmission links and faster voltage control of load-buses. (Ch. 45-C)

Power System Stability is a common objective of the power system engineers from the view point of electrical machines, transmission of power, Switchgear, Protection and Automation and voltage control. This chapter explains the principles and applications of various aspects of Power System Stability in a simple and up-to-date manner. The most recent Definitions by IEEE have been mentioned. Ch. 45-C Covers Voltage Stability.

In A.C. system, the generation should be continuously adjusted to match with the load requirements. If this condition is not satisfied, the frequency of the system goes beyond targeted limits. The problem of load-frequency control ; load shedding and Network islanding is discussed in Ch. 45, *Autoreclosing* of circuit-breakers has been described in Sec. 2.12. In this chapter, the protection and stability aspects regarding auto-reclosing have been covered.

44.2. CONCEPT OF POWER SYSTEM STABILITY

The term stability is closely related with synchronism. Synchronous generators (alternators) and synchronous motors have a tendency to remain in synchronism or in step with each other. During system disturbance such as sudden increase in load, sudden switching, power swings etc., the synchronous machines experience oscillations of torque angle about the mean position. However, the synchronous machines have inherent tendency or maintaining synchronism. Loss of synchronism is called loss of stability.

Ability of synchronous machine or part of a system to develop restoring forces equal to more than disturbing forces so as to remain in synchronism is called stability.

The disturbance may be sudden or the change in load may be very gradual. Accordingly, there are two distinct terms called *transient stability* and *steady state stability.*

The term *steady state stability* refers to ability of a system or its part to respond to small, gradual change in power at a given point of the system. Steady state stability limit is the maximum possible power that can be transferred at a given point of the system without loss of synchronism, with very gradual increase in power.

The term *transient stability limit* refers to the maximum power that can be transferred at a given point of the system without loss of synchronism for given sudden large change in power.

The concept of stability can well be explained by means of two machine system. The system is used as a conceptual aid. The system comprises a synchronous machine A connected with B by means of interconnector having reactance X.

Referring to Fig. 44.1 (a), power transfer P between buses A and B is given by

$$P = \frac{|V_1| \cdot |V_2|}{X} \sin \delta \qquad ...(44.1)$$

where $|V_S|$ = Sending end voltage magnitude

$|V_R|$ = Receiving end voltage magnitude

X = Reactance of interconnector

δ = Power angle : Angle between V_S and V_R

The resistance of interconnection is neglected. The voltages are assumed to be constant. Reactive power flow is neglected. The effect of voltage drop on stability is a sub-topic of stability studies covered under title "Voltage Stability". (Ch. 45-C).

Consider, the power transfer being very gradually affected by increasing angle by increasing the load at receiving end and maintaining magnitudes $|V_S|$ and $|V_R|$ constant. The variation in P given by Eq. 44.1 is plotted in Fig. 44.1(*b*). For values of delta above 90°, increase in δ does not result in increase in power-transfer. On the contrary, the power transferred is reduced, this causes further reduction in P. Thus for values of P above P_{max} corresponding to $\delta = 90°$ the stability is lost. Hence P_{max} at $\delta = 90°$, *i.e.*

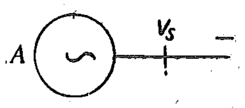


Fig. 44.1 (*a*). Two-machine system (a.c.).

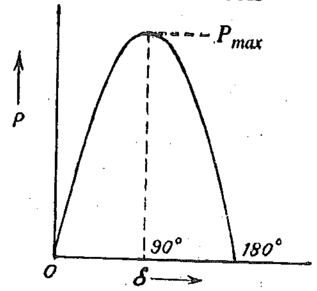


Fig. 44.1 (*b*). Power-angle diagram.

δ = Power angle in degree electrical
P = Power transfer
$P = P_{max}$ at $\delta = 90°$
X = Resistance of interconnector
A, B = Equivalent synchronous machine.

$$P_{max} = \frac{|V_S| \cdot |V_R|}{X}$$

is called *steady state stability limit.*

Example 44.1. *A 115 kV, 3 phase AC line has per phase series reactance of (j7) ohms between sending end and receiving end. The sending end and receiving end voltages of line are 115 kV rms. Phase to phase. Calculate maximum possible power transfer through the transmission line (steady state stability limit of the line).*

Solution. $$P_{ss} = P_{max} \frac{|V_S| \cdot |V_R|}{X} \text{ MW per phase}$$

where $|V_S|$ and $|V_R|$ are phase to neutral kV rms, X is series reactance per phase, ohm and $P_{SS} = P_{max}$, is steady state stability limit, *i.e.* maximum power per phase, MW. Substituting the given values :

$$|V_S| = |V_r| = 115/\sqrt{3} = 66.4 \text{ kV rms, ph. to neutral}$$

$$P_{max} \text{ per phase} = \frac{(66.4)^2}{7} = 629.76 \text{ MW per phase}$$

$$3 \text{ phase } P_{max} = \text{Steady State Stability Limit}$$

$$= 629.76 \times 3 = 1889.29 \text{ MW} \quad \textbf{Ans.}$$

Example 44.2. *Without Neglecting Line Resistance. A 115 kV, 3 phase AC line has per phase series impedance of (4 + j7) ohms between sending end and receiving end.*

The sending end and receiving end voltages of line are 115 kV rms, phase to phase. Calculate maximum possible power transfer through the transmission line (steady state stability limit of the line).

Solution. Without Neglecting Resistance, the Power Equation gets modified as :

$$P_{max} \text{ per phase} = \frac{|V_S| \cdot |V_R|}{\sqrt{R^2 + X^2}} - \frac{R V_R^2}{R^2 + X^2}$$

In the given Example :

$$P_{max} \text{ per phase} = \left[\frac{(66.4)^2}{\sqrt{4^2 + 7^2}} - \frac{4\,(66.4)^2}{4^2 + 7^2}\right] = 275.5 \text{ MW/ph}$$

$$3 \text{ phase } P_{max} \text{ total} = 275.5 \times 3 = \mathbf{826.5\ MW} \quad \textbf{Ans.}$$

Transient Stability. *The maximum value of power that can be transmitted after a given large sudden change in the system is called the transient limit.* When the system experiences faults and the relays switch off affected circuits, the system goes from an initial power-angle operating point to a final operating point, and in between a swing condition exists where the power-angle relationship still holds, but these quantities can vary with time over a wide range.

(Refer Fig. 44.2). Let the power transferred through a part of the system shown in Fig. 44.2 be P_1 and corresponding angle be δ_1. Now a sudden large incremental load ΔP is added at receiving end. As a result, the sending end generator slows down and angle increases. The angle should get settled to a new value δ_2 corresponding to power P_2. However, due to inertia of rotors, to rotor overshoots to angle δ_3 corresponding to power P_3. This power transfer being more than required, the angle starts reducing. Thus the angle swings about the value 2, between the limits 1 and 3 resulting in power-swings.

If the power transferred P_1 and sudden increment of load P are above certain value, the value of increases beyond 90°. In this region, the increase in results in reduction in power transferred. Thereby the angle further increases and power transferred is further reduced. The result is loss of stability. The transient stability limits refer to the maximum possible flow of power through a point of the system without loss of stability when a sudden disturbance occurs. (The value given by initial load plus increment).

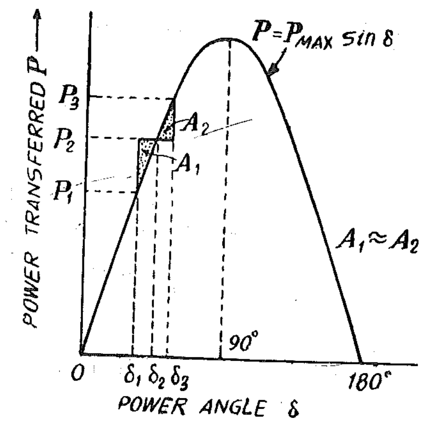


Fig. 44.2. Explaining Transient Stability.

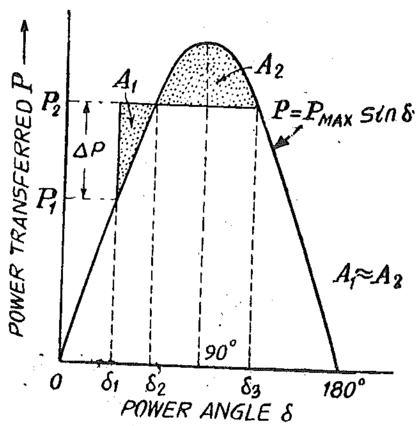


Fig. 44.3. Explaining Transient Stability.

The transient stability is analysed by means of swing equation; network analyser, digital computer. However, **Equal Area Criterion** is a good conceptual aid. It is a graphical method of equating areas of segments on the power angle *vs.* power transferred diagram.

Referring to Fig. 44.1 (*a*)

$$A_1 = \int_{\delta_1}^{\delta_2} (P_2 - P_1)\, d\,\delta \; ; A_2 = \int_{\delta_2}^{\delta_3} (P_3 - P_2)\, d\,\delta$$

Area A_1 is above the curve P and below P_2.

Area A_2 is below the curve P and above P_2.

Area $A_1 = A_2$, if the machine continues to remain synchronism after disturbance.

However, consider Fig. 44.3 in which P_1 and ΔP are of limiting value, where $A_1 = A_2$. If P_1 is more, for the same given ΔP, the area A_2 above curve P would be less than area A_1 and the system will fall out of-step. The maximum allowable sudden increase in power ΔP on the system transferring power P_1 is illustrated in Fig. 44.3. The method of equating areas, described above is called Equal Area Criterion of stability studies. The criterion can be applied to study the effect of fault clearing, auto-reclosure and single pole-switching on transient stability limit.

In Fig. 44.3, P_2 is a maximum permissible power transfer for given conditions of P_1 and P_2 such that beyond P_2 that transient stability is lost. P_2 is, therefore, the transient stability limit for given conditions.

In the above analysis a simple two machine system having an interconnector has been analysed with the help of Power-Angle diagram and the Equal Area Criterion. The method of approach for the following two models is the same :

— The synchronous machines connected by a tie-line (inter-connector) : **Two Machine System.**

— One synchronous machine connected to an infinite bus : **Single Machine Against Infinite Bus.**

What is an Infinite Bus ?

Infinite bus has constant voltage, constant electrical angle of the voltage, infinite fault level and, therefore, the quantities of infinite bus do not get affected by connecting or disconnecting individual machines or transmission lines. A large interconnecting power system having very high fault level (compared with the rating of an individual machine/transmission line) can be considered to be an infinite bus for the purpose of analysis.

44.3. SINGLE MACHINE AGAINST INFINITE BUS

Consider a synchronous machine operating with constant field current (excitation current) and connected to infinite bus. Refer Fig. 44.4.

Synchronous Generator connected to infinite bus.

Vector Diagram of Salient Pole Generator.

Fig. 44.4

E = Excitation voltage, *i.e.* voltage behind the synchronous impedance ; this is called e.m.f. and is dependent on excitation.

V = Terminal voltage, considered as constant for infinite bus.

δ = Angle between V and E.

X_s = Direct Axis Synchronous Reactance (Steady state) for

$$\left.\begin{array}{l}\text{generator action, } V = E - IX_s \\ \text{for motor action } V = E + IX_s\end{array}\right\} \qquad ...(44.2)$$

Refer Fig. 44.7 for Generating Action.

Under steady state condition, for a cylindrical rotor machine, the electrical power output P of the cylindrical rotor generator may be expressed in terms of V, I, X_s and as by the well known power equation :

$$P = \frac{|E| \cdot |V|}{X_s} \sin \delta \qquad ...(44.3)$$

where, δ = Power angle between E and V,

$|E|$ = E.M.F. Excitation voltage, magnitude Voltage behind reactance, proportional to excitation.

$|V|$ = Terminal voltage magnitude

X_s = Synchronous Reactance (Steady State), Series resistance is neglected.

In the above equation the quantities E, V, X_s are per phase and the power P is also per phase. The positive P indicate generating action. Negative P indicates motoring action (negative δ). Refer Fig. 44.6.

Angle corresponds to the electrical angle between rotor poles and the stator rotating magnetic field. Under synchronous condition the rotor pole axis is locked with the stator-rotating magnetic field with an angle δ which varies with the load. Increased load causes increases in angle δ and increased power P. The graph of power delivered to the infinite bus by synchronous generator against power angle is a sine curve.

At $\delta = 90°$, the power delivered

P reaches a maximum limit, *i.e.*

$$P_{max} = \frac{|E| \cdot |V|}{X_s} \sin 90° = \frac{|E| \cdot |V|}{X_s} \qquad ...(44.4\ a)$$

This limit of maximum possible power delivered is called steady state stability limit of the synchronous machine.

Hence $$P = P_{max} \sin \delta \qquad ...(44.4\ b)$$

Eqs. 44.3 and 44.4 apply to cylindrical rotor synchronous machines used for turbo-generators used in thermal and nuclear (steam) power plants. For *Salient Pole Machine the equations get modified as follows :*

$$P = \frac{EV}{X_d} \sin \delta + V^2 \left(\frac{X_d - Xa}{2X_d X_d}\right) \sin (2\ \delta) \qquad ...(44.5)$$

$$= P_1 + P_2 \qquad \text{...Ref. Fig. 44.5}$$

where X_d = Direct axis reactance

X_a = Quadrature axis reactance

E = Voltage behind reactance

V = Terminal voltage

δ = Angle between V and E, electrical radians positive for generating action

The second terms on the right hand side of Eq. 44.5, is due to saliency of poles. If this term is neglected we get the expression 44.3 applicable to cylindrical pole machines (Fig. 44.5).

For transient state, E in these equations is replaced by E' and X_d by X'_d, *i.e.*

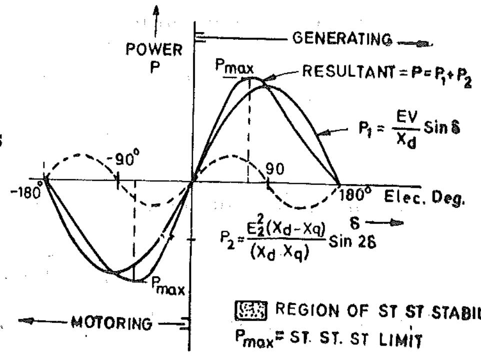


Fig. 44.5. Power angle characteristic of a salient pole Synchronous Machine (P *v/s* δ).

For salient pole machines

$$P = \frac{E'\,V}{X'_d} \sin \delta - V^2 \left(\frac{X_q - X'_d}{2X_d X_q}\right) \sin (2\delta) \qquad ...(44.6)$$

for cylindrical rotor machine

$$P = \frac{E'\,V}{X_d^1} \sin \delta \qquad ...(44.7)$$

where E', X_d^1 refer to transient state.

P is considered positive for positive generating action.

P is considered negative for negative motoring action.

Example 44.3. *A cylindrical rotor synchronous generator is connected to infinite the bus and is delivering current 1 of 1.00 p.u. at 0.91 p.f. lag, the busbar voltage is 1.00 p.u.*

The direct axis sub-transient reaction $X_d^1 = 0.37$. Determine the equation for power angle curve. Calculate the steady state stability limit.

Solution. Power equation for a cylindrical rotor machine :

$$P = \frac{EV}{X_d} \sin \delta \ \ldots \text{ for steady state}$$

$$P = \frac{E'V}{X'_d} \sin \delta \ \ldots \text{ for transient state}$$

where E, E' = voltage behind reactance

V = Terminal voltage

δ = Angle between E and V.

Consider V as reference vector

$$V = V \angle 0°$$

$$= 1.00 \angle 0 = 1 + j0$$

$$I = 1.00\ °\text{–}\cos^{-1} 0.91 = 1.00 \angle -24.5°$$

$$= \text{Angle between } I \text{ and } V = 24.5°$$

$$E' = V + j\,IX'_d \qquad \ldots(44.8)$$

$$= (1 + j0) + (1.00\ °\text{–}\ 24.5°)\ (0.37 \angle 90°)$$

$$= 1.00 + 0.37 \angle 65.5° = 1.00 + 0.15 + j0.34$$

$$= 1.15 + j0.34 = 1.20 \angle 16.3$$

between E' and V at

$$t = 0 \text{ is } 16.3°$$

Power angle curve is given by :

$$P = \frac{E'V}{E_d^1} \sin \delta$$

$$= \frac{1.20}{0.37} \sin \delta \text{ p.u.} \qquad \ldots(44.9)$$

The maximum possible power transfer is

$$P = \frac{E'V}{X_d^1} = \frac{1.2 \times 1}{0.37} = 3.24 \text{ p.u.}$$

Steady State Stability Limit = 3.24 p.u. (Answer)

The value of P for various values are from Eqn. 44.8 are as follows :

From these values Power Angle Diagram can be plotted.

°Elec.	0	15	30	45	60	75	,	
	180	165	150	135	120	105	90	16.3°
Sin δ	0	0.259	0.50	0.70	0.86	0.96	1.00	0.281
P	0	0.84	1.62	2.29	2.80	3.13	3.24	0.91

The graph of angle δ *v/s* time t is called Swing Curve.

Power Angle δ

Power Angle δ between rotor pole axis and stator rotating field axis (both rotating together at synchronous speed) is expressed in electrical degrees or electrical radians. It is equivalent to the angle between Stator Flux Axis and Rotor Flux Axis, both at synchronous speed. The angle between two consecutive poles is π radians or 180° electrical.

Understanding the Power Angle Diagram

A synchronous machine has inherent tendency to remain in synchronism with the busbar. This can be visualized by means of the Power-Angle-diagram (Fig. 44.6).

Any increase in load on synchronous generator results in increase in the angle δ (angle between rotor-pole axis and the stator rotating magnetic field axis) and consequent increase in power while the angle δd is over the linear portion of power-angle characteristics.

Likewise, over the linear portion of the power angle diagram any decrease in load causes reduction in angle (*i.e.* the angle between stator rotating magnetic field and in the rotor pole axis) and consequent reduction in power transfer *P*.

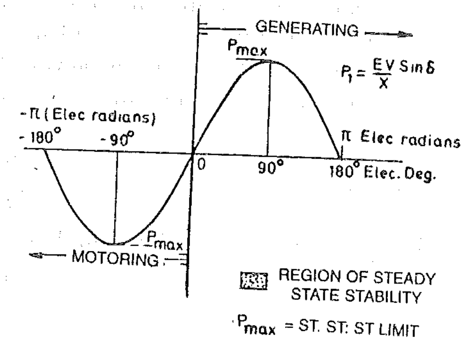


Fig. 44.6. Power angle characteristic of Cylindrical Rotor Synchronous Machine (P v/s δ).

Note. Here, the response of the governor which adjusts the input to turbine to match the output to maintain set frequency is not considered.

Refer Ch. 45 for Governor action and load-frequency control. The synchronous speed and the frequency are determined by input and output relations for the total grid. For the present analysis, the angle δ between the rotor pole axis and the stator-rotating magnetic field axis both rotating at synchronous speed corresponding to the prevailing frequency is being discussed.

Coming back to the power-line diagram; in the linear portion of the power line diagram the increase in load causes increase in the power transfer. *The angle between the rotor-pole axis and stator field axis (both rotating at synchronous speed and locked with each other) gets adjusted to meet the changes in load P.*

This ability of the synchronous machines to adjust with changes in load and remaining in synchronism is the basis of stability.

The load on a synchronous machine connected to the system continues to change by small amounts at all times and the inputs to turbines get correspondingly adjusted to maintain the balance between input and output to maintain constant frequency (Refer Ch. 45). However, when the power P_1 delivered by a synchronous machine corresponding to a certain load angle δ_1 *is disturbed* by change in loading the synchronous machine tends to attain a new load angle δ corresponding to new power delivery P_2.

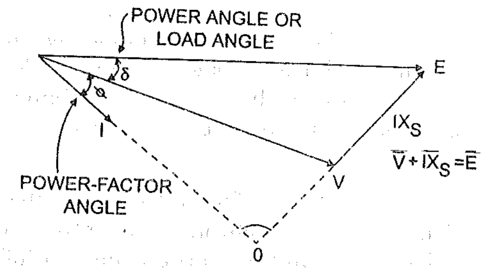


Fig. 44.7. Vector diagram for cylindrical rotor machine operating as generator.

The synchronous machine should remain in synchronism with the system, *i.e.* it should operate in parallel with the system and the angle δ should remain over the straight line portion of the power-angle diagram.

Now, consider the curved portion of the power-angle diagram. The change in load P brings about a large change in δ in this region and beyond $\delta = 90°$; increase in delta does not give increase in P and the machine tends to fall out-of step. The rotor poles slip from the stator magnetic field and the machine tends to fall out-of step. This is called unstable condition.

The synchronous machine remains in synchronism only if the angular displacement brings about corresponding appropriate change in power delivered to attain a new stable value of δ.

Synchronizing Power. From the above analysis we shall make two simple statements: During disturbance,

— *in the linear portion* of the power-range diagram (P *vs* δ) the change in P brings about corresponding change in δ to achieve new values of P and which are stable.

Note the following :

— Excitation voltage E depends on field current hence quick acting excitation system is necessary for higher transient stability unit of synchronous machines.

— In case of salient pole machines, the slope of linear portion of power angle diagram ($dP/d\delta$) is higher (steeper) than that of cylindrical rotor machine. In case of salient pole machine, the maximum power P_{max} occurs approximately at $\delta = 70°$ whereas as case of cylindrical rotor machine P_{max} occurs approximately at $\delta = 90°$ as seen from Figs. 44.5 and 44.6.

Substituting $$P_1 = \frac{EV}{X_d} \sin \delta_1 \text{ in Eq. 44.9}$$

Synchronising power P, an angle δ_1 is

$$P = \frac{dP_1}{d\delta} = \frac{EV}{X_d} \cos \delta_1 \qquad ...(44.10)$$

where δ_1 = angle between V and E in electrical degrees of electrical radians.

PART B : SWING CURVES AND SWING EQUATION, EQUAL AREA CRITERION

44.4. DYNAMICS OF SYNCHRONOUS MACHINES, KINETIC ENERGY, INERTIA CONSTANT AND STORED ENERGY

These terms will be reviewed to enable understanding of the *Swing Equation* and *Transient Stability Studies* to be covered in subsequent paragraphs.

Earlier, we dealt with the electrical relation.

$$P = \frac{VE}{X} \sin \delta \text{ and } P = \frac{V_1 V_2}{X} \sin \delta$$

Now, we will study the moment of inertia of rotor, torque and kinetic energy terms and their co-relation with the transient stability. The *Stability* is a question of electrical and mechanical energy transfer during the system disturbance and, therefore, the mechanical terms gain equal importance. It is assumed that the rotor is running in synchronism and rotor mass includes total mass on the shaft.

44.4.1. Kinetic Energy of a Rotating Mass

The rotors of synchronous machines including shaft and drive machine has certain kinetic energy (KE) corresponding to their moment of inertia (J), and the angular speed (ω). From fundamentals, we know,

$$KE = \frac{1}{2} J\omega^2 \text{ ... Joules} \qquad ...(44.11)$$

where, $K.E.$ = Kinetic Energy in rotor ... Joules

J = Moment of Inertia of rotor

Units : kg m^2 or $\dfrac{\text{Joules. sec}^2}{\text{Radian}^2}$

also called mass-inertia and also denoted by symbol I in some American Books.

where N = RPM. One Rev. = 2π radians

$$\text{K.E.} = \frac{\text{Joules sec}^2}{\text{Rad}^2} \cdot \frac{\text{Rad}^2}{\text{sec}^2}$$

K.E. = Joules

ω = Angular speed of rotor, radian/sec.

If N_s = Synchronous speed rpm

$= 120\, f/P$ where P = No. of poles

$\omega = \dfrac{2\pi N}{60}$ mech.radians/sec., Mechanical Angular Speed

J = Moment of Inertia of rotor is expressed in kg-m^2 and depends upon dimensions and mass of the complete rotor including the generator rotor and turbine rotor /load rotor.

The moment of inertia J of the rotor in kg-m^2 should be obtained from the dimensions and weight of the machine and this value should be substituted in Eqs. 44.10 to get value of K.E.

Example 44.4. *A synchronous motor driver has moment of inertia J = 400 kg-m^2 and runs at no load speed of 500 rpm. Calculate the kinetic energy in the rotor.*

Solution. Angular speed $\omega = \dfrac{2\pi N}{60}$ rad/sec

$$= \frac{2\pi \times 500}{60} = 52 \text{ rad/sec}$$

$$\text{K.E.} = \frac{1}{2} J\,\omega^2 \qquad ...(44.12)$$

$$= \frac{1}{2} \times 400 \times 52^2 \text{ Joules} = 200 \times 2704$$

= 540,800 Joules **Ans.**

= 540.8 Kilojoules. **Ans.**

Angular Momentum M. Eqn. 44.10 is usually presented in another form for stability studies as

$$\text{K.E.} = \frac{1}{2} J\omega^2 = \frac{1}{2} (J\omega) \times \omega$$

$$= M \times \omega \text{ Joules (44.11)}$$

Dark Print indicates 'Mega'.

i.e. $$\mathbf{KE} = KE \times 10^{-6}$$

$$\mathbf{M} = J\omega \times 10^{-6}$$

where, $M = J\omega$ = Angular Momentum $\dfrac{\text{kg-m}^2\text{ rad}}{\text{sec}}$ ...(44.13)

J = Moment of inertia of rotor kg-m^2

ω = Angular speed of rotor, radian/sec

Angular Momentum values depend upon size, type, speed of machines.

44.4.2. Inertia Constant H

Inertia constant H is defined stored energy in rotor at synchronous speed divided by the volt-ampere rating of the machine, *i.e.*

$$H = \text{Inertia Constant} = \frac{\text{Stored Energy}}{\text{Volt Ampere Rating}} \cdots \frac{\text{Joules}}{\text{VA}}$$

– at synchronous speed of machines ...(44.14)

The inertia constant is usually expressed in terms MJ and MVA as

$$\mathbf{H} = \frac{\text{Megajoules}}{\text{MVA rating of machine}} = \frac{\text{Joules} \times 10^{-6}}{\text{VA} \times 10^{-6}}$$

*Joule = Watt. sec.

Inertia constant H of a machine is always calculated at synchronous speed. *Value of H depends upon type of machine* and it is usually within a narrow limits for a particular type of machine. Whereas the value of angular momentum M varies widely with size, speed, moment of inertia of the machine). Typical values of H are as follows :

Table 44.1. Typical Values of H is MJ/MVA

	Synch. Turbo-Generator			*Hydro-Gen.*	
Types of Synch. machine rotor	*Condensing 1500 rpm*	*Non-condensing 8000 rpm*	*Condensing 3000 rpm*	*Low Speed 3000 rpm*	*High Speed 3000 rpm*
H2 MJ/MVA	6-9	3-4	4-7	2-3	3-4

44.4.3. Stored Energy in Rotor of a Syn. Machine

Stored Energy (GH) is usually expressed in Megajoules and is given by

$$GH = \text{Stored Energy in Rotor mega-joules}$$

$$= G \times H \qquad \ldots(44.15)$$

where G = Machine rating in MVA

$$H = \text{Inertia constant of machine } \frac{\text{MJ}}{\text{MVA}}$$

Dimensionally, $$(GH) = \frac{\text{Mega-joules}}{\text{MVA}} \times \text{MVA}$$

$$= \frac{\text{Mega-Watt. Sec}}{\text{MVA}} \times \text{MVA}$$

Substituting Eq. 44.13.

Comparing Eq. 44.15 with 44.10. Kinetic Energy of rotating body (KE) can be expressed in terms of Eq. 44.10 and Eq. 44.11 as,

$$\text{KE} = \frac{1}{2} J\omega^2 \text{ Joules} = \frac{1}{2} M\omega^2 \text{ Joules}$$

or as Eq. 44.12 as $$\text{GH} = \frac{1}{2}\mathbf{M}\omega \text{ mega-joules}$$

where $$\mathbf{M} = M \times 10^{-3} \text{ as in } \frac{\text{mega-joule sec}}{\text{radian}}$$

Therefore, referring ω as synchronous speed

$$(\mathbf{GH}) = 2\frac{\mathbf{GH}}{\omega}\frac{\text{Mega-joule}}{\text{radian}}$$

$$2\pi \text{ radians} = 360^\circ \text{ Electrical degree}$$

and $$\omega = 360\, f \text{ electrical degrees/sec.}$$

where f is the frequency of system Hz ...(44.17)

$$\omega = 360\, f \text{ electrical degrees/sec.}$$

For one cycle, the rotor moves through 360° electrical degree or 2π radians electrical. In one second, there are f cycles, hence

$$\omega = 360 \text{ electrical degrees/sec.}$$

$$= 2\pi f \text{ radians/sec.}$$

Substituting Eq. 44.17 in 44.16 we get inertia constant **M** in terms of **GH** as :

$$\mathbf{M} = \frac{2\,\mathbf{GH}}{360f} = \frac{\mathbf{GH}}{180f}\;\frac{\text{M.J.s.}}{\text{elec. degree}} \qquad \ldots(44.18)$$

or $$= \frac{2\,\mathbf{GH}}{2\pi f} = \frac{\mathbf{GH}}{\pi f} = \frac{\text{M.J.s.}}{\text{elec. radian}}$$

These equations of G, H, M, J, etc, are summarised in the following table for ready reference :

Bold, Dark Prints of **G, H, M** signify units in Mega, Plain print G. H. M. signify mega 10^6.

Example 44.4. *Stored Energy and Inertia Constant. Calculate stored kinetic energy in the rotor of a 100 MVA, 2 pole, 60 Hz Generator rotating at rated synchronous speed ; the moment of inertia of rotor is 50 × 10². Determine Inertia Constant H and Angular Momentum M.*

Solution. Kinetic Energy stored in Rotor $KE = \frac{1}{2} J\,\omega^2$ joules

J = Moment of inertia. Given $J = 50 \times 10^2$ kg m²

N_s = Synchronous speed for 2 pole 60 Hz = $120\, f/p$

$= 120 \times 60/2 = 3600$ rpm

= Angular speed of rotor at Synch. speed rad/sec.

$= 2\pi N/60 = 2\pi \times 3600/60$

$$\text{K.E. (stored)} = \frac{1}{2}(50 \times 10^2)(2\pi \times 3600/60)^2 = 35553 \times 10 \,..\, \text{J}$$

$$= 3553.1 \text{ MJ}$$

Inertia Constant $$H = \frac{\text{K. E. (Stored)}}{\text{MVA rating}}$$

$$= \text{MJ/MVA} = 3553/100 = 355.31 \text{ MJ/MVA}$$

Angular momentum $$M = \frac{GH}{180f} = \frac{100 \times 35.33}{180 \times 60} = 0.329 \text{ MJs/ele.degree} \quad \textbf{Ans.}$$

[For MJs/radians, use factor 2π rad = 180°]

Table 44.4. Quantities related with Kinetic Energy of a Rotating Mass

Symbol	*Quantity*	*Equation*	*Units*
θ	Angular displacement		radius
ω	Angular velocity	$\omega = \frac{d\theta}{dt}$	$\frac{\text{radians}}{\text{second}}$
J* or *I	Moment of inertia	$J = \int r^2\, dm$ for complete rotor dm = mass of element at radius r	kg–metre²
KE	Kinetic energy	$\frac{1}{2}J\omega^2$	Joules
M	Angular momentum at angular velocity W	$J\omega \times 10^{-6}$	$\frac{\text{Mega-joules}}{\text{Radians}}$
G	MVA Rating of the synchronous machine	$G = VI\sqrt{3}\, 10^{-6}$	MVA
H	Inertia constant	$\frac{\text{Stored energy}}{\text{MVA rating}}$	$\frac{\text{Mega-joules}}{\text{MVA}}$
GH	Stored energy in complete rotor including shaft and connected machine at a synchronous speed	$GH = \frac{1}{2}J\omega \times 10^{-6}$ $= \frac{1}{2}M\omega,$ where, $\mathbf{M} = \frac{\text{Megajoules sec}}{\text{Elec. Degree}}$ $\omega = \frac{\text{Elec. Degree}}{\text{Sec.}}$	Megajoules
M	Angular momentum	$M = \frac{GH}{180f}$ $= \frac{GH}{\pi f}$	$\frac{\text{Mega-joule sec}}{\text{Elec. Degree}}$ $\frac{\text{Mega-joule sec}}{\text{Elec. Radians}}$

Note. Bold, dark print refers to Mega-Units.

44.5. SWING CURVE

During steady state, when the machine is running at constant speed the rate of change of power angle (δ) with respect to time (t), *i.e.* d/dt is zero. The angle δ is the angle between the axis of stator-rotating magnetic field and the rotor-pole axis; both rotating at synchronous speed.

When the load on the synchronous machine is changed, the angle δ changes to attain a new value corresponding to the new load situation, and $d\delta/dt$ is not zero, during the swing.

The graph of δ *versus* time t is called *Swing Curve.* The swing- curve is useful in predicting the stability as follows. If the swing curve is such that the value of load angle δ starts reducing after reaching the maximum value and tends to attain a steady new value; the system will *not* loose stability. It will come to a equilibrium position after the oscillations are damped out (Fig. 44.8 Curve B). (If oscillations are sustained with time, are not damped out, the phenomenon is called Hunting).

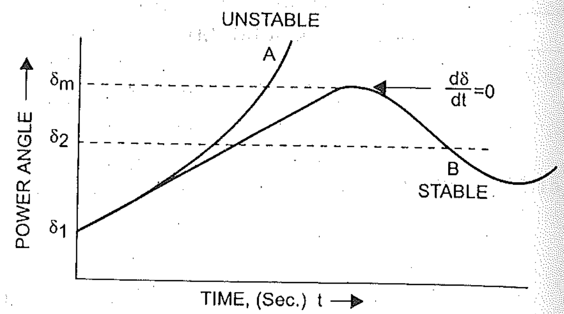


Fig. 44.8. Swing Curve.

If the swing curve is such that the angle goes on increasing and does not come to a equilibrium with time, the system will loose stability (Fig. 44.3.7 Curve A).

Refer Fig. 44.8 Curve B. This swing curve indicates that $d\delta/dt$ is maximum during initial straight portion of the swing curve. Then it goes on reducing and becomes zero at P_{max}. After this $d\delta/dt$ becomes negative (negative slope). Thus the δ oscillates about the desired value. The oscillations are damped out with time and finally attains a steady desired value corresponding to the new load. The fact that $d\delta/dt$ is reducing after attaining zero value at the peak of first swing indicates stability. Thus from the observation of the 'Swing Curve', *i.e.* the graph of load angle δ *versus* time t, we note :

1. If during the first swing, $d\delta/dt$ goes on reducing and reaches zero value and then reverses, the condition indicates stability.

2. If $d\delta/dt$ goes on increasing and $d\delta/dt$ does not reduce with time, the δ goes beyond 90° electrical and the interlocking between stator flux and rotor poles is lost and the machine looses synchronism. The stability is lost. The swing equation co-relates the following quantities related with a synchronous machine.

Angular Momentum	$\mathbf{M} \ldots \dfrac{\text{Mega Joule sec.}}{\text{electrical degree}}$
Load Angle	δ ... Elect. degree
Time	t ... Sec.
Accelerating Power	P_a ... Mega watt.
Electrical Power	P_e ... Mega watts
Shaft Power (Mechanical)	P_s Megawatts.

The solution of the swing equation (by step-by-step method) gives the value of load angle for different values of time. From this solution the swing curve of δ *versus* time can be plotted and the stability can be predicted.

Statement of the Swing Equation :

$$\mathbf{M}\frac{d^2\delta}{dt^2} = P_a = P_s - P_e \qquad \ldots(44.20)$$

where P_a = Acceleration Power ... MW

P_s = Shaft Power ... MW

$\mathbf{M}$ = Angular Momentum ... $\dfrac{\text{Mega Joule sec.}}{\text{elect. degree}}$

We know, from Eq. 44.3

$$P_e = \frac{VE}{X}\sin\delta \qquad \ldots(44.3)$$

Substituting in Eq. 44.20, we get the Swing Equation as :

$$\mathbf{M}\frac{d^2\delta}{dt^2} = P_a = P_s - \frac{VE\sin\delta}{X} \qquad \ldots(44.21)$$

From Eq. 44.4 (b),

$$\mathbf{M}\frac{d^2\delta}{dt^2} = P_s - P_{max}\sin\delta \qquad \ldots(44.22)$$

44.6. DERIVATION OF SWING EQUATION FROM FUNDAMENTALS

The *Swing Equation* co-relates the angular momentum **M** and angular acceleration $\dfrac{d^2\delta}{dt^2}$. The swing equation is applicable to synchronous motors and synchronous generators. Consider a synchronous machine. It develops certain electromagnetic torque to the rotor shaft. If electromagnetic torque T_e and shaft torque T_s are *not* equal, the rotor will accelerate or decelerate.

If electrical torque T_e and shaft torque T_s are equal then the rotor acceleration will be zero.

Consider the stator-rotating magnetic field axis as a reference. The acceleration/deceleration of the rotor can then be expressed in terms of $d^2\delta/dt^2$, where δ is the angle between rotor pole axis and stator-rotating magnetic field axis.

Thus we get following quantities :

T_a = Accelerating torque

T_s = Shaft torque

T_e = Electromagnetic torque.

Difference between shaft Torque and Electrical Torque gives Accelerating Torque. Hence

Accelerating Torque = Shaft Torque − Electromagnetic Torque

$$T_a = T_s - T_e \qquad \ldots(44.13)$$

But Power = Torque × Angular Velocity

i.e. $P = T\omega$

i.e. $P_a = T_e\omega\,;\ P_s = T_e\omega\,;\ P_e = T_e\omega$ ...(44.14)

Hence, $P_e = P_s - P_e$

Accelerating Power = Shaft Power − Electromagnetic Power

$$T_a\omega = T_s\omega - T_e\omega$$

Thus, we get

$$\boxed{\begin{array}{ccccc} \text{Accelerating Power} & = & \text{Shaft Power} & - & \text{Electromagnetic Power} \\ P_a & = & P_s & - & P_e \end{array}} \qquad \ldots(44.15)$$

For *generator* the shaft torque is input and the electromagnetic torque is output. *In Eq. (44.13) and Eq. (44.15) the terms are considered positive for synchronous generator.*

In shaft torque T_s for generator is higher than electromagnetic torque T_e then the rotor will accelerate and T_a is positive. Thus for *generator* the terms T_a, T_s and T_e are positive and shaft torque T_s > Electromagnetic Torque.

Likewise for *Synchronous motor,* shaft torque T_s is output and considered negative ; electromagnetic torque T_e is input and is considered positive.

Thus, for Eqs. (44.13) and (44.15).

For Generating Action T and P_s positive.

For Motor Action T_s and P_s negative.

Now, Power = Torque × Angular Acceleration.

Therefore,

Accelerating Power = Accelerating Torque × Angular Acceleration

$$P_a = T_a \cdot \omega$$

As Torque = Moment of Inertia × Angular Acceleration

$$T_a = Ja$$

Hence $P_a = J\alpha\,\omega = (Ja)\,\omega$

But $= J\omega = M$

Hence $P_a = Ma$

$$a = \text{Angular Acceleration} = \frac{d^2\delta}{dt^2}$$

Hence
$$P_a = M\frac{d^2\delta}{dt^2} \quad \text{...(44.16)}$$

From Eq. (44.15) and Eq. (44.16)

$$P_a = P_s - P_e = M\frac{d^2\delta}{dt^2} \quad \text{...(44.17)}$$

This is called Swing Equation.

From Eq. (44.3), $P_e = \frac{VE}{X}\sin\delta.$

Hence the Swing equation (44.17) can be rewritten as

$$\boxed{\begin{aligned} P_a &= P_s - \frac{VE}{X}\sin\delta = M\frac{d^2\delta}{dt^2} \\ P_a &= P_s - P_e = M\frac{d^2\delta}{dt^2} \end{aligned}} \quad \text{...(44.18)}$$

where, P_e = Electromagnetic Power $= (VE/X \sin\delta)$; P_a = Accelerating Power

P_s = Shaft Power (Mechanical Power) ; V = Terminal Voltage

E = Excitation e.m.f., induced e.m.f. ; X = Synchronous Reactance

δ = Load angle between E and V ; M = Angular Momentum,

t = time.

Solution of Swing equation gives values of δ for various values of t. The graph of load angle δ versus time t gives Swing curve. Swing curve is useful in indicating whether the system is stable or unstable. *Swing equation gives correlation between mechanical power, electrical power and the load angle* δ. Under **steady condition** when shaft power and electrical power are equal and the variation of load angle δ with respect to time is zero.

$$M = \frac{d^2\delta}{dt^2} = P_s - P_e = 0$$

and the machine is operating at constant δ corresponding to power $VE\sin\delta/X$. However, when the load changes, the angle δ undergoes a swing with respect to time for a short time of the order of a few seconds. The variation of δ with respect to time is given by equation and the graph is called Swing Curve.

Example 44.5. *A 4 pole, 50 Hz, 12.5 kV Turbogenerator is rated 200 MVA. Its inertia constant H is 8.0 MJ/MVA.*

Determine :

(*a*) *Stored energy in rotor at its synchronous speed.*

(*b*) *If mechanical input to shaft suddenly raised from 100 MW to 160 MW, find rotor angle acceleration neglecting electrical and mechanical losses.*

Solution.

(*a*) Stored Energy $= GH = 200 \times 8 =$ **1600 MJ Ans.**

(*b*) Accelerating Power = Shaft Power − Original Power

$$P_a = P_s - P_e = 160 - 100 = 60 \text{ MW}$$

From Swing Eq.
$$M\frac{d^2\delta}{dt^2} = P_s - P_e = 60$$

$$M = \frac{GH}{180f} = \frac{1600}{180 \times 50} = \frac{8}{45} = \text{MJ sec/elec. deg.}$$

Hence
$$\frac{8}{45}\frac{d^2\delta}{dt^2} = 60$$

Hence
$$\frac{d^2\delta}{dt^2} = \text{Angular Acceleration} = \frac{60 \times 45}{8}$$

$$= 337.5 \text{ elec. degree/sec}^2 \quad \textbf{Ans.}$$

Example 44.6. *Stored Kinetic Energy K.E. in the rotor of a 50 MVA, 60 Hz, six-pole synchronous alternator is 200 MJ. While accelerating, the machine is developing power of 22.5 MW while the input is 25 MW. Calculate the Angular Momentum M and the acceleration of rotor.*

Accelerating power $P_a = P_S - P_e = 25 - 22.5 = 2.5$ MW

Further,

Inertia constant H of machine $= \frac{\text{K.E. (stored)}}{\text{MVA rating}} = \frac{200}{50} = 4$

$$M = \frac{GH}{180f} = \frac{50 \times 4}{180 \times 60} = 0.0185 \text{ MJ.s/elec. degree}$$

$$2\pi \text{ rad} = 180 \text{ elec. degrees}$$

$$M = 1.06 \text{ MJs/rad}$$

$$M\frac{d^2\delta}{dt^2} = P_a = P_s - P_e = 25 - 22.5 = 2.5 \text{ MW}$$

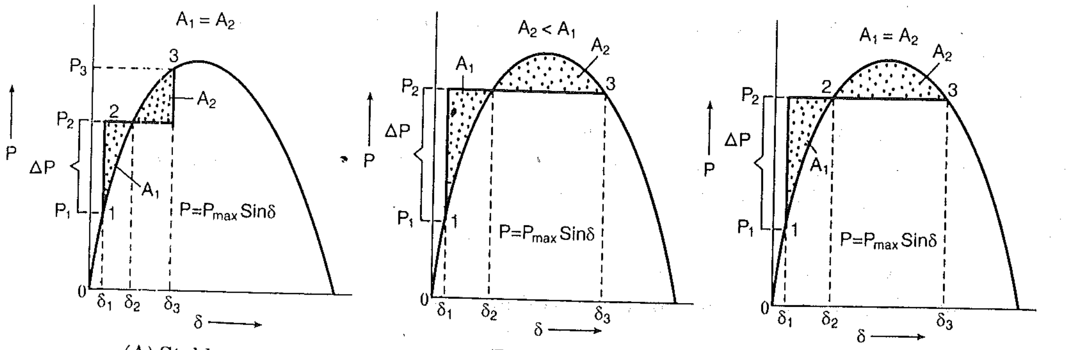
Hence acceleration
$$d^2\delta/dt^2 = \frac{2.5}{1.06} = 2.35 \text{ rad/sec.}^2$$

PART C. EQUAL AREA CRITERION

44.7. EQUAL AREA CRITERION OF TRANSIENT STABILITY

This is a simple graphical method to predict the transient stability of two machine system or a single machine against infinite bus. This criterion (method of evaluation/prediction) does not require Swing equation or solution of swing equation to determine stability conditions. *The stability conditions are determined by equating the areas of segments on the Power Angle Diagram between the P-curve and the new power transfer line for the given conditions.*

Refer Fig. 44.10 explaining the Equal Area Criterion. The Power-angle diagram of P (Power Transfer) Versus (Power angle) δ is drawn for the given single or two machine system. Let the



(A) Stable (B) Unstable (C) TR. Stability limit

Fig. 44.10. Explaining equal area criterion of transient stability.

Initial Conditions be P_1, δ_1 at point 1. The position of initial power P_1 and corresponding power angle δ_1 are marked, point 1 on the power-angle curve corresponds to $P_1 = P_{max} \sin \delta_1$. Let a sudden increase in power transfer be ΔP. The power-angle should take a new final steady-state position δ corresponding to the new power $P_2 = P_1 + \Delta P$. The point 2 on the power angle curve corresponds to the new load condition P_2 and corresponding required steady state power angle δ_2. *However since the change in power transfer ΔP is suddenly supplied, the angle (δ) overshoot the desired position (δ) due to the inertia of the rotor upto (δ_3) and then comes back towards (δ_2) under the stable conditions. The power angle (δ) oscillates about the mean desired position δ_2.* The oscillations are damped out by system resistance, governor action and voltage regulators.

Finally the position of (δ_2) corresponding to new *Power P_2 2 is reached. Fig. 44.10A indicates a stable condition.* In Fig. 43.10*A*, the point 3 on the power curve is graphically located such that the Area A_1 (between the δ_1 and δ_2) is equal to Area A_2 above the P_2, below power curve P and the limiting load angles δ_2 and δ_3, *i.e.* $A_1 = \int_{\delta_1}^{\delta_2} (P_2 - P_1)\, d\delta$ is equal to $A_2 = \int_{\delta_2}^{\delta_3} (P_3 - P_2)\, d\delta$. If $A_2 = A_2$; the retarding torque A_1 is equal to accelerating torque A_1 and system is stable.

The conditions of initial load P_1, change in load ΔP and power angle diagram P are such that a point 3 is available on the curve for which $A_1 = A_2$. This is the criterion of Equal Areas – to predict transient stability.

Refer Fig. 44.10B which indicates unstable condition. Hence point 3 has reached extreme position corresponding to δ_2 such that the further movement of point P along the curve does not give any area above the horizontal line P_2 and $A_2 < A_1$. *In such a case, where a point 3 is not available on the power curve* for which area $A_1 = Area\ A_2$, *the system is unstable* (Fig. 44.10*B*).

For transient stability under given conditions of P_1, ΔP and the power-angle diagram the system remain stable if a point is available on the power angle diagram such that $A_1 = A_3$. If such a point (3) is not available on the curve and $A_2 < A_3$, the system is unstable. This rule of determining transient stability of a system by equating the areas of segments, on power angle diagram is called Equal Area Criterion (Method) of transient stability.

Refer 44.10*C*. For given initial condition of P_1, δ_1 there is a limiting value of sudden increase in load ΔP, such that area, A_2 above the power line P_2 has reached its maximum limit and $A_2 = A_1$. In such case, P_2 is the maximum permissible power transfer after the application of increased load and is called transient stability limit of the system for given conditions of initial load P_1 and increase in load ΔP.

Mathematical Derivation of Equal Area Criterion

Consider area of Power Angle Diagram between the given limits. Dimensionally it has units of (Power × Electrical Radians) = (Energy) or (Work done). Consider the Swing Equations :

$$\mathbf{M}\frac{d^2\delta}{dt^2} = P_1 - P_2 = P_1 - \frac{VE}{X}\sin\delta_2 \qquad \text{...(44.19)}$$

where $\mathbf{M}$ = Angular momentum of rotor

P_1 = Shaft power, mechanical power

P_2 = New Steady State Electrical Power $= \frac{VE}{X}\sin\delta_2$

X = Reactance between V and E

δ = Angle between V and E, Power Angle

P_2, P_1 refer to steady state condition.

Multiply both sides of the Eqn. 44.19 by $\frac{d}{dt}$

$$\mathbf{M}\frac{d^2\delta}{dt^2}\frac{d\delta}{dt} = (P_1 - P_2)\frac{d\delta}{dt} \qquad \text{...(44.20)}$$

But
$$\frac{d}{dt}\left(\frac{d\delta}{dt}\right)^2 = d\,\frac{d\delta}{dt}\cdot\frac{d^2\delta}{dt^2}$$

Hence,
$$\frac{1}{2}\mathbf{M}\frac{d}{dt}\left[\left(\frac{d\delta}{dt}\right)^2\right] = (P_s - P_2)\cdot\frac{d\delta}{dt} \qquad \text{...(44.21)}$$

i.e.
$$\frac{d}{dt}\left[\left(\frac{d\delta}{dt}\right)^2\right] = 2\,(P_1 - P_2)\frac{d\delta}{dt}\cdot\frac{1}{\mathbf{M}} \qquad \text{...(44.22)}$$

Integrating with respect to t,

$$\left(\frac{d\delta}{dt}\right)^2 = 2\int\frac{(P_1 - P_2)\,d\delta}{\mathbf{M}} \qquad \text{...(44.23)}$$

Therefore,
$$\frac{d\delta}{dt} = \sqrt{2\int\frac{(P_1 - P_2)\,d\delta}{\mathbf{M}}} \qquad \text{...(44.24)}$$

Considering $\frac{d\delta}{dt}$ as the slope of the swing curve (δ versus t), for stability, the swing should reach a maximum value and then start reducing, *i.e.* $d\delta/dt$ should reach zero, maximum swing. (at δ_{max}). Hence, for stability,

$$\frac{d\delta}{dt} = 0$$

$$\int_1^3 (P_1 - P_2)\,d\delta = 0 \qquad \text{...(44.25)}$$

Putting the limits from initial condition $\delta = 1$ to final condition $\delta = 3$.
Referring Fig. 44.10 *B*,

$$A_1 = \int_1^3 (P_1 - P_2)\ d\delta\ ;\ \ A_2 = \int_2^3 (P_e - P_2)\,d\delta$$

$$A_1 - A_2 = \int_1^3 (P_1 - P_2)\,d\delta - \int_2^3 (P_3 - P_2)\,d\delta$$

which gives
$$A_1 - A_2 = \int_1^2 (P_1 - P_2)\,d\delta \qquad \text{...(44.26)}$$

from Eqns. 44.25 and 44.26,

$$\textbf{For Stability} \int_1^3 (P_1 - P_2)\, d\delta = A_1 - A_2 = 0$$

$$A_1 = A_2 \qquad \ldots(44.27)$$

Transient Stability of Transmission System having Parallel lines will be reviewed in the next section.

Solution for δ_2

From Fig. 44.10 (*c*), applying Equal Area Criterion, for Stability, Area A_1 = Area A_2

$$\int_{\delta_1}^{\delta_2} (P_2 - P_{max} \sin\theta)\, d\delta = \int_{\delta_2}^{\delta_3} (P_{max} \sin\delta - P_2)$$

After performing integrations, we get

$$P_2(\delta_2, \delta_1) + P_{max}(\cos\delta_2 - \cos\delta_1) = P_2(\delta_2 - \delta_3) - P_{max}(\cos\delta_2 - \cos\delta_3)$$

However, $P_2 = P_{max} \sin\delta_2$, Hence

$$(\delta_3 - \delta_1)\sin\delta_2 + \cos\delta_3 - \cos\delta_1 = 0 \qquad \ldots(44.28)$$

From given values of δ_1 and δ_2, the Eqn. 44.28 can be solved for δ_3.

Example 44.7. *A synchronous generator is capable of developing maximum power P_{max} of 500 MW is operating at initial power angle of 8°.*

(*A*) *How much power is being delivered at δ = 8° ?*

(*B*) *How much can the shaft power be increased suddenly without loss of transient stability ?*

Solution. Maximum power P_{max} occurs at power angle δ = 90° degrees. For other power angles, $P_o = P_{max} \sin\delta = 500 \sin\delta$

(A) Power developed at δ = 8°, $P_{8°} = 500 \sin 8° = 69.6$ MW **Ans.**

(B) Let initial angle δ = 8°

Sudden increase in load up to angle θ without losing synchronism should bring is to be calculated. Let δ_2 be the rotor angle to which rotor can swing without losing synchronism. Then as per Equal Area Criterion, $\delta_m = \pi - \delta_1$

From Eqn. 44.28, substituting $\delta_3 = \pi - \delta_1$, we get

$$(\pi - \delta_2 - \delta_1)\sin\delta_2 + \cos(\pi - \delta_2)\cos\delta_1 = 0$$

$$(\pi - \delta_2 - \delta_1)\sin\delta_2 - \cos\delta_2 - \cos\delta_1 = 0 \qquad \ldots(44.29)$$

In given problem, $\delta_1 = 8 = 0.13885$ rad, Substituting in Eqn. 44.29,

$$(3.14 - \delta_2 = 0.138)\sin\delta_2 - \cos\delta_2 - 0.99 = 0$$

Solving, we get $\delta_2 = 50°$, corrresponding power

$$= P_{max}\sin\delta_2 = 500 \cdot \sin 50 = 383 \text{ MW}$$

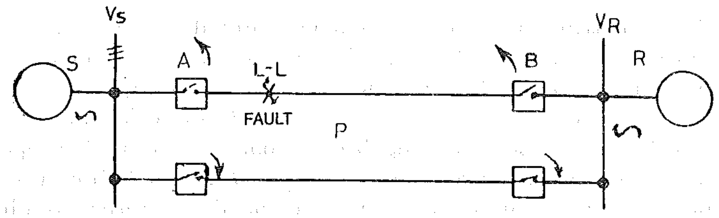
$$P_2 = 383 \text{ MW}$$

Permissible sudden additional loading without loss of transient stability with initial rotor angle 8° is :

$$P_2 - P_1 = 383 - 69.6 = 313.4 \text{ MW} \quad \textbf{Ans.}$$

44.8. CRITICAL CLEARING ANGLE

Refer Fig. 44.11 explaining the transient stability of parallel transmission line system between two distant generating stations *S* and *R*.



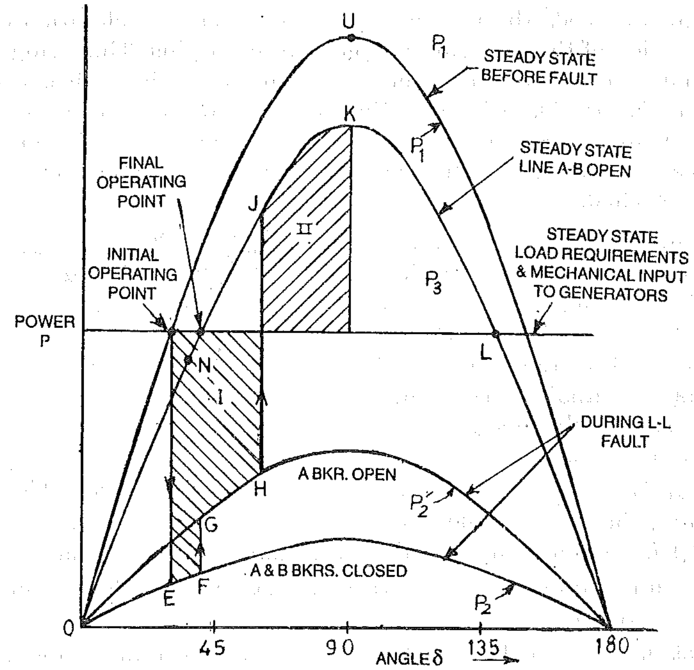


Fig. 44.11. Power transfer curves before, during and after line-to-line fault.

Power transfer from *S* to *R* is given by the equation $P = V_S V_R \sin\delta/X$, where V_S and V_R are bus voltages ; δ is the angle between V_S, V_R and *X* is the reactance of transmission line.

Transient stability is defined as the ability to properly adjust to (remain in synchronism) sudden *large* changes in the system, (load changes, faults and switching). Three phase faults are the most severe type of fault as far as stability is concerned since the voltage is reduced on all phases. *The effect of faults on power transmission is in increase the equivalent series reactance, X, and therefore, decrease the electrical power that can be transmitted.* During the fault the electrical output of the sending and generators is less than the mechanical input, so that they speed up, increasing angle, δ_2. At the same time the rotating equipment at the receiving end slow down, since the load is greater than the mechanical input to the receiving end generators. The receiving and slow down further increases angle δ.

Refer Fig. 14.11, which gives the following four power angle curves for the power transfer between *S* and *R*.

Curve P_1 = Steady state *P vs.* δ before fault

Curve P_2 = Both Breakers *A*, *B* closed, power transfer *P* is minimum.

Curve P_2^1 = Only breaker *A* opened.

Curve P_3 = Both Breaker *A* and *B* opened.

Curves 1, 2, 3, 4 are drawn from corresponding steady state. Power equation $P = (V_S V_R / X \sin\delta$, where V_1, V_2, *X* depend on the condition of fault and breaker position.

Transient stability of the transmission system is determined by means of Equal Area Criterion considering the sequence of events 1, 2, 3, 4 and the Swing of angle δ on corresponding segments of power curves. The events occur in the sequence 1, 2, 3, 4. During this disturbance the power angle swings about its mean position. When the line-to-line fault occurs, the transmitted power is reduced to point E, and the swing begins along E-F. At point F, breaker A, opens and the transmitted power increases to G. The swing continues along G-H and at H the fault is cleared. By the time H is reached, the sending end rotor inertia has increased, as represented by area I, since the mechanical input has exceeded the transmitted electrical power. With the fault cleared the transmitted power is J, which exceeds the mechanical input, so that deceleration of the sending end generation and acceleration of the receiving end generation begins. The swing continues to point A, where the additional sending end rotor inertia resulting from the fault is completely absorbed by the load (Area II equals Area I). Since at K, the electrical output of the sending end exceeds the mechanical input, the swing reverses until a point such as N, where the swing reverses again. Voltage regulator and governor action, as well as system resistance, will dampen the oscillation, until the operating point is reached.

Note that if the initial swing went as far as point L and the sending end generators still had excess rotor inertia (Area II smaller than Area I), the swing would continue in the same direction and the system would go out-of-step. When point L is passed, the mechanical input of the sending end generators again exceeds the electrical output and the swing becomes accelerated.

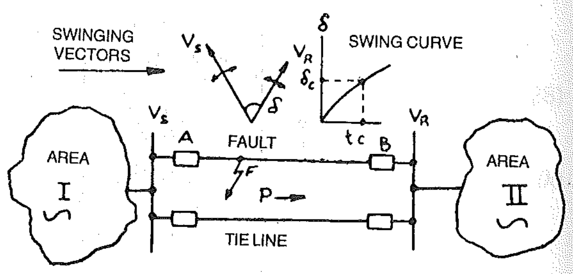


Fig. 44.12.

By opening circuit-breaker A, B on both sides of the faulty line ; the power angle curve jumps from (P_2) to (P_3), *i.e.* power transfer ability of the single line CD is more than power transfer of double line with one line faulty. During the transient state, early clearing of faulty line (Point H) will reduce accelerating area (I).

If faulty line is not cleared quickly, area I increases. There is a limiting value of clearing angle δ_c and corresponding clearing time T_c (obtained from swing curve δ *vs.* t) such that the faulty line *must* be opened before the swing reaches δ_c , *i.e.* the breakers A, B should be opened and fault cleared before time t_c corresponding to power angle c. This limiting value of δ_c and t_c are illustrated in Figs. 44.12 and 44.13.

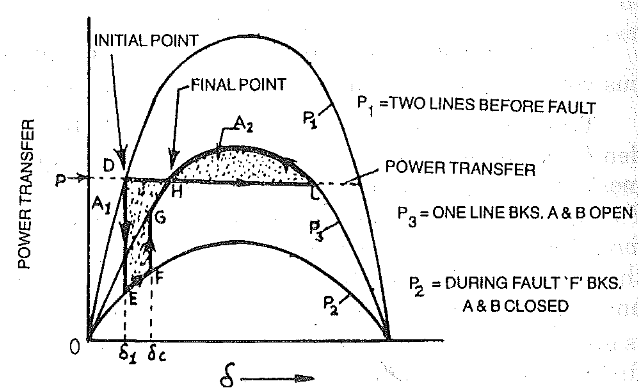


Fig. 44.13.

Refer Figs. 44.12 and 44.13 explaining Critical Clearing Angle, P is the power transfer from area I to II. *δ_c is the critical clearing angle between V_S and V_R such that area A_1 is equal to area A_2 and area A_2 has reached maximum limit. Any further increase in angle δ_c will increase area A_1 and the $A_2 < A_1$ and stability would be lost.*

Mathematical Expression for Critical Angle δ_c

Refer Fig. 44.12. Explaining critical clearing δ_c

Let δ_1, P = Initial point on curve P_{1max}

δ_c = Critical clearing angle

P_{2max} = Maximum power transfer during fault

P_{3max} = Maximum power transfer with fault cleared and faulty line open.

P = Initial operating point for stability limit.

Critical clearing angle δ_c is obtained by applying Equal Area Criterion to Fig. 44.12, *i.e.*

$$\int_{\delta_1}^{\delta_c} (P - P_{2max} \sin \delta)\, d\delta + \int_{\delta_c}^{\delta_3} (P - P_{3max} \sin \delta)\, d\delta = o$$

$$\therefore \quad \left[P\delta + P_{2max} \cos \delta\right]_{\delta_1}^{\delta_c} + \left[P\delta + P_2 \cos \delta\right]_{\delta_c}^{\delta_3}$$

As $$\delta_3 = 180° = \sin^{-1}\left(\frac{P}{P_{3max}}\right)$$

$$\cos \delta_c = \frac{P(\delta_1 - \delta_3) + P_{2max} \cos \delta_1 - \delta_{3max} \cos \delta_3}{P_{2max} - P_{3max}}.$$

Critical angle δ_c can be calculated by using the above expression instead of graphical solution.

Example 44.8. Critical Clearing Angle. *A synchronous generator at 50 Hz is on load of 1 p.u. connected to infinite bus. Resistance is neglected.*

The maximum possible power transfer under healthy condition (steady state stability limit) is 1.8 p.u.

During a fault, the maximum possible power transfer (steady state) is 0.4 p.u.

During post fault condition, after fault clearing the limit of power transfer limit is 1.3 p.u.

Determine the critical clearing angle either graphically or by calculations.

Solution. Draw Fig. 44.12 in which

$$\left.\begin{array}{ll} \text{Peak of curve } P_t : & P_{2max} = 0.4 \\ \text{Peak of curve } P_3 : & P_{3max} = 1.3 \\ \text{Peak of curve } P_1 : & P_{1max} = 1.8 \\ \text{Power Transfer at } \delta_1 & = 1 \text{ p.u.} \end{array}\right\} \text{given}$$

δ is to be determined.

Graphically

Draw P such that Area $DEFGH$ = Area HLH

Adjust δ_c finally to get $A_1 = A_2$.

Alternatively

Use expression 44.20 $\quad \delta_1 = \sin^{-1}\left(\frac{1}{1.8}\right) = 33.8$ elect. degrees

$$\delta_3 = 180 - \sin^{-1}\frac{P}{P_{3max}} = 80 - \sin^{-1}\left(\frac{1}{1.3}\right)$$

$$= 180 - 50°24' = 129°\ 36'.$$

Critical Clearing Angle δ_c

$$\cos^{-1} \delta_c = \frac{P(\delta_1 - \delta_3) + P_{2max} \cos \delta_1 - P_{3max} \cos \delta_3}{P_{2max} - P_{3max}}$$

$$= 1(33.8 - 129.5) + 0.4 \times 0.83 + 1.3 \times 0.77 = 0.377.$$

Hence δ_c = **67° 52'** (Electrical) **Ans.**

44.9. METHOD OF IMPROVING TRANSIENT STABILITY LIMIT

— increasing switching system voltage (Refer Eq. 44.2)

— reduction of series reactance X by introducing parallel lines (Refer Eq. 44.1).

- use of high speed circuit breakers.
- use of high speed protecting relaying.
- use of carrier current protection to obtain simultaneous opening of circuit-breakers on either end of transmission lines.
- use of auto-reclosure.
- use of single pole switching.
- use of single pole auto-reclosure.
- use of series capacitors to reduce reactance.
- use of HVDC transmission with damping control.

As seen from Eqs. (44.1) and (44.2), by increasing the voltage at station buses, P_{max}, *i.e.* steady state stability limit increases.

The power curve is raised when P_{max} is increased. This allows larger limits of swinging of angle δ. Thus raising P_{max} increases critical time and possibility of maintaining stability for given disturbance.

Reducing in series reactance results in increase in P_{max}. Parallel transmission lines reduce equivalent reactance as compared with a single line. Secondly, when fault occurs on one of the lines, the other line continues supplying power. Thus power transfer capability during fault condition is increased.

Faster fault clearing always results in reduction in disturbance. There is a limiting fault clearing time called 'critical fault clearing time' before which the fault should be cleared by opening of circuit-breakers for the system to maintain stability. The use of high speed circuit-breakers, therefore, improve the stability. This method is more convenient than those which need changes in design of system.

44.10. HIGH SPEED CIRCUIT BREAKERS AND FAST PROTECTIVE RELAYING FOR IMPROVED TRANSIENT STABILITY.

By high speed circuit-breakers, we now mean, circuit-breakers of operating time less than 3 cycles. Fast relaying refers to instantaneous relaying assisted by carrier current protection for transmission systems.

Details about fault clearing time, relay time and circuit-breaker time are given in chapter 2.

Fig. 44.14 (*a*) illustrates a simple system subjected to various types of faults such as (*P*) single line to ground, (*Q*) Line to line, (*R*) Double line to ground, (*S*). Three phase fault; at sending end on one of the lines. The limit of power that can be transferred for duration of faults is plotted on Fig. 44.14 (*b*). The circuit-breakers at both ends of the line are simultaneously opened. From the graph it is visualised that *"Power transfer limit for given type of fault, for given system configuration can be increased by reducing the fault clearing time"*.

Hence fast and simultaneous opening circuit-breakers at both end of transmission lines improves the transient stability limit. Therefore, *for important bulk power transmission lines and interconnectors fast circuit-breakers, carrier current protection or pilot wire-differential protection, static relays having better and faster characteristics are desirable.* The higher cost is justified by the increased limit of power transfer.

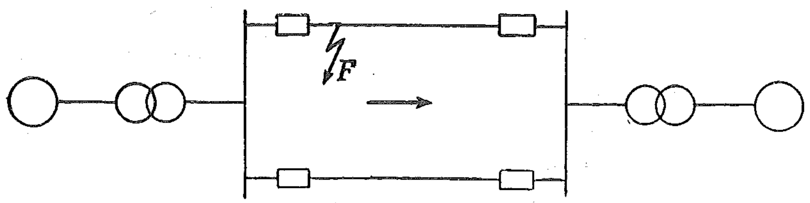
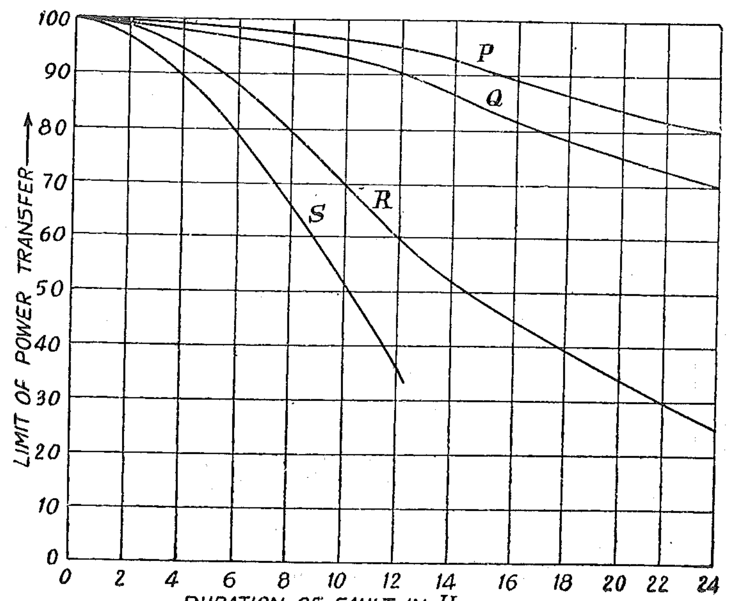


Fig. 44.14 (*a*). The system subjected to fault F at sending end on one of the two lines.



P = Single line to round fault
Q = Line to line fault
R = Double line to ground fault
S = Three phase fault.

Fig. 44.14 (*b*). Effect of duration of fault on limit of power transfer for various types of fault.

Consider a two machine system with double circuit interconnection (Fig. 44.15).

Table 44.1. Required Operating Time of Circuit Breakers and Protective Relaying Function with Reference to American Grid

Function	*Time in Cycles 1 Cycle = 1/60 sec*	
	EHV-AC Lines	*UHV-AC Lines*
Primary Relay	1 – 2	0.5 – 10
Circuit-breaker	1.5 – 2 – 3	1 – 2 – 2.25
Current Detector Dropout	0.5 – 2	0.25 – 0.5
Margin	3.5 – 6	3
Auxiliary Relay	1	0.25 – 0.5
Back-up Breaker Clearing	2 – 3	2 – 2.5
Total Time	10.5 – 17.0	8 – 10.5
Representative Total Time	12	9

In this system, assume that phase-to-phase fault occur between breakers *A* and *B* which is cleared by high speed relay scheme simultaneously at both *A* and *B*. During the time the fault exists, the equivalent transfer reactance between the sending and the receiving ends of the system is increased. Because of fault power there is a decrease in the electrical power that can be transferred.

This reduction can be represented on the power angle diagram as *DE*. While the fault is on the angle δ increase but assuming high speed relaying and fast breakers *A* and *B* the fault is isolated from the system quickly. During the fault, the power transfer and increase in angle δ is defined by the curve *EF*. When the breakers open the reactance between the sending and receiving ends of the system is reduced but not to its original value, because line *A* – *B* is open. The transmitted power then appreciably increases and operation shifts instantaneously from *F* to *G*. This electrical power output is still below the initial operating point, so the sending generators continue to accelerate until point *N* is reached where the electrical power output equals the initial power output and the mechanical input.

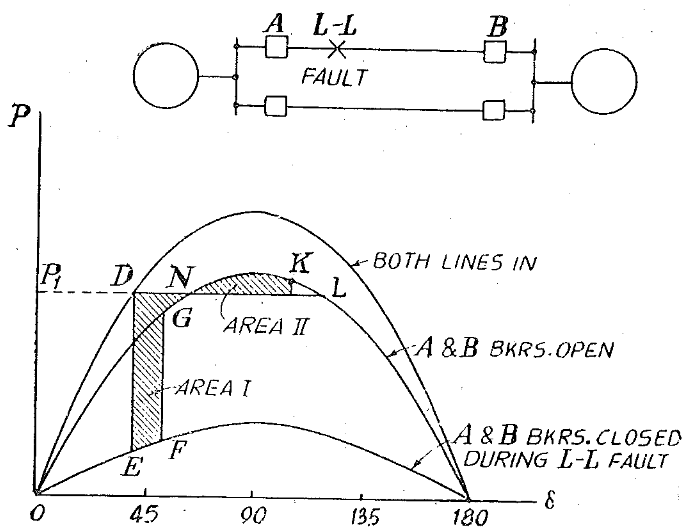


Fig. 44.15. Power angle diagram before, during and after line-to-line fault.

However, this is not the end of the swing because sending generators are still going faster than the machines at the receiving end of the system. Neglecting losses the swing will continue to point K where area II equals area I. Provided the area NKL under the curve and above line P_1 is greater than the area I of $DEFGN$ the system will ultimately reach equilibrium at a final operating point N. If the area NKL is less than area, I, the system will not maintain stability.

For any given power transfer P, there is a **critical clearing angle**. Unless the fault is cleared before the power angle δ reaches angle, the system loses synchronism. For larger power transfer, therefore, faster fault clearing is required to ensure stability. This demands for fast relaying and fast circuit-breakers. The distance relays should be stable during power swings.

44.11. AUTO-RECLOSURE IMPROVES TRANSIENT STABILITY

Rapid auto-reclosure of circuit-breakers at both the ends of transmission lines is advantageous.

The benefits of automatic high-speed reclosing can be represented on the power angle diagram, a system is shown in Fig. 44.16, where if line $A-B$ is opened accidently at either line terminal with an initial power flow P_1, the stability limit will be exceeded. This can be determined by the

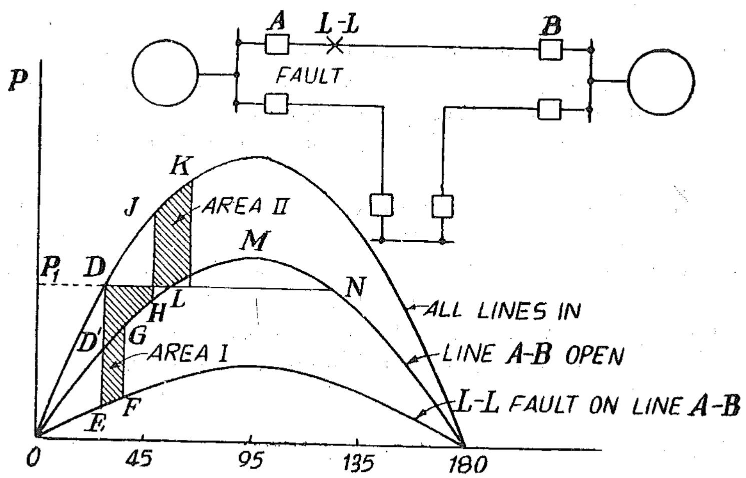


Fig. 44.16. Power angle diagram for L-L fault with rapid reclosing.

equal area criterion, where area $DD'GHL$ below the P_1 line is larger than the area LMN above P_1. However, rapid reclosing after a fault clearing would permit stable operation.

(Refer Fig. 44.16). Upon the occurrence of a fault as shown on line $A-B$, the electrical power flow drops to E. During the fault the angle increases from E to F. With simultaneous fault clearing the power flow instantly increases from F to G. With line $A-B$ open δ continues to increase until at H the breakers at both A and B are reclosed. Now the power instantly increases from H to J, and the system will continue to swing to K until area II equals area I. Equilibrium will finally be reached again at D.

Thus the rapid auto-reclosure of circuit breakers at either ends of the line in the event of fault, improves the transient stability of system. And the power that can be transferred can be increased with the use of auto-reclosure systems.

44.12. SINGLE POLE RECLOSING OF CIRCUIT-BREAKERS

Where bulk power is transmitted, single pole reclosing has certain advantages. In single pole switching, the protective relaying and breaker operating mechanism is such that single pole of breaker can be opened for fault on the corresponding phase. The unfaulted phases continue getting power. Since most single line to ground faults are temporary in nature, auto-reclosure can be readily applied to such schemes. The merits of single pole switching are the following :

— the healthy phases continue to supply power and only faulty phase is opened. Therefore, power transfer is more than three pole opening.

— single pole reclosing further improves the power transfer limit (Fig. 44.17).

— the power transfer on fault can be substantially increased for single pole auto-reclosure schemes.

Single pole reclosing breakers and single pole relaying are more expensive because three independent mechanisms and complex relaying are required.

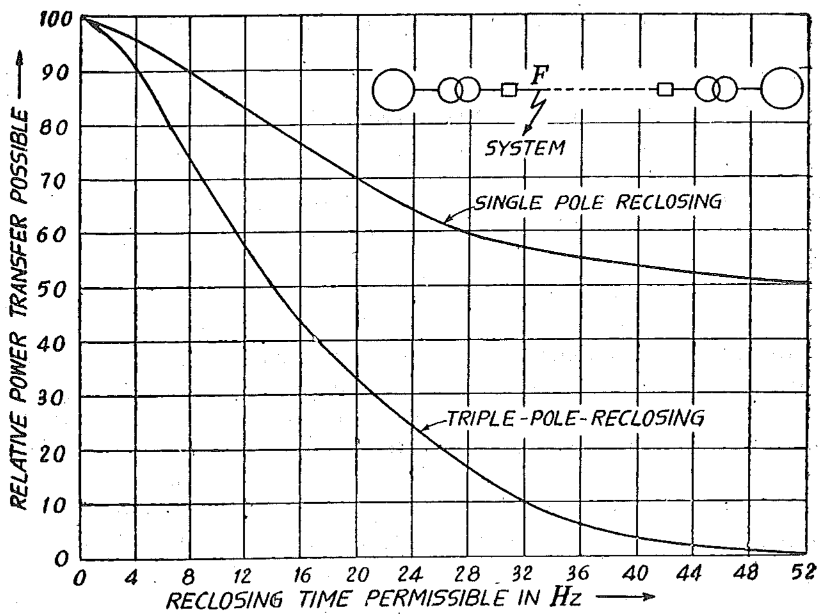


Fig. 44.17. Comparison between three-phase auto-reclosure and single phase auto-reclosure.

Choice of Autoreclosing schemes varies in different countries.
About 93% E.H.V. Schemes in U.S.S.R. are with three phase autoreclosure.

44.13. INDEPENDENT POLE MECHANISM

It refers to the use of separate mechanism for each pole of the breaker. Recent 245 kV and 420 kV circuit-breakers are provided with this feature. In this feature, although the breaker poles operate independent of each other, the relaying may be arranged to trip all three poles for some types of fault.

44.14. SINGLE POLE TRIPPING*

It refers to use of separate operating mechanical for each pole and use of relaying such that for single line to ground fault on a phase, only the pole of faulty phase is tripped. For other fault such as phase-phase, double line-to-ground, three phase; all the three poles are tripped. The relaying required for such tripping is more complicated. However, where large generating station is tied to a single transmission line, such a scheme is preferred.

44.15. SELECTIVE POLE TRIPPING

It is a new system, in which the relaying is such that the faulty phases are tripped for corresponding type at fault, *i.e.*

L-G fault — Only one ; affected phase operated

$\left.\begin{matrix} 2L\text{-}G \text{ fault} \\ L\text{-}L \text{ fault}\end{matrix}\right\}$ — Two, affected phases opened

3-Phase fault — All three phases opened.

Selective pole tripping can provide adequate improvement in stability to satisfy many system requirements.

Independent pole operation requires three independent operating mechanisms on the circuit-breaker, one for each pole. These are *not* mechanically connected in any way. Three separate trip coils are required for primary relaying, one for each pole. In case of double trip-coil schemes where trip coil for primary and back-up are provided on same breaker, totally six trip coils would be necessary.

44.16. SEGREGATED PHASE COMPARISON RELAYING (SPCR)**

(*Courtesy* : Westinghouse Electric Corporation, U.S.A.)

Independent pole operation of power circuit-breakers requires segregated phase relaying. Segregated Phase Relaying developed by Westinghouse Electric Corporation, USA facilitates Independent Pole Protection.

The SPCR scheme compares the phase (angular) position of current in each phase (and ground) separately. The comparisons are based on square waves derives directly from raw (unfiltered) power system currents. This approach compares with conventional phase-comparison schemes that compares a single square-waves train derived from a three-phase network of sequence fitters and mixing transformer, as depicted in Fig. 44.18. There are many variations of that conventional phase-comparison technique - some use two separate comparisons, one for positive sequence and one for negative sequence. However, all incorporate positive sequence and/or negative sequence networks and, therefore, are vulnerable to abnormal frequencies and phase impedance imbalances.

The new approach, shown in Fig. 44.19 consists of four separate sub-systems-three phases and ground. The ground sub-system is included to protect against the single-line-to-line ground fault with high fault resistance and heavy through-load, and to provide back up detection for all normal ground faults.

* Power system is not allowed to operate with unbalanced condition for more than 1 second. All three poles are opened after unsuccessful single pole autoreclosing.

** Segregate = To set apart, to separate.

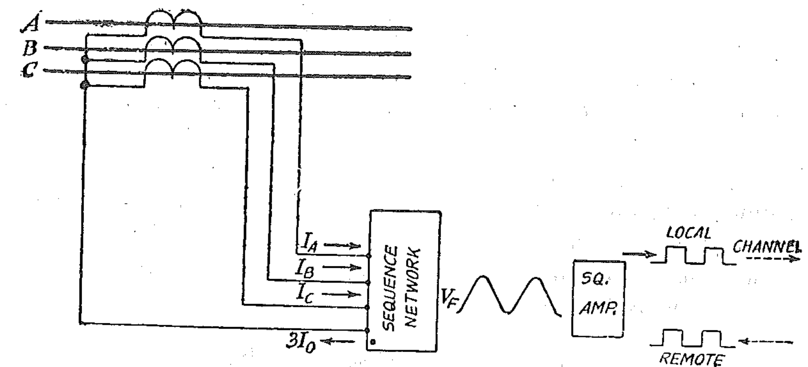


Fig. 44.18. Carrier signals in conventional phase comparison relaying.

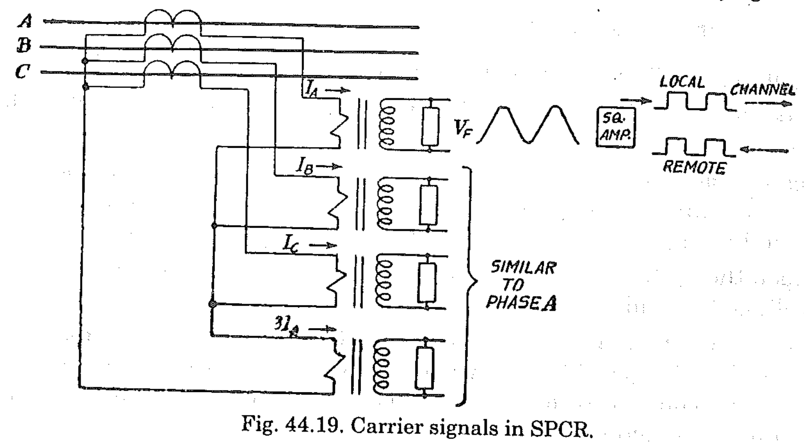


Fig. 44.19. Carrier signals in SPCR.

The main *disadvantages* of the isolated phase approach is the requirement for four separate pilot signals (*A, B, C* and *G*) per terminal. However, offsetting those disadvantages are many relaying *advantages.*

1. The SPCU approach overcomes the three major problems of series compensated lines — abnormal frequencies, phase impedance unbalance, voltage reversals.

2. High speed operation, due to angle diversity between phase and eliminated of filters required in conventional phase comparison circuitry.

3. Inherent redundancy because for sub-systems back-up each other.

4. All the advantages of carrier current relaying : not responsive to power swings, not subject to mutual inductance problems, unaffected by loss of potential, relays correctly operate for 3-phase zero voltage faults and unaffected by voltage transients.

5. Phase isolation, independent pole concept extended to relays and circuit-breakers.

6. Inherent phase selectively for all types of faults which alone with phase isolation provides greater flexibility in system design.

44.17. INFLUENCE OF POWER SWINGS ON TRANSMISSION LINE PROTECTION

A sudden change in loading on transmission lines causes change in the power angle and the power angle δ oscillates about its new equilibrium position. This produces power swings resulting in heavy equalizing currents in the transmission lines. The power swings influence the distance protection. The distance protection should be such that it should be stable over a wide range of power swings and does not trip unselectively if power swings subsides to normal within reasonable time. But if special conditions arise, such as very large oscillations following a sudden disconnection of large load, load shedding, clearance of fault, etc. It is necessary to use additional *out of step block-*

ing or *out of step tripping* relays. The selection and location of these relays is made after study and analysis of network.

The starting element of a distance relay usually responds to overcurrent or minimum impedance.

During power swings there is flow of equalising currents in transmission lines. Since the phenomenon is symmetrical in all three phases the swing causes starting elements to pick-up in the *three* phases during power swings.

Since starting element pick-up during power swings, it becomes a task of the measuring elements to decide whether the system should be tripped or locked.

PART D : AUTORECLOSING

44.18. AUTORECLOSING SCHEMES

Autoreclosing of high voltage a.c. circuit-breakers has been covered in chapter 2.

These sections may please be referred. In this chapter we will study autoreclosing schemes with static relays.

Autoreclosing schemes can be regarded as an inherent features of protection system and network automation. The ultimate aim of Autoreclosing is to eliminate the supply interruption due to temporary faults and to improve transient stability limit (Refer Sec. 44.5).

Depending upon the system requirements there can be five varieties of autoreclosing schemes in today's high-voltage transmission systems.

1. **Rapid autoreclosing scheme to improve stability and prevent loss of synchronism.** In cases where there is a danger of losing synchronism, non-repetitive rapid autoreclosing is used for one or three phases. The first reclosure can be critical from stability considerations (Refer Fig. 44.7). Hence the process should not be repeated.

Before systems can be interconnected, there must be synchronised. For this purpose a quick-acting automatic synchronizer can be used instead of mutual synchronizing process. The automatic synchronizer is used in conjunction with autoreclosing equipment.

2. **Delayed Autoreclosing Schemes.** Delayed autoreclosing is used appropriately meshed networks where synchronism is maintained during the dead time after the line interruption. A rapid autoreclosing scheme can also be continued with several delayed autoreclosing versions.

3. **Autoreclosing Schemes with Desired Switching Sequence.** In cases where a circuit-breaker in conjunction with isolators, interrupts several lines (as in stations with ring buses), the autoreclosing scheme must ensure that the switching sequence follows a correct pattern. Therefore, such autoreclosing scheme must have a certain built-in logic so the correct autoreclosing sequence is carried out in spite of large number of switching combinations required in a particular power system.

4. **Programmed Autoreclosing and Programmed Interruption.** A further step is scheme for power system with central monitoring system which involves not only programmed autoreclosure but also programmed interruptions.

5. **Multi-shot Autoreclosing for Low Power Distribution Lines** (Refer Fig. 2.14). *Autoreclosing is adopted only for over-head lines. It is not used for* underground cables or gas insulated cables, generator circuit-breakers etc.

44.19. TERMS AND DEFINITIONS REGARDING AUTORECLOSING

1. **Autoreclosing.** The process of automatic closing of a circuit-breaker after its opening.

2. **Single Shot Autoreclosing.** A scheme providing only one reclosing operation, lock-out of circuit-breaker follows if breaker opens after first reclosure.

3. **Rapid (high speed) Autoreclosing.** A scheme in which the circuit-breaker is reclosed within 0.3 second after the fault trip operation.

4. **Delayed (low-speed) Autoreclosing.** A scheme in which the CB relcoses more than 1 sec. after the fault trip operation.

5. **Lock-out.** A feature in autoreclosing scheme, which prevents closing of the circuit-breaker after its second tripping.

6. **Antipumping.** A feature in autoreclosing scheme which prevents repeated $C - O$ operations even if closing impulse continues to be prevented.

7. **Time Designations.** (Refer Fig. 44.20).

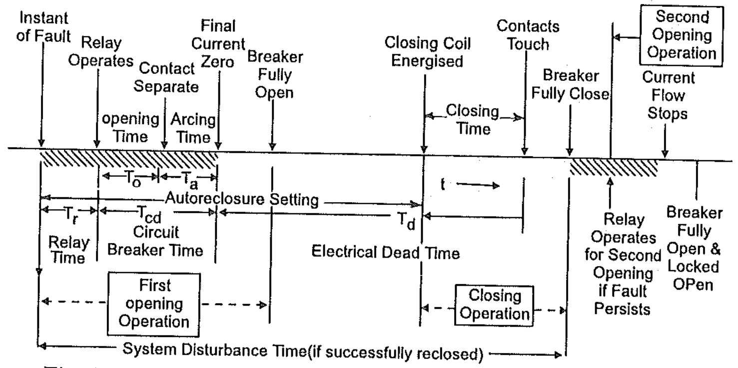


Fig. 44.20. Sequential events in single shot autoreclosing scheme.
(Chapter 2 for detailed description)

(*a*) **Fault Clearing Time T_f.** Time between occurrence of fault and final arc extinction in circuit-breaker.

(*b*) **Relay Time, T_r.** Time between occurrence of fault and closing of tripping contacts or energising of shunt trip release.

(*c*) **Opening time of C.B. T_o.** Time between energising of shunt trip release and opening of circuit-breaker contacts.

(*d*) **Arcing Time of C.B. (T_a).** Time between separation of circuit-breaker contacts and final current zero.

(*e*) Total fault clearing time = Relay time + Circuit-breaker time

$$T_f = T_r + T_{cb} = T_r + (T_o + T_a)$$

(*f*) **Dead Time T_d (of CB). Time between final current zero of first opening and contact touch during subsequent reclosing.**

(*g*) **De-ionizing Time (of Transmission Line Fault).** Time for deionizing the arc space after opening of circuit-breaker. (Refer Ch. 2).

(*h*) **System Disturbance Time.** Time between occurrence of fault and successful reclosing of contacts.

44.20. RAPID AUTORECLOSING SCHEME

Rapid single shot auto-reclosing scheme must always be considered as integral part of line protection. Whether the auto-reclosing should be single phase or three-phase and the optimum dead time depends on system studies carried out on transient network analyzer and digital computer. The present trend is to have carrier aided distance protection schemes for long transmission lines and carrier current phase comparison protection for relatively short lines upto say 50 km length.

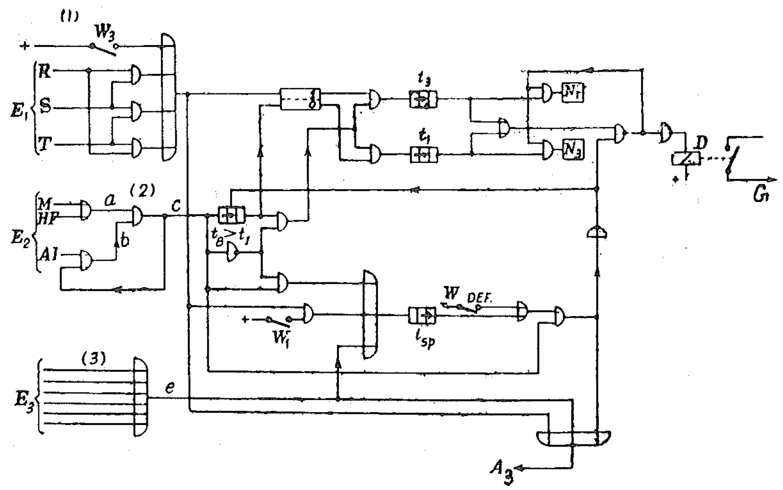
The Distance Protection Scheme provided for long transmission lines are fitted with Autoreclosing Apparatus (Refer Ch. 42).

Recently Directional wave Relays are used in conjunction with distance protection.

In static distance protection schemes, although the auto-reclosing unit is a self-contained unit, it is designed as a functional unit, it is designed as a functional accessory of the distance relay. (Refer Ch. 42). The general trend is to combine the whole protection system for each line in one cabinet. Thus static auto-reclosing scheme should be selected as an integrated aspect of static distance protection scheme. The basic advantage include the reduction of space and reduced time of installation and commissioning (in addition to advantages mentioned in Ch. 42).

Static autoreclosing schemes comprise integrated circuit logic elements (Refer Ch. 38). The logic elements include flip flops AND, NAND, NOR, Time delay etc.

Fig. 44.21 give a logic diagram of a static reclosing unit for a commercial static distance relay.



AI = Current through the circuit-breaker tripping coil
D = Contactor
E_2 = Inputs for instigating single or three-phase reclosure
G = Reclosure
K = Flip-flop (signals 1 at both inputs result in a 1 single at output 1)
N_1, N_3 = Counters for single-phase or three-phase reclosing
W = Selector switch (see Table)
t_B = Operating time (release time) Reclosure signal 1 appears at output only if there is also a 1 signal at the side input
t_1, t_3 = Dead time of signal-phase or three phase reclosing.

C = Outputs of (2), (3) respectively.
A_3 = To distance relay trip for effection three-phase interruption
E_1 = Inputs for instigating three-phase reclosure
E_2 = Inputs for blocking reclosure : such as time zones of distance relay, air pressure monitor, switching, etc.
HF = High-frequency trip
M = Distance measurement
R, S, T = Phase selection signals
W_{Def} = Breaker lock-out
I_{sf} = Blocking time
d = Output of sub circuit (1)

Fig. 44.21. Logic diagram of a static rapid reclosing unit accompany a distance protection for rapid autoreclosing scheme (*Courtesy* : Brown Boveri, Switzerland)

The autoreclosing unit described above is used in conjunction with tripping circuits of the distance relays.

The selection of such that

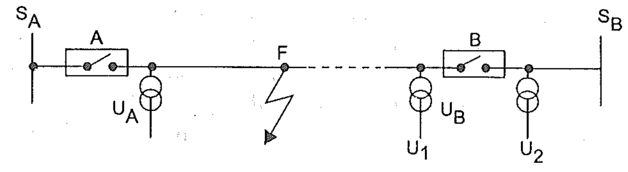
— all three phases trip if a single phase faults occurs while the reclosure is blocked, or
— all three phases trip when three phase tripping is required for all types of faults.

In general the autoreclosing scheme used for other types of protection schemes (differential directional comparison, phase comparison) is also similar to the above mentioned scheme.

44.21. DELAYED AUTORECLOSING SCHEME

As mentioned earlier, on highly interconnected meshed systems, loss of single line is not likely to cause these two sections of the system to drift apart and lose synchronism. Delayed Autoreclosing is preferred in such cases.

Delayed autoreclosing can also be employed as follow-up of an unsuccessful rapid auto-reclosing. The object of delayed reclosure is to reclose after a delay of several seconds, following an unsuccessful rapid auto-reclosing such schemes are used in Switzerland.



S_A, S_B Substations
U_A, U_B Voltage-transformers
U_2 Busbar voltage.
A, B Circuit-breakers
U_1 Line voltage

Fig. 44.22. Explaining delayed autoreclosing.

In highly interconnected meshed network, delayed auto-reclosing has an advantage over rapid autoreclosing that the line is not likely to close on to a likely existing fault immediately after interruption and at higher generator excitation. The delayed reclosure permits the generator excitation to be reduced to normal level before the reclosing takes place. In England, the Central Electricity Generating Board (CEGB) employ delayed autoreclosure with dead times of the order of 5 — 60 seconds. The analysis of relative performances of rapid reclosing and delayed reclosing system showed was as follows :

Rapid auto-reclosing : 68% successful reclosure

Delayed auto-reclosing : 78% successful reclosure

Thus the probability of successful reclosure increases with delayed reclosing.

Some design features. In rapid auto-reclosing principle, the line is reclosed at both ends simultaneously without voltage monitoring.

44.22. SYNCHRONISM CHECK

Consider delayed auto-reclosing of line circuit-breakers A, B interconnecting sub-stations S_A and T_B. It is presumed that the system is quite stable and opening of line AB has not resulted in loss of stability however this could result in voltage phase difference between ends A and B. Hence reclosing of line A and B, after a delay could result in on unacceptable shock of the system.

It is a usual practice to incorporate a synchronism monitor relay in the reclosing system to determine whether auto-reclosing can take place. The synchronism monitor relay gives a three-fold check between voltages on both sides of circuit-breaker.

— phase angle difference in voltages
— voltage magnitude difference
— frequency difference.

Phase Angle Difference. Suppose circuit-breaker B is being closed. U_1 and U_2 are voltages on either sides (Refer Figs. 44.22 and 44.23). Voltage U_2 will oscillate with respect to vector U_1. When the phase angle between U_1 and U_2 is less than say ± 30° (shaded area) the contacts of synchronism monitor relay close.

(Refer Fig. 44.23). Vectors U_1 and U_2 oscillate with respect to each other. When they fall within shaded area, the phase difference is less than 30° and contacts of synchronous monitor close. When they are beyond the shaded area, the phase angle is more than 30° the contacts of synchronous monitor remain open and closing relay of auto-reclosing scheme is blocked out. It takes the next opportunity when the two vectors come near synchronism again.

The voltage check incorporated when the synchronism monitor prevents reclosure if any of the voltages U_1 and U_2 are less than predetermined value (say 80% U_n).

The frequency difference check is generally based on a timer in conjunction with phase difference relay. When the two frequencies are nearly equal, the phase difference between voltage vectors varies very slowly. For example, a relay closes only if phase difference between voltage vectors does not exceeded 30° over a period of 2 seconds. This limits the frequency difference between two vectors to a maximum of 0.19% of 50 Hz.

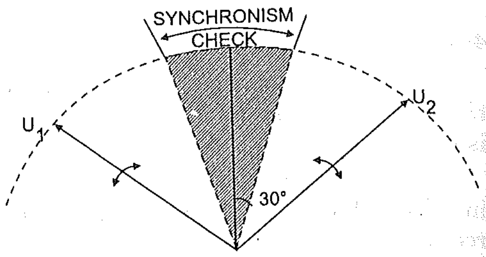


Fig. 44.23. Condition for closure of synchronism monitor contracts.

The delayed reclosing permits enough time to carry out the synchronising check.

Sequence of Delayed Reclosing the Circuit Breaker. Consider the tripping of line AB on fault. The normal practice is to reclose the breaker at one end first. This is called 'dead line charging'. Closing of this breaker, say A, does not require synchronism check. Reclosing at other end B is then under the control of synchronism monitor and is called live line reclosing.

The dead time selected for reclosing A and B are different. For example, if dead time for dead line reclosing (A) is set at say 6 seconds, the corresponding dead time for live line reclosing (breaker B) is of the order of 16 seconds. The events for autoreclosing sequence for breakers A and B are then as follows :

Table 44.3

Sequence of delayed reclosing of circuit breakers A and B. (Refer Fig. 44.21).

(1)	$t = 0$	Fault occurred
(2)	$t = 0.1$ sec	Circuit-breakers A and B open and make the line dead.
(3)	$t = 6$ sec.	Voltage monitor relay at A check whether line is dead and then reclose breaker A.
(4)	$t = 16$ sec.	Synchronism monitor at B check the synchronism between charged line and busbar B and then permit reclosing the circuit-breaker B.

Under-voltage Relay. The end of the line which closes first, (A is this case, Refer Fig. 44.22) connects the dead line to busbar S_A. An undervoltage relay is used for measuring the line voltage to establish categorically that the line is dead. The undervoltage relay is set very low (8 to 10 V for normal voltage $U_n = 110$ V) is connected to the lines a voltage transformer U_A.

44.23. CONTROL SCHEMES FOR AUTO-RECLOSING

As mentioned earlier, the autoreclosing device is a part of line protection scheme. Hence it is to be incorporated with the type of line protection. (Distance/differential/overcurrent/carrier aided directional comparison/phase comparison). The auto-reclosing device is initiated automatically by one of the following means :

— Circuit-breaker auxiliary contact

When circuit-breaker opens on fault, the auxiliary switch also operates and closes the circuit which initiates auto reclosing device.

— Protective relay contacts.

This method is preferred because it prevents accidental reclosing.

The distance relays incorporate starting element operates and initiates auto-reclosing scheme. Any interlock needed to prevent the initiation can be devices through AND circuit on an-interlock contact in series with the starting element contact.

For example in air blast circuit-breakers, the pressure switches contacts for low-pressure locking may be connected in series with starting element of distance relay and auto-reclosing relay so that breaker does not reclose during low air pressure.

Summary

Power system stability refers to condition during which the synchronous machines in the system have ability to remain in synchronism. Transient Stability Limit refers to the maximum power that can be transferred through a point after the given sudden large disturbance without causing loss of synchronism.

Transient stability limit of transmission system can be improved by several means such as

— fast fault clearing by means of fast circuit-breakers and fast relays. [One cycle relay and two cycle C.B.]

— auto-reclosing circuit breakers.

— single pole switching.

— single pole auto-reclosure, etc. [Also refer Sec. 18.26]

The distance relays should remain stable for permissible power swings. Beyond these limits, out-of-steps blocking or out-of-step tripping is resorted to.

Autoreclosing refers to the reclosing or circuit breaker after its opening on fault. Autoreclosing feature is provided for protection of overhead transmission lines.

— single phase or three phase autoreclosing.

— rapid autoreclosing

— delayed autoreclosing

Rapid autoreclosing is preferred for transmission lines whose disconnection for longer time can cause loss of synchronism. Delayed auto-reclosing is preferred for reclosing transmission lines large interconnected (meshed) systems in which delay in reclosing does not affect the system stability substantially.

PART E. MODERN DEFINITIONS OF POWER SYSTEM DISTURBANCE, STABILITY

44.24. TERMS AND DEFINITIONS IN POWER SYSTEM STABILITY STUDIES (1980)

Power System Stability has been an area of study from the early days of electrical power generation and transmission. This subject has become very important as the various power systems over large geographic areas has been interconnected to form a network. Long distance high power EHV transmission lines have been introduced. Sophisticated equipment have been added for control, automation and protection. Better Mathematical models and computer softwares have been established for analysing and predicting transient stability.

Considering these aspects, the terms and definitions have been revised by CIGRE and IEEE.

1. **Power System.** A network of one or more electrical generating units, loads, power transmission lines, including the associated equipment connected to the networks.

2. **Operating Quantities of a Power System.** Physical quantities, which can be measured or calculated that can be used to describe the operating conditions of a power system.

Note. Operating quantities include r.m.s. values of corresponding phasors of alternating or oscillating quantities.

3. **Steady-state operating condition of power system.** An operating condition of a power system in which all of the operating quantities that characterize it can be considered to be constant for the purpose of analysis.

4. **Synchronous Operation**

4.1. **Synchronous operation of a machine.** A machine is in synchronous operation with a network or another machine to which it is connected if its average electrical speed (products of its rotor-angular velocity and the number of pole pairs) is equal to the angular frequency to the a.c. network voltage or to the electrical speed of the other machine.

4.2. **Synchronous Operation of the Power System.** A power system is in synchronous operation if all its connected synchronous machines are in synchronous operation with the a.c. network and with each other.

5. **Asynchronous Operation**

5.1. **Asynchronous operation of a machine.** A machine is in asynchronous operation with a network or another machine to which it is connected if it is not in synchronous operation.

5.2. **Asynchronous operation of a power system.** A power system is in asynchronous operation if *one or more* of or its connected synchronous machines are in asynchronous operation.

Note. The term 'non-synchronous' is some times used as a synonym for 'asynchronous'.

6. **Hunting of a Machine.** A machine is hunting if any of its operating quantities experience sustained oscillations.

7. **Disturbance in a Power System.** A disturbance in a power system is a sudden change or a sequence of changes in one or more of the parameters of the system, or in one or more of the operating quantities.

7.1. **Small disturbance in a Power System.** A small disturbance for which the equations that describe the dynamics of the power system may be linearized for the purpose of analysis.

7.2. **Large Disturbance in Power System.** A large disturbance is a disturbance for which the equations that described the dynamics of the power system cannot be linearized for the purpose of analysis.

8. **Steady-state Stability of a Power System.** A power system is a steady state stable for a particular steady state operating condition if, following any small disturbance, it reaches a steady state operating condition which is identical or close to the pre-disturbance operating condition. This is also known as *Small Disturbance Stability of a Power System.*

9. **Transient Stability of a Power System.** A power System is transiently stable for a particular steady-state operating condition and for a particular disturbance, if reaches an acceptable steady-state operating condition.

10. **Power System Stability Limits**

10.1. **Steady-state Stability Limits.** The steady-state stability limit is a steady-state operating condition for which the power system is steady state but for which an arbitrarily small change in any of the operating quantities in an unfavourable direction causes the power system to lose stability. This is also known as the *small disturbance stability limit.*

10.2. **Transient Stability Limit.** The transient stability limit for a particular disturbance is the steady-state operating condition for which the power system is transiently stable for which an arbitrarily small change in any of the operating quantities is an unfavourable direction causes the power system to lose stability for that distance.

11. **Critical Clearance Time.** If a particular disturbance includes the initiation and isolation of a fault on a power system, the critical clearing time is the maximum time between the initiation and isolation such that the power system is transiently stable.

12. **Monotonic Instability.** A power system is monotonically unstable for particular steady-state operating condition if following a disturbance its instability is caused by insufficiently synchronizing torque.

Note. The trajectory for monotonic instability may not be strictly monotonic or have less than one oscillation. The main criterion is insufficient synchronizing torque and the nomenclature is

derived historically from the fact that in most cases for such instability the trajectories are monotonic.

13. **Oscillatory Instability.** A power system is oscillatorily unstable for a particular steady-state operating condition if following a disturbance its instability is caused by insufficient damping torque.

14. *Power System* includes not only generators and transmission lines but also associated equipments such as turbines, connected mechanical loads, control system etc. For analysis of the stability problem, the models of concerned significantly influencing equipment need only be considered and other parts of the systems are neglected. Power system is usually an interconnected grid which is divided into hierarchical areas and each area has its automatic control of load, frequency and stability. Power is exchanged between areas during normal condition and during emergency condition. When there is major disturbance in a part of a grid, that part is quickly isolated from the remaining system. To avoid the collapse of the whole grid, the network is Islanded or segregated during a major fault (Refer Ch. 45).

15. *Steady-state Operating Condition* does not exist truly in any power system because the disturbances such as load fluctuations, voltage fluctuations occur almost continuously. The steady state is assumed for the purpose of analysis-under such an assumed state that all the operating quantities are considered to be constant for the purpose of analysis.

16. *Loss of Synchronism* means transition from synchronous state to asynchronous state and is the usual indication of *Loss of Stability.* This is true only for purely a.c. system having only synchronous generators. With increased use of asynchronous generators and HVDC transmission, this is above concept does not apply to all the machines and all the transmission links. The power system of its parts may be in asynchronous operating condition. *e.g.* Two Areas connected by HVDC link may even operate at different frequencies and are as a rule *not* in synchronism with each other.

17. Synchronous operation of a machine is usually defined by average electrical speed. Instantaneous electrical speed may experience some deviation from synchronous speed *without* loosing synchronism. During and after the disturbance, machine rotors may 'Swing' from their steady state position but their average electrical speed over several seconds, should be same as synchronous speed if synchronism is not lost. It means, while analysing the swing and in the swing equation, the synchronous speed of rotor poles and the stator magnetic flux is assumed as the machine is running in synchronism. The swing in angle δ is with reference to the synchronous rotating axis.

18. *Hunting* is a special operating condition. Some quantities oscillate with constant, finite magnitudes with constant runs value of oscillation. This condition is considered as stable or unstable depending upon the other definitions applicable to stability. However, hunting comes in the category of steady state stability since r.m.s. values of oscillations are constant.

19. *Disturbance* refers to the *cause* of change in operating quantity. The analysis of the power system is usually performed in three categories (Ref. Sec. 50.8.2.) :

— Pre-disturbance steady operating state (Normal)

— During disturbance (Emergency)

— Post-disturbance steady operating state. (Restoration)

The disturbance is called 'small' or 'large' depending upon whether linear approximation of system model is valid or not. For small disturbance, linear approximation is valid.

Disturbance are usually made up of sequence of a sudden changes *e.g.*

"Occurrence of fault — opening of breaker — reclosing of breaker — opening for the second time — locked open".

this chain of events can be considered as one disturbance. The stability of the system is usually studied with reference to such a 'sequence of events' and not an individual 'event'.

20. *Natural or Inherent Stability* is a new term. A power system is inherently stable for a particular steady-state operating condition and particular disturbance is no automatic control action

is required to maintain stability. For example, if there is a sudden change in load and the system absorbs this change on its own, without loss of stability by adjustment of δ corresponding to new P, the system is inherently stable for given condition. (During 1970's, new automatic control systems and protection systems have been introduced to enhance (increase) transient stability limits. The inherent stability gets further improved by using such means).

21. The **short term stability** refers to behaviour for several seconds.

22. The **long term stability** refers to behaviour for period of more than several tens of seconds. For short term stability study, the faster automatic controls operating within a few tens of seconds (*e.g.* excitation control, governor control, circuit breaker operation etc.) are considered. For long term stability study, the slower controls operating in more than a few tens of seconds or minutes (*e.g.* Load-frequency control; load shedding, boiler control etc.) are considered. The exact time for short term and long term has not been defined. Sometimes a term : 'Mid-term stability' is used to bridge the gap.

Types of Instability. In some cases instability may be due to insufficiently synchronising torque. Such instability is called *Monotonic Instability.*

If instability is caused by insufficient damping torque, the term *oscillators instability* is used. In practice it caused by combination of 'monotonic' and 'oscillatory' causes. But for analysis and conceptual aid, these terms have been separately defined. By such a separation the most effective ways to stabilize the system can be pin-pointed.

Instability can also be caused by insufficient supply of reactive power resulting in voltage collapses. The instability caused by inadequate reactive power and fall of busbar, voltage is called *Voltage Instability.* However the term Voltage Instability is not used widely as yet (1982).

44.25. OPERATIONAL LIMITS WITH REFERENCE TO STEADY STATE STABILITY LIMIT AND TRANSIENT STABILITY LIMIT

The power transfer P is related with voltage V_s and V_R. From the equation, $P = (V_s V_R/X) \sin \delta$, and the study of the power angle diagrams for each synchronous machine and the transmission system, the operational limit are mainly concerned with maintaining the power transfer and the bus-voltages within limits to maintain transient stability.

(*A*) Under Normal operating conditions, Power transfer P should be of the order of 75% P_{max} where P_{max} is steady state stability limit ($V_S V_R/X$) for generator units.

During post fault conditions, the power transfer P may be as high as 90% P_{max} till the human intervention takes corrective action over from automatic process, for generator units.

For transmission systems, angle δ is kept within ± 30° for transfer stability.

$$P_{max} = \frac{1}{2} \frac{|V_s| \cdot |V_R|}{X}$$

(*B*) The busbar continuous voltages $|V_s|$ and $|V_R|$ should held within specified limits by controlling excitation, by tap changing transformers, by shunt compensation and series compensation etc. to maintain the steady state and transient stability limits. The limits of busbar voltages as per standards are as follows :

kV rms, Phase to Phase, steady state

Nominal rated voltage	33	66	132	220	400
Lower Limit of Rated voltage	30	60	120	200	380
Upper limit of rated voltage	36	72.5	145	245	420

(C) **Stability of Large Induction Motor Loads**

Large motors should run stably for busbar voltages upto 85% of normal rated voltage, under steady state loading condition.

During voltage dips due to faults somewhere else, the transient stability of loads will be affected. Special measure should be taken to provide for asynchronous operation, auto-reclosing/re-synchronizing etc., for large, important motors.

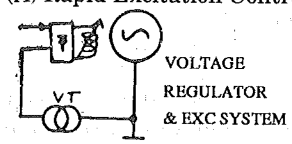
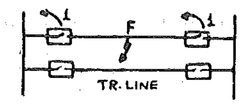
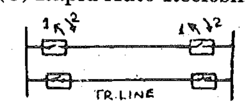
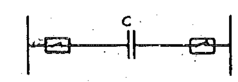
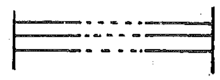
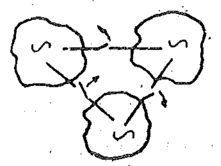
Large motors take high starting currents for a few seconds. The bus-voltage shall not dip below 85% under starting conditions.

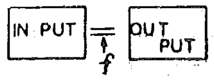
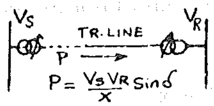
PART F : IMPROVEMENT IN STEADY STATE TRANSIENT STABILITY LIMITS

[*An integrated modern approach towards improving transient stability of interconnected Network (Grid),* transmission systems, synchronous machines].

Table *44 F* summarises the various methods of improving transient/steady state stability limits in modern power systems. Actually, these methods are interdependent. However, each method plays a significant role in improving stability of corresponding part of the system.

Table 44-F Methods of Improvement of Transient/Steady State Stability of Power System

Method	*Description*	*Reference*
(A) Rapid Excitation Control 	— Automatic Voltage Regulators — High Excitor Ceiling Voltage — Rapid Excitation Response.	Sec. 44.23-D
(B) Rapid Fault Clearing 	— Simultaneous operating of circuit-breakers on both ends of transmission line for rapid fault clearing.	Sec. 44.10
(C) Rapid Auto Reclosing 	— Rapid Autoreclosing of circuit-breakers for transient faults as overhead lines.	Sec. 44.18
(D) Series Capacitors Reduce X 	— Reduction in reactance of transmission line by use of series capacitors. Power transfer limit increased. — Use of controllable series capacitors.	Sec. 44.23-B
(E) Paralles Lines Reduce X 	— Reactance X reduced giving higher power transfer limit $V_s V_R/X$.	Sec. 44.23-B
(F) Network Islanding 	— Unstable Area segregated from neighbouring healthy Areas by automatic Network Islanding.	Sec. 45.9

Method	*Description*	*Reference*
(G) Load Frequency Control 	— Total generation in the Grid equal to total load. — Load frequency control and load shedding to maintain constant frequency.	Sec. 45.4
(H) Voltage Control 	— Voltage of sub-station buses held constant by voltage control techniques.	Ch. 45-B
(I) Use of HVDC Transmission with damping control.	— The power flow through HVDC link is modulated to damp system disturbances.	Sec. 44.23.4

44.26. METHODS OF IMPROVING TRANSIENT STABILITY LIMIT

Refer the power equations

$$P = \frac{|V_S| \cdot |V_R|}{X} \sin\delta \text{ for transmission lines}$$

$$P = \frac{|V| \cdot |E|}{X} \sin\delta \text{ for synchronous machine.}$$

The methods of improving steady state stability limit $P_{max} = \frac{|V_S| \cdot |V_R|}{X}$ or $\frac{|V_1| \cdot |E|}{X}$ gives corresponding improvement in the transient stability limit considering the increase in decelerating area available above the power line on the swing curve. Hence the improvements in transient stability can be explained by above steady state equation.

The methods of improvement of transient stability limit can be considered in four inter-dependent categories :

1. Methods associated with Network Stability.
2. Methods associated with Transmission Lines and Tie line stability.
3. Methods associated with circuit-breaker and protective Relays for transmission system and Network.
4. Methods associated with stability of synchronous machines. *This section gives an integrated approach to stability studies.*

(1) **Stability of the complete Network.** Power System means all the connected power stations. Synchronous machines in the Network are in synchronous operations with the A.C. network and with each other. If one or two connected power stations loose synchronism due to some disturbance, they should be isolated from the Network before the instability spreads to a larger part of the power system.

Frequency and rate of change of frequency of each generator and sub-station bus is monitored to judge the stability condition of the respective generating station and sub-station. The total generation is adjusted to match with the total load so as to maintain constant Frequency. Load-frequency control is monitored from the grid control centre, generating station control rooms and sub-station control rooms. The power system may be in :

— normal operation condition
— emergency condition (Major fault)
— transient from normal to emergency
— post-emergency condition during which the system is being brought to normal condition after the disturbance.

The steps associated with total network include —

1. Load-frequency control and system frequency control during normal and emergency condition post fault condition.

2. Back-up breaker operations. If fault is not cleared by main (Primary) breakers; the back-up breakers should be opened to clear the fault. When back-up breaker should be opened to cause least disturbance to the system ?

3. Network Islanding (segregation).

To split the network into appropriate islands to prevent cascade tripping and the total black-out.

4. Alternate routes of power transfer during emergency depending upon prevailing generation position in various areas and loading of lines.

5. Use of system Damping Resistors (SDR). These are switched in when faulty line is opened and are switched-off after reclosure.

6. Increasing interconnections (tie lines) to reduce reactance X and increase available power.

7. Adding transmission lines of higher voltage levels.

(2) *Method of improvement of Transient Stability of Transmission systems and Tie Lines, and Methods associated with Circuit-breakers and the Protection.*

2.1. *Adding Parallel lines* to increase power transfer ability. If single circuit transmission line has a reactance X, a double circuit line will have reactance $X/2$; corresponding steady state stability limit would be double.

$$P_{max} = \frac{|V_S| \cdot |V_R|}{X} \quad \text{... for Single Circuit line}$$

$$P_{max} = 2\frac{|V_S| \cdot |V_R|}{X} \quad \text{... for Double Circuit line.}$$

2.2. *Increasing the transmission voltages for higher power transfer.*

$$P_{max} = \frac{V_1 V_2}{X}$$

P_{max} for a 400 kV line would be approximately $4^2/2^2 = 4$ Times the P_{max} for 220 kV line.

2.3. *Isolating the faulty line from the system by using faster transmission line protection and use of fast circuit-breakers.* Opening the circuit-breakers at both ends of transmission line simultaneously with total fault clearing time of 3 to 4 cycles.

Relay Time = 1 cycle = 20 ms
Circuit-break time = 2 cycles = 40 ms
(Total break time) = (Circuit breaker time).
Total fault clearing time = 1 + 2 = 3 cycles = 60 ms

During the presence of fault, the line voltage falls equivalent resistance X between ends of transmission lines increases, Power Transfer Ability P between sending end and receiving end is reduced and power-angle curve is lowered.

Permissible duration of short-circuits in Network

Nominal Voltage kV	33	132	220	400	760
S.C. Duration seconds maximum	0.3	0.2	0.18	0.14	0.10

By operating the faulty line from both the ends simultaneously, the Power angle curve for the healthy line will be above the previous condition (faulty line in circuit), and stability limit is therefore, increased.

Secondly a continued fault on transmission line will result in loss of stability of stations in the sending end and receiving end. Opening the faulty line quickly will prevent the loss of stability of sending end receiving end stations.

2.4. *During major faults, the voltage collapses, fault current increases, power transfer reduces, frequency drops.* Hence faulty parts should be isolated as quickly as possible to prevent loss of stability of the corresponding part of the system.

2.5. *Rapid Auto-reclosing of circuit-breakers at both ends of the transmission lines (for temporary faults) improves the transient stability limit.* About 70% faults in power systems are on overhead transmission systems and are caused by temporary flashover.

Caused by birds or lightning over-voltages. The line can be safely put into service after certain minimum time for de-ionization of fault by automatic reclosing of circuit-breakers at both ends of the line. (Refer Sec. 2.12).

Overhead transmission lines for bulk power supply are provided with protection and circuit-breakers suitable for Rapid Auto-reclosing [0 – 3 sec – CO].

Single Pole Switching. For a single line fault on overhead transmission line, only the faulty phase may be opened and reclosed.

(Refer Sec. 45). The protection and circuit-breakers should be suitable for single-pole switching.

2.6. **Use of appropriate protection system for EHV, high power transmission lines.** The distance protection for transmission lines readily responds to power swings. The relays should have characteristics such that for permissible Power Swings during the disturbance, the relays are blocked (Refer Sec. 45).

During network islanding, the measurements by relays should be such that, the separation of two neutrals should be approximately at the electrical centre of the swing (Refer Sec. 43).

2.7. **Voltage Regulation and Excitation System.** Synchronous Generators have excitation winding on rotor supplied with low voltage d.c. current from the excitation system.

The terminal voltage V of a synchronous generator is given by

$\mathbf{V = E - IX}$

$\mathbf{V}$ = Terminal Voltage

$\mathbf{E}$ = Induced emf (excitation emf).

$\mathbf{IX}$ = Voltage-drop in machine reactance

$\mathbf{IX}$ = Drop varies with variation in load current $\mathbf{I}$ and it's power factor. The induced emf $\mathbf{E}$ can be varied by varying excitation current. Automatic *Voltage Regulators* of synchronous generators adjust the excitation current automatically to maintain constant terminal voltage.

The **Automatic Voltage Regulator and Excitation System** has certain :

— Upper and lower limits of excitation (*e.g.* ceiling voltage 100 V for 500 V nominal voltage).

— Excitation response (Volts per sec or per unit volts per sec. *i.e.* slope of 'open-circuit voltage of main exciter v/s Time' curve *e.g.* 1000 volts/sec. for a 500 V nominal voltage).

Due to these limitations, actual excitation system are unable to hold constant terminal voltage during transient conditions. During transient disturbance the reactance X of the machine varies due to the changes in flux linkage. The current I varies due to the disturbance and power swing. Hence IX drop varies. Excitation emf E cannot instantaneously respond to these transient variations. However, the steady state (after a few tens of cycles, say 20 cycles) power limit P_{max} depends on emf E as given by the equation.

$$P = \frac{|E| \cdot |V|}{X} \sin \delta \, ; \quad P_{max} = \frac{|E| \cdot |V|}{X}$$

where $|E|$ = Excitation voltage behind reactance

$|V|$ = Terminal voltage .

Excitation voltage E is continuously adjusted to require steady state value of V by automatic voltage regulators. Hence automatic voltage regulators of a synchronous generators improve the steady state stability limit. The excitation system should have *quick response*. Quick response excitation systems with high ceiling limit have these features.

1. High value of Nominal Response.
2. High Ceiling Voltage.
3. Quick action (Fast response)
4. High Reliability.

Nominal Excitation Response is defined as "average slope of exciter open circuit-voltage versus time" characteristic measured over a period of first 0.5 second after short circuiting the regulating resistance.

Ceiling Voltage is the value of final maximum, steady state open circuit voltage of exciter.

The excitation response values upon the type and design of excitation system. Excitation response (slope of excites terminal voltage v/s time curve) varies widely *e.g.*

Slow response	: 1.00 unit	: V/sec for 125 V Exciter.
Medium response	: 2.00 unit	: 200 V/sec.
Fast response	: 5.00 units	: 500 V/sec.
Super Excitation	: 30.00 units	: 3000 V/sec.

Increase speed of excitation response is the important means for improving power system stability. If the fault has substained for a long time, a machine may sustain the first swing of its rotor; but because of continuous reduction in field current under sustained fault condition, the machine may pull out of step during the second or third swing. The excitation system having high excitation response and controlled by automatic voltage regulator causes reduction in the initial decrease of flux linkage; *i.e.* the flux-linkage reduces more slowly on fault. Therefore, the e.m.f. E drops more slowly and machine does not fall out-of-step during the first swing. Meanwhile the exciter voltage is increased resulting in higher e.m.f. E and the machine not fall out of step during the second swing. For a more severe disturbance however, the machine may fall out-of-step during the first swing, with high excitation response, if machine does not fall out of step in the first swing, it will not fall out of step in subsequent swings.

2.8. **Machine Parameters**

The parameters of synchronous machines influence the power system stability. Low synchronous reactance increased the stability limit. Damper winding on rotor poles (of salient poles) gives better damping.

2.9. **HVDC Interconnection**

With AC interconnection, the power transfer is given by

$$P_s = \frac{V_1 V_2}{X} \sin \delta = \frac{V_1 V_2}{2X} \text{ for } \delta = 30°.$$

Due to series reactance X, the AC transmission has a very low transient stability limit. HVDC line does not have such a limit due to absence of reactance X.

Power flow through HVDC link can be quickly increased/decreased/ reversed/modulated.

HVDC system control can be modified such that the swing oscillations are damped. Thereby the stability of both AC Networks and the transmission system is improved.

Synchronous HVDC interconnection has parallel AC lines. HVDC power flow improves stability of parallel AC lines.

Asynchronous HVDC link does not have any parallel AC line. The control is modified to damp the oscillations in connected AC networks.

HVDC link may be in form of a transmission line or in the form of back-to-back coupling system. (Ref. Sec. 47.2.11)

5. **System Damping Resistors (SDR).** When a faulty line is switched off by opening of circuit-breakers, the rotor angle δ of sending end generators accelerates (swings). If the line was carrying significant power; swing would be severe because of sudden load throw-off. The machines in the sending-end power station would loose stability even though the faulty line was isolated. To prevent such a happening, the method of *system damping resistor* is used.

System damping resistors are switched in after isolating faulty line, before the swing reaches the first peak. These resistors are of high power consumption rating (200 MW, 300 MW) and are connected in star with neutral grounded either to substation bus or near generator terminals. The SDRs are switched off after the swing is reduced and the auto-reclosing of line is executed.

(SDR is used as an alternative method to series capacitors).

QUESTIONS

1. Fill in the gaps :
   (*a*) Swing curve of a synchronous machine is a graph of ____ *Versus* ____.
   (*b*) Power angle diagram of a synchronous machine is a curve of ____ *v/s* ____.
   (*c*) Steady state stability of a synchronous generator connected to infinite busbars can be expressed in terms of e.m.f. E, terminal voltage V by equation ____.
   (*d*) Fast relays used for transmission line protection have a relay time of ____ ms and circuit-breaker time of ____ ms.
   (*e*) System Damping Resistors used for improving stability are switched-in when ____ and are switched off again when ____.
   (*f*) Rapid Auto-Reclosing sequence of circuit-breakers is expressed as ____.
   (*g*) System Damping Resistors are installed in ____.
   (*h*) Series capacitors are usually used for transmission lines of rated voltage ____.
   (*i*) Power Angle δ is the angle between the vectors ;
   Maximum permissible steady state value of angle δ for a salient pole machine is about ____.
   (*j*) Maximum permissible value of angle δ for a cylindrical rotor machine is ____.
   (*k*) Transient stability of synchronous generators can be improved by means of ____.
2. Define the following :
   (*a*) Steady State Stability Limit (*b*) Transient Stability Limit
   (*c*) Critical Clearing Angle (*d*) Disturbance
3. State and explain Equal Area Criteria of Stability.
4. State and explain the co-relation between swing curve and stability.
5. Explain with the help of power angle diagram the effect of fast fault clearing and auto reclosing on transient stability limit.
6. Explain the term Critical Clearing Angle with the help of equal area criterion.
7. State and Explain Swing Equation. Derive Swing Equation from fundamentals. State the units of each term used in the expression.
8. Explain the significance of HVDC interconnecting link in improving transient stability.
9. A generator is operating at rated voltage and is connected to infinite bus at 50 Hz. Power transfer is at 1 p.u.
   Maximum possible power transfer is 1·8 p.u.
   Consider a 3-phase fault under which maximum power transfer is reduced to 0.4 p.u.
   The power transfer after fault is 1.3 p.u. (Refer Ex. 43.5). Determine critical clearing angle .
10. A 2 pole, 50 Hz, 11 kV turbogenerator has a rating 50 MW.
    0.8 pf lag-rotor has moment of inertia $J = 8800$ kg m^2
    Calculate inertia constant M in mega joules per elect degree. **[Ans.** 0.0483 MJ/elec. deg.]

11. Explain with the help of power-angle diagram for two machine system having double circuit transmission line, the concept of transient stability.
12. What is Auto-Reclosing of circuit-breakers ? How does it affect stability of transmission systems?
13. Explain these terms with reference to transient stability
    (*i*) independent pole operation
    (*ii*) single pole tripping
    (*iii*) selective pole tripping
14. Explain the difference between :
    rapid auto-reclosing and delayed auto-reclosing.
    Explain the sequence of operations and the check features in delayed autoreclosing schemes.

Ref : Ch. 45-C Voltage stability
Ch. 45-D Automatic Voltage Regulators and Excitation Systems for Alternators.

45-A

Load-Frequency Control, Load Shedding and Static Frequency Relay

Introduction to system frequency control — Characteristic of rotating machines — Primary-frequency control — Secondary Load frequency control — Load-frequency control in a Grid-Network — Load shedding — Use of frequency relays for load shedding — Static frequency relay — Network Islanding — Applications of frequency relays, Load Dispatching and Network Controller — Summary.

45.1. INTRODUCTION TO SYSTEM FREQUENCY CONTROL

The regulation of power supply insist that the supply frequency variation should remain with ± 1% about the declared frequency of 50 Hz**. When load on the generator or a group of generators increases, the rotors slow down resulting in reduction in frequency. However, the governors adjust the input so as to bring the frequency to original level. This control of frequency by the action of governors is called **Primary Control.** The action of governors is automatic. A drop in speed due to increased load causes governor action so as to admit more stream into turbine and increase the electrical output. In the event of loss of load or sudden change in load, the governor controls the speed of generators. However, frequency control by governors alone is not adequate and 'Secondary control' is necessary. In secondary control, the loading on different plants is changed according to the instructions of the load dispatcher*.

Method of Frequency Control

Manual Control. Very small isolated generating stations can have manual control of frequency. The generator adjusts the input to bring the frequency with permissible limits**.

Flat Frequency Control. Consider system illustrated in Fig. 45.1. By controlling frequency of G_1 at station A, frequency of G_2 at station B is controlled. This method is called flat frequency control. The disadvantage of this method is that, the station A should have enough capacity to absorb the changes in load. Further, the tie line also should have enough capacity to transfer the power.

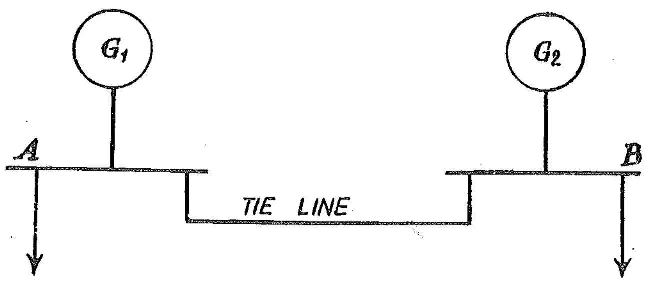


Fig. 45.1. Parallel operation of station A and B.

Flat-tie-line Regulation. In this method, the station A is used for frequency control and also, the regulation is improved by adjusting the input at station B.

* The increase in electrical output of generator is achieved by the increase in mechanical input to turbine. The setting of inlet valve to turbine is adjusted to get desired input.

** The CEGB, UK has operational target limits of 49.8 and 50.2 Hz, *i.e.* 0.4% variation. Under frequency is harmful to blades of steam turbines. As per IS, permissible variation is ± 3%.

Parallel Frequency Control. In this method, the frequencies of station A and B are regulated simultaneously. By this method, the swings are shared by both stations and swings of each station are reduced. Automatic control of load is desirable, for maintaining proper operating conditions. In automatic frequency control, the inputs to generators get automatically adjusted to meet the changing load conditions.

45.2. LOAD-FREQUENCY CHARACTERISTICS OF ROTATING MACHINES

The frequency control is influenced by the favourable characteristics of the large rotating machines (Induction and Synchronous) connected in the network.

- Reduction in frequency of supply causes reduction in speed of the induction motors, thereby causes reduction in power requirement and the demand.
- Inertias of the rotating machines have flywheel effect. Energy is released when the frequency falls and the energy is absorbed by the rotor when the frequency increases.

The effective load connected to the network, therefore, depends upon the supply frequency (and voltage). A drop in voltage and frequency results in a reduction in effective load (Load Reduction Factor). This in turn leads to a reduction in the frequency drop, *i.e.* to the rate of drop of frequency (df/dt) becomes flatter.

45.3. PRIMARY LOAD-FREQUENCY CONTROL

Electrical energy cannot be stored in large quantities. The energy stored in other forms. This fact plays an important role in power generation. The mechanical output of the turbines must be continuously adjusted to the electrical load on generators. Every condition of electrical load should bring appropriate change in mechanical input to the turbines. This relative simple equation is made complicated by the fact that load on the network is affected by many consumers and is supplied by several generators located in various power stations.

The frequency of a generator and generating station bus is controlled partly by the action of the mechanical governors controlling the turbine speed and partly by changes in load conditions. The plant output is increased by increasing input. How much load the plant should share is decided by Grid Control Loading Engineer.

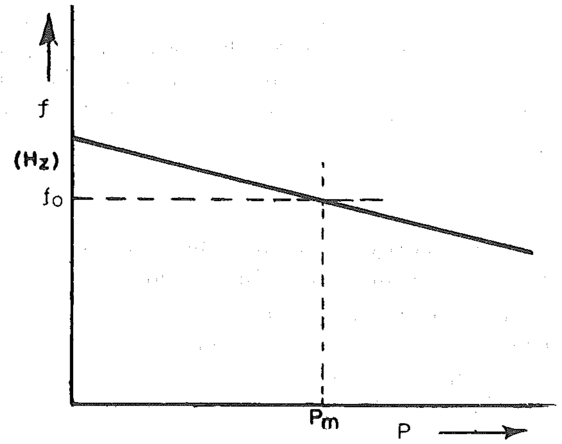
The frequency control by the action of the mechanical governor is called the 'primary control'. The governor admits more steam turbine or more water in hydro turbine. Thereby the electrical output of the generator is also increased. To avoid hunting, the governors are designed to remain stable at a speed corresponding to new output which is not the earlier speed. Hence frequency control by governor action alone would not return the frequency to the original (required) value (50 Hz).

45.4. SECONDARY LOAD FREQUENCY CONTROL

The frequency of a generating station is brought to the required value by appropriate load transfer. This is in addition to primary frequency control.

The amount of load shared by each generator is determined by the setting of turbine control system (primary control) and the amount of the load shared by generating station or a group of generating stations in an area is determined by Central Load Dispatching Centre (Load dispatching engineer or Network Controller). (Refer sec. 45.11). The secondary control takes into account the economic operations of the complete system having several interconnected generating stations.

The control loop, comprising turbine control system and machine, has a well-known straight line characteristic of output *vs.* Frequency (Fig. 45.2). As long as the consumption of the total network is equal to the sum of the outputs of the generating sets, there is zero deviation from the target frequency. If the load on the system deviates, the output point of all the machines move along their respective characteristic curves until the sum of the generating power is equal to the



(Machine : Turbine = Generator Unit)

f_o = Rated frequency P_m = Machine output at frequency.

Fig. 45.2. Machine load frequency relation.

new load, and the balance is restored. Each individual generator shares that protection of load change which corresponds to its characteristic curve.

There remains a residual frequency deviation described above that can be eliminated altering the set values of the individual generating units, *i.e.* by displacing the straight line characteristic.

45.5. LOAD-FREQUENCY CONTROL OF A GRID

Todays power systems have several interconnected regional grids. The entire interconnected system network is called the Grid. The grid network has following merits as compared with an isolated system :

— Transfer of power between areas (Zones) which are predominantly hydroelectric, thermal and nuclear *e.g.* in Karnataka, Maharashtra and Tamil Nadu State Electricity Boards etc.

— Mutual assistance in the event of a fault which means reduction of spinning reserves.

— Improve compensation of load fluctuations.

Entire Grid is divided into certain Regional Grids. Exchange of power between two adjacent zones is usually governed by a fixed programme so that during a given period of time, a certain amount of power is exchanged between two Zones.

If there is a frequency drop in an area, (Zone) that Zone is instructed to increase its import, (if it is already importing) or reduce its export (if it is exporting) such a control is based on the *Line Frequency Bias.*

For example, neighbouring Zone (*A*) generating 6000 MW with a programmed export of 1000 MW would increase its generation by 120 MW and export 1120 MW to the Region (*B*) when the frequency of station (*B*) has dropped by say 0.2 Hz below desired level of 50 Hz.

The import of power from Zone *A* to Region *B* is possible only if the local load in Region *A* is (6000 – 1000) = 5000 MW, when the additional demand of 112 MW. The frequency of Region *A* will drop below 50 Hz when its loading is increased. However by proper load sharing the frequencies of both Zones *A* and *B* are maintained within the targetted frequency limits (49.5—50.5 Hz).

The tie line control is a secondary action following the primary governor action. The grid control loading centre covers all zones under the secondary control. The task of the grid control centre is to keep the power transfer between various zones and frequencies of various zones within set limits. As a consequence each zone needs its own load control centre to control and regulate its own frequency and also to ensure the mutual interchange of power according to the instruction of Grid Control Centre.

45.6. LOAD SHEDDING

When generators get overloaded beyond the maximum mechanical power input, it becomes necessary to interrupt some load to save the system from loss of stability. This process is called load shedding. In majority of power systems, load shedding is automatically performed because the time available is insufficient for manual operation. For automatic load shedding, the overloads should be sensed by relaying in suitable form. During overloads beyond maximum mechanical input, the frequency of generators or part of system decays proportional to the generator inertia and amount of overload.

Rate of frequency decay is probably the quantity most indicative of an overloaded condition. Frequency relay is frequently utilized for load shedding. This relay consists of an induction disc with two sets of potential coils, one of which has capacitance in series with it. Therefore, as the frequency changes the phase angle of the potential flux changes. A typical pick-up frequency would be 48.5 cycles. Time of operation of the relay is a function of the difference between the set frequency and the actual frequency. To this extent the greater the rate of decay of the frequency the faster will be the relay operation. For example, for Δf of 1/2 cycle, the relay operates in 0.6 sec and for Δf of 1 cycle relay operates instantaneously. (Refer sec. 45.8).

The load is disconnected in steps. To ensure the co-ordination of all the relays in a particular network, the frequency relays must measure with high accuracy and the measured value should be preferably independent of voltage.

The frequency of a network usually varies in the following manner :

$$\Delta F = \text{function } (\Delta P, H)$$

where ΔF = change in frequency

ΔP = Power deficit

H = Inertia constant of network.

In load shedding programme, the following points should also be considered :

— Variation of the frequency with respect to the time in the event of deficit and subsequent load shedding.

— The nature of loads to be disconnected as well as their dependence on frequency and voltage.

— Behaviour of system voltage before and after load shedding.

— Topographical distribution of the energy reserves, load centres. (This information is useful in assessing possibilities of dividing the network into separate load/generation islands in the event of energy deficit).

The load shedding may cause the voltage rise in the network due to cutting off of reactive loads. Therefore, control of reactive power flow and voltage rise should be considered while planning the load shedding scheme.

45.7. USE OF FREQUENCY RELAYS FOR LOAD SHEDDING (Refer sec. 26.18 Frequency Relays)

The load shedding is carried out in small steps instead of a sudden large step. This prevents power swings and shocks to system, secondly the load shedding is preferably carried out at the level of distribution voltage and not at transmission voltage. Thereby load blocks to be shed are more evenly distributed over the system and the difficulties of voltage, rise, power swings etc. are minimised.

The load shedding programmes are generally in two to four steps.

The maximum frequency step is just below the normal service frequency whereas the lowest step to be sufficiently above the frequency at which auxiliaries have to be switched off in the power station. By such settings, there is no need of disconnecting power station auxiliaries when the system frequency decreases. (During 1970s, some large interconnected system in USA, Canada, Europe suffered a complete black-out due to disconnection of power system auxiliaries during under frequency).

Each of the two to four steps shed about 10 to 20% of the available load. The frequency relay used for the load shedding responds to rate of change of frequency (*df/dt*) and the sustained under frequency (< *f*). Fig. 45.3 indicates the stepped characteristics of a frequency relay. It can be seen that at lower frequency the relay becomes more sensitive and operates for lesser *df/dt*.

When planning the load shedding programme, the steps are arranged to be disconnected consecutively until the equilibrium between output and input is established the frequency begins to rise again.

The frequency should not rise above the permitted level after load shedding as it is harmful particularly to steam-turbine blades.

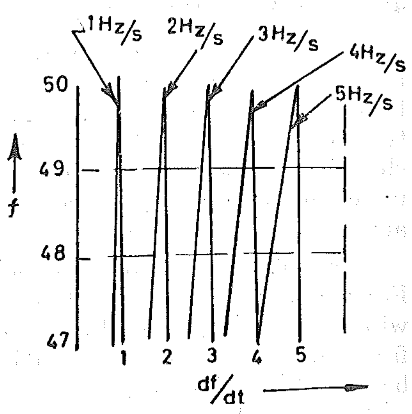


Fig. 45.3. Stability of a frequency relay with respect to *df/dt* and *f*. (*Courtesy* : Brown Boveri, Switzerland)

The frequency relay for load shedding has three operating criteria,

— The frequency is below the set release frequency.

— The gradient *df/dt* is greater than setting.

— The gradient *df/dt* must stay above the set value throughout the whole set time.

In the event of large energy deficit, *i.e.* high *df/dt* the load shedding covers first, second and third step, at a earlier pace.

45.8. STATIC FREQUENCY RELAY

(*Courtesy* : Brown Boveri, Switzerland)

The following basic requirements are satisfied by static frequency relays :

(*i*) high reliability

(*ii*) accuracy

(*iii*) high measuring speed.

A recently developed static frequency relay employs digital principle for measurement. The reference value of frequency is supplied by a built-in, high precision quartz-crystal oscillator of 100 kHz. The oscillations of the oscillator are counted during one cycle of the system under supervision. If the number of oscillations counted during one cycle exceeds the set number, this means that the measured frequency is lower than the set value for the time of measurement.

To improve the immunity to noise, the relays contain filters or special means of evaluating the signals and the input transformers are equipped with screening. In addition, during the set tripping time, all measured cycles have to exceed the setting (for under-frequency steps). In this way, high degree of immunity to noise and harmonics is assured.

For over frequency relays, the measured cycles have to be shorter than the setting.

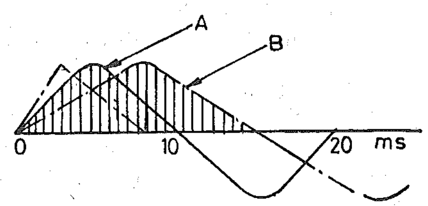


Fig. 45.4. Number of counts during half a cycle increases with reduced frequency.
A = Normal frequency waveform *B* = Reduced frequency waveform (exaggerated)

The frequency relay consists of a single stage basic unit and can be augmented by three plug in frequency steps.

Instead of frequency measuring step, a *df/dt* stage can be plugged in. It operates between 0.1 and 9.9 Hz/s and can be adjusted in steps of 0.1 Hz/s. The tripping frequency may be set between 39.1 and 65 Hz. The time lag of this stage can be set to different values between 33 and 130 ms.

The frequency measuring stages are designed for frequency range between 39.2 and 65 Hz adjustable in steps of 0.025 Hz, and are accurate within ± 0.003 Hz. The pick-up time may vary between 0.15 and 1.15 sec or between 0.5 and 5 sec. If the auxiliary voltage is derived from the measured voltage, the relay operates between 0.6 and 1.2 times rated voltage when the measuring system is supplied from d.c. source, the relay can operate between 0.2 and 1.2 times rated voltage. When the voltage falls below the set value (0.2 and 0.6 of rated) the operation of the relay is blocked.

45.8.1. Turbine Frequency Capability and Under-frequency Limits

Thermal power stations supply bulk power. In thermal power stations, each turbo-generator is driven by its associated steam turbine. Steam turbines are comprised of several stages of turbine blades of varying lengths, shapes and natural frequencies of vibrations. Design is such that at synchronous speeds, vibrations are within limits. Off-frequency operation of a loaded turbine gives vibration stresses on the turbine blades and may eventually damage the turbine blades. The investigation of failures of turbine blades by Westinghouse, USA indicates the limits of duration of off-frequency operation as :

60 Hz rated frequency in USA : Continuous
59.6 Hz : 1000 minutes, cumulative
58.9 Hz : 90 minutes cumulative for life time
58.4 Hz : 13 minutes cumulative for life time
57.9 Hz : 1.8 minutes "
57.4 Hz : 15 seconds "
56.9 Hz : 2.4 seconds "
56.5 Hz : 1 second " (Note : Rated $f = 60$ Hz)

Over-frequency operations also has similar limits obtained by mirror-image graph.

Off-Frequency Limits. Under-frequency operation of turbine-generators was also studied by General Electric, USA in mid-1960's following the North-east Blackout. Using known material properties and assuming the largest expected stimulus. General Electric's analysis estimated the minimum time to cracking some part of the turbine bucket structure. Assuming the turbine was carrying load, these calculations produced the following limits) :

1. A reduction in frequency of one per cent to 59.4 Hz would not have any effect on blade life.
2. A reduction of frequency of two per cent to 58.8 Hz for about 90 minutes could result in damage.
3. A reduction in frequency of three per cent to 58.2 Hz for about 10 to 15 minutes could result in damage.
4. A reduction in frequency of four per cent to 57.6 Hz for a period of one minute could result in damage.

It was noted that comparable increase in frequency above rated frequency can be expected to produce similar results.

Steam-Turbine Generator Under-frequency Protection

Two level under-frequency protection were planned based on unit size *viz. units 100 MW and below, and units above 100 MW.*

Units 100 MW and Smaller. This class of unit will be protected with one electromechanical induction-disc under-frequency relay with input supplied from the generator bus potential transformers. The relay is set with a minimum pickup of 58.0 Hz to operate in 9 seconds for a step decrease in frequency from 60 Hz to 57 Hz.

This under frequency relay is armed for tripping only when the unit is connected to the transmission system. It will be connected to operate a lockout relay, which will trip the breaker(s) required to separate the generator from the system. These units, having drum-type boilers, will be allowed to carry station service loads after separation from the system to facilitate rapid reloading of units after the disturbance has subsided.

Unit larger than 100 MW. Southern electric system engineers made the decision to protect all large units, regardless of manufacturer, with a six-band solid-state frequency relay system designed around existing relays to meet the six-band programmable under-frequency limits. This relay system will be supplied from the unit potential transformers and will have an inhibit circuit to prevent undesired underfrequency accumulations when a unit is not connected to the transmission system.

Each frequency band will feed a mechanical, preset, continuous memory counter to accumulate the time duration of the underfrequency condition for that band. The frequency relay system will contain six frequency thresholds and two continuous monitoring stages. Ten cycles after an underfrequency condition picks up the highest set underfrequency threshold, the mechanical counter for band 1 will begin accumulate time. As long as the frequency remains between the highest set threshold and the next lower frequency threshold, the band 1 counter will continue to accumulate time. If the frequency continues to decline and passes through the next lower frequency threshold, the band 1 counter will stop accumulating and the band 2 counter will begin to accumulate time after a ten cycle delay, and so on for the other bands. The time accumulated in each frequency band will be independent of all other frequency bands.

When the mechanical counter accumulates its preset value, an output contact on the counter will initiate tripping or alarm. It is expected that frequency bands 2 through 6 will be used for direct unit tripping; band 1 will be used for annunciation. Drum type boiler units will be separated from the system but allowed to carry station service load; however once through boiler units will be shutdown since this type of unit is not expected to be capable of such continued operation.

UNDERFREQUENCY PROTECTION CO-ORDINATION

Turbine-Generator and Load Shedding Co-ordination. Graphs are drawn for the co-ordination of the turbine-generator underfrequency schemes with the 40 per cent load shed program which will be implemented on the Southern electric system. The frequency response curve shown is for 40 per cent loss of generation which corresponds to the maximum design limit of the adopted load shed programme. The rectangular blocks show the time accumulated for each frequency band of the six-band relay. The use of graphical techniques to evaluate co-ordination of relay setting with inverse time relays to estimate the co-ordinating margin for each of the overload simulations. The percentages of contact closure or band operations shown in the graph are quite small, indicating a very adequate co-ordinating margin.

The high degree of co-ordination shown in the above case implies that the 40 per cent load shed scheme can tolerate loss of generation somewhat greater than 40 per cent without incurring a turbine trip. Note however, that the multiband relay scheme was assumed to have had no previous underfrequency experience, whereas in continuous operation the relay will "rechet" or accumulate underfrequency experience, such that severe disturbances which pick up the lower frequency bands could result in substantial margin loss due to the relatively short permissible times within these bands.

Volts per Hertz Co-ordination. During an under frequency excursion, the possibility of over-exciting the generator and/or unit connected transformers is increases. For this reason, it was necessary to evaluate generation units volts-per-hertz (V/Hz). Relay schemes employed on system generators to ensure co-ordination with the adopting 40 per cent load shed scheme. Unit susceptibility to V/Hz tripping was determined by examining the frequency and voltage profiles of each unit in the 147 bus, 42.9 per cent loss of generation case with respect to each unit's V/Hz relay settings. Generally, each unit on the Southern electric system has at least one V/Hz relay stage with a minimum

pickup setting of 110 per cent V/Hz. A 96 per cent minimum drop out ratio as specified by the relay manufacturer was used for estimating the relay reset level, which in this case was 105.6 per cent V/Hz. Time delay settings for this relay stage range from 45 to 60 seconds ; however, the worst case encountered was a pickup duration of only 15 seconds. Higher V/Hz stages set at a 118 or 120 per cent were not affected since the over-excitation peaked around 114 per cent V/Hz. Thus it appeared that unit over-excitation tripping would not be a problem up to the design capability of the load shed programme.

Plant Auxiliary System Co-ordination. Nuclear units having a pressurized water reactor (PWR) steam supply use special under frequency protection for their primary system reactor coolant pumps. If the frequency stays below limits prescribed by the pump and reactor manufacturer, this protection will trip these pumps, shutting down the reactor. Presently there are two PWR units on the Southern electric system, both having reactor coolant pump underfrequency protection with a static underfrequency relay fixed time delay of 0.25 second and a pickup setting of 57.0 Hz. Evaluation of this particular setting verified sufficient co-ordination with the adopted 40 per cent load shed scheme to avoid a unit shutdown for any overload within the load shed scheme's capability. The disturbance voltage swings were similarly reviewed for co-ordination with unit auxiliary system undervoltage tripping relays. The undervoltage relay setting used within the system provided sufficiently long time delays to allow voltage recovery without tripping.

45.9. NETWORK ISLANDING

In a large system adequate precaution should be taken to prevent complete collapse of the network and to leave maximum possible portion of network unaffected. To achieve this, the network is divided into smaller Islands, each island has set limits of frequency (output of generators and load) that can be handled by load shedding.

When the frequency begins to decrease (due to peak load or heavy faults) the network is split into definite sections at predetermined points by frequency relays.

The difference between the output and load is reduced in every section by load shedding or load equalization in every island.

This formation of islands is possible for homogeneous systems where load centres and generating centres are uniformly distributed over a geographical area.

45.10. OTHER APPLICATION OF FREQUENCY RELAY (Refer Sec. 26.18)

— disconnection of small in-plant generating sets (factory supply system with their own turbine-generator) from feeding the network when a fault occurs in the latter Ch. 43.

— protection of generators and auxiliaries in large power stations. The settings of such frequency relays should be different (generally much lower) than those for load shedding.

45.11. LOAD DISPATCHING AND NETWORK CONTROLLER

Refer Sec. 45.5. The total interconnected AC Network. (National Grid) operates at common prevailing frequency (F). It means the total MW Generation is matched with total MW load plus MW Losses. The National Grid is controlled from *National Load Control Centre* (National Load Despatch Centre).

The National Load Control Centre allocates (1) the MW Generation to each Regional Grid depending upon the prevailing MW load in that Regional Grid and required MW Export/Import from that Regional Grid (2) Amount of MW Power trough Tie-Lines between Neighbouring Regional Grids.

* *Courtesy* : Westinghouse USA, refer "Coordination and Load Conservation with Turbine-Generator under-frequency Protection"—D.W. Sinha, C.R. Roaland, J.W. Pope.

Each Regional Load Control Centre controls Load and Frequency of its own by Matching Generation in various Power Stations with total regional MW load plus MW losses plus/minus amount of tie line power flow.

The Network Controller installed in each Regional Load Control Centre and is in communication with the National Load Control as well as with control rooms in Power Station and Major Substations in its zone through power line communication channels, microwave communication channels, telephone communication channel, Fax etc.

Load/Generation Controller installed in Power Station Control Rooms ensures that the station frequency is within targetted limits. The settings of turbine input are adjusted by the station load controller automatically depending upon required generation allocated by the regional grid and the turbine governor of each generator unit operates to control the speed and frequency automatically.

The task of the load control centre is to keep the exchange of power between various zones (electricity boards or areas) and system frequency at desired values. Each zone may have its own load control centre to regulate the generating stations and loads in its own zone. The national load control centre controls the exchange of power between different regional zones. The function is performed automatically by *network controller* installed in the load control centre. It has a digital computer or a microprocessor with other accessories (Refer Ch. 46).

The planned output and loading is programmed. The computer system sends instructions to various generating stations by means of carrier signals (Telemetery). The machine controllers receive these instructions and adjust the turbine governors to give required loading.

The output control function is obtained by local frequency control loop in machine controller.

The network controller operates on load frequency principle. Its input variable e comprises a combination of linear deviation from frequency and transmitted power :

$$e = \Delta P + K\,\Delta F$$

where e = Input variable of load frequency controller

$$\Delta P = \sum_{i=1}^{n} (p_i + P_{io})$$

$\Delta F = F - F_o$

K = Constant MW/Hz

P_{io} = Target power transmission [MW]

P_i = Tie–lineup power [MW]

F_o = Target frequency

F = Actual frequency

n = Number of supply points.

A PI controller is used for regulating system and its output variable y is givne by*

$$y = C_p \times e + \frac{1}{T_n}\int^{t} e\,dt$$

where C_p = Proportionality constant

T_N = integral action time constant.

The integral component eliminates the control deviation in the steady state and the proportionately constant influences the dynamic response of the control loop.

According to the principle of load-frequency control, any load fluctuation within a system must be compensated by the machine sets controlled by the network controller for that system. If the basis K has been selected correctly, the system controllers in the adjacent networks do not vary their controlled variables.

* Refer Ch. 46-B for Automatic Economic Dispatch and Load Frequency Control. Ch. 50. Operation and SCADA systems.

The load change in this systems are rectified by the influence of dropping characteristics of the machine (Fig. 45.1).

Set values of f_o and P_{io} and constants C_P and T_N are fed into system controller by hand and the actual values of transmitted power and frequency deviation are measured in the system and fed back to the controller. The controlled variable y of the network controller determines the set values of the machine involved. These values are applied to various units according to predetermined plan which takes into account. (Refer Ch. 46-B Economic loading).

— economy of generator — safety

— operational requirements.

The signals are transmitted to individual machines are fed to the turbine control systems. If the turbine control is designed to suit the input signal directly, the signals can be directly interpreted. If the turbines are fitted with conventional mechanical controllers, additional units are necessary for converting the signals into suitable form to control the turbines.

In systems where large, sudden change of loads and frequency can occur, it is necessary to limit the power change of individual unit (Fig. 46.1) to protect the turbines from excessive loads.

SUMMARY

Under stable steady state operation, all synchronous machines in the grid operate at synchronous speed. Frequency is the measure of load/generation balance.

Prevailing frequency of synchronous generators and the Grid depends on matching between (Total MW Load on the Grid plus Losses) and the (Total MW Generation) at that time. Excess Load causes frequency drop. Excess Generation causes frequency rise. Hence frequency is a major control parameter.

Primary frequency control is by governor-control of turbine speed to maintain constant rated frequency of generator unit.

Secondary frequency control is by instructions of Regional Load Dispatch Centre to Generating Stations to *adjust turbine setting* to increase/decrease the generation such that total Regional Grid not only maintains its own frequency within target range but also imports/exports allocated power to neighbouring Regional Grids.

The Network Controller (Load Controller) has a computer aided closed loop control system. The frequency difference ΔF, is measured to determine the required generation difference ΔP.

The instructions are sent to turbine-governor of each generator turbine unit for appropriate setting. The turbine governor controls the speed (hence frequency) as per that setting and generator gives corresponding power output.

When the frequency of a generator-turbine unit falls below safe value, the *frequency relay* operates and gives alarm so that load should be shed. Load is shed at distribution level.

When system frequency starts falling due to overloads or fault, there is a possibility of cascade tripping of turbine-generator units in the *entire regional Grid* and the *total National Grid*. To avoid this and maintain save the Grid, the Network is Islanded into separate *Islands*. Frequency relays between adjucent islands measure and monitor df/dt and f such that during faster rate of fall of frequency, the Network is divided into separate islands, each having certain generation and load. Load shedding is carried out in each island. Thereby each island is saved from loss of synchronism and after the disappearance of the disturbance, the islands are reconnected and the original Network is restored.

QUESTIONS

1. Explain the effect of load on frequency of generating stations. Describe primary and secondary control of load and frequency.
2. Explain the need of secondary load and frequency control. Explain the procedure of Load-Frequency Control at National Grid Level, Regional Grid level and local power station.
3. Explain how a frequency relay is useful in load frequency control. Describe a typical frequency relay and its method of measurement.
4. Write detailed notes on any two :
   — procedure of load shedding
   — network load-frequency controller
   — static frequency relay for load shedding
   — network islanding
5. Fill in the gaps :
   1. The supply frequency of ... Hz should not increase above ... Hz and should not drop below ...
   2. Frequency relay used for load shedding measures ... and ... .
   3. If the load on a generator increases, the frequency tends to ...
   4. Frequency of a synchronous generator having $2p$ number of poles and rotating at synchronous speed N is given by ...
   5. The load shedding is carried out when the frequency reaches about ... Hz.
6. Explain the harmful effects of underfrequency on steam-turbine blades in steam-thermal power plants. What are the under frequency limits ?
7. Explain harmful effects of overfrequency on Power Transformers in generating station. What are the limits of v/f for safety of transformer.

45-B

Voltage Control and Compensation of Reactive Power

CAPACITORS FOR SHUNT COMPENSATION AND SERIES COMPENSATION

Voltage control in Network—Rated Voltage and Limits—Methods of Voltage Control—Tap changing—Voltage Regulators—Series and Shunt Compensation—Static Shunt Compensation of Reactive Power—Law of Reactive Power—Series Capacitors—Installation Details—Effect of Reactive Power Flow on Voltages.
Part B : Power Factor Improvement and Power Capacitors
Shunt Capacitors for various applications Protection of Shunt Capacitor Banks—Details about Capacitors Scheme—Applications—Individual Load—Group Correction—33 kV Bank.
Summary

45.12. VOLTAGE CONTROL IN NETWORK (POWER SYSTEM)

The voltage of buses in generating stations, switching substations and receiving substations and load-points should be held within permissible limits under conditions of gradual increase or decrease in load flow and also during sudden disturbances. Such as short-circuits, load switching. The voltages of distribution lines and supply points to consumers should be held at constant rated values (within permissible limits) under fluctuating load conditions. The task of voltage control is closely associated with fluctuating load conditions and corresponding requirements of reactive power compensation (kVAr Compensation) under steady state and transient state.

Load-frequency Control is achieved by continuous matching of generation (production) of electrical power with prevailing load conditions by joint actions of Load control rooms in Generating Stations. Voltage Control is achieved by appropriate tap-changing and shunt compensation in *respective sub-stations,* and Automatic Voltage Regulators in the excitation system of generators :

Fig. 45.5 illustrates the various methods of voltage control which are applied simultaneously.

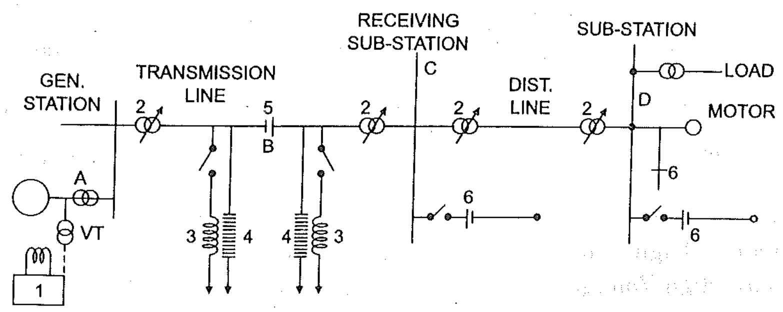


Fig. 45.5. Methods of voltage control in network.

1. Excitation Control.
2. Surge Diverters
3. Tap Changing Transformer
4. Series Capacitors
5. Shunt Reactors
6. Shunt Capacitors (Switched).

45.13. PERMISSIBLE VOLTAGE VARIATION

During heavy loads (or lower factors loads) the IX drop in transmission and distribution lines increases and the *receiving-end voltages decrease.*

During low loads the IX drop in series reactance of lines is negligible. The shunt capacitance of transmission lines taking Capacitive Currents causes *increase in receiving-end voltages.* Thus, the substation bus voltage experience :

REDUCED VOLTAGE ⟵⟶HIGH LOAD
INCREASED VOLTAGE ⟵⟶LOW LOAD
NORMAL VOLTAGE ⟵⟶NORMAL LOAD

Low voltages cause higher current flow through supply line for same load causing higher line losses. Low voltages also cause increased current to deliver same power, hence increased heating of lines, motors, transformers. Below certain voltage (70 to 80% Rated Voltage) the motors get stalled and are tripped automatically by the over-current or under-voltage protection. Sustained low voltage cause failure of insulation of transformers and motors due to overheating. The permissible values of upper and lower voltage limits are as follows :

Table 45.1. Reference Values of Voltage Limits in A.C. Network

Class	*System Voltage*	*Highest Voltage*	*Permissible Lowest System Voltage*
	Line to Line R.M.S.	*Line to Line R.M.S.*	*Line to Line R.M.S.*
LV (1. ph.)	240 V Ph. to n.	264 V	220 V
LV (3 ph.)	415 V	440 V	380 V
M.H.V.	3.3 V	3.6 kV	3 kV
M.H.V.	6.6 kV	7.2 kV	6 kV
M.H.V.	11 V	12 kV	10 kV
M.H.V.	22 kV	24 kV	20 kV
M.H.V.	33 kV	36 kV	30 kV
H.V.	66 kV	72.5 kV	60 kV
H.V.	132 kV	145 kV	120 kV
E.H.V.	220 kV	245 kV	200 kV
E.H.V.	400 kV	420 kV	380 kV
U.H.V.	760 kV	800 kV	750 kV

Note. L.V. = Low voltage M.V. = Medium Voltage
M.H.V. = Medium High Voltage H.V. = High Voltage
E.H.V. = Extra High Voltage U.H.V. = Ultra High Voltage

Permissible variation is approximately ± 10% of nominal Value.
Permissible values of Transient Overvoltages are covered in Ch. 18, Sec. 18.7.

45.14. METHODS OF VOLTAGE CONTROL

The various methods of steady state and transient voltage control in the Network include :

— *Excitation Control* and voltage regulators in generating stations.
— Use of *Tap-Changing transformers at sending*-end and receiving- end of transmission lines.
— Switching in *shunt reactors* during low-loads or while energizing long EHV lines. Un-switched shunt reactors.
— Switching-in *shunt-capacitors* during high loads or low p.f. load.
(Ref. Fig. 45.5)
— Use of *series capacitors* in long EHV transmission lines, (distribution lines in certain cases of fluctuating loads).
— Use of tap-changing transformers in factory, sub-stations, distribution sub-stations, transmission substations.
— Use of *static shunt compensation* having shunt capacitors and thyristorised control for step-less control of reactive power and voltage. (This method is used instead of synchronous condensers).
— Use of *synchronous condensers* in receiving sub-stations for reactive power compensation.

All the above methods are appropriately applied in respective sub-stations to achieve voltage control of various networks buses (Ref. Fig. 45.5).

Time Span of Voltage Phenomena. Slow and gradual changes in voltage have time span of half a minute to several tens of minutes. Such phenomena are called *long term (steady state) voltage phenomena.* Sudden disturbances in voltage are covered by the term "transient voltage phenomena." Ref. Ch. 45-C.

(A) **Excitation Control and Voltage Regulations of Generators :**

The induced e.m.f. synchronous generator (E_1) depends upon excitation current (Field current). The terminal voltage V of a synchronous generator is given by the equation

$$V = E - IX$$

The generators have excitation and voltage regulation system. The functions of this system are :

— To control voltage under steady state operating conditions for operation near steady state stability limit.
— To regulate voltage under rapidly changing load conditios, *e.g.* starting of induction motor loads, sudden switching in of large load, fault.
— To regulate voltage under faulty conditions (Fault elsewhere beyond generator protection zone).
— To enable sharing of reactive power. The reactive power shared by a generator depends upon its excitation level.

Time span of AVR response is of a few seconds.

The terminal voltage of synchronous generator is held within permissible limit by means of automatic voltage regulators. (Ch. 45D)

(B) **Tap-Changing Transformer**

The voltage control of transmission and Distribution systems is obtained basically by Tap-changing.

Tap-changers are either on-load or off load type. By changing the turns ratio of transformer the voltage ratio and the secondary voltage is changed and voltage control is obtained. Tap-changing is the most widely used method of controlling voltages at various levels.

The voltage control of the range ± 16% can be achieved by tap changing transformers.

Table 45 B-1
Methods of Voltage Control in Electrical Power System (Network)*

Method	*Location and Nature*	*Description and Remarks*
(A) Excitation Control and Voltage Regulation (SS + TS) SS = Steady state, slow TS = Transient state, fast	Used for synchronous generators in generating station control room Automatic Voltage Regulators (AVR) are provided with the excitation system of generators.	Generators supply active and reactive power. AVR maintain constant terminal voltage of generator by means of automatic control of field current. Change in d.c. excitation current changes reactive power supplied by generators Ref. Ch. 45-D.
(B) Tap Changing Transformers (SS)	— Fitted with transformers. — Off circuit switch at generating end and load for seasonal voltage variation.	Simple and most common method of changing secondary voltage of transformers of given primary voltage. Variation of ± 16% possible.
	— On-load tap-changes at receiving and distribution sub stations, near load Points.	Response to voltage regulating relay automatically.
(C) Shunt reactors (Low Loads) — Unswitched (TS) — Switched (SS) — Thyristor controlled (TS)	Sending-end and receiving-end sub stations for long transmission lines. Or in intermediate switching sub-stations.	Compensate the shunt capacitance of long transmission lines during low loads or no loads to reduce receiving-end voltage (to cancel Ferranti effect). Reactor switching is difficult. Hence reactors are connected to bus bars without C.B.
(D) Shunt Capacitors (Heavy Load) — Switched — Thyristor Controlled	Receiving-end sub-station distribution sub-station, factory sub-stations, near group loads, near individual loads.	— Switched-in type or static (thyristor controlled) of fixed type (for motors). Switched in during heavy, low p.f. loads. — Improve p.f., improve voltage — Saves energy due to reduced line losses — Should be switched-off during normal voltage.
(E) Static Shunt Compensation	Receiving sub-stations and Distribution sub-stations for smooth and step-less variation of compensation of reactive power injected into line.	— Thyristorised — Capacitance brought into circuit during heavy or low p.f. loads — Inductors brought into circuit during low loads to reduce receiving end voltage.
(F) Series Capacitors	Usually at each end of long lines. To compensate for inductive reactive power requirements of transmission lines.	Usually about 50% of line inductance is compensated. This improves voltage and stability
(G) Flexible AC Transmission (FACT)	— Recently introduced (1988) — Thyristor controlled series capacitors and thyristor controlled shunt compensation at intermediate substations	— Series compensation varied as per requirements of power transfer. — Shunt compensation varied as per voltage requirement — Improves stability.

Fig. 45.6. Various methods of voltage control in sub-stations and power stations.

* Appropriate Method (from A to G) used simultaneously to maintain voltages at each bus within specified limits.

Time Spans of Various Voltage Control Means

The various voltage control means mentioned in Table 45B-1 have different effective times for voltage control. Some are useful for steady state slow voltage control. Some others are for very fast transient voltage control and some are moderately fast.

	SSVS	*TVS*
Excitation Control and AVR for Generators⁺		*
Synchronous Condensers with Excitation Control	*	*
Thyristor Controlled Shunt Compensation (TCS/SVS)	*	*
On Load tap Changers	*	
Switched Shunt Capacitors and Switched Shunt Reactors	*	
FACT Systems	*	*

SVSS = Steady State Voltage Stability : 30 sec to several minutes
TVS = Transient voltage stability : A few seconds to about 30 sec.
*Further details in Ch. 45-C
⁺Further details in Ch. 45-D

Off-circuit Tap-changing. Occasional Adjustment Of Voltage ratio can be made by off-circuit tap-changing. These adjustments are usually for seasonal load variations of special operating requirements of local sub-stations. Typical range of the off-circuit tap-changers are : $\pm 12\frac{1}{2}\%$ variations in 5-7 steps. *Daily and short-time voltage control is not possible by off-circuit tap-switch.*

Off-circuit tap-changer operation is manually executed by sub-station operator.

On-Load Tap-Changers. *The daily voltage variation due to changing load, and short period voltage variations are controlled by on-load tap-changers automatically.*

On load tap-changing is also useful industrial applications where variable voltage is required for the process loads (e.g. arc-furnace duty).

The voltage ratio of a transformer can be varied by about ± 16% by means of on-load tap changers. Time required for one tap changing operation is 8 to 12 seconds.

On-load tap-changers have about 16 steps with provision of automatic voltage control. The voltage regulating equipment for automatic control of on-load tap-changer comprises a line-drop compensator, voltage sensitive regulating relay, time-delay relay etc.

A tap-changer is provided on a transformer for maintaining specified outgoing voltage where the incoming voltage is subjected to voltage variations. The tap-changer is mounted in/on the transformer tank. It comprises a motor driven mechanism and associated control circuit for starting and stopping the motor. The motor can be run in the direction for a *'raise'* tap-changer or in the reverse direction for *'Lower'* tap-changer.

In order to initiate the tap-changing, the line/bus voltage is sensed from secondary of a V.T. by voltage sensitive relay. The voltage sensitive relay has two pairs of contacts for 'raise' and 'lower'. A time delay element is provided within the voltage sensitive relay or in its circuit separately. The time delay relay prevents tap-changing operation during transient voltages and hunting of tap changers. Time delay can be adjusted between minimum 10 sec. to 60 sec. or more. A line-drop compensator is provided within control circuit used for regulating transmission line voltages.

When the line voltage varies beyond certain set value, the voltage sensitive relay connected in the secondary circuit of V.T. is actuated either to close 'raise contacts' or 'Lower Contacts'. The driven motor rotates in required direction to achieve tap-changing.

The motor stops automatically after changing the tap as the unit switch provided in the mechanism operates.

Line-drop compensator is a replica of transmission line (consisting of adjustable resistor and inductor elements). The current flowing through R and L of L.D.C. is equivalent to current flowing in transmission line. *The voltage drop in L.D.C. is proportional to voltage drop in transmission line.*

The voltage drop across the R.L. of L.D.C. is injected in to main regulating voltage coil circuit. Therefore, the operation of voltage regulating relay is in accordance with the requirements of the voltage drop in the transmission line. The tap-changing is therefore, obtained as per the transmission line requirements of changing load currents and reactive drop in the line. Thus the tap-changing by on load-tap changer provides automatic regulation of bus bar voltage. Static voltage regulating relays are available for automatic tap-changing.

(C) **Shunt Reactors :**

Shunt reactors are provided at sending-end and receiving end of long EHV and UHV Transmission line. They are usually unswitched type and connected to busbars without any circuit-breaker for switching.

When the line is on no load or low load; the shunt capacitance predominate and receiving end voltage is higher than the sending-end voltage. (This is called Ferranti Effect).

The receiving-end voltage of a 400 kV, 1000 km long line may be as high as 800 kV. The shunt capacitance of such lines is neutralised by switching in the shunt reactor. *During high loads, the series inductive reactance of the line produces IX_L drop and the receiving-end voltage drops, the shunt reactors are switched off.*

Shunt reactors may be connected to the low voltage tertiary winding of a transformer via a suitable circuit-breaker, EHV shunt reactors may be connected to transmission line without any EHV circuit-breaker. Usually, oil immersed magnetically shielded reactors with gapped core are used. Appearance is similar to power transformers.

(D) **Shunt Capacitors** (Switched in during heavy loads)

Static shunt capacitors are installed near the load terminals, in factory sub-station, in the receiving sub-stations, in switching sub-stations. Most of the industrial loads (induction motors, welding sets, furnace transformers etc.) draw inductive currents of poor power factor (0.7, 0.6 lag). The shunt capacitor provide leading voltampere reactive (MVAr) thereby the total kVA loading of sub-station transformer and the current is reduced. Thereby IX_L drop in the line is reduced and the voltage regulation is improved.

Shunt capacitors are switched in when kVA demand on the distribution line goes up and voltage of the bus voltage goes down. Switching in the shunt capacitor should improve the busbar voltage if the compensation is effective (necessary).

(E) **Static Shunt Compensation**

A fast stepless variable compensation is possible by thyristorised control of shunt capacitors and shunt-reactors. SVS acts within a few seconds and provides transient (fast) voltage control and improves voltage stability.

During heavy loads, the thyristors of capacitors control are made conduct for a longer duration in each cycle. During low loads, the thyrist in reactor circuit are made to conduct for longer duration in each cycle. Thus a stepless variation of shunt compensation is achieved by means of static compensation. (Further details in Sec. 48.27; SVS)

(F) **Synchronous Condenser**

Synchronous condensers are loadless synchronous motors connected to the line a suitable transformer. The synchronous condensor has wide variation excitation control. *Under excited synchronous machine takes leading currents. Thus, by changing the excitation, the reactive power drawn/supplied by the synchronous condenser is varied.* Synchronous condensers connected in receiving sub-stations, for voltage control. During low load they are operated with over-excitation. Due to high capital cost and complexity, synchronous condensers are no more preferred.

(G) **Series Capacitors**

Series Capacitors are used for long EHV and UHV transmission line compensate the effect of series reactance. During high loads, the voltage drop in series inductive reactance of the transmission line is compensated the series of Capacitance *i.e.*

$$V_R = V_S = I\,(X_L - X_C)$$

where V_R = Receiving-end voltage

V_S = Sending-end voltage

I = Current

$X_L = 2\pi fL$ of line

$X_C = \dfrac{1}{2\pi fC}$ of series Capacitor

Usually, the 40 to 60% of X_L is compensated by series capacitor.

Series capacitors are used for increasing power transfer ability of transmission line. The voltage regulation is improved by shunt capacitors and not by series capacitors.

(H) **Flexible AC Transmission (FACT).**

Very long high power transmission lines have high series reactance and shunt capacitance. It becomes difficult to control voltage, power and stability by conventional means. FACT has been developed recently (1988). The transmission system comprises intermediate substations an interval of 250 to 350 km. In each intermediate substation, following equipment are installed.

— Controllable series capacitor banks (capacitor bank with thyristor bypass switching.

— Controllable shunt compensation (SVS)

Thyristors are controlled by feed-back control system.

Voltage, power flow and swing-angle δ are controlled. FACT preferred for high power interconnecting lines.

Transient voltage stability of the transmission link is improved by FACT system.

45.15. COMPENSATION OF REACTIVE POWER

Reactive power flow (Q) is closely related with the voltage control. The apparent Power S (kVA) is given by

$$S = P \pm jQ$$

where S = Apparent power, kVA

P = Real Power kW

Q = Reactive Power, kVAr

The various equipments in the network 'Absorb' or 'generate' reactive power

By present AIEE Convention :

Voltamperes reactive are absorbed by inductive loads and Q for inductive loads is considered positive.

Voltamperes are supplied by Capacitive loads and Q for capacitive load is considered negative.

1. **INDUCTIVE LOADS**

— Inductive reactance (X_L) — Induction motors — Welding Transformer etc. — All Inductive loads — Series reactance — Under excited synchronous motor.	— Absorb Reactive Power — Q : positive — p.f. lagging	$+Q$

2. **CAPACITIVE LOADS**

— Shunt Capacitor — Series Capacitors — Capacitance of transmission line — Over-excited synch. Condenser/motor — Cables — Transmission lines on low loads	— Supply Reactive Power — Q : negative, — p.f. leading,	$-Q$

In complex notations :

Complex Power S is the product of voltage E and complex conjugate of I or *vice-versa, i.e.*

$$S = EI* \quad \text{or} \quad S = IE*$$

consider

$$S = EI*$$
$$S = P + jQ$$

Read power P controls the active power which is converted into mechanical/heat or some other form...(watts) and influence frequency f.

Reactive power Q is exchanged between inductive and capacitive loads in the network and influences the voltage in the network. Reactive-power flow increases losses. Hence compensation is provided at each bus.

The control of various bus voltage is achieved by supplying absorbing the reactive power requirements (kVAr) of respective busbars by means of series or shunt compensation.

Compensation of Reactive Power means supplying/absorbing reactive volt-amperes.

45.16. EFFECT OF REACTIVE POWER FLOW ON VOLTAGE AT SENDING-END AND RECEIVING END OF TRANSMISSION LINE

Let P = Power transfer watts per phase

Q = Reactive Power Transfer VARs per phase

$|V_S|$ = Sending-end Voltage Volts, ph. to n, magnitude

$|V_R|$ = Receiving-end voltage, ph. to n, magnitude

$\Delta V = V_S - V_R$ ... *drop in the line voltage*

$R_{+\,i}\,X$ = Series impedance of line/ph.

The relationship between V_S, V_R and P, Q is given by the equation :

$$\Delta V = |V_S| - |V_R| = \frac{RP + XQ}{|V_R|}$$

If the resistance R is neglected, *i.e.* $X >> R$, then

$$\Delta V = |V_S| - |V_R| = \frac{XQ}{V_R}$$

Hence voltage drop in line depends mainly on the flow of Reactive Power Q.

The power angle δ between V_R and V_S is proportional to

$$\delta \propto \frac{XP - RQ}{|V_R|} = \frac{XP}{|V_R|}$$

if $X \gg R$, angle δ *depends mainly on P*

Thus,

Voltage is mainly controlled by reactive Power flow power-angle δ is mainly controlled by real power flow. For voltage control, the flow of reactive power through the transmission line should be controlled. The flow of reactive power is controlled by injecting required VAr into the system by means of

- **Static shunt Capacitors/reactors (SVS)**
- **Synchronous Condensers (Compensators).**

45.17. SERIES CAPACITORS

Series capacitors are connected in series with the line conductors. They reduce the effect of inductive reactance between the sending-end and the receiving-end of the line.

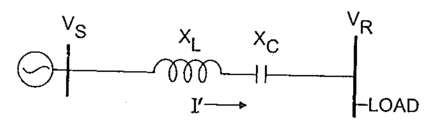
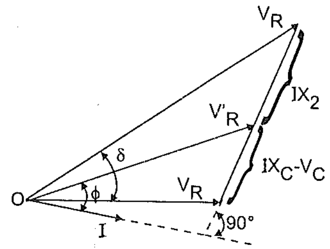


Fig. 45.7 (*a*). Series Capacitor.



(*b*) Vector Diagram for (*a*).

Ref. Fig. 45.7(*a*), (*b*). The load current flowing through the transmission line produces voltage-drop ($\Delta V = IX_L$) in the line.

$$\Delta V = I\,(X_L) \text{ ... without series capacitor}$$
$$\Delta V = IX = I\,(X_L - X_C) \text{ ... with series capacitor.}$$

Thus with series capacitors in the circuit the voltage drop ΔV in the line is reduced and receiving-end voltage V_R on full load is improved.

Series capacitors improve the power transfer ability *i.e.*

$$P = \frac{|V_S| \cdot |V_R|}{X_L - X_C} \sin \delta$$

hence series capacitors are used for long EHV transmission system to improve power transfer ability (Stability Limit) as δ is reduced [Refer Fig. 45.7(*b*)].

Vector Diagram. Ref. Fig. 45.7 (*a*) and (*b*) explaining the principle of series capacitor, I is the load current flowing through the transmission line. IX_L is the voltage drop in series inductive reactance of the line. IX_C is the voltage drop across series capacitor. V_R is the receiving voltage with series capacitor in the circuit. Due to the effect of series capacitor the receiving-end voltage will be VR^1 instead of V_R. Angle δ between V_S and V_R is also reduced giving higher stability.

Series Capacitor Installation Scheme. (Ref. Fig. 45.8). Series Capacitors are installed either at both ends of the transmission line (in sending-end and receiving-end sub-station) or in an intermediate switching sub stations. Fig. 45.8 illustrates the scheme of *one* pole of a three bank. Fig. 45.16 illustrates the location of Fig. 45.8.

During normal operation, isolator (1) is open isolator (2.2) are closed; circuit-breaker (3) is open and the line current (I) flows through the capacitor bank (5).

Since the capacitors and its connections are at extra-high voltage (corresponding to the line voltage) the equipment are installed on a raised platform supported on post insulators of adequate insulation level.

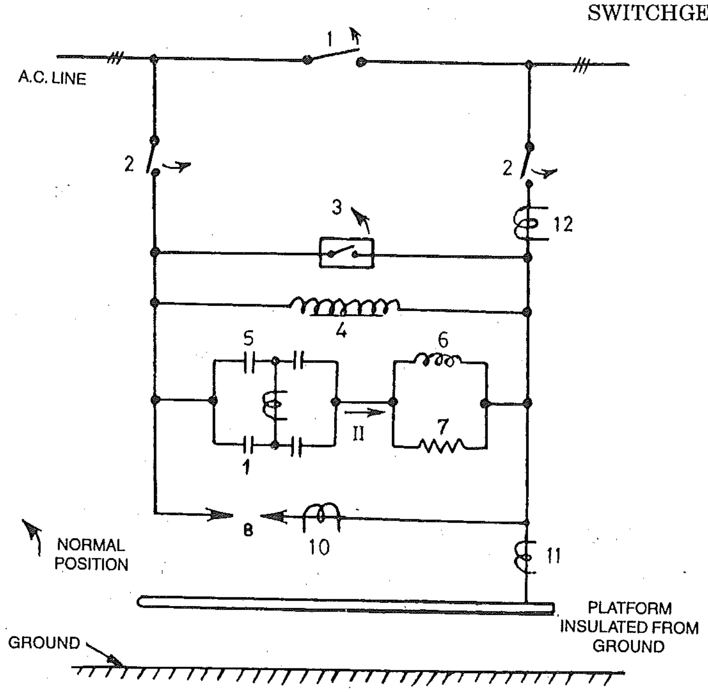
Series capacitor bank (5) comprises capacitor units connected in series, parallel combination to give desired capacitive reactance and MVA capacity.

Damping circuit (6, 7) limits the frequency and peak of inrush currents through the capacitor bank when capacitor is switched in or by passed by closing of the circuit breaker (3).

Circuit-breaker (3) is closed, first wherever the capacitor-bank is to be bypassed. Bypass isolator (1) is closed after closing the breaker (3). Thus the series capacitor bank can be bypassed and normal line current flows through the isolator (1).

Over-current protection is provided by overcurrent relays connected on secondary side of CTs (9.12). Earth-fault protection is provided by relay connected to CT (11). Discharge reactor (4) provides a path for discharging the capacitor after its switching off.

During external fault on the line fault current (I) passes through series capacitor (5) causing excessive voltage IX_C resulting in damage to capacitors. To protect the capacitors from such a failure; a spark gap (8) is provided. When voltage across (5) increases, the spark-gap is triggered. The CT (10) gets



1. Bypass Isolator
2. Series Isolator
3. Bypass breaker
4. Discharge Reactor
5. Damping Reactor
6. Damping Resistor
7. Protective Spark-gap
9-12. Protective Current Transformers

Fig. 45.8. Series-Capacitor Installation Scheme.

current and is arranged to *close the bypass circuit-breaker (3), is closed.* This is an unusual and special application of the circuit-breaker.

The line fault should be cleared by circuit-breaker at sending-end and receiving-end of the transmission line.

APPLICATIONS OF POWER CAPACITORS IN ELECTRICAL NETWORK

45.18. APPLICATIONS OF POWER CAPACITORS IN ELECTRIC POWER SYSTEMS

There are four distinct applications of capacitors in electric power system :

1. *Shunt Capacitors* connected near load points/receiving sub-stations for power factor improvement and voltage control during his load period (Discussed here). These are applied in low voltage/medium/high voltages.

2. *Series Capacitors* used in EHV and UHV transmission lines to improve power transferability.

3. *Surge Suppressor* connected between line and earth near terminals or rotating machines or circuit-breakers (Refer Sec. 18.12).

4. *Coupling Capacitors* used for connection between carrier current equipment and high voltage line (Refer Sec. 30.18).

5. *Capacitor voltage-transformer* used for EHV applications, (Refer Sec. 36.6)

6. In HVDC circuit-breakers.

7. In A.C. circuit-breakers for voltage grading.

(A) **Capacitor.** Comprises conductors separated by insulation capacitance C of a parallel plat capacitor is given by

$$C = \frac{\varepsilon A}{d} \text{ ... farads.}$$

where C = Premittivity of dielectric medium

$= \varepsilon_0 \, \varepsilon_r$

ε_0 = Premittivity of vacuum

$= 8.85 \times 10^{-12}$ farads/metre

ε_r = Relative permittivity of dielectric.

Capacitors have following important attributes.

— Voltage across capacitor cannot change instantaneously. Hence it acts like a surge suppressor.

— It stores electrical energy in static voltage form. Energy stored in a capacitor is given by

$$W_C = \frac{1}{2} CV^2 \text{ ...... joules.}$$

where C = Capacitance in farads

V = Voltage across C in volts

W_C = Energy stored in capacitance.

In alternating current circuit, the capacitance give capacitive reactance $X_C = \dfrac{1}{2\pi fC}$ ...... ohms, and takes leading power factor currents, *i.e.* current leads voltage.

In other words, the capacitors supply leading volt-amperes reactive and Q is negative.

$$Q_C = I_C V = V^2 \omega C$$

$$= \frac{V}{X_c} \cdot V = \frac{V^2}{X_C} \text{ Voltamperes reactive}$$

where Q_C = Voltamperes reactive

V = Voltage Volts

$X_c = \dfrac{1}{2\pi fC}$ .... ohms

Q_C = Apparant or Reactive Power supplied by a capacitor of C farads and charged to voltage V.

(B) **Standard Capacitor Units Available Commercially***

Indoor Type Unit			*Outdoor Type Units*		
Rated Voltage Volts	*Number of Phases*	*kV Ar of Unit*	*Rated Voltage, Volts*	*Number of phases*	*Rated kV Ar*
230	1	5, 7.5	230	1	1, 2.5, 5, 7.5
440	1 and 3	10 and 15	440	1 and 3	5, 10, 15
660	1 and 3	10 and 15	660	1 and 3	5, 10, 15
2400	1 and 3	15 and 25	2400	1 and 3	5, 10, 15
3600	1 and 3	15, 25	3600	1 and 3	10, 15, 25
7200	1	15, 25	7200	1	10, 15, 25
10500	1	50, 75, 150	10500	1	50, 75, 150
12500	1	50, 75, 150	12500	1	50, 75, 150
13800		Upto 200	13800	1	Upto 200

* Table gives typical ratings of capacitor units for reference. For application aspects, please consult the manufacturers.

(C) **Standard Rating of Shunt Capacitor Banks***

Rated Voltage 3-phase kV phase to phase	*Total Rating of Shunt Capacitor Bank (having series + parallel combination of units)*
0.420	20, 30, 50, 100, 125, 150, 180, 250, 300, 500, 750, 1000 kV Ar
3.3	Upto 5 MV Ar.
6.6	Upto 10 MV Ar.
11	Upto 15 MV Ar.
33	Upto 25 and 50 MVAr.
66	Upto 50 and 100 MVAr.
132	100, upto 200 MVAr.

(D) **Shunt Capacitors and Power Factors Improvement**

The function of shunt capacitors applied in the form of a single unit or a bank (comprising a group of units in series parallel combination) is to supply capacitive volt-amperes to the system at the point of connection.

The shunt capacitors compensate the lagging kVAr absorbed by the inductive loads such as induction motors transformers/welding sets.

The shunt capacitors improve the power factor and thereby reduce the total kVA demand. Hence the $I^2 R$ losses through line are reduced and the voltage regulation is improved. This is illustrated in the well-known Fig. 45.10.

Shunt capacitors are as a rule, connected near the load end and also receiving sub-stations.

When used in the sub-station, the shunt capacitor banks should be provided with switching device. *So that during low loads, capacitors are switched off and voltage does not rise above specified limit.* When used with loads, the capacitor units may be non-switched type (*e.g.* with induction motors). Recently thyristorised (Static) control has been introduced to provide shunt compensation.

The shunt capacitor banks (groups) comprise standard capacitor units of 20 kVAr connected in series/parallel combination. Such banks are used factory-sub stations, distribution-sub-stations. The all kVAr ratings of the banks are 15 MVAr at 12kV; 50 MVAr at 36 kV recently).

(E) **Advantages of Shunt Capacitor Banks connected at load/reving end.**

1. Reduced lagging-current through supply circuit. Reduced I^2 Rt losses supply line. Improve power factor. Energy Saving; Economy.

2. Increased voltage at load-end during full load. Reduced Voltage fluctuations at load end.

3. **Improved voltage regulation if capacitor units are properly switched.** If not properly switched, the voltage rises during low load and no load periods resulting in overessing the transformer insulation.

4. **Reduced kVA demand, hence same transformer and distribution circuit having certain rated kVA can deliver higher kW. (This is called "Release" of capacity of** supply circuit).

5. Reduced kVA demand, hence lesser charges to be paid to the electricity board for the same consumption of electrical energy. The tarrif generally two part tariff with certain charges for maximum kVA demand; This component reduces due to use of shunt capacitors at load end.

(F) **Disadvantages of Low Power Factor (PF)**

An electrical plant or sub-station operating at a low power factor has following demerits :

— Reduced kW capacity; over loading of cables, transformers, lines for same kW load. Increased kVA demand for same kW load.

* The size is limited by circuit breaker capacity also.

— Reduced voltage level due to increased IX_L drop in supply circuit. Poor efficiency of motors due to reduced voltage.

— Poorer illumination of lamps due to required supply voltage.

— Increased power losses due to higher currents drawn during low power factor.

— Increased cost of power due to high kVA demand.

(G) **kVA, kVAr, kW, Cos φ**

Refer Fig. 45.10. Power factor is defined as the ratio of active power W to the total apparent power (kVA).

$$\text{P.F.} = \frac{\text{kW}}{\text{kVA}} = \cos\phi \quad \ldots(1)$$

Hence,

$$\text{kW} = \text{kVA} \times \text{P.F.} = \text{kVA} \times \cos\phi$$

In a 3-phase circuit,

$$\text{kVA} = \sqrt{3}\,\frac{VI}{1000} \quad \ldots(2)$$

where V = line to line volts

I = Amperes

$$\text{kW} = 3\,\frac{VI\cos\phi}{1000} \quad \ldots(3)$$

ϕ = Angle between I and V

In case of capacitors I leads V

In case of inductive loads I lags behind V.

Summarising for 3-phase circuits : Fig. 45.9.

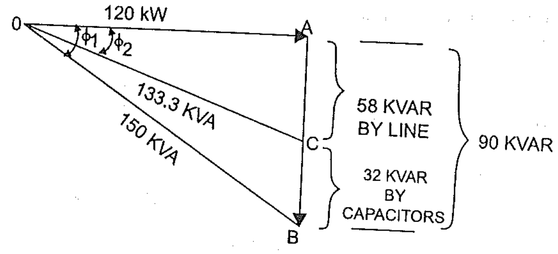


Fig. 45.9.

$$\text{kW} = \sqrt{3}\,\frac{VI\cos\phi}{1000} = 1.73\,\frac{VI\cos\phi}{1000}$$

$$\text{kVAr} = \sqrt{3}\,\frac{VI\sin\phi}{1000}$$

$$\text{kVA}^2 = \text{kW}^2 + \text{kVAr}^2 \quad \ldots(4)$$

$$\text{kVA} = \sqrt{3}\,\frac{VI}{1000} \quad \ldots(5)$$

$$\cos\phi = \frac{\text{kW}}{\text{kVA}}$$

$$\text{kW} = \text{kVA} \times \cos\phi$$

$$\tan\phi = \frac{\text{kVAr}}{\text{kW}}$$

$$\sin\phi = \frac{\text{kVAr}}{\text{kVA}}$$

$$\cos\phi = \frac{\text{kW}}{\text{kVA}}$$

$$\text{h.p.} = 746\ \text{W} = 0.746\ \text{kW} \quad \ldots(6)$$

Example 45. kW, kVA, kVAr cos ϕ

A 3-phase 460 V, system having current 200 amp, total power 120 kW. Determine power-factor, kVA, kVAr, cos ϕ.

Solution.

$$\text{kVA} = \sqrt{3}\,\frac{VI}{1000} = \frac{1.73 \times 460 \times 200}{1000} = 159.2$$

$$\text{kW} = 120 \text{ (given)}$$

$$\cos\phi = \frac{\text{kW}}{\text{kVA}} = \frac{120}{159.2} = \mathbf{0.55} \quad \textbf{Ans.}$$

$$\text{kVAr} = \text{kVA}^2 - \text{kW}^2 = 159^2 - 120^2 = 104$$

or

$$\text{kVAr} = \frac{3VI\,[1 - (\cos\phi)^2]}{1000} = 159.2\,[1 - 0.752] = 104 \quad \textbf{Ans.}$$

(H) **Supply of kVAr, Absorption of kVA** according to presently accepted terminology.

— Inductive loads take lagging currents and *absorb* kVAr, Q is positive.

— Capacitors take leading currents and *supply* kVAr.

— Synchronous condensers take lagging p.f. currents and absorb kVAr when under-excited. They take leading p.f. currents and supply kVAr when overexcited. Hence they are used for step-less p.f. control in receiving sub-stations. Alternatively static shunt compensation has reactors connected at load by means of thyristors. Capacitor current is increased to supply kVAr during heavy loads, inductor current is increased to absorb kVAr during light loads.

(I) **Loads of Poor Power-factor**

Induction motor, induction melting and refining furnaces, welding sets, fluorescent lights etc. take supply currents of lagging p.f. Refer cable C-3.

Examples 45-B-2. P.F. of Group Load

A factory sub-station supplies power to three loads as follows :

— Synchronous motors total 75 kVA at 0.8 p.f. leading.

— Induction motors total 150 kVA at 0.8 p.f. lagging.

— Lighting load filament lamps, 50 kVA at unity p.f.
Calculate overall power-factor of sub-station.

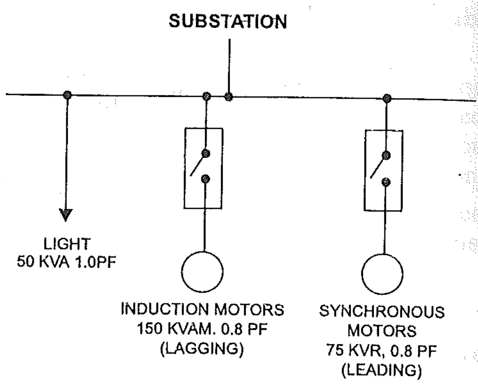


Fig. 45.10. Combined power factor of a group of loads with different PFs'.

Solution.

Method of Solution. Calculate total kW by algebraic sum of component kW's. Calculate total kVAr by summing up component kVAr's. From total kW's and total kVAr's, calculate P.F.

Thus

$$\text{P.F.} = \frac{\text{kW}}{\text{kVAr}} = \frac{\text{kW}_1 + \text{kW}_2 + \text{kW}_3}{(\text{kVAr} - 1) \times (\text{kVAr} - 2) + (\text{kVAr} - 3)}$$

Note. Overexcited synchronous motor acts like a capacitor and supplies kVAr. The power factors of individual loads are used for calculating the power-factor of a group of loads as explained in example below.

Numerical Solution.

Subscript 1, 2, 3 for component loads.

Synchronous motor (1)

$$\text{kVA}_1 = 75 \text{ at p.f. 0.8 load (given)}$$

$$\text{kW}_1 = \text{kVA}_1 \cos\phi_1 = 75 \times 0.8 = \mathbf{60\ kW}$$

$$\mathbf{kVAr_{-1}} = \text{kVA}_1 \sin\phi_1 = 75 \times 0.6 = 45 \text{ kVAr } [-]$$

(This is negative *i.e.* opposite, that of kVAr of induction motor).

Induction motor (2)

$$\text{kVA}_2 = 150 \text{ at lagging P.F. of 0.8 (given)}$$

$$\text{kW}_2 = \text{kVAr}_2 \cos\phi_2 = 150 \times 0.8 = 120 \text{ kW}$$

$$\text{kVAr}_{-2} = \sqrt{\text{kVA}_2^2 - \text{kW}_2^2}$$

$$= \sqrt{150^2 - 120^2} = 90 \text{ kVAr } (+)$$

Lighting Load (3)

$$\text{kVA}_3 = 50 \text{ at unity P.F. (given)}$$

$$\text{kW}_3 = \text{kVA}_3 \cos\phi_3 = 50 \times 1 = 50 \text{ kW}$$

$$\text{kVAr}_{-3} = 0$$

Total $\quad \text{kW} = \text{kW}_1 + \text{kW}_2 + \text{kW}_3$

i.e. $\quad \text{kW} = 60 + 120 + 50 = 230 \text{ kW}$

Total $\quad \text{kVAr} = \text{kVAr}_1 \pm \text{kVAr}_{-2} \pm \text{kVAr}_{-3}$

i.e. $\quad \text{kVAr} = -45 + 90 + 0 = 45 \text{ kVAr}$

$$\text{kVA}^2 = \text{kW}^2 + \text{kVAr}^2 = 54925$$

$$\text{kVA} = 54925 = 234$$

Power-factor of sub-station

$$= \frac{\text{kW}}{\text{kVA}} = \frac{230}{234} = \mathbf{0.982.} \quad \textbf{Ans.}$$

Example : Power Factor Improvement

Example 45-B-3. The power factor of a 120 kW group load is 0.8 and 120 kW group load is 0.8 lag. This p.f. is to be improved to 0.9 by means of shunt capacitors. Calculate kVAr of capacitors required.

Solution.

Draw kVA triangle (Fig. 45.9) as follows :

For $\quad \cos\phi_1 = 0.8$. Draw triangle OAB

$$OA = \text{kW}_1 = 120 \text{ (given)}$$

$$OB = \text{kVA}_1 = \frac{\text{kW}}{0.8} = \frac{120}{0.8} = 150$$

$$\text{kVAr}_{-1} = \sqrt{\text{kVA}_1^2 + \text{kW}_1^2} = \sqrt{150^2 - 120^2} = 90$$

or

$$\text{kVAr}_{-1} = AB = OA \tan\theta_1 = 120 \tan\theta_1$$

For $\cos\phi_2 = 0.9$

$$\text{kVA}_2 = \frac{\text{kW}}{\text{p.f.}} = \frac{120}{0.9} = 133.3 \text{ kVA}$$

$$\text{kVAr}_{-2} = \sqrt{\text{kVA}_2^2 + 120^2} = 58 \text{ kVAr}_{-2}$$

Note. For p.f. 0.9 kVA is only 133 for same kW of 120. The kVAr to be supplied by the shunt capacitors.

$$\text{kVAr}_{-1} - \text{kVAr}_{-2} = 90 - 58 = 32 \text{ kVAr.} \quad \textbf{Ans.}$$

Note. Capacitors provide kVAr opposite to the kVAr required by inductive loads. Hence a common terminology is the inductive loads absorb the kVAr and capacitors supply the kVAr.

Economic aspects of capacitor installation based on cost of capacitor installation and sub-station.

The cost of capacitor installation can be calculated as follows :

The cost of Installation = Total cost of capacitors + cost of protective and switching devices + cost of installation and commissioning.

Suppose the cost of capacitor installation is K Rs/kVAr (*e.g.* Rs. 100 per kV Ar) cost of sub-station is S Rs./kVA. (*e.g.* a 1200 kVA sub-station costing Rs. 480,000 will have

$$S = \frac{480{,}000}{1200} = \text{Rs. } 400 \text{ kVA}$$

Most economic p.f. considering cost of kVA released by the capacitors is given by

$$\text{P.F.} = 1 - \left(\frac{K}{S}\right)^2$$

Example 45-B-4. A sub-station costs Rs. 400 per kVA and capacitor installation cost Rs. 100/kVA.

Calculate the economical p.f.

Solution.

Most economical P.F. is given by

$$\text{P.F.} = 1 - \left(\frac{K}{S}\right)^2 = 1 - \left(\frac{100}{400}\right)^2 = \mathbf{0.955} \quad \textbf{Ans.}$$

Another approach to decide the most economic P.F. is *on the basis of kVA maximum demand.*

Let the capacitor installation be Rs. K per kVA (chargeable for a certain period). Let the charges for kVA maximum demand be Rs. M per kVA (chargeable for the same period).

The most economical p.f. is given by

$$\text{P.F.} = 1 - \left(\frac{K}{M}\right)^2.$$

Example 45-B-5. The tariff of electricity is Rs. 72 per kVA maximum. The charges of capacitor installation are Rs. 12 per kVA calculated for the same period. Calculate the most economic power factor.

Solution. $$\text{P.F.} = 1 - \left(\frac{K}{M}\right)^2 = 1 - \left(\frac{12}{72}\right)^2 = 0.98 \text{ (lag)}$$

Example 45-B-6. Mixed Load.

An industrial sub-station is supplying power to following mixed loads :

1. A 150 h.p., induction motor 1 having efficiency of 89% and p.f. 0.9 lag.
2. A 200 h.p. induction motor 2 having efficiency of 90% and p.f. 0.8 lag.
3. A synchronous motor rated 500 h.p. having efficiency of 93% and p.f. 0.707 lead.
4. Unity p.f. lighting load of 100 kW.

Calculate the p.f. of the sub-station. Calculate kW taken by the sub-station.

Solution. Subscripts 1, 2, 3, 4 are as in the same example. Refer example C-2, proceed in similar way.

Let η = efficiency

$$kW_1 = \frac{\text{h.p.} \times 0.746}{\eta} = \frac{150 \times 0.746}{0.89} = \mathbf{125.7}$$

$$kW_2 = \frac{\text{h.p.} \times 0.746}{\eta} = \frac{200 \times 0.746}{0.9} = \mathbf{165.9}$$

$$kW_3 = \frac{\text{h.p.} \times 0.746}{\eta} = \frac{500 \times 0.76}{0.93} = \mathbf{401}$$

$$kW_4 = 100$$

$$kWAr_{-1} = kW_1 \tan \phi_1$$

$$\phi_1 = \cos^{-1} 0.9 = 25° \, 50'$$

$$\tan \phi_1 = 0.484$$

$$kVAr_{-1} = 125.7 \times 0.484 = 60.8 \text{ (inductive)}$$

Similarly,
$$kVAr_{-1} = 1244 \text{ (inductive)}$$
$$kVAr_{-3} = -\,401 \text{ (capacitive)}$$
$$kVAr_{-4} = 0$$

$$\text{Combined p.f. angle } \theta = \tan^{-1}\left(\frac{\Sigma\, kVAr}{\Sigma\, kW}\right)$$

$$= \tan^{-1}\left(\frac{60.8 + 124.4 - 401 + 0}{125.7 + 165.9 + 401 + 100}\right) = 15° \, 14'$$

$$\mathbf{\cos \phi = 0.965 \text{ Leading.}}$$

Since the load is predominantly capacitive.

45.19. INSTALLATION OF SHUNT CAPACITORS

Capacitors are installed at every distribution voltage level (415 V, 3.3 kV, 11 kV, 33 kV, 66 kV, 110 kV). The capacitors are connected to provide :

(*a*) Localised p.f. improvement, or (*b*) Group p.f. improvement

Several technical and economic aspects should be considered before deciding the location of capacitors in industrial electrical scheme distribution system. The main technical aspects include :

(*i*) Variations in load (*ii*) Type of motors/other loads
(*iii*) Load distribution (*iv*) Circuit diagram
(*v*) Length circuits (*vi*) Voltage conditions
(*vii*) Cost aspects.

Localised P.F. Improvement. This is made by placing capacitors near motor/small feeder feeding the load.

To obtain maximum advantage, capacitors should be connected near the load or near the end of feeders. This reduces losses in supply circuit and improves voltage near load point.

Localised power factor for improvement can be with switched capacitors or unswitched capacitors depending upon the voltage rise during low load period.

Fig. 45.11 illustrates locations of capacitors in industrial electrical scheme, C_4, C_5 indicate localised p.f. correction. C_1, C_2, C_3 indicate group correction.

C_1 is capacitor bank installed 36 kV or 66 kV network.

Group Power Factor Improvement. This is made at the primary or secondary side of supply transformer (C_1 in Fig. 45.11) or near main switchgear for motor control centre (C_2 and C_3 group p.f. correction is used when load shifts suddenly between feeders. Group correction is also used when they are several small capacity loads mixed with medium capacity loads.

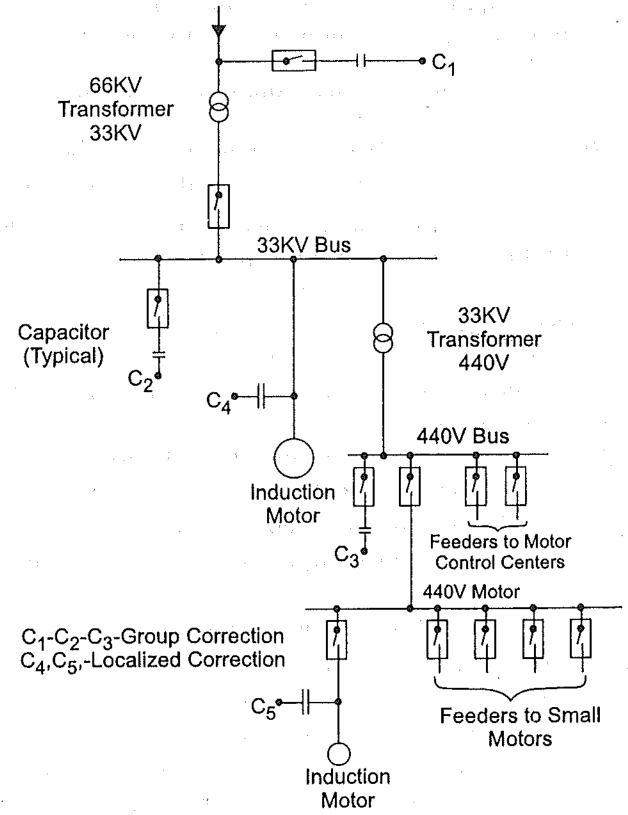


Fig. 45.11. Location of Capacitors in Industrial Scheme.

Capacitors near Motor Terminal. Capacitors are generally installed across terminals of the induction motors when connected in this way, the kVAr should be limited to such a value that the voltage rise near motor terminals is within safe limits when the breaker is open. Refer Table 45-B for reference values of capacitor rating for motors.

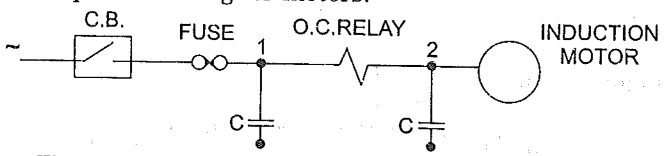


Fig. 45.12. Alternative positions of capacitor connected to motor.

When capacitors are switched along with motor, attention should be paid towards setting of overcurrent relay. Refer Fig. 45.12 explaining alternative position of capacitor with reference to position of over current relay. When capacitor is on supply side (1), capacitor current is not seen by over-current relay. Hence, over current-relay setting is unchanged.

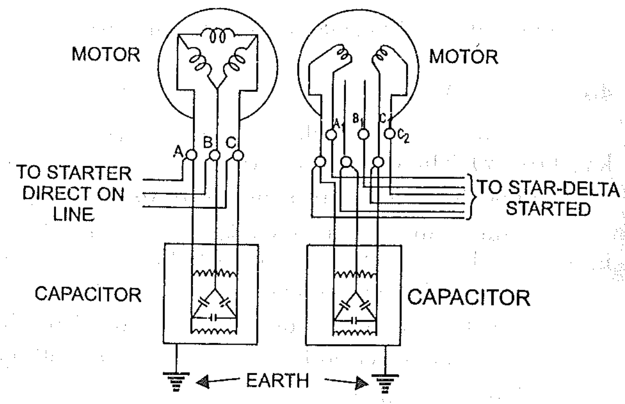


Fig. 45.13. Connections of Capacitor to Induction Motors.

When capacitors are switched along with motor with over-current-relay on supply side (position 2) the over-current relay on supply side (position 2) the over-current relay will see lesser current. Hence lower setting required. For example line current for full load operation of motor with improved power-factor is given by the following expressions :

$$\text{Line current} = \text{Motor full load current} \times \frac{\cos \phi_1}{\cos \phi_2}$$

where, $\cos \phi_1$ = Full load P.F. without capacitors

$\cos \phi_2$ = Improved P.F. with capacitors.

This aspect should be considered when O.C. relay is on supply side as shown in position 2, Fig. 45.12. Fig. 45.13 illustrates typical connections of capacitors for direct connections with motor.

Installation of 33 kV shunt Capacitor Bank. Fig. 45.14 illustrates a typical scheme. The capacitor bank is connected in star and its neutral is *not* grounded. The circuit breaker should be suitable for capacitor switching. It should not re-strike while capacitor current breaking.

While closing parallel capacitor banks, one bank discharges into the other giving high frequency in rush currents. Series reactor shown in Fig. 45.14 is of such reactance that the frequency *fn* of L.C. circuit is within specified limits of breaker capability of closing operation.

Vacuum circuit-breakers are suitable for capacitor switching, because

— They can perform repeated operations without need for maintenance.

— They can open large capacitor banks without restrike due to rapid rate of rise of recovery voltage.

— They can withstand high amplitude of inrush currents of higher frequency.

Refer Fig. 45.14 giving essential protections. Lightning arrestors provide protection against over-voltage.

Over-current and earth fault relays provide respective protection to capacitor bank.

Residual voltage transformer (RVT) gives protection against unbalanced loading due to blowing of individual unit fuse. Fuses with capacitor units give short-circuit protection to individual capacitor units.

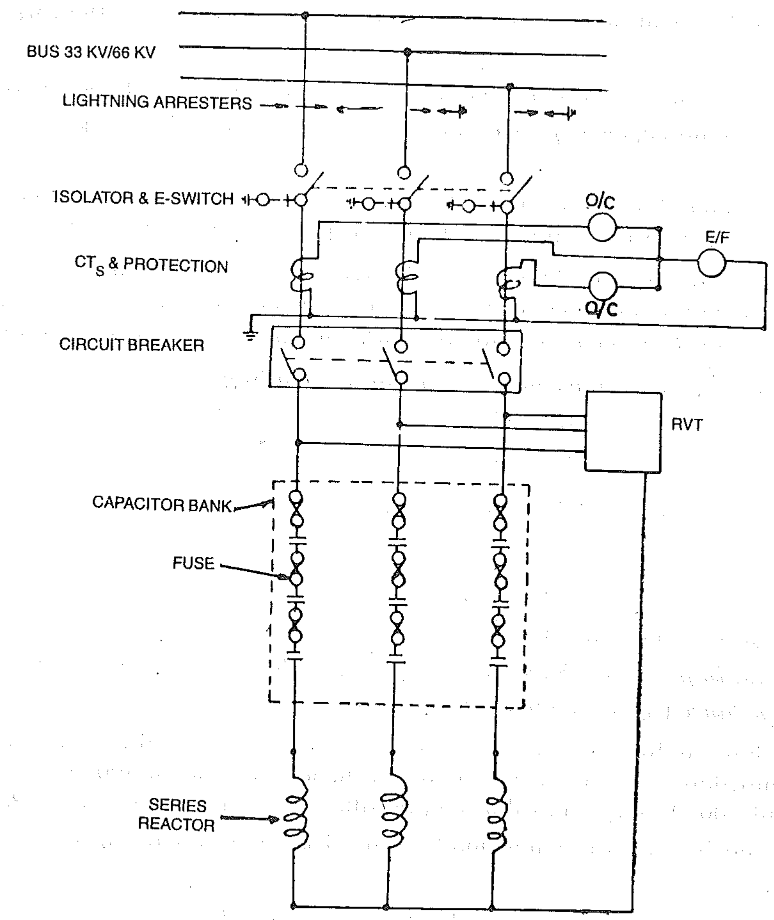


Fig. 45.14. Star connected H.V. capacitor bank.

45.20. REACTIVE POWER REQUIREMENTS AND VOLTAGE REGULATION OF EHV/UHV A.C. LINES. SURGE IMPEDANCE LOADING

The reactive power requirements of long EHV/UHV lines pose a serious problem in voltage regulation.

The voltage variation occurs along the length of line and with charging load. Refer Sec. 48.13.

Let
E = Series inductance phase, henry
C = Shunt capacitance, phase to n, Farads
V = Phase to neutral voltage, Volts
I = Line current
$\omega = 2\pi f = 314, \quad f = 50$ Hz

Reactive power *produced* by shunt capacitance of the line (Q_C) is given by :

$$Q_C = VI = V,\ V/X_C = V^2/X_C$$

$$= \omega C V^2 \quad \text{Volt amperes reactive/phase } (-)$$

Q_C for a given line will depend on voltage of line. Reactive power *Absorbed* by series inductance of the line (Q_1) is given by

$$Q_L = \omega L I^2 \quad \text{Volt ampere reactive/phase, } (+)$$

Q_L for a given line will depend upon line current I. [As per convention, Q_C is negative and Q_L is positive].

By shunt compensation at receiving end, the line current I is reduced and the reactive power absorbed by the line is reduced, *i.e.* $[Q_L = \omega LI^2]$ is reduced by switching-in shunt capacitors at receiving-end.

The compensation requirements of the EHV line depends on line loading is generally expressed in terms of Surge Impedance Loading (P_n) as a multiple of P_n. (Say 1.2 P_n or 0.9 P_n).

If the load on the line is such that (the load current I is such that) the reactive power produced by the line (Q_C) is equal to the reactive power supplied by the line (Q_L) the load impedance is called Surge Impedance (Z_S). The line is said to have natural load or unit Surge Impedance Load.

Thus for unit *surge impedance loading, or natural loading*

$$Q_C = Q_L$$

$$\omega CV^2 = \omega LI^2$$

Hence $$CV^2 = LI^2$$

i.e., $$\frac{V}{I} = \left(\frac{L}{C}\right)^{\frac{1}{2}} = Z_s$$

(This has a unit of impedance).

Hence the load impedance which gives Q_C produced by the line equal to Q_L absorbed by line is called surge impedance (Z_S) of the line.

Surge impedance of line depends on L and C parameters of the line and is independent of line length. Surge impedance of a single conductor overhead line is about 400 Ω and with twin bundled conductors about 300 Ω. Surge impedance of oil filled cables is of the order of 25 Ω.

Power carried by the line when load is equal to (Z_S) and it carries current I such that $V/I = Z_S$ is called

Surge impedance loading or Natural loading. It is given by

$$P_n = VI = \frac{V^2}{Z_s} \text{ Watts.}$$

where P_n = Natural load or Surge impedance loading

Z_s = Surge impedance of line = $\sqrt{\frac{L}{C}}$ ohms

V = Rated voltage of line = Volts

Hence for Surge Impedance Loading.

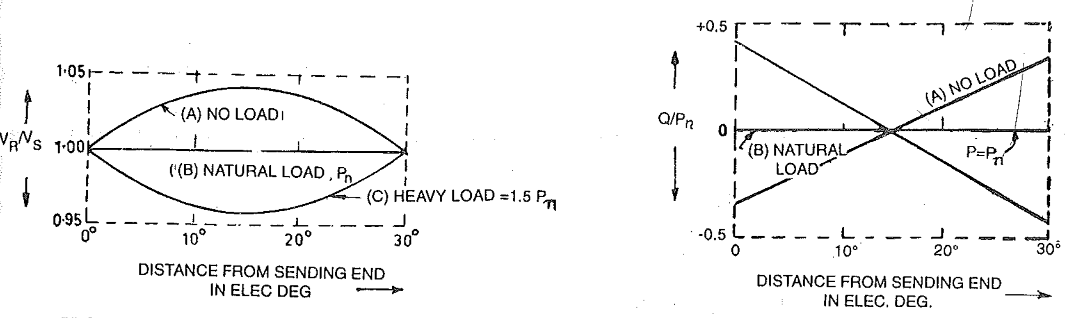
$$I_n = \frac{P_n}{V} \text{ ...... Amperes}$$

Since Z_S for a given line is independent of line length, and depends mainly L and C of line, typical values can be mentioned.

Rated Voltage of Line, kV	132	220	400	765
Surge impedance loading, MW (Natural Load P_n)	40	125	500	1700

Surge impedance loading gives approximate idea of loading of line.

Ref. Fig. 45.15 illustrating the variation of voltage along a line carrying a load (*a*) No load (*b*) Natural load and (*c*) Heavy load.



(*a*) Voltage variation along length of a long line. (*b*) Reactive power Active power ratio for a long line.

Fig. 45.15.

When line is carrying natural load ($P = P_n$) the magnitude of voltage is the same everywhere along the line.

In Fig. 45.15, the line length has been expressed in terms of electrical degrees. This is obtained as electrical angle θ,

where $\theta = l\sqrt{LC}$

l = length of line actual, metres

L = series inductance of line per metre per phase

C = shunt capacitance of line per metre per phase

If the line voltage V is to be regulated within say 105% and 95% throughout the line for both low loads and heavy loads, compensation of reactive becomes necessary when power transferred P through line becomes equal to P_m.

$$P_m = P_n \sec\theta$$

where $\theta = l\sqrt{LC}$

P_n = Natural load of line.

Above $P = 1.5\ P_n$ the reactive power requirement increases rapidly.

From curve B in Fig. 45.15, to maintain constant voltage throughout the length of line.

— Reactive Power should be absorbed during low loads, *i.e.* shunt reactors should be switched-in.

— Reactive power should be supplied during heavy loads, *i.e.* shunt capacitors should be switched-in.

— Reactive power requirement increases as the length of line increases.

Reactive power compensation requirements of transmission line varies with line loading.

The transmission line loading based on thermal ratings of conductors is much higher than $P = 1.5\ P_n$. But the increased requirements of compensation and voltage regulation problems set a limit of power transfer to about 1.3 P_n.

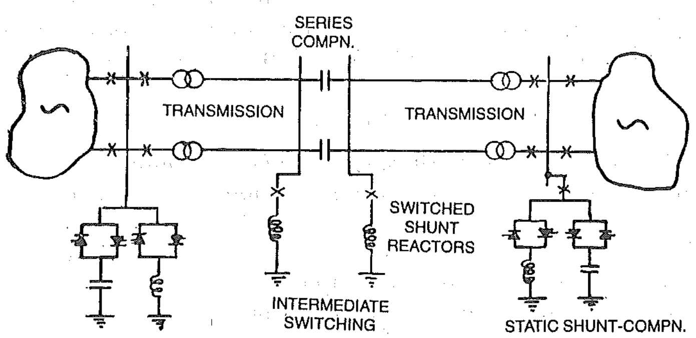


Fig. 45.16. A typical EHV/UHV AC Transmission Line indicating series compensation and shunt compensation.

Long EHV transmission lines need an intermediate switching sub-station to enable installation of series capacitors and shunt reactors. A typical scheme is illustrated in Fig. 45.16.

Summary

Voltage of various sub-stations buses should be held within specified limits, the variation allowed is ± 10%.

Whereas the active power flow (*P*) determines directly the frequency (*f*) it does not affect the voltage significantly.

Voltages are affected significantly by the flow of reactive power (*Q*).

$$\Delta V = \frac{QX}{|V_R|}$$

where $|V_R|$ = Receiving end voltage of the line

Q = Reactive power flow through the line

X = Series reactance of line

ΔV = Voltage drop in line = $|V_S| - |V_R|$

Voltages are controlled by supplying reactive power Q called compensation.

Generator voltage is regulated by automatic voltage regulator and excitation system.

Transmission line voltage is regulated by tap-changing transformer, shunt capacitors, shunt reactors, series capacitors, SVS.

Tap-changing transformers are widely used for network transformers distribution transformers and transformers in the industrial electrical schemes. Off-load tap-changers are used for seasonal voltage variation, on-load tap-changers are used for daily voltage variation. Tap-changers have tap selector, diverter switch and motor drive unit voltage measuring relay having two sets of contracts.

— "raise" and "lower" sends command to the tap-changer. Tap changer operates automatically. Change in voltage ratio is achieved by change in turns ratio.

Shunt capacitors are connected near load point, in factory sub-stations, distribution and sub-stations, receiving stations. They improve power factor, reduce kVA demand, reduce line current and line losses.

Shunt capacitors should be switched in during low voltage, heavy load and switched off during high voltage, low load.

Series capacitors are used for long EHV transmission lines for voltage control and stability improvement. During high load, the reactive power loss in the line reactance is compensated by kVAr supplied by series capacitors.

Flexible AC Transmission (FACT) combines the controllable series capacitors and SVS to achieve control of voltage, power, swing angle (δ).

Voltage control in transmission system is influenced by reactive power flow. By appropriate action in each sub-station, the voltage control is achieved.

Voltage control methods are of three different types : (1) Slow and steady state (2) Medium fast (3) Very fast for transient voltage stability improvement.

45.21. REACTIVE POWER MANAGEMENT

1.0. As we now know that, reactive power compensation improves power factor, stabilizes and maintains the voltage. Series compensation is suitable for transmission line while shunt compensation is used at the distribution sub-station and at the load. For lower capacities, synchronous condenser may be employed which gives smooth control of reactive power, while for larger capacities, static capacitors are employed. Shunt reactors are required to compensate for charging reactive power under light load conditions. Self adjustment in the reactive power is possible by Static VAR Compensators (SVC) which also damps the system oscillations.

2.0. In an integrated power system, efficient management of active and reactive power flows is very important. Quality of power supply is primarily judged from the frequency and voltage of the power made available to the consumer. Keeping in view of the safety, security, quality and

economic considerations, reactive power (VAR) has to be supplied by utilities, as certain loads like Induction Motors, Arc furnances, Welding Machines etc. can not function without reactive power. Further-more, there are statutory limitations of voltage & power factor variation in every country and these are required to maintained within specified limits under all operating conditions. Voltage and reactive power are interrelated fields. Voltage levels are index to measure of balance of generation and consumption of reactive power. In India, the load curve shows wide fluctuations at various hours of the day. The variation is different in various regions of the country. At light load condition, there is excess reactive power available in the system, this causes rise in the system voltage (leading power factor condition). When load demand is heavy, more reactive power is consumed and there is low voltage (lagging p.f. condition). During both the conditions reactive power is to be minimized.

3.0. Disadvantage of Reactive Power

In the peak demand hours, due to inductive or lagging p.f. loads in the system e.g. Fluroscent lamps, Arc Furnances, Agricultural pumps, Traction Motors etc. voltage is less and thus leading VAR demand is more. It has got the following effects :

(*i*) *Effect on Load :* It is extremely important that a consumer gets a constant stable voltage as all the equipments are rated for a constant specific voltage. This results into reduction in the output or in some equipments current drawn increases i.e. IR loss is more and due to heating equipments may get damaged for voltage consumers use voltage Regulators etc which is again a drain on the resources & cause of unnecessary load & harmonics.

(*ii*) *Effect on Transformers :* For the same power to be transmitted over the line, it will have to carry more current at a low power factor. As the line is to carry more current, its cross sectional area will have to be increased, which increases the capital cost of the lines. Also increased current increases the line loss, or the efficiency of the line is lowered, and the line drop is also increased.

(*iii*) *Effect on Generators :* With the low power factor the KVA as well as KW capacities are lowered. The power supplied by the Exciter is increased, as well as the Generator copper losses are increased, so their efficiency is decreased.

(*iv*) *Effect on Prime Movers :* When the p.f. is decreased, the Alternator develops more reactive KVA or the watt less power generated is more, but a certain energy is required to develop it which is supplied by the Prime Mover. This is, the part of the Prime Mover capacity is idle and represents dead investment. Working at low p.f. also decreases the efficiency of Prime Mover.

(*v*) *Effect on Grid :* Due to poor p.f. loads, voltage will be far behind from the rated value. To boost up load bus voltage additional reactive power will be supplied by the Generators. Due to over load Generator/Generators may trip.

(*vi*) *Effect on Switchgear and Bus Bars :* The cross-sectional area of the bus bar, and the contact surface of the Switchgear must be enlarged for the same power to be delivered at low p.f.

(*vii*) In the off-peak hours, due to minimum inductive loads (leading p.f. situation) in the system, system runs in leading VAR (i.e. leading p.f.) condition, which causes high voltage in the system because of which equipments get damaged.

4.0. Advantages of Compensation

(*i*) A greater load can be carried before system reinforcement becomes necessary. An improvement in p.f. from 0.65 to 0.90 increases the system capacity by 30%.

(*ii*) Due to reduction in the current drawn, additional load can be met without additional rating of equipments i.e. loading capacity of the power distribution system is increased.

(*iii*) Because of less heating, the ageing of the insulation becomes slow and thus the life of cable/equipment increases.

(*iv*) Switchgear wear and tear is minimised because of lesser arcing energy dissipation.

(*v*) The KW capacity of Prime Movers/Generators/Transformers & Lines are increase i.e. efficiency is more.

(*vi*) The overall cost per unit is lower.

(*vii*) The voltage regulation of the line is improved.

(*viii*) Reduction in power-cuts, due to reduced demand.

(*ix*) User gets reduction in 'KVA demand' charges, avoidance of penal rate for low p.f. and rebate for higher p.f.

(*x*) Reduced depreciation charges on capital outlay and less capital investment.

5.0. Sources of Reactive Power/Var Compensating Devices

(*i*) Generating Units	(*ii*) Synchronous Condensers
(*iii*) Extra high voltage lines	(*iv*) Reactors
(*v*) Series Capacitors	(*vi*) Shunt Capacitors
(*vii*) Static VAR Compensators (SVC)	(*viii*) Phase Advancers

5.1. Various Var Compensating Devices

(*i*) *Generating Units :* The Generating Units are the major sources to generate as well as to absorb reactive power at different load conditions. An under-excited Generator absorbs reactive power whereas an over-excited Generator will generate it. The terminal voltage of the Generator is regulated by its automatic voltage Regulator (AVR). By setting appropriate reference values in AVR and adjusting field current, reactive power can be generated or absorbed within limits. To maintain rated voltage in the bus in case of heavy load/peak demand VAR generated by the Machine as the system voltage is less and in case of less load/lean demand hours VAR absorbed by the Machine as the system voltage is more.

(*ii*) *Synchronous Condensers :* It is a Synchronous Motor working at over excitation or under excitation mode with no load.

Its advantages :

— It can be operated either over excited mode to compensate for reactive power lost during the heavy load periods (lagging VAR condition) or under excited during light load periods to absorb reactive power generated by the Capacitance of the Transmission Line (leading VAR condition).

— By suitable control of excitation it is also possible for the Synchronous Condenser to improve the stability of the Grid during transient fault.

— Fine control of voltage and/or reactive output.

— High speed response by using static excitation system.

— Synchronous Condenser has an inherently sinusoidal wave form and the harmonics in the voltage do not exist.

— Short time overloading is possible.

— Wide continuous operating range, from an over-excited reactive generation of 100% to an under-excited reactive absorption of approximately 60%. Usually Units between 10-100 MVA are generally considered for the purpose.

Its disadvantages :

— Flexibility of installation is more difficult compared to Capacitor Bank.

— Increase of rating is not possible without installation of a major Unit.

— Losses vary between 1.5 to 4% which are more than Capacitor Bank.

— Costly compared to Capacitor Bank.

— Due to rotating parts, wear & tear is more compared to static Capacitor Bank.

(*iii*) *Extra High Voltage Lines :* 400 KV, 220 KV EHV/Transmission Lines are a potential source of high voltage/leading VAR. In the off-peak hours EHV Lines are some times switched off to avert

high voltage. For example, the charging capacity of one circuit at 400 KV, 1000 KM long, is 500 MVAR. So, in peak demand hours, all the EHV circuits should be in service, to provide VAR support in the Grid.

(*iv*) *Reactors :* In extra high voltage networks, capacitive generation often creates problems during operation at low loads; switching operations and disturbances. The severity of such problems increases with the increase in system voltage and increase in line length. Shunt Reactors are a radical means of decreasing the excessive capacitance effects associated with the switching on and off of long lines. They also help to distribute the voltage along the line, decrease the active power losses and the internal over voltages & also enhances system stability under transient fault. The number, size and location of Reactors depend on technical and economic considerations. In case of 400 KV Circuit, Shunt Reactors are connected at both end of the line and at 400 KV Sub-Stations according to need shunt type Bus Reactor is provided. Some times Bus Reactors are also connected in the Tertiary winding of the Transformer. They are all passive elements. In the peak demand hours, Bus Reactors are switched off to avoid low voltage. Generally 60 to 75% of reactive compensation is considered satisfactory, the remaining reactive power being required for the load itself. Under certain load conditions, the number of Reactors connected to the line is varied so as to regulate the transmission voltage and flow of reactive power.

(*v*) *Series Capacitor :* Construction wise, Shunt & Series Capacitors are identical. The two types differ in their method of connection. They are also passive elements like reactors. The voltage on a shunt installation remains constant but the drop across series bank changes instantaneously with load. Series Capacitor is connected in series with the line. A Series Capacitor compensates for the drop or part of, across the inductive reactance of the feeder. The effect of this compensation is valuable in two classes of application. One, on radial feeders to reduce voltage drop and two on tie feeders to transfer power. Series Capacitors are suited particularly to radial circuits where lamp flicker is encountered due to rapid and repetitive load fluctuations, such as frequent Motor starting, varying Motor loads, Electric Welding and Electric Furnaces.

Its advantages :

— The principal application for Series Capacitor is to reduce the effective length of Transmission Lines employed for long distance power transfer, so that the line loading can still approach the Surge Impedance Level (SIL) without encountering problems of transient stability. In other words, it provides increased Line capacity which, in certain cases, obviates the need for constructing additional Transmission circuits.

— The compensation employed in practice is 50 - 60%. For example, the power transfer capability of a Line with 50% compensation is approximately equal to the power transfer capability of two parallel Lines of the same length and voltage. Thus, for example in Russia, by using Series Capacitors on two 850 KM long 400 KV Lines, the capacity has been increased from 450 MW per circuit to 700 MW, obviating the need for a third circuit.

— Enhances transmitting capacity and stability.

— Improved voltage regulation and reactive power balance.

— Elegant and simple.

— The benefit of Series compensation is that the reactive power is self regulating i.e. when more current (varies square of the load current) flows through the Line under load conditions, both, lagging and leading reactive power increases.

Its disadvantages :

— Relay co-ordination aspect

— With the introduction of Series Capacitors, problem of sub-synchronous resonance (SSR) problem arises. The SSR problem comprises of :

(*i*) Self excitation involving resonance of electrical system.

(*ii*) Torsional interaction involving both electrical and mechanical systems.

(*iii*) The transient torque problems occuring during fault and switching operations. For example, when an Induction Motor is started through a Series Capacitor, the Motor may lock in and continue to rotate below normal or synchronous speed. This condition is known as sub-synchronous resonance. It is caused by the Capacitor whose capacitive reactance in conjunction with inductive reactance of the circuit and Motor establishes a resonant circuit at a frequency that of supply.

(*iv*) The cost of Series Capacitor per KVAR is higher than that of Shunt Capacitor.

(*v*) Series Capacitor carry full load current, therefore, the current rating of the Capacitor must be at least as high as load current and preferably, greater than load current to cater future growth.

(*vi*) Under fault conditions, full fault current passes through the Capacitor and voltage across the Capacitor may exceed the permissible limit and may damage the Capacitor. Hence, series Capacitors will have to be provided with special protection schemes devices to take care of fault conditions.

(*vii*) On energisation, a Transformer Bank drawn high transient magnetizing current. If a Series Capacitor is there in the circuit, it may create a resonant condition known as Ferroresonance, and consequent demages.

(*viii*) Shunt Capacitors : Shunt Capacitors are installed in parallel with the inductive load. They are generally distributed at various load points in the Distribution System. The reactive power supplied by Shunt Capacitor varies as square of the voltage applied. In peak demand hours, this should be kept on to generate leading VAR and off-peak hours this should be kept off to avoid high voltage. Shunt Capacitors are normally connected in the 33/11/.415 KV Bus.

Its advantages :

— Static Shunt Capacitors are the most economical means of generation of reactive power.
— Less costly than Synchronous Condenser.
— Lesser Losses (1.5% or less)
— Simple Installation.
— Rating can be increased easily be adding more Units.
— Less maintenance is required.

Its disadvantages :

— Due to harmonic voltage generation, resonance may occur.
— Supply of lagging reactive current not possible.
— Short service life of 10 to 15 years.
— It is difficult to repair a damaged Capacitor.
— They break down easily at voltage exceeding 1.1 times the rated voltage.

(*ix*) Static VAR Compensators (SVC) : In a power system, load varies with the time. In India, there is a considerable fluctuation in the load throughout 24 hours. Over and above matching the supply and demand of active power, reactive power also should be managed continuously to result into reduction in KVA demand, maintaining voltage etc. When demand on the system is more, power factor is less and vice versa.

If fixed Capacitors are employed, on heavy load conditions during peak hours, reactive power compensation may not be achieved fully, while under light load conditions, voltage may shoot up. This is because, when fixed type Capacitors are installed, KVAR is based on average load so that over voltage may not take place under light load conditions.

By employing automatic switched Capacitors, reactive power compensation can be achieved according to changing load. There may be three or four steps. During light load conditions, Capacitors can be switched off. With fixed Capacitors KVA demand reduces but p.f. fluctuates. It is observed that when SVC are used, KVA demand reduces and p.f. & voltage are maintained almost constant. By reducing the peaks, it helps to smoothen the load curve. The SVC is a parallel combination of

Thyristor controlled VAR absorption components (Reactors) and VAR generation components (Capacitor Banks). This provides automatic reactive power control.

Its advantages :

— Reliable, fast acting and maintenance free as compared to Synchronous Condenser.
— It has low losses
— Improves p.f. and regulates voltage, & also damps the system oscillations.
— It also increases power handling capacity and transient stability of the system.
— It has a high degree of reliability and is cost effective.

(*x*) Phase Advancers (PA) : Most of the Motors used as drives are Induction Motors. Phase Advancers improve p.f. of an Induction Motor (IM). The induction Motor has low p.f. as stator winding draws magnetizing current which lags behind the supply voltage by 90°. If the magnetizing ampere turns can be provided from some other source, stator winding will be relieved of the magnetizing current and the p.f. can be drastically improved. A PA is an a.c. excite connected in rotor circuit of an IM, which provides the magnetizing Ampere turns at slip frequency. In IM the rotor frequency is much less than that of the stator so it is desirable to supply the magnetizing Ampere turns from the rotor at slip frequency rather than from the stator at supply frequency. The IM may operate at a leading p.f. if magnetizing Ampere turns provided are more than that required, PA may be of following types :-

(*i*) Leblanc's Exciter   (*ii*) Schebious Phase Advancer
(*iii*) Walker Phase Advancer   (*iv*) Kepp Vibrator

Main advantage with PA is that as compared to Synchronous Condenser, they have small output. However, they are economical only for large capacity Induction Motor.

QUESTIONS

1. Explain the methodology of voltage control in electrical power system.

2. State whether the following statements are right or wrong. Write correct statements.
(*a*) Shunt capacitors are switched off during low load.
(*b*) Series capacitors is generally used for power factor improvement.
(*c*) Voltage control in power system is achieved by changing load.
(*d*) Load shedding is used when voltage falls below specified limits.
(*e*) Synchronous condensers are installed in generating stations.
(*f*) Voltage control is possible from load control centre.

3. Explain the function of shunt capacitors. State the various locations of shunt capacitors.

4. Illustrate the electrical scheme of a typical 33 kV shunt capacitor installation. Explain the function of each component.

5. Explain the function of series capacitor for EHV transmission. Draw a schematic diagram of a series capacitor installation. State the function of circuit-breaker.

6. Fill in the gaps :
(*a*) Capacitor bank is switched ... when load increases and is switched... when load decreases.
(*b*) Over excitation of synchronous motor causes current of ... P.F.
(*c*) Series capacitors are generally used for transmission lines rated ... kV.
(*d*) Capacitors take current of ... P.F.
(*e*) Induction motor has P.F. of the order of ....

7. Explain the relation between voltage and reactive power of a transmission line. Explain the use of :
1. Shunt capacitor   2. Series capacitors   3. Shunt reactors.

8. Fill in the blanks :
(*a*) Shunt capacitors are installed in ...

(b) Typical ratings of shunt capacitor banks for

11 kV sub-station one ... MVAr and
33 kV sub-station one ... MVAr.

(c) Typical rating of a shunt capacitor for a 5 kW motor is ... kVAr.

(d) Series capacitors are usually used for transmission lines of rated voltage ....

(e) Series capacitors improve the ...

9. State the various methods of voltage control in electrical network.

10. Explain the methods of voltage control in a 220 kV/132 kV sub-station.

11. Explain the co-relation between reactive power flow and voltage regulation of a transmission line.

12. With the help of neat schematic diagrams explain the following (*any one*).

1. Layout of a 33 kV Shunt Capacitor Bank.
2. Layout of one pole of an EHV Series Capacitor Bank.
3. Static Shunt Compensation Scheme.

45-C

Voltage Stability of Electrical Network

Introduction — Voltage Instability — Vr/Pr and Q/V characteristics — Voltage Collapse Occurances and their time-spans — Preventive Measures against Voltage Collapse — Terms and definitions.

45.22. INTRODUCTION TO VOLTAGE STABILITY STUDIES

The traditional *Steady State Stability Studies* and *Transient Stability Studies* take into account the active power flow P and power angle δ, and assume constant receiving and sending end bus-voltages. The *reactive power flow* Q and voltage fall during heavy current flow are neglected. This approach could not explain the several power system black-outs in USA, Europe, Japan etc. during the last quarter of the twentieth century. The black-outs were due to the voltage collapse. Voltage collapse phenomena are of more frequent occurance in rapidly growing interconnected power systems in India and other developing countries where reactive power management is inadequate.

The voltage collapse incidents have occured under high lagging load currents, stalling of induction motors, inadequate shunt compensation at receiving end, sudden tripping of a generator unit or a bulk-power transmission line, heavy HVDC power flow without adequate shunt capacitors at inverter, a line fault or bus fault, starting of a large induction motor, sudden or gradual increase in distribution load up to limiting power flow through transmission lines, etc. During voltage collapse, the *bus voltage starts falling* and as a result the power transfer P through the transmission lines *starts reducing* resulting in ultimate voltage collapse and loss of system stability of entire Network.

The term *voltage instability* was introduced in 1982. The Voltage Stability Studies have received more attention after 1982 and have acquired a vital place in power system studies (1995). The loss of power system stability due to fall of voltage (voltage collapse) is called Voltage Instability. Voltage stability is one of the several type of Stabilities (Ref. Sec. 44.24). Voltage stability is of three types depending on the time span (t) of voltage collapse :

— Short-term Voltage Instability ($t < 1$ to 10 seconds). (Also called transient voltage instability.) This corresponds to rotor angle oscillations in transient state stability.
— Mid-term Voltage Stability
— Long-term Voltage Stability

45.23. EXPLAINING VOLTAGE INSTABILITY

We recall from Sec. 45.16 that the voltage drop ΔV in the transmission line and receiving voltage $|V_r|$ of a transmission line are closely related with reactive power Q and line reactance X and the relationship is given by

$$\Delta V = |V_s| - |V_r| = \frac{XQ}{V_r} \qquad ...(45.2)$$

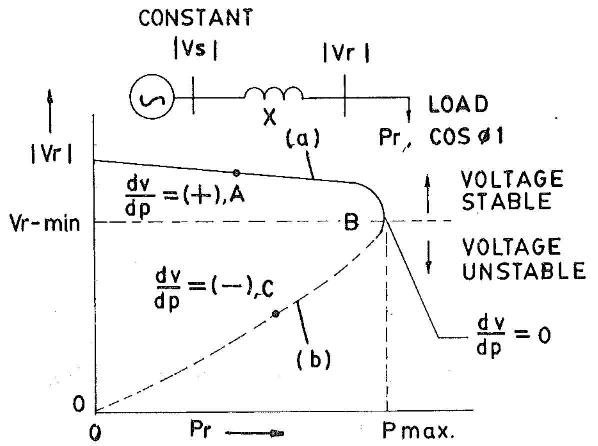


Fig. 45.17. Explaining voltage stability.
(Receiving Voltage Characteristics of an AC transmission line with constant sending end voltage $|V_s|$ and increasing load P_r at power factor cos·1.)

Assuming constant sending end voltage $|V_s|$, the receiving voltage $|V_r|$ reduces with increasing lagging power factor load. Fig. 45.17, gives typical graphs of $|V_r|$ versus active power P_r, *with sending end voltage* $|V_s|$ *constant.*

The characteristic are U curves with axis parallel to P coordinate. Any point A on the upper half (a) of the curve has negative dV/dP where increase in P gives drop in voltage, hence condition of stable voltage. Any point C on lower half (b) of the curve has positive dV/dP, where increase in P gives increase in voltage, hence an unstable voltage. Point B at the tip of the V curve corresponds to P_{max} and $dV/dP = 0$ represents Steady State Voltage Stability Limit. If MVA load with constant p.f. is increased beyond P_{max}, voltage collapses and it is not possible for the transmission line to feed the increasing power demand, P_r start reducing and Voltage Stability is lost. The reason for voltage instability is understood from Eqn. 45.2 above. The voltage drop ΔV in the line is due to reactive power Q_r demanded by the load. If this reactive power is not supplied at the receiving end of the transmission line, the voltage drop ΔV increases and receiving end voltage $|V_r|$ falls. *The reactive power cannot be conveyed through the transmission line,* it must be supplied by capacitors at receiving end. The real power flow is proportional to $\left[\,|V_s| \times |V_r|\,\right]$. Fall of $|V_r|$ results in reduction in P_r. The P_r also falls progressively due to fall in $|V_r|$ resulting in Voltage instability.

45.24. INCREASING VOLTAGE STABILITY LIMIT BY SUPPLY OF REACTIVE POWER

Refer Fig. 45.18, which gives curves of receiving end voltage $|V_r|$ plotted against P_r of various power factors achieved by supply of reactive power Q_r by switching in capacitor banks in steps. Curve 1 is for load p.f. 0.8 with shunt capacitor bank 1 in circuit. The corresponding long term stability limit is P_{m1}. Curve 2 is with shunt capacitor banks 1 and 2 in circuit and corresponding stability limit is P_{m2}; Curve 3 with capacitor bank 1, 2, 3 in circuit has stability limit P_3 and so on. We observe that the Voltage Instability occurs at higher active power with increased supply of reactive power Q_r at load end. By supplying Q_r at receiving end, the voltage drop ΔV in transmission line is reduced and receiving end voltage $|V_r|$ is held in the nearly flat portion of upper half of voltage curve $|V_r|$ vs P_r. The generators become unstable for leading p.f. load supply. Hence the power factor at sending end should be held lagging, slightly below unity.

The dynamic performance is not shown in Fig. 45.17 and 18. It can only be visualised by dashed line of trajectory for short term stability shown in Fig. 45.18.

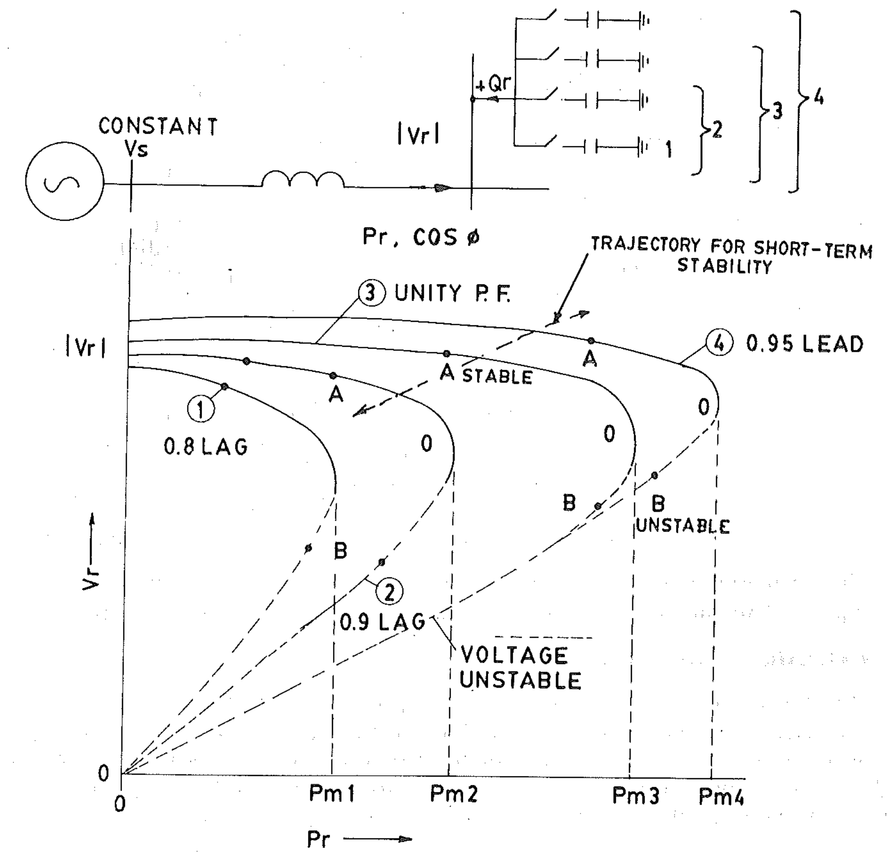


Fig. 45.18. Supply of reactive power Q_r at receiving end by switching on Capacitor Banks.

45.25. SEQUENCE OF SWITCHING-ON AND SWITCHING-OFF SHUNT CAPACITOR BANKS

The receiving end bus voltage should be held constant between specified V_{r-min} and V_{r-max} corresponding to rated nominal bus voltage V_r during regular load variation in power system. For mid-term steady state variation of few minutes this voltage control is achieved by switching-on capacitor banks during fall in voltage and switching on capacitor banks during rise in voltage. Refer Fig. 45.19, curves 1, 2, 3, 4 correspond to receiving end voltage V_r is plotted against P_r for various power factors of P_r.

Curve 1 is for load p.f. 0.8 with shunt capacitor bank 1 in circuit. At point A on curve 1, the voltage has reached V_{r-min} corresponding to permissible lower system voltage. Capacitor bank B is switched on. Point shifts to point a on curve 2. At point B, capacitor bank B is switched in and operating point shifts to b on curve 3, and so on. With load increasing, the capacitor banks are switched on in steps to maintain voltage above V_{-min} and to avoid voltage collapse. During decreasing load P_r, the voltage would tend to rise above V_{r-max}. Capacitors are switched-off in reverse order, at highest permissible system voltage V_{r-max}.

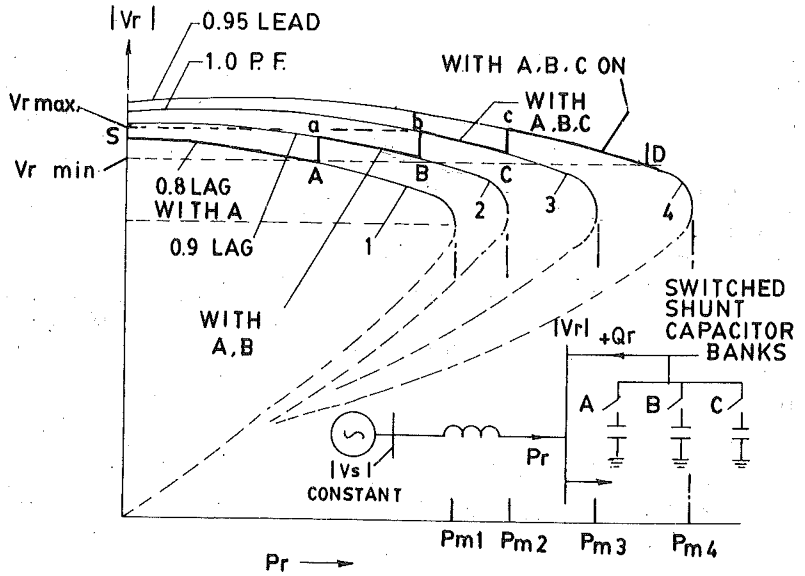


Fig. 45.19. Switching sequence for capacitor banks for voltage stability.

V_{r-min} = Specified Minimum system voltage, Capacitor bank switched in during increasing load

V_{r-max} = Specified Maximum system voltage, Capacitor bank switched off during decreasing load.

45.26. Q—V CHARACTERISTICS

Fig. 45.20 shows how the receiving voltage V_r varies with variable Q_r. The operating point moves along constant power curve. By supplying capacitive reactive power (+ Q), the voltage of operating point increases. By absorbing inductive reactive power (– Q), the operating point comes down resulting in fall of voltage. Fig. 45.21 illustrates effect of switching in the shunt capacitor banks 1 and 2, on voltage at operating point along constant power curve P_1.

The shunt capacitor banks provide compensation $Q_c = V^2/X_c$, which is proportional to square of voltage and is represented by curves 1 and 2. The operating point a corresponds to intersection

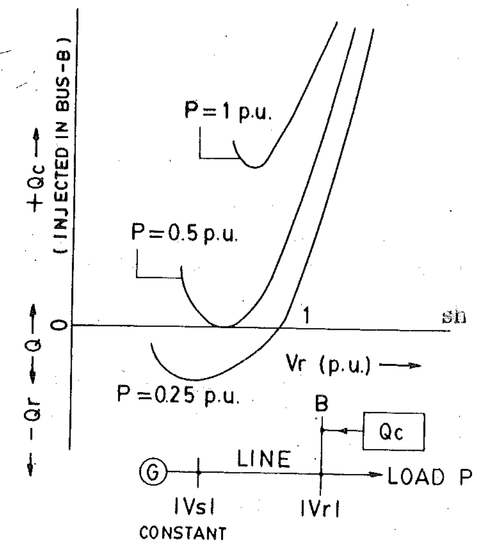


Fig. 45.20. $Q - V_r$ curves for constant

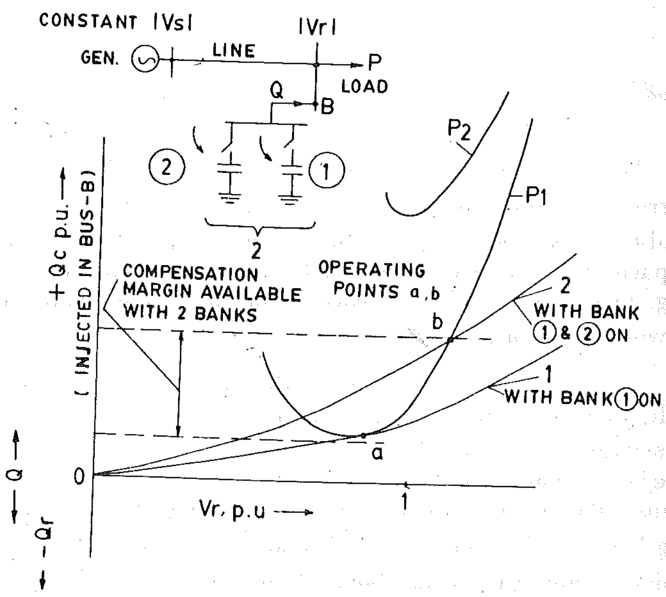


Fig. 45.21. $Q_C - V_r$ curve with curve 1 and 2 for reactive power supply.

point of load curve P_1 and the curve for 1 Bank 1. Likewise, point b is for Bank (1 and 2) in circuit and load P_1. By making Bank 1 and 2 on in steps, the voltage V_r is raised to V_a and V_b respectively.

By thyristor control of shunt capacitor current + Q_r is varied, the operating point on P_1 line could be moved steplessly from a to b and voltage could be raised steplessly from V_a to V_b.

45.27. VOLTAGE COLLAPSE OCCURANCES, AND THEIR TIME-SPANS

Voltage stability is of three types depending on the time span of voltage collapse :

— Short-term Voltage Instability (t < 1 to 10 seconds). (Also called transient voltage instability.)

— Mid-term Voltage Stability (t < 10 sec to 3 minutes)

— Long-term voltage stability (t > 3 min. to an hour)

Voltage collapse can occur due to several individual incidents or sequential combination of incidents occuring under unfavourable load generation and reactive power compensation situations.

	STVS	*MTVS*	*LTVS*
1. Gradual increase on line load,			*
2. Gradual increase in Distribution Load			*
3. Inadequate Shunt compensation at Receiving End			*
4. Starting of Large Induction Motor	*	*	
5. Step increase in Export of Power	*		
6. Fault on Line, Busbar, Equipment	*		
7. Tripping of Local Generator/Feeder	*		
8. Inadequate Shunt Compensation of HVDC AC bus			*

STVS — Short-term Voltage Instability (t < 1 to 10 seconds). (Also called transient voltage instability.) The time corresponds to oscillations in rotor angle during power swings.

MTVS — Mid-term Voltage Stability (t < 10 sec to 3 minutes)

LTVS — Long-term voltage stability (t > 3 min. to an hour)

These time spans are approximate and for classification of voltage stability.

Fig. 45.22 illustrates various possible causes described below.

1. *Gradual Increase in Load with Poor P.F.* (> P, < cos ϕ)

The load may be combination of distribution load and subtransmission line load. The time span of such occurance is a few tens of minutes to a few hours near peak load hours on daily load cycle. Station operators can take manual action for increasing turbine settings and increasing power supply. The switched capacitor banks can be switched in. The Voltage Stability comes under *Long Term Voltage Stability*. As the load approaches P_m the stability limit is reached. The value of P_m is very low for poor lagging p.f.

2. *Inadequate Supply of Reactive Power to Loads*

The AC bus voltage starts falling with increasing lagging p.f. load. If reactive power compensation is inadequate, the operating point on V_r/P_r curve goes beyond V_r-min resulting in Loss of Voltage Stability. The occurance comes under Long Term Voltage Instability and takes several tens of minutes.

The reactive power can be despatched through transmission line. It should be supplied directly into receiving end/load bus appropriate shunt compensation. If this is not done, the voltage of receiv-

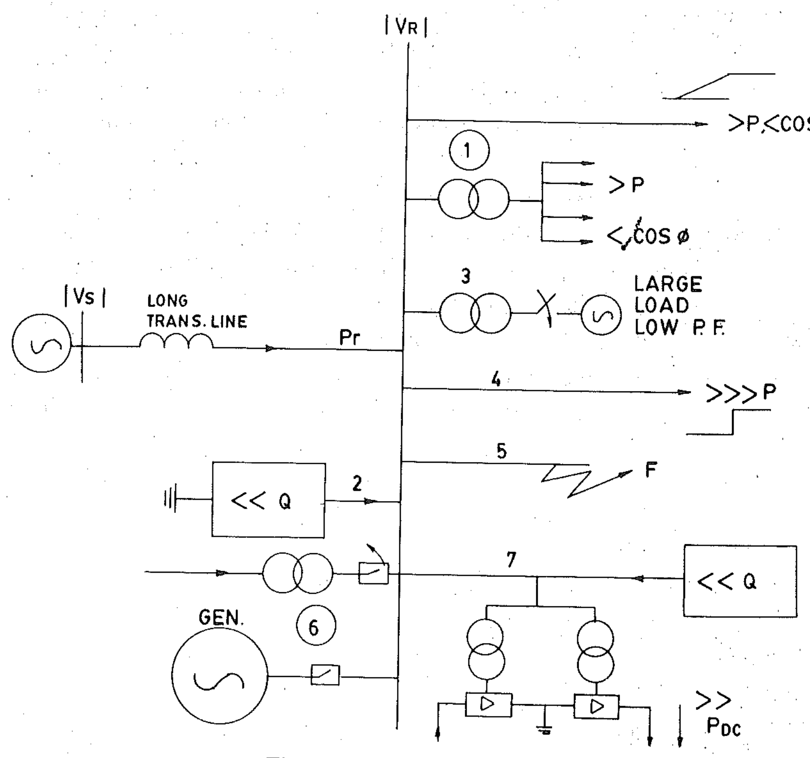


Fig. 45.22. Occurances leading to voltage collapse and their time spans.

ing bus falls gradually resulting in ultimate loss of voltage stability. This comes under *Long Term Voltage Stability*.

3. *Slow staring and Stalling of a Large MV Induction Motor direct on line, during peak load.* The voltage dips and motor takes longer time to start. If motor circuit breaker does not pick-up, motor bus voltage collapses. This has cascade effect on substation bus voltages and voltage collapse may occur. The occurance takes several seconds upto a minute and comes under "short term voltage stability and mid term voltage stability."

4. *Sudden Step-power import by Remote Substation.* The operating point on V_r/P curves shifts beyond stability limit under "Transient instability condition." The occurance is called Short term Voltage Instability or Transient Voltage Instability. The time span is less than 10 seconds.

5. *Fault on Busbar or Transmission Line.* The voltage collapses, power is diverted to fault. Voltage Stability is lost within a few seconds, and the incidence is under Short Term Voltage Stability Regime.

6. *Tripping of Generating Unit or Parallel in-feed transmission Line.* This has an effect on sudden increase in P_r supplied by the Transmission Line, beyond its Stability Limit P_{max} and increased voltage fall below $V_{r-\min}$ due to loss of local generation/infeed support. The category of such occurance is under Short Term Voltage Stability.

7. *Sudden Increase in Pdc through HVDC Line without Corresponding Increase in Supply of Reactive Power Q at inverter terminal.*

When the bus is connected to HVDC Convertor, the voltage support is provided by additional shunt capacitors/AC filter capacitors. Total MVAr drawn by HVDC Inverter from AC bus is of the order of 60% P_{dc}. If the reactive power supplied to HVDC Inverter AC bus is not increased, the reactive power is drawn from the incoming AC transmission lines and the receiving end voltage

$|V_r|$ falls. The load on HVDC line should be reduced to avoid collapse of AC bus voltage, at inverter end to ensure : "Long Range Voltage Stability".

45.28. PREVENTIVE MEASURES AGAINST VOLTAGE COLLAPSE

The preventive measures against voltage instability are taken simultaneously at load points, distribution level, sub-transmission level and main transmission level. The methods are listed in Table 45-D.1.

Table 45-D.1. Preventive Measures Against Voltage Collapse

Method	*Time*	*Application*				
		Generation	*Main Trans.*	*Sub Trans.*	*Distri.*	*Load*
AVR	(ST)	*				
OLTC	(MT, LT)		*	*	*	*
Shunt Reactor Unswitched			*			
Shunt Capacitor	(MT, LT)			*	*	*
SVS	(ST)			*	*	*

Ref. Ch. 45A and Ch. 46.

45.29. DEFINITIONS

Voltage Stability is a type of Power System Stability and the terms covered in Sec. 44.24 are suitably applied.

The difference between Long Term and Short Term Voltage Stability are on *time frame of disturbance/change in load.* The Mid-term voltage instability is applicable for time zone in between short term and long term voltage stabilities.

Steady State (Long Term) Voltage Stability. A power system is steady state voltage stable if following a small *slow* disturbance or increase in load, the system voltages regain steady state equilibrium values without voltage collapse.

Long-term voltage stability refers to behaviour of system which takes 3 minutes to several minutes. The means available for voltage control over long term are voltage relays and tap changing transformers, switched shunt capacitors, switched shunt reactors, load shedding, HVDC interconnection, etc.

Mid-term Voltage Stability refers to behaviour of the system lasting for about 10 to 30 seconds. The means available for improving mid-term voltage stability improvement are : Switched shunt capacitors, Switched shunt reactors, Tap changing transformers.

Short Term Voltage Stability. A power system is short term voltage stable if following a *sudden aperiodic* disturbance or increase in load, the system voltages regain steady state equilibrium values without voltage collapse.

Short-term Voltage Stability refers to behaviour of the system for a few seconds. For short term voltage stability improvement available means are : Excitation system control and AVRs of synchronous machines, thyristor controlled shunt compensation, tap changing of transformers, FACT systems, unswitched shunt capacitors and shunt reactors, series capacitors.

Voltage security. It is the ability of the power system to operate stably with voltages within permissible limits following a disturbance or load increase.

Load-frequency control is carried out simultaneously from generating stations and distribution systems to match total generation systems to match total generation with total prevailing load to maintain frequency within specified limits. However this is not enough. Voltage Stability must also be maintained to ensure system stability.

QUESTIONS

1. Explain the phenomena of voltage collapse during high lagging power factor load on receiving end of long AC transmission line.
2. Describe the procedure of switching in of shunt capacitors to prevent voltage collapse.
3. Define Short term voltage instability and long term voltage instability. Give examples of occurances of voltage instability in short term and long term range.
4. State the various methods of maintaining steady state and short term voltage stability.

45-D

Automatic Voltage Regulators, Voltage Control and Stability of Synchronous Generators

Introduction —Operation of Synchronous Generator—EMF and No Load terminal voltage, Saturation curve—Significance of Field Current I_f— Terminal Voltage of an Isolated Generator with constant field current and without AVR —Synchronous Generator in parallel with the Grid —Types of Excitation Systems and AVRs—Terms and definitions on AVR and Excitation Systems—Excitation Systems and AVR (Synchronous Machine Regulators)—Steady state performance Excitation Systems and AVRs— Transient Performance of AVRs-Excitation System Voltage Response— Generator Capability Curves—Protective Limiters—V/Q Diagram— Power System Stabilizer—Protective, Regulating and Limiting Features.

45.30. INTRODUCTION

The voltage control and reactive power flow control of various Network-busses is carried out simultaneously from load-substations, distribution substations, transmission substations and generating substations; by means of OLTCs, SVS, Shunt Capacitors and AVRs. The bus voltages and reactive power supply in generating stations are controlled by and the Excitation Systems and Automatic Voltage Regulators (AVR) of synchronous generators. The modern term for the Automatic Voltage Regulator is *Synchronous Machine Regulator.*

We will use the term Generator for Synchronous Generator (Alternator) and AVR for Synchronous Machine Regulator.

The variable associated with generator are :

— Frequency f — Induced emf E_a,

— Stator armature current I_a, — Terminal voltage V_t,

— Power factor cos ϕ, — Field current I_f, (DC)

— Apparent power S MVA, Active power P MW and Reactive power Q MVAr

$$S = P + jQ$$

— Rotor speed N_s and Power angle δ between vectors $\mathbf{E}_a$ and $\mathbf{V}_t$.

These variables are *interdependent.* MW output, Speed and frequency are controlled by Governor of Prime Mover and load MW. Voltage, MVAr and power factor are controlled by the AVR in Excitation System under steady state and dynamic state and compensation of reactive power at load bus. The load conditions and/or Grid condition also influence the operating characteristics.

Mechanical Active power P_m is supplied by prime mover and converted to electrical Active Power P (MW) by Generator. AVR does *not* control active power MW, speed N_s and frequency f.

AVR controls the terminal voltage V_t and, power factor cos ϕ, and the Reactive Power supply MVAr by generator.

In addition to voltage control and reactive power control, the AVR performs steady and transient stability functions, limiting functions and protective functions.

Reactive power MVAr and power factor of armature current are closely associated with the *magnetic field* in the generator air gap which is resultant of (1) rotor magnetic field due to field current of generator and (2) armature reaction due to current and its power factor. Net reactive power demanded by the load from the generating station bus, is equal to [Load MVAr ± Shunt Compensator MVAr]

Neglecting losses, with *subscripts* : pm for prime mover, g for generator, L for load and sc for shunt compensator)

1. Active Power $P_{pm} = P_g = P_L$. for constant speed N_s

Controlled by Governor to Prime Mover and input to prime mover

2. Reactive Power $Q_g = Q_L \pm Q_{sc}$ for constant p.f.

Controlled by Excitation System and its AVR.

Three phase, 50 Hz, AC Synchronous generators (Alternators) supply Active Power P (MW), Reactive Power Q (MVAr) and resultant Apparent power MVA. Power factor cos ϕ = MW/MVA.

Under normal steady state load conditions the terminal voltage should be held within specified limits and the power factor should be between 0.85 lag and 0.95. Generators are not stable under leading power factor as the armature reaction has magnetising effect and voltage rises with leading load current and excitation current looses control.

During disturbances in the Network such as sudden increase/decrease of load, faults, switching of loads, starting of large motors, in the network, etc. the generator should remain stable. The rotor angle swing should be damped. The terminal voltage should be recovered within few seconds for maintaining stability. This is achieved by field forcing (high field current) and fast excitation response (fast rate of change in excitation) characteristics of Excitation Systems and AVR.

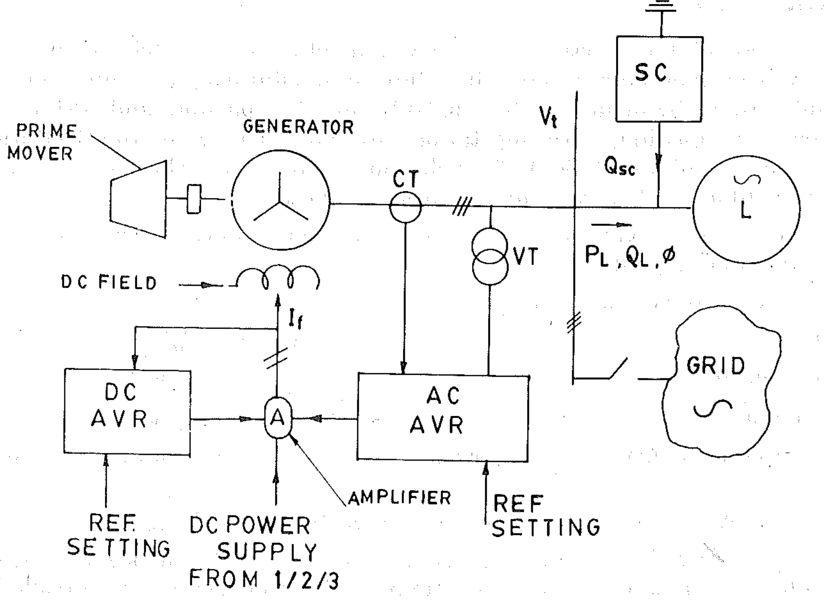


Fig. 45.23. Schematic of a Generator unit, load and AVR.

1. DC Generator 2. Controlled Thyristor Rectifier 3. Uncontrolled Diode Rectifier

SC = Shunt Compensation *REF* = Reference setting

A = Amplifier *CT* = Current Transformer

VT = Voltage Power Transformer not shown for simplicity.

Note. DC AVR senses DC field voltage. AC AVR senses AC voltage and AC current. Actual configuration varies with design philosophy of AVR of particular manufacturer. Power Supply DC is either from DC Generator—Amlidyne combination or from Rectifier mounted on generator shaft or Static Rectifier receiving power from auxiliary source or the Generator itself.

The Automatic Voltage Regulators (AVR)(Synchronous machine regulator) in the excitation system play a very vital role for voltage control, controlling reactive power supply, emf, voltage and power factor of generator, and also maintaining power system dynamic stability, and in protection of alternators by imposing several limits on generator variables.

Modern term for Voltage regulator is *Synchronous Machine Regulator (1986-IEEE Std.).* It is defined as "The regulator that couples the output variables of a synchronous machine to the input of the exciter through a feed back and feed forward control elements for controlling the synchronous machine output variables."

The active mechanical power supplied by prime mover to shaft is equal to active power supplied by generator to load plus losses in the generator. *AVR does not change the active power P of generator; nor does it change the frequency and speed.* However the AVR influences the power angle δ between the revolving stator plus and revolving rotor flux, both locked up synchronously at N_s.

EXCITATION SYSTEM AND AVR

PROTECTION SYSTEM AND LIMITING ⟷ CONTROL SYSTEM FOR MW, f, MVAr, P., F., V

POWER SYSTEM STABILITY AND VOLTAGE STABILITY

Excitation system has a strong **interface** with the generator protection, generator control and power system stability as indicated above.

The functions of an AVR (Synchronous machine regulator) and the Excitation System are :

1. *Regulation of Terminal Voltage automatically.* To regulate the terminal voltage within specified limits of the generator *automatically* under steady state operating condition of varying load/p.f. This is done by controlling field current by means of a feedback system involving Voltage Transformer and Automatic Voltage Regulator.

2. To facilitate reactive power load sharing with other generators operating in parallel.

3. *To regulate the voltage and load angle δ under abnormal conditions and transient disturbing conditions* such as faults, power swings, sudden switching in of large loads, etc. and ensuring higher transient stability limit. This is ensured by rapid control of excitation current during disturbance.

To ensure transient and dynamic stability of the generator and the power station by rapid and automatic control of reactive power supply and to ensure that the synchronous machine does not fall out of step and trip under emergency condition.

4. *To damp swing and electromagnetic oscillations in load angle* δ under abnormal conditions and transient/dynamic disturbing conditions rotor oscillations of synchronous generators and to ensure transiently and dynamically stable operation.

5. *To ensure protection of generator* and excitation system by giving tripping command under appropriate abnormal conditions of variables.

To arrange tripping and rapid field discharge during generator stator faults.

6. *Limiting Features.* To inhibit the tripping of the generator unit by the protection system under permissible swings in active power and reactive power. AVR operates in close liason with the generator protection system and raises the operating limits for ensuring generator service during disturbances.

Choice of features, rated characteristics and complexity of an Automatic Voltage Regulator of a generator may vary from simple manual control with protection interface to a very complex automatic control and improved dynamic stability features and performance limiting features, depending upon application, size and importance of the generator duty.

The terminal voltage characteristics of a synchronous generator depend on following three distinct operating conditions :

1. Single generator is operating in isolation and supplying stand alone load (without supply from the Grid.)

— Terminal voltage varies with Excitation Current, ($V_t \propto I_f$)

— Power factor of generator stator current is equal to load current power factor.

— Reactive power supplied by the generator depends on the reactive power demand by the load, and load power factor.

2. Two or more generators operating in parallel and supplying stand alone load (without supply from the Grid). The terminal voltage depends on the operating conditions of parallel machines and the load conditions.

3. Generator connected to Infinite Bus (Grid or several Generators operating in parallel)

— Terminal voltage is constant and equal to grid voltage.

— Terminal voltage does not vary with excitation current.

— Power factor of generator stator current and Reactive Power Q shared by the generator varies with the excitation current.

Under steady state conditions, the terminal voltage of a generator connected to *infinite bus* bar (Grid or a large power system) is constant and is determined by the prevailing Grid Voltage and not by the generator field current. The power factor of armature current is decisively influenced by the excitation current.

The demands made on AVR performance depend on the load characteristics and the load p.f. The various applications of synchronous generators are represented in Fig. 45.24.

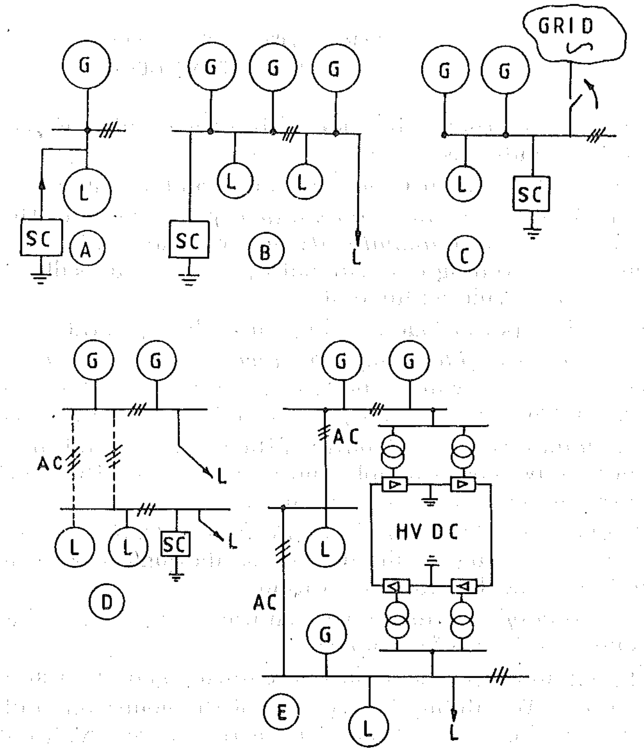


Fig. 45.24. Applications of synchronous generators.
SC = Shunt Compensation L = Load G = Generators

Note : Specifications and type, characteristic features etc. of Controller differ significantly for A to E due to difference in load characteristics/p.f. and protection/control and stability requirements.

A. Single generator feeding a isolated local load.

B. Two or more generators in parallel, feeding a local load and a distribution line.

C. Two or more generators with local load and operating in parallel with the Grid.

D. Two or more generators in parallel, feeding a remote load centre via long AC transmission lines.

E. Two or more generators in parallel, feeding a remote load centre via a long AC transmission line in parallel with a HVDC line.

45.31. OPERATION OF SYNCHRONOUS GENERATOR

A synchronous generator (alternator) has a 3-phase distributed AC armature winding on *stator* and a DC excitation main field winding on the *rotor*.

The rotor is driven at synchronous speed by prime mover (Steam turbine/Hydro turbine/Gas turbine, Diesel engine etc.). The main excitation field winding on rotor of the alternator is supplied DC voltage by the *Exciter*. The main alternator excitation field current. It is increased or decreased by changing Exciter Voltage by Automatic Voltage Regulator and its feedback control system. Rotating magnetic field of DC excitation field of rotor induces 3 phase AC emf in stator armature winding. Flow of stator armature current Ia produces induced revolving magnetic field in the air-gap, revolving at synchronous speed and locked with the rotor magnetic field. The angle between the stator field and rotor field is the load angle δ which increases with load and which undergoes oscillation during disturbances.

The *Main Exiter* provides DC Field voltage to the rotor field winding of the Generator. The exiter-terminal voltage decides the Excitation current (Field current of the generator. The AVR controls exciter terminal voltage and alternator excitation rotor field current to regulate Generator terminal voltage. The pilot excitor (if any) feeds power to the field winding of main exciter.

The generator supplies active power P (MW) at voltage V_t (kV) and power factor cos ϕ, and stator current I_a, (kV), where :

$$P = 3\, V_t\, I_a \cos\phi$$

Consider an isolated generator-load operating mode (without grid connection). The power factor cos ϕ is decided by the load power factor. Magnitude $|V_t|$ is decided by Excitation Current and its control by the AVR.

In case of Parallel operation with the Grid, terminal voltage $|V_t|$ is decided by the Grid Voltage in parallel operation with grid. In that case the power factor of generator armature current Ia is decided by the Excitation Current. I cos ϕ will be get adjusted to required power level, as V_t is constant corresponding to Grid voltage.

The generator also supplies reactive power Q (MVAr)

$$Q = 3\, V_t\, I_a \sin\phi$$

where, I_a = Armature current, V_t = Terminal voltage, and ϕ = Power factor angle

In isolated generator-load operating mode (without grid connection) the Reactive Power Supplied by the generator is equal to Reactive Power demand by load side (Load + Compensator). In that situation, the power factor cos ϕ is decided by the power factor of (load + Compensator). By providing separate shunt compensation to load, the Generator is relieved of reactive power burden to that extent.

The characteristics of generator depend on the net active and reactive power load on the generator.

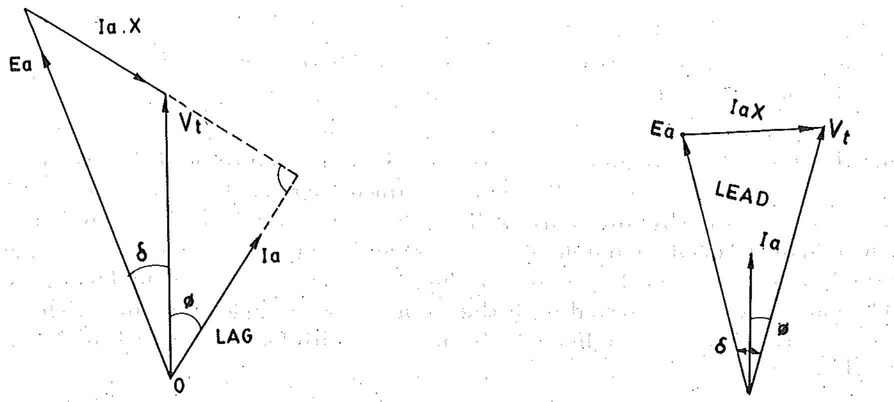
The apparent power is $S = (P + jQ) = 3\, V_t\, I_a$ Voltamperes

Power Factor $\cos\phi = P/S = MW/MVA$

The power angle δ between the two revolving magnetic fields increases with increasing load. During sudden changes in active load or reactive load, the power angle δ undergoes a *swing*. The conditions are studied under transient and dynamic stability studies. In vector diagram, the power angle δ is represented by angle between vectors emf $\mathbf{E}_a$ and voltage $\mathbf{V}_t$. With increase in power P_a, δ should increase.

The vector relationship between emf $\mathbf{E}_a$, terminal voltage V_t and power factor cos ϕ is given by $[\mathbf{V}_t = \mathbf{E}_a - \mathbf{I}_a X.]$

The vector diagram is given in Fig. 45.25. The terminal voltage V_t is equal to vector difference between emf E_a and voltage drop in armature winding ($I_a \cdot X$ drop). Resistance is neglected. $\mathbf{I}_a \cdot X$



A
Lagging p.f. (Overexcited, $\gg E_a$)

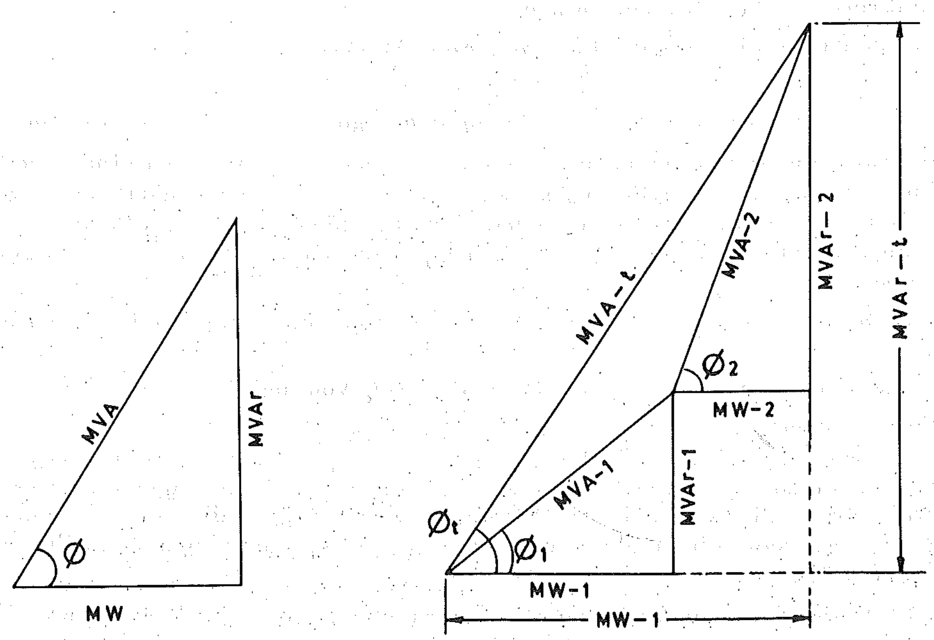
B
Leading p.f. (Under excited, $\ll E_a$)

Fig. 45.25. A, B. Vector diagram of a synchronous generator.

V_t = Terminal voltage E_t = E.M.F. excitation emf or induced emf
I_f = Field current (rotor current) I_a = Armature current (stator current)
cos ϕ = Armature current p.f., ϕ angle between V_t and I_a
δ = Power angle, Load angle, angle between E_t and V_t
[$I_a \cdot X$ drop is perpendicular to $I_a \cdot E_a$ is proportional to I_f. $I_a \cdot$ cos is proportional to P_a]

is perpendicular to I_a. The angle δ between $\mathbf{E}_a$ and V_t increases with active load P_a. The armature current I_a is at certain p.f. angle ϕ with respect to voltage V_t.

The lagging p.f. armature current in generator stator has a demagnetising effect on magnetic flux. Hence the excitation current should be increased to maintain the terminal voltage constant. This is called overexcited condition. The *leading p.f. armature current* in generator stator has a



A
Single generator

B
Two Generators in Parallel

Fig. 45.26. MVA, MW, MVAr and ... relationship.

magnetising effect on magnetic flux. Hence the excitation current should be reduced to maintain the terminal voltage constant. This is called underexcitation condition.

In *isolated operation of generator-load combination,* the power factor of load is same as that of the generator. Hence the net reactive power required by load is supplied by the generator.

In *parallel operation of two or more generators feeding isolated load* without grid connection, the net reactive power demanded from the bus bars by the load-compensator combination is supplied by all the generators operating in parallel. These generators share the reactive power in accordance with their excitation levels and rated MVA.

Two or More Synchronous Machines in Parallel

Synchronous generators operating in parallel have tendency to remain in synchronism with each other.

Terminal voltages of machines operating in parallel are the same total active power generation is equal to total active load on the power plant. Active power supplied by the generator is equal to the active power input to its prime mover.

The total reactive power supplied to load is equal to reactive power supplied by the generator units operating in parallel. The reactive power shared by the generator depends on the excitation current.

The vector difference between emfs in the two generators produces a synchronising current in the local circuit of the two generators operating in parallel.

With grid connection, the terminal voltage V_t remains constant and emf and p.f. of generator is determined by the emf/excitation current level of the generator and the load power factor at generator bus. The latter changes with load/network/bus/compensation conditions.

45.32. EMF AND NO LOAD TERMINAL VOLTAGE, SATURATION CURVE AND AIR LINE

The induced emf of generator depends on the excitation field current. The terminal voltage V_t and power factor cos ϕ depend on other conditions prevailing at bus side depending on operating mode and active plus reactive power load.

Induced electro motive force (emf) varies with excitation current in accordance with the no-load characteristics emf Ea versus field current I_f. This characteristic is called *saturation curve.* The extended straight line is called the *air gap characteristic.* At no load voltage drop in synchronous reactance ($I_a \cdot X$ drop) is zero and the no-load, terminal voltage V_t is equal to emf.

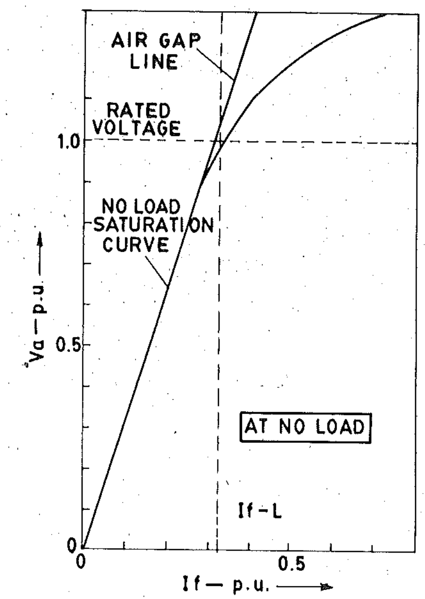


Fig. 45.27. No load terminal voltage V_t against Field Current (Saturation characteristics) of a synchronous generator. V_t on no load = *EMF* that is proportional to I_f.

45.33. TERMINAL VOLTAGE OF AN ISOLATED GENERATOR WITH CONSTANT FIELD CURRENT AND WITHOUT AVR

If field current is held constant, the terminal voltage of an isolated generator (not connected to the grid) would drop with increasing lagging p.f. load current due to I_aX voltage drop in the generator stator winding and demagnetising effect of armature reaction on lagging currents. If the field current is held constant, the terminal voltage of an isolated generator (not connected to the grid) would rise with increasing leading p.f. load current due vector addition of I_aX voltage in the generator stator winding and magnetising effect of armature reaction of leading p.f. current.

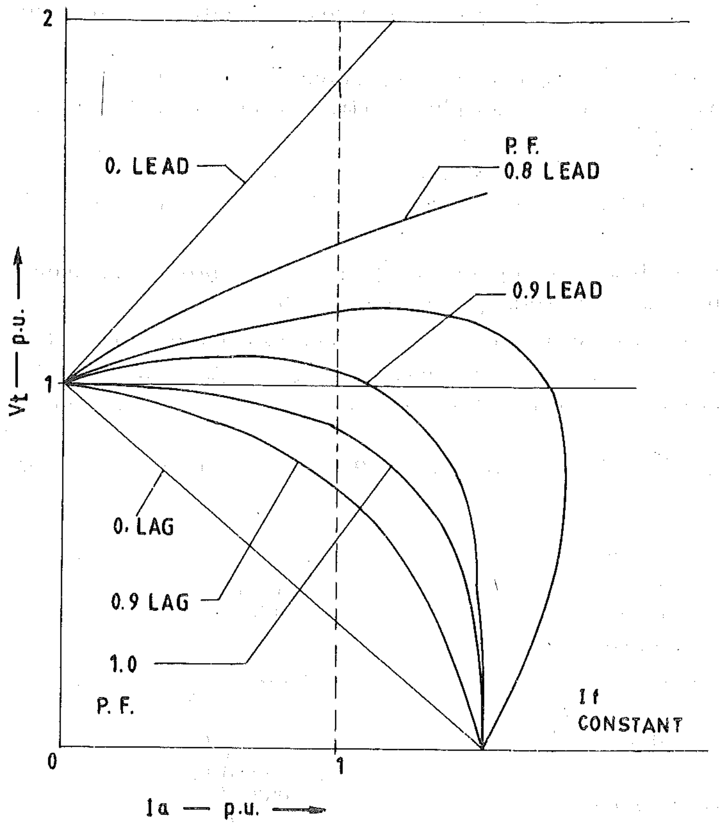


Fig. 45.28. Terminal voltage V_t against Armature current I_a, at constant field current I_f in Islanded operation. (Not connected to Grid)

(**Note** : I_f constant corresponds to constant emf E_a)

Constant Terminal Voltage -V Curves

The well known *V-Curve,* for a synchronous generator is the graph of MVA load on *Y* axis and Field current on *X* axis, *for constant terminal voltage.* Each *V* curve is for a particular level of active power P_a. The power factor curves are also plotted on the same graph. The unity p.f. curve is at the center of the *V.* The right side is for lagging p.f. loads and the left side is for leading p.f. load.

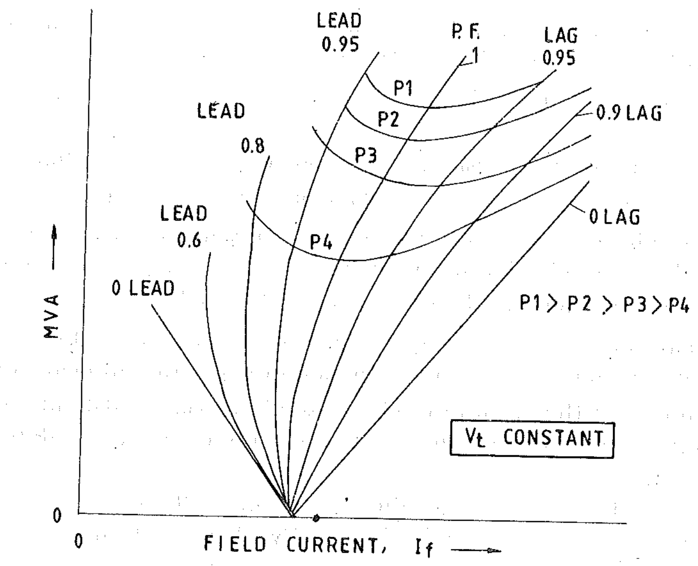


Fig. 45.29. V-curves for synchronous generator.

45.34. TYPES OF EXCITATION SYSTEMS AND AVRs

Automatic Voltage Regulators are a part of Excitation System of Synchronous Machines. Over the past decades the Excitation Systems and AVRs have been developed into several different versions and designs. The principal differences in configuration are in the equipment for supply of DC excitation current and method of feed back from generator output.

As per American Practice, the Excitation System has

1. DC Regulator, DC Regulator is optional in some versions.
2. AC Regulator.

In AC Regulators, the current and voltage supplied by the Synchronous Generator to busbars is measured by the Current Transformers and Voltage Transformers. The reduced secondaries are connected to the AC Voltage Regulator. The AVR compares the actual current and voltage with the desired reference value and gives feed back to the input side of excitation system via an Amplifier. The Amplifier receives DC Power from an Auxiliary Source or the Main Generator and Feeds DC Power to Generator Field as per feed back signal from AVR.

In DC Regulators, the DC field voltage supplied by the Exciter to Field Winding of Synchronous Generator is fed to the DC Voltage Regulator. The DC Voltage Regulator compares the actual DC Field voltage with the desired reference value and gives feed back to the input side of excitation system via an Amplifier. The input is in the form of DC voltage across the field winding of main Synchronous machine.

A. Before 1970s, the earlier versions of Excitation Systems, were with DC Generators and Rotating Amplifier. The DC current required for field was obtained from a DC generator with commutator and brushes. The types of such excitation systems with DC Generators are :

1. DC Generator—Commutator Exciter with Rotating Amplifier The DC generator may be motor driven or generator-shaft driven.
2. DC generator—commutator Exciter with Static amplifier.
3. DC generator—commutator Exciter with Noncontinuously acting Rheostatic Regulator.

B. During 1970s. the of Solid State Devices (Diodes and Thyristors) and Rectifiers were successfully developed and were introduced gradually in the Excitation Systems. The modern Excitation Systems are with Diode Rectifiers (Uncontrolled) or Thyristor Rectifiers (controlled).

With the availability of semiconductor diodes and thyristors, the DC commutator generator excitors are no more used in new installations. The types of modern Excitation systems are :

1. Brushless Excitation System : Alternator—Rectifier Exciter employing Rotating Diode Bridge Rectifier.

2. Alternator—Exciter, employing Stationary Noncontrolled Diode Rectifier.

3. Alternator—Exciter, employing Stationary Controlled Thyristor Rectifier.

Under steady state conditions, the *terminal voltage* of an *isolated generator* (without any other machine or grid in parallel) is decided by the (1) Field Current I_f (excitation current) (2) Armature current (I_a) which in turn depends on load current and (3) Power factor of I_a.

With lagging p.f. load, the terminal voltage tends to drop and the field current should be increased. The load p.f. must be improved by providing shunt capacitors in load side.

With the leading p.f. load the terminal voltage tends to rise and field current should be decreased and the load p.f. should be brought near unity or high lagging by adding shunt reactors in the load side.

Fig. 45.28 shows how the terminal voltage will vary *without* voltage regulator for various power factor loads. However, in practice the terminal voltage of Synchronous Generator bus must be regulated within specified limits *i.e.* rated voltage with tolerance ± 1%.

As per standard specifications of Synchronous Machines, the permissible variation in generator voltage is ± 5%. The AVRs ensure voltage variation within ± 1%.

In case of isolated generator-load, the terminal voltage is regulated by increasing the field current during increasing lagging p.f. load, manually by the operator or automatically by AVR. Likewise, during increasing leading p.f. load current, the excitation current is reduced manually or automatically to reduce emf and regulate the terminal voltage.

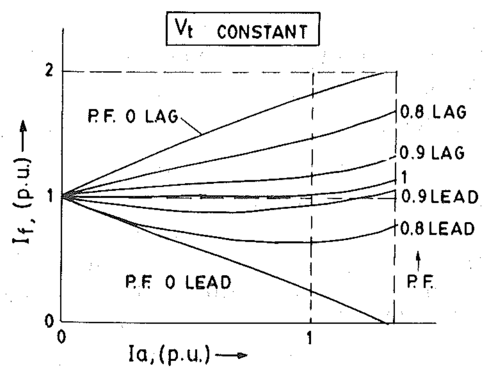


Fig. 45.30. Field current I_f versus Armature current I_a for constant terminal voltage V_t.

For stand-alone (isolated load) synchronous generator the DC field current (excitation) is varied to regulate the terminal voltage. The field current may be varied by manual control by intervention of the control room operator or by Automatic Voltage Regulators in the feed back control system in the excitation system of the generator.

Lagging p.f. load requires higher field current of generator (over excitation), leading p.f. load requires less field current (under excitation. The leading p.f. load current has a magnetising effect on the stator magnetic field and therefore there is a lower limit imposed on the value of load current.

For lagging p.f. higher load, higher field current is necessary to maintain the terminal voltage within specified limits.

Alternatively the shunt capacitors on load side may be switched on to improve load p.f. and relieve the excitation system from overcurrent and heating. Power factor of armature current I_a. The power factor of armature current is decisively influenced by the power factor of the load current and not by the excitation current.

45.35. SYNCHRONOUS GENERATOR IN PARALLEL WITH THE GRID (INFINITE BUS)

Generator operating in parallel with the grid has a tendency to remain in synchronism (in step with) the grid. Grid can be considered. Infinite Bus having constant voltage and constant frequency. With generator in synchronism with the infinite bus (grid), the terminal voltage V_t is controlled by

the prevailing Grid Voltage which is constant. The terminal voltage of the generator does not change by change in its field current (unlike in the case of generator operating on isolated load). The change in field current of the generator affects the power factor of the generator armature current and reactive power shared by the generator. Active power shared by the generator remains unaffected.

The synchronous machine connected to infinite bus (Grid) operates as generator or motor or condenser (compensator) depending upon the power input to generator shaft and electrical power delivered by the synchronous machine.

For generator operation mechanical power input is more than electrical output and o is considered to be positive, and we get

$$V_t + I_a X = E_t$$

For motor operation, electrical power input is more than the mechanical power output and o is considered to be negative, we get,

$$V_t - I_a X = E_t$$

For compensator operation, the electrical power is equal to mechanical shaft power and δ is zero, $V_t = E_t$.

The amount of field current of the synchronous machine connected to grid determines mainly the machine-power factor and to lesser extent the load angle. The load angle is determined by the electrical load on generator terminals and the mechanical power input to the shaft. If mechanical shaft input power is stopped, the machine continues to rotate in motor mode taking electrical input from grid.

The *V*-curves shown in Fig. 45.30 illustrate the characteristics of the synchronous generator operating at constant terminal voltage achieved by changing field current I_f.

Table 45D.1
Types of Excitation Systems and Source of Excitation Power

Exciter Category	*Type of Exciter*	*Exciter Power Source*	*Initial Response*
DC	DC Generator commutator Exciter	Motor-Generator set or Syn. Machine Shaft	Slow
AC	Alternator-Stationary Non-controlled Diode Rectifier	Syn. Machine Shaft	Slow
AC	Alternator-Rotating Non-controlled Diode Rectifier Brushless Exciter	Syn. Machine Shaft	Fast
AC	Alternator-Stationary Controlled Thyristor Rectifier	Syn. Machine Shaft	Fast
St	Potential Source Controlled Rectifier	Synch. machine voltage or Aux. Bus Voltage	Fast
St	Compound Source Non-controlled Diode Rectifier	Synch. machine voltage and Current	Slow
St	Compound Source controlled Thyristor Rectifier	Synch. machine voltage and Current	Fast

45.36. TYPES OF AVR AND EXCITATION SYSTEMS

A1. DC Generator-Commutator Exciter with Amplidyne Voltage Regulator

Fig. 45.31 shows a simplified schematic of a typical earlier excitation system. The DC generator (Main Excitor) was driven by a separate motor or was mounted on main generator shaft through

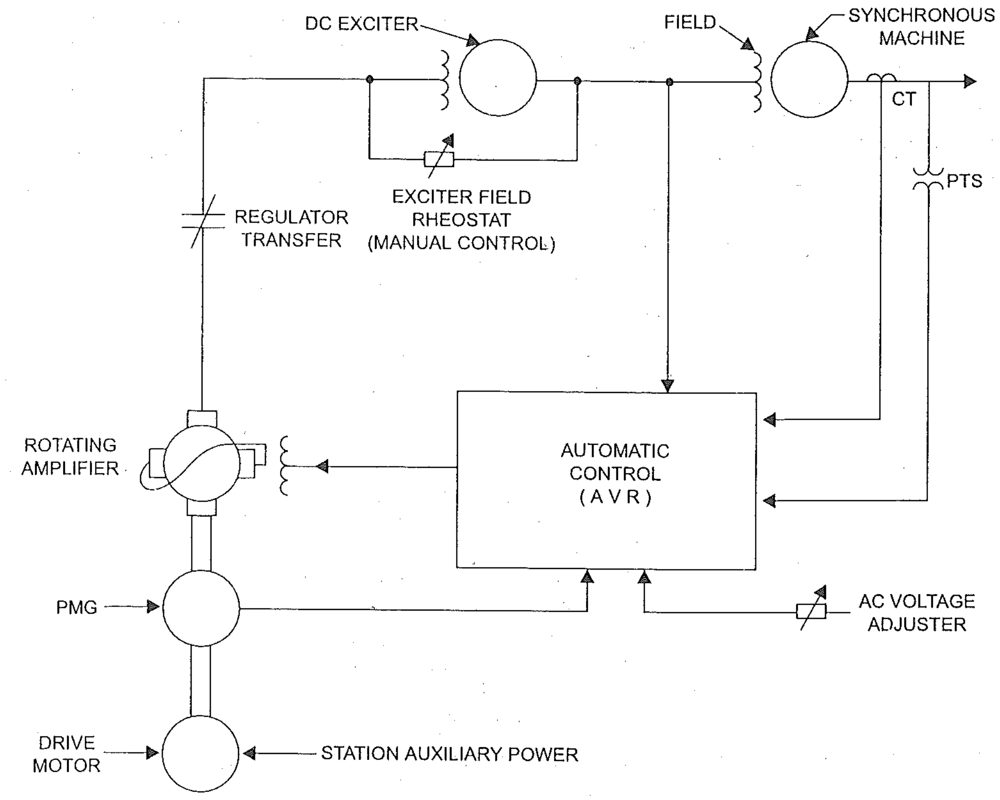


Fig. 45.31. Schematic of excitation system with DC generator-commutator exciter with rotating amplifier.

gear arrangement for speed change. The feed back signal was amplified in Amplidyne (DC Rotating Amplifier). The field current for Main Excitor DC generator was supplied by Pilot Excitor (a permanant magnet DC generator PMG).

The DC generator may be motor driven or generator-shaft driven.

The DC Generator Exciter System had achieved a high degree of reliability and was well accepted universally upto mid 1970s. However the modern Excitation systems are with Diode or Thyristor rectifiers, lesser weight/size, having superior characteristics and lesser maintenance.

B. Brushless Excitation System

Fig. 45.32 gives a schematic of a Brushless Excitation System with Rotating Noncontrolled Diode Rectifier Excitation System.

It consists of an AC Exciter and a rotating diode bridge mounted on generator shaft. A small permanant magnet generator (PMG) provides excitation current to the stator AC exciter field. The excitation current supplied to stator of AC Exciter field is controlled by stationary AVR by manual control or Automatic control.

Brushless excitation systems have no brushes/slip rings/commutators. The AC Exciter-rotor and, Rotating Diode Rectifier Bridge are mounted on the generator shaft without the need of brushes. Alternator field winding is connected to the two terminal plates of Rotating Diode Rectifier Bridge. The rotating rectifier bridge receives 3 phase input from AC Exciter Rotor and gives DC output to alternator field. The AC Exciter Stator has DC winding which receives DC power from Permanant Magnet Generator (PMG) through AVR Control.

The *flow of excitation power* is as follows :

Main field of Generator ← Diode Bridge on Rotor Shaft of Gen. ← Three phase rotor winding of AC Exciter on Gen shaft

↑

Field current for stator of AC exciter from PMG through AVR (PMG has rotating Poles and Stationary DC winding)

AVR The brushless excitation system is preferred for alternators where the control requirements are not very stringent or where sparking at brushes or commutators is not permissible due to chemically explosive environment (*e.g.* mines).

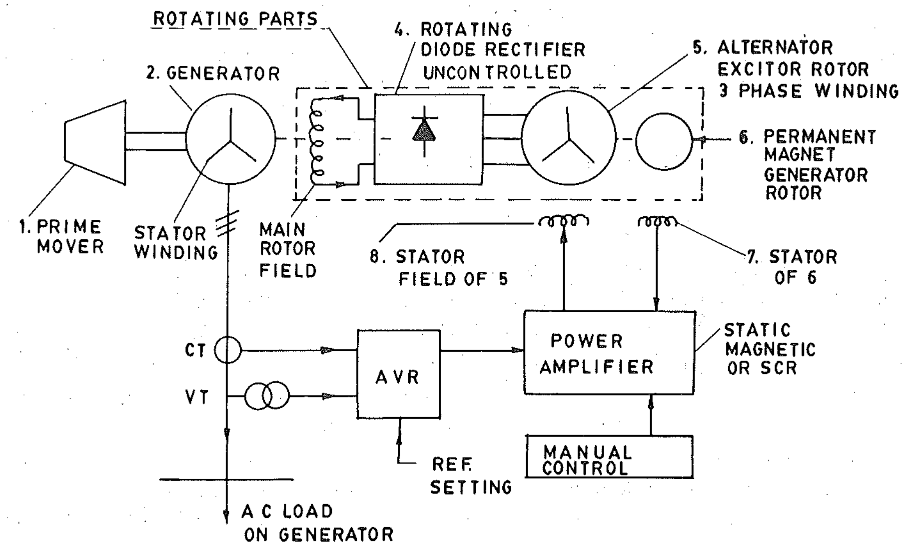


Fig. 45.32. Simplified schematic of brushless excitation system with rotating Noncontrolled diode rectifier.

Note : Design configurations may differ, the above figure illustrates a typical example.

C. Alternator-Exciter with Stationary Noncontrolled Diode Rectifier

The excitation power is supplied by Alternator Exciter. The Alternator Exciter is a direct coupled AC generator driven by main generator shaft. The Alternator-Exciter has a stationary 3 phase armature winding and rotating DC field winding. The 3 phase stator winding supplies AC power to stationary uncontrolled diode rectifier bridge. The output of this rectifier bridge is supplied to the Main Generator rotor field through two slip rings.

The rotor DC field of Alternator Exciter is supplied current through stationary controlled thyristor rectifier bridge. The firing angle of thyristor bridge is controlled by AC Regulator or DC Regulator.

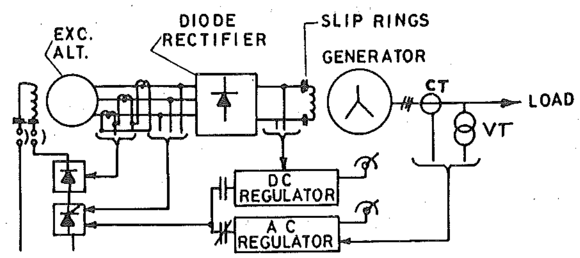


Fig. 45.33. Excitation system with "Alternator-Exciter employing stationary uncontrolled diode rectifier bridge".

Note : Design configurations may differ, the above figure illustrates a typical example.

The power for excitation is derived from the Power CT and Power VT whose primaries are connected in the main power circuit between Alternator **Exciter** and Stationary Rectifier Bridges.

D. **Alternator-Exciter Employing Stationary Controlled Thyristor Rectifier**

Like in the C above with a difference that the Stationary Rectifier feeding DC to Main Generator field is a controlled *Thyristor Rectifier Bridge* supplying DC Field current, the excitation power is supplied by Alternator-Exciter. The control of thyristor bridge firing angle is by Regulators.

The Alternator Exciter is a direct coupled AC generator driven by main generator shaft. The Alternator-Exciter has a stationary 3 phase armature winding and rotating DC field winding. The 3 phase stator winding supplies AC power to stationary controlled thyristor rectifier bridge. The output of this thyristor-rectifier bridge is supplied to the Main Generator Rotor Field through two slip rings.

The rotor DC field of Alternator Exciter is supplied current through stationary controlled thyristor rectifier bridge. The firing angle of thyristor bridge is controlled by AC Regulator or DC Regulator.

The power for excitation is derived from the Power CT and Power VT whose primaries are connected in the main power circuit between Alternator Exciter and Stationary Rectifier Bridges.

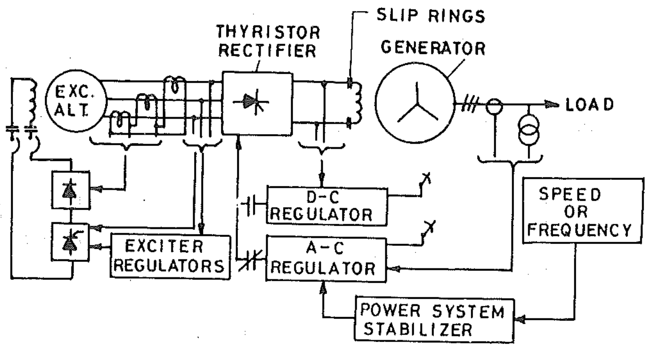


Fig. 45.34. Excitation system with "Alternator-Exciter employing stationary controlled thyristor rectifier bridge".

Note : Design configurations may differ, the above figure illustrates a typical example.

E. **Voltage Source Controlled Exciter**

The excitation power is supplied by the generator through Voltage-Power Transformers.

F. **Compound Source Controlled Exciter**

The excitation power is supplied by the generator through compounded output of Voltage-Power Transformers and Current Power Transformer.

45.37. TERMS AND DEFINITIONS ON AVR AND EXCITATION SYSTEMS (Ref. IEEE Std. 1986, BS Std. 1987)

1. **Excitation System.** The equipment for providing field current (excitation current) to a synchronous machine. The equipment includes all power/control/regulating and protective elements.

2. **Regulated Voltage.** The voltage which is held within specified band or zone during steady or gradually changing load conditions within specified range of load.

3. **Band or Zone of regulated Voltage** is expressed as percenta of rated value of rated voltage. (*e.g.* + 3 per cent of rated V_t).

4. **Exciter.** The equipment providing field current for excitation of a synchronous machine.

5. **Pilot Exciter.** The equipment providing field current to the exciter field.

6. **Automatic Voltage Regulator.** A subsystem of the excitation system for regulating the terminal voltage of synchronous machine automatically.

7. **Voltage regulator** is a hystoric term. Modern term is Synchronous machine regulator. (1986)

8. **Synchronous Machine Regulator.** The regulator that couples the output variables of a synchronous machine to the input of the exciter through a feed back and feed forward control elements for controlling the synchronous machine output variables.

9. **Rated field current.** Direct current in the field winding of the synchronous machine operating at rated : voltage, current, power factor.

10. **Rated field voltage.** Direct voltage required across the terminals of the field winding of the synchronous machine under rated continuous load conditions with its field winding at specified temperature. (*e.g.* 75°C)

11. **Excitation system nominal response.** Rate of increase of excitation system output voltage divided by rated field voltage. (Ref. Sec. 45.40) Rate of increase of excitation system output voltage is determined from excitation system nominal response curve. Fig. 45.36.

12. **Exciter voltage response time.** Time in seconds for exciter voltage to reach 95% of the (difference between ceiling voltage and rated load field voltage) under specified conditions.

13. **Excitation system Ceiling Voltage.** The maximum DC voltage which the excitation system can supply to the generator field winding for a specified short time.

Excitation system Ceiling Current. The maximum DC current which the excitation system can supply to the generator field winding for a specified short time.

14. **Field forcing.** The control function that rapidly forces the field current in the synchronous machine in positive or negative direction.

15. **Voltage Regulating Adjuster.** A device associated with the Regulator by which the adjustment in terminal voltage of synchronous generator can be made.

16. **Limiter.** An element in the excitation system which acts to limit a variable under certain predetermined conditions. *e.g.*

(*a*) **Under Excitation Limiter :** Prevents the voltage regulator from lowering field current below specified limit.

(*b*) **Over Excitation Limiter :** Prevents the voltage regulator from raising field current above specified limit.

(*c*) **Volts per hertz Limiter :** Acts through voltage regulator to limits V/f ratio within specified limits and takes corrective action to make V/f normal.

16. **Manual Control.** The control of terminal voltage of synchronous generator by operators action, *e.g.* by adjusting field rheostat, controlling angle of firing the thyristors of controlled rectifier.

17. **De-Excitation.** Removal of excitation (field current) of main exciter or pilot exciter. For example by opening field circuit and discharging the field by means of Field Discharge Circuit Breaker.

18. **Field Forcing.** Control function that rapidly increases or decreases the field current of the synchronous machine.

19. **Power System Stabiliser.** A group of elements in the excitation system that supplement the voltage regulating function and provide additional regulating function to improve the dynamic performance of power system.

20. **Types of AVRs (Synchronous Machine Regulators).** In the past, the DC current required for field was obtained from a DC generator with commutator and brushes. The types of such excitation systems are :

(*a*) DC Generator—Commutator Exciter with Rotating Amplifier. The DC generator may be motor driven or generator-shaft driven.

(*b*) DC generator—Commutator Exciter with Static amplifier.

(*c*) DC generator—Commutator Exciter with Noncontinuously acting Rheostatic Regulator.

With the availability of semiconductor diodes and thyristors, the DC commutator generator excitors are no more preferred. The types of modern Excitation systems are :

(*d*) Alternator—Rectifier Exciter employing Brushless Rotating Noncontrolled Diode Rectifier.

(*e*) Alternator—Rectifier Exciter employing Stationary Noncontrolled Diode Rectifier.

(*f*) Alternator—Rectifier Exciter employing Stationary Rectifier.

(*g*) Voltage source supplied controlled/uncontrolled Exciter.

(*g*) Compound Voltage and Current supplied controlled source controlled Exciter.

21. **DC Regulator** senses DC Voltage from field winding terminals and uses it for control of field voltage. DC Regulator is in addition to AC Regulator.

22. **AC Regulator** senses AC Voltage and Current from generator terminals and uses them for control of field voltage.

23. **Slip Rings with Brushes.** DC current is transferred from stationary terminals to rotating winding via the Slip rings on rotor and brushes in stator. Brushes provide a sliding contact.

45.38. EXCITATION SYSTEMS AND AVR (SYNCHRONOUS MACHINE REGULATORS)

Synchronous Machine Regulator (AVR) regulates voltage and reactive power generated by the synchronous machine. The controlled variables received by AVR are generator stator current I_a from *CT* secondary, generator stator voltage V_t from secondary of *VT* and DC field voltage. These variables are measured by the AVR against set reference value and corrective feed back signal is given to Amplifier. The Amplifier amplifies the signal and corrected DC voltage is supplied to Generator Field. The feedback control system controls the variables (V_t and MVAr). AVR is a part of the excitation system.

The excitation system consists of mechanically and electrically coordinated components which together perform the following functions

1. Power Source. 2. Rectification. 3. Cooling 4. Control and stabilising function. 5. Protective function.

1. **Power Source.** The required excitation power is supplied by the power source. The required power may be derived from the main generator-turbine shaft or an auxiliary bus, or a special electrical machine mounted on the generator turbine shaft, or from special winding in the, main generator, or from main generator terminals via power transformer.

2. **Rectification.** In earlier excitation systems of 1960s, DC current for excitation was obtained from Rotating—Commutator type DC Generators. Todays excitation systems without exception use Diode Rectifier or Thyristor Rectifier to obtain DC current from AC Supply derived from main generator output.

3. **Cooling System.** In the earlier designs, air cooling is used for cooling the components of excitation system. For compact and optimised designs of large size, gas cooling or liquid cooling is preferred in modern designs.

4. **Control Functions.** The voltage of generator under wide range of load variation is held within permissible narrow limits by adjusting field current manually or automatically by generator voltage regulator. The generator voltage regulator is a controller in the excitation system. The automatic voltage regulator controls the terminal voltage during normal load conditions and also during abnormal conditions causing sudden voltage change.

In addition to voltage regulation, following control functions are usually incorporated in the modern excitation system depending upon application requirement.

Improved Stability. Improvement in Steady State, Transient Stability Limits of Generators with respect to Power system by continuous, fast control of excitation current to match the requirements of generator and power system. During steady state operation of generator, excitation current is adjusted continuously to maintain the terminal voltage of generator at rated value. Thus the steady state stability limit of generator is improved and generator can be loaded to higher limit.

During transient state, the excitation current is rapidly increased or decreased by field forcing to ensure voltage recovery within minimum time. Thus ensuring synchronous operation during transient disturbances.

When the generator voltage overshoots during sudden load throw-off, the controller forces the field in negative direction and reduces the terminal voltage within a few seconds by fast response.

When the generator voltage falls during sudden loading, the controller forces the field in positive direction and increases the terminal voltage within a few seconds by fast response.

Dynamic Stability. The fast acting voltage regulators provided with power system stabilising features, improve the dynamic performance of the power system by rapid damping of oscillations in load angle *O*. With such a feature the loading on transmission line outgoing from the generating station can be increased.

Power System Stabiliser. A control function added to the Automatic Voltage Regulator for improving power system stability is called the Power System Stabiliser. The power system stabiliser may utilise signals from shaft speed, frequency, power or other variable. The dynamic performance of the power system is improved by rapid damping of system oscillations.

Reactive Power Compensator. The controllers for generators operating in parallel in the same power plant may be provided with additional feature for sharing reactive power in proportion to their rating (or some other assigned ratio).

Line Drop Compensation. When a generating station is feeding a remote load via a transmission line, the terminal voltage may be controlled such that the voltage at some point on the line length is held constant (instead of the terminal bus voltage constant). Such control function is called lone drop compensation or active and reactive compensation.

Limiter. The excitation system is provided with several limiters which acts to limit a variable under certain predetermined conditions. *e.g.*

- **Under Excitation Reactive Ampere Limit (URAL) :** Limits the under excited reactive MVA that the generator can supply so that adequate steady state stability margin is available with respect to powersystem and the generator, and safe operating conditions are not crossed.
- **Over Excitation Limiter** : Prevents the voltage regulator from raising field current above specified limit.
- **Volts per hertz Limiter** : Regulate V/f ratio for protection of the generator and the associated transformers to limits V/f ratio within specified limits and takes corrective action to make V/f normal.
- **Other limiter include** : Stator current limiter, Load angle limiter. Ref. Fig. 45.42.

5. **Protective Functions.** AVR has a strong interface with the generator protection system (Ch. 33) The coordination between protective relay characteristics and AVR characteristics permits maximum loading of generator excitation system under steady state condition and transient condition. Protection system acts to remove faulty parts from the rest of the system. If short circuit occurs in generator stator winding, the excitation current is reduced rapidly and the field is discharged by means of Field Discharge Circuit Breaker and Field Discharge Resistor. Various Limiters provided in the excitation system protect the Generator and power system equipment against over heating, excessive mechanical stresses and yet allow the machine to operate at higher MW output.

45.39. STEADY STATE PERFORMANCE EXCITATION SYSTEMS AND AVRs

During normal operation of synchronous machine, the excitation system should automatically provide an adjustment in generator field current to maintain terminal voltage within cloase limits and ensure sharing of reactive power properly. This means that the excitation system should be capable of supplying a wide range of DC current to generator field.

The Range of Permissible Steady State Generator Voltage V_t and Frequency f Variation

The synchronous machines are designed for continuous rated output, at rated power factor; at rated voltage with tolerance ± 5% and rated frequency with tolerance ± 2%. The combination of operating voltage and operating frequency is of importance with reference to overheating of excitation winding and overfluxing of power transformers of the generator unit. Fig. 45.35 gives the operating range of V and f combination recommended by *the standard of synchronous machines.* (However, in practice the terminal voltage of Synchronous Generator bus must be regulated within specified limits *i.e.* rated voltage with tolerance ± 1% by the Automatic voltage regulator.)

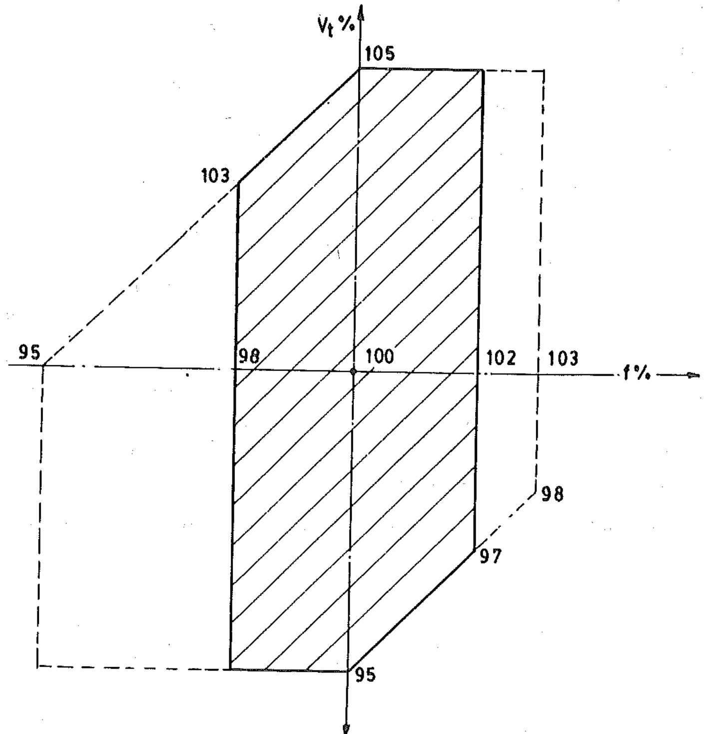


Fig. 45.35. V_t and f operating range for steady state operation of synchronous generators.

For isolated generator-turbine unit, the voltage is controlled by the Automatic voltage regulators and the frequency is controlled by the turbine-governor and voltage by the Automatic Voltage Regulator. For grid connected Generator unit, the voltage and frequency is decided by Bus voltage and bus frequency respectively.

High V/f is harmful for unit transformer and Auxiliary transformer as the core gets heated due to overfluxing. V/f limiter in excitation system prevents V/f above permissible limit. (Usually 1.1 pu.)

45.40. TRANSIENT PERFORMANCE OF AVRs

System faults, sudden load throw-off, sudden loading, switching, etc. produce transient disturbances in the power system. These disturbances are of short term time duration in several cycles or long term duration of several seconds.

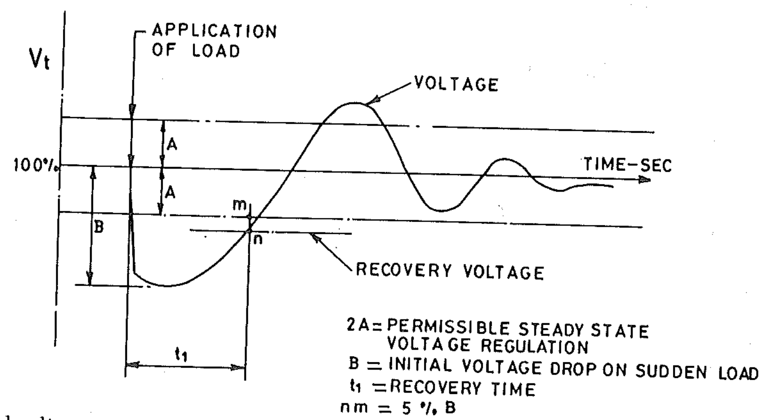


Fig. 45.36. Typical voltage response characteristic of generator on application of sudden load on generator. (95% of difference between ceiling voltage and rated load field voltage is attained in time t_1)

During transient disturbance in the Network, the excitation system of generators should rapidly respond so as to maintain the stability of the generators and the power system. Thus, during voltage dip, the excitation current must be rapidly increased and during voltage rise, the excitation current should be rapidly reduced.

The excitation current must then be brought to normal after the disturbance has subsided.

Modern excitation systems have provision of *Field forcing* by which the controller acts rapidly to (1) increase the field current to ceiling current level during fall in terminal voltage, (2) decrease field current during rise in terminal voltage.

Two important transient characteristics of the excitation system—Excitation System Ceiling voltage—Excitation Response.

These two characteristics are important in evaluating the effectiveness of Excitation systems and AVRs in maintaining transient stability.

Excitation system Ceiling Voltage. The maximum DC voltage which the excitation system can supply to the generator field winding for a specified short time under defined conditions.

45.41. EXCITATION SYSTEM VOLTAGE RESPONSE

Under sudden disturbances, load fluctuations, faults, Switching, etc. the AVR forces the field current in positive or negative direction such that field current is changed rapidly to recover terminal voltage within a few seconds and the stability is maintained.

Consider sudden application of load. As the sudden load occurs, there is a sudden fall in terminal voltage of the generator. The AVR is called upon to operate rapidly and increase the exciter terminal voltage and thereby the generator field current exciter. The field being inductive, the DC current in field winding cannot rise instantaneously. Hence the exciter current rise slowly and the generator voltage is recovered slowly. By field forcing, the exciter voltage is increased rapidly for a short duration to *almost twice normal exciter voltage,* thereby the terminal voltage of the generator is recovered rapidly.

Earlier Definition of Excitation Response. The rate of increase or decrease of exciter terminal voltage when change in voltage is demanded.

Exciter voltage response time. Time in seconds for exciter voltage to reach 95% of the (difference between ceiling voltage and rated load field voltage) under specified conditions.

For a turbo generator exciter, exciter response was of the order of 200 V/sec with nominal voltage of 400 V. The required excitation response of hydro generators was much higher due to possible overspeeding of hydro turbines.

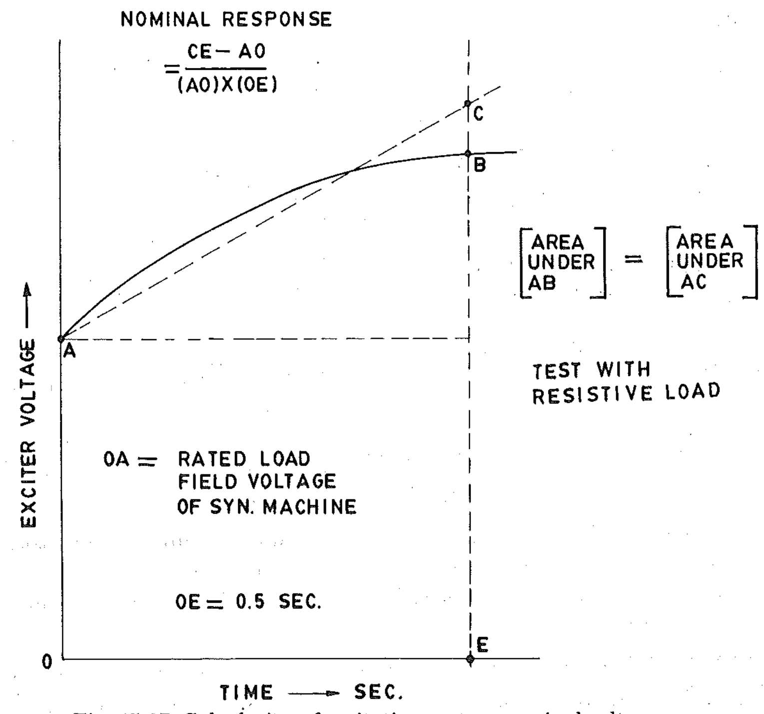


Fig. 45.37. Calculation of excitation system nominal voltage response.
(For testing excitation system with resistive load equal to field winding resistance).

Excitation system nominal response. Rate of increase of excitation system output voltage divided by rated field voltage. (Ref. Sec.) Rate of increase of excitation system output voltage is determined from excitation system nominal response curve.

The Nominal Response is calculated as shown in Fig. 45.38. Initially the exciter voltage is at rated value, *i.e.* rated field voltage of synchronous generator. The exciter is loaded with resistance equal to resistance of synchronous machine field winding. The exciter voltage is increased rapidly to the exciter ceiling voltage by introducing command through feed back loop.

The excitation voltage response defined as above adequately describes the performance of various conventional old type AVRs. But it is not adequate to describe the performance of many faster AVRs in use today having *high initial response.*

High Initial response (IEE Standard). For the high performance fast acting Excitation Systems, 95% of difference between Ceiling voltage and rated load field voltage is attained within 0.1 sec.

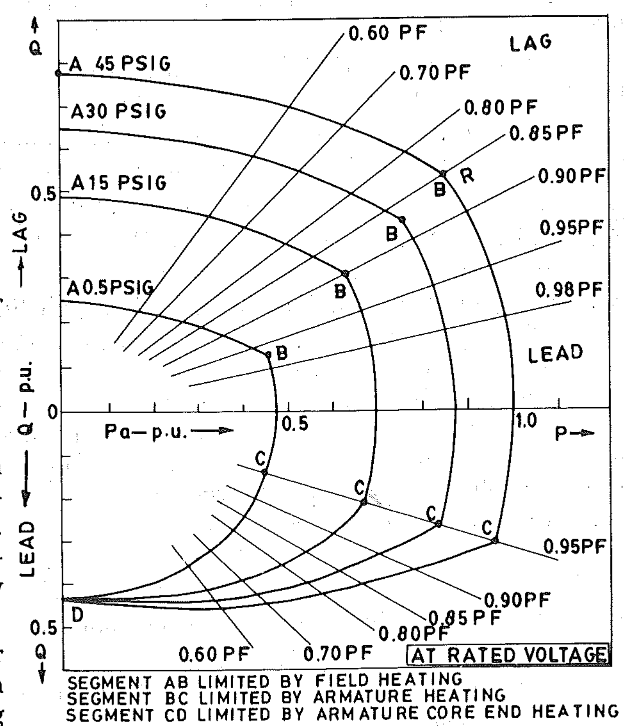


Fig. 45.38. Generator capability curves at rated voltage.

45.42. GENERATOR CAPABILITY CURVES

The capability of the generator terms of Active Power P and Reactive Power Q is usually represented in the form of the Generator Capability Curves (Fig. 42.38). Any point on the curve has certain P MW-p.u. and certain Q MVAr p.u. Inclined lines are the Power factor lines. The diagram has three segments, each segment represents limit imposed by most adversely influenced generator component. *Segment AB* in the upper part of the diagram is for overexcited lagging p.f. condition during which limit on generator capability is imposed by heating of field winding. For segment *AB*, the field current is at rated value.

Since the field current should not exceed rated value, segment AB is the limit imposed by maximum field current. With power factor below 0.6 lag, the active power capability of generator is reduced below 0.5 p.u. MW.

Referring to Fig. 45.38, the *segment BC* the power factor range is from rated p.f. 0.85 lag to leading p.f. 0.95; the generator is giving maximum output MW and the limit is set by the rated stator current heating. Maximum rated nameplate current shall not be exceeded. The protection is provided by Stator Overcurrent Protection.

The *segment CD,* the power factor range is in Leading p.f. from 0.95 lead at *C* to leading 0 p.f. lead at *D.*

In this range, the generator field is underexcited. The armature current magnetic flux has a predominantly magnetising effect which adds to the main field flux. The rotor core is at right angles to the stator laminations. The stator flux causes excessive heating of rotor core and stator end laminations. The active power capability reduces rapidly below 0.5 p.u. MW for leading power factors below 0.7. The generator output is reduced drastically. The limitation is provided by Under Excitation Reactive Ampere Limiter. Secondly, the leading power factor stator currents provide magnetic field of their own in air gap and excitation currents loose control over terminal voltage. The generator becomes Voltage Unstable in leading p.f. stator current range. *Hence Stability considerations are imposed in addition to heating limitations shown by segment CD.* Active power P MW should be reduced to ensure stable operation of Generator feeding leading power factor loads (*e.g.* night load in Megacities of distribution cable network with p.f. improvement compensators not disconnected and lighting load of unity p.f. in Mega cities). In the underexcited condition, the synchronising torque is less and stability is adversely affected.

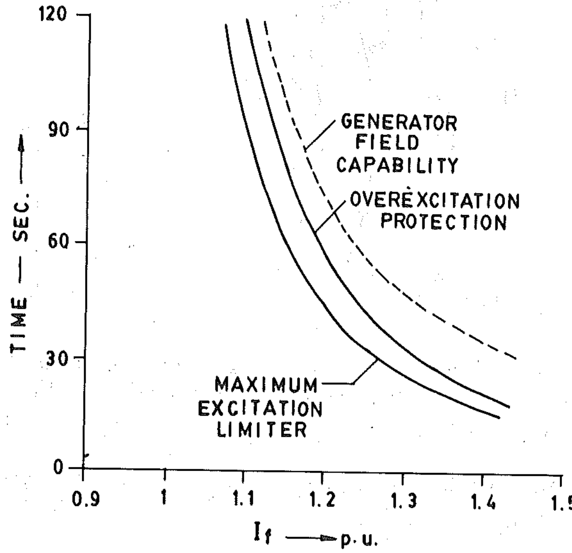


Fig. 45.39. Coordination of field capability curve with overexcitation protection and overexcitation limiter.

In practice, the reactive power, power factor, terminal voltage and cooling system, ambient temperature influence permissible loading of generators. The protection systems and limiters provide safeguards. The Generator Operators should be provided guidelines regarding generator capabilities under poor p.f. loads and adverse operating conditions of voltage and poor cooling.

Fig. 45.40 shows the time versus Field Current I_f characteristics of Generator Field Capability Curve and corresponding Protection Curve and Over Excitation Limiter Curve.

Table 45.D.2. Generator Armature an Field Overload Capabilities

Time sec	10	30	60	120
Armature current % of rated I_a	226	154	130	116
Field Voltage % of rated V_f	208	146	125	112

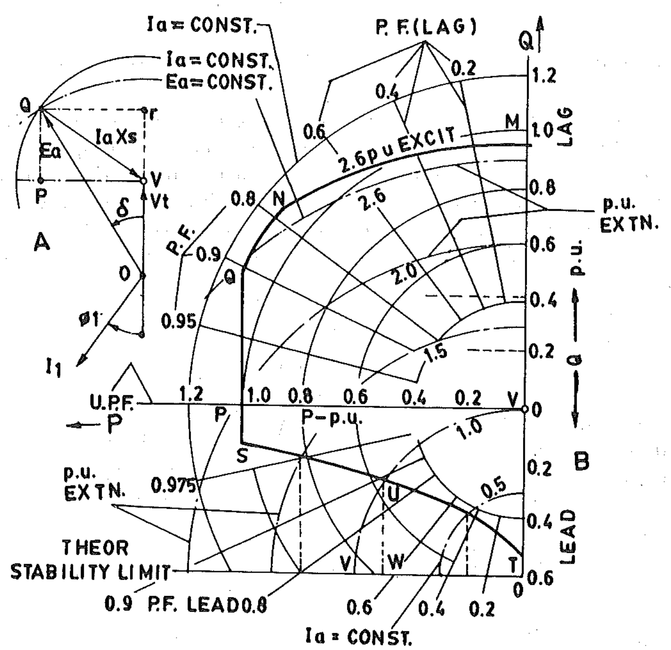
45.43. ELECTRICAL LOAD DIAGRAM OF A SYNCHRONOUS GENERATOR OPERATING IN PARALLEL WITH THE GRID (VT CONSTANT)

By plotting p.f. lines and constant excitation circles on the P-Q diagram, we obtain the Generator Loading Diagram (Fig. 45.41).

For grid connected generator, the terminal voltage remains constant.

The relationship between active power P_g, reactive power Q_g for various excitation currents I_f and power factors is plotted and is called Electrical Load Diagram. The limits of excitation current, active power, reactive power and armature current are drawn as dark curve on the same electrical load diagram.

Active power shared $V_t I_a$ cos depends on input to prime mover. Neglecting active power loss, the X coordinates give active power.



E_t = E.M.F. which depends on excitation current I_f

V_t = Terminal voltage, which depends on grid voltage, constant

o = Load angle between E_t and V_t

P_g = Active power

Q_g = Reactive power

Fig. 45.40. Typical electrical load diagram of a synchronous machine in parallel with the grid.

Active Power of Generator P_g = Active power of Prime Mover

In electrical load diagram, the Y coordinate of operating point represent active power P_g and X coordinate represents reactive power Q_g supplied by the Generator to busbars. The reactive power Q_g shared by the generator depends on Power Factor of armature current and Excitation Current. The Y coordinates give reactive power.

The vector diagram on the corner of Fig. 45.41 shows the relationship between E_t, I_a, load angle o and power factor angle. The load diagram is an extension of the vector diagram.

Fig. 45.29 illustrates a typical Load Diagram for a synchronous machine operating in parallel with the Grid.

The dashed circles represent constant p.u. excitation circles with origin 0' (0.5, 1.0, 2.0, 2.5, 2.6 p.u. Exc.). The firm curve circles with origin 0 correspond to p.u. armature current. The inclined lines represent power factors. **The dark line represents generator capability segments.**

45.44. CONTROL AND PROTECTIVE CIRCUITS OF AN EXCITATION SYSTEM

Additional protective, controlling and limiting systems in the Excitation System serve as regulators, Limiters and Protective Elements. Proper coordination between these elements and the Generator Protection System permits maximum short time overloading of the Excitation System under normal and emergency conditions thereby improving service continuity of the Generator.

Limiter. The excitation system is provided with several limiters which acts to limit a variable under certain predetermined conditions. *e.g.*

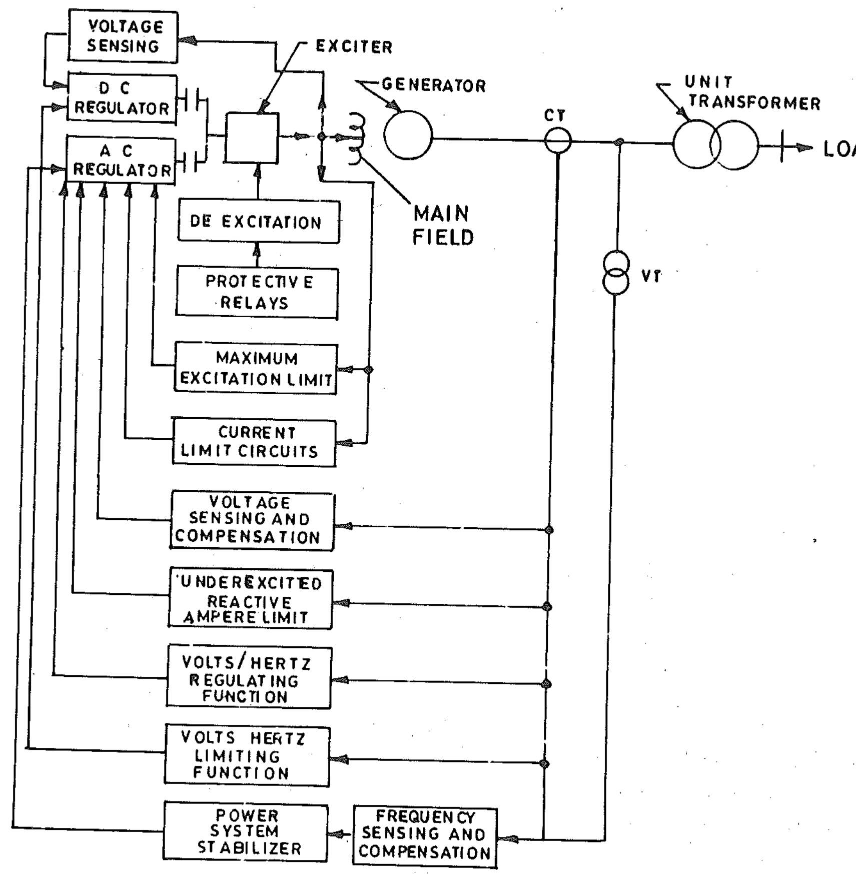


Fig. 45.41. Additional Protective, Regulating and Limiting Features in Excitation System.

— **Under Excitation Reactive Ampere Limit (URAL) :** Limits the under excited reactive MVA that the generator can supply so that adequate steady state stability margin is available with respect to powersystem and the generator and safe operating conditions are not crossed.

— **Over Excitation Limiter :** Prevents the voltage regulator from raising field current above specified limit.

— **Volts per hertz Limiter :** Regulate V/f ratio for protection of the generator and the associated transformers to limits V/f ratio within specified limits and takes corrective action to make V/f normal.

— **Other limiter include :** Stator current limiter, Load angle limiter. Rotor current limiter, Stator current limiter etc. Ref. Fig. 45.42.

45.45. VOLTAGE-REACTIVE POWER CHARACTERISTIC FOR CONSTANT POWER

Consider a Generator connected to Network (Grid). The voltage V_t remains almost constant and is determined by the Grid voltage. Hence the operating characteristic is very flat line on V_t versus Q diagram. The characteristic is similar to that for SVS. (Ch.)

The flat characteristics indicates, a small change in grid voltage *necessates* a large change in the reactive power output of Generator. Thus the operating point P moves along line AB with change in generator field current with Terminal voltage Vt determined by the Grid. The limits by Field current, Armature Currents and Rotor Angle are imposed on the operating range.

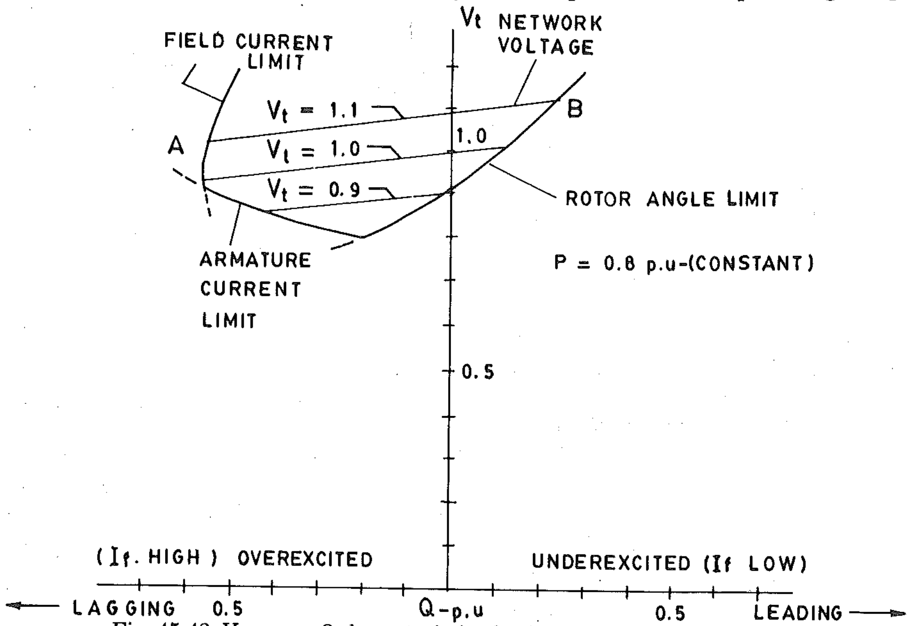


Fig. 45.42. V_t versus Q characteristics for Generator connected to Grid.

Power System Stabiliser

The Power System Stabiliser is an additional feature provided in the Excitation System for improving dynamic performance and rapid damping of system oscillations. The signal is taken from rotor shaft speed or rotor angle or frequency. The excitation voltage is rapidly controlled to damp the oscillations in load angle o.

SUMMARY

Excitation Systems and Voltage regulators of Generator regulate the terminal voltage within + 1% during normal load variation and improve transient stability during disturbances. Additional limiting and controlling, protective, stabilising features are also provided within Excitation Systems and AVR.

During terminal voltage fall, the excitation current is rapidly increased by Field Forcing. During voltage rise, the excitation current is rapidly reduced by Field Forcing. Two important features the ceiling voltage (app. 200% rated exciter voltage), and Excitation Response. The rated terminal voltage of generator is recovered within a few seconds to ensure transient stability.

The types of Excitation Systems are : DC Generator Amplidyne Exciter, Brushless Exciter, Alternator—Stationary Diode Rectifier Exciter, Alternator Stationary Thyristor Exciter etc. The source of excitation power is the Min generator/Auxiliary Station Supply/Aux. Motor Generator Set.

Under lagging power factor load, generator must be overexcited. The field current sets the upper limit. Under leading power factor load, the heating of rotor core end and stator magnetic

circuit set a limit. Under normal p.f.) 0.85 lag to 0.95 lead, stator armature heating sets the limit of loading. Excitation system has several limiters for protection of excitation system and the generator. Generator Excitation System and AVR control the voltage and improve the stability.

QUESTIONS

1. With the help of a schematic diagram, explain the configuration of a typical Brushless Excitation System. Define the terms "Excitation Voltage Response, Ceiling Voltage."
2. With the help of a simple Voltage versus time Graph, show how an AVR helps in rapid recovery of voltage after sudden loading on Generator.
3. Explain how the power factor of stator currents of a synchronous generator influence the limit of Active Power Supply in case of Lagging Power Factor Loads.
4. Explain the various Limiting Features in the Excitation System of a synchronous generator and their significance.
5. Explain the difference in terminal voltage of a Synchronous generator operating with its load in isolated operation (without grid connection) and that in parallel with the grid, with reference to changing its Excitation Current.
6. Why does the Leading Power Factor Current pose a limit on the active power load on Synchronous generator.
7. Explain a P/Q Capability Diagram of a Generator. Explain the Limits imposed by Overexcitation, Armature Load and Underexcitation.
8. What happens if V/f of Generator exceeds 2 P.U.?
9. (A) What happens to the field current of Generator on Full MW load at 0.4 p.f. lag ?

   (B) What happens to the field current of Generator on Full MW load at 0.1 p.f. lead ?

   (C) What happens if full excitation current is given to generator field with rotor speed at half the rated Synchronous Speed and generator stator is connected to Unit Transformer and Auxiliary Transformer.
10. Explain the need of improved load power factor of load for better Generating Unit output MW.
11. Draw and Explain V_t versus Reactive power Q characteristic of a synchronous generator connected to Grid voltage. Draw the limiting characteristics. Explain why a small change in Grid voltage produces a large change in MVAr of the generator.
12. Explain Stabilising Features provided in excitation system of a Generator.

46-A

Digital Computer Aided Protection and Automation

Introduction to Power System Control — *Terms related with Computers and Microprocessors* — Equipment for Automatic Control of Power Systems — Data Transmission Equipment — Power Line Carrier — Application of Digital Computer in Power Line Automation — Microprocessor — Applications of Digital Computers in protection — Microprocessor based over current-protection — On line digital computer for protective relaying — Summary.

46.1. INTRODUCTION TO POWER SYSTEM CONTROL AND OPERATION

Consider the basic variables related with electrical energy :

(*i*) current (*ii*) voltage
(*iii*) frequency (*iv*) power factor, real power, reactive power
(*v*) time.

The energy is generated (infact converted from other forms), transmitted, distributed and finally utilised (in fact converted to some other form such as heat, mechanical drive). At every stage, certain supervision, control and protection are necessary (Fig. 46.1). Until recently (1960's) the system control was carried out exclusively by analogue or digital equipment with fixed wiring. Some functions were automatic (*e.g.* voltage regulation, system protection) and some functions were by more manual interaction between man (supervisor) and machines (equipment). In a small independent generating station, the supervision and co-ordination of various parts can be carried out by the operator with the aid of analogue and digital control systems for the plant. For a large interconnected power system, task of supervisions, operation, co-ordination, control and protection become very complex and the traditional equipment requiring operators skill and judgement are not adequate.

During recent years several new types of process control equipment have come in market. These include : digital computers (large, mini and micro), micro-processors, static control devices, static protective relays. Even the most complex tasks which could not be carried out efficiently by the traditional equipment can be easily performed with the aid of these recently developed (1960-70's) equipment.

During last few years (1970's) programme packages have been developed or carrying out the various duties related with supervision, control and protection. This software enables several functions to be performed automatically from a central system control centre. Extensive monitoring of network operations, load dispatching, load and frequency control (Ch. 45), load shedding (Ch. 45), optimum loading of various plants, remote back-up protection etc. are possible from a Central Grid Control Centres. Whereas many functions should be decentralised and carried out from zonal control centres and control rooms of individual plants. Table 46.1 states the main tasks of control centres at different levels.

* Voltage control is achieved by means of (1) Excitation control (2) Tap-changing (3) Shunt compensation, (4) Series compensation. It is applied in generating stations, sub-stations and near load points. Centralised voltage control of Grid is not possible. Refer Ch. 45-B. Ref. Ch 49 and Ch 50.

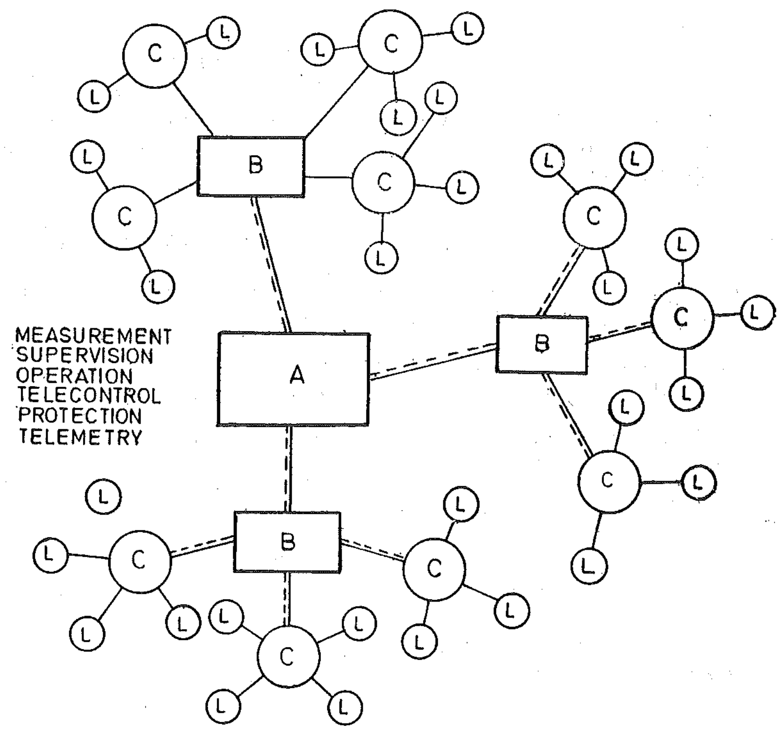


Fig. 46.1. Complex functions of measurement, supervision, operation, control, protection, communication need the team work-of.

Measurement — Telemetry — Switchgear and Power System
Protection — Power System Control Devices aided by Digital Computers
A = Master Control (Grid control) centre ; B = Regional Control centre
C = Power Plants ; L = Loads.

To assist the work in the control centres, certain functions are automated with the aid of computer based (or microprocessor based) control systems. Such a *Supervisory Control And Data Acquisition system* is intended to facilitate the work the operator (dispatcher) by acquiring and compiling information as well as locating, identifying and reporting faults. On the basis of the information received, the operator makes the necessary decisions *via* the control system he can then perform different control operations in power stations or influence the processing of the information acquired. (Refer Ch. 50 SCADA and AGC system).

The size and topography of the power system as well as the emphasis on generation, transmission or distribution influence the functions which are to be automated in a particular control centre. Finally, the scope is determined by the organisation and policies of the electricity boards.

Different electricity boards impose rather, different demands on their control systems. However, it is quite clear that there is a trend to include more and more planning and following up functions. There is always a need to perform such functions regularly and accurately. Developments have now reached such a stage in the areas of powerful minicomputers, microprocessors, mathematical models and real time programming methods that automation of these functions are possible.

Load Dispatching. Large power system comprise several power stations, load centres, interconnected to form a single grid. The operations of such grid can be controlled from a centralized 'load control centre' or 'load dispatch centre'. The central load control centre is linked with various local dispatching stations, each of which covers certain area the operations concerned with a particular area, which do not affect. The system performance are carried out by persons in the local dispatching stations. The operations concerned with the system, and no limited to a particular area are performed from central load dispatch centre. The central load dispatcher takes decisions about loading of large stations, loading of interconnected lines, etc. Supervisory control is a method of controlling and supervising from a central point, the operations of equipment at one or more remote locations. Carrier signals are used for remote control. Relay settings need a change with major changes in load flow. Refer Ch. 46-*B*.

46.2. TERMS RELATED WITH COMPUTERS AND MICROPROCESSORS

1. Access time. Times interval between the instant at which information is called from storage and the instant at which delivery is completed (read time).

2. **Accumulators.** Parallel storage registers for work-in-process. Some are available for application while some are built-in for internal use within the processor.

3. **Adaptive control system.** A system able to tune itself with a changing environment.

4. **Address.** Lable name or number that designates a register or memory location, generally refers to the number that designates the memory.

5. **Algorithm.** A finite set of well defined rules for the solution of a problem in a finite number of steps. Fixed step-by-step procedure for accomplishing a required result.

Table 46.1. Main tasks of control centre at different levels

Level	*Planning*	*Operation*	*Following up*
National Grid Control Centre	Load prediction and generation schedules, power balance planning co-ordination of overhauls, planning of reverses	Supervision of load generation, power exchange reserves, transmission networks, Tile-line loading and exchange	Reporting and accounting, statics, following up of efficiency, fault analysis
Zonal control centre	Load prediction and generation schedules, power balance planning, coordination of over-hauls, planning reserves	Supervision of load generation, power exchange, reserves, transmission networks	Reporting and accounting, static, following up of efficiency, fault analysis
District control centre	Short-term according to directives	Supervision of load, generation, and power exchange supervision of different components in power system, operation and control of underlying power station and sub-stations	Load generation and water flow reports, accounting data statistics
Power station, substation Control Room	Work planning	Control of power, level, etc., sequential Start/Stop functions, automatic system restoration, protective functions, supervision of process variables.	Sequential events recording

* Courtesy : ASEA, Sweden

** All India National Grid will have five zonal load control centres : Northern zone, Western zone, Eastern zone, Southern zone and Central zone. The National Grid Control Centre will be near Delhi.

Table 46.2. Main Functions of Supervisory Control and Data Acquisition Systems (SCADA)

Operation Supervision	Data acquisition and presentation of quantities such as power, voltage current, temperature, water level as well as fault signals and breaker position. Monitoring of limit values. Acquisition of metered energy values. Following up of power balance with interconnected utilities and between own regions. Following up of production and load within different regions. Calculation of spinning reserves. The monitoring of limit values can be carried out as function of time and ambient temperature network modelling. Filtering of measured values. Calculation of non-measured values and transmission losses. Contigency analysis of the consequences of disconnection of a lines of generating set. Short-circuit calculations.
Operational Control	Start/Stop of generating sets. On/Off operation of breakers and disconnectors. Hand/Auto for local automation equipment. Increase/Decrease of set-point control for power generation voltages gate positions.
Planning (Time horizon < 1 week)	Power balance planning with operation schedules. Load prediction, Economic production, distribution between generating sets, Planning of power exchange (Purchase-Sales-analysis). Simulation operation schedules with respect to load distribution, economic production distribution and security.
Following up	Daily, weekly and monthly logs for generation, load power exchange and power flow. Even reports in power systems and control centre. Hydrological following up through calculation of head losses, heads, water flow and spillage Statistics. Compilation (calculation) of transmission losses.

6. **Assembly language.** Operator's (source) language composed of brief expressions, usually uneconomic form, it is translated into machine language by *Assembler*.

7. **Autonomous.** Independent.

8. **Architecture.** Preset, physical and logical arrangement of a computer; it determines how a computer operates.

9. **Binary.** Numbering system represented by two digits 0 and 1.

10. **Bipolar.** Most popular fundamental kind of integrated circuit (IC).

11. **Bit.** Abbreviation for binary digit, the fundamental unit of information.

12. **Bootstrap.** Short sequence of instructions, which when executed by the computer, will operate a device to automatically load the programmable memory with a large programme.

13. **Branch.** To depart from normal sequence of executing programme instructions, done by one or more branching instructions in the programme.

14. **Buffer.** Device which stores information temporarily during data transfer.

15. **Bus.** Channel along which the data is sent. Often refers to physical connections as contrast to channel of logical path.

16. **Byte.** Sequence of binary digits usually operated as a unit. A byte is commonly 8 bits long.

17. **CMOS.** Complementary MOS and refers to combination of P-channel and N-channel transistors. CMOS is faster than MOS but consume lesser power.

18. **Computer.** (Digital) a device which can perform substantial computations including numerous arithmetic, logical operations without interventions of human operator during the run. It needs a stores programme.

19. **Computer system.** A system comprising *software* system (programmes) and hardware system (computer, memories etc.)

20. **Core memory.** A magnetic storage in which data are stored by elective polarisation of magnetic cores.

* *Courtesy* : ASEA, Sweden. Ref. Ch. 49 and Ch. 50.

21. **CPU (Central Processing Unit).** A portion of computer that includes three main sections Arithmetic, Control, Logic elements. It directs functions such as I/O.

22. **CRT.** Cathode Ray Tube.

23. **Channel.** Path along which electrical signals can travel. That portion of computer memory to which particular output station has access.

24. **Code.** To prepare a set of computer instructions.

25. **Compiler.** Built-in system that permits the compute to generate its own machine readable (object) programme from the programmers instructions written in one or several languages more easily understood by human.

26. **Compiler language.** Computer language more humanly readable than assembly language, which instruct the compiler to translate the source language into machine language.

27. **Control Unit.** Portion of a computer that directs the operation of computer, interprets computer instructions and initiates proper signals to other computer circuits to execute instructions.

28. **Counter.** Device or location which can be set to an initial number and increased or decreased by a number.

29. **Clock.** Device contained within computer which times events or keeps events co-ordinated.

30. **CROM.** Control read only memory a ROM which has been microprogrammed to decode control logic.

31. **Cycle.** Sequence of operation that respects regularly.

32. **Data.** Information, facts.

33. **Data processing.** The recording and handling of data (information) by means of electrical, electronic equipment.

34. **Data logger.** The equipment which makes a 'log' (record) of the reading of instruments.

35. **Digitise.** To convert an analogue form to digital form.

36. **Discrete.** Pertaining to distinct electronic elements (resistors, transistors, capacitors etc.)

37. **Dual computer system.** A computer system containing two computers where one computer is generally a back-up for the other.

38. **Driver.** Small programme which controls peripheral devices and their interface with the central processor.

39. **Executive control programme.** Main system programme designed to establish priorities and to process and control other programmes. Also called Monitor.

40. **FETCH.** To bring a portion of main memory - in case of microprocessor, the instruction resister-for execution.

41. **FORTRAN.** A specific problem oriented language for numerical computation by digital computer.

42. **Hardware.** Mechanical, magnetic, electrical and electronic devices which make the computer.

43. **Firmware.** Programmed loaded in read Only Memory (ROM or PROM). Firmware is often fundamental part of the system, system, hardware design, as contrasted to software, which is not fundamental to hardware operation.

44. **Hardwired.** Physically connected.

45. **Hexadecimal.** Number notation in the base 16.

46. **IC.** Integrated circuit.

47. **Index.** Integer uses to specify the location of information with a table or a programme.

48. **Instructions.** Set of bits cause computer to perform certain prescribed operations.

49. **I/O.** Input-output.

50. **Interface.** Refers to machining or interconnecting of system or devices having different functions.

51. **Loader.** Programme that operates to input devices to transfer information from off-line memory or storage to on-line memory.

52. **MOS.** Metal oxide semiconductor. MOS circuits have higher component densities.

53. **Machine language.** Language that can be understood by the computer without need of translation.

54. **MNEMONIC CODE.** Group of symbols that can be easily understood by humans, *e.g.*, MPY means multiply.

55. **Main memory.** Programme addressable storage from which instructions and other data can be loaded directly into registers for subsequent execution.

56. **PLA.** Programmable logic array. It uses a standard logic network programmed to perform a specific function.

57. **PROM.** Programmable read only memory, a type of can be programmed after it is packaged.

58. **Programme.** Sequential instructions that direct the computer to perform a specific task.

59. **RAM.** Random access memory, generally understood to mean memory with both read and write capability and in which the location can be accessed in any (random) sequence.

60. **ROM.** Read only memory, a memory which cannot be erased and reprogrammed.

61. **Real Time.** Actual time during which physical process transpires (outside the computer). It pertains to processing the data by a computer in connection with another process outside the computer, according to time requirements imposed by outside process and requiring immediate utility and the immediate access to the data relevant to the process.

62. **Sampling.** The process of obtaining a sequence of values at regular or irregular intervals.

63. **Scanning.** To examine in sequence to check automatically (the values or states) with scanning devices that may then act upon the information so received.

64. **Software.** Programmes or routines and supporting documents.

65. **Software systems.** Collective name for all programmes in a specific computer system.

66. **Subroutine.** Series of computer instructions which perform a specific task apart from main routine.

67. **Throughput.** Speed with which problems are performed.

68. **TTL.** Transistor-Transistor logic.

69. **Word.** Set of bits comprising smallest addressable unit of information in memory.

70. **Word length.** Number of bits in a word.

46.3. SUPERVISORY CONTROL AND DATA ACQUISITION SYSTEM FOR POWER-SYSTEM OPERATION AND CONTROL

This includes :

— data collection equipment
— data transmission telemetric equipment
— data monitoring equipment
— man/machine interface.

Table 46.3. Data Regarding Generating Units

System data	Units	Input form			Input internal and/or check interval
		Remote control	*Programme*	*Manual*	
Operating condition (on/off, load frequency control)	0/1			×	during variation
Based load	MW		×		2 min
Based load				×	If no connected to ELD*
Gradient of power	MW/min		×		20 sec
Power set point	MW		×		20 sec
Active power	MW	×			20 sec
Reactive power	MVA	×			20 sec
Minimum active power	MW		×		1 hr, 4 hr
Generated voltage	kV	×			20 sec if selected
Emergency generated	MWh		×		1 hr, 0.5 hr, 5 min
Power generated	MW				1 min (with integration)
Breaker condition	0/1	×			If changed
Isolator position	0/1	×			If changed
Protection signal	0/1	×			On occurrence
Alarm signals from auxiliaries	0/1	×			On occurrence
Limiting value of MW, MVAr, MW/min				×	1 min, 1 min, 20 sec

** Courtesy : Brown Boveri, Switzerland.
* ELD : Economic load dispatcher

The data (information) regarding various power-system variables is necessary for effective supervision, operation and control. This data can be broadly classified as :

— data regarding generating plants and power station
— data regarding transmission stations (sub-stations)
— data regarding conditions of supply region, receiving stations.

(Refer Table 46.3, 46.4, 46.5) (Ref. Ch. 50)

Table 46.4. Power Station Data**

System data	Units	Input form			Input internal and/or check interval
		Remote control	*Programme*	*Manual*	
Power set point	MW		×		1 min
Spinning reserve (target)	MW			×	1 min
Spinning reserve (actual)	MW		×		1 min
Voltage at main bus	kV	×			1 min
Voltage at aux bus	kV	×			20 sec
Ambient temperature	°C				1 hr
Fuel consumption	100 kg	×			1 hr
Water level	cm	×			1 hr
Volume flow	m^3	×			1 hr
Output	MWhr	×			1 hr
Limiting value of voltage at busbar	kV	×			1 min

** *Courtesy* : Brown Boveri, Switzerland.

46.4. DATA COLLECTION EQUIPMENT, DATA LOGGERS (Refer sec. 46.2 - 34)

This collects the primary data from the data sources and converts it into suitable form for information transmitting and processing.

For successful operation of any plant, it is necessary to record (*log*) the readings of variables from different locations in the plant. This is done automatically by *Data Logger*.

In addition to presenting data for a large number of points at regular intervals of time, the data can be *scanned* and recorded very quickly under fault condition by automatic initiation.

Data logger can be designed for plant performance computation for logical analysis of alarm conditions, thus minimising the possible confusion during emergency.

The intervals of readings (scanning) can be selected by setting of a dial of a push button on the data logger.

The basic parts of a data logger and interface are shown in Fig. 46.2. The input scanner is an automatic sequence switch which selects each signal in turn. Transducers are used to convert original variable to suitable electrical form for the input scanner. The signal amplifies low level signals (say 10 mV) to higher level (say 5 V). *The analogue signals are converted into digital signals.* The programmer is used to control the sequence operations of the logger.

Table 46.5. Transformer Station Data**

Data system	Units	Input forms			Input Interval and/or check interval
		Remote control	*Programme*	*Manual*	
Load on line					20 sec
Active power	MW	*			20 sec
Reactive power	MVAr	*			1 min if required
Apparent power	MVA				
Load at transformers					20 sec
Active power	MW	*			20 sec
Reactive power	MVAr	*			20 sec
Apparent power	MVA				
Limiting values of					
Min. bus bar voltage	kV			*	1 min
Max. load at transformer	MVA			*	1 min
Max. load at station	MVA			*	1 min
Voltage at main bus	kV	*			20 sec
Voltage at aux. bus	kV	*			20 sec if required
Temp. at windings	°C	*			15 min
Ambient temperature	°C	*			If changed
Breaker condition	0/1	*			If changed
Isolator condition	0/1	*			If changed
Protection signal	0/1	*			If occurs

**Courtesy : Brown Boveri, Switzerland.

The signals are fed to the input interface of the input scanner. The input scanner selects each signal in turn. The rate of scanning has to match with the requirements (Refer Tables 46.3, 4.5). Mixed scan rates are generally preferred.

The data logger supplies the digitized data to microprocessor.

Scanning and Indication. The automatic control necessitates a series of scans and checks at regular intervals which provide indication whether and when appropriate action can be initiated. For example consider change in power supplied to a mesh point. An initial indication should be obtained as to how large the change in power must be counteract the overload (drop in frequency). The scanning gives the necessary data regarding the value of various input variables. The decision regarding the follow up action (change in input in this case) can be taken according to the programmes. The logic operations and computations can be performed rapidly by on line microcomputer.

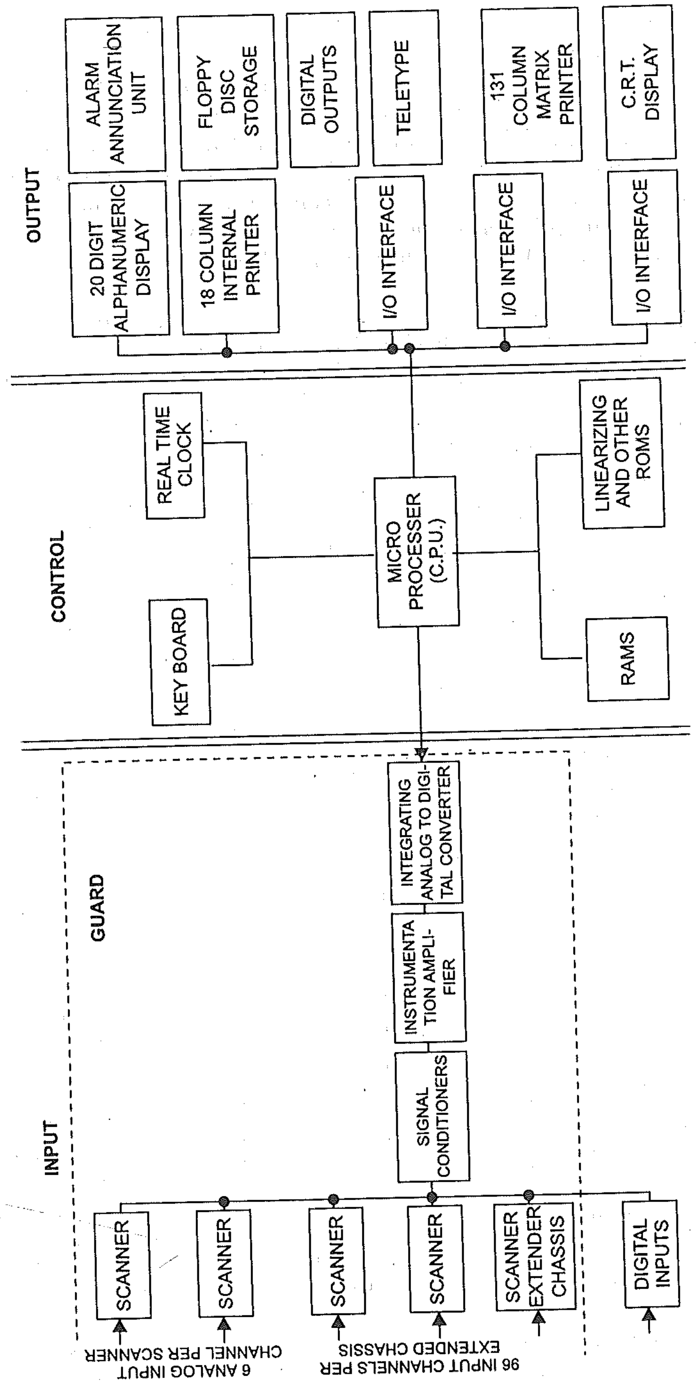


Fig. 46.2. Data logger with interface.

Based on the results of computer calculations, the decision can be taken about follow-up action (say switching of a remote distribution line to reduce load or opening of a faulty line).

CRT Display. (Refer Sec. 46.2-22) (Ref. Ch. 50)

The operator in the control room needs information regarding parameters and network configurations. CRT display provides the operator with these informations whenever he wants. (When he processes an appropriate button on control desk) two types of displays include :

— Tabulated values of parameters, measured values and computed characteristic.

— Symbolic representation of equipment status usually in form of mimic diagrams of sub-stations or synoptic displays of parts of network.

Alarm System. Alarm can be divided into group according to the nature of their occurrence. The first group comprises signals regarding abnormal (generally undesirable) conditions in the network which are detected at the place they occur and are passed to the central control room *via* the *telemetry system.* These are alarms in the conventional sense.

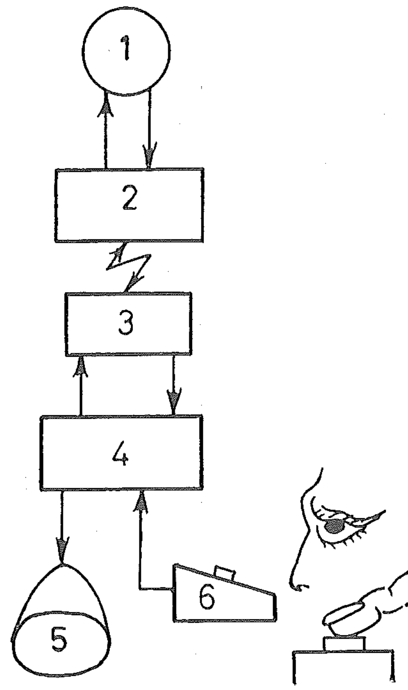
Another group of alarms is initiated by computer programmes when some computed quantity exceeds the present limit. These can be quite complex parameters. Registering alarms of this kind provides valuable supplementary information, but it is not possible to get and process such information without the aid of computers. As digital computer/microprocessors are able to respond very fast, there is a danger of overwhelming the operator with certain transient alarms. Therefore, he must have the facility for suppressing short-lived but repetitive transient alarms for a set period (about 30 sec) and then have them brought to his attention only if they are still present after this interval.

46.5. DATA TRANSMISSION EQUIPMENT (TELEMETRY)

Tele means remote. Telemetry refers to the science of measurement from a remote location. Telecontrol refers to remote control of equipment. Telemetering and telecontrol equipment necessary for control of a power plan from the control centre. The telemetering system comprises electronic equipment which converts the data received from transducers into analogue or digital signals and transmits it to the control room for the use of computers.

(Telemetering systems have been used with space-craft which sends data to earth control station).

The instructions from control centre should be sent to the remote power stations for necessary action. This two-way interaction is illustrated in Figs. 46.3 and 46.4.



1. Item supervised/controlled
2. Substation of Telementary system
3. Control station of telementry system
4. Process computer
5. Cathode ray tube display
6. Input console.

Fig. 46.3. Telemetry for supervisions and controls.

Method of Data Transmission. Different types of data transmission system can be used depending upon the network conditions and requirements. These include :

(*a*) Use of telephone lines (cables)

(*b*) Use of separate cables

(*c*) Power line carrier (PLC) ;

(*d*) Radio wave (microwave) channels.

For large systems power line carrier (PLC) is used for data transmission. (Ref. Ch. 30).

The choice of telecontrol equipment depends upon the following :

— kind of information to be transmitted.

— quantity of information to be transmitted, rate of increase.

— available transmission channels, lines.

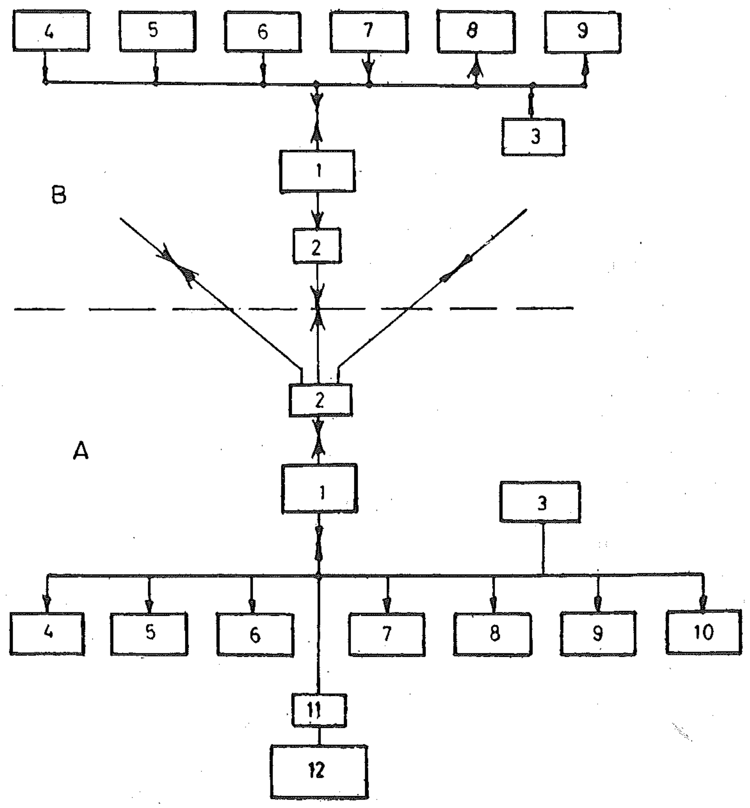
— degree of security demanded against error or loss of information.

The kind of *Traffic* means how the information is transmitted communication systems. It is necessary to send different data. It should be possible to distinguish between the data received.

It is a general practice in communication system to distinguish between lines and networks.

Line traffic is characterized by the fact that the transmission of information between two points is able to take place without having to pay any attention or transmission from other stations using other channels of the same system.

Network traffic, on the other hand, enables information to be transmitted between two or more stations of the network but the transmission is dependent on information being transmitted by



A = Master Station B = Outstation
1. Logic 2. Transmitter 3. Test Unit 4. Measured value (analogue)
5. Data and incremental input/output 6. Meter readings 7. Signal
8. Command output for *A*, input for *B* 9. Setting (analogue and digital)
10. Digital Display (for measured values and matter readings)
11. Computer adapter 12. Computer.

Fig. 46.4. Arrangement of Telecontrol of power system.
Courtesy : Brown Boveri, Switzerland.

other channel of system. The difference is not in the geographical location of the stations nor the properties of the transmission channel.

Point-to-point Traffic. Simple line traffic between two stations.

Simplex Traffic. Traffic in one direction at a time.

Duplex Traffic. Traffic in both directions at the same time.

Multiplex Traffic. Several data transmitted at the same time in both directions between different stations.

Time-division Multiplex. Traffic staggered in time.

One way line traffic is typical of telemetering. In complex, two-way networks, depending upon the quantity of information to be transmitted and the specified transmission time, the signals are transmitted either one-way line traffic or staggered one way traffic.

A typical *one-way telemetering equipment* employs continuous, analogue transmission of measured value. It operates on frequency shift principle. The frequency range of 1500-3300 Hz is used with the bandwidth of 60 Hz at a spacing of 120 Hz. Its short time constant is 0.2 sec, and makes it suitable for transmission of measurement signals and positional signals for control devices (*e.g.* Load-frequency control Ch. 45). (Refer Fig. 46.6).

A typical two-way telemetering equipment employs two one-way equipments, one command channel for direction and the other feedback channel for one transmitting the measured value. A frequency range of 420-3300 Hz may be used. (Refer Table 46.6).

Equipment for *Radial Traffic* enables Telemetering, remote indication remote control and data transmission (Fig. 46.4). A central station serves either one out-station in semi-duplex traffic (with arbitrary division of the information capacity). In the command direction, commands sustained commands and general commands can be transmitted to all out-stations in the independent signalling directions, status indications, plus indications and measured values.

A central logic system in each stations controls various functional units. The master station controls the flow of information by cascaded scanning cycles for signals and data.

The telemetering equipment is used in conjunction with process control computer. The computer with its peripherals performs various tasks.

46.6. APPLICATIONS OF POWER LINE CARRIER

Power line carrier equipment (described in Chapter 30) is used for the following applications :

— *Carrier Communication*

The person in power stations and receiving stations can communicate with each other by using this facility.

— *Carrier Protective Relaying. (Ch. 30)*

— *Carrier Telemetering*

Telemetering is the indicating or recording of quantities at a location remote from the point. The quantities telemetered on power systems are electrical quantities like kilowatts, kilovars, voltage, tap-changer position, circuit breaker position, and many other quantities. In carrier telemetry by impulse-rate system, frequency or rate of pulses varies according to the magnitude of telemetered quantity. In impulse-duration system the duration impulses is proportional to the magnitude of the telemetered quantity. The pulse telemetering system is telemetered by suitable for carrier channels.

— *Load Control and Frequency Control*

Load-frequency control is the control of outputs of group of generators on the system in such a way as to maintain the system frequency and regulate the interchange of power between parts of the system according to a predetermined plan. The carrier signals are used for load and frequency control in a similar way to telemetering of two quantities. The two types of impulses to be transmitted one for increase in power and the other for decrease.

— *Carrier supervisory control*

Controlling the operations of the equipment from a central location.

Table 46.6. Technical Data Regarding Some Telecontrol System

Type of designs	*Electrical with discrete components or IC*
Tasks	Telemetering (Analogue) Telemetering (Digital) Positioning signals for Load-frequency control Remote control Indication (Digital) Protection Remote back-up
System capacity	Number of outstations : 1/1 — 10/1 — 16 Number Control Commands : 1 — 25 Number of pulse commands : 25/100/180 Number of signals : 25/2500/1000/3000 Number of measured values : 20/0/300
Data Transmission Features	Method — Frequency Multiplex — Time div. Multiplies Kind — Point to point — Single Direction, staggered Frequency Range : — 1500 — 3000 Hz — 400 — 3000 Hz — 30 — 500 kHz Transmission Medium : — Cable/Power Line Carrier Time of Measured value : Continuous/9.00s/4.5 s/cycle

46.7. MAN-MACHINE INTERFACE

The data monitoring and processing system (scanners, data loggers, microprocessor, display, permit statistical processing, control regulation and optimization). The data processing equipment are based on either of fixed type of adaptive models.

The interaction between man and machine is illustrated in Fig. 46.3. The facilities of display of process condition through (5) CRT enables the operator to initiate manual instructions (*P*).

Many large systems need a process computer to perform the multifarious tasks which are very difficult for human.

46.8. APPLICATION OF COMPUTERS IN NETWORK AUTOMATION

In traditional equipment for network automation, equipment such as teleoperation, load frequency controllers, protection equipment etc. are fixed-wire type. The nature of the equipment is determined by the fixed wiring. Consequently, the flexibility of the operation is restricted. It is possible for this equipment to be provided with programming units or setting potentiometers to facilitate matching to the given applications.

Process computers are freely programmable and are capable of carrying out the tasks of the fixed wired equipment. The process computer can be adapted to a given problem without involving design modification on the hardware. It would be, therefore, an ideal instrument for solving various problems. The computer may be classified in three groups :

— equipment computers

— freely programmable process computers

— process computers with developed programme packages.

'Equipment' Computers. When the process computer takes the place of fixed-wire equipment, it stimulates central functions. The readily developed programmes are available and may take form of ROM's (Refer Sec. 46.2/60).

Process Computers for Free Programming. Where the process computers are used as units for free programming, the initial computer software can be based on the final application. Basic software packages are available with assembling, compiler, operating and debugging systems and other programmes for communication between the central unit and peripheral.

Process Computers with Predeveloped Programme Packages. General programmes for network automation have been developed and are generally available in the form of software packages as a marketed product. Such packages include automatic generator controls, load-frequency regulation, real time load flow programme.

The software system is divided into modules which perform different tasks. Certain system modules perform basic functions such as process communication, man machine communication, data base management, alarm and event processing.

Large digital computers may not be necessary for performing specific tasks of power protection and control. These specific tasks may be performed more economically and conveniently by microprocessor based minicomputer. Though these applications are very recent, they gaining rapid popularity and are likely to change the art of power-system protection and control with increasing use of digital techniques.

Super, Mini, Micro Computing Machines. Various manufacturers of computers, computer systems, research workers etc., use new terminologies in the field of computers. As a result many words like super computer, large computer, minicomputer, microcomputer, parallel processor, array process etc. are introduced. Firstly the words large, super, mini and micro describe the size and capacity of computers.

The characteristic of any computing machine is its floating point word length. The word length determines the precision by which the number can be represented and is fixed for a given machine, *e.g.* a 32 bit single precision floating point world may be adequate for simpler computing techniques.

Super-computer class has arithmetic unit in which arithmetic functions can be broken down into number of segments (*e.g.*, fetch normalize, add, etc.). This process is known as pipelining. Super-computers have multiple pipes which operate in parallel and assist in achieving high rate of computing speeds. Supercomputers are costlier (50 to 150 million rupees - 1978).

Array processor carry out high speed signal processing. These machines have low or no pipelining. They achieve their high speed by use of efficient use of parallel arithmetic elements and memory.

Parallel processor type computing machines contain several processors which operate on multiple instructions multiple data mode MDM. The parallel processing means ability to achieve higher computation rates in a computer by dividing arithmetical work among several distinct arithmetic processors are in experimental stage.

Micro-computer and minicomputers generally are of smaller physical size, hence the names. Their computing capability may not be limited by size. Basically, microcomputers is classified by the number of binary digits (bits) it can handle at one time. The smallest and cheapest microcomputer system can handle 4-bit block (words). Eight bit micro-computers are most popular for general control applications. Sixteen and 32 bit micro-processor may be suitable for simple programmes.

Micro-computers based on microprocessor system are of almost half price than minicomputers, require less power (fraction of a watt).

46.9. MICROPROCESSORS

One of the most recent (1980) advances in solid-state technology which is gaining rapid popularity in power system protection and control is the microprocessor.

A microprocessor has one or more semiconductor chips (IC's) containing several transistors and other solid state components. The device is programmable and functions similar to the central processing unit (CPU) of a computer in that it performs both arithmetical and logic functions. The CPU in the microprocessor system is called microprocessor.

Adding memory and interface circuitry for connections to external devices converts the microprocessor to a microcomputer. Two types of memory can be used. Read only memory (ROM) has a fixed content and contains the operating programme of the microcomputer. A programmable read-only memory (PROM) can be programmed in the field.

The second type of memory used with microprocessor is Random- Access Memory (RAM). RAM's are generally used to store continually changing data used by the microcomputer. Frequently changing programs can also be stored by RAM.

When a microprocessor system requires clocks, control logic, interface buffers to sensors, actuators, displays and data terminals trade-offs must be examined between using microprocessors and hard-wave (random) logic. As thumb-rule, when a digital system requires 50 or more hard wired logic IC's, a microprocessor should be considered.

Microprocessors are now being used in controllers for generating station, power system, control systems, protective relaying systems.

Microprocessors is based on the technology which allows many elements on a single chip with low energy consumption. This leads to the microprocessor having low cost but a slower speed and shorter word length than its big brother minicomputer.

A complete microprocessor system (called microprocessor or μP for convenience) was also called microcomputer earlier. It consists of :

— central processing unit (CPU) microprocessor
— random access memory (RAM)
— read only memory (ROM)
— input/output parts (I/O).

The ROM serves as a bank or a store-house of instructions to control the operations of CPU.

The instructions stored sequentially in ROM are referred as programme. The RAM serves as a data bank I/O parts give the device communication with the outside world.

As mentioned earlier, a microprocessor contains several diodes, transistors, flip-flops etc. on a single or several chips. These logic elements are grouped into various functional blocks, each having a specific capability. The basic blocks re-memory, Arithmetic Logic Unit (ALU), input/output (I/O) and control section.

Memory. The programme that a microprocessor executes is stored in read only memory (ROM). Other parts of the systems can read information held by this memory, but the information can be further removed nor replaced. A separate memory is used both accepting information for storage and for transmitting information to other digital circuits. Thus it is called read-write or random-access memory (RAM). And because this type of memory is handy for temporary storage during the manipulation of digital data, it is also called Scratch-pad memory.

Arithmetic Logic Unit (ALU). The section contains decisions making elements of the microprocessor, such as AND, OR, NOR, NAND, exclusive OR. The ALU also has digital circuits which can perform addition, subtraction, multiplication and division of binary numbers.

Input / output Circuits. A microprocessor communicates with external devices through arrays of flip-flops called registers. Input registers receive logic signals from limit switches, thumb wheel switches, relay contacts or any TTL compatible device and store them until the microprocessor is ready to receive them output register operates in reverse.

Control Section. The various building blocks of microprocessor are connected together by common set of lines called data bus. The control section contains timing circuits that synchronise. The starting and stopping of data flow between building blocks. The entire system is kept in-step by a pulse generating clock.

A microprocessor is similar to central processing unit (CPU) of a computer in that it manipulates digital information by interpreting and executing coded program instructions. Alone, however, a microprocessor (CPU) cannot be anything. It needs interface devices to link, it to the outside world.

Besides power supply for operating power, a microprocessor needs. Switches for human inputs, digital to analogue converters to energize read out devices, and relays to convert logic signals to electrical signals.

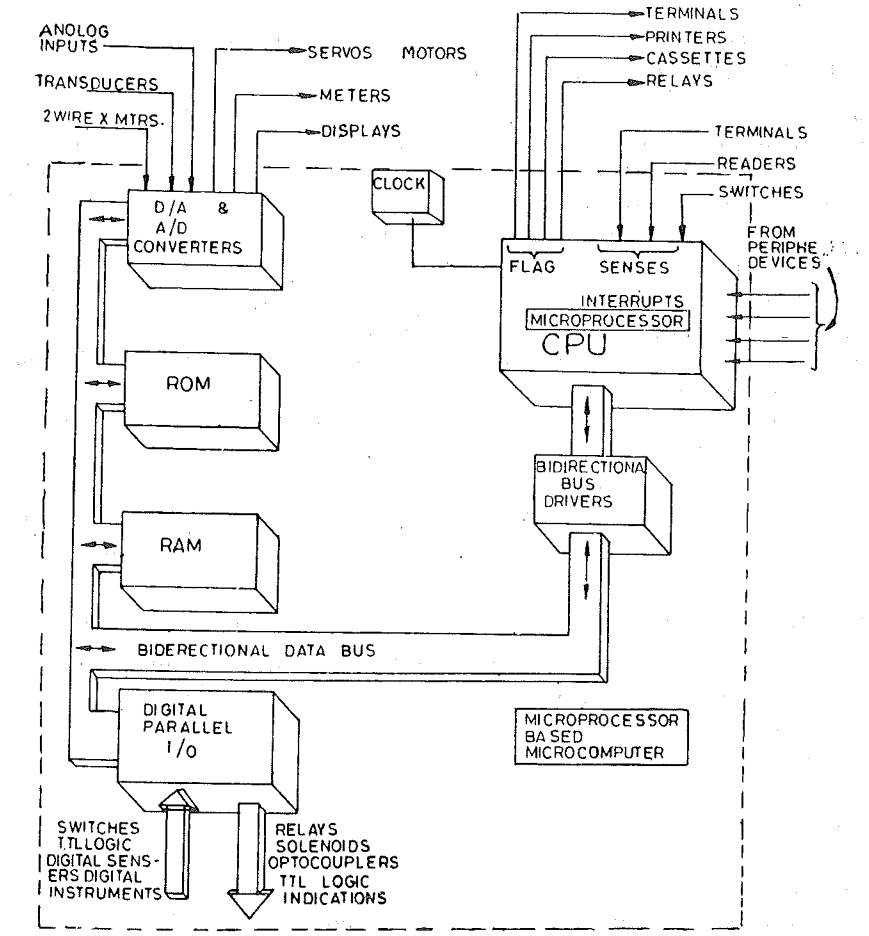
When a *microprocessor* is used as CPU in a system containing the extra memory and the required I/O circuitry, it becomes a *microcomputer.*

46.10. MICRO-PROCESSOR BASED MICRO-COMPUTER

(*Courtesy* : National Semiconductors, USA)

Fig. 46.5 illustrates a typical microprocessor based microcomputer. Microprocessors forms the heart of a sophisticated digital control system. The central processing unit (CPU) contains the logic and arithmetic circuits. There circuits interpret and route incoming instructions from digital peripheral devices such as data readers and switches to appropriate data- processing station in the micro-computer. Incoming interrupt signals order the computer to stop main programme routines contained in the memory and execute subroutines also contained in the memory.

Information flows between the computer and digital devices such as relays, switches, indicators, sensors and instruments pass through digital Input/Output (I/O) circuits. Information flows be-



CPU = Central Processing Unit RAD = Random Access Memor ROM = Read Only Memory

Fig. 46.5. Simplified Block Diagram of a Microprocessor Based Microcomputer
(*Courtesy* : National Semiconductor)

tween the computer and analogue devices passes through analogue-to-digital and digital to analogue (A/D and D/A) converts.

All this information travels on a common data bus, typical consisting of eight lines for machine control.

To prevent garbling of data, information transfer between building blocks in synchronized by a block.

Thus, basis control-process sequences are contained in memory as digitally coded instructions. The micro-processor turns the controlled process elements (motors, solenoids, valves) on and off through power-module interface devices as per programme stored in memory. As a microprocessor ticks off the basis sequence from its memory, it constantly receives updated data on process status from sensor inputs, and it awaits special instructions from the machine operators *via* panel switches and keyboards.

These inputs are constantly analyzed by microprocessor logic circuits. When these inputs form certain combinations as determined by conditional logic circuits, the microprocessor switches off from main programme to subroutine that alters controlled-process operation, to meet new requirements. Through it all, arithmetic logic circuits make the necessary conversions on incoming numerical data for display on record on external devices. Refer Sec. 43.28 for details.

46.11. APPLICATIONS OF DIGITAL COMPUTER AND MICRO-PROCESSORS IN POWER SYSTEM PROTECTION.

During the recent past there is increasing trend towards use of one line digital computers and micro-processor in power system protection. Many new areas in which conventional protection systems (incorporating individual electromagnetic or state relays) are now being explored for use of digital static relays and protection system based on microprocessors. This trend is likely to grow rapidly as the cost of single chip micro-processor is low.

In classical centralized control, about sixty per cent of operating time of the computer is used for data processing and for reading signals from remote regional load centres. Thus much time is taken by conveying of each data to some distance through telemetric equipment. Thus with large number of power plants and controlled variables the limitation is the time required for data reading and processing. A costly digital computer cannot be effectively utilized for data collecting, data processing and computation purposes. The recent trend is to separate the functions of computer into three hierarchical levels.

Level 1. National load control centre which co-ordinates regional load control centres and is relieved of the direct supervision and data processing of individual plants.

Level 2. Regional control centre controlling several power stations in the region.

Level 3. Control rooms of individual power stations.

The distribution of functions in three levels presents the following advantages :

— higher computation efficiency due to optimum utilization of computer time at every level.

— supervisory programmes of level (3) are simpler and identical for all power plants of similar types. These programmes supervise *more data* than the levels (2) and (3). This ensures better control quality.

— higher reliability due to independence of computing systems.

— lower cost.

The types of computers and microprocessors at three levels can be economically selected. The commercial computers for business purposes have to perform multifarious functions such as accounts, material control, personal data design calculations, management aid. Hence it has more memories and peripherals. Such a computer cannot be economically used for the power system control. The process control computes for the three levels are selected to perform specific functions and

can have only required architecture to suit the functional requirement. Thus several functions can be performed by microprocessor based microcomputer giving economic and operational advantages.

The central functions (level 1) are performed by minicomputer. The regional control function (level 1) are performed by microcomputer. The total control of individual power plants is performed by microcomputer based microcomputers.

46.12. MICROPROCESSOR BASED INVERSE TIME OVERCURRENT (IOT) RELAY

Fig. 46.6 illustrates a schematic diagram of an experimental system. The output of line CT's is given to the signal processing block. The signal processing block containing auxiliary CT's surge suppressors, rectifiers, filters etc. depending upon design. The processed signals are given to A/D converters. The digitized inputs are given to microprocessor. The microprocessor processes the data and determines the condition for tripping the circuit-breaker.

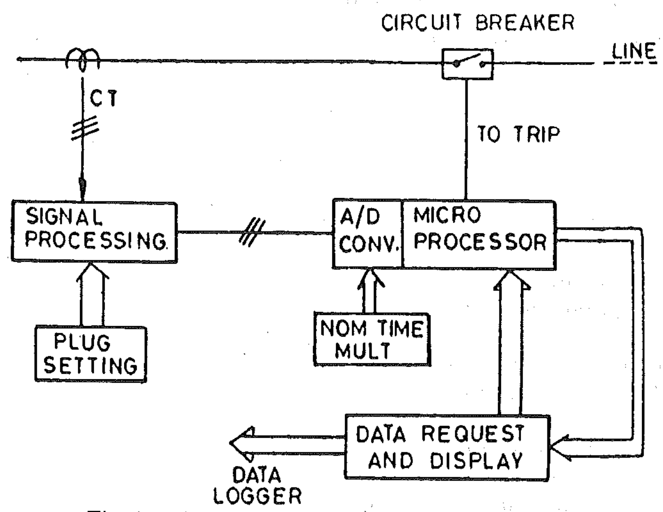


Fig. 46.6. Microprocessor based overcurrent relay.

46.13. DIGITAL COMPUTERS FOR POWER SYSTEM OPERATION

Digital computers (Refer Ch. 27) are taking over several important functions in today power systems. These functions include data acquisition, determining sequence of events monitoring automatic control, voltage regulation, determining, loading on generators, switching of lines, transformers, shunt reactors/capacitors, recording of events etc. This method of using Digital computer for power protection has been outlined in the paper "Fault Protection with a Digital Computer", by G.D. Rockefeller, IEEE Trans, PAS, Vol. 88, April, 1969.

The merits of digital computers in power protection include :

— faster main and back-up protection.

— greater reliability as continuous on line feature (convention relays remain idle till fault occurs)

— economical for large systems, as a single computer performs protection of several equipment. (Refer Sec. 46.12)

Protection of power systems has become to be very much complex. Digital computers will play diverse role in the protection of power system. Computering power system protection in a broad sense, the digital computers will be used for the following purposes :

1. Checking fault levels.
2. Loading of plants to ensure reliable supply and avoid outages.
3. Relaying analysis, setting of trip levels to suit loading conditions.
4. Determine switching sequence.

5. Main protection : Computer will judge whether the system is healthy of faulty. It will give instructions to circuit-breaker.
6. Back up protection and main protection of system element by Digital Computers.
7. Protective relaying management.

46.14. ON LINE DIGITAL COMPUTER FOR PROTECTION OF LINE

In a protection of transmission line by means of digital computer carrier signals are sent over the transmission line. The computer compares the signals cycle by cycle. Each sample is compared with the corresponding sample of the previous cycle. If the values differ in excess of permitted tolerance, the counter of that phase is incremented. The counter decides by means of logic circuits which sub-routine to follow. Thereby the fault is determined in the corresponding sub-routine. Thus in the protection scheme, the disturbance is detected, the fault is classified and trip signal is sent to the corresponding circuit-breaker by the digital computer.

In conventional protective relaying, the following principles are used for sensing the abnormal condition.

— Level detection : Overcurrent, low voltage, low frequency etc.
— Comparison of Magnitudes ; current/current, voltage/current etc.
— Comparison of phase angles.

For use of digital computer, the analogue, data should be converted into digital form. (Refer Definitions, Sec. 46.2).

Consider protective relaying of a power station comprising several equipment such as buses, transforms, circuit-breakers, incoming and outgoing lines. For protective relaying purposes several a.c. quantities (say v_n and i_n voltages and currents are assessed. These are derived from secondaries of CT's and PT's. These quantities are first converted into digital form. Raw a.c. information passes through a.c. signal conditioning to Analogue to Digital Conversion(A/D) sub-system. In A/D unit the information is sampled, converted and under control of the Data Buffer (Scratch Pad Memory or SPM) control circuits and is then transferred to the memory of computer sub-system for processing. The type-writer and programmers console provides facility for logging of desired data by the computers as well as convenient means of executive control, software generation, loading modification, programme check-out.

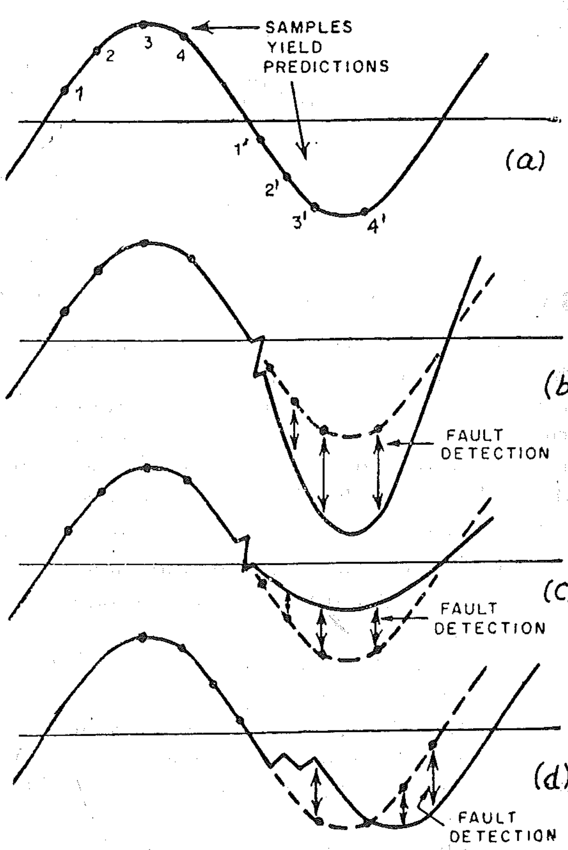


Fig. 46.7. Phase fault detector (PFD) compares reading with previously computed predictions.
Courtesy : Westinghouse Electric Corporation, U.S.A.

The Analogue-to-digital conversion unit converts the instantaneous values of a.c. quantities into samples in a sequence with time interval of the order of 0.5 milliseconds. The various sub-routines are called at a definite interval. For example, sub-routines MA (Memory action), CPD (Line current peak determination). VED (Voltage fault detector) are called at an interval of every 0.5 milliseconds, while TFD (Transformer Differential Protection) is called at every 32 milliseconds. Depending upon sub-routine, certain method is used for

detection of abnormal condition. One of the method which compares current reading with previous computed predictions is illustrated in Fig. 46.7(*a*) shows current samples yielding predictions. During normal conditions the predictions match with current samples within adaptive limits. The adaptive limit follows variation in load current, up or down. A fault causes an abrupt aberration in the waveform is illustrated in the figure. As a result the predicted sample diverges from corresponding actual sample beyond permissible limit. This difference is used for fault detection.

Fault Programme of Prodar 70 system is described in Fig. 46.8.

(*Courtesy* : Westinghouse, USA).

The key purpose of the fault programme is the calculation of apparent line impedance for directional distance checking. These calculations require considerable execution time relative to required speed, so the programme can only make them repetitively for one potential/current data pair at a time. There are six pairs to choose from - the three phase-to-ground voltage with corresponding compensated phase currents, and three data voltage with corresponding delta currents. To choose the faulted pair as quickly as possible, it is necessary to being the fault programme with an analysis of symptoms.

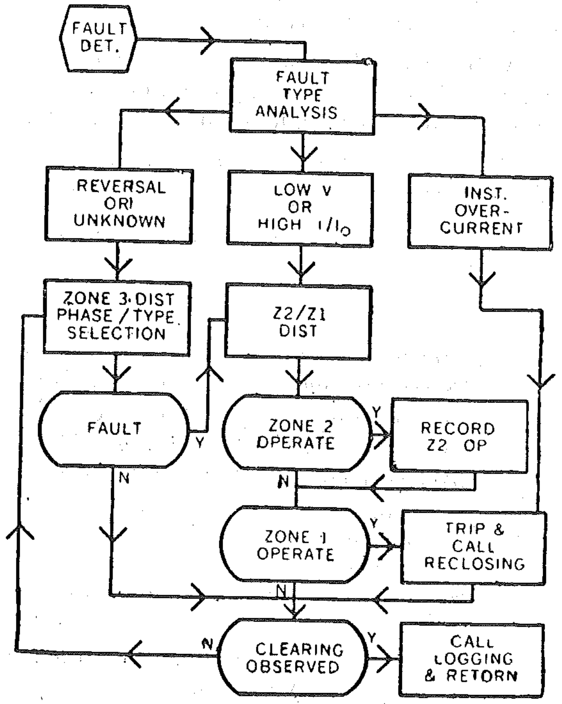


Fig. 46.8. Fault programme, Flow Diagram.
Courtesy : Westinghouse Electric Corporation, USA.

Referring to Fig. 46.8, a fault-type analysis (FTA) routine attempts to find characteristic of the fault which can aid processing. It looks for : (*a*) severe instantaneous overcurrent - this result causes an immediate output to the SL card for fast tripping; (*b*) low-line to ground or line-to-line voltage, indicating faulted phase(s) for a distance check : (*c*) high phase and/or residual currents, also indicating faulted phases and type of fault, and (*d*) voltage phase reversal due to capacitive faults.

If none of these severe conditions are found or if the result (*a*), ground distance (Using phase-to-ground voltage and compensated phase current) and phase distance (using data voltage and current) checks are made on all phases, using the zone 3 reach characteristic. For either result (*b*) or (*d*) a memory voltage (software generated from prefault data) must be used for current directional is made strictly on the most severely faulted phase(s), with either ground or phase distance logic, using the zone 2 and zone 1 reach characteristics. The location of a fault in zone 2 results in recording of pertinent data for later logging; zone 1 location causes a trip output as well. If memory voltage directional sensing was used in zone 3 check, it is continued for zones 2 and 1.

If the fault-type analysis results in (*b*) or (*c*), the logic proceeds directly to a zone 2/1 check on the apparently faulted phase(s), using ground or phase distance as appropriate. In the case of (*b*), memory voltage is again used, this time to mitigate the effects of the poor signal to-noise ratio which results from severe voltage collapse.

For a distance check, the fault programme finds the apparent impedance from calculated peaks of voltage and current, using integer numerical approximation techniques.

The apparent impedance is subtracted from the magnitude of the reach at the calculated angle. A positive sign on the result indicates, of course, that this impedance is inside the zone. Mathematical integration techniques and repetitive result requirements render the logic secure against noise and transients which may cause error in specific impedance calculations.

After a trip output the reclosing task is initiated. In any case, there follows a fault clearing check. Hence, the computer performs non-directional distance calculations on all phases, using both ground and phase distance logic. If all checks do not confirm clearing of the fault, whether internal or external, after a reasonable period of time, the zone 3 distance check logic is re-entered. If an internal fault was not found during the first instance check, it can be located now. Whatever the result of this second pass, the fault programme again makes the clearing check, with the same action. It two returns to zone 3 distance. Yield no clearing, the fault programme is exited, with the failure to see clearing noted as a breaker failure where tripping was attempted; otherwise, a failure of external relays is recorded.

With prompt fault clearing, the logic will exit after the first clearing check. During the exit, logging tasks are bid for and the data-store-and-process logic are reset for normal operation. A reservation is made for a table of fault clearing data.

Throughout the fault programme are points where sequence-of-events recording takes place. Software events codes, times, involved phase, etc. are stored for logging at a less busy time.

Microprocessor based protective and control systems have proved economical in complex power systems.

QUESTIONS

1. Explain the tasks of Grid Control Centre and its interaction with individual power plants.
2. Describe the functions Telemetry and Telecontrol in operation of a large power system.
3. Explain with the help of neat block diagram the various functions of a Data Logger used in a power plant.
4. Explain the terms in brief :
   (*i*) Data Log (*ii*) Scanning
   (*iii*) Display (*iv*) Data processing
   (*v*) Telemetry
5. Explain the techniques of transmitting the data from Load Control Centre to individual power plants and *vice versa*.
6. Explain the architecture of a microprocessor based microcomputer. State **clearly** the function of
   RAM, ROM, CPU, I/O
   State applications of microprocessor in power system protection.
7. Explain the principle of a digital computer (or microprocessor) aided power system protective scheme.
8. Write detailed notes (any two) :
   — Microprocessor and its application in power system.
   — Automatic control of power system operation and control
   — Data logger
9. Fill in the blanks :
   1. Load-frequency control is achieved by matching ... with the prevailing ....
   2. Frequency of power system depends upon the balance between ... and ....
   3. Voltage control is achieved by means of ...., ..., ...
   4. the total grid is controlled by joint efforts at following levels :
   ......, ..., ...
   5. Digital computers are used for following on-line functions in power system operation and protection :
   ......, ..., ...

46-B

Economic Operation of Power System and Automatic Economic Load Dispatch

Introduction—Classical method of load Distribution—Economic Load distribution between units in a Generating Station—Incremental Operating Costs (λ)—Criterion for Economic Loading.

PART-A

Economic Loading Criteria

Modern Method of Distribution of Load Between Generating Stations based on equal Incremental Operating Costs. Solved Examples on Economic Load Distribution. Transmission Losses, Loss formulae Coefficients—Penalty Factors—Economy Distribution based by considering Transmission Losses.

PART-B

Automatic Load-frequency Control and Economic Load Despatch by means of Digital Computer.

INTRODUCTION

As seen in Ch. 44-A and Ch. 45-A, the generation of power is always matched to meet prevailing load conditions so as to maintain constant frequency (f) and stability of the network. Besides this technical requirement ; *the energy should be supplied to the consumers at the lowest possible cost; i.e.* the cost of power delivered should be minimum for any load conditions.

Load conditions change from time to time. *The basic object of economic operation of power system is "the distribution of total generation of power (P) in the network between various regional zone; various power stations in respective zones and various units in respective power stations such that the cost of power delivered is minimum".* The cost of *power delivered* takes into consideration : the cost of *power generation* and the cost of *transmission losses.* It means for every load conditions, the load control centre should decide.

1. How much power to be generated to meet the prevailing load condition to maintain constant frequency.

2. How much should each 'Region' generate ?

3. What should be the exchange of power between the Regions (Areas) ?

This aspect can be decided by regional control centre.

Exchange of power should be decided by considering *technical aspects plus economic aspects.* The economic aspect include cost of generation plus cost of transmission losses for inter region exchange *e.g.*. If hydro-electric power is cheaper and at shorter distance and is available in surplus this should be used by neighbouring region.

(4) As the regional control centre gets a command from the load control centre, the regional control centre has to decide the total power generation in its jurisdiction in various Generating stations based on technical and economic criteria. The economic criteria include cost of generation of various plants and cost of transmission losses.

The criterion usually applied is *equal incremental fuel costs for various and various units therein.* (And not the minimum cost of generation of units as will be seen in subsequent paragraphs).

If F_n = R/shr ..... operating cost of a unit 'n'

P_b = MW ..... output of nth unit.

Incremental operating cost of the nth unit is defined as λ_n

$$\lambda_n = \frac{dF_n}{d\lambda_n}$$

The units in a power station are operated economically when their incremental operating cost are equal, *i.e.*

$$\lambda_1 = \lambda_2 = \lambda_3 = \ldots.\ \lambda_n$$

i.e.

$$\frac{dF_1}{dP_1} = \frac{dF_2}{dP_2} = \frac{dF_3}{dP_n} \cdots \frac{dF_n}{dP_n}$$

where F_1, F_2 ... operating costs ... Rs/hr of unit 1, 2, ...

P_1, P_2 ... Power shared ... MW

λ_1, λ_2, ... Intermental operating costs Rs/MWhr

This criterion should be understood to know the method of economic load distribution between units in the same plant or between different plants in the same region. The *transmission losses* are taken into consideration by modifying the basic equations of economic plant loading.

The functional assignments for economic power system operation are as follows :

National Load Control Centre. To decide generation allocation to various regions and to decide exchange between regions on overall economy and energy policy/reserves.

Regional Load Control Centre. To decide generation allocation to various generating stations within the region on the basis of equal incremental operating considering line losses are equal.

Plant Load Control Room. To decide allocation of generation for various units of the plant on the basis of equal incremental operating costs of various units.

To minimise reactive power flow through lines so as to minimise line losses and maintain voltage levels. (Ch. 44-B).

Sub-station Control Room. To minimise reactive power through transmission lines by compensation to minimise line losses and to maintain voltage levels.

46.15. CLASSICAL METHOD OF LOADING THE UNITS IN A PLANT

The ancient method was to load the most efficient plant to deliver the power during low loads first. When the most efficient plant is fully loaded, then bring the next efficient plant, as so on.

Thus, the steps were as follows :

Suppose A, B, C, D is the order of efficiency of units

— Load most efficient unit *A*.

Increase its input to meet higher loads when unit A is loaded fully, bring-in the next efficient unit *B*.

— Increase input to unit *B* to increase power shared by *B* till *B* is also loaded fully. Then bring-in the next efficient unit *C*.

— Follow the same for unit *D*.

While reducing the load,

— Reduce loading on unit *D* first.

— Then take out unit *D* and reduce load of unit *C*.

— Further, reduce load on unit *B* and finally keep the low loads supplied by unit *A*.

The classical method of economic load *distribution* between *generating units in the order of efficiencies, i.e.*, "Load most efficient unit first and less efficient unit later *fail to give minimum cost of generation.*

The same method was applied to loading of various generating plants in the region, *i.e.* load most efficient plant first : then less efficient, and subsequently in the *order of efficiencies of plants, transmission losses were totally neglected.*

The classical method of loading the plants in the order of efficiencies does not give the *economic loading* because

— The operating cost of a unit or a power station varies with load. The variation of operating cost with respect to variation in load (dF/dP) is not considered in the classical method.

— line losses are neglected in the classical method.

Hence, the *modern method of economic loading of units in the plant* and economic loading of various plant in the region was evolved. This method was further modified to take into account the line losses.

46.16. ECONOMIC LOAD DISTRIBUTION WITHIN A GENERATING STATION BY MODERN METHOD

(*a*) **The Problem Definition.** Suppose a generating station (G_A) has n generating units. Each unit comprises a generator, turbine, boiler and auxiliaries. Suppose the power generation of the stations (G_A) is P_R : and corresponding operating cost of the n units is F_R : what should be the criterion for distribution of total power P_R within the n units ?

(*b*) **Data.** Let G_A be the generating station having n units.

F_1, F_2, F_n = Input cost of respective units, Rs/hr

P_1, P_2, P_n = Output power of respective unit, MW

Each unit 1 to n will have respective curves (Figs. 46.9 and 46.10). A typical curve of operating cost (Rs/hr) against output (MW) is shown in Fig. 46.9. The slope of this curve at any point would have the units.

$$\text{Slope} = \frac{\Delta Y}{\Delta X} = \frac{\text{Rs}}{\text{hr}} \times \frac{1}{\text{MW}} = \frac{\text{Rs}}{\text{MWhr}}$$

This is called Incremental operating cost and has units Rs/MWhr.

Let F_n = Input to nth unit in Rs/hr.

Pn = Output of nth unit in MW

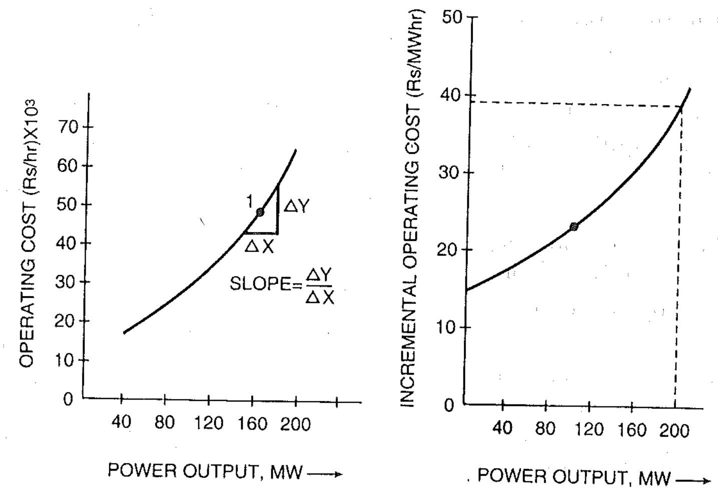


Fig. 46.9. Operating Cost and Incremental Cost Curves.

Incremental operating cost at a given point.

L on the P *vs.* F curve is defined as the slope dF/dP at that points thus

$$\lambda \frac{dF_n}{dP_n} = \text{Incremental operating cost.}$$

Likewise from calculated values of $\lambda = \frac{dF}{dn}$

for various output values P, the curve of output P *vs.* incremental operating cost is/drawn (*e.g.* Fig. 46.10).

(*c*) **Criterion for Economic Loading**

Let F_T = Total operating cost of power station Rs/hr

P_T = Total output of power station, MW.

$$F_T = F_1 + F_2 + F_3 \ldots + F_n$$

$$P_T = P_1 + P_2 + P_3 \ldots + P_n$$

where n = number of units.

$P_1, P_2, P_3 \ldots P_n$ = loading of respective units.

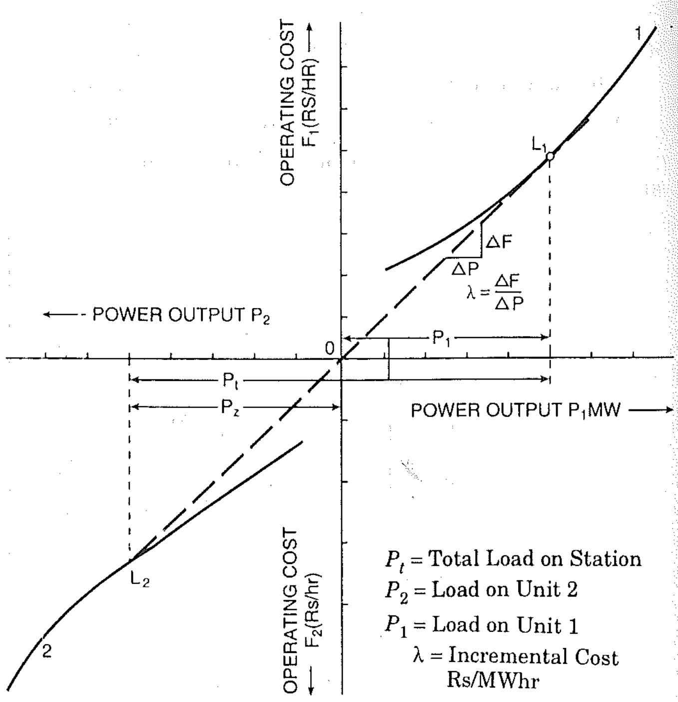
$F_1, F_2, F_3, \ldots F_n$ = Operating costs of respective units.

Minimum operating cost of generating station is obtained when Incremental operating cost (λ) of each unit is equal *i.e.*

$$\lambda = \frac{dF_1}{dP_1} = \frac{dF_2}{dP_2} = \frac{dF_3}{dP_3} = \frac{dF_n}{dP_n}$$

or $$\lambda = \frac{dF_n}{dP_n} \quad \text{where } n = 1, 2, 3, 4, \ldots n,$$

In practice, each unit has certain minimum and maximum loading. A curve of λ *vs.* power output is drawn for each unit indicating maximum and minimum loading. For each *power output of plant,* the load distribution should be such that, the incremental operating costs of units should be equal ($\lambda_1 = \lambda_2 \ldots = \lambda_n$) and sum of loading of units should be equal to total power output of the power station. ($P_T = P_1 + P_2 + \ldots + P_n$) since maximum and minimum outputs of each units are specified, for lower loads, some units whose incremental operating cost is *higher* will not be operated on low loads.



ECONOMIC LOAD DISTRIBUTION

Fig. 46.10.

Refer Fig. 46.10 illustrating economic load distribution P_1 and P_2 for total P_t in a generating station having two units 1 and 2.

The F *vs.* P curves are drawn for unit 1 and 2 as in Fig. 46.10. For various points on curve (I), tangents are drawn to curve L and a corresponding parallel tangent is drawn to curve 2 also. Thus there will be two points L_1 and L_2 having equal slopes dF_1/dP_1 and dF_2/dP_2. Let P_1 and P_2 be powers corresponding to L_1 and L_2. Thus PT = Total power of stations = $P_1 + P_2$ and $\lambda = dF_1/dP_2$ is equal for 1 and 2.

Fig. 46.10 shows only one pair of points L_1, L_2 likewise for different points on curve 1, corresponding points having some slope can be obtained on curve 2 and corresponding powers P_1 and P_2 can be computed. Thus, for various points the following can be tabulated.

Total Power Output of Power Station $P_t = P_1 + P_2$	*Power output of Unit 1 P_1*	*Power output of Unit 2 P_2*	*Incremental Operating cost λ*

Putting limiting conditions P_1-maximum and P_2 maximum. P_1-minimum and P_2 minimum in the table, the power shared P_1 and P_2 should be held its *limiting value.*

For more than 2 units, a similar method may be used. The table of Total P ; P_1, P_2, P_3, P_4, P_n and λ is drawn for various slopes of F *vs* P curves. $P = P_1 + P_2 + \ldots P_n$. Thus, for various table loads P, the economic loading $P_1, P_2, P_3 \ldots Pn$ are known. Each unit operates at same incremental operating cost λ such that

$$dF_1/dP_1 = dF_2/dP_2 = dF_3/dP_3 = \lambda$$

46.17. MODERN METHOD OF ECONOMIC LOAD DISTRIBUTION BETWEEN VARIOUS GENERATING STATIONS IN A REGION

The method of loading based on equal incremental operating cost (Refer Sec. 46.17) is applicable for deciding economic load distribution between Generating Units in a Region.

Thus : $$F_T = F_1 + F_2 + F_3 \ldots F_n$$

$$P_T = P_1 + P_2 + P_3 \ldots P_n$$

For economic loading, incremental operating cost should be equal, *i.e.*,

$$\lambda = \frac{dF_1}{dP_1} = \frac{dF_2}{dP_2} = \ldots \frac{dF_n}{dP_n}$$

where F_T = Total operating cost of 'n' stations, Rs/hr

P_T = Total power generation of n stations, MW

$F_1, P_2, \ldots P_n$ Power generation by individual stations MW

$F_1, F_2, \ldots F_n$ Operating costs of individual station Rs/hr.

λ = Incremental operating cost

Thus the various generating stations are loaded such that the incremental operating cost $\lambda = dF/dP$, R_s/MWhr of the generating stations are equal and total power of the region is equal to the sum of power output of generating units.

Example 46.1. Economic Load Distribution :

A 250 MW generating station has two 125 MW units. The incremental operating costs of the two units are as follow :

$$\lambda_1 = \frac{dF_1}{dP_2} = \text{Incremental operating cost of Unit 1} = \frac{R_s}{\text{MWhr}}$$

$$\lambda_2 = \frac{dF_2}{dP_2} = \text{Incremental operating cost of Unit 2} = \frac{R_s}{\text{MWhr}}$$

P_1 = Output of Unit 1 MW

P_2 = Output of Unit 2 MW.

$$\lambda_1 = 0.1\, P_1 + 20 \ldots \frac{R_s}{\text{MWhr}}$$

$$\lambda_2 = 0.12\, P_2 + 16 \ldots \frac{R_s}{\text{MWhr}}$$

Limits of loading of P_1, P_2 are maximum 125 MW and minimum 20 MW (same for both)

Determine load allocation for each unit for various loads on generating station from 50 to 250 MW. Also determine incremental operating costs for these load values.

Solution. There are only two units in the generating station. The total load is increasing from 50 to 250 MW. Minimum and maximum load of each units 20 MW and 125 MW respectively. Unit 1 will have high incremental cost for lower loads, hence it should be operated in its lowest limit of 20 MW for low loads (light loads), and Unit 2 will share 50—20 = 30 MW.

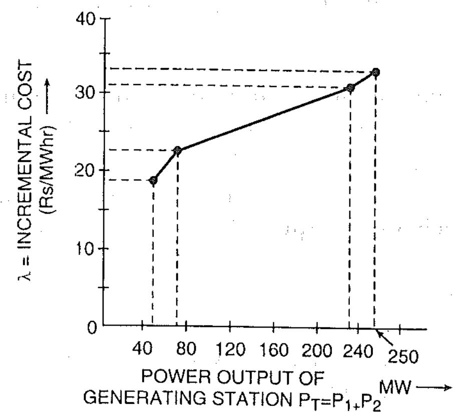


Fig. 46.11. λv/s Plant Output Solution to Example 46.1

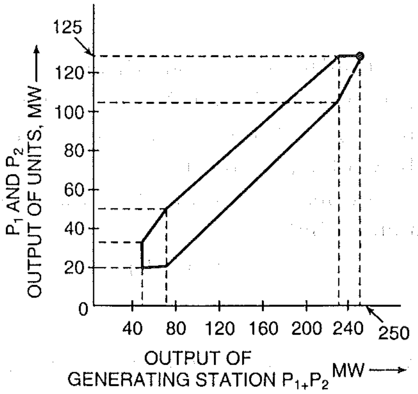


Fig. 46.12. Loading of Units For Economic Operation Solution to (Ex. 46.1)

For low loads. For low loads, unit 1 will be loaded to 20 MW and unit 2 will share 30 MW.

$$\lambda_1 = \frac{dF_1}{dP_1} = 0.1\,P_1 + 20$$

$$= 0.1 \times 20 + 20 = 22 \ldots R_s/\text{MWhr}$$

$$\lambda_2 = \frac{dF_2}{dP_2} = 0.12 \times 30 + 16 = 19.6\ R_s/\text{MWhr}.$$

Further increase in load. The loading on unit (1) to remain at its minimum 20 MW and further increase in load to be shared by unit (2) till the incremental operating costs of unit (2) and unit (1) become equal, *i.e.* when dF_2/dP_2 increases to 22 R_2/MWhr, *i.e.*

$$\frac{dF_2}{dP_2} = 0.12\,P + 16 = 22$$

Hence $$P_2 = \frac{22-16}{0.12} = \frac{6}{0.12} = 50 \text{ MW}$$

Thus at $$P_2 = 50 \text{ MW}, P_1 = 20 \text{ MW}$$

and $$\lambda_1 = \lambda_2 = 22\ R_s/\text{MWhr}.$$

After this, the loading P_1 and P_2 is allocated for equal values of incremental operating cost λ till upper limit of 125 MW of individual unit is reached.

Thus the values of P_1, P_2 are calculated for various values of λ such as 24 R_s/MWhr, 26 R_s/MWhr, 28 R_s/MWhr, 30 R_s/MWhr and 31 R_s/MWhr.

$P_T = P_1 + P_2$ is calculated by adding P_1 and P_2

Upper Limit 125 MW

Substituting $P_2 = 125$ MW in Eq.

$$\frac{df_2}{dP_2} = 1.12\,P_2 + 16 = 0.12 \times 125 + 16 = 31\ R_s/\text{MWhr}.$$

For this, $\lambda_2, \lambda_1, P_1$ are calculated :

$$31 = 0.1\,P_1 + 20$$
$$P_1 = 110 \text{ MW}$$
$$P_T = P_1 + P_2 = 110 + 125 \text{ MW} = 335 \text{ MW}.$$

Above 335 MW Total Load :

Unit 2 is loaded upto 125 MW

Unit 1 is loaded to take $PT - 125 = P_1$

Finally both units share 125 MW each to give total 250 MW.

Thus the allocation of loads P_1 and P_2 for various values of incremental operating costs λ are as follows :

Incremental Operating costs λ Rs. / MWhr.	*Loading of Unit 1 P_1 MW*	*Loading of Unit 2 P_2 MW*	*Total load on Generating station $P_1 + P_2$ MW*
19.6	20	30	50
20	20	33.3	53.3
21	20	41.7	61.7
32	120	125	245
32.5	125	125	250

Note. $$\lambda_1 = 0.1\,P_1 + 20$$
$$\lambda_2 = 0.12\,P_2 + 16$$
P_1 and P_2 max = 125, min = 20

Example 46.2. *Incremental Operating Cost for Economic Loading*

A generating station has two units (1) and (2). The incremental operating cost of the two units are as follows :

Unit : 1 $\lambda_1 = 0.1\,P_1 + 20\ \ R_s/\text{MWhr}$

Unit 2 : $\lambda_2 = 0.12\,P_2 + 16\ \ R_s/\text{MWhr}$

where P_1 = Load on Unit (1) MW, P_2 = Load on (2) in MW.

Calculate (*A*) the load distribution based on economic loading of the two generating stations for total equal to 180 MW.

(*B*) Corresponding value of incremental costs.

Solution. P_t = Total load $P_1 + P_2$ = 180 MW ... given. For economic load distribution, the incremental operating costs are equal.

Hence, $$\lambda_1 = \lambda_2 = \lambda$$

i.e. $$0.1\,P_1 + 20 = 0.12\,P_2 + 16$$

Expressing P_1 in terms of P_2,

$$0.1\,P_1 = 0.12\,P_2 + 16 - 20$$
$$0.1\,(180 - P_2) = 0.12\,P_2 - 4$$
$$18 - 0.1\,P_2 = 0.12\,P_2 - 4$$
$$22 = 0.22\,P_2\ ;\ P_2 = 100 \text{ MW}$$
$$P_1 + P_2 = 180$$
$$P_1 = 180 - 100 = 80\ MW$$
$$\lambda_1 = 0.1\,P_1 + 20$$

$$= 0.1 \times 80 + 20 = 28\ _s/\text{MWhr}$$

$$\lambda_2 = 0.12\, P_2 + 16$$

$$= 0.12 \times 100 + 16 = 28\, R_s/\text{MWhr}$$

Check :D $\lambda_1 = \lambda_2$ for economic loading

Answers : $P_1 = 80$ MW

$P_2 = 100$ MW

$\lambda = 28\, R_s/\text{MWhr}$.

Example 46.3. *Comparison-Economy Loading and Equal Loading.*

In a generating station having two units, the incremental operating costs of units as follows :

Unit 1 : $$\frac{dF_1}{dP_1} = \lambda_1 = 0.1\, P_1 + 20\, R_s/\text{MWhr}$$

Units 2 : $$\frac{dF_2}{dP_2} = \lambda_2 = 0.12\, P_2 + 16\, R_s/\text{MWhr}$$

Total load on the station is 180 MW.

Find difference in operating cost per hour between economy loading and equal loading for

(*A*) Unit 1 (*B*) Unit 2 (*C*) Total Power Station.

Also detemine annual saving for the station for economy loading instead of equal loading.

where P_2 = Transmission loss total

P_1 = Loading of plant 1

P_2 = Loading of plant 2

B_{11} = Loss formula co-efficient for plant 1

B_2 = Load formula co-efficient for plant 2.

$$B_{11} = \frac{R_1}{|V_1|^2\,(P\,F_1)}$$

$$B_{32} = \frac{R_2}{|V_2|^2\,(PF_2)}$$

46.18. DISTRIBUTION OF LOAD BETWEEN GENERATING STATIONS BY TAKING INTO ACCOUNT THE TRANSMISSION LOSSES : PENALTY FACTOR

If transmission losses are neglected, the economic loading of generating is such that the Incremental Operating Costs and equal,

i.e. $$\frac{dF_1}{dP_1} = \frac{dF_2}{dP_2} = \frac{dF_3}{dP_3} = \ldots \lambda = \frac{dF_n}{dP_n}$$

When transmission losses are considered as functions of respective plant loadings, the above criterion gets modified as follows :

$$\frac{dF_n}{dP_n} + \lambda\,\frac{dF_L}{dP_n} = \lambda \ldots\ i.e.\ \frac{\partial F_n}{\partial P_n}\left[\frac{1}{1 - \dfrac{\partial P_2}{\partial P_n}}\right] = \lambda$$

i.e. $$\frac{dF_n}{dP_n}\,L_n = \lambda.$$

where L_n is a multiplier for incremental operating cost dF_n/dP_n for nth plant is called 'Penalty factors'. *Penalty Factor* L_n is obtained from the transmission loss P_L and power delivered P_n by nth plant, *i.e.*

$$L_n = \frac{1}{1 - \lambda\, P_L/\partial P_n}$$

where L_n = Penalty factor for nth plant

P_L = Transmission loss

P_n = Power delivered by nth plant.

Thus for economic loading of plants considering respective transmission losses, the total incremental cost should be equal for all the plants, *i.e.*

$$\frac{dF_n}{dP_n} \cdot L_n = \lambda$$

should be equal for n plants in the system

Summarising for economic load distribution between various n number of plants, considering transmission loss P_L, the minimum operating cost of entire system is obtained for equal λ for each plant, *i.e.*

$$\frac{dF_n}{dP_n} \cdot L_n = \lambda \ldots \text{ equal for all } n \text{ plant.}$$

For economic load distribution,

$$\frac{dF_1}{dP_1}\,L_1 = \frac{dF_2}{dP_2}\,L_2 = \ldots \frac{dF_n}{dP_n} \cdot L_n$$

where $\dfrac{dF_1}{dF_2}, \dfrac{dF_2}{dP_2} \ldots$ incremental operating costs of plant

$L_1, L_2, L_3, \ldots$ penalty factors of plants

$$L_n = \frac{1}{1 - \dfrac{\partial P_L}{\partial P_n}}$$

where L_n = Penalty factor for nth plant

P_L = Total transmission loss

P_n = Output of nth plant.

46.19. AUTOMATIC LOAD DISPATCH INCORPORATING LOAD FREQUENCY CONTROL AND ECONOMIC LOAD DISPATCH

Refer Sec. 45.11. Load Dispatching and Network Controller. This topic will be elaborated in this section.

The *Load Control Centre* determines the allocation of generation by various plants on the basis of economic load distribution considering incremental operating costs λ and penalty factors for transmission losses (*Ln*) for each plants. The *load centre sends* commands to *Power Station* control room periodically by telemetric data transmission. The automatic load-frequency control in the control system of Generator-Turbine-Governor basically aims at maintaining constant frequency/speed as a primary control (Secs. 45.3 and 45.4). But the setting of governor to turbines (Secondary Load-Frequency Control) is changed according to the instructions of Central Load Control Centre. *Thus the input to turbines of generators gets automatically adjusted by primary load-frequency control and the frequency is maintained. And the governor setting is determined by economy load dispatch instructions.*

Fig. 46.13 illustrates the basis functional scheme of *Automatic load-frequency control and economic load dispatch.*

The total control is achieved jointly by :

(*A*) Load Control Centre

(*B*) Telemetry and Telecontrol Equipment and

(*C*) Power Station Control Room.

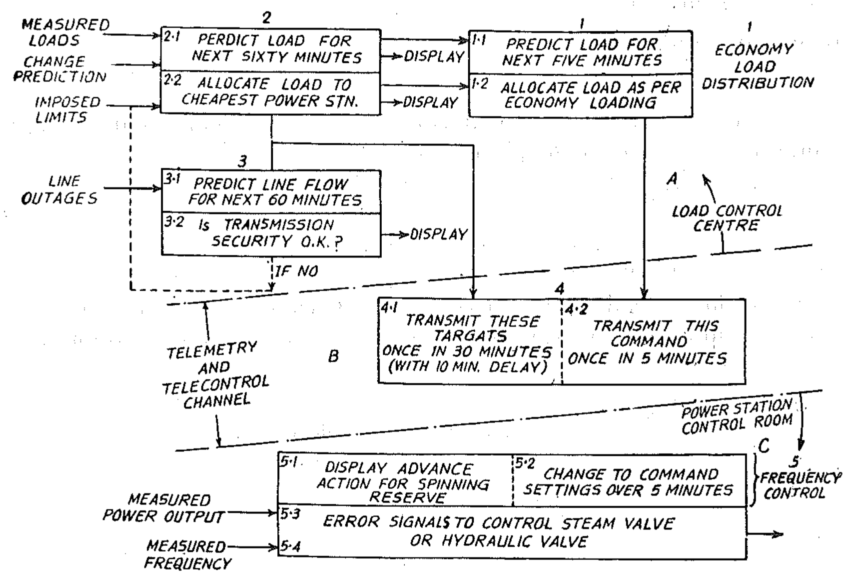


Fig. 46.13.

Function of Load Control Centre (A). The load control centre (Load Dispatch Centre) A has a central micro-processor (Refer Sec. 46.9) which performs the following functions :

— Functional Block 2 in Fig. 46.13.

Calculate the estimated load on the network for the next one hour ahead; display it, calculate economy loading for that load and allocate for the next one hour the load of each power station ... Functional Block (2) Display for next one hour the allocated loading for each power station in the region. These predictions and instructions are telemetered by B to power station (C).

Functional Block (1) in Fig. 46.13 located in the Load Control Centre.

— Calculate Economic Load Distribution for say every next five minutes ahead (slower control than load frequency central) and allocates the economic loading to each generating station (C) *via* telemetric channels (B).

— Load Control Centre (A) may also instruct certain power stations to control the *output* to control system frequency without considering economic loading. This for higher priority to frequency control overriding the economy control.

Function of Telemetry and Telecontrol B. Telemetry and Telecontrol Channels (B) transmit instructions from load control centre (A) to power Station Control Room (C). These instructions are for :

— Targets for next half hour ahead for advance action for spinning reserves in power station (4.1).

— Commands regarding plant outputs for achieving economic loading. These commands are transmitted once in five minutes (or two minutes) (Block 4.2).

Functions of Generating Station Control Room (C). The generating station control room has machine controllers for each generator unit. These controllers provide basic load-frequency control. The frequency of generator bus is taken as a reference. The input to turbines is changed to achieve desired electrical output to maintain the desired frequency. The setting to governor valve determines the range between which the input to turbines can be varied automatically be the primary load frequency control Refer Block (1) and Block (5) in Fig. 46.13. The setting of governor valve itself is changed in accordance with the command of load control centre once in five minutes. Thereby the input to turbines is adjusted once in five minutes in accordance with economy loading

command by block 1. Thus the load frequency control (5) in the power station (C) receives data regarding.

5.1.... Measured power output of the generating station.

5.2.... Measured Frequency.

5.0....Instructions for setting of power output from load control centre.

The control system for frequency control adjusted the turbine valve setting an accordance with the error signal based on 5.0, 5.1, 5.2 above.

Solution.

Refer Ex. 43.2 for Economy Loading Incremental Operating Cost

$$\text{Cost} = \frac{dF}{dP}$$

$$\text{Operating Cost of } F = \int \frac{dF}{dP}\, dP$$

Difference in operating costs with different loadings say P economy and equal will be

$$\int_{P\text{ economy}}^{P\text{ equal}} \frac{dF}{dP} \cdot dP = \text{Difference in operating cost.}$$

For Unit 1

Refer Ex. 46.3. For economy loading

$$P_1 = 80 \text{ MW}$$

For equating loading $\quad P_1 = 90$ MW

Difference in operating cost would be

$$\int_{80}^{90} \frac{dF}{dP} \cdot dP = \int_{80}^{90} (0.1\, P_1 + 20)\, dP$$

$$= [0.05\, P_1^2 + 20\, P_1]_{80}^{90}$$

$$= 0.05\, [90^2 - 80^2] + 20\, [90 - 80] = 0.05\, (1700) + 20\, (10)$$

$$= 85 + 200 = \mathbf{285\ Rs./hr.} \quad \text{Answer to } (A)$$

Similarly, for Unit 2

Economy loading from Ex. 43.3 = 100 MW

Difference in operating cost would be

$$\int_{P\text{ economy}}^{P\text{ equal}} \frac{dF_2}{dP_2} \cdot dP_2$$

$$= \int_{P\text{ economy}}^{P\text{ equal}} [0.12\, P_2 + 16]\, dP_2$$

$$= [0.06\, P_2^2 + 16\, P_2]_{100}^{90}$$

$$= [0.06\, (8100 - 10{,}000) + 16\, (90 - 1000)]$$

$$= -[190 + 160] = -\mathbf{250\ Rs.\ hr.} \quad \text{Answer to } (B)$$

Note. Negative sign indicates increase in operating cost of operating cost of unit 2 for economy loading.

$$285 - 250 = 35 \text{ Rs./hr.}$$

Annual saving = Hourly saving × Annual Hours

$$= 35 \times 8760 = 306{,}600 \text{ Rs/year}$$

Annual saving = **306,600 Rs. Ans**

Note. This figure indicates the probable magnitude saving due to economy loading in one small power station.

46.20. TRANSMISSION LOSS AS A FUNCTION OF OUTPUT POWER OF GENERATING STATION

In earlier analysis, the transmission losses have been neglected. These are generally considered as multiple of power generation of generating stations. The transmission losses from a power plant having lower incremental operating cost may be higher due to longer distance from the load and it may be more economical to load a generating station at a lesser distance considering lower transmission losses.

In the economic loading of power stations, the transmission losses are taken into account as functions of respective generating stations outputs.

Consider a simple system having two generating stations G_1 and G_2 feeding power P_1 and P_2 to a load *via* transmission lines 1 and 2 respectively.

$$\text{Power loss in line } 1 = 3/|I_1|^2 R_1 \quad ...(1)$$

$$\text{Power loss in line } 2 = 3\ |I_2|^2 R_2 \quad ...(2)$$

where R_1 and R_2 are resistance of conductors.

$$I_1 = \frac{P_1}{\sqrt{3}\ |V_1|\ (PF_1)} \quad ...(3)$$

$$I_2 = \frac{P}{\sqrt{3}\ |V_2|\ (PF_2)} \quad ...(4)$$

Total transmission loss P_L watts

$$P_L = 3\ |I_1|^2 R_1 + 3\,|I_2|^2 R_2 \quad ...(5)$$

$$= \frac{3P_1^2 R_1}{\sqrt{3}\ |V_1|^2 (PF_1)^2} + 3\,\frac{P_3^2 R_2}{3\ |V_1|^2 (PF_2)^2}$$

$$= P_2^2 \frac{R_1}{|V_1|^2 (PF_1)^2} + P_2^2 \frac{R_2}{|V_2|^2 (PF_3)^2} \quad ...(6)$$

(PF_1), (PF_2) are power factors.

In the above expression the transmission loss *PL* is expressed in terms of plant loads P_1 and P_2. Rewriting eq. (6) in terms of Loss Formula Co-efficients B_{11} and B_{22} as

$$P_L = P_1^2 B_{11} + P_2^2 B_{22}$$

46.21. NETWORK CONTROLLER IN LOAD CONTROL CENTRE (Refer Sec. 45.11)

Consider the power generation in an area (Region). The tasks of the power system network controller in the load control centre is to maintain the power exchange through the tie-lines with neighbouring regions at the desired values, and simultaneously to control the system frequency *f*.

The network controller compares the action sum of Tie-line Power P_1 with Scheduled sum of Tie-line Power P_{io} : to calculate the Deviation ΔP

$$\Delta P = \sum_{1}^{n} (P_i - P_{i0}) \quad ...(1)$$

where ΔP = Deviation of actual power transfer through tie-lines from targeted values

1, ... n = No. of Tie-Lines with neighbouring regions

P_i = Tie-line Power Flow, MW

P_{i0} = Scheduled Tie-line Power Flow, MW

Thus,
$$\Delta P = \sum_{1}^{n} (P_i - P_{i0})$$

gives total deviation of power exchange with interconnected areas from the scheduled exchange.

It means, the generation in the area under the control of the network controller should be changed by ΔP to meet targeted exchange.

Next, the network controller has to control the system frequency. Let ΔP be the frequency deviation *i.e.*

$$\Delta F = f - f_o$$

where Δf = frequency deviation

f_0 = target frequency .... Hz

f = actual frequency ... Hz

A factor K called *System Frequency Bias* is introduced.

The system frequency bias K is *amount of power generation required to change the system frequency by one cycle.* Thus,

K = System Frequency Bias MW/hz

Thus to correct the frequency deviation Δf, the amount of power change would be

$$K\,\Delta F\ ...\ (\text{MW}) \quad ...(2)$$

Combining (1) and (2), the *Area Requirement e* is given by

$$e = \Delta P + K\,\Delta F$$

Thus the network controller determines Area Requirements (e), where

$$\boxed{e = \Delta P + K\,\Delta f}$$

e = Area Requirement Correction MW

ΔP = Deviation in Power Exchange through Tie-Lines ... MW

K = System Frequency Bias

Δf = System Frequency Deviation

Kf = Power change required to achieve target frequency ... MW

This area requirement correction is transformed into output signals by the network controller. These output signals for *correcting conditions* are set to various generating stations under automatic control. (Block 1.2 in Fig. 46.13).

The primary load frequency control in response to automatic governor action to achieve target frequency is faster (a few seconds). This corrects the input to turbines within set limits of turbine to control the frequency.

The secondary load-frequency control (in response to instructions from network controller) is slower (once in say 5 minutes). It adjusts the governor settings.

Refer Fig. 46.14 illustrating load frequency control of generating unit.

The output of the turbo-generator P and the frequency f is controlled by the load frequency control system as follows. The frequency of generator output is measured by frequency measurement (F) and is fed into operational amplifier *OM* in the form of $K_m\,\Delta f$. The output power of the generator P_m is measured by Power Measuring Convertor *MC* and its equivalent d.c. P_m is fed into the operational amplifier. Thirdly, the area requirement correction e computed by the network controller is converted into equivalent proportional- integral signal called Y which is an analogue d.c. signal (d.c. voltage or current) and is given as input to the operational amplifier. Thus the operational amplifier *OA* gets three inputs (1) P_m, (2) $K_m\,\Delta f$ and (3) $Y_m \propto e$. The operational amplifier *OA* processes these three inputs and gives an output ΔG.

$$\Delta G = \frac{P_m + K_m\,\Delta f}{P_{m-\max}}\,100\% - Y_m\ (\%)$$

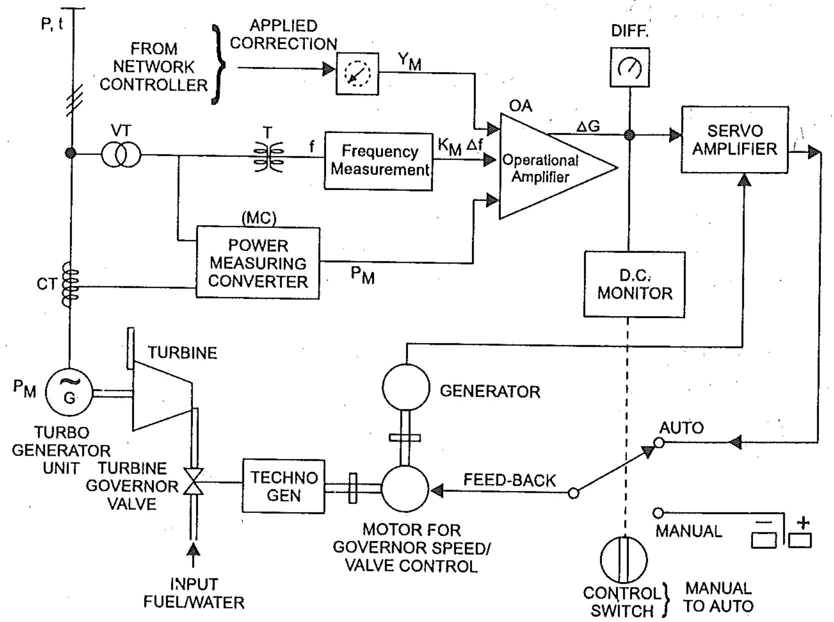


Fig. 46.14. Load-frequency control of a unit.

The value of ΔG passes through the servo amplifier to the two phase servo motor such that the speed of the servo motor is proportional to ΔG. A techo-generator coupled to the motor produces a feedback voltage which is fed-back to the servo-amplifier and the speed of the motor is made independent of the torque. The difference ΔG is monitored by d.c. monitor DCM and is shown on the control desk by the indicating instrument difference.

The servo-motor rotates in required direction by required number of turns in response to ΔG and the setting of turbine-governor-valve is changed. Thereby the input to turbine is changed and generator output is changed.

The running time of the motor for governor valve control is of the order of 20 to 100 seconds. In order to avoid-regulation, hunting etc. the stopping time is short of the order of 0.5 second.

The centrifugal governor should have dead-band of less than ± 0.5%. There is a provision of changing-over from automatic to annual as shown in Fig. 46.14 when difference ΔG is higher than present limit the change-over from automatic to manual takes place and an alarm is sounded.

Thus the load frequency control system of turbine-generator unit serves the function of maintaining target frequency and scheduled generation for economic loading.

SUMMARY

The load-frequency control and the economic loading of generators is achieved by a combined action of network controller in the load control centre and the frequency control system in the generator control rooms.

For economic loading of the *unit the plant,* there incremental operating costs are equal, *i.e.*

$$\lambda = \frac{dF_1}{dP_1} = \frac{dF_2}{dP_2} = \ldots = \frac{dF_n}{dP_n} \ldots \frac{R_s}{\text{MWhr}}$$

Some principle is applied to the loading of power stations in the area economically neglecting line losses.

$$\lambda = \frac{dF_1}{dP_1} = \frac{dF_2}{dP_2} = \frac{dF_3}{dP_3} = \ldots \frac{dF_n}{dP_n}$$

However lines losses should be considered and they are generally expresses as a function of plant loading. The incremental operating cost of each plant is multiplied by its penalty factor. Penalty factor for nth plant is

$$\text{Penalty Factor } L_n = \frac{1}{1 - \partial P_1/\partial P_n}$$

For economic loading of power stations in an area considering line losses is given by

$$\frac{dF_1}{dP_1} L_1 = \frac{dF_2}{dP_2} L_2 = \ldots \frac{dF_n}{dP_r} L_n = \lambda$$

The load Frequency Control is achieved by combination of

— Primary load frequency control by the control action of generator frequency control in the control room of the generator.

— Secondary frequency control according to the instructions of network controller situated in the load control centre.

The network controller calculates

Deviation ΔP give by

$$\Delta P = \sum_{1^n} (P_i - P_{i0})$$

and $$K\Delta F$$

where K = System Frequency Bias.

Network controller gives the error

$$e = \Delta P + K\Delta F$$

This error transmitted to the generating station control room.

The operational amplifier in the frequency control system gets signal (e) from network controller and produces output G.

$$\Delta G = \frac{P_m + K_m \Delta f}{P_{m-max}} 100\% - Y_m\ (\%)$$

where y_m% is proportional to (e).

Turbine Governor Gate valve is adjusted by the servo-motor in the closed loop system of frequency control system. The turbine input gets adjusted to maintain required frequency and to give economic loading.

QUESTIONS

1. Explain the following terms related with economic loading :
   - — Incremental operating cost of power station
   - — Penalty Factors
   - — Loss formula coefficients

   Explain the modern criterion for economic load distribution between generating stations.
2. Explain the function of network controller and generator control room in frequency control and economic loading by a suitable block diagram.
3. Explain the function of a typical control system for frequency control of a synchronous generator stating the function of each component and the control action.
4. Explain the following equation :

   $e = \Delta P + K\Delta F$

   where e = Area requirement correction
   ΔP = Deviation in power exchange
   K = System Frequency Bias
   ΔF = Deviation in frequency.

5. Explain the co-relation between load-frequency control and economic loading of power stations. How are both of these achieved simultaneously ?

6. Fill in the blanks :

1. For economic loading of generating stations, the ... should be equal.
2. The unit of incremental operating cost of generating cost is ....
3. Incremental operating cost for a particular load is given by ... curves.
4. Loss formula coefficient is expressed as

Ch. 49 Covers interconnected power systems.

Ch. 50 Covers further details about SCADA systems used in todays Power System Operation and Control.

47

HVDC Transmission Systems

Introduction — Choice — Merits — Economy — Limitations — Bipolar/Mono polar/Homopolar — Arrangements — Thyristor Convertor — Convector Operation — Control of Thyristors and D.C. Line-Layout — Components — Control, Measurement, Protection — Operation — Maintenance — HVDC Simulators — Typical HVDC Line — Summary

47.1. INTRODUCTION CHOICE OF HVDC TRANSMISSION

In India, 400 kV a.c. transmission lines have been introduced during 1970's. 4 HVDC transmission links have been executed (1997). By the year 2000, about six HVDC transmission links are expected to be commissioned in India. HVDC transmission systems are selected as an alternative to extra high voltage a.c. transmission systems for any one or more of the following reasons :

1. **For long distance high power transmission lines.**

2. **For interconnection (Tie-lines) between two or more a.c. systems having their own load frequency control.**

3. **For back-to-back asynchronous-tie sub-stations.** Where two a.c. systems are interconnected by a convertor-sub station without any a.c. transmission line in between. Such a tie-link gives an asynchronous interconnection between two a.c. systems.

4. **For underground or submarine-cable transmission over long distance at high voltage.**

At present 40 HVDC links have been installed in the world and by the year 2000, about 55 links are expected with a total transfer capacity of 70,000 MW. *The choice between 400 kV a.c., 765 kV a.c., 1100 kV a.c. and HVDC transmission alternatives is made on the basis of technical and economic studies for each particular line and associated a.c. systems. Alternating current continues to be used for generation, transmission, distribution and utilization of electrical energy.*

47.2. HVDC TRANSMISSION SYSTEMS

47.2.1. Applications of HVDC Transmission Systems

For generation, transmission, distribution, and utilization of electrical energy, 3-phase AC systems are used universally and have a definite superiority over HVDC.

However in following particular applications, High Voltage, Direct Current Transmission (HVDC) is a strong alternative to EHV-AC transmission and HVDC lines are preferred.

— Long distance high power transmission by overhead lines.

— Medium high power submarine or underground cables.

— System interconnection by means of overhead lines, or underground/submarine cables, or back-to-back HVDC coupling stations, or Multi-Terminal DC systems (MTDC).

— Frequency conversion links (*e.g.* 60 Hz/50Hz)

— Incoming lines in mega-cities.

In HVDC link AC power is converted by thyristor-convertor valves at one end. The energy is transmitted in HVDC form to the other end. At the other end, the DC power is inverted to AC and fed into the receiving AC system. Fig. 47.1 illustrates a typical bipolar HVDC link.

A 2-Terminal HVDC transmission system has a HVDC convertor sub-station at each end and an HVDC transmission line in between. In case of back-to-back coupling station, the convertor and invertor are at the same place and there is no HVDC line. Multi-Terminal HVDC interconnects 3 or more AC systems, by HVDC transmission lines.

47.2.2. Choice of HVDC Transmission System

HVDC system are selected as an alternative to extra high voltage, a.c. transmission systems for any one or more of the following reasons : (Table 47.1 gives the summary).

1. **For long distance high power transmission lines** for economic advantage of HVDC with respect to lesser cost of transmission line, and better control of power flow. Though the HVDC link needs additional conversion substation equipment (convertor transformers and convertor etc.) on each side, for long distance high power transmission, the total cost of a d.c. system becomes lower than that of a.c. system. The break-even point is decided by economic studies for each scheme.

The per km cost of one bipolar single circuit HVDC line is lesser than that of an equivalent 3-phase double circuit AC line. Number of conductors for 3 phase AC line is 6 to 24 as against 2 numbers required for an equivalent bipolar HVDC line. HVDC line does not need intermediate sub-station for compensation, whereas for EHV-AC line such a sub-station is required at an interval of 300 km. HVDC becomes favourable above 800 km, 1000 MW when cost of EHV-line/sub-station exceeds that of equivalent HVDC line/sub-station. (Refer Sec. 47.2.8)

2. **For Interconnection (Tie-lines) between two a.c. systems** having their own load frequency control, HVDC links have several advantages over a.c. links. HVDC links form an asynchronous-tie *i.e.*, the two a.c. systems interconnected by HVDC tie-line need not in synchronism with each other.

HVDC interconnection is superior to EHV-AC interconnection in many respects and is selected due to its technical superiority. With HVDC interconnection, power flow can be controlled, the frequency disturbances are not transferred, short-circuit levels remain unchanged at both ends, transient stability of AC network at both end can be significantly improved.

Power flow through the HVDC line can be quickly modulated reversed, changed to dampen the power swing in connected AC Network. Thereby the system stability can be greatly improved.

HVDC interconnection can provide a weak tie (of lesser capacity) between strong and a weak AC Network. This is difficult with AC interconnection.

Most important task of interconnector is to transfer required amount of power in required direction and to assist the interconnected AC Network to maintain transient stability. AC interconnectors have severe limitations. HVDC interconnections are without such limitations.

HVDC system control can be modified to dampen oscillations in load angle δ. Thereby the stability of both AC systems is improved.

3. **For Back-to-back synchronous tie-stations.** Where two a.c. systems are interconnected by a convertor sub-station without any a.c. transmission line inbetween. Such a tie-link gives an asynchronous interconnection between two adjacent AC systems. The back-to-back coupling stations can be located at any suitable location, where to networks meet geographically and exchange of required amount of power is desired.

4. **Multi-terminal HVDC Interconnection.** This is the new HVDC possibility (1987). Three or more AC networks can be interconnected asynchronously by means of a multi-terminal HVDC network. Power flow from each connected AC Network can be controlled suitably. Large powers can be transferred. Overall stability can be improved. At present only one such scheme is under execution (Hydro Quobec Canada to New England USA). More and more multi-terminal HVDC schemes are likely to be executed.

5. **For underground or submarine cable transmission.** Over medium distance at high voltage. The submarine cables are necessary to transfer power across lakes, oceans, etc. In case of AC cables, the temperature rise due to charging currents forms a limit for loading. For each voltage

rating, there is a limit of length beyond which the cable cannot transfer load current due to this limit. In such cases HVDC cables are essential. HVDC cable has no continuous charging current.

Table 47.1. Criterion of Choice of HVDC.

	Type of link	*Criterion of choice*	*Features*
1.	Long high power transmission by overhead line *e.g.* 1000 km ± 400 kV, 1000 MW ± 500 kV, 1500 MW	*Lower Total cost of HVDC Link.* — Less number of line conductors — No need of intermediate sub-stations.	— Normal mode Bipolar. — Two terminal — Can be operated with reduced rating in monopolar mode.
	± 600 kV, 2200 MW	— Simpler and economical tower. — Line cost per km lower. — Higher sub-station cost. — Break-even above about. 800 km., 1000 MW	Line design and construction simpler.
2.	*System Interconnection by*	*Technical Superiority of HVDC Link.*	— Usually two terminal. Recently multiterminal.
	— Overhead line — Underground or submarine cable	— Provides Asynchronous tie. — Power flow can be quickly controlled	— Overhead line simpler ; may be mono-polar or bipolar.
	— Back-to-back station	— Improved stability — Fault levels remain unchanged	— Submarine cable may be monopolar or bipolar.
	— Multi-Terminal HVDC (MTDC)	— Strong AC Network can be connected to weak AC Network. — Frequency conversion possible.	— Coupling stations have no transmission line.
3.	Underground cables or submarine cables *e.g.* ± 100 kV, 500 MW ± 200 kV, 200 MW 5 km to several hundred km.	— *Technical Superiority of HVDC Line.* — No continuous charging current. — No limit of power or distance.	— Two terminal

47.2.3. Types of HVDC systems and brief description

An HVDC transmission system transmits electrical energy from one/or more AC sub-station(s) to another AC sub-station(s) in the form of Direct Current. *A two-terminal HVDC system* transmits electrical energy is direct current form from one AC sub-station to another AC sub-station.

A multi-terminal HVDC system transmits power in direct current form between three or more AC sub-stations.

In *bioplar HVDC transmission system,* the mid-point of convertors at each HVDC convertor sub-station is earthed and earth return path is usually available.

The word Pole refers to the path of direct current which has the same polarity with respect to the earth. The total pole includes sub-station pole and transmission line pole (Refer Fig. 47.18 b)

Types of HVDC systems (Fig. 47.1)

The types of HVDC systems include the following :

— Two terminal system has two terminal substations.

— Multiterminal system has three or more terminals.

— A bipolar HVDC transmission system has two poles, one positive and the other negative with respect to the earth. Mid-point of convertors is earthed. Bipolar system can be operated in monopolar mode.

— A monopolar HVDC transmission system has one pole and earth return.

— A homopolar HVDC transmission system has two poles of same polarity and return earth.

— A back-to-back HVDC coupling system has no DC transmission line. Rectification and inversion is done in the same sub-station by a back-to-back convertor.

An HVDC transmission system has an AC and HVDC terminal sub-stations and inter connecting DC line(s). The type of an HVDC transmission system is identified on the basis of the arrangement of the pole and earth return. Modern HVDC systems have thyristor convertors. A convertor converts AC to DC or DC to AC.

Monopolar HVDC System (Fig. 47.1.-*b*)

This system has only one pole and the return path is provided by permanent earth or sea. The pole generally has negative polarity with respect to the earth.

In monopolar HVDC system the full power and current is transmitted through a line conductor with earth or sea as a return conductor. The earth electrodes are designed for continuous full current operation and for any overload capacity required in the specific case.

The sea or ground return is permanent and of continuous rating.

Monopolar HVDC systems were used only for low power rated links and mainly for cable transmission. In some cases the monopolar systems installed earlier are converted into bipolar systems by adding additional sub-station pole and transmission pole.

The rated currents of the existing three monopolar transmission installations range from 200 to 1000 A. The earth current flows in one direction only in these links. The earth path offers an inexpensive, low resistance, low-loss conductor which effectively contributes to the economy of the system.

Monopolar HVDC transmission system has only the rating equal to half of corresponding bipolar system rating and is, therefore, not economically competitive with EHV-AC scheme. For submarine cables longer than 25 km and having power rating of about 250 MW. For such cables transmission HV-AC is not technically feasible because of high charging currents with AC cables beyond thermal limit. And bipolar cable is not justified for ratings upto about 500 MW. Recent HVDC cable schemes are bipolar.

Homopolar-HVDC System (Fig. 47.1 *c*). In such a system two transmission poles are of the same polarity and the return is through permanent earth. Such a scheme may be used for the following :

— Two homopolar overhead lines feeding to a common monopolar cable termination.

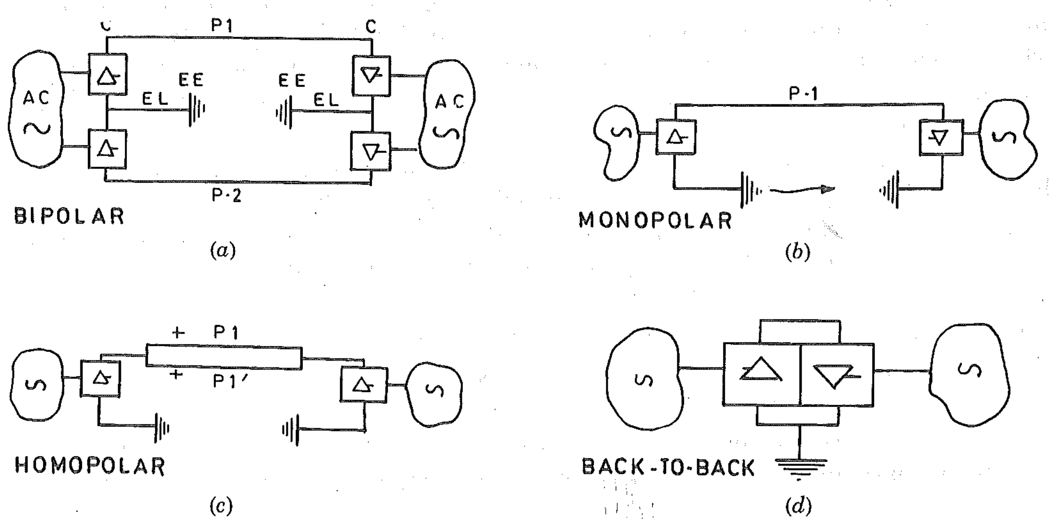


Fig. 47.1. Type of HVDC systems.

— One overhead transmission tower carrying insulator strings supporting two homopolar transmission line conductors.

Applications of homopolar transmission are limited and are not discussed further.

Bipolar HVDC Transmission. (Fig. 47.1 *a*). This is most widely used for overhead long distance HVDC systems and also for Multi-Terminal HVDC systems (MTDC).

The HVDC sub-station and HVDC line has two poles, one positive and the other negative with respect to earth. The midpoints of convertors at each terminal station are earthed *via* electrode line and earth electrode. Power rating of one pole is about half of bipole power rating.

The earth carries only a small out-of-balance current during the normal operations.

During fault or trouble on one of the poles, the bipolar HVDC system is switched over automatically to monopolar mode. Thereby, the service continuity is maintained. After taking corrective action, the system is switched over to normal bipolar operation.

A bipolar HVDC line has two conductors, one of positive polarity with respect to the earthed tower structure and the other of negative polarity. The voltage between poles is twice that of the pole to earth voltage. Therefore, a bipole HVDC system is described as say ± 500 kV.

The normal bipolar HVDC system is composed of two separate monopolar system with a common earth. The two poles can operate independently. Normally they operate with equal currents and, therefore, there is no ground current. In the event of a fault on one of the poles, the other pole can carry upto half of bipolar power.

Earth Electrodes in a Bipolar System. The mid-point of convertors (Called neutral point or the joint) in each station is earthed with a suitable switching arrangement. This earthing is independent of the station earthing. This electrode earthing is through electrode installed 5 to 20 km from the HVDC sub-station. The mid-point of convertor is connected to earth electrode *via* electrode line. The definitions are as follows :

— **Earth electrode.** An array of conducting elements placed in the earth or sea which provide a low resistance path between the DC circuit and the earth and which is capable of carrying continuous current for some extended period.

— **Earth electrode line.** An insulated line between the HVDC sub-station and the earth electrode.

— **Station earth.** An array of conducting elements placed in earth at the sub-station location and which provides connection between the earthed parts of sub-station equipment and the earth.

The earth electrode is installed away from the sub-station earth to avoid the *galvanic corrosion* of the sub-station earthing system, underground pipes, buried cables and structures.

Electrode line is either a cable or an overhead line.

Table 47.2. Examples of Bipolar HVDC Systems

Year	*1987*	*1990*
Name	*Itaipu Brazil*	*Rihand-Delhi India*
Configuration	Two Bipole circuits	Single Bipole Circuit
Power	2 × 6000 MW	1500 MW
Direct bipole Voltage, each circuit	± 600 kV	± 500 kV
Voltage, pole to pole, DC	1200 kV	1000 kV
No. of convertors/station	2 × 2	2
Transmission	Overhead	Overhead
Main reason for HVDC	High Power Long distance, Frequency conversion 60/50 Hz.	Long distance, High power.

A bipolar HVDC line has only two line conductors. One called positive pole line conductor and the other is called negative pole line conductor. Earth electrode and electrode line. Besides line conductors, an HVDC transmission system needs *earth electrodes and electrode lines.* The earth electrode is located at a distance of a few tens of km from the HVDC sub-station. The connection between the mid-point or earthed end of the convertor valve and the earth electrode is *via* the electrode line. The electrode line is insulated from the earth. Earth electrode is located away from main sub-station earth to avoid galvanic corrosion of the sub-station earth.

Rectification and Inversion. In an HVDC transmission system or HVDC back-to-back coupling station, alternating current is converted into direct current by means of a combination of convertor-transformers and convertor valves. The conversion from AC to DC is called Rectification or Rectifier operation.

The transmission is in the form of direct current. In bipolar line, there will be two line poles. The earth return carriers negligible current. In monopolar line, the direct current flows through one pole line and return through earth.

At the receiving end of the HVDC transmission line, the direct current is converted to alternating current alternating current by means of convertor valves and convertor transformers. The conversion of DC into AC is called inversion (or inverter operation).

Essential Parts of HVDC Systems. An HVDC transmission system has the following essential parts :

— AC sub-station and HVDC sub-station at each terminal.

— Interconnecting HVDC line(s).

— Electrode lines and earth electrodes.

A two terminal HVDC transmission system has only two terminal sub-stations and two earth electrodes.

A multi-terminal HVDC transmission system has three or more terminal sub-stations and equal number of earth electrodes, all located at different locations.

The HVDC terminal sub-station has following main parts :

— AC Switchyard.

— Convertor Transformers.

— AC Harmonic Filters.

— Valve Hall and Control Building.

— Smoothing Reactors.

— HVDC Yard.

— Electrical and Mechanical Auxiliaries.

Sec. 47.2 (*a*), (*b*) gives details about layout of a bipolar HVDC sub-station.

Table 47.3. Typical Rating and Main Specifications of Bipolar HVDC Transmission System

Operating voltage of A.C. yard	400 kV A.C.
Operating voltage of D.C. yard	± 500 kV D.C.
Rated Power of D.C. line	1500 MW
Number of Converter Transformers : each 300 MVA : 3 winding 1 Phase	6, (each terminal)
Number of quadruple valves	6, (each terminal)
Minimum clearance, phase-to-phase on 400 kV A.C. side	5.75 m
Minimum clearance phase-to-ground on 400 kV A.C. side	3.65 m
Minimum phase-to-phase clearance on 500 kV D.C. side	12 m
Minimum phase-to-ground clearance on 500 kV D.C. side	7 m
Size of Busbars in D.C. yard	10″ IPS
Size of Busbars in A.C. yard	4″ IPS
Type of HVDC transmission	Bipolar
Transmission line voltage	± 500 kV
Transmission line length	1000 km
Power rating of transmission line	1500 MW
Total MVAr of AC Filters	2000 MVAr
Number of PLCC Repeater Stations	2

* One such sub-station at each end of the 1000 km, 1500 MW HVDC transmission line. IPS-International Pipe Standard.

47.2.4. Long Distance, High Power Bipolar HVDC Transmission Systems

Large hydroelectric power stations with low generating costs are generally located far away from load centres. Large thermal power stations are generally built near coal mines. Long distance bulk power transmission lines are required to transfer power from such remote power stations to distant load centres located in industrial towns and megacities.

By HVDC, bulk power of any magnitude can be brought to load centres over distances upto 1000 km, or more, simply and efficiently by using a single bipolar link without any intermediate sub-station or parallel line.

Long distance HVDC transmission between individually controlled power systems allows daily and seasonal balancing of peak load requirements.

Thermal power plants, conventional or nuclear can be grouped in 'energy parks' for away from the load centres and thereby the environment can be preserved.

47.2.5. Power rating of long bipole HVDC transmission system

Power rating of bipolar HVDC line P_{dc} is given by

$$P_{dc} = V_{dc} I_{dc} \ldots \text{MW}$$

$$V_{dc} = \text{D.C. voltage, kV between pole-lines}$$

$$= 2 \times (\pm \text{ Rated Bipole Voltage}).$$

$$I_{dc} = \text{Current in conductors, kA}$$

$$P_{dc} = \text{Power transfer through line, MW}$$

I_{dc} is decided by normal current rating of thyristor valve. Valves range between 0.5 KA and 4 KA; V_{dc} is decided by rated voltage of a convertor pole. Values of V_{dc} range between 500 kV for ± 250 kV and 1200 kV for ± 600 kV bipolar HVDC links. By appropriate choice of voltage and current combination, the required power rating of the HVDC link is obtained. Table 47.2 gives typical ratings of present HVDC Bipolar links for long distance lines.

Table 47.4. Power transferability of bipolar HVDC line

Rated Bipolar Voltage kV	± 400	± 450	± 500	± 600
Voltage between pole conductors kV	800	900	1000	1200
Power per circuit, MW (Bipolar)	1440	1620	1800	2160

Note. Basic for the above table : $I_{dc} = 1.8$ kA.

$$P_{dc} = V_{dc} \times I_{dc} \ldots \text{MW}$$

$$V_{dc} = \text{Voltage between pole conductors kV}$$

$$I_{dc} = \text{Line current, kA (assumed 1.8 kA)}$$

47.2.6. Configuration and description of a Bipolar Scheme

Modern HVDC links are as a rule, bipolar. A bipolar link has two poles. The convertors valves at each terminals are connected in series. The mid-point at each end is grounded. Convertors act for conversion from A.C. to D.C. or from D.C. to A.C. (Rectification and Inversion).

During bipolar operation one pole acts positive and the other pole negative. Only a negligible out of balance current flows through ground path. During fault on any one pole, the power transfer can be continued as a mono-polar operation with ground return. Thus the bipolar d.c. Line is more reliable than a three phase a.c. Line. Three phase line cannot be operated with one phase open for more than one second due to unbalance and disturbance in communication circuits.

Fig. 47.2 (*a*) and (*b*) illustrates the configurations of a HVDC transmission system connected between two AC networks.

Transmission link has the following parts :

— Terminal sub-station at each end.

— Electrode lines and earth electrodes.
— HVDC transmission line poles (one positive and other negative)

Following parts are indicated in Fig. 47.2.(*a*)

E — Electrode for earthing mid-points of convertors.
EL — Electrode lines (5 to 20 km length each) to connect mid-points of convertor to the earth electrode *EL*
F — Filters for AC harmonics.
R — Smoothing reactor (DC)
T — Convertor Transformer
V — Convertor valves. These are installed in Valve Halls.
SC — Shunt Capacitors.

The AC sub-station is generally an EHV-AC sub-station with usual AC switchgear, busbars, CTs, VTs etc. One and a half breaker arrangement is preferred. Surge Arresters in AC yard are co-ordinated with surge arresters in DC yard, valve hall and neighbouring AC yards in the network. More details about the layout have been covered in sec. 47.7 and Fig. 47.18 (*a*) and (*b*).

Convertor transformer. (*T*) are connected between convertor valves (*V*) and the AC bus (*B*). These are specially designed as they have a d.c. voltage component coming from valve side. They are either single phase units, or three phase units with either two winding type of three winding type. *Valves* (*V*) are made-up of series connected thyristors. Valves are connected in bridge formation. Valves transfer power from AC to DC or *vice versa*. Valves are usually water cooled. *Smoothing Reactor* (*R*)

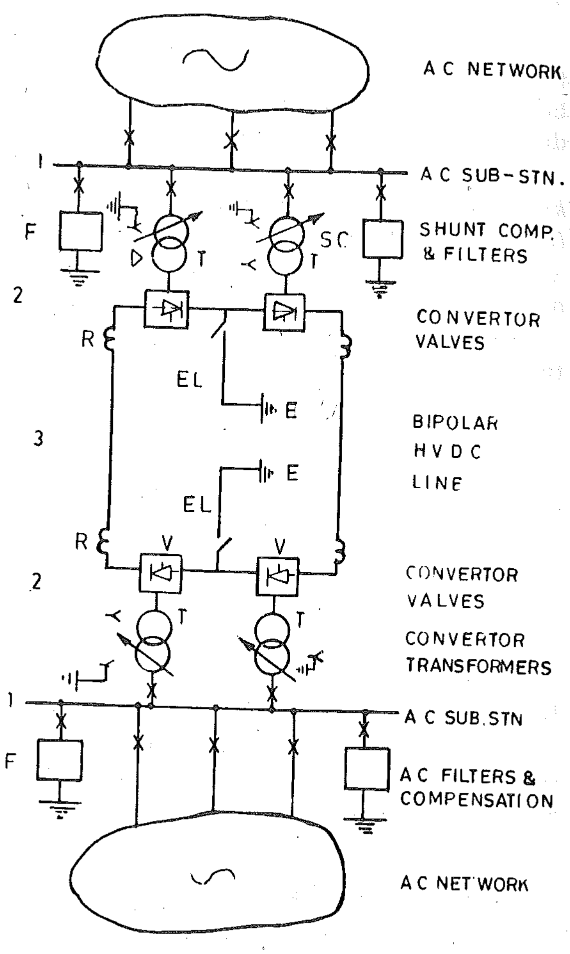
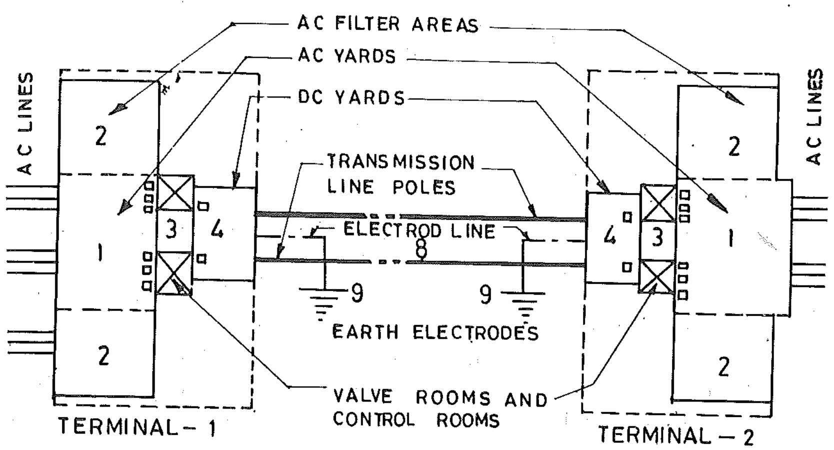


Fig. 47.2 (*a*) Configuration of a Bipolar HVDC system.



1. AC yards 2. AC filter areas 3. Valve hall and control room 4. DC yards
8. Electrode line 9. Earth electrode.

Fig. 47.2 (*b*) Layout of a Bipolar HVDC system and terminal sub-station.

is necessary for convertor operation and for smoothing the DC current smoothing reactor is generally oil cooled.

Electrode line (EL) connects the mid-point of convertors with a distant earth electrode (*E*). The earth electrode is located to 5 to 20 km away from HDVC sub-station so as to prevent galvanic corrosion of station earth-mat.

Operation of thyristor convertor valves (*V*) results in generation of AC harmonics. AC filters (*F*) are connected to the AC bus bars at each end. DC filters are connected between pole bus and neutral bus in DC yard.

AC Harmonic Filters (F) cover a large are near AC yard. These filters are composed of resistor banks, reactors, capacitor banks. They eliminate the AC harmonics arising out of the convertor operation.

Shunt Compensation is provided by shunt capacitors. This is for supplying reactive power needed for convertor operation.

47.2.7. Economic Comparison of Bipolar HDVC Transmission System with EHV-AC System (Fig. 47.3)

The total capital cost of a transmission system is equal to the sum of capital cost of sub-station plus capital cost of the lines. The cost also includes cost of land, buildings, PLCC system, etc.

Capital cost of sub-stations is higher in case of HDVC. Line cost is variable and per km line cost of HVDC line is lesser than AC line.

Total capital cost of transmission system.

$$= \left[\begin{array}{c}\text{Cost of} \\ \text{sub-stations}\end{array}\right] + \left[\begin{array}{c}\text{cost of} \\ \text{line}\end{array}\right]$$

$$= \left[\begin{array}{c}\text{Cost of} \\ \text{sub-stations}\end{array}\right] + \left[\begin{array}{c}\text{Per km.} \\ \text{cost of line}\end{array}\right] \times \left[\begin{array}{c}\text{Length of} \\ \text{line km.}\end{array}\right]$$

Below certain length of line (800 km) the total capital cost of HVDC link is more than AC link and HVDC link is not preferred due to economical disadvantage (except for interconnections).

The cost of a DC transmission line per km is considerably less than that of equivalent AC line. The DC circuit requires *only two conductors* as against minimum six for a double circuit 3-phase AC line*. A bipolar HVDC line with facility of the convertor mid-point earthing can carry the same power and gives the same reliability as a double circuit 3-phase AC line. The corridor width of HVDC line is only half of that of an equivalent AC line. The cost of tower, insulators and conductors of HVDC line is lesser than that of an equivalent AC line.

The HVDC bipolar line tower is simpler, easy to install and cheaper than EHV-AC tower. Land cost is less due to narrow Right-of-way.

HVDC bipolar line needs only two line conductors. For a equivalent 3-phase EHV-AC lines, the number of line conductors would be 6, 12, 18, 24. For longer lengths the number increases. Against one bipolar HVDC line, two or four 3-phase AC lines are required for long high power transfer.

EHV-AC lines need intermediate sub-stations at an interval of 300 km. HVDC line does not need any intermediate sub-station.

As against the above, HVDC transmission systems need additional convertor sub-stations at each end having convertor transformers, valves, controls, auxiliaries, filters etc. The cost of conversion sub-stations is extra.

HVDC has a clear cut economical advantage over AC line soon as the benefit of lower line cost is more than the higher sub-station cost. In other words, when the transmission distance is beyond the break-even point, HVDC is more economical than equivalent EHV-AC. This advantage becomes still more pronounced with very long distance (above 800 km) for which EHV-AC transmission system requires intermediate switching stations as well as intermediate shunt or series compensation.

* 3-phase AC line requires a double circuit for each transmission path. Thus it requires minimum six conductors per route.

Fig. 47.3 explains the concept of the break-even distance. The break-even distance is different for each project due to variations in local conditions and cost of imported equipment. The choice of AC or DC is based on technical and economical studies for particular project.

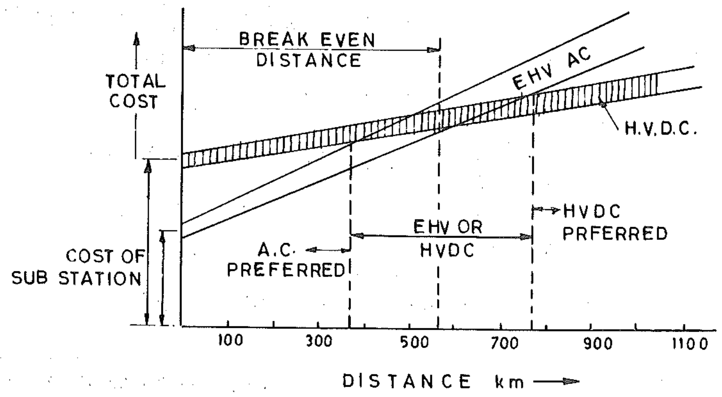


Fig. 47.3. Concept of break-even distance.

[HVDC becomes economically viable only above certain distance and power. This varies with each project].

47.2.8. EHV-AC Versus HVDC.

Table 47.5 gives summary of comparison between EHV-AC and HVDC for long distance high power transmission lines. For point-to-point transmission HVDC is preferred. For multi-terminal mesh network and for intermediate tap-off sub-stations etc. EVH-AC is preferred.

Table 47.5. Comparison of Long Distance Overhead Transmission Systems

Characteristics	*HVDC Link*	*EHV-AC Link*	*Remarks*
1. Capital Cost	— Line cost lower — Sub-station cost higher — Number of circuit one — Intermediate sub-station not required	— Line cost higher — Sub-station cost lower — Number of circuits more conductors more — Intermediate substation required.	HVDC lines becomes economically above 800 MW choice based on economics.
2. Power Transfer	— No limit due to power single — No limit due to X_L.	— Limit imposed by power angle and inductance and X_L	Single HVDC link adequate upto 3000 MW.
3. Voltage Control	— Easier as reactance is not effective	— Difficult for long lines due to shunt capacitance and series reactance. — Compensation of lines is necessary	For very long lines, single HVDC links without intermediate sub-stations.
4. Stability Limit	— No limit imposed by line reactance on power angle. — Power flow can be quickly controlled	— Limit imposed by power angle and reactance X_L	HVDC line can be loaded upto the thermal limit of equipments.
5. Corona and Radio Interference	— DC voltage does not have $\sqrt{2}$ factor for r.m.s. to peak. — Corona losses and radio interference less for same conductor to ground water voltage	— AC voltage has factor $\sqrt{2}$ for r.m.s. to peak.	

Characteristics	*HVDC Link*	*EHV-AC Link*	*Remarks*
6. Skin effect	— Absent because of zero f.	— Present	
7. Earth return	— Possible	— Not possible	Only single bipolar HVDC line adequate for most cases.
8. Reliability and availability	— One bipolar line sufficient	Two AC circuit necessary	
9. Line losses	Low (See 12)	Higher (See 12)	HVDC station has sub-station losses.
10. Control system	Difficult, Costly Fast, Accurate control	Simpler, Cheaper limitations of control	For interconnections, HVDC provides advantages due to superior control.
11. Stability of AC Networks	Much higher. HVDC system control is modified to dampen swings in load angle.	Very low. The line reactance X_L brings down power transfer ability.	AC line loaded upto fifty per cent of its thermal rating. DC line upto 90 per cent.
12. Reactive Power flow	— Absent through transmission line	— Flows through the transmission line	AC line has higher line losses due to flow of reactive power
13. Power flow control	— Very rapid (30 MW/min)	— Very slow and difficult	HVDC preferred for tie lines

47.2.9. HVDC Cable Transmission.

High voltage, high power cables are used in the following applications :

1. Underground transmission from a distant sub-station to an indoor sub-station feeding a large city or from a hydro plant to open outdoor sub-station.

2. Underwater transmission through a cable laid on sea-bed or through a lake. Such submarine cables may be for tie-up between two national grids separated by an ocean or between an off-shore gas-turbine generating station and an on-shore sub-station.

The EHV-AC cables take continuous alternating charging currents. These currents become significant for longer lengths of cables and result in dielectric heating. Thereby the thermal limit is reached even without loading the cables. Hence power transferability of long AC cables is very low. The length of AC power cables is, therefore, limited by charging currents and temperature rise.

HVDC submarine cables do not take continuous charging currents. Hence the power transfer is not limited by the thermal effects of the charging currents. Due to lesser temperature rise, higher dielectric stresses are permitted. Hence HVDC cables are more compact and of lesser cost.

Monopolar HVDC links with sea-return are economical. There is no limit on length. Steady charging current of three-phase AC cables are as follows :

Charging kVA for AC cables (continuous)

132 kV	1250 kVA/circuit/km
220 kV	3125 kVA/circuit/km
400 kV	9375 kVA/circuit/km

Due to the above, the a.c. cables have limiting length beyond which shunt compensation would be necessary. These lengths are as follows :

Limiting length of a.c. cables without intermediate shunt compensation.

132 kV	50 km
220 kV	40 km
400 kV	45 km

AC cables can be loaded only upto 0.3 Pn, where Pn is the Natural loading of the cable.

47.2.10. HVDC System Interconnection

By HVDC link, it is possible to interconnect two individually controlled AC systems which operate at different prevailing frequencies. Even AC systems having different rated frequencies can be interconnected by an HVDC interconnection. HVDC interconnection is an asynchronous tie. The exchange of power can be controlled precisely and rapidly.

The AC systems interconnected by HVDC asynchronous tie remain individually controlled despite their interconnection with each other. Each can thus be operated independently from their individual load control centre using their own control principle.

The HVDC interconnecting line may have any length from zero (back-to-back) to several hundred to a few thousand km.

Back-to-back HVDC conversion sub-station (HVDC coupling system) interconnect two AC systems meeting in a common geographical area. Such sub-stations do not have a transmission line. The convertors are connected back-to-back in a common coupling sub-station connecting two AC systems.

Merits of HVDC Systems Interconnection

1. **Stable weak tie between large AC systems.** The linking of large AC systems by means of low-rated AC ties can pose difficulty in controlling the power flow. Even minor events causing a slight change in frequency on one of the AC systems may cause the link to carry power which may easily exceed the permitted limit. As a result, the link gets tripped by tie overload protection of transmission line.

The HVDC link on the other hand, acts as a buffer between the AC systems. It, therefore, prevents fluctuations in one AC system from affecting the other AC system and the transfer of power remains steady at the presecribed set level.

2. **Improved Stability.** The amount of power transferred by an HVDC link, and its direction, can be controlled reliability and rapidly. By introducing control parameters from the AC network (*e.g.* frequency deviations or phase angle of a parallel system etc.) it is possible to improve the stability of the network as a whole, or of adjacent transmission lines. Disturbance in one AC Network is quickly damped by modulating the power flow through the HVDC interconnection.

3. **Limiting the Short-Circuit levels.** The increased generating capacity results in higher short-circuit levels in various sub-station buses and each sub-station equipment should be made suitable for the required fault level. The fault levels in large AC networks having AC interconnection tend to become extremely high resulting in uneconomical equipment design. With HVDC interconnection, the fault levels of each AC Network remain unchanged.

Table 47.6 compares the HVDC and EHV-AC for system interconnection purpuse.

4. Control of direction and magnitude of power flow. HVDC interconnection can given fast, accurate control of power flow magnitude and direction.

Table 47.6. Comparison of Characteristics for Systems Interconnections

	Characteristic	*HVDC Link*	*EHV-AC Link*	*Criterion for Preference*
1.	Power transferability	High practical limit	Lower, limited by power angle and *X*.	HVDC link for higher power
2.	Control of power flow	Fast, accurate, by directional.	Slow, difficult, Direction dependent on frequency	HVDC preferred
3.	Frequency disturbance	Reduced due to asynchronous tie	Transferred from one AC system to other	HVDC preferred
4.	System support	Excellent, power flow through line quickly modulated for damping oscillation	Poor oscillations continue for long duration	HVDC preferred
5.	Transient performance	Excellent	Poor	HVDC preferred
6.	Fault levels	Remain unchanged after interconnection	Get added after interconnetion	HVDC preferred
7.	Power swings	Damped quickly	Continue for long time	HVDC preferred
8.	Submarine cable	No charging currents, high ratings possible	Charging current set a limit on length and power	HVDC preferred
9.	Interconnection	Asynchronous	Synchronous	HVDC preferred
10.	Cascade Tripping of AC systems	Avoided	Likely	HVDC preferred
11.	Frequency conversion (50 to 60 Hz)	Possible	Not possible	HVDC preferred
12.	Back-to-back conversion stations	Possible	Not possible	HVDC preferred
13.	Spinning Reserves of AC Network	Reduced	Not much reduced	HVDC preferred
14.	Transient stability limit	Very high upto thermal limit of equipment	Less than half of thermal limit of line conductors	HVDC preferred

HVDC links technically superior to AC links and are preferred for interconnection between two individually controlled AC systems. HVDC System Control can be modified for (1) Damping of Power Swings (2) Frequency Control of Small Network by larger network.

47.2.11. HVDC Coupling System (Fig. 47.4)

(Back-to-back HVDC Convertor Station)

HVDC coupling system is used for interconnection between two geographically adjacent AC networks for the purpose of frequency conversion or for an asynchronous interconnection. The direction of power flow and amount of flow through the coupling system can be controlled in magnitude and direction irrespective of the conditions in the connected AC networks. A strong AC network can be interconnected to a weak network by back-to-back interconnection.

The back-to-back HVDC schemes are rated about 500 MW. The DC voltage and DC current of thyristors can be suitably selected for economical valve design *e.g.* a 400 MW back-to-back station can have DC voltage 400 kV and current 1000 A.

The configuration of a back-to-back HVDC coupling system is illustrated in Fig. 47.4. The two AC networks are coupled by a back-to-back convertor. The rectifier and inverter are connected to form a DC loop. There is no DC transmission line. A DC smoothing reactor is connected in the DC loop.

Back-to-back coupling stations are generally designed for Bipolar operation only and the return earth is, therefore, not provided. In such cases, the main DC loop is earthed at a single point between the rectifier and the inverter to provide a reference earth on DC side.

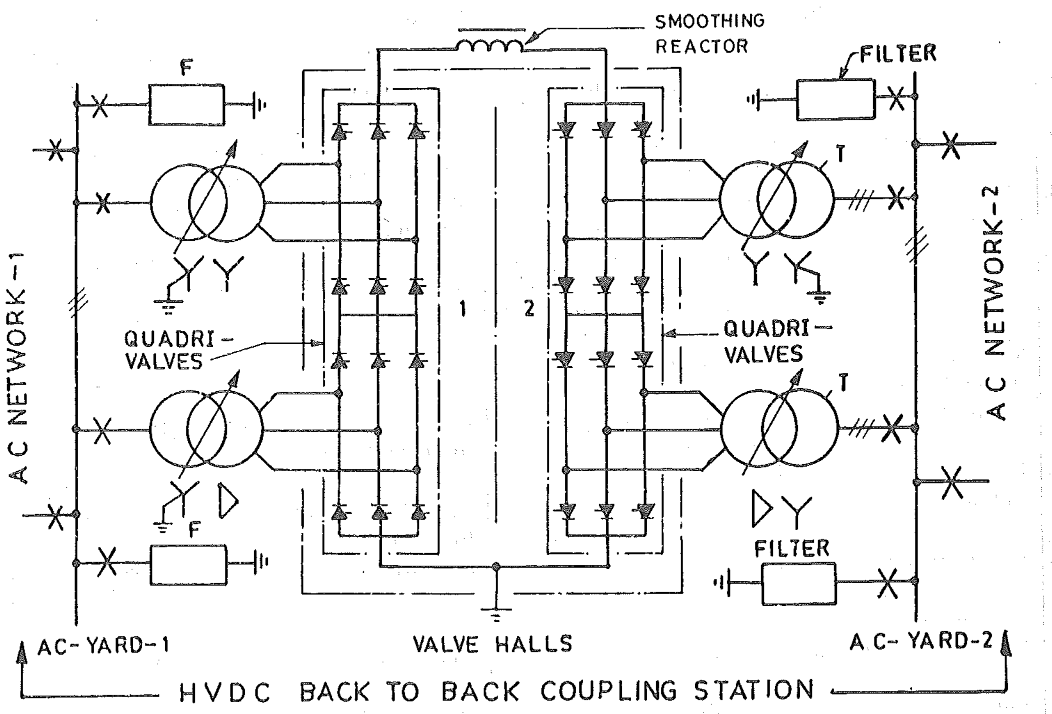


Fig. 47.4. HVDC Back-to-back coupling station.

As the earthing is only for reference, it does carry any direct current and there are no problems of galvanic corrosion of sub-station earth and underground pipes, structures etc.

47.2.12. EHV-AC Versus HVDC Transmission

The various aspects are summarised here.

1. **For Backbone Network.** EHV-AC is superior for forming the mesh. Voltage can be easily stepped up, stepped down. The network has natural tendency to maintain synchronism. Load-frequency control is easy and simple. Network can be tapped at intermediate points to feed underlying submission network.

2. **Bulk power load distance transmission lines.** HVDC proves economical above breakeven distance. Number of lines are less for HVDC. No need of intermediate sub-stations for compensation.

3. **Stability of Transmission System.** HVDC gives asynchronous tie and transient stability does not pose any limit. Line can be loaded upto thermal limit of the line or valves (whichever in lower).

4. **Line Loading.** The permissible loading of an EHV-AC line is limited by transient stability limit and line reactance to almost one-third of thermal rating of conductors. No such limit exists in case of HVDC lines.

5. **Surge Impedance Loading.** Long EHV-AC lines are loaded to less than 0.8 Pn. No such condition is imposed on HVDC line.

6. **Voltage along the line.** Long EHV lines have varying voltage along the line due to absorption of reactive power. This voltage fluctuates with load. Such a problem does not arise in HVDC line. EHV-AC line remains loaded below its thermal limit due to the transient stability limit. Conductors are not utilized fully.

7. **Number of lines.** EHV-AC needs at least two three-phase lines and generally more for higher power. HVDC needs only one bipole line for majority of applications.

8. **Intermediate Sub-stations.** EHV-AC transmission needs intermediate sub-station at an interval of 300 km for compensation. HVDC line does not need intermediate compensating sub-station.

9. **Asynchronous Tie.** System having different prevailing frequencies or different rated frequencies can be interconnected. HVDC link provides asychronous tie. Frequency disturbance does not get transferred, large black-outs are avoided.

10. **Better Control.** Power flow through HVDC tie line can be controlled more rapidly and accurately than that of EHV-AC interconnector.

11. **Corona Loss and Radio Interference.** For the same power transfer and same distance, the corona losses and radio interference of DC system is less than that of AC systems, as the required DC insulation level is lower than corresponding AC insulation.

12. **Skin Effect.** This is absent in d.c. current. Hence current density is uniformly distributed in the cross-section of the conductor.

13. **Charging Current.** Continuous line charging currents are absent in HVDC lines.

14. **Tower Size.** The phase-to-phase clearances, phase to ground clearances and tower size is smaller for DC transmission as compared to equivalent AC transmission for same power and distance. Tower is simpler, easy to installed and cheaper due to absence of central window.

15. **Number of Conductors.** Bipolar HVDC transmission lines require two-pole conductors (instead of several three-phase conductors as in case of AC) to carry DC power. Hence HVDC transmission becomes economical over AC transmission at long distance when the saving in overall conductors cost, losses, towers etc. compensates the additional cost of the terminal apparatus such as rectifiers and convertors.

16. **Earth Return.** HVDC transmission can utilize earth return and, therefore, does not need a double circuit. EHV-AC always needs a double circuit.

17. **Reactive Power Compensation.** HVDC line does not need intermediate reactive power compensation like EHV-AC line.

18. **Flexibility of Operation.** Line may be operated in a monopolar mode by earth as a return path when the other pole develops a permanent fault.

19. **Superior Control.** HVDC system control can be modified for (1) frequency control of AC networks (2) Damping control for improved stability of AC networks.

20. **Short-Circuit Level.** In AC transmission, additional parallel line result in higher fault level at receiving end due to reduced equivalent reactance. When an existing AC system is interconnected with another AC system by AC transmission line, the fault level of both the system increases.

However, when both are interconnected by a D.C. transmission, the fault level of each system remains unchanged.

21. **Rapid Power Transfer.** The control of converter valves permit rapid changes in magnitude and direction of power flow. This increases the limits of transient stability.

22. **Cables.** DC transmission can be through underground or marine cables since charging currents are taken only while energizing the d.c. link and are not effective later. In a.c. systems there is limit on length of cable depending upon rated voltage.

This limit is about 60 km for 145 kV, 40 km for 245 kV and 25 km for 400 kV AC cables.

23. **Voltage Regulation.** In HVDC systems, the line can be operated with constant current regulation or constant voltage regulation by suitable adaptation of phase control of rectifiers and inverters.

24. **Lower Transmission Losses.** Line losses are lesser than equivalent AC transmission losses as the reactive power does not flow through D.C. line.

47.2.13. Limitations of HVDC Transmission

— High cost of terminal apparatus such as a.c. to d.c. rectifiers and d.c. to a.c. inverters, AC and DC filters, controls etc.

— Lack of HVDC circuit-breakers (at present). This limitation has been recently overcome by development of HVDC circuit-breaker system. However HVDC circuit-breaker system comprises several components including the main circuit-breaker, capacitors, reactors etc. and the total cost is likely to be several time that of an a.c. circuit-breaker of equivalent voltage class.

— D.C. voltage cannot be transformed easily. Here it is not used for distribution, sub-transmission, backbone transmission, mesh.

— Complexity and dependance of high technology.

— Several abnormal operating conditions and consequent failures.

The operation of inverter (d.c. to a.c.) requires reactive power at leading power factor. The reactive power can be as high as 50% of real power, *i.e.*, $\frac{\text{kVAR}}{\text{kW}} = 0.5$.

— Thyristor valves are complex and the controls are extremely complex. EHV-AC line has only simple protective systems. EHV-AC lines are, therefore, easy to execute and operate.

— HVDC sub-station has several additional equipment like converter transformers, valves, electrical and mechanical auxiliaries, valve control, pole control etc. Most of these equipment are of specialised high technology class and are imported at high cost.

— HVDC convertor require complex cooling systems.

— HVDC convertor stations require larger number of harmonic filters.

— HVDC is not very suitable for multipoint, multi-terminal networks.

— Losses of valves and convertor transformers are extra in case of HVDC substation. These are continuous and, therefore, nullify lesser line losses of HVDC line.

47.2.14. Terms and Definitions regarding HVDC

1. **HVDC.** High voltage direct current (system) HVDC sub-station and HVDC systems.

2. **HVDC System.** An electrical power system which transfers energy in the form of high-voltage direct current between two or more alternating current buses.

3. **HVDC Transmission system.** An HVDC system which transfers energy in the form of high voltage direct current from one geographical location to the other.

4. **Two terminal HVDC system.** An HVDC transmission system consisting of two transmission sub-stations and connecting transmission line.

5. **Multiterminal HVDC System.** An HVDC transmission system consisting of more than two transmission sub-stations and interconnecting DC transmission lines.

6. **HVDC Coupling system.** An HVDC system which transfers energy between AC buses at the same location. Such a system is generally called as back-to-back HVDC sub-station.

7. **HVDC transmission line.** A part of HVDC transmission system consisting of overhead lines and or underground cables connected to HVDC transmission sub-stations at terminals.

8. **HVDC sub-stations.** A part of an HVDC system which consists of one or more convertor units installed in a single location together with building reactors, filters, reactive power supply control, monitoring, protective measuring and auxiliary equipment.

9. **HVDC system Pole** (abbreviated to 'pole'). A part of an HVDC system consisting of all the equipment in the HVDC sub-station and interconnecting transmission lines (if any) which, during normal operating condition exhibit a common direct polarity with respect to earth.

10. **Sub-station pole.** The part of an HVDC system pole which is connected within a sub-station.

11. **HVDC transmission pole.** A part of an HVDC transmission link which belongs to the same HVDC system pole.

12. **Monopolar HVDC system (Unipolar).** An HVDC system having only one pole and earth return.

13. **Bipolar HVDC system.** An HVDC system with two poles of opposite polarity.

14. **Conversion (in HVDC system).** Transfer of electrical energy from AC to DC or/and *vice versa.*

15. **Converter Unit.** An operative unit comprising one or more converter bridges together with one or more convertor transformers, convertor unit control equipment, essential protective and switching devices and auxiliaries if any for conversion of energy from AC form to DC form or/and *vice versa.*

Note. If a convertor unit comprises two converter bridges with a phase displacement of 30°, then the convertor unit is called a 12 pulse unit.

16. **Valve.** A complete operative controllable array (which has a combination of thyristors and other associated devices) normally conducting only in one direction which may function as a convertor arm or a part thereof in a converter connection.

17. **Rectifier operation** (Rectification). The mode of operation of a converter or a convertor sub-station when the energy is transferred from AC side to DC side.

18. **Inverter operation.** The mode of operation of a converter or a converter sub-station when energy is transferred from DC side to AC side.

19. **Delay Angle** α. The time expressed in electrical degrees from the starting instant of forward current conduction to the zero crossing of communicating voltage.

20. **Extinction Angle** β. The time expressed in electrical degrees from the end of current conduction to the zero crossing of commutating voltage.

CONTROL OF HVDC SYSTEM

47.3. CONTROL OF HVDC LINK

47.3.1. Steady-state Ud/Id characteristic of converters.

The steady state characteristic of a converter for HVDC system is plotted on rectangular coordinates with direct current *Id* on *X*-axis and direct voltage *Ud* on *Y*-axis. The *Ud/Id* characteristic of rectifier and inverter are similar but not identical.

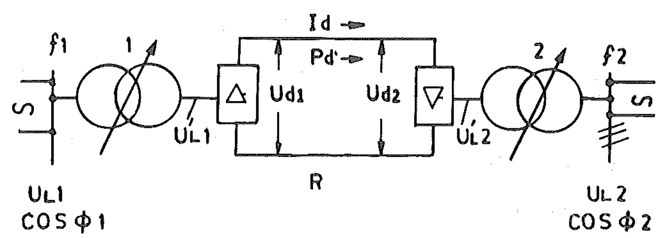
They are similar because it should be possible to interchange the operation of rectifier to inverter and *vice-versa* for achieving reversal power.

They should have difference in voltage level and current level because they should *intersect at a point* (say A) for giving a stable point of operation with definite value of direct current *Id* common to rectifier and inverter (forming a series circuit on DC side). The stable point *A* should lie on the *Ud/Id* characteristics of the rectifier as well as that of the inverter.

Fig. 47.5 illustrates a typical steady-state *Ud/Id* characteristic of a converter (either inverter or rectifier) for an HVDC link. The dark lines give idealized characteristic having two segments.

Let *Ud* = DC Voltage
Id = Direct Current
Ud = AC Voltage
Pd = Direct Power
R = Line Resistance

Subscript 1 for rectifier, 2 for inverter.



1. Horizontal segment *RS* representing constant value of *Ud* as obtained by natural characteristic of a converter.

2. Vertical segment ST representing a constant value of current Id as obtained by constant current controller fitted to the converter control system.

Operating point (say A) should lie on the vertical segment ST so that same current Id flows through rectifier and the inverter.

Actual characteristics has a certain slope and is shown by the dashed segments in Fig. 47.5.

Control functions are so arranged as to shift horizontal segments RS for voltage change and shift the vertical segment ST for current change.

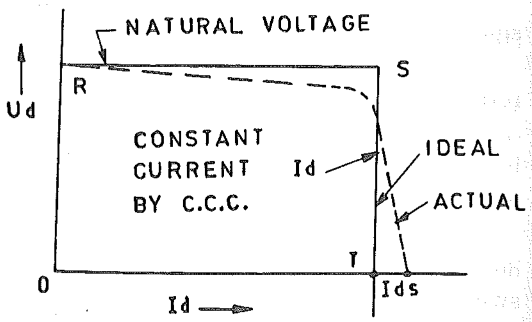


Fig. 47.6. Ud/Id steady state characteristic of a converter

If inverter voltage is changed, the rectifier voltage should also be appropriately changed to satisfy the equation.

$$Ud_1 = Ud_2 + Id \cdot R$$

For shifting the horizontal segment RS upwards or downwards, following means are available :

— Tap changer on line side of converter transfer. By changing the tap position, the turns ratio is changed. Thereby valve side voltage is changed, thereby DC voltage is changed (slow change).

— Change of delay angle α of the convertor (Rapid change).

For shifting the vertical segment ST the setting of constant current controller fitted with the control system of the converter is changed. However since the operating point A is on constant current segment, the direct current will be adjusted to a new valve A with at constant current control of point A. Fig. 47.6.

47.3.2. Intersecting Characteristics of Rectifier and Inverter under Normal operating mode

For stable operation, the operating point should lie on the Ud/Id characteristic of rectifier and inverter simultaneously. To check this, the characteristic are drawn on a common diagram at a point of the HVDC line.

Fig. 47.6 illustrates idealized steady state characteristic of rectifier (1) and inverter (2) drawn on a common diagram, assuming higher DC voltage on rectifier end than that at the inverter end. *This diagram is applicable for the normal operating mode of the HVDC link.*

R_1, S_1, T_1 represents rectifier characteristic (1); R_2, S_2, T_2 , represents the inverter characteristic (2) as seen from rectifier end, *i.e.*, the voltage drop of line is taken into account such that

$$Ud_1 = Ud_2 + Id \cdot R.$$

The constant current segment of inverter characteristic S_2. T_2 has current margin ΔI with respect to constant current segment of rectifier characteristic S_1, T_1.

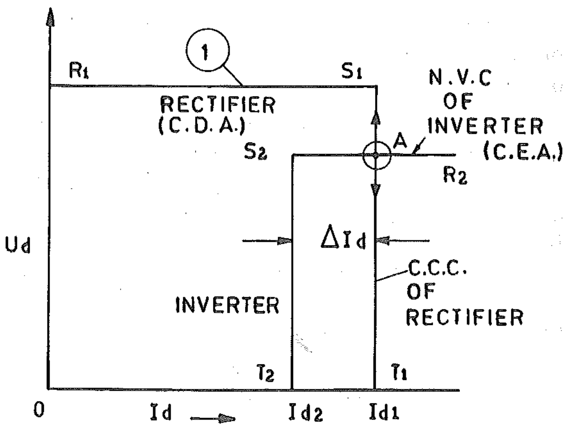


Fig. 47.7. Intersecting characteristics of rectifier (1) and Inverter (2) under normal mode.

The operating point A is obtained where characteristic (1) intersects the characteristic (2).

Point A lies on the constant current segment of characteristic (1) of rectifier and natural voltage characteristic (2) of the inverter.

For this operating point, the current (Id) is determined by the constant current setting of the rectifier (Id_1), *i.e.*. S_1, T_1.

The voltage Ud is determined by the natural voltage characteristic of the inverter, (Ud_2), *i.e.*., (R_2, T_2).

Hence for stable operation with normal steady state operation mode the following conditions apply :

— the direct current is controlled by the rectifier current control set on constant current mode.

— the direct voltage is adjusted at the inverter such that the operating point is on the inverter natural voltage characteristic of the inverter determined by the tap changer and phase angle control of inverter.

Hence under normal operating mode, the rectifier sets the current and the inverter controls DC voltage.

Hence the rectifier is provided with constant current control (with a provision of adjusting current setting) and the inverter has a provision of variation in voltage. The inverter end DC voltage gets adjusted automatically to the value of natural voltage characteristic of inverter corresponding to point A. The rectifier end has higher voltage as given by the $Ud_1 = Ud_2 + Id \cdot R$.

47.3.3. Intersecting Characteristic under steady condition with Current Margin control

Fig. 47.8 shows the characteristic in which the natural voltage segment of inverter ($R_2 S_2$) is above the natural voltage segment of rectifier (R_1, S_1.)

This is not for a normal situation but for contingency arising in the event of fall of rectifier DC voltage due to say a fall in AC side voltage at rectifier-end. Under such eventuality, the operating point A should remain on constant current segment and should be on point of intersection.

To fulfil these conditions, the inverter is also provided with constant current control (segment $S_2 T_2$) with a current margin (ΔId) with respect to current setting of rectifier ($S_1 T_1$).

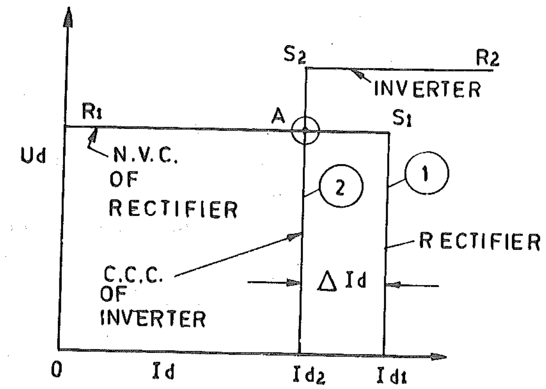


Fig. 47.8. Intersection of characteristics under current margin control.

This control mode is called *current margin control*. In this mode of control, the rectifier-end has a lower DC voltage than the inverter-end. The direct current Id in the link is determined by inverter constant current controller setting (Id_2). The voltage of the inverter is adjusted along the natural voltage characteristic passing through point A.

47.3.4. Power Transmission Characteristic with constant current regulation of Rectifier and constant extinction angle regulation of Inverter.

Figs. 47.6. and 47.7 show the working characteristic of HVDC system having following features :

— Constant current control at rectifier as shown segment $S_1 T_1$ re-presenting Id_1 corresponding to setting of rectifier constant current controller.

— Constant extinction angle (Δ) on inverter with corresponding natural voltage characteristic $R_2 S_2$ representing receiving voltage Ud_2 as seen from say sending end.

This practical working characteristic is generally used for present HVDC schemes.

Rectifier Characteristic. Suppose the constant current controller of rectifier is set at Id_1. The rectifier, line and inverter have to carry the same current Id. The voltage drop in line is $I_d \cdot R$ the Ud_1 should be equal to $Ud_2 + Id_1 \cdot R$. In the rectifier characteristic, account is to be taken to adjust delay angle α such that the natural voltage characteristic represented by segment $R_1 S_1$ is shifted to Ud_1 value corresponding to $Ud_2 + Id_1 \cdot R$.

When inverter AC voltage Ud_2 reduces (say due to fall of AC system voltage Ud_2), the rectifier DC voltage Ud_1 also reduces. Corresponding drop in rectifier voltage is brought about by the control system to maintain Ud_2 constant.

Rectifier voltage reduction is achieved by reducing delay angle α upto minimum limit say 60 below this, further reduction in Ud_1 is achieved by tap changing.

Fast acting tap changer are provided for quick control.

Invertor characteristic. Invertor is operated with α greater than 90°. It is provided with limit of constant minimum extinction angle γ. The line voltage is determined by the inverter voltage control. The inverter side DC voltage is held under control near rated value by appropriate actions on AC side voltage control (shunt compensation, tap changing) and controlling the extinction angle. Fall in AC voltage is corrected by increased shunt compensation of AC bus and appropriate actions at AC networks for voltage control. However the tap-chargers of converter transformers are set such that desired value of Ud_2 is obtained quickly. The current Id is decided by setting Id_1 of rectifier.

47.3.5. Reversal of Power Through an HVDC link : Necessity of Reversal of Power.

Power reversal becomes necessary in following cases :

1. Normal operation of an interconnecting HVDC line in which power flow is scheduled in either forward or reverse direction.
2. Sudden need of power for AC system at sending end due to deficit power generation and drop in frequency.
3. Fault on HVDC line pole during which the line is temporarily de-energized by changing over the rectifier to inverter. After a certain lapse of time attempts are made of re-energize the line by changing the same to rectifier. These operations require ability of each converter to operate as a rectifier or an inverter.
4. During frequency oscillations in AC system, the power flow through DC line is modulated to dampen the oscillations.

Method of Reversal of Power. The converter at each terminal is provided with controls such that their delay angles α can be adjusted at desired value. When delay angle is less than 90° the converter acts as a rectifier.

When α is between 90° and 180°, the converter acts as an inverter. The convertor can be operated as a rectifier or an inverter by setting of its α controller.

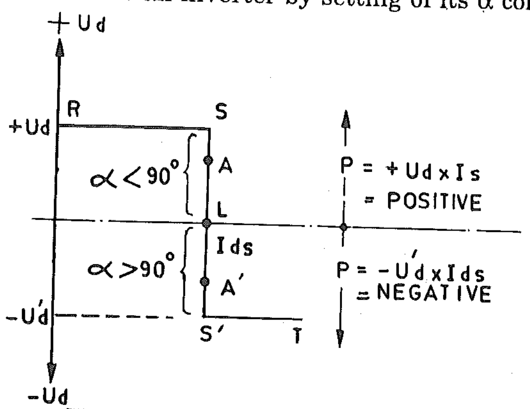


Fig. 47.8. For forward power, α of rectifier is less than 90°.

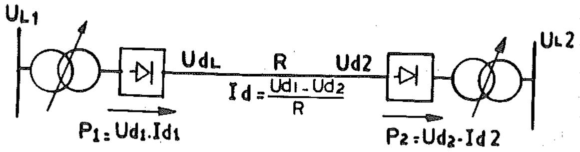


Fig. 47.9. Current Id changed by changing difference ($Ud_1 - Ud_2$).

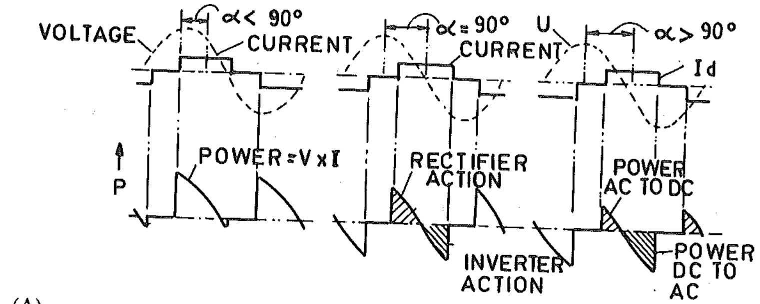
For *forward power flow,* the convertor at Terminal 1 is operated as rectifier by setting angle $\alpha < 90°$ and convertor at Terminal 2 is operated as an invertor by setting angle α between 90° and 180°.

The effect of change in delay angle α on the average DC power is illustrated in Fig. 47.9.

The direction of power ($P = Ud \cdot Id$) depends on polarity of Ud and direction of Id. Direction of current I_{dc} and instantaneous i in thyristor valves remains unchanged. But polarity of communicating voltage with respect to Id changes with angle.

In Fig. 47.10 (*A*), α is less than 90° and average power during a cycle is positive indicating rectifier operation, *i.e.*. power is transferred from AC system with DC line.

In Fig. 47.10 (*B*), α is equal to 90° and average power per cycle is zero as for one cycle the positive area is equal to negative area of P.



(A) (B) (C)

Fig. 47.10. Effect of delay angle α on the direction of power flow through DC link. $\alpha < 90°$ — Rectifier action. $\alpha > 90°$— Inverter action.

In Fig. 47.10 (*C*), α is more than 90° and less than 180°. Average power P during a cycle is negative indicating a reverse power flow (inversion). The power flows from DC line into AC system. Power flow through the HVDC link can be reversed by simultaneous action of reversal at the two terminal stations. The direction of direct current Id through the valves and DC line remains unchanged. The polarity of voltage of the HVDC pole is reversed as shown in Fig. 47.11 (*A*), (*B*), (*C*).

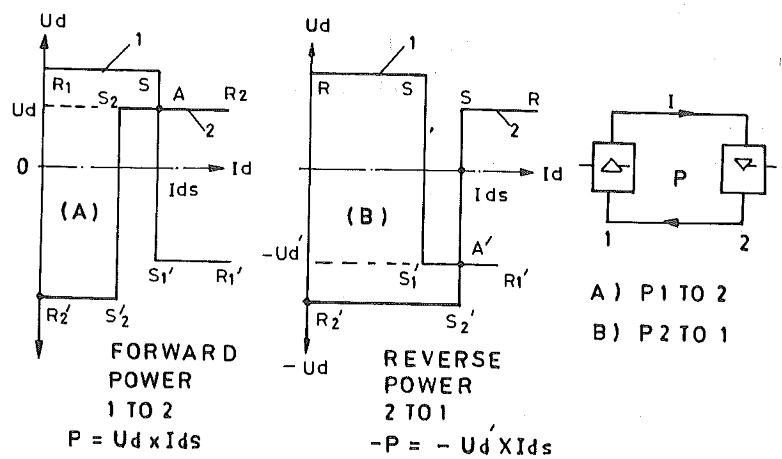
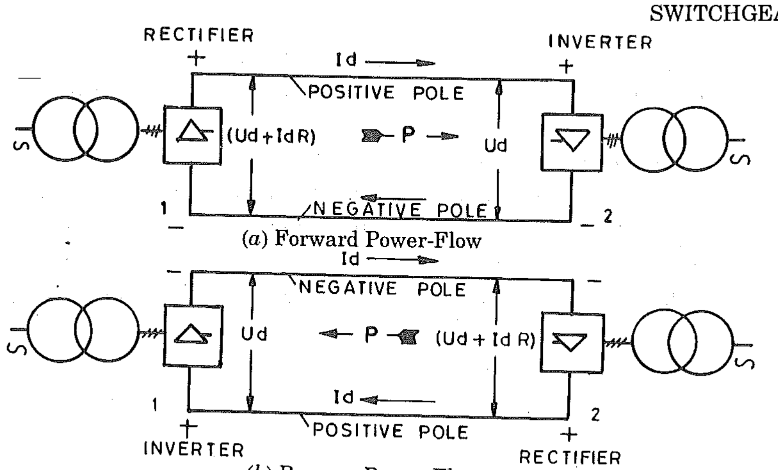


Fig. 47.11 (A). Reversal of power in HVDC link.

Combination Rectifier/Inverter Characteristic. The combined *Ud/Id characteristic* of a convertor indicating rectifier and inverter range is illustrated in Fig. 47.8. The current Id remains in the same direction as indicated by Ids. The direct voltage Ud reverse in polarity as delay angle is changed from $\alpha < 90°$ (Rectifier) to $\alpha > 90°$ (Inverter) as indicated by segments RS (+ Ud) and



(a) Forward Power-Flow

(b) Reverse Power-Flow

Fig. 47.11 (B)

ST (– Ud). For point A on segment S′L, P is positive and for point A′ on segment S′L, P is negative (Reverse).

Power Reversal Operating point on Ud/Id characteristic. Fig. 47.11(A) illustrates the point of intersection A between characteristics of convertor 1 and convertor 2 for forward power flow. Point A has + Ud and + Ids giving + P. Power flows from AC system to DC line. This is forward power as seen from terminal 1.

Fig. 47.11 (b) illustrates reversal of power. The point of intersection A′ has co-ordinates – Ud and + Ids giving power as (– Ud × Ids) = – P. During reverse power flow, the convertor of terminal 1 operates as an invertor (α > 90°) and convertor of terminal 2 operates as a rectifier (α < 90°).

47.3.6. Alternatives of HVDC Control

$$P_d = U_d \times I_d \quad \text{...(47.1)}$$

Power control is achieved by one of the following three alternatives :

1. **Constant U_{dc} and variable I_{dc}.** This method has a disadvantage that during short-circuit on DC lines, short circuit currents reach a very high values. However advantage are low currents for low power and low I^2R losses.

2. **Constant I_{dc} and variable U_{dc}.** This method has disadvantage that I_{dc} is constant irrespective of load. The I^2R losses are also constant and correspond to full load value.

As U_{dc} is variable, U_{dc} has to have a very wide range which is beyond permissible limits of AC system voltage. This method is not used.

3. **Hybrid Method of Controlling Ud and Id appropriately.** This method combines advantages of (1) and (2) above. The method comprises control of Ud_1 and Ud_2 simultaneously so as to control I_d given by the equation.

$$I_d = \frac{Ud_1 - Ud_2}{R} \quad \text{...(47.2)}$$

where I_d = Direct current, Amp

U_{d_1} = Sending end direct voltage, Volts

Ud_2 = Receiving end direct voltage, Volts.

$$P_{dc} = U_{dc} \cdot I_{dc} \quad \text{...(47.3)}$$

where $U_{dc} = \frac{Ud_1 + Ud_2}{2}$ ...(47.4)

Id **is generally controlled by rectifier constant current controller setting.**

Ud_2 is generally controlled by inverter natural voltage characteristic corresponding to Ud/Id characteristic of inverter with minimum extinction angle limit setting.

Ud_1 is held at

$$Ud_1 = Ud_2 + Id\,R \quad \text{...(47.5)}$$

The current in the link would be

$$Id = \frac{Ud_1 - Ud_2}{R} \quad \text{...(47.6)}$$

Current in rectifier and current in inverter is same (Id).

Voltage at rectifier end Ud_1

Voltage at inverter end Ud_2

Power flow $Pd_1 = Ud_1\,Id$ at (1) ...(47.7)

$P_{dc} = Ud_2\,Id$ at (2) ...(47.8)

Difference P_{dc} (1) – P_{dc} (2) = Line loss = I_d^2R

The control characteristic of rectifier and inverter should intersect as described earlier.

From Eq. (47.5) it is observed that, due to small value of DC line resistance R and absence of reactance X_L *a small change between* Ud_1 *and* Ud_2 *can bring about a large change in* Id_{dc} *and therefore in* P_{dc}. This aspect is used for quick and accurate control of power flow through an HVDC link. Power flow is controlled by changing the difference between sending-end voltage and receiving voltage so as to change value of direct current.

Two means are available for achieving this difference ($Ud_1 - Ud_2$) and thereby changing Pd_1.

— Tap change control — Control of delay angle α.

47.3.6. (a) Tap-changer control : change in tap position of convertor-transformer tap changer

Multi point fast tap-changers are provided at each and for each convertor transformer for controlling DC voltage under steady state.

Assuming constant AC line side voltage U_{L1}, the valve side voltage U_L depends upon the turns ratio (K).

$$K = U_L / U'_L$$

AC bus voltage U_L is held constant by voltage control of AC system. K is changed by means of tap-changer. Tap-changer method is slower and takes 8 to 10 seconds to change one tap. This method is used for slow, steady state variation of DC power.

Tap-changers used for HVDC converter transformers have a very wide range of tappings.

Refer Fig. 47.6 explaining characteristic with changing of Ud. Refer Fig. 47.6 illustrating normal operation of the HVDC link in which operating point A is on natural voltage characteristic of inverter.

The inverter tap-changer is controlled so that the direct voltage Ud_2 at some receiving end is close to desired value obtained by ($Ud_2 = Ud_1 - IdR$), Ud_1 being nearly rated DC voltage tap-changer of inverter raises for lowers Ud_2 raising or lowering turns ratio $k = U_{l2}/U'_{L2}$

Likewise the voltage Ud_1 at rectifier end is held at value.

$$U_{d1} = Ud_2 + Id \cdot R$$

Required Ud_1 is computed and fed as input to tap changer controller of rectifier. The tap position is raised/lowered to obtain desired voltage on valve side of convertor and thereby required Ud_1.

The rectifier tap-changer is controlled so that if α becomes less than 10°, it raises the direct voltage by raising the transformer ratio k. If α becomes more than 20°, the voltage is lowered by reducing transformer ratio k.

The delay angle α of rectifier is held between 10° and 18° under steady state by tap-changer control.

The on-load tap-changer is fitted on AC side of convertor transformer.

For star connection transformer with solidly grounded neutral, the taps and the tap-changer are generally placed on the grounded neutral end of the winding. Though the winding may be of very high voltage at line end (400 kV for example) the maximum voltage to which the tap-changer at neutral end is subjected is equal to voltage between highest tap position and neutral. By placing the taps nearer the neutral end, the voltage rating of the tap-changer can be minimised.

For example for convertor transformers rated 400 kV on AC side on-load tap changers are connected on 400 kV AC side winding located at the neutral end of windings. The neutral is earthed. Number of steps large (say 16) step voltage is 1.25 to 2.0%. A typical tap-changer has a range of $+ 10 \times 1.3\%$ to $- 14 \times 1.3\%$.

The dead band between tap-changing is more than tap step voltage, *i.e.* between ± 1.3 to 2%.

The tap-changing operation is initiated by pressing the push button on the motor drive housing of the tap-changer or by a contactor operated by automatic voltage regulator, in the tap-changer control system. The voltage control relay operates when the line voltage increases or decreases by set amount. When the voltage control relay operates, the motor gear unit of on-load tap-changer gets a command for raise or lower. Depending upon signal, the motor rotates to complete one tap-changing operation to 'Raise' or 'Lower' the tap. To prevent tap-changing operation during transient fluctuations, a time delay relay is provided in a control circuit. The time delay relay can be adjusted upto 60 seconds.

In order to avoid hunting (alternate raise/lower) dead band between taps should be more than tap step and time delay should be provided between two consecutive tap changers.

Tap changers on inverter side convertor transformers should be identical to those on rectifier side.

47.3.6. (*b*) Control of phase angle of thyristor firing (Control of α and γ)

Rapid control of DC voltage is achieved by control of phase angle of firing the thyristor, *i.e.* the delay angle α of rectifiers. This change can be very rapid and accurate (10 to 20 milliseconds) and is used for rapid variation of power flow by changing $(Ud_1 - Ud_2)$.

The tap-changer control is slow as the tap-changing takes about eight seconds per step. The thyristor control is rapid (a few milliseconds). Both the above methods are used at each terminal. The thyristor control is used initially for rapid variation of voltages. This is followed by tap-changer control.

Lower value of delay angle α (of rectifier) gives higher of DC voltage and lower kV Ar demand of AC Bus (Lower shunt capacitors). Hence α should be kept as low as possible at rectifier end. But if α is kept too low (near zero) no margin would be available for increasing the voltage by further reduction of α. Hence in practice angle α at rectifier end is kept between 72° elect, and 18° elect.

Limit of extinction angle γ for inverter. As the delay angle α for inverter is more than 90° elect, it is usually more convenient to define extinction angle γ for the inverter. The inverter requires certain minimum extinction angle γ for safe commutation. Higher γ is better for commutation but causes increase in kVAr demand of inverter.

Hence the inverter is operated with a setting for minimum extinction angle limit γ. In practice the extinction angle of inverter is held between 15° and 18° elect. Larger value gives lower risk of commutation failure and increased kVAr demand.

47.3.6. (*c*) Frequency control of AC Networks by means of HVDC Link

AC Networks connected at each terminal of an HVDC link operate at their respective prevailing frequencies. Each AC Network controls its own frequency by adjusting the total generation to match the total load. All the synchronous machines should run at synchronous speed corresponding to the prevailing frequency f, as given by the equation :

$$N_s = 120\, f/P$$

N_s = Synchronous speed, R.P.M.

f = Frequency, Hz, cycles/sec)

P = Number of poles.

The two AC Networks connected by only an HVDC link operate asynchronously, *i.e.* they are not in synchronism with each other and each operates at its own prevailing frequency. For keeping the frequency within targeted limits (49.5 -50.5 Hz).

The power flow from AC Network (*a*) to AC Network (*b*) through an HVDC link can be controlled quickly and precisely by phase control of rectifier and invertor such that frequency of AC Network (*b*) is controlled by AC Network (*a*).

47.3.6. (*d*) Damping Control of AC Networks by HVDC Link

AC Networks experience violent swings in load angle δ during faults, sudden tripping of generators or loads etc. If swing angle δ is not damped or controlled, the stability of both AC Networks is likely to be lost. By modifying HVDC system control, the swing curve is damped. Swing angle is not allowed to go beyond, permissible limit. The oscillations are damped quickly and systems are made stable. The HVDC power flow magnitude and direction is modulated to damp the oscillation in δ.

Summary of Power Control

Power control of HVDC link is achieved by means of

1. Tap-changer control at rectifier end and inverter end to control Ud_1 and Ud_2. The tap-changer is used for slow variation of Ud_1 and Ud_2 and thereby Pd.

2. By controlling phase angle α (called delay angle α).

Phase angle control is used for rapid variation of α or γ thereby Pd.

U_L on AC side is not varied and held within specified limits.

Power Reversal is achieved by changing of polarity of DC voltage, keeping the direction of current in valves and pole unchanged. For this the delay angle α of rectifier is extended beyond 90° and delay angle α of inverter is advanced to less than 90°.

Power can be quickly changed at a rate of about 30 MW/min.

Operating point A deciding Ud and Id should be on CCC characteristic of rectifier and NVC characteristic of inverter. Same Id flows through both. Id is decided by constant current controller setting of convertor Ud is decided by the natural voltage characteristic of inverter. Operating point is shifted by changing power command at invertor end. This changes Id and thereby Pd.

Frequency control of AC systems is normally achieved by matching generation with load. With HVDC interconnection the flow of power Pd is changed suitably so as to assist frequency control of connected AC systems. In some schemes the frequency control of a weak AC system is governed totally by the power flow through HVDC link.

47.4. CIRCUIT ARRANGEMENTS

Modern HVDC links have thyristorized convertors. A convertor *converts* a.c. into d.c. into a.c. An HVDC link comprises an a.c. sub-station and conversion sub-station at *each end* and a HVDC transmission line in between the two. In case of *back-to-back* HVDC line, there is only a conversion sub-station between two a.c. sub-stations ; there is no d.c. transmission line.

Bipolar Arrangement is used universally for bulk power overhead transmission lines and overhead lines for interconnection. Each pole has one or more 12-pulse convertors. Configuration of one 12-pulse convertor is shown in Fig. 47.12.

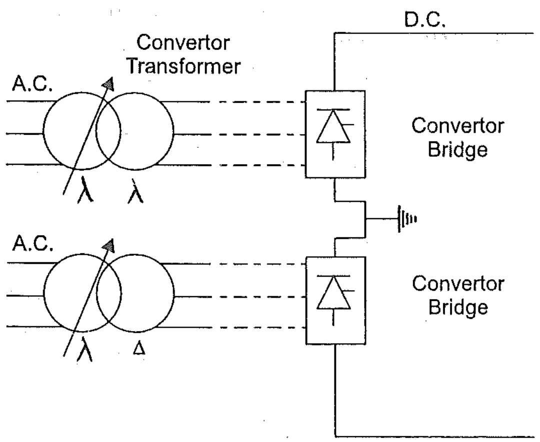


Fig. 47.12. Configuration of one 12-pulse convertor formed by two 6-pulse Convertor Bridges (Fig. 47.14).

47.5. THYRISTOR VALVES FOR HVDC CONVERTOR

The commercial success of HVDC lines is mainly due to successful development of high power, high voltage thyristor valves (1970's). These 'valves' are built-up from :

— Several thyristors connected in series with additional thyristor in parallel for each thyristor for redundancy and higher current rating.

— 'Snubber' (Voltage grading circuit) for equal distribution of voltage across thyristors. The Snubber is made up of following :

— Saturable reactors included in voltage grading circuit to control *du/dt* and *di/dt*.

— Surge arrestors connected across thyristors or across phases or both to protect insulation of valves.

— *RC* circuit across each thyristor for voltage grading. Additional *RC* circuit of low time constant across a group of thyristors to improve voltage distribution for fast transients.

— Controlled Avalanche Diodes (*CAD*) across each thyristors to limit peak value of voltage across thyristor.

Cooling System. The valves are cooled by air or SF_6 gas of oil or a combination. The cooling system and insulation are interdependent. The temperature of silicon wafer joint should be held below critical value (90°) to 125°C prevent change in characteristics and damage to thyristors.

A typical arrangement of voltage grading circuit for a thyristor string is shown in Fig. 47.13.

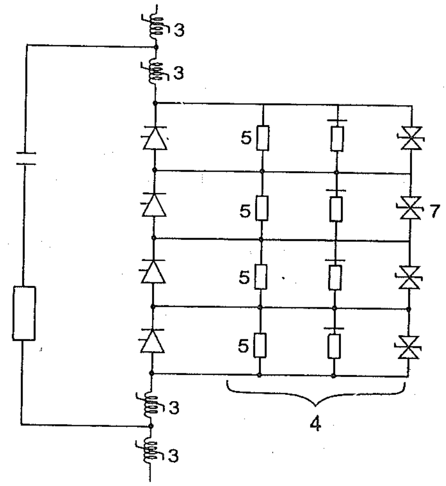
The *valve* comprises a set of thyristors along with associated voltage grading and other components.

A typical *Quadruple valve* comprises four valves placed vertically one above the other to form one limb of the convertor. These are placed in the convertor room.

A typical quadruple valve has 16 modules, each module comprising set of four to twelve thyristors and some reactors. There are totally 64 thyristors and 32 reactors in a quadruple valve.

A typical 12-pulse convertor has four valves connected in series, as shown in Fig. 47.15. *Two* twelve-pulse convertors are connected in series to get a high power convertor (Fig. 47.20).

Optical Control Signals. The thyristors should be triggered in desired sequence and at desired instants. Different kinds of triggering systems have been developed. Most modern method



1. Thyristors
2. *RC* circuit across branch
3. Saturable reactors
4. Voltage guarding and protective circuit : "Scrubber"
5. *RC* circuit
6. Surge arrester
7. Controlled Avalanche Diode

Fig. 47.13. Circuit of a thyristor string in HVDC valve.

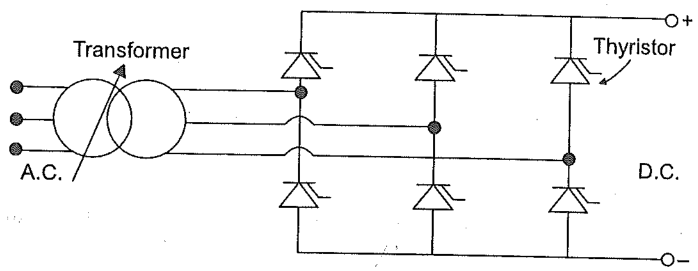


Fig. 47.14. A six pulse thyristor convertor bridge (Graetz bridge).

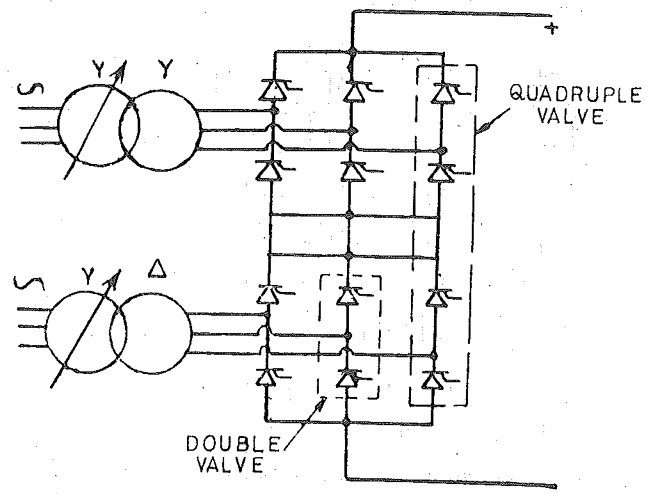


Fig. 47.15. A 12 pulse thyristor convertor formed by connecting two six pulse convertors in series.

is called "optronics" which uses light-guide system. In such a system the electrical pulses are converted into light signal pulses by fibre-optic techniques. The light pulses are transmitted through glass-fibre optical cables upto the individual thyristor. Each thyristor is provided with a small separate thyristor which is triggered by the light pulse. Thereby the main thyristor is triggered. Fibre-optic cables provide insulation as well.

Cooling and Insulation

Following alternatives are used :

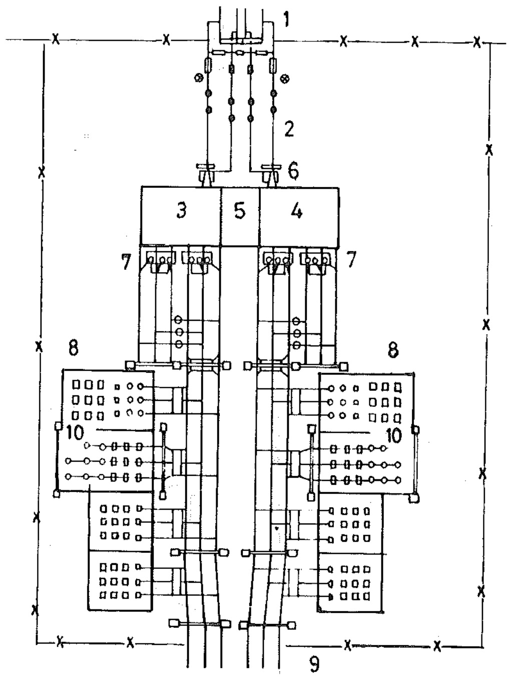
- — Air for cooling and insulation. (This alternative is used for indoor valves). Fine water cooling for thyristors.
- — Special deionised, deoxidised water having high dielectric strength is circulated through plastic pipes and heat sinks of thyristors. Fibre-optic cables are necessary for control of valves as they have insulating property.
- — Oil for insulation and cooling. (This alternative is used for outdoor valves).

The cooling system removes heat due to looses and maintains the temperature of junction within limits. Indoor valves are installed in air-cooled valve rooms.

47.6. REVERSAL OF POWER

Change in direction of power flow of HVDC transmission is usually performed by changing the polarity in the DC voltage.

Rectifier is changed to inverter by advancing angle 90° to beyond 90°. Inverter end is changed to rectifier mode by reducing α to less than 90°.



1. DC line.
2. DC yard.
3. 3, 4. Valve halls.
5. Control room.
6. Smoothing reactors
7. Convertor transformers
8. AC yard
9. AC Lines
10. AC Filter

Fig. 47.16. Layout of HVDC bipolar sub-station.

47.7. TYPICAL LAYOUT OF HVDC CONVERSION OF SUB-STATION

Typical conversion of sub-station comprises the following :

1. A.C. switch yard.
2. Valve hall.
3. Filter area, shunt capacitors.
4. Convertor transformers ; Smoothing reactors.
5. D.C. Switch yard.

A very large portion of area is covered by shunt capacitors and filters. The conversion sub-station layout depend upon the type valve and its design. A typical conversion sub-station has air insulated indoor quadruple valves. These quadruple valves are installed inside air-cooled valve-halls. The convertor transformers and smoothing reactors are installed out-door, very near to the

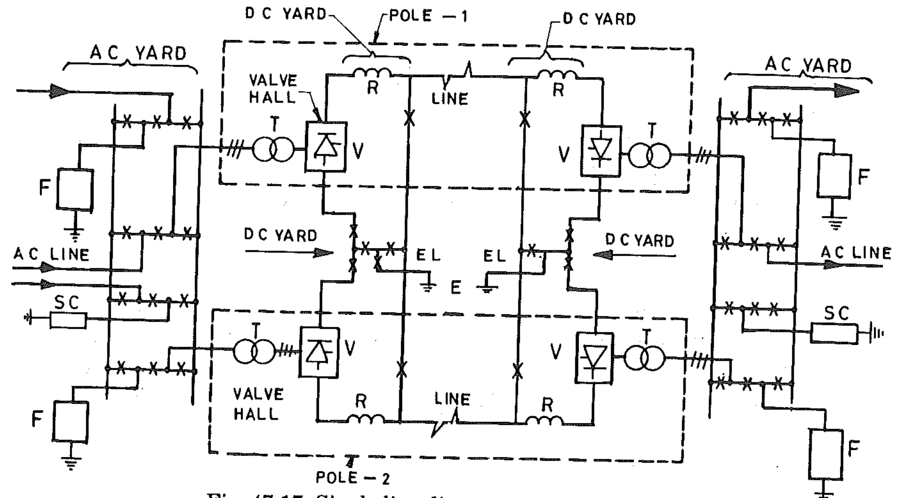


Fig. 47.17. Single line diagram of bipolar HVDC line.

F = Filters
SC = Shunt-capacitors
E = Earth electrode
EL = Electrode lines
V = Valves (12-pulse Bridge)
T = Convertor transformer
R = Smoothing reactor
M = Metallic Return Transfer Breaker

valve halls. The valve side bushing of convertor transformers are installed pointing into the valve side bushing of convertor air-cooling system are installed in the basement below the valve hall. The *valve hall* contains quadruple valves, bushings, reactors connected to the HVDC terminals, surge arrestors. The space for control and auxiliary equipment etc., is provided in the lower part of the building between the two valve halls. The A.C. switch-yard, filter capacitors and shunt capacitors are installed on one side of the valve hall. On the other side of the hall, smoothing reactors, line and neutral bus arrestors, voltage divider, current measuring transductor, disconnecting switches, D.C. circuit, breaker for change over from metallic earth return to ground-earth return etc. are provided.

Requirement of Areas in a bipolar substation are as follow :

- — Valve building 10%
- — A.C. Filters 30%
- — A.C. bus-work and transformer 50%
- — D.C. yard 10%

In modern installation, SF_6 GIS may be used for AC and DC switch yard, AC harmonic filters, etc. The area requirement is about 2 m^2/MW which are about 10% of conventional air-insulated switch yard.

47.8. OVER-VOLTAGE SURGE PROTECTION

The convertors are protected by surge arrestors against over-voltage approaching from AC side and DC side. In additional arrestors are also provided for limiting over-voltage surges that may be generated by the convertor itself.

47.9. D.C. SURGE ARRESTORS

For protective convertor equipment from DC side surges have a different design criteria as compared with AC application. The DC arrestors should be suitable for operations in inductive circuit and should be capable of discharging relatively long duration surges. In some cases resealing has to take place without aid of zero passages. To fulfil such requirement and to provide low protective levels a special design of active gap is necessary. ZnO arrestors (metal oxide arrestors) with active gaps are used. These have superior characteristics and high discharge capability.

47.10. LINE PROTECTION SYSTEM

In HVDC transmission system, the grid control of the convertors is used for clearing line faults and subsequent restoring of normal operation. Thus the current control scheme can give very rapid change in line current to reduce full fault current to fraction of rated current within 20 to 40 ms. The reduction of fault current and fault time prevents damage to line conductors, insulators and also deionises the fault zone. This helps in restoring the normal operation rapidly.

47.11. AC HARMONICS

The 3-phase bridge convertor used in HVDC transmission should convert pure sinusoidal AC waveform to pure DC form. But in practice the operation of convertor generates harmonic currents and harmonic voltages on AC side and DC side. These harmonics do not interfere with convertor operation but they flow through AC lines and DC lines and thereby produce the following harmful effects :

— Excessive harmonic currents in syncrhronous machines, power factor capacitors and other equipment.

— Overvoltages at points in the networks.

— Interference with protective gear.

— Interference in adjusting telecommunication lines, radio interference (RI); Television Interference (TI).

These disturbance spread over the AC network and DC line and surrounding residential areas.

In HVDC convertors, following predominant Harmonics are encountered :

AC Harmonics : $H_{ac} = nx + 1$

DC Harmonics : $H_{dc} = nx$

n = Pulse number of convertor. x = Integers 1, 2 ...

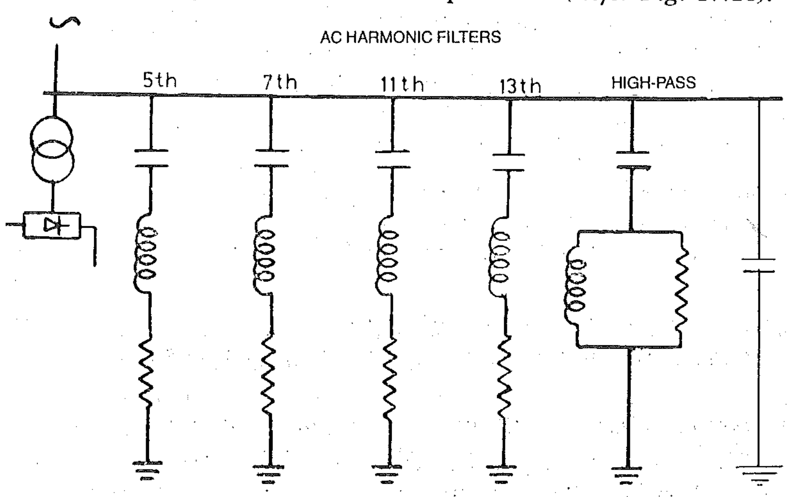
47.12. HARMONIC FILTERS

These are provided on A.C. side for following purposes :

— To reduce harmonic voltages and currents in the A.C. power network to acceptable limits.

— To provide all or a part of reactive consumed by the convertor, the additional reactive power being supplied by shunt capacitor banks.

A.C. shunt filters having R.L.C. in series are preferred *(Refer Fig. 47.18).*



Single line schematic diagram of AC harmonic filters.
Fig. 47.18. AC Harmonic Filter Circuit.

Convertors generates harmonic voltage and currents at both A.C. and D.C. sides. A convertor of pulse No. 'n' generates harmonics predominantly of the order 'H' as follows :

$$H_{ac} = nx \pm 1 \text{ on a.c. side.}$$

$$H_{dc} = nx \text{ on d.c. side.}$$

where n = number of pulses of rectifier/inverter usually 6 or 12.

x = an integer

H_{ac} = Predominant a.c. harmonic

H_{dc} = Predominant d.c. harmonic.

Table 47.3 gives the list of likely predominant harmonics.

Table 47.3. Predominant Harmonics

Number of Pulses n	*Harmonics on A.C. side* $H_{ac} = nx \pm 1$	*Harmonics on D.C. side*
6	1, 5, 7, 11, 13, 17, 19, 23, 25	0, 6, 12, 18, 24
12	1, 11, 13, 23, 25	0, 12, 24

A.C. Harmonic Filters. Two complete harmonic filters, each comparing tuned band-pass branches for the 11th and 13th harmonics and a high pass branch tune to 24th harmonic are provided in each station for a typical 12 pulse convertor system in Fig. 47.19.

D.C. Harmonic Filters. In bi-polar operation, under ideal conditions, the induced voltages would be negligible and filters are not necessary. However under real operating conditions, assuming certain unbalance (in transformer reactances etc.). The induced voltage level would increases. Therefore, use of high pass d.c. filter turned to 12th harmonic is usually made for a 12 pulse convertor circuit.

47.13. HVDC SIMULATOR

HVDC simulator is a model of HVDC system on which various system conditions and abnormal conditions can be simulated. The simulators are used for analysing dynamic performance of HVDC systems. Before designing an HVDC link and determining the specifications of various equipment, it is necessary to carry out system studies for the proposed HVDC line. These studies are carried out with the help of HVDC simulators. The simulator is a small-scale model of actual HVDC system and comprises the following functional blocks :

— 12 pulse convertors (8)

— Bipolar DC lines (2)

— Synchronous machine models (10)

— Static VAR compensator models (2)

— AC filter bank models for 3rd, 5th, 7th, 11th, 13th and high pass branch.

— A large number of reactor models of AC network representation.

— Complete set of control and protection sub-system of both convertor and pole levels.

Such a simulator can model two bipolar HVDC systems.

Types of studies preformed on HVDC simulator. The performance of a HVDC transmission has a significant influence on the behaviour of complete power system including AC networks to which the convertor stations are connected. On the other hand, this performance is greatly dependent on the control and protection system and their sub-functions. The operation of an HVDC transmission is much more dependent on the control system than that of an A.C. transmission. The control systems should be tested very thoroughly during the development stage and prior to commissioning. A simulator operating in real time is necessary too for this type of testing. In the simulator it is possible to inject different kinds of faults and disturbances in A.C. network and D.C. line and to study the effect of the control and protection system, firing the control design concepts.

Some control circuits like convertor firing control cannot be successfully developed without using real time simulator. The following types of studies are performed in a simulator :

— Development of control and protection systems.
— Main circuit design.
— Requirements on, and improvement of, A.C. network characteristics.
— Dynamic interaction between HVDC convertors and the A.C. systems.
— Transient studies.
— System tests on control equipment for a total project.
— Support for HDVC schemes in operation.

47.14. PROTECTION SYSTEMS IN HVDC SUB-STATION

Table 47.1. Protection chart for HVDC Sub-station

Category	*Protective systems*
1. D.C. side protection	1.1 Convertor protection 1.2 Pole protection 1.3 Bipole protection
2. Convertor transformer protection	2.1 Convertor transformer line side differential protection 2.2 Convertor a.c. bus and transformer differential protection. 2.3 Convertor-transformer differential protection 2.4 Supervision of gas and temperature in the convertor transformer
3. A.C. Filter-bank protection	3.1 Complete a.c. filter-bank and feeders upto a.c. bus are protected by — Overcurrent protection — Differential protection 3.2 Tuned a.c. filter branches are protected by — Unbalance protection — Backup portection — Earth-fault protection — Overload protection
4. Protection of Apparatus (Protective functions distributed to sub-systems demand that convertor be taken out-of service)	4.1 Supervision of smoothing reactor gas and temperature 4.2 Cooling system of valves. 4.3 Power supply to valve control 4.4 Convertor firing control power supply supervision. 4.5 A.C. bus voltage supervision and distributed overcurrent protection.
5. A.C. yard protection	5.1 Power transformer protection (in any) 5.2 Bus differential protection 5.3 Line protection
6. Auxiliary power transformer protection	6.1 Bus overcurrent protection 6.2 Transformer differential protection 6.3 Overcurrent protection and earth-fault protection. 6.4 Supervision of gas and temperature.

47.14.1. Protection of HVDC Transmission System

In HVDC transmission systems, the faults and abnormal conditions can develop in DC line, convertor, DC yard, Auxiliaries etc. The faults on DC side may call for blocking of convertors, de-energizing the DC pole. There are no DC circuit-breakers. DC fault current is reduced to low value by convertor control.

During fault on one pole, only faulty pole is isolated and the other pole continues to transmit. The faulty pole is removed from service by tripping AC circuit-breakers feeding that pole. The entire HVDC system is segregated into two poles.

The protection system in HVDC substation is integrated with the convertor control system. Protective and control action is taken in both terminals of 2 TDC system simultaneously. For this, the microprocessor based protection and control systems in both the terminals are linked by means of Power Line Carrier Communication system or Microwave system.

The present HVDC system are mostly 2-Terminal Bipolar systems without HVDC circuit-breakers. The protection functions of DC line are served by control of thyristor valves. In future, the availability of HVDC circuit-breakers may change the scene and will provide scope for simpler control system and operational flexibility.

The designers of HVDC system feel that there is no need of DC circuit-breakers for clearing faults on DC line side as the control takes care of all faults and abnormal conditions on DC side.

In the HVDC transmission, the function of protective and control systems are integrated. The protective and control functions include sensing (detection) or abnormal operating conditions and faults in the main AC circuit, DC circuit and auxiliaries and to initiate appropriate control action and protective action so as to prevent, minimise the damage to equipments and ensure the service continuity *via* the healthy system. Service continuity of HVDC transmission is very important because of high power through a single transmission link.

During a fault on DC side, there is no provision of tripping HVDC circuit breaker. However, the fault current is reduced rapidly by thyristor control. No tripping is carried out on DC side. Permanent faults in DC side are cleared by tripping AC circuit-breakers associated with the faulty pole.

The entire protection and control sub-system of HVDC system is divided into two poles : Pole 1 and Pole 2 (Fig. 47.17-dashed lines). For any fault in Pole-1 ; the control actions of Pole-1 are initiated automatically to minimise the fault current. If fault continues, pole-1 is tripped by means of AC circuit-breakers in AC yard.

Polewise segregation of HVDC system. The entire substation is divided into 4 parts for protection control and maintenance purpose :

1. Pole-1
2. Pole-2
3. Auxiliaries and Earth Return, common to both poles.

Pole-1 covers zone between AC substation and Pole-1 DC transmission line. In the event of a permanent fault on any of the sub-zones within Pole-1, the total pole-1 is tripped from AC side by tripping AC circuit-breakers behind the convertor transformers of pole-1. (Fig. 13.4-CB-1).

Likewise, for a permanent fault in Pole-2, the entire Pole-2 is tripped from AC side by tripping of AC circuit-breakers of feeding the convertor transformers of Pole-2 (Fig. 13.4-CB-2).

Thus, for a fault in Pole-1 only pole-1 is de-energized and then tripped from AC side. Pole-2 continues to serve.

In principle of one of the poles should be available when the other pole is out of service.

Faults in DC line pole are sensed by protection system in the DC line pole zone. The primary (fast) protection is provided line protection system. The back-up protection with certain time delay is also provided in the line protection system. For a line fault in pole-1, appropriate control actions and protective actions are taken by the control and protective system of pole-1, likewise for pole-2.

Short-circuit (faults) in two-terminal bipolar HVDC line are generally single pole to ground faults due to lightning and flashover across insulators. Such faults are temporary and involve only one pole. Each line pole is covered by a separate line pole protective zone having its own protective and control systems.

The control and protective actions for each DC line pole are integrated with the convertor control of that pole.

The line pole protection has an interface with the convertor pole protection and the operating mode control (change-over from bipolar to monopolar during a line pole fault). During a line pole fault, the operating mode is quickly and automatically changed over to the monopolar operating mode. This is done without interruption in power flow through the healthing DC pole.

De-energizing Line and Re-energizing of DC line. For a fault on DC line pole, by putting both convertors in invertor mode, the line voltage of faulty pole is brought to zero and line current is brought to zero. The fault zone gets de-ionized in about 0.3 sec. After automatic clearing of line fault, the line pole may be re-energized automatically. This is called re-energization of line. The re-energization is carried out in one of the following two alternatives.

1. At normal voltage and with full power before the fault. In such attempt if the fault re-appears, one or two more attempts are made with increased dead time.

2. At reduced voltage and reduced power. This attempt is generally tried during rainy season when the flashover is on wet, dirty insulators the re-energization at reduced voltage may give a success.

The re-energization with reduced voltage is preferred. The direct voltage is not raised in one big step but is raised slowly and upto to the final value. The increase in voltage is under the control of starting control unit so that there is no overshooting of voltages.

The total sequence of occurrence of line fault, de-energization of line pole, re-energizing of line takes approximately 200 ms. If the fault has continued, the complete faulty pole is tripped by means of AC circuit-breakers.

47.15. LINE INSULATION

The requirements of HVDC lines insulation is based on the stresses caused by lightning surges, switching surges and polarity reversal. Insulators of porcelain or toughened glass are used for transmission line. The recommended value for specific creepage distance of HVDC line insulators is between 2.3 cm/kV and 7.0 cm/kV depending upon zones of pollution. (Refer Table below)

Table 47.2. D.C. Specific creepage distance for line insulation.

Zone	*Description*	*Creepage distance cm / kV*
1.	Agricultural area	2.3
2.	Outskirts for industrial complex and a few km from sea	4.0
3.	Industrial area and near sea shores	5.0
4.	In highly polluted areas like dirty insustrial area, some industries, some power stations	7.00

The impulse level of a 400 kV to ground line is about 1400 kV peak.

The creepage distance for indoor HVDC equipment in the range of 1.5 to 2.0 cm/kV of operating voltage.

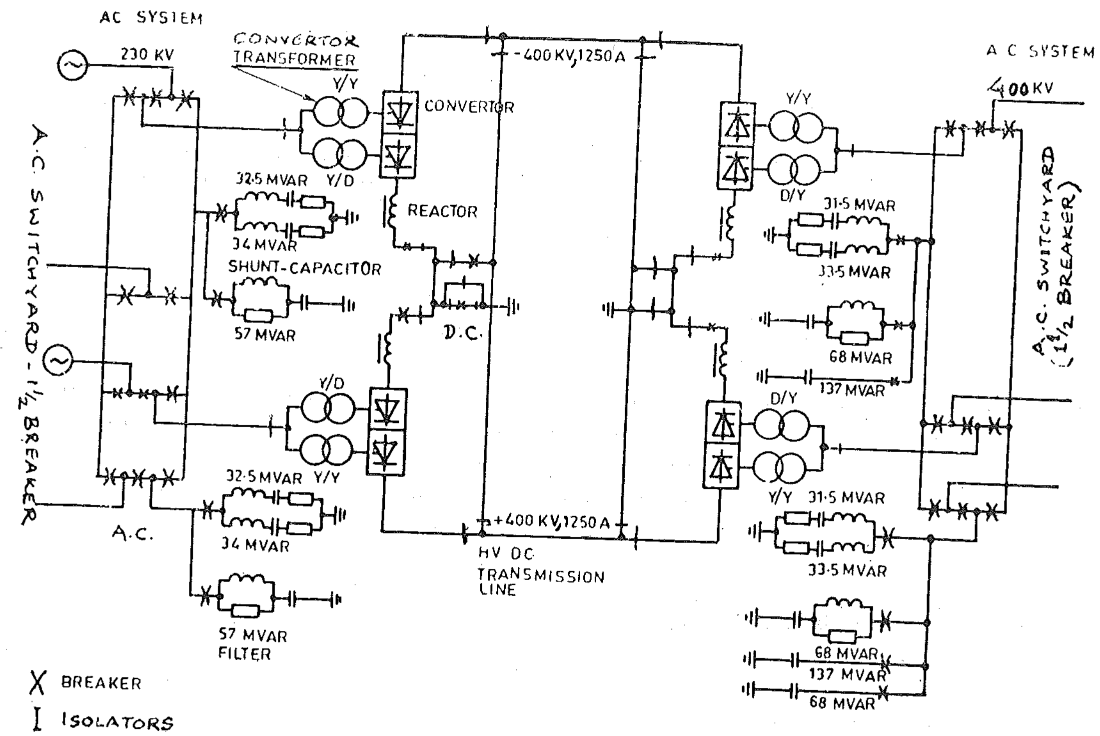
For HVDC overload lines, bundle conductors with two or more sub conductors are used per pole. The support insulators are of following types :

— Vertical suspension insulator strings.

— V-shaped suspension insulator strings.

— Strain insulator strings.

For straight run of transmission line, V-shaped configuration is preferred as these insulators have a better washing effect during rains. Strain insulators are used at dead-ends, turning points and at regular intervals (for stringing purposes). The insulator units are either of glass or of porcelain. Anti-fog type units are used.



TYPICAL HVDC SYSTEM

Fig. 47.19. *Courtesy* : ASEA, Sweden.

47.16. MAINTENANCE OF HVDC LINKS

The maintenance of HVDC conversion station is similar to that of an A.C. power station. The entire HVDC link is divided into maintenance zones such that one pole continues to operate while the other pole is taken for maintenance. Maintenance is of two types

— Planned Maintenance — Troubleshooting

The substation maintenance zones include

1. Pole I and Pole II
2. AC Filter Areas
3. AC Yard
4. DC Yard
5. Valve Halls
6. Auxiliaries

For purpose of maintenance the operating mode of HVDC system is changed to Monopolar Operation with substation-earth. Other pole and Earth. Return line and Earth Electrode are available for maintenance.

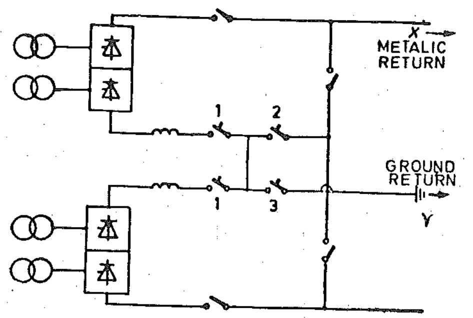
47.17. D.C. BREAKERS AND LOAD SWITCHES

D.C. breakers or load switches are used in three d.c. switching applications, namely :

1. Neutral bus load switch.
2. Load switch for metallic return to ground transfer.
3. Breaker for ground to metallic return transfer.

Fig. 47.20 shows the locations of these units whose design has then adapted to the particular application.

1. The neutral bus switch is normally operated as a dis-connector, that is under no-load conditions. In the unlikely case of a ground (earth) fault on the convertor side of the switch, this must



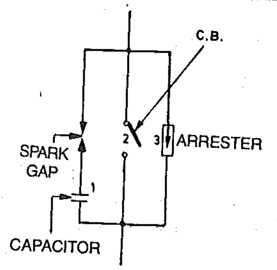
1. Neutral bus switch
2. Switch for metallic to ground. Transfer (Transfer of data from x to r).
3. HVDC Breaker to Ground to Metallic Return Transfer (from y to v).

Fig. 47.20. Switches for neutral bus and return to ground.
Courtesy : ASEA Sweden.

also to commutate the fault current to the electrode line. The fault current corresponds to the difference between the current in the healthy pole and the current in the electrode line. A slightly modified a.c. circuit-breaker with artificial current zero is used here.

2. The switch for metallic return to ground transfer is operated in connection with the normal routine for the change over from single pole metallic return operation to bi-polar operation. After the electrode line has been connected, about 20 per cent of the direct current still remains in the return pole conductor and the switch is needed to commutate this current to the ground return path. The same type of breaker as in point is used also here.

3. The breaker for ground to metallic return transfer is subjected to higher d.c. stresses owing to the higher current and high d.c. recovery voltage. An HVDC breaker is, therefore, used here. As shown in Fig. 47.21 this breaker consists of three principal components.



1. a circuit breaker (SF_6/MOCB/vacuum)
2. a capacitor with a series-connected spark gap and
3. HVDC surge arresters

Fig. 47.21. D.C. Circuit breaker for (3) in Fig. 47.20.

Conventional HVAC and HVDC components are used in this breaker. It shall be capable of commutating the current in the ground return (approx. 80% of the total pole current) to the metallic return conductor. For this application it is, therefore, designed interrupt a maximum direct current of 1500 A and to absorb an energy of 2 MWs.

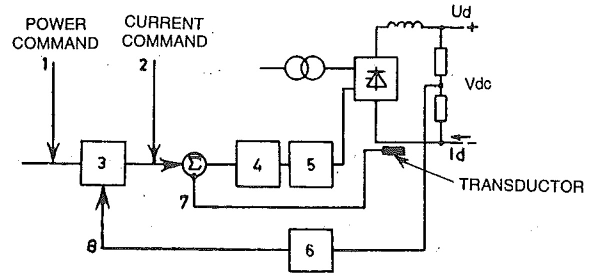
47.18. CONTROL AND PROTECTIVE EQUIPMENT

The main requirements of a HVDC system is to deliver scheduled amount of power. The power control is obtained by

— Combined voltage and current control by controlling thyristors in the convertor bridge.

— Tap changing of convertor-transformers on a.c. side.

Both the above methods are used. Thyristor control is rapid (few milliseconds), tap-changer control is slower (5 to 10 seconds per step). Both these means of voltage control are applied at each terminal. Thyristor control is used initially for rapid action and this is followed by tap changing for distorting certain quantities. Fig. 47.22 illustrates the control system for power control. The power is measured either on a.c. or d.c. side.



1. Power order
2. Current order
3. Divider (Analogue)
4. Amplifier
5. Trigger pulse system
6. Voltage measuring system
7. Current feedback
8. Direct voltage feedback.

Fig. 47.22. Control system for power control in HVDC.

The voltage is measured on d.c. side by voltage measuring system (6) and is given to analogue divider (3). Thus the power command and measured voltage is used in addition to current control. The main current control is achieved by a closed loop system (7). The transductor measures d.c. currents and feeds it to comparator *via* feed back loop (7). The current command is to compared with feed back current (7) and the error is given as input to amplifier (4). The output of amplifier (4) is given to trigger pulse system (5).

The analogue divider 3 receives power compound P and feedback voltage V_d. The output signal of analogue divider 3 is proportional to $I_d = P/V_d$, this signal is added to current command (2).

Thus the automatic control system is derived from a combination of current control, voltage control and power control.

Increase and decrease of power command (1) is executed manually at the two stations. The communication between the two stations is achieved by microwave communication system.

The following limits are imposed on current control :

1. *Maximum current limit.* This is from 1 to 1.2 times rated current depending upon thermal ratings of valves and ambient temperature.

2. *Minimum current limit.* This is usually 0.1 times rated current.

3. *Voltage dependent current limit.* For lower voltage higher current limit and corresponding power limit is fixed.

Shunt Compensation. (Reactive power equipment). The d.c. line itself does not require reactive power compensation and the voltage drop on the line is purely IR drop. The convertors convert, transformers on both sides drawn reactive power from a.c. side. It varies with amount of power transferred and is 50 to 70% of DC power flow. AC filter capacitors provide compensation of reactive power required for convertor operation.

Reactors

D.C. smoothing reactor with an inductance of 0.4 H to 1 henry is generally located on the low voltage side of the convertors. Air-core reactors on the line side of the convertors limit any steep front surges entering the station from the d.c. side. In addition, air-core reactors are installed in each phase on the a.c. to reduce the rate of the current on firing of the thyristors.

SUMMARY

HVDC transmission is selected as an alternative to EHV transmission for one of the following :

— Bulk power long distance transmission lines for economy, energy conservation, power flow control.

— For interconnecting lines between two or more A.C. system as an asynchronous tie.

— Long distance submarine cables.

In India, HVDC line will be used for bulk power transmission and interconnections. (Back-to-back HVDC substations).

A typical two terminal HVDC link has A.C. sub-station, conversion sub-station at each end and the two such sub-stations are linked by the bipolar transmission line.

In bipolar D.C. transmission system has two poles, one positive with respect to earth and the other negative.

The convertors are made up thyristor valves, 12 pulse convertors are used. The convertor is supplied from convertor transformer. The quadruple valve has 4 valves placed vertically to form a limb. These are installed in valve halls.

The convertor transformer is of special design as D.C. voltage on convertor sides causes additional magnetising currents and voltage stresses.

The rating of a typical long-distance HVDC link are :

(*i*) ± 500 kV (*ii*) 1500 MW (*iii*) 900 kM.

The control of HVDC power flow is by tap changing of convertor transformer and gate control of thyristors valves.

The HVDC lines having point-to-point contact do not need HVDC breaker as the line current can be reduced rapidly in the event of fault by blocking thyristor.

With the development of thyristor valves, the HVDC lines have become commercially viable for long distance high power transmission systems, interconnections, sub-marine cables.

Recently multi-terminal HVDC transmission systems having link between 3 or more AC systems have been commissioned in Italy, USA/Canada.

HVDC Back-to-back coupling stations are being preferred for system interconnections. Several Back-to-back HVDC sub-stations have been commissioned and several new contracts have been signed.

HVDC Projects in India :

1	Vindhyachal Back-to-back(WR-NR)	500 MW (1989)
2	Rihand-Delhi	1500 MW ± 500 kV 820 km, Bipolar (1991)
3	Chandrapur, Padghe	1500 MW, ± 500 kV, 850 km Bipolar 1998
4	Chandrapur Back-to back (WR-SR)	1000 MW (1996)
5	National Experimental HVDC (Barsur-Lower Silera)	± 100 MW, 250 kM (1992)
6	Gujwaka-Jaypur Back-to-Back (SR-ER)	1000 MW, (2000)

Note : WR = Western Region NR = Northern Region
SR = Southern Region ER = Eastern Region

48-A

EHV — AC Transmission Systems and Static VAR Sources

Hierarchical levels in Transmission systems—Characteristics of transmission systems—Design aspects : Electrical, mechanical, structural—Power transferability of AC lines and DC lines—Choice of voltage of AC lines and DC lines—Transient stability limit—Control of power flow—Short circuit levels—Voltage control and reactive power compensation—Insulation co-ordination and surge arrester protection—Conductor design, corona, radio interference— Subsynchronous resonance—Static VAr Sources (SVS).

48.1. GENERAL BACKGROUND OF EHV-AC TRANSMISSION

Modern civilization depends heavily on the consumption of electrical energy for industrial, commercial, agricultural, domestic and other purposes. Electrical power is generated in large thermal, hydro, nuclear power stations. The energy transfer from these generating systems to distant distribution networks is *via* transmission systems. The modern electrical power system is in the form of a large interconnected network. The generating stations, transmission and distribution systems are interconnected by means of 3 phase AC system operating synchronously at the common single frequency of 50 Hz (60 Hz in USA). The total network covers a vast geographical area.

The basic function of a transmission system is to transfer (convey) electrical power from one location to another location or from one network to another network. A transmission system includes terminal sub-stations, transmission lines and intermediate sub-stations.

Transmission system are necessary for (1) bulk power transfer from large group of generating stations upto the main transmission network (2) for the main transmission network (3) for system interconnection and (4) for transfer of power from the main transmission network to the distribution sub-stations.

A transmission system is used either for transfer of power from sending-end to the receiving-end or for system interconnection for exchange of power between independently controlled networks.

The network of transmission and distribution lines is formed by three-phase alternating current system. For longer lines and higher power transfer, higher transmission voltages are necessary, ($P \propto V^2$). Higher voltage gives lesser current, lesser $I^2 R$ line losses, higher power transferability.

As a rule, higher the power rating higher is the requirements of transmission voltage. Longer the lines, higher is the required transmission voltage. In the ending-end sub-station, the voltages are stepping up and then transmitted. At the receiving end the voltage may be appropriately stepped down by using power transformers.

Upto 1970's, the choice was exclusively in favour of high voltage AC (upto 220 kV) and extra high voltage AC (above 220 kV, upto 760 kV, AC).

By 1990's Ultra High Voltage AC (1000 kV, 1100 kV, 1200 kV) transmission lines were introduced for bulk power transfer in USSR, USA, Canada etc.

First commercial High Voltage Direct Current transmission system (HVDC) was introduced during 1953. With the successfully development of high power thyristor valves in early 1970's the HVDC transmission systems have become a technically and commercially viable alternative to

EHV/UHV AC transmission particularly for long distance bulk power transmission, cable transmission and system interconnection. For these applications HVDC transmission system have a distinct superiority over EHV-AC and are being increasingly preferred.

Thus, the choice of transmission systems and rated voltages for a transmission line is made from HV AC (upto 220 kV) ; EHV AC (between 400 kV and 760 kV AC); UH-VAC (above 760 kV AC) and HVDC (upto ± 1600 kV DC) depending upon technical and economic considerations.

48.2. VOLTAGE LEVELS FOR TRANSMISSION LINES

The network is formed by several HV, EHV(AC) lines with a few HVDC systems.

The following table give the reference values of voltages used for AC and DC transmission systems.

Table 48.1-A. Reference values of voltages for 3 phase AC lines

Description	*HV-AC*			*EHV-AC*			*UHV-AC*		
Nominal Rated Voltage kV, rms, Phase to Phase	132	220	275	345	400	500	750	1000	1100
Higher operating voltage kV, rms, Phase to Phase	145	245	300	362	420	520	765	1050	1200

Table 48.1-B. Increasing highest transmission voltage in the world

Year	*1965*	*1969*	*1988*	*1990*	*1985*	*2000*
Highest AC Transmission Voltage kV	735	756	1100	1000	1200	1600
Country	Canada	USA	USA	Italy	USSR	USA

Table 48.2. Reference values of Rated Voltages of Bipolar Overhead HVDC Transmission

	I			*II*				*III*
Rated voltage, kV, DC	± 100	± 200	± 300	± 400	± 450	± 500	± 600	± 800
Rated voltage, between poles, kV, DC	200	400	600	800	900	1000	1200	1600

I. Earlier HVDC systems

II. Present HVDC systems

III. Possible future requirement

* Rihand-Delhi HVDC Project, India

± Voltage refers to voltages of poles to earth. One pole is positive with respect to earth and other pole is negative with respect to earth.

48.3. HIERARCHICAL LEVELS OF TRANSMISSION AND DISTRIBUTION

During 1950's small stand-alone AC systems were generally adequate for limited geographical coverage. Such networks were formed by a few radial transmission lines emanating from generating stations.

Modern Transmission systems are interconnected networks and cover a vast geographical area and transmit a large amount of power from various generating stations to various sub-stations and loads. For systematic power transmission and control ; the network is divided into three hierarchical level of transmission and distribution : (Refer Table 48.3).

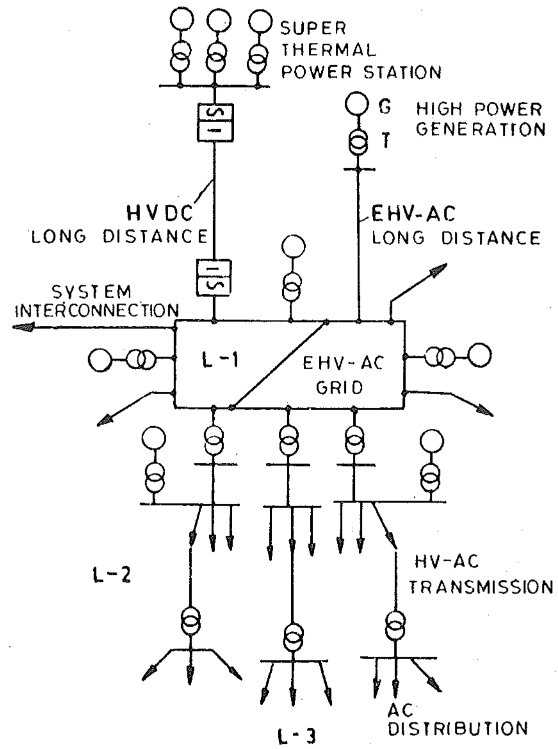
* 400 kV lines introduced in India during 1974 and are now well established for back-bone transmission Network and bulk-power transmission in various regional grids.

** Two 750 kV lines under consideration in India (1997).

1. Backbone or Main Transmission Network (EHV - AC)
2. Sub-transmission Network (HV - AC)
3. Distribution Network (MV - AC, LV - AC).

Fig. 48.1 illustrates the concept of hierarchical levels in transmission systems.

The three levels cover the entire geographical area. The distribution network is formed by several distribution sub-stations and distribution lines reaching a wide range of consumers. The distribution sub-stations receive power from local receiving sub-stations. Local receiving sub-stations receive power from sub-transmission lines and sending-end sub-station of these sub-transmission lines receive power from back-bone EHV-AC Network. The EHV-AC Network receives power from large power stations. Back-bone transmission Network is of EHV-AC lines. It is in a ring form (mesh). The long bulk power transmission lines between distant super thermal power stations and this network are either EHV-AC or HVDC.



L—1 : Back-bone EHV-AC network
L—2 : Underlying sub-transmission
L—3 : Distribution

Fig. 48.1. Hierarchical levels in the transmission network.

Table 48.3. Functions of Hierarchical Levels in Transmission and Distribution Network

	Level Title	*Function*	*Remarks*
L-1.	Back-bone EHV-AC network	— To receive power from generating stations and long bulk power EHV-AC/HVDC transmission lines. — To deliver power to sub-transmission system *via* HV transmission lines	— In meshed or Ring Form. — Interconnected with neighbouring network. — Generally EHV-AC lines (400 kV or 760 kV) — Generally double circuit for radial lines.
L-2.	Sub-transmission Network (underlying below the back-bone network)	— To receive power from the back-bone network and some local power stations — To deliver power distribution system *via* HV transmission lines	— Less method — More radial lines — Generally at High voltage AC (220 kV. 132 kV)
L-3.	Distribution Network. (Underlying below the sub-transmission)	— To receive power from the sub-transmission Network and — To deliver power to consumers	— Medium voltage AC and Low voltage AC. Medium voltage : 33 kV, 22 kV, 11 kV, 6.6 kV, 3.3 kV, Low voltage : upto 1000 V

Interconnections between neighbouring independently controlled AC networks are by one of the following :

— Overhead HV/EHV/UHV AC lines, or

— Overhead HVDC lines, or
— Underground/Underwater HVDC cables
— Back-to-back HVDC coupling station.
— Multi-terminal asynchronous HVDC interconnecting system.

Chapter 49 covers power system interconnections.

48.4. TASKS OF TRANSMISSION SYSTEMS

The tasks associated with transmission and distribution systems include :

— Transmission of electric power at specified voltage and frequency.
— Control of power with respect to magnitude and direction. Controlling exchange of energy flow.
— Economic load despatch.
— Ensuring steady state stability and transient stability of the transmission link and associated AC Networks.
— Control of flow of reactive power compensation of reactive power.
— Voltage control at sending-end and receiving-end of transmission lines and voltage control of distribution buses.
— Assistance in frequency control by rapid exchange of power maintaining stability. Network islanding, (Network segregation) and load shedding.
— Security of supply by feeding at various points, providing adequate line-capacity, facility for alternate transmission paths.
— Data transmission *via* power line carrier communication channels (PLCC) for the purpose of telemetry, telecontrol and network automation.
— Minimise transmission losses by selecting shorter transmission paths.
— Adequate protection, minimum faults and minimum fault duration. Pinpointing location of fault, causes and subsequent improvements.

For convenience the transmission lines, sub-stations, distributions circuits and generating stations are identified separately. However, the Network is homogeneous. The function of these parts overlap. Each part has a significant influence on the others.

48.5. FUNCTIONAL REQUIREMENTS OF TRANSMISSION SYSTEMS AND DESIGN ASPECTS

The lines and sub-stations constituting transmission systems are designed to deliver required amount of power continuously, reliably with voltages within specified limits and with environmental factors within specified limits, with lowest overall annual cost over the service period. The system should also have provision of expansion, with minimum changes in existing layouts.

The transmission system designs have four important parts :

— Electrical design — Mechanical design
— Structural and civil design — Miscellaneous design

Furthermore, the transmission system design includes :

— Sub-station design — Transmission line design
— Network planning

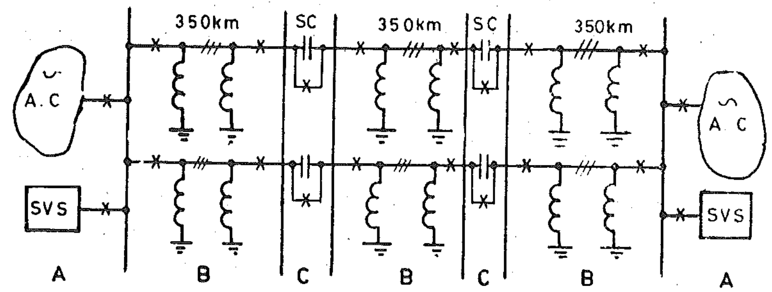
Electrical Design Aspects. The electrical design of AC transmission systems is quite different from that of HVDC transmission systems. The electrical design involves the following aspects :

1. Choice of transmission voltage.
2. Choice of conductor configuration.
3. Voltage control and reactive power compensation.

4. Corona losses and Radio Interference.
5. Transient stability, autoreclosing of circuit-breakers.
6. Abnormal operating conditions and protection systems.
7. Insulation coordination and surge arrester protection.
8. Neutral grounding.
9. Sub-station grounding, tower grounding.
10. Earth electrodes and electrode lines (for HVDC).
11. Harmonics and filters (for HVDC).
12. Overhead shielding wires and lightning protection.
13. Power line communication (PLC).
14. Radio Interference (RI), Telephone Interference (TI).
15. Television Interference (TI).
16. Audible noise (AN).

48.6. CONFIGURATION OF EHV-AC TRANSMISSION SYSTEM AND BIPOLAR HVDC TRANSMISSION SYSTEM

Fig. 48.2 illustrates the configuration of a very long EHV-AC transmission system. Intermediate sub-stations are required at an interval of 300-350 km for installing shunt reactors and series capacitors.

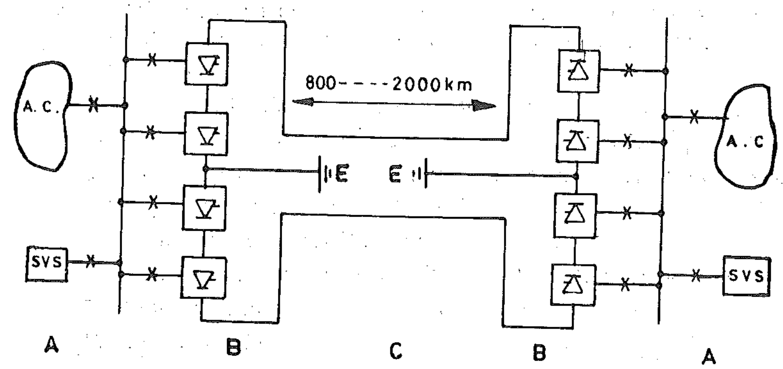


A = Terminal AC systems.
B = Transmission line.
C = Intermediate substation.
SVS = State VAr Source.

Fig. 48.2.

An EHV-AC line always needs a parallel line so that if a fault occurs on one line, the other line continues to provide the transmission path between two ends and system stability is maintained. SVS is necessary at terminal sub-stations for providing controllable shunt compensation.

Fig. 48.3 illustrates the configuration of a bipolar HVDC link. Only two conductors are sufficient. No intermediate sub-station is needed for compensation.



A = Terminal AC systems.
B = Convertor station near *A*.
C = HVDC bipolar transmission line.

Fig. 48.3. Configuration of a bipolar HVDC link.

48.7. POWER TRANSFERABILITY OF AC LINE

Power transferability of AC lines is governed by the equation :

$$P_{dc} = \frac{|V_1| \cdot |V_2|}{X} \times \sin \delta \qquad ...(48.1)$$

where $|V_1|$ = Sending-end voltage, kV

$|V_2|$ = Receiving-end voltage, kV

X = Series inductive reactance, ohm

δ = Power angle, Angle between V_1 and V_2

P_{dc} = Power transfer, MW

In practice angle δ is held around 30° to maintain transient stability. Therefore, power transfer of a single circuit, 3-phase AC line is approximately equal to :

$$P_{dc} = 0.5\ |V_1| \cdot |V_2|\ / X \qquad ...(48.2)$$

By introducing a parallel line, the series reactance of the double circuit is reduced to $(X/2)$ resulting in doubling of power transferability. By introducing series capacitor banks is series with a 3-phase AC line, the effective series reactance X is reduced to

$$X = X_L - X_C$$

where X = Equivalent series reactance of the link, ohm

X_L = Series inductive reactance of the line, ohm

X_C = Series capacitive reactance of capacitor banks.

However, series capacitor banks are used only in EHV lines when paralleled lines are not economical. Normally, compensation of the order of 50% of X_L is used *i.e.*, $X_C = X_L/2$.

As seen from Eqs. 48.1 and 48.2 ; the power transferability of AC lines is proportional to the square of transmission voltage *i.e.*

$$P_{AC} \propto V^2 \qquad ...(48.3)$$

48.8. LINE LOSSES

Current I, through three phases conductors having resistance R ohms each, causes power loss of $3I^2 R$ per circuit.

$$P_{ac} = \sqrt{3}\ VI \cos \phi \qquad ...(48.4)$$

$$I = \frac{P_{ac}}{\sqrt{3}\ V \cos \phi} \qquad ...(48.5)$$

where I = Current in line conductor, A r.m.s

V = Phase to phase voltage

$\cos \phi$ = Power factor of the line current

$$\text{Line loss } P_L = 3I^2 R \text{ watts} \qquad ...(48.6)$$

$$= 3\left[\frac{P_{ac}^2}{3V^2 \cos^2 \phi}\right] R$$

$$P_L = \frac{P_{ac}^2 R}{V^2 \cos^2 \phi} \qquad ...(48.7)$$

$$R = \frac{P_L V^2 \cos^2 \phi}{P_{ac}^2} \qquad ...(48.8)$$

Line loss decreases with increase of transmission voltage and improvement of power factor, for the same power transfer.

In addition to active power flow P_L, every AC line has reactive power flow Q. Reactive power flow results in additional transmission losses in AC lines.

48.9. CONDUCTOR COST

Volume of an AC conductor = v

$$\text{Resistance } R = \frac{\rho l}{A}$$

where ρ = resistivity,

l = length

A = Cross-section area.

$$v = A \cdot l$$

$$= \frac{\rho l \cdot l}{R} = \frac{\rho\, l^2}{R} \qquad ...(48.9)$$

Volume of three line conductors for AC transmission = 3v

$$3\,v = \frac{3\rho\, l^2}{R} \qquad ...(48.10)$$

Substituting R from Eq. 48.8 in Eq. 48.9 volume of conductors :

$$3v = \frac{3\rho\, l^2 P_{ac}^2}{V^2 \cos^2 \phi\, P^2} \qquad ...(48.11)$$

From Eq. 48.11, we note the following :

The volume of conductor v for AC line is proportional

— directly to square of power transfer P_{ac}.

— inversely to the square of voltage V.

— inversely to the square of loss.

For given loss P_L, the volume of conductor and the cost of conductor reduces in inverse proportion of voltage square.

$$\text{For a given voltage,} \quad P_L \propto \frac{1}{\sqrt{V}} \qquad ...(48.12)$$

For a given voltage V, the transmission loss is inversely proportional to the volume (v) of the conductor.

The choice of higher voltage results in reduced losses and reduced conductor size. However, the cost of line insulation and tower sizes also increase.

Table 48.4 gives the reference values of power per circuit (P_{ac}) percentage loss P_L resistance r per km, reactance X per km of AC lines for various rated voltage.

Refer Fig. 48.2. A high power AC line always needs a double circuit for each transmission path, thus minimum 6 conductors.

Ref. 48.3. An HVDC bipolar HVDC line needs only 2 conductors per path.

Table 48.4. Reference values for AC lines

Rated Voltage kV	*r ohm/km*	*X ohm/km*	*Length* km*	P_{ac} *MW*	*Loss* $P_L\%$
400	0.031	0.327	400	640	5.1
750	0.0136	0.272	400	2600	2.7
1000	0.0036	0.231	400	5500	0.85
1200	0.0027	0.231	400	8000	0.64

* For other lenghts l, multiply P_{ac} by $400/l$ because P_{ac} is inversely proportional to the line length l.

48.10. TRANSIENT STABILITY LIMIT OF AC LINE

The power transfer through an AC line has a limit dictated by the transient stability limit (refer Eq. 48.2). During system disturbances such as sudden changes in load, tripping of a line, fault on a busbar the power angle (δ) oscillates widely over a long period. The system tends to fall out of synchronism. The limit of earlier power transfer for given change of load without loss of stability is called transient stability limit. In case of AC lines, the transient stability can be improved by rapid fault clearing, rapid autoreclosing of line circuit breakers, etc. However, with AC transmission, the power angle (δ) swings widely and over longer duration resulting in power swings in AC networks and in the transmission line.

With HVDC transmission, the power flow through the line is dependent on thyristor control of rectifier and invertor. The power flow through the line can be quickly modulated to dampen the power swings in connected AC networks. Moreover HVDC link itself does not have a limit of power flow imposed by transient stability limit related with power angle (δ) and reactance (X). The limit of HVDC link is imposed by convertor rating and stability of convertor control system.

HVDC transmission system can be operated at its rated power transferability which is nearly equal to the thermal limit of convertors.

AC transmission system is operated at only 50% of its thermal limit due to the transient stability consideration.

During a fault on an AC line, the fault power is fed from both the terminal sub-stations. During a fault on a DC line the fault current is limited by the thyristors and does not endanger the stability of connected AC systems.

48.11. CONTROL OF POWER FLOW THROUGH LINE

The magnitude and direction and rate of change of power flow through a transmission line should be controllable, especially for interconnecting lines.

In case of AC lines, the phase angle (δ) gets adjusted naturally in accordance with the load/generation/frequency balance at each end and power flows from surplus end to the deficit end. In some interconnected lines special phase shifting transformers are installed at each end of the transmission line to enable adjustment of angle between V_1 and V_2. However, control of magnitude, direction and rate of change of power flow through AC lines is slow and difficult.

In case of highly meshed lines, parallel lines; phase shifting transformers are necessary for forcing power through AC tie-lines. (Chapter 49).

Control of power flow through a HVDC link is fast, accurate, bidirectional and has a wide range of magnitude limits. The power flow through DC lines is achieved by changing the current I_{dc} by varying the difference ($V_{dc}\,1 - V_{dc}\,2$) *i.e.*

$$P_{dc} = V_{dc} \cdot I_{dc}.$$

$$V_{dc} = \left(\frac{V_{dc} \cdot 1 - V_{dc} \cdot 2}{R}\right)$$

where $V_{dc}\,1$ = Sending end DC voltage

$V_{dc}\,2$ = Receiving end DC voltage R = Line resistance

V_{dc} = Average value of DC voltage

$V_{dc}1$ and $V_{dc} \cdot 2$ are changed by changing delay angle α of the thyristor valves at respective ends. The line resistance (R) being small, a small change ($V_{dc}\,1 - V_{dc}\,2$) bring about a quick significant change in I_{dc} and P_{dc}.

48.12. SHORT CIRCUIT LEVELS

The fault power for a three phase fault is called short-circuit level or fault level at the fault-point.

Addition of new EHV-AC lines and tie lines changes the short-circuit levels of the various sub-stations buses due to reduced equivalent reactance of the network. *With AC interconnected lines,* the fault levels at both ends increases. *With HVDC interconnection* the fault levels at each end remains unchanged, as the current through the line is controlled by firing the thyristor valves.

The short-circuit studies are carried out and equipment ratings are verified while planning transmission networks and designing transmission systems. HVDC interconnections have a distinct advantage that the fault levels at AC station buses remain at previous levels (before interconnections).

With interconnection between two AC networks by AC tie line, the fault levels of both networks get nearly added resulting in higher fault levels at terminal sub-stations. This may call for replacement of sub-station equipment of higher short-circuit capability. Such a replacement is not envisaged with HVDC interconnections.

Limiting Short-circuit Levels in today's AC system

Rated Voltage kV, r.m.s.	220	400	760	1000
Short-circuit level, kA r.m.s.	40	40	63.5	63.5

48.13. VOLTAGE CONTROL OF AC LINES AND COMPENSATION OF REACTIVE POWER (Ref. Sec. 45.20)

The voltages at sending end bus and receiving end bus of AC line should be held within specified limits under conditions of varying power flow and reactive power flow. The algebraic difference ($V_1 - V_2$) between sending-end AC voltage and receiving end-end AC voltage is related with flow of reactive power (Q).

During low loads, the receiving end voltage increases above sending-end voltage due to predomination of shunt capacitance of the transmission line (Ferranti Effect). During heavy loads or low power factor loads, the receiving voltage drops below sending end voltage. In case of long AC lines, the natural voltage variation is much beyond permissible limits. However, the voltages are maintained within specified limits by following means :

— Use of on-load tap changers with power transformers.

— Use of shunt reactors connected between line and earth at each end of the transmission line section to compensate the shunt capacitance of the transmission line.

— Use of shunt capacitor banks in receiving-end sub-stations to compensate lagging power factor load currents.

— Use of static VAr Sources (SVS) Sec. 48.B.

In case of very long lines of above 500 km, intermediate switching sub-stations are necessary to install the shunt reactors for compensation. For very long lines intermediate compensation would be required at certain intervals of line length (250 to 300 km).

In the case of DC lines, the effects of shunt reactance and series reactance are absent. The voltage drop $I_{dc}\,R_{dc}$ is small, uniform along the line and is directly proportional to the line load. Hence voltage control of HVDC line is easier. Intermediate compensating station is not required even for longest HVDC lines.

48.14. INSULATION CO-ORDINATION AND SURGE ARRESTER PROTECTION

Transmission lines and sub-stations are subjected to over voltages due to lightning, switching, faults, resonance and other causes. The surge *arrestors* are provided at strategic locations to protect the line insulation and sub-station equipment insulation from transient and temporary overvoltages.

The basic insulation level of an apparatus refers to the rated values of power frequency withstand voltage, lightning impulse withstand voltage and switching impulse withstand voltage.

The insulation level of an apparatus should be co-ordinated with the protective characteristics of surge arresters.

Insulation levels of EHV systems is determined from considerations of *switching surges.* Switching over-voltages are causes by switching of lines with no load/low inductive current/short-circuits etc. The overvoltages called dynamic over-voltages are caused by line dropping. Ferranti effect, overspeeding of generators, increase in emf due to leading power factor currents, etc. The insulation characteristic of various equipment is defined in terms of rated voltage, standard switching impulse, standard lightning impulse. These are co-related with protective characteristic of surge arresters.

The insulation levels of various sub-stations apparatus and the transmission line should be co-ordinated with various surge arresters such that the overvoltages are discharged to earth without causing damage to the equipment insulation.

The general method of insulation co-ordination in HVDC transmission systems is basically same as for an AC system. The insulation of each equipment is correlated with the protective characteristics and current/energy stresses of surge arresters.

The overvoltage in AC system are classified as switching surges, lightning surges and temporary overvoltages.

Switching overvoltages in AC system occur with high amplitude and only for first half cycle.

The temporary overvoltages last for a few cycles to several hundred cycles.

The overvoltages in HVDC system are caused by

- — Pole faults
- — Switching operation on DC side
- — Loss of pulses in convertor control
- — Short circuits near convertor terminals
- — Transformation of overvoltage from AC side
- — Switching of AC filter banks

Zinc oxide surge arresters (ZnO Arresters) are connected in DC yard, Valve hall, AC yard. Filter circuits, etc. HVDC system needs a large number of surge arresters. These are co-ordinated with surge arresters in AC yard.

The rated voltage switching impulse withstand characteristics, lightning impulse withstand characteristics, test voltages, test procedures, connection surge arresters, etc. form a part of insulation co-ordination studies. In case of HVDC system design, these studies are carried out with the help of

- — HVDC simulator
- — Digital computer simulation
- — Transient network Analyser (TNA)

48.15. LINE INSULATION, CLEARANCE AND CREEPAGE DISTANCES

The clearance refers to the insulating distance along a stretched string. The creepage (leakage) distance refers to the shortest distance along the insulation surface.

The principles of insulation design for AC lines are same as those of DC lines. However the stresses due to alternating electric field are quite different than those with unidirectional fields. Hence the requirements of clearances and creepage for AC are quite different than those for DC.

The clearances, contours of conducting parts, design of grading rings etc., are determined on the basis of required impulse withstand levels. Lightning impulses wave (1.2/50 μs) and switching impulse wave (250/2500 μs) impose different kind of voltage stresses. The polarity of the impulse wave (+/–) also has a different influence.

The creepage distance (leakage distance) is the distance between live metal part and earthed metal part along the surface of an insulator. The atmospheric dust, carbon particles, chemicals, salt, etc. get deposited on the surface of insulator along the lines of electric field. The insulator fail due to tracking. DC insulators need more creepage distance (mm/kV) than AC insulators, because of unidirectional electric field in DC. The requirements of creepage distance of HVDC insulators is almost twice the corresponding valves of EHV-AC insulators.

Table 48.5. Leakage Distance (Creepage Distance)

Type of Atmosphere	*HVDC⁺ mm/kV⁺*	*EHV-AC *mm/kV**
1. Very heavily polluted industrial area	70	30
2. Sea shore, industrial area	50	25
3. Moderately polluted area	40	22
4. Agricultural, forest area	30	16
5. Indoor insulators	26	15

⁺Rated phase-to-ground voltage of DC pole.
*Rated rms voltage of AC line, phase-to-phase.

48.16. RIGHT-OF-WAY (ROW)

Transmission line requires right-of-way for the line through urban, rural, jungle and other areas en-route. The cost of purchase of land, clearing and keeping right-of-way clean, free from trees is considered while selecting the line route.

In some cases, big cities, industrial localities it is becoming impossible to acquire right-of-way for EHV-AC lines.

48.17. CORONA

The design of conductors for EHV-AC transmission lines and HVDC transmission line should be such that the corona losses and radio interferences are within specified/permissible limits. *Corona is a visible, audible, partial electrical discharge at the surface of conductors at high voltage.* The corona discharge occurs in the air surrounding a charged conductor when the voltage stress at the conductor surface reaches the critical value. Corona generally occurs in foul weather.

Corona commences at voltage (V_c) called critical voltage at which the maximum voltage gradient at the surface E_{max} attain critical valve (E_c) · (E_c = 30 kV/cm at n.t.p., *i.e.* 760 mm Hg and 25°C).

The critical value of voltage stress depends upon pressure, temperature, humidity, pollution level in air and condition of conductor surface.

The conductor diameter should be made so large by using bundle-conductors or hollow conductors that the corona losses and radio interference are within limit.

Critical corona voltages are different for positive voltage and negative voltage, the negative voltage being more severe.

Corona cause losses, losses, radio interference and television interference.

In DC corona, the charges releases from one conductor must be carried to the ground or the other conductor because of the opposite polarity. Therefore the corona performance is characterised by the line voltage rather than the surface gradient.

The corona behaviour of a monopolar HVDC line is different from that of bipolar line due to the difference in release of the charge from the vicinity of the conductor surface.

Corona losses depend upon the roughness, cleanliness of conductor surfaces, and also weather condition. It is difficult to predict the corona loss in exact mathematical form. Corona losses vary through the year depending upon weather condition. Table 48.6 gives reference values of average annual corona loss for AC and DC lines.

In case of AC voltage, the peak value of voltage wave is $\sqrt{2}$ times the rms value. In case of DC there is no such great factor.

Corona losses of AC lines increase more rapidly with increase in rated voltage than the corresponding increase in DC line voltage.

With AC voltage, the ions going away from the conductor surface due to like polarity of charge during a half cycle get attracted towards the conductor during the next half cycle of AC wave.

With DC voltage, the ions with the same polarity as that of the conductor get a time to go away from the conductor. Therefore the corona phenomenon acts differently with AC and DC lines.

Table 48.6. Reference values of corona Losses of AC and DC lines

Weather Condition	*Corona loss kW/km*	
	± 400 kV DC	*500 kV AC*
Average loss in fair weather	1.35	1.33
Minimum losses in fair weather	0.62	0.12
Maximum loss worst weather condition	8.00	18.00
Annual mean loss kW/km	2.5	5.5
Line Particulars		
Conductor numbers	2	3
Conductor diameter, mm	46	36
Spacing between conductors, m	10.5	11
Average height	21	18.06

Corona inception voltage gradient is an important parameter for conductor design. For AC lines, standard bundled conductors are generally used. The corona inception voltage gradient should have about 25% margin above the surface voltage gradient at maximum operating voltage, based on fair weather conditions. If this margin is 0%, under foul weather severe radio interference is likely to occur along the line route and the width of the corridor should be increased.

Corona losses under foul weather conditions should be limited to about 5 kW/km. If more, the power available at receiving end would be reduced due to high corona losses.

48.18. TOWERS (SUPPORTS)

Galvanised steel structures are most common for transmission lines above 132 kV. Towers must be strong enough to support the line conductors and shield wires.

Self-supporting steel towers are commonly used for 132 kV and above.

Upto 220 kV, the towers are designed for supporting double circuit three-phase lines, with three conductors on each side and one overhead shielding wire on top.

For 400 kV and 765 kV, the self-supporting tower for single circuit three-phase line is used.

During development testing of 765 kV AC lines in USA and Canada, it was learnt that switching surge withstand level of EHV-AC towers is influenced by tower width (in direction of line). Losser width gives higher withstand level. Entirely new design configurations like chainnete, flexible, semi-flexible towers have been developed.

48.19. BUNDLE CONDUCTORS (MULTIPLE CONDUCTOR)

The voltage gradient at the surface of a conductor is inversely proportional to its radius.

The surface voltage gradient, hence the corona, corona losses, radio interference are reduced by increasing the radius of conductors, by using bundled conductor.

For EHV-AC lines bundled conductors are used. Only in a few cases, expanded ACSR conductors of 2.5 to 4 inch diameter are used.

Bundle conductors or multiple conductors consist of two or more (individually standard) conductors per phase, supported on one or more insulator string (per insulator span). A bundle conductor is said to have N sub-conductors per phase. These sub-conductors are distributed uniformly on a circle of radius R with a spacing B between adjacent sub-conductors.

Let N = Number of sub-conductors in a bundle
R = Bundle radius
B = Sub-conductor spacing
r_{eq} = Geometrical mean radius of a bundle

Normally, $N = 2, 3, 4, 6, 8, 12, 18$
$R = B/2 \sin(\pi/N)$
$B = B/2 \sin(\pi/N)$
$r_{eq} = (N_r R^{N-1})$

In India, for a 400 kV AC line a bundle conductor with two sub-conductors are used. For this bundle conductor

$N = 2$ $r_{eq} = 0.51$ metre $B = 46$ cm

For a 1000 kV line in Italy, a bundle conductor with six subconductors is used.

In case of AC lines, the equivalent radius of a bundle conductor is larger than the single conductor. Therefore, as compared with the single conductor.

— Inductive reactance is lesser — Capacitive reactance is higher
— LC product is the same.

In case of HVDC line conductors. The corona is dependent on the conductor voltage rather than the surface voltage gradient. The crest factor $\sqrt{2}$ is not applicable. For ± 500 kV HVDC lines in India, twin-bundle conductor is used.

To reduce corona losses and in the bundle conductors or hollow conductors are used. *The choice of configuration and cross-section of AC conductors with reference to corona considerations is generally above the economic cross-section based on thermal considerations or transient stability considerations.*

In other words, the design of AC conductors based on corona limitations gives a cross-section much larger than that with respect to economical power transfer limit (imposed by stability limit).

However with DC conductors, the conductor design based on corona can be optimised by suitable choice of transmission voltage as the question of the stability limit does not arise.

Conductor Material

Aluminium Conductor Steel Reinforced (ACSR) conductors are used universally for overhead transmission lines. The steel reinforcement gives high tensile strength. Aluminium gives higher conductivity with lower weight. Table 48.7 gives data about ACSR bundle conductors for AC transmission lines.

Table 48.7

Normal Voltage kV	*Highest Voltage kV*	*Phase Spacing m*	*Sub-conductor Diameter mm*	*No. of sub-conductors per phase*
230	245	6	25	1
345	365	8.3		2
500	550	11		3
765	800	15.3		4
1100	1200	20		8

Overhead Shielding Wire. The line conductors are protected from direct lightning strokes by overhead shielding wires. One or two overhead shielding conductors are attached on the topmost point on tower. The angle of protection with reference to vertical plane is 30° to 45°. The over-head shielding wire is usually of galvanised steel standed wire. Earthing is provided at each tower *via* flexible earthing conductor between the overhead shielding wire and tower-earth mat.

48.20. SWITCHING PHENOMENA ASSOCIATED WITH EHV-AC LINE SWITCHING

The circuit-breakers to be used for switching of EHV-AC lines should be capable of performing following duties :

1. Short-line fault duty (Sec. 3.16)
2. Switching unloaded lines (Sec. 3.14.2)
3. Phase opposition switching (Sec. 3.17)

Switching Overvoltages occurring during opening and closing transmission line breakers should be held within specified limits. The permissible *Switching overvoltage factors K* should be held within the following specified values by using pre-closing resistors with circuit-breakers and other means (Sec. 18.7).

Rated voltage, kV	245	525	750	1000
Permissible switching overvoltage factor K	3	2.5	2	1.7

48.21. AUDIBLE NOISE (AN)

Audible noise is generated by EHV-AC and HVDC transmission lines and sub-stations due to the following causes :

— Corona
— Humming of transformers
— Cooling systems and mechanical and electrical auxiliaries.

The design of transmission lines and sub-stations is governed by the limits of AN. The limits of audible noise are specified by some national standard specifications and the specifications of major utilities in terms of dB at a particular distance from the line sub-station, transformer.

EHV-AC and HVDC line generate audible noise, generally when the corona is present on the conductor during bad weather. The audible noise is in the frequency range from very low frequency to 15 kHz.

The design of lines and sub-stations is the basis of limit of audible noise. The reference values of the limits of audible noise are used on complaints from people working in the vicinity. These limits are given below :

No complaints	:	Below 52.5 dB
A few complaints	:	52.5 59 dB
Many complaints	:	Above 59 dB.

The width of *right-of-way* (ROW) for the line corridor has a reference to the decision about audible noise. *Line geometry is based upon 50 dB at the edge of ROW.*

The AN caused by a transmission line is a function of the following :

(*a*) Voltage gradient on surface of conductor.
(*b*) Number of sub-conductors in a bundle.
(*c*) Diameter of conductor.
(*d*) Atmospheric condition
(*e*) Lateral distance between the line and the point of measurement of noise.

The audible noise is caused by vibrations produced in the air due to change in the air pressure.

48.22. BIOLOGICAL EFFECT OF ELECTRIC FIELD AND LIMITING VALUE OF ELECTRIC FIELD STRENGTH.

The biological effect of electric field of EHV lines and EHV sub-stations has been studied extensively during 1970s.

EHV and UHV lines are designed such that maximum electrostatic field gradient is below 9 kV/m at mid-span under the line near ground level.

Safe line is ground clearance of 20 m at mid-span is recommended for 400 kV lines and 24 m for 1100 kV lines. This permits movement of vehicles safely.

48.23. RADIO INTERFERENCE AND TELEVISION INTERFERENCE

Operation of EHV-AC and HVDC transmission lines and transmission sub-stations can cause Radio Interference (RI). The lines and sub-stations should be so designed that the RI and TI shall be less than 40 dB and 1 m V/m at 1 MHz at the edge of ROW. (Refer Table 48.7).

Radio interference and television interference is caused by electromagnetic waves in the frequency range of broad cast frequencies

RI : 0.5 MHz — 1.6 MHz
TI : 54 MHz — 216 MHz

The line is designed such that the radio noise within the width of the line corridor should be below permissible limits (say 40 dB at 1 MHz).

Radio interference is more important factor in line design and in deciding right of way (ROW).

The main causes for RI are the following :

Table 48.8

		EH-AC	*HVDC*
1.	Corona	*	
2.	Partial discharges on insulators	*	
3.	Sparks across gaps	*	
4.	Pulses due to triggering of thyristors		*

The RI can be eliminated and/or minimised by appropriate design of line conductor and hardware.

The main source of RI in case of AC lines is corona discharge on the surface of conductors surface corona on insulators and sparking at conductor insulator hardware of lines and sub stations. For AC lines bundling of conductors reduces surface voltage stress corona and radio interference.

Corona rings are provided for conductor insulator assembly to reduce surface stress.

Table 48.9. RI limits in various countries

Countries	*Distance from outermost phase*	*R limit*	*Frequency*
USSR	100 m	40 dB	500 kHz
Switzerland	20 m	200 μ V/m	500 kHz
Poland	20 m	760 μ V/m	500 kHz

In case of DC line the space charge surrounds the conductor eliminating the advantage of bundling of conductors. Radio interference is normally not a decisive factor to choose a bundle conductor.

In case of HVDC transmission systems, the triggering of thyristors give high frequency harmonics in the range of 0.1 MHz to 10 MHz. The radio interference is reduced by

— Selection of a valley as the site for a sub-station.
— Screening of valve hall for electromagnetic radiation
— Installing ground wires on switchyard
— Limiting the height and the length of the conductors in the switchyard.
— Proper selection of insulators and hardware to prevent partial discharges.

48.24. RAPID-AUTO RECLOSING AND DELAYED AUTO-RECLOSING OF CIRCUIT BREAKERS

EHV-AC lines are provided with static distance protection incorporating *auto-reclosing* feature. (Sec. 44.20, 44.21).

Rapid-Auto Reclosing (Breaker reclosed within 20 cycles) — are used for transmission lines which are not strongly interconnected. The rapid autoreclosing helps in reclosing without synchronous check.

Delay auto-reclosing (5 to 60 sec.) is used for strongly interconnected system. Synchronous check is necessary before reclosing.

48.25. SURGE IMPEDANCE LOADING OF AC TRANSMISSION LINES

Surge impedance loading is defined as (SIL) the load at the receiving end which is equivalent to $\sqrt{(L/C)}$. The concept of surge impedance loading gives an approx. loading of transmission line. We can say, the loading of transmission line is 1 p.u. SIL or 1.5 p.u. SIL.

$$\text{Surge Impedance} = \sqrt{(L/C)},$$

where L = Inductance per km Henry

C = Capacitance per phase per km, Farads

1 p.u. SIL is called natural load (P_n).

When the line carries natural load $P = P_n$, the voltage along the entire length of line is the same.

When the line carries load above 1 P_n, the voltage at the middle of the line is higher.

Typical values of surge impedance of transmission lines are given in the table.

Rated voltage kV	132	230	400	765	1100
Natural load P_n, MW	40	125	500	1700	5000

Considering the voltage along the line (Fig. 45.15) short lines can be loaded to more than 1 P_n.

Medium lines can be loaded upto 1 P_n.

Long lines can be loaded to less than 1 P_n.

48.26. SUB-SYNCHRONOUS RESONANCE IN SERIES COMPENSATED AC LINES

Series capacitors are installed in series with long lines for providing compensation of reactive power and giving higher power transferability. (Sec. 45.14F).

Series compensated lines having capacitance C have a tendency to produce *series resonance at frequencies lower than power frequency. This is called sub-synchronous resonance.*

The sub-synchronous resonance currents produce mechanical resonance is turbogenerator shafts. The mechanical resonance causes following in the generator shafts :

— induction generator effect — torsional torques — transient torques

These problems have resulted in damage to rotor shafts of turbine generators. Sub-synchronous resonance causes failure of series capacitors.

Sub-synchronous resonance is, therefore analysed in the design of series compensated lines.

Let f_n = Normal (Synchronous) frequency

f_r = Sub-synchronous resonance frequency of series compensated line

$2\pi f_n L$ = Series inductive reactance of EHV line at normal frequency

$1/(2\pi f_n C)$ = Series capacitive reactance of series compensation at normal frequency.

$X_C/X_L = K$ = Degree of compensation

X = Equivalent reactance of compensated line

$X = X_L - X_C = X_L (1 - K)$

Let sub-synchronous resonance occur at frequency f_r. Then

$$2\pi f_r L = 1/(2\pi f_r C)$$

$$f_r^2 = \left(\frac{1}{2\pi L} \cdot \frac{1}{2\pi C}\right)$$

Dividing both sides by f_r^2

$$\left(\frac{f_r}{f_n}\right)^2 = \frac{1}{2\pi f_n L} \cdot \frac{1}{2\pi f_n C} = \frac{X_C}{X_L} = K$$

$$f_r = f_n \sqrt{K}$$

Thus sub-synchronous resonance occurs at frequency f_r, equal to normal frequency multiplied by square-root of degree of compensation.

Table 48.9 gives the resonance frequency f_r, for various degree of compensation for a 50 Hz series compensation.

Table 48.10

Degree of Compensation $K = \frac{X_C}{X_L}$	0.1	0.2	0.3	0.1	0.5	0.6
Sub-synchronous Resonance Frequency for 50 Hz system	15.8	22.4	27.4	31.6	35.36	38.7

A single series compensated line with 40 to 60% compensation can resonate at frequencies between 30 and 35 Hz for normal 50 Hz system.

The condition of sub-synchronous resonance can occur during the faults on the power system, during switching operations and changing system configurations.

Solution to Sub-synchronous Resonance Problem and Series Compensated lines.

Several methods are employed to overcome the problem. These include :

1. *Use of filters* for eliminating/damping the harmonics. The various filters include Static blocking filters, bypass damping filters, dynamic filters.
2. Bypassing the series capacitor bank under resonance condition.
3. Tripping of generator units under conditions of sub-synchronous resonance.

Section 48-B

48.27. STATIC VAR SYSTEM (SVS)

The static VAr systems (SVS), static VAr control (SVC) Utilize shunt reactors and shunt capacitor combination with high voltage high power thyristor control for achieving fast, accurate source of controlled reactive power (Q, kVAr). Ref. Sec. (45.20)

48.28. APPLICATIONS

SVS has several applications including the following :

1. **Normal voltage Regulation of transmission Systems.** Better stepless, fast accurate *voltage control* of sub-station buses over a wide range of loads by supplying reactive power.

2. **Dynamic Compensation of fluctuating reactive loads.** With arc furnaces, rolling mills etc. SVS are used for *rapid change* (a few cycles) *in reactive power compensation* in accordance with varying load. This reduces lamp flicker and voltage dips. The first application of SVS to reduce lamp flicker was introduced in 1973. Now SVS is commonly used in industrial distribution systems.

3. **Control of Over voltages in transmission systems arising due to load rejection.** When a large load is switched off due to any reason (frequency control/fault), the receiving bus voltage rises rapidly (few seconds) SVS provides rapid change in reactive power compensation (few cycles) and regulates the voltage.

4. Compensation of reactive power to HVDC sub-station AC buses for Reactive power required is about 60% of active power P, for stable operation of convertors.

5. Damping of sub-synchronous Resonance Frequency Oscillations in power systems.

6. Improving transient stability of power system by rapid voltage control. By controlling V_S and V_R and load angle δ. SVS helps in improving stability (indirectly).

Configuration of SVS. In conventional shunt compensation schemes shunt reactors in switched in during low loads and shunt capacitors are switched in during heavy loads or low lagging power factor loads (Sec. 45.14 C, D).

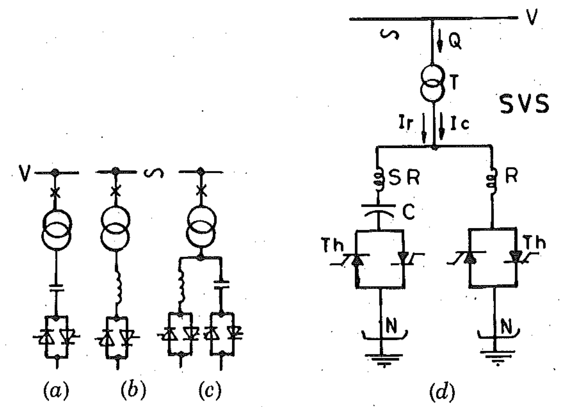
In SVS, the compensation is controlled by any of the following :

— Thyristor switched capacitors (TSC).

— Thyristor controlled reactors (TCR).

— Thyristor switched capacitors combined with thyristor controlled reactors (TSC/TCR).

Thyristor controlled capacitors (TSC). Fig. 48.4 (*a*) illustrates principle of thyristor switched capacitor. The principle of thyristor switch illustrated in Fig. 38.11, Sec. 38.7.6 is employed in switching of required number of capacitor units. The thyristors are used as power switching device. The capacitor banks are connected in shunt with the sub-station bus *via* the thyristor switches. During heavy loads the thyristor switch is switched on. Here, the thyristors are used as switching devices and the scheme is called *Thyristor Switched Capacitor (TSC).*



(*a*) Thyristor Switched Capacitors (TSC)
(*b*) Thyristor Controlled Reactor (TCR)
(c) Combined TSC/TCR. Total SVS
R = *Reactor*,
C = Capacitor,
S.R. = Smoothing Reactors
T = Transformer.

Fig. 48.4. Static VAR sources.

Thyristor Controlled Reactor (TCR). Fig. 48.4(*b*) illustrates the TCR. In this scheme the duration of the current flowing through reactor during every cycle is controlled by controlling phase angle of thyristor gate pulses.

For every half cycle, the thyristor is given a triggering pulse by the control circuit. The TCR scheme is used for EHV lines are providing lagging, kVr during low loads or load throw-off.

Combined TSC/TCR (Fig. 48.4 *c*) **SVS.** In case of EHV-transmission systems, the compensation requirements demand shunt capacitors during high loads and shunt reactors during low loads. Depending upon the desired control range of reactive power compensation required, thyristor-controlled compensation (Static VAR Source-SVS) is built up using a suitable combination of Thyristor Switched Capacitors (TSC) and Thyristor Controlled Reactor (TCR), SVS (Fig. 48.4 *d*) is used for voltage control of transmission system buses.

The *Power Transformer* (T) interface is used for stepping down bus-voltage (from 420 kV or 245 kV to practical voltage levels such as 36 kV) for economic design of SVS.

Thyristors (Th) connected in series with Reactor R phase controlled (control of phase angle of triggering pulses) to allow continuous adjustment of inductive current (Lagging Q) Refer Fig. 48.5.

As per convention Q absorbed by inductive loads is considered positive (Sec. 45.15). Hence by increasing the current conduction through reactor R, the operating point A is shifted towards right from C to D. The capacitor C are either by switching discrete capacitor groups or fixed depending upon the system requirements.

Automatic Voltage Regulator (AVR) for SVS is programmed to regulate transmission bus voltage with pre-selected tolerances and time delays.

As the transmission voltage varies with load, the AVr preforms the function of controlling current flowing through the reactor R during each half cycle *via* the thyristor (*Th*). Smoothing Reactor (SR) provides a smoothing effect for current flowing through capacitor branches.

Filters. Harmonic filters are necessary with each SVS to eliminate harmonics from AC bus voltage.

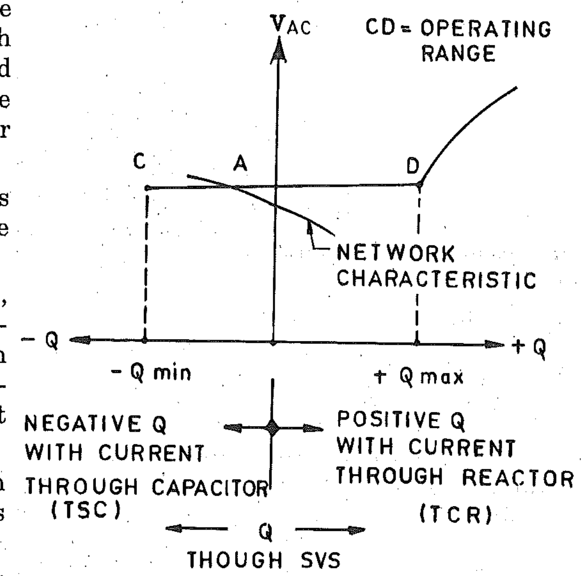


Fig. 48.5. Static characteristic of a SVS system. (Point A moves along CD with variation of Q of SVS)

Speed. An important advantage of SVS is its speed. SVS controls the voltage by varying reactive current drawn by the combination of capacitors are reactors. SVS can respond to system voltage variation automatically within a few cycles. As a result lamp flicker due to load variations is reduced in case of distribution systems.

Also it provides dynamic voltage control to sub-stations buses and improves system stability.

Steady Characteristic of SVS. Fig. 48.5 illustrates the Voltage V/Reactive power Q steady State characteristic of sub-station bus as affected by the reactive power compensation Q by SVS.

The operating range is represented by segment CD. Operating point A moves towards left (negative Q) with increasing current in capacitors C. Operating point A moves towards right (positive Q) by increasing current through reactor R.

Operating point A is decided by intersection of network characteristic (dashed) with line CD.

Control System for SVS. The amount of sophistication required for control system of SVS depends on application.

The basic requirements of the control include :

(*i*) Voltage control (*ii*) VAr flow control

Refer Fig. 48.16. The busbar voltage (V) and current flowing into compensator (I) are both sensed by means of VT and CT. Both these values are fed to the automatic voltage regulator (AVR)

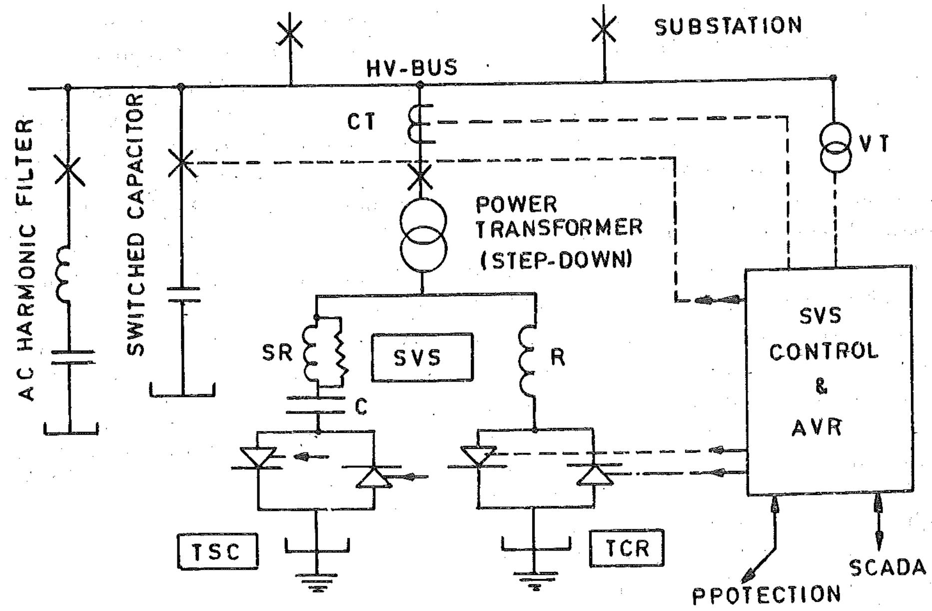


Fig. 48.6. SVS system – Schematic diagram of an SVS system and centre.

and automatic VAr compensator. The Automatic Voltage Regulator and Automatic VAr compensator performs the following tasks :

— Sends command to switched capacitor banks for voltage control.

— Controls phase angle of triggering of thyristor in SVS.

SVS control is integrated with sub-station protection and SCADA system.

Harmonic Filters. Operation of thyristor causes generation of harmonic frequencies on AC bus side. The harmonic tuned filters appropriate frequencies (*e.g.* 11th, 13th, 23rd) are connected in shunt with the AC bus. The requirements of filter is matched with the prevailing system condition. (Refer Fig. 48.7).

An Example of SVs Scheme. (*Courtesy* : Westinghouse, USA).

Fig. 48.7 gives a single line diagram of SVS scheme for 245 kV sub-station bus at Langdon (USA).

The ± 250 MVAr rated, SVA system was installed to regulate 245 kV bus voltage and to improve stability limit of transmission.

The 12-pulse thyristor switched capacitor (TSC), thyristor controlled reactor (TCR) type system, selected for fast response, low average operating losses and very low harmonic content. SVS can provide ± 302.5 MVAr output continuously at 1.1 PU line voltage and upto 496 MVAr absorption on overload at 1.17 PU line voltage for 10 minutes.

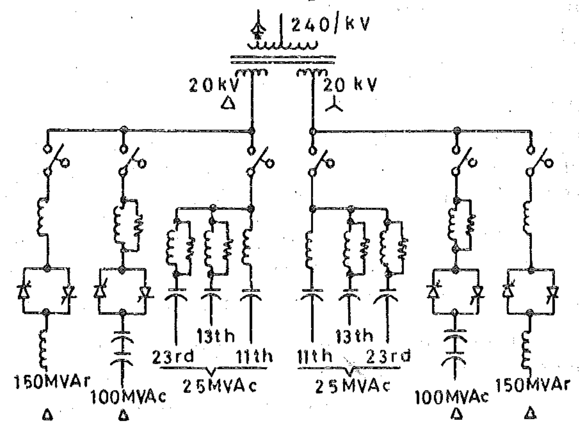


Fig. 48.7. A practical SVS scheme for 220 V sub-station.

The SVC control is of recent design utilizing advanced analogue and microprocessor techniques to provide optimum performance for all system conditions. The control techniques used had been tested prior to final equipment design with the model of the TNA (Transient Network Analyser).

Thyristor valves

Two types of thyristor valves are used in the SVC at Langdon, six of each type to control the current in the main reactors and in the capacitor banks respectively. The single-phase thyristor valve, rated nominally at 20 kV, are constructed of individual, self-contained, bi-directional thyristor switch modules connected in series.

Each module contains one reverse parallel pair of thyristors between liquid called copper heat sinks with their associated firing circuits and snubber components. These modules are supported on a "deck" structure accommodating upto 12 interconnected modules, the associated piping for the coolant and the conductor bus elements.

The TCR valves for the control of reactor currents contain two decks of 12 thyristor modules each per phase (24 in series). The TSC valves for switching capacitor current contains four decks of 10 thyristor modules each per phase (40 in series).

Gating control signals are transmitted to the valves from the SVC control via fibre optic cables. Fibre optics are used also for the transmission of the thyristor failure indication to the remote thyristor status scanner at the SVC control.

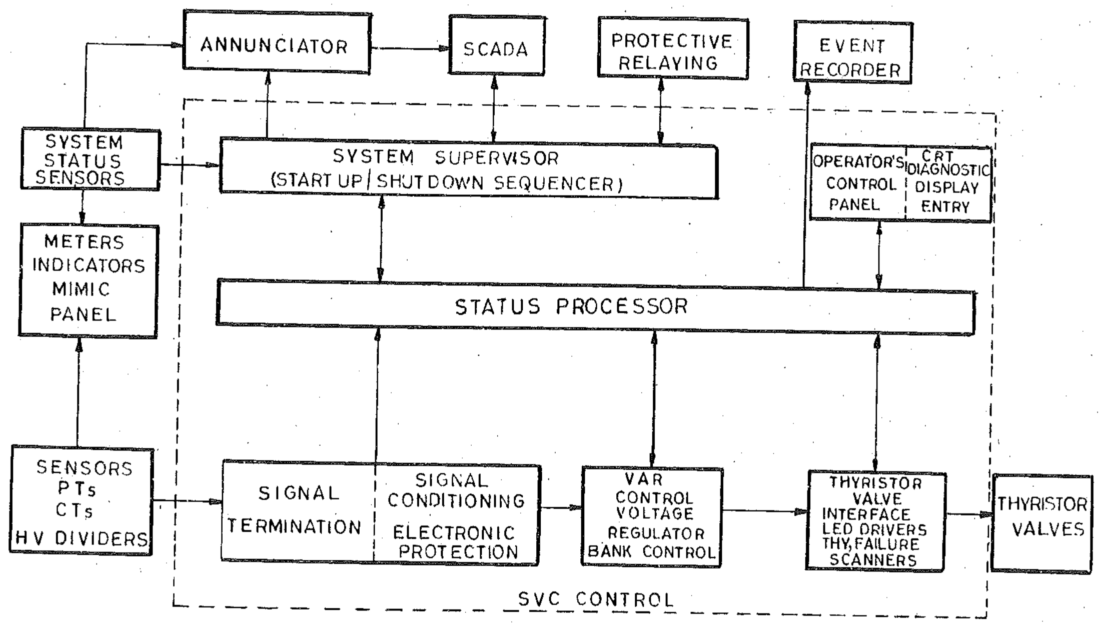


Fig. 48.8. Control system for SVS system shown in Fig.

The gate firing circuits of each thyristor are powered from energy derived locally at each thyristor module. The firing circuit is able to provide continuous gate drive to the thyristor. Overvoltage protection for the thyrsitors at the module level is provided by the individual emergency triggering circuit. The emergency triggering circuit normally operates at a "high" voltage level that is switched to a "low" level if repeated operations are called for without normal gate fire pulses (*e.g.* signal or gate firing circuit failure).

Controls. The major functional blocks in the control of SVS are illustrated in Fig. 48.8. The SVS control receives signals from CTs , VTs, HV voltage dividers. The control is arranged for :

(*i*) line voltage control (*ii*) VAr control

This is achieved by controlling phase angle of thyristor valves of thyristor switched capacitors (TSC) and thyristor controlled Reactor (TCR). In addition to the above usual controls of SVC, the SVS control has interface with the following :

(*i*) SCADA system (*ii*) Protective relaying

(*iii*) System status processor

The total control system incorporates a status processor and cathode ray tube (CRT) display/data entry terminal in the control system.

The primary functions of the status processor are the monitoring of the control circuits in operation for any alarm or trip conditions and the execution of control commands and adjustments of operating parameters by the operator.

The status processor also includes diagnostic software routines accessible by maintenance personnel *via* the CRT terminal on the SVC control panel aid trouble shooting and system checkout. A detailed status history is also maintained by the status processor which can be displayed on the CRT terminal.

This capability has provided to the extremely useful and a flexible tool in diagnosing control and thyristor valve related problems.

49

Interconnected Power Systems

Introduction — System configuration and Principle of Interconnection — Merits — Limitations — Tie-line Power — Obligation of Participating System — Relative priority — Correlation between Real Power Generation, Tie-line Power Flow and Load Frequency Control — Control of Tie-line Power in 2 Area System and 3 Area System — Scheduled Interchange and Actual Interchange — Tie-line Bias Control — Basic Equations — Actions by operators — Phase shifting Transformers — SCADA Systems — National Grid of India.

49.1. INTRODUCTION

During the early years small local generating stations supplied power to respective local loads. Each generating station needed enough installed capacity to feed the local peak loads. Gradually, the merits of interconnected AC power systems were recognised.

The interconnection of individually controlled AC networks gives several advantages such as :

— Lesser spinning reserves
— Lesser installed capacity
— Better use of energy reserves
— Economic generation
— Minimise operational costs, maximise efficiency
— Better service to consumers.

Modern power system (Network) is formed by interconnecting several individually controlled AC networks. Each individually controlled AC network has its own generating stations, transmission and distribution systems, loads and a load control centre. The regional load control centre controls the generation and in its geographical region to maintain the system frequency within targeted limits (50.5 – 49.5 Hz). The exchange of power (Import/Export) between neighbouring AC networks is dictated by the National Load Control Centre. Thus the entire AC network is an interconnected network called National Grid. Even neighbouring National Grids are interconnected to form a Super Grids. (*e.g.* USA Canada; European Grid ; UK-France). Interconnections between India-Pakistan, India-Shri Lanka, India-Nepal etc. are in initial planning stage (1997).

The main task of an interconnecting transmission system is to transfer adequate power from one AC system to the other AC system during normal conditions and also during emergency condition and maintain system security. Traditionally AC lines have been used for interconnection. However, HVDC links give asynchronous interconnection and have a distinct superiority over AC links for the application of system interconnection. HVDC system interconnection may have a transmission line/cable or it may be in the form of a back-to-back convertor station without a transmission line. HVDC links are also used for interconnection between AC systems having different frequencies *e.g.* 50 Hz to 60 Hz. The choice of voltage of EHV-AC or HVDC Inter-connection link is decided by the economic studies related with power transfer and distance.

Present HVDC interconnections are with two terminals. Recently multi-terminal HVDC systems have been executed (1987). With multi-terminal HVDC systems, several AC systems can be interconnected. Back-to-back HVDC stations are preferred for interconnecting adjucent AC systems to provide Asynchronous tie.

Inter-connection has significant influence on load-frequency control, short-circuit levels, power system security and stability, power system protection and control, energy management, financial accounting etc.

Energy management EM has received due attention during recent years and the Interconnections have received greater importance.

49.2. SYSTEM CONFIGURATION AND PRINCIPLE OF INTERCONNECTION

Fig. 49.1 gives a schematic diagram of a Group of Interconnected Power Systems (called National Grid in Indian Context).

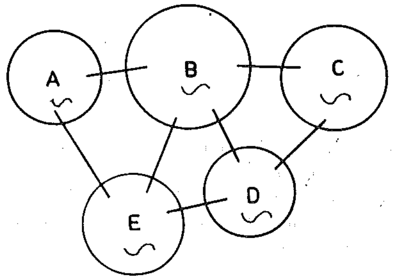


Fig. 49.1. Interconnected Power systems.

A, B, C, D, E are interconnected by Tie Lines. Each Area has its individual load-frequency controls which controls the total generation of the Area to match the load, losses and the net interchange. The generation control is by AGC (Automatic Generation Control System). Total control of

Each individual AC system (A, B, C) etc. called Regional Grid has its own Regional load control centre for its Automatic Generation Control (AGC) such that the load-frequency is controlled and frequency is maintained within target limits.

49.2.1. Individual System (Region or Area).

Each individual system generates enough power equal to the Regional load plus losses, plus required net interchange with adjacent systems *via* the tie-lines (interconnectors).

Total Generation = Total area load+Total net interchange by area

$$P_{GA} = \Sigma P_{LA} + \Sigma P_{iA} \qquad ...(49.1)$$

where P_{GA} = Total Generation of Area A, MW

ΣP_{LA} = Total load on Area A, including losses, MW

ΣP_{iA} = Total net interchange by Area A, MW

By maintaining the balance between RHS and LHS in Eqn. 49.1; the frequency of area A is maintained within targetted limits. This condition is fulfilled by *Automatic Generation Control* (AGC) performed by the Regional Load Control Centre (of area A). Thus each area has to fulfil the following obligation :

Total generation = Total load plus losses + Net interchange

$$\left.\begin{aligned} \Sigma P_{GA} &= \Sigma P_{LA} + \Sigma P_{iA} \\ \Sigma P_{GB} &= \Sigma P_{LB} + \Sigma P_{iB} \\ \Sigma P_{GC} &= \Sigma P_{LC} + \Sigma P_{iC} \\ &\ldots \quad \ldots \quad \ldots \\ \Sigma P_{GN} &= \Sigma P_{LN} + \Sigma P_{iN} \end{aligned}\right\} \qquad ...(49.2)$$

where ΣP_{NG} = Total Generation of N_{th} Area

ΣP_{LN} = Total load plus losses of N_{th} Area MW

ΣP_{iN} = Total net interchange by N_{th} Area.

49.2.2. Total Generation in Interconnected Systems (National Grid)

Total Generation of the Group of Interconnected systems (called the National Grid) is equal to **the total load plus total losses**, the algebraic sum of net interchanges becomes zero *i.e.*

$$\Sigma\text{Imports} = \Sigma\text{Exports}$$

$$\Sigma P_G = \Sigma P_L + \Sigma P_i \qquad ...(49.3)$$

$$\Sigma P_G = \Sigma P_L, \ \Sigma P_i = 0 \qquad ...(49.4)$$

where ΣP_G = Total generation of all areas in the National Grid, MW

ΣP_L = Total load of all Areas, plus total losses in all Areas, MW

ΣP_i = Total algebraic sum of net interchanges of all Areas.

Note : Total net interchange (ΣP_i) in the Grid is the algebraic sum of interchange by all individual Area *i.e.*

$$\Sigma P_i = \Sigma P_{iA} + \Sigma P_{iB} + \ldots + \Sigma P_{iN}$$

$$\Sigma P_i = 0 \qquad ...(49.5)$$

The algebraic sum of interchange of all areas is zero.

This has been explained in Sec. 49.9.

For stable frequency.

$$\Sigma P_G = \Sigma P_L.$$

$$\Sigma P_s = \Sigma P_L$$

This condition is fulfilled by the control by National Load Despatch Centre. National Load Control Centre Instructs Regional Load Control Centres to export/import scheduled power so as to satisfy Eqn. 49.5.

If total Generation in Grid is lesser than total load on the Grid, the frequency of entire grid starts falling. Fall of frequency causes increase power inflow from neighbouring region.

If total Generation is more than total load, frequency starts rising.

National load control centre determines the total generation requirement and allocates the amount of generation to each Area for fulfilling the requirements of interchange.

Load-frequency control is automatic. The generation in each Area is made equal to the load plus net tie-line exchange so as to maintain the frequency within the targetted limits.

This is achieved by two actions :

1. Primary load frequency control : by Governor action of each turbine generator.

2. Secondary control : by enough interchange of power between Regional Grids as per instructions of Load Control Centre.

49.3. MERITS OF INTERCONNECTED POWER SYSTEM

Interconnections offer several advantages subject to the conditions mentioned in Sec. 49.5. Limitations of Interconnections have been mentioned in Sec. 49.6. Due to tremendous advantages, Interconnections have been accepted universally by various National Networks and also between neighbouring National Networks (*i.e.* between USA and Canada ; between England and France ; several Nations in Europe ; Sweden/Denmark etc.).

Main advantages include the following :

1. **Reduced Overall Installed Capacity.** Interconnected Power Systems reduce the overall requirement of installed capacity.

Peak loads in individual areas occur during different clock-times of the day depending upon the working hours and daily load cycles and sleeping habits in that geographical area/city.

Installed capacity of the power system should be adequate to meet the peak demand of consumers.

With interconnection between adjucent power systems, peak demand in an area is met by importing power from neighbouring area. Thus the installed capacity of each Area can be selected to meet the average demand. This results in tremendous reduction in overall installed capacity and reduction in investment and yet better fulfilment of peak demand.

2. **Better utilization of Hydro Power.** During rainy season, the hydro stations are loaded fully and thermal stations lightly. The flow rate of rivers and water reservoirs fluctuates with rains. Wastage of water during rainy season can be avoided by interconnection between hydro and thermal plants. During summer, the hydro power can be minimised and thermal power enhanced. *Interconnection enables useful Hydro-thermal co-ordination.*

3. **Better utilization of Energy Reserves.** By better coordination between hydro, thermal, nuclear and other energy sources, *the energy conservation can be planned for optimum utilization.* This has long term benefits for the nation. Modern interconnected systems have total automatic EMS (Energy Management System).

4. **Reduction in operating costs and better efficiency.** Different plants have different operating costs, efficiencies. By interconnections, economic loading can be achieved and overall efficiency enhanced. *Energy can thereby be supplied to consumers at lowest cost.*

5. **Higher Unit Size Possible.** Generating units of higher unit capacity (200 MW, 500 MW etc.) can be installed and operated economically.

6. **Higher System Security.** The overriding factor in the operation of power system is to maintain System Security. The simple definition of power system security is as follows :

System Security is defined as the ability of the power system to continue to supply power through alternative transmission path in the event of a fault in a line or a generating unit.

Interconnections contribute to higher system security. In isolated power system, a fault in a generating station results in black out in the local region.

In interconnected system, the power is imported from adjucent area so as to continue to supply power to the consumers. This increases security of power supply.

7. **Improved Quality of Voltage and Frequency.** By interconnection, the frequency can be easily held within targetted limits by appropriate generation control and interchange. Isolated systems have higher frequency fluctuations with change in load cycle. *With more interconnections, the system becomes stronger and influence of load fluctuations is reduced.*

49.4. LIMITATIONS OF INTERCONNECTED POWER SYSTEMS

— Interconnection assumes that some areas have surplus generation/installed capacity/spinning reserves. *This does not apply to many developing countries where load growth is more rapid than the growth of installed capacity.* In absence of surplus power, the merits of interconnection cannot be accrued.

— With synchronous tie, the frequency disturbance of one area are transferred to adjacent areas, resulting in overall disturbance.

— Cascade trippings and overall black-outs occur in large interconnected systems.

— Each Regional Load Control Centre should fulfil its obligations and cooperate with the Master Load Control Centre. This may not occur if each Regional Load Control Centre seeks greater autonomy.

— Larger interconnections require more investments for Load control centres and automatic control.

— Technical problems of larger interconnected systems regarding planning, operations and control etc. are more complex.

— Large interconnections require more automation. Reliability and security of each system should be high.

49.5. OBLIGATIONS OF EACH INTERCONNECTED SYSTEMS

While deriving benefits of interconnections, each participant power system has to fulfil its obligations inluding :

— Each Area should have its load control centre with sufficiently advanced Automatic Generation Control, load-frequency control, reliable protection system etc.

— Each area should plan its installed capacity and should maintain adequate spinning reserves.

— Each area should have efficient voltage control and reactive power compensation to ensure voltage stability.

— Each Area should cooperate with National Load Control Centre with regard to interchange of power as per the instructions of National Load Control Centre. The levels should be respected.

— Control principles and requirements of parallel operations, overall load frequency control, steady state/emergency and post emergency stability should be maintained.

— Each Region should have a strong system analysis group and system operation group with trained man power.

49.6. OBJECTIVES OF AUTOMATIC GENERATION CONTROL AND TIE-LINE POWER FLOW CONTROL

Automatic Generation Control (AGC) and automatic control of Tie-line power Flow are essential for smooth and effective operation of Interconnected Power Systems. A multiple area interconnection has several Areas and several tie-lines. The main objectives of the AGC are the following :

Objective 1. Total generation in the entire interconnected system should be matched at continuously with total prevailing consumer demand plus losses. This objective is achieved by AGC primary and Secondary Load Frequency Control (Sec. 45.3 and 45.4).

$$\Sigma P_{GN} = \Sigma P_{LN} \qquad \text{...(49.6)}$$

ΣP_{GN} = Total generation of all the generating stations in the Network at an instant of time.

ΣP_{LN} = Total load plus losses in entire Network at that time.

G = Generation, L = Load, N = Number of Areas

— Inertia and favourable characteristics of large rotating machines provide self-regulating forces to satisfy Eqn. 49.6 during momentary load fluctuations (Sec. 45.2).

— The action of turbine governor (Primary frequency control adjusts the speed of each turbine-generator unit to prevailing synchronous speed (Sec. 45.3).

— The setting of turbine governor is determined on the basis of the prevailing requirement of generation. The requirement is allocated by Load Control Centre/Control Room. (Secondary frequency Control Sec. 45.4).

Refer Sec. 44.5 — Load frequency control of a Grid.

Objective 2. Total generation of the interconnected system should be allocated among the participant Areas is accordance with the requirements of load in each area and the scheduled interchange *i.e.*

$$\begin{aligned}\Sigma P_{GN} &= \Sigma P_{GA} + \Sigma P_{GB} + \ldots \Sigma P_{GN}' \\ &+ \Sigma P_{iA} + \Sigma P_{iB} + \ldots \Sigma P_{iN}' \\ &+ \Sigma P_{LA} + \Sigma P_{LB} + \ldots \Sigma P_{LN}'\end{aligned}$$

— This applies to Multi-Area Interconnected System.

— Each area has allocated generation.

— This allocation is done by National Load Control Centre.

— The implementation of Generation in the Area is the responsibility of Regional Load Control Centre.

— The scheduled tie-line exchange is decided by National Load Control Centre.

Objective 3. Each Area generates allocated power. The Regional Load Control Centre of that Area allocates the total area generation among various generating stations in accordance with the following :

— Principles of economic load despatch — Primary frequency control by governor action

— Secondary frequency control in accordance with allocation by the National Load Control Centre.

Relative Priority Between Frequency Control and Economic Loading

Electrical energy cannot be stored in large quantities. The load varies, the total generation should be matched with total load so that service to customer at specified frequency is continued. This objective (1) is given higher priority than priority for economic loading of individual generating stations objective (3).

Therefore, priority is given in order of objectives 1, 2, 3. Thus in the automatic generation control, the load frequency control is given higher priority over the economic load despatch.

49.7. OVERALL OBJECTIVE AND CO-RELATION BETWEEN REAL POWER AND REACTIVE POWER CONTROL AND TIE-LINE POWER FLOW

The overall objective of the Power supply company is to supply required electrical power to all the consumers at all times at

— Specified frequency — Specified voltage

This ideal objective is not possible to be achieved in practice because

— Load changes continuously resulting in continuous change in Real Power Flow (P) and Reactive Power Flow (Q).

— With change in load (Real Power P). The frequency tends to change.

— With change in load (P) reactive drop (IX) changes thereby the voltages of buses change.

— With increase in generation, the net interchange from an area increases.

(*a*) **Real Power** (P). The total generation of electrical power should match with total load and the mismatch between the prevailing generation is judged by the measurement of prevailing frequency (f) and rate of change of frequency (df/dt). Sec. (45.11).

(*b*) **Reactive Power** (Q). The change in real power flow causes change in flow of reactive power through lines, transformers and generators etc. change in Q causes change in voltages of buses (Ref. Sec. 45.16).

System governing deals with total generation with total load by joint action of the following :

— National load control centre

— Regional load control centre

— Control Rooms in power stations

Section 46.22 gives further details about function of each :

(A) **Load frequency Control.** When the system load changes, corresponding changes are brought about in generation in following steps.

Increased System load. Increase in load, ΣP_G increased.

— Stored energy, decreases

— Decrease in the spinning energy in the rotating machines decrease of system speed or frequency.

— Frequency (f) : Decreases

Change in effective load. The drop in frequency brings about drop in effective load, because of frequency bias K (Refer Sec. 45.2). The factor K called system frequency Bias (or coefficient) in the amount of power generation required to change the frequency by one cycle.

This factor co-relates the rates real power P (in MW) with frequency f (Ref. Sec. 46.3).

Change in Generation (increase). The change in frequency brings about governor action (primary frequency control) and increases (Sec. 45.3) the input to generator-turbines and increase in generator outputs.

This results in :

— Change in generation of area : Increase

— Consequent change in frequency : Increase

Fig. 49.2(*a*) illustrates the above steps for increased load. Fig. 49.2(*b*) illustrates the steps for decreased load.

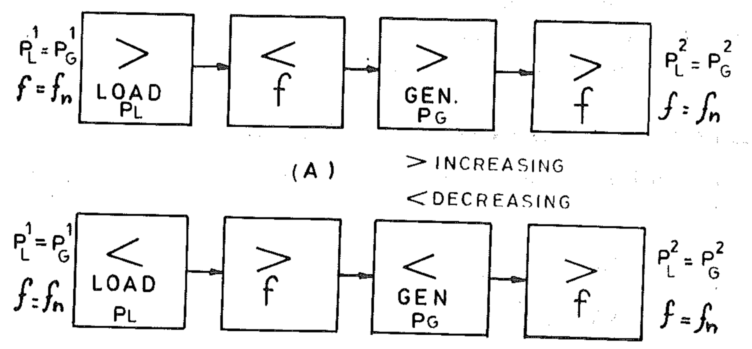


Fig. 49.2. Sequence of actions in Automatic Generation Control (AGC) and Load frequency control.

(A) Increasing load (B) Decreasing load

P_L = Load f = Frequency P_G = Generation > Increase < Decrease

P_L^1, P_G^1 = Initial condition P_L^2, P_G^2 = New condition

(B) **Voltage Control.** The change in load brings about change in IX drop in transmission lines, power transformers, generators, rotating machines, etc. Whereas real power follows the equation :

$$\Sigma P_G = \Sigma P_L \,;$$

the voltage is controlled by reactive power flow (VAr flow) and the control is achieved by following :

— Generator excitater control, AVR control

— Shunt reactor or static VAR sources at substation buses

— Shunt capacitors near loads and receiving substations.

Further details have been given in Sec. 45.14.

(C) **Control of Tie-line Power Flow.** The overall generation is matched with overall load.

The generation gets allocated between the various generating units in proportion to the inputs to their turbines. Total system generation of all the areas in the interconnected system is equal to total load on the entire system.

$$\Sigma P_{GN} = \Sigma P_{LN} + \Sigma P_{iN}$$

Since

$$\Sigma P_{iN} = 0$$

$$\Sigma P_{GN} = \Sigma P_{LN}$$

where LHS for generation on RHS for loads and losses.

The net algebraic sum of power interchange of all the interconnected systems is zero. But interchange through individual tie-lines is not zero.

Power transfer through tie-lines depends on the sharing of generation and load by Areas and the basic equation of power flow through a tie-line (Eqn. 44.1)

$$P_{AB} = \frac{V_A \cdot V_B}{X} \sin \delta$$

where δ = Power angle

X = Reactance of Interconnector

V_A, V_B = Voltages magnitudes at sending and receiving end.

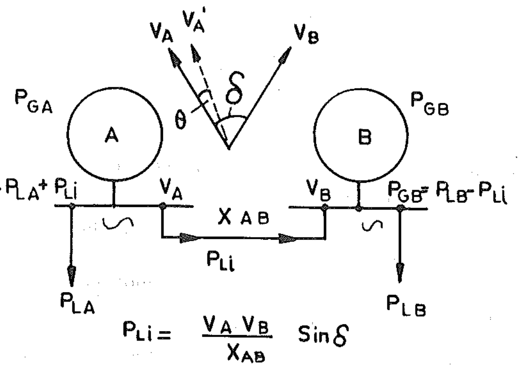
Details of tie-line power flow control is described in the following sections.

Following means are available for controlling the power flow through the tie-lines.

— Increase in generation by area which is exporting power and reduction by generation by Area which imports power.
— Use of phase shifting transformer
— Line Switching.
— HVDC interconnection, long distance
— HVDC Back-to-Back interconnection
— Flexible AC Transmission line

49.8. TIE-LINE POWER FLOW CONTROL IN 2-AREA SYSTEM

Fig. 49.3 co-relates Fig. 44.1(*a*) with Fig. 45.1 with respect to control of power flow through tie-line *AB*.



P_{GA}, P_{GB} = Generation in area *A*, *B*
P_{LA}, P_{LB} = Area loads plus losses in *A*, *B*
P_{Li} = Tie-line power flow between *A*, *B*

Fig. 49.3. Tie-line power flow control in 2-area system.

Area *A* generates P_{GA} and feeds local load P_{LA}

$$P_{GA} = P_{LA} + P_{iAB} \quad ...(49.7)$$

P_{GA} = Generation of Area *A*

P_{LA} = Load of Area *A*

P_{iAB} = Tie-line power flow between area *A*, *B*.

In 2-Area system, Tie-line power flow from station *A* is equal to the algebraic difference between the Generation and load of Area *A*.

$$P_{GA} + P_{GB} = P_{LA} + P_{LB} + P_{LI}$$

As generation of station *A* is increased, the voltage vector advances such that angle δ increases. This results in increased power flow through the tie-line (P_{iAB}).

Eqn. 49.11 is satisfied by Primary load-frequency control (Governor Action) in station *A* and station *B*.

The Eqn. 49.8 and 49.9 are satisfied by action of load control centre which instructs control room of station *A* to generate P_{GA} and station *B* to generate P_{GB} such that exchange P_{iAB} takes place.

Thus, the phase shifting transformer is not essential for achieving power flow through the interconnector AB between two areas A and B in case of a 2-Area System.

49.9. TIE-LINE POWER FLOW IN 3-AREA SYSTEM

Refer Fig. 49.4. The net power outflow or inflow of *Nth* area is decided by the equation

$$P_{GN} = P_{LN} \pm P_{iN}$$

If load of area *N* is more than generation of area *N*, there will be *inflow* of power in Area *N*, *i.e.* Area *N* imports.

If generation of Area *N* is more than load of area *N*, area *N* exports power.

Assuming total generation of all the areas is equal to total load of all areas by action of load-frequency control, the *power flow through tie-lines is decided by the difference between load and generation and also paths available for power flow between areas.*

Actual net interchange of all areas is zero.

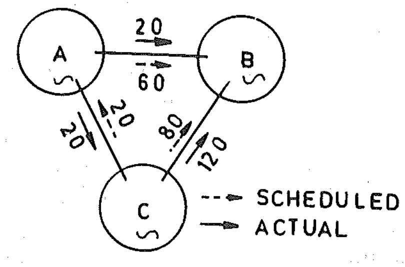


Fig. 49.4. 3-Area interconnected systems [Algebraic sum of net interchange

Consider area *A* exporting P_{GA}. This will flow through all the tie-lines emanating from *A*.

$$P_{iA} = \pm P_{i1} \pm P_{i2} + P_{i3} \quad ...(49.12)$$

The net interchange by area *A* is given by

$$P_{GA} - P_{LA} = P_{iA} \quad ...(49.13)$$

P_{GA} = Generation of area A

P_{AL} = Load on Area A

P_{iA} = Net interchange from area A

The magnitudes and directions of power flow through tie-lines from *A i.e.*, Pi_1, Pi_2, Pi_3 etc. is determined by basic circuit equations, following Ohms law.

From area *A*, power may flow to area *B* entirely through tie-line *AB* or partly through tie-line *AB* and through tie-lines *BC* and *CD*. Thus it may be noted that the net interchange of all areas is zero. *The paths of interchange of power are decided by circuit conditions and cannot be exactly matched. There occurs a difference between scheduled tie-line flow and Actual tie-line flow.*

From this analysis, it is clear that the total net interchange of all areas in a system is zero. The actual interchange between Areas *via* the Tie-lines differs from scheduled values. The total generation in entire system is equal to total load in entire system. This basic principle is applicable to multi-area interconnected system.

For increasing power flow through tie-line *AB*, the direction of power flow is decided by export/import conditions in areas *A* and *B*. If area *A* has to export, it should increase its generation over its load. Simultaneously area *B* should reduce its generation between its load. Thereby power with flow naturally from area *A* to area *B*.

The phase angle of voltage vectors V_A and V_B will follow Eqn. 49.6 such that angle δ gets adjusted to new value corresponding to P_{AB}. This is the basic principle behind power flow through tie-lines.

49.10. Alternative Principles of Control and the Tie-line Bias Control

(Ref. Sec. 45.11 and Sec. 46.23).

Various types of control principles have been developed for achieving effective area regulation of interconnected power systems consider the following two alternatives :

1. In one control principle, one area is assigned the task of controlling the system frequency while the other areas are assigned with the task of holding the tie-line power flow at fixed levels. This principle is used in interconnection between a very large Area with a very small Area.

2. In another control principle, one area is assigned the task of controlling system frequency while the other areas are asked to vary the tie-line power in accordance with the system frequency.

Both the above principles had limitations in Multi-Area systems and resulted in improper distribution of regulation requirements and inter-area oscillations of power flow. The above principles are however used in certain specific cases.

The above principles may still be used for two-area system such as interconnection between a large system and a small system. The large system controls the frequency and the smaller system controls the tie-line power flow within assigned limits.

With possibility of HVDC tie-lines and HVDC back-to-back coupling stations the above limitations may be overcome further.

According to the universally adopted control principle for large interconnected system, each participant area regulates its net tie-line power flow so as to regulate its own frequency such that the net tie-line power flow (net interchange) may depart from scheduled interchange within predetermined limits. With this principle, there is a difference between scheduled tie-line flow and actual tie-line flow ; scheduled interchange and actual net interchange as described in Fig. 49.4, Tables *A, B*. With this control principle, the following control tasks can be achieved.

1. Under normal operating conditions each area is able to execute its control tasks. Load changes in the area are absorbed by the same area. Tie-line power flow is maintained near scheduled level within predetermined departure from scheduled flow.

The control of system frequency should be all the areas and normal frequency is maintained.

2. Under abnormal or emergency condition, one or two Areas may be in trouble and may not be able to fulfil their control task. The area continues to remain interconnected and in synchronism. Under such conditions, the Emergency Control Mode takes over. All the other Areas automatically assist the area in trouble.

The Tie-line power flows are readjusted in magnitude and direction such that the assistance is provided to the Area in trouble.

Such an automatic control of interconnected systems is called *Tie-line Bias Control.*

In the Tie-line Basic control each area controls its own generation to match its load and the required net tie-line interchange. The power flow through each tie-line is adjusted to required scheduled level with permissible departure limits. As each Area controls the frequency, the task of controlling system frequency is shared by all the areas.

Principle of Tie-line Bias Control

— Each area generates power equal to its own load plus or minus net interchange so as to maintain frequency.
— Actual tie line flow departs from scheduled tie-line flow within certain limits.
— System frequency remains within target limits.
— Algebraic sum of net interchange of all areas is zero.
— Algebraic sum of total generation is equal to algebraic sum of total load plus total losses of all areas in the interconnected system.

49.11. EQUATIONS OF TIE-LINE POWER FLOW CONTROL REVIEWED

Refer Sec. 45.11, Sec. 46.23.

Let f = System frequency, Hz.
P_i = Actual tie-line power, MW
P_{io} = Scheduled tie-line power flow, MW
ΔP = Deviation in P_i, MW
f_o = Target frequency
K = System frequency bias MW/Hz
e = Area requirement correction MW
Δf = System frequency deviation
ΔP = Net deviation of power exchange through tie-lines, MW
$K\Delta f$ = Power change required to achieve target frequency.

Consider the power generation in an area (Region). The task of the power system network controller in the load control centre is to maintain the power exchange through the tie-lines with neighbouring regions at the desired values, and simultaneously to control the system frequency f.

The network controller compares the action sum of Tie-line power P_i with scheduled sum of Tie-line power P_{io} to calculate the deviation ΔP.

$$\Delta P = \sum_{1}^{n} (P_i - P_{io})$$

where ΔP = Deviation of actual power transfer through tie-lines from targeted values.
1, 2, ... n = No. of Tie-lines with neighbouring regions
P_i = Tie-line Power Flow, MW
P_{io} = Scheduled Tie-line Power Flow, MW

Thus
$$\Delta P = \sum_{1}^{n} (P_i - P_{io})$$

gives total deviation of power exchange with interconnected areas from the scheduled exchange.

It means, the generation in the area under the control of the network controller should be changed by to meet targeted exchange.

Next, the network controller has to control the system frequency.

Let Δf be the frequency deviation *i.e.*

$$\Delta f = f - f_0$$

where Δf = frequency deviation ; f_0 = target frequency, Hz C/s ; f = actual frequency, Hz C/s

A factor K called System Frequency Bias is introduced.

The system frequency bias K is amount of power generation required to change the system frequency by one cycle. Thus,

K = System Frequency Bias MW/Hz.

Thus to correct the frequency deviation Δf the amount of power charge would be

$$K\Delta f \ldots \text{MW}$$

Combining (1) and (2), the area requirement e is given by

$$e = \Delta P + K\,\Delta f$$

Thus the network controller determines area Requirement (e), where

$$\boxed{e = \Delta P + K\Delta f}$$

e = Area Requirement Correction MW
P = Deviation in power exchange through Tie-lines MW
K = System Frequency Bias
Δf = System Frequency Deviation
$K\Delta f$ = Power change required to achieve target frequency, MW

This area requirement correction is transformed into output signals by the network controller. These output signals for correcting conditions are set to various generating stations under automatic control (Block 1.2 in Fig. 46.13). The primary load frequency control in response to automatic governor action to achieve target frequency is faster (a few seconds). This corrects the input to turbines within set limits of turbine to control the frequency.

The secondary load-frequency control (in response to instructions from network controller) is slower (once in say 5 minutes). It adjust the governor settings.

Refer Fig. 46.14 illustrating load frequency controls of generating unit.

Turbine Governor Gate valve is adjusted by the servo-motor in the closed loop system of frequency control system. The turbine input gets adjusted to maintain required frequency and to give economic loading. Turbine-governor setting can be changed by operator or by automatic SCADA.

49.12. ACTIONS BY THE CONTROL ROOM OPERATORS TO CHANGE TIE-LINE POWER

— Change in turbine setting within permissible limits so as to
1. Increase the input to overcome fall in frequency.
2. Decrease the input to overcome rise in frequency.
— Adjusting interchange of tie-line power flow by the above mentioned action.
— Adjusting phase shifting transformer to force power through alternative tie-lines.
— Appropriate switching of transmission line paths.
— Load shedding at distribution level.

49.13. ACTIONS BY CONTROL ROOM OPERATORS FOR VOLTAGE CONTROL

These are taken at each power station and sub-station.
— Change in exciter settings to change generator terminal voltage.
— Change of tap position of on load tap changer.
— Switching in shunt reactors during low loads and switching off during high loads.
— Switching in shunt capacitors during heavy loads and switching off during light loads.

49.14. CONTROLLING TIE-LINE POWER BY MEANS OF PHASE SHIFTING TRANSFORMER (REGULATING TRANSFORMERS)

In simple two terminal interconnected transmission line, power flows from surplus area to deficit area automatically. By increase in generation above the own load, the area forces the power through the tie-line. The load angle δ gets automatically adjusted. (Fig. 49.3) to allow the exchange of power to follow equation.

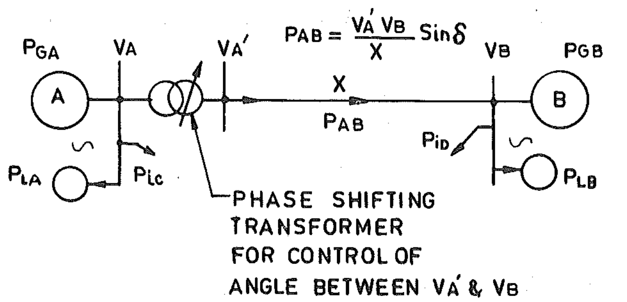


Fig. 49.5. Illustrating need for phase shifting transformer for forcing power P_{AB} through tie-line AB.

[By increasing generation in area A and reducing generation in area B, power flow through tie lines is changed. But the exact power flow through tie line A_B is determined by phase angle between V_A and V_B. This can be controlled by means of phase shifting transformer in case of AC tie line. In

$$P_{AB} = \frac{V_A\, V_B}{X} \sin \delta$$

Refer Sec. 45.16 $|V_A| - |V_B| = \Delta V = \dfrac{XQ}{V_B}$

and $$\delta \propto \frac{XP}{V_B}$$

For forcing the power flow P through a tie-line, angle δ between terminal voltages V_A and V_B of that tie line should be changed.

In multi-area system having meshed interconnections, parallel lines, loop circuits etc. increased generation may not increase tie-line power flow through the desired path. For adjusting the tie line power flow through a particular tie-line, angle δ between terminal voltage vectors of that line should be adjusted. This can be achieved by means of phase shifting transformer connected in series with the tie line at one of the terminals. Real power flow through the tie-line P_{AB}, is adjusted by controlling phase angle δ between V_A' and V_B by means of phase shifting transformers.

$$P_{AB} = \frac{V_A' \cdot V_B}{X} \sin \delta$$

By changing angle δ and keeping magnitudes of V_A and V_B within permissible limits, the power flow is changed. Angle δ is kept within about 30° considering the transient stability limit. Increase in δ gives increase in tie-line power flow. The magnitude of V_A and V_B are controlled by controlling reactive power flow Q.

$$|V_A| - |V_B| = \Delta V = \frac{XQ}{V_B}$$

By changing reactive power flow Q (by shunt compensation), the voltage difference ΔV is changed. (Refer Sec. 45.16).

ΔV can be changed by means of

1. Tap-changing 2. Reactive power injection

Phase angle can be changed by

1. Increasing generation above load.
2. *Use of phase shifting transformer* (Voltage Regulating Transformer).

49.15. PHASE SHIFTING TRANSFORMER (REGULATING TRANSFORMER)

Figs. 49.5 and 49.2 illustrates the function of a phase shifting transformer. The phase shifting transformer brings about the phase shift in line voltage (V_A to V_B by angle θ). Thereby, the load angle can be changed and power flow through tie-line AB can be changed. For increasing power flow angle δ is increased by adjusting angle θ. *This adjustment is in addition to control of angle θ by controlling the difference between generation and load.*

Fig. 49.5 illustrates the principle of voltage control by phase shifting transformer. Only one phase is shown for simplicity. By using the phase shifting transformer, the phase angle between the input side and output side voltage vectors two can be changed. In the phase shifting transformer, voltage from other phases (Y, B) is stepped down and injected into the first phase R.

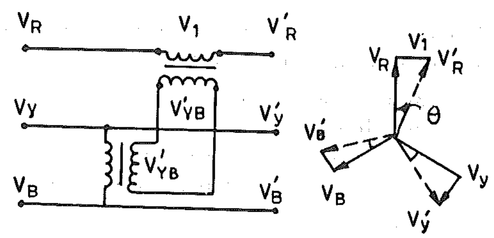


Fig. 49.6. Principle of Phase shifting transformer.

Thus the output voltage of phase R becomes ... V_R'

The phase shifting transformer has two sets of windings, one connected between two phases and the other one in series with line phase. Thus by injecting voltage V_1 in series with V_R the vector V_R' is shifted in phase by angle θ. The magnitude of V_R is varied by means of tap-changing on the shunt winding. Phase shifting transformers are three-phase units though only one phase has been shown in Fig. 49.6 for simplicity.

[Only one phase shown for simplicity. Voltage V_1 is injected in series with the line

49.16. TYPES OF INTERCHANGES IN INTERCONNECTED SYSTEM

Interconnections are generally for obtaining economic benefits and other bonus advantages mentioned in Sec. 49.3. Power systems are interconnected for any of the following significant purposes :

1. **Capacity Interchange.** Normally, a power system adds to its installed generation capacity to meet the predicted increased peak load plus surplus reserve for taking care of outages.

Instead of adding to the installed capacity, the power system may enter into capacity interchange agreement with an adjacent power system having surplus capacity. In such interchange; the adjacent system supplies power during peak load hours as per schedule in the agreement.

2. **Diversity Interchange.** Both the interconnected systems may not have same peak load hours. Peak loads may generally occur at different clock hours of the day. One system may lag behind the other by say 2 hours due to the difference in working hours, sleeping habits etc. Such system can have daily diversity interchange covering operating areas having different time zones.

3. **Energy Banking Arrangement.** A power system having predominantly hydro power, may be interconnected to another system having predominantly thermal power to have energy banking arrangement.

The purpose of such interconnection is to utilize hydro energy during monsoon periods and feed it to predominantly thermal area. During low water levels, the generation of hydro stations is reduced and thermal stations increased.

During Monsoon : Predominantly Hydro system exports power.

During low water : Predominantly thermal system exports power.

The purpose of such interconnection is better utilization of energy resources.

4. **Emergency Power Interchange.** The power system are interconnected mainly to support each other under emergency condition. The rate of power for such an interchange is generally very high.

5. **Inadvertant Power Interchange.** The interchange due to error by the operator or the control system is called inadvertant Interchange.

Hydro-thermal Co-ordination. During monsoon, the water level of reservoirs is high and excess water is wasted. Each hydro scheme has different capacity and load pattern. An area has some hydro-electric power stations and some thermal power stations. The hydrothermal co-ordination deals with interchange of power between predominantly hydro area and predominantly thermal area.

The schedule of exchange between predominantly thermal area ; and predominantly hydro-area depends on capacity of each area and requirement of load throughout the year. Generally, during rainy season, the Hydro-area does maximum generation and exports power. During low water level, the Thermal area does maximum generation and exports power.

If hydro-area has enough reservoir capacity throughout the year, the exchange is based on economics of power interchange.

General Pattern. Modern interconnected systems have various types of generating stations *viz.* thermal hydro, nuclear, gas-turbine, diesel, electric, wind power, solar power, geo-thermal power etc. In addition, energy storage schemes like pumped stored (hydro) ; compressed air storage, battery storage etc. are also used for limited capacity.

The generating stations are divided into three categories :

— Base-load stations — Midrange load stations

— Peak load stations.

Large generation (thermal/hydro/nuclear) are generally used for base load stations.

Heavy duty thermal stations are used for midrange stations. Gas-turbine stations are quick to start and flexible and are preferred for peak loads. Hydro stations are used as base load stations during rainy season and peak load stations during summer. Wind power plants are used as energy

displacement plants. These are installed very near the load points. The system planners explore many types of generating stations available and select the suitable types for base, midrange and peak loads. The choice depends upon economics and variable energy resources.

49.16.1. Control of Power Flow through Interconnector

Three types of interconnectors are used in todays power systems. These are :

— 3 Phase AC lines

— HVDC lines or HVDC cables

— HVDC Back-to-Back coupling stations

The functional requirements are rapid and accurate control of power flow from one AC network to the other. In AC transmission system, the power flow through the tie-line is controlled by increasing generation in one system and reducing the generation in the other. However, this is a slow process.

Recently, Flexible AC Transmission Systems (FACT) have been introduced. In HVDC systems, the power flow can be rapidly controlled by changing delay (α) of converters.

49.17. NATIONAL GRID AND GROWTH OF POWER SYSTEM IN INDIA

Fig. 49.7 indicates the Regional Zones in the National grid of India.

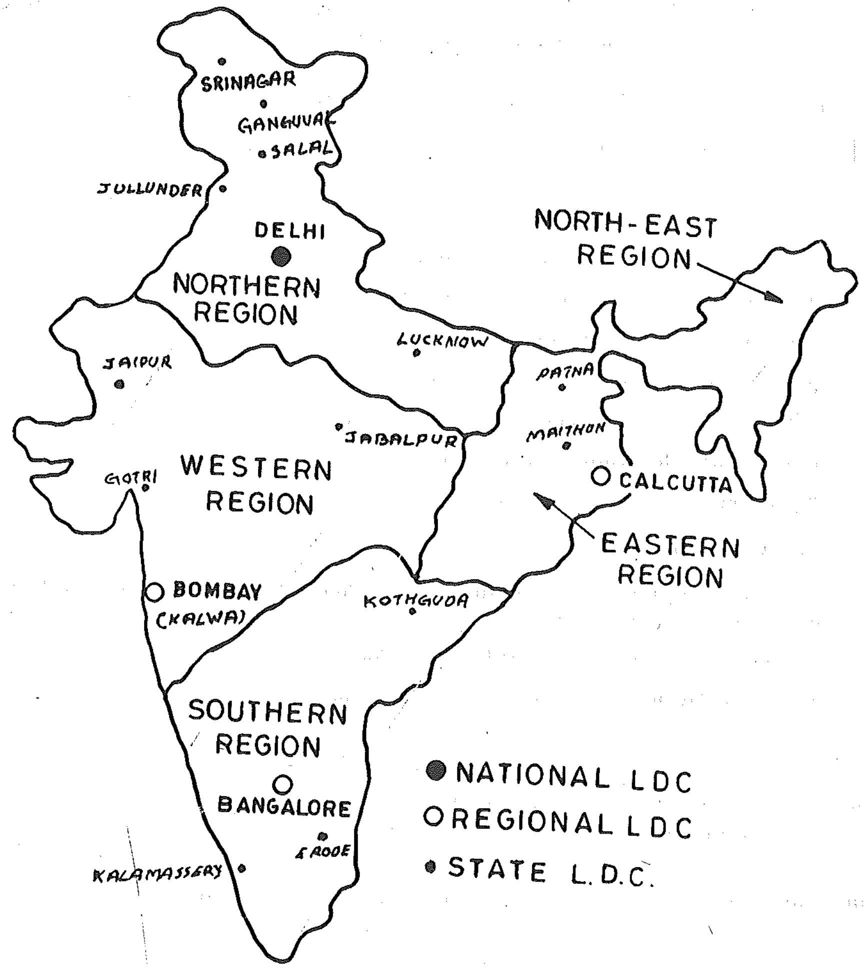


Fig. 49.7. Power Map of India.
Indicating National and Regional Load Control Centres.

Refer Ch. 56, Sec 56.21 for India's Power Plans.

India, like other developing Nations is on the verge of perpectual Energy Crisis. The loadgrowth is faster than the growth of power system. The energy resources and status of power sector are covered in Sec. 56. 21. The summary is as follows :

Table 49.1. Growth of Installed Capacity in India

5 year Plan	1	2	3	4	5	6	7	8	9
Span Start	1951	1956	1961	1966	1972	1978	1984	1990	1995
End	1955	1960	1965	1971	1977	1983	1989	1979	2000
Installed Capacity by End Year of plan									
$\times 10^3$ MW	3.4	5.7	10.1	14.7	23	30	42	92	132

Approximate Break-up (1997)

Hydro (Renewable)	30%
Coal Thermal	65%
Nuclear	4%
Gas Turbine and Noconventional	1%

Approximate Contribution of Regional Grids in Installed Capacity 1997

Western	*Nothern*	*Southern*	*Eastern*	*North-Eastern*
30%	*28%*	*25%*	*15%*	*2%*

Landmarks in India's Power Sector

1955	- First 132 kV Transmission Line Commissioned
1961	- First 220 kV Transmission Line Commissioned
1965	- National Grid and regional grids identified
1966	- First nuclear power plant commissioned
1975	- First 400 kV AC transission line commissioned
1978	- First 500 MW Generator Unit Commissioned
1979	- SF_6 and Vacuum Circuit-Breakers introduced
1985	- SF_6 GIS Introduced
1989	- First HVDC Back-to-Back Coupling Station Commissioned (Vindhyachal Back to Back, Northern Grid - Western Grid)
1991	- First Long Distance Bipolar HVDC Link Commissioned Rihand (UP) to Delhi (Dadri)
1992	- First Wind Turbine generator unit commissioned.

SUMMARY

Interconnected power systems have been established all over the world. The interconnection is by 3 phase AC line or by Back to Back HVDC link or by Multi terminal HVDC. National Load Control Centers ensures that : Total power generated = Total load + Losses.

Regional Control Centre controls generation/Load balance in the region plus Import/Export requirement as per instructions of national control centre. Recent Renewable energy power plants either stand alone or grid-connected depending on location.

50

Operation and Control of Interconnected Power Systems, AGC and SCADA

50.1. INTRODUCTION

The role of Master Control Centre, Regional Control Centres, Control Rooms in power stations in the supervision, operation and control of power system has been illustrated in Fig. 46.1. Chapter 46 and also in Sec. 46.22.

The principles of interconnected power systems and tie-line power flow have been described in Chapter 49.

The object of the power supply company is to generate and supply required amount of electrical power at specified voltage and frequency to all the consumers at all times. The extensive growth of interconnected power system has resulted in complex operation and control requirements.

AGC refers to Automatic Generation Control. AGC involves maintaining generation in each area at such a value as to keep the frequency in the area within targetted limits and to keep the net interchange with adjacent interconnected areas within scheduled limits.

SCADA refers to Supervisory Control and Data Aquisition Systems. SCADA systems are essential in the operation of todays large interconnected systems. Basis equipments required in SCADA systems have been mentioned in Sec. 46.3.

Most SCADA equipment operate in scanning mode providing continuous monitoring of several large power stations and substations. SCADA requires two way communication between Master Station (A) and remote outstations (B) which are usually at the sub-station level.

The various aspects of power system operation and the inter-relation between control functions has been reviewed in this chapter.

50.2. MAIN TASKS IN POWER SYSTEM OPERATION

The main tasks in power system operation at different levels are divided into following categories (Table 46.1).

1. Planning of operations
2. Operation control
3. Operation follow-up and accounting.

The functional responsibilities in performing the above tasks are shared by the following (Table 46.1).

1. National Grid Control Centres
2. Regional Load Control Centres
3. Power Station Control Rooms
4. Major Substation Control Rooms.

Tables 46.1 and 46.2 in Sec. 46.1 cover the responsibilities and tasks.

50.2.1. Planning of Operations

Planning refers to formulating and preparing action plan before hand. Planning is done for the next hour, next day, next week, next month, next year and for long range.

Planning tasks include the following :

(*A*) **National Level Planning**

1. Load prediction (forecasting) for total grid
2. Generation scheduling for total grid
3. Spinning reserves determination for total grid
4. Generator unit commitment scheduling
5. Planning of reserves
6. Planning of maintenance schedules
7. Energy resource planning
8. Selection of energy sources
9. Hydro-thermal generation co-ordination
10. Planning of interchange between regions
11. Planning of installations and HVDC tie-links

(*B*) **Zonal (Regional) Level Planning**

1. Load prediction (for casting) for region
2. Scheduling of generation in the region
3. Planning of overhauls and maintenance of various stations and major sub-stations in the area.
4. Planning of reserves in the area.
5. Selection of load scheduling programmes in the area.

(*C*) **District Control Centres (State Electricity Boards within an area)**

1. Short-term planning according to directives of regional control centres.
2. Planning of generation and spinning reserves in the district.
3. Planning of load shedding in the district.

(*D*) **Power Station and Major Sub-station control room**

1. Work planning for hourly, daily, weekly, monthly tasks.

The *Load Control Centres* have the following functions :

1. They act as communication centre between various areas generating stations and sub-stations.
2. Analysis of future operating conditions.
3. Co-ordination of emergency procedures and analysis of disturbances.
4. Co-ordination between planning and operation.

50.2.2. Operational Tasks

An electricity supply undertaking generally aims at the following :

— Supply of required electrical power to all consumers continuously at all times.
— Maximum possible coverage of the supply network over the given geographical area.
— Maximum security of supply.
— Shortest possible fault-duration.
— Optimum efficiency of plants and the network.
— Supply of electrical power within targeted frequency limits (say 49.5 Hz and 50.5 Hz).
— Supply of electrical power within specified voltage limits.
— Supply of electrical energy to the consumers at the lowest cost.

As a result of these objectives, there are various tasks which are closely associated with the generation, transmission, distribution and utilization of the electrical energy. These tasks are performed by various manual, semi-automatic and fully automatic devices located in generating stations and sub-stations.

These tasks are accomplished by the teamwork of the following controlling centres :

— National load centre
— Regional load control centre
— District load control centre
— Generating station control rooms
— Transmission divisions and transmission sub-stations
— Distribution sub-stations and feeder sections.

The above control centres are linked by communication system for two way communication of

— Data
— Control signals
— Voice or Teletype information

National Load Control Centre performs the following operational tasks :

1. Supervision of generation, load and frequency of each area and tie-line flow.
2. Power exchange under emergency condition
3. System frequency control and follow-up of network Islanding (Segregation).

Zonal Control Centre performs the following operational tasks :

Supervision of generation, load and frequency in each of the districts, power exchange between districts, reserves.

District Load Control Centres perform the following operational tasks :

1. Supervision and control of generation in the district to match with the load by AGC (Automatic Generation Control).
2. Operation and control of power stations.
3. Operation and Control of transmission system and tie-lines.

Power Station and sub-station Control Rooms perform the following operational tasks :

1. Generation, start, stop function.
2. Automatic restoration functions.
3. Control and protection functions.
4. Supervision of process variables.
5. Maintenance, overhauls.

Transmission Sub-stations perform the following operational functions :

1. Switching operations.
2. Protective functions.
3. Voltage control, reactive power compensation.
4. Data collection and reporting.
5. Load shedding instructions to distribution sub-stations.

Operational Tasks associated with Major sub-stations. The tasks associated with major sub-stations in the transmission and distribution systems include the following :

— Protection of transmission system.
— Controlling the exchange of energy.
— Ensuring steady state and transient stability.
— Load shedding and prevention of loss synchronism. Maintaining the system frequency within targeted limits.
— Voltage control; reducing the reactive power flow by compensation of reactive power, tap-changing.

— Securing the supply by providing adequate line capacity and facility for changing the transmission paths.
— Data transmission via power line carrier/microwave/other channels for the purpose of network monitoring ; control and protection.
— Determining the energy transfer through transmission lines and tie-lines.
— Fault analysis and pin-pointing the cause and subsequent improvements.
— Securing supply by feeding the network at various points.
— Establishing economic load distribution and several associated functions.

These tasks are performed by the team work of load-control centre, control rooms of generating stations and control rooms of sub-stations. The sub-stations perform several important tasks and are integral part of the power system.

The locations of important sub-stations, power stations and the transmission lines are decided while designing the power system by considering the geographical locations of load centres, and energy reserves.

A small power system is generally controlled by direct supervision of generating stations and sub-stations through respective control rooms. A large network having several generating stations, sub-stations and load centres is controlled from central load despatch centre. Digital or voice signals are transmitted over the transmission lines via the sub-stations. The sub-stations are linked with the load control centres via Power Line Carrier System (PLCC) and Microwave Channels. The data collected from major sub-stations and generating stations is transmitted to the load control centre. The instructions from the load control centre are transmitted to the control rooms of generating stations and sub-stations for executing appropriate action. Modern power system is controlled with the help of several automatic, semi-automatic equipment. Digital computers and microprocessor are installed in the control rooms of large sub-stations, generating stations and load control centres for data collection, data monitoring automatic protection and automatic control.

50.2.3. Operating Accounting and Financial Control

The operating accounting deals with the data collection and evaluation and thereafter preparation of financial reports and billing *e.g.* the tasks include :

1. Collection data regarding MWhr produced, MWhr interchanged.
2. Billing on adjacent area for the interchange MWhr.
3. Evaluation of performance of power stations, districts.
4. Evaluation of pricing after the interchange.

Though the costing of interchange power is on the basis of the agreed rates, the participant power system may like to verify the economic gains loss of interchange against the estimated values.

50.3. AUTOMATIC GENERATION CONTROL (AGC)

Automatic Generation Control (AGC) is performed by the team work of Regional Load Control Centre and the Power Station Control Rooms.

The regional control centre receives real time data (Second to Second) of
— Power generation in each power plant (MW)
— Tie-line power flow (MW) through each tie-line.
— System frequency.

This data is received through transmission channels between the generating stations, major sub-stations and the Regional Load Control Centre.

The Regional Load Control Centre evaluates the data, determines the action and sends instructions to each generating station as to how much generation they should increase or decrease.

The operator in Generating Station Control room receives these instructions and takes appropriate action to change turbine governor setting so as to raise or lower the input to turbines and thereby output of the generating units and the generating station.

Automatic Generation Control (AGC) refers to the closed loops control system having three major objectives.

— To hold the system frequency within targetted limits (near 50 Hz).
— To maintain correct value of net power interchange between adjacent systems through the tie lines.
— To maintain generation of each plant within the area at economical value.

Area Control Error (ACE) refers to the shift in generation required to restore the frequency and net interchange to the desired value.

Load frequency control of a unit has been explained in Sec. 46.23 and Fig. 46.14.

AGC is integrated with SCADA.

50.4. SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA) SYSTEM

The functions and configuration of Supervisory control and Data Acquisition systems (SCADA) have been described in chapter 46. SCADA systems are indispensable in the operation and control of interconnected power systems.

SCADA equipment are located in *Master Control Centre* National Grid Control Centre) ; Zonal (Regional) Control Centres, District (State Electricity Board) Control Centres, Control Rooms of Generating stations and large sub-station.

SCADA requires two-way communication channels between the *Master Control Centre* and *Remote Control Centre* (Fig. 50.1).

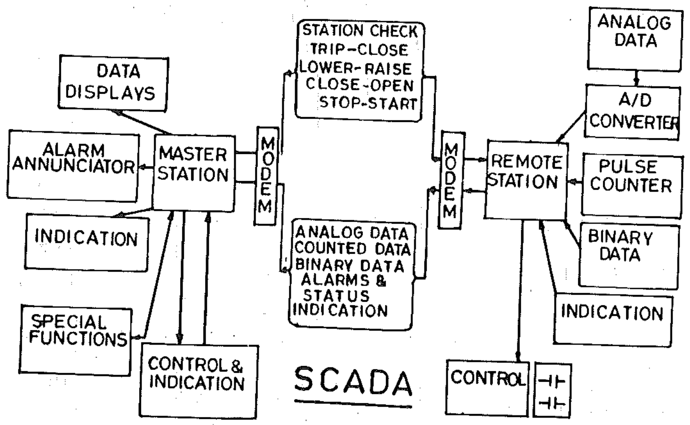


Fig. 50.1. SCADA requires communication between Master Control Station and Remote Control Station.

Traditionally, the SCADA systems were used by the operators in scanning mode, providing data regarding generating stations, Generating units, Transformer Sub-stations etc. (Tables 46.4-46.6) Traditional hard wired SCADA systems were arranged to perform several functions to supplement Automatic Control and Protection Systems.

All the protective relays and most of the control relays and control systems are necessary for automatic control of generating stations and transmission systems even when the supervisory control is used. Only initiating devices may be different or omitted with fully automatic SCADA control. For example, tap changing may be initiated either by the sub-section control room operator or by the automatic voltage control relays connected in the protection panel of the transformer.

With traditional SCADA systems, the function of protection and control were segregated. Controls systems were arranged to keep the values of controlled quantities within target limits. Protection equipments were arranged for sounding alarms and for tripping circuit-breakers. With the recent revolution in microprocessor technology, the size, performance and cost of digital automation

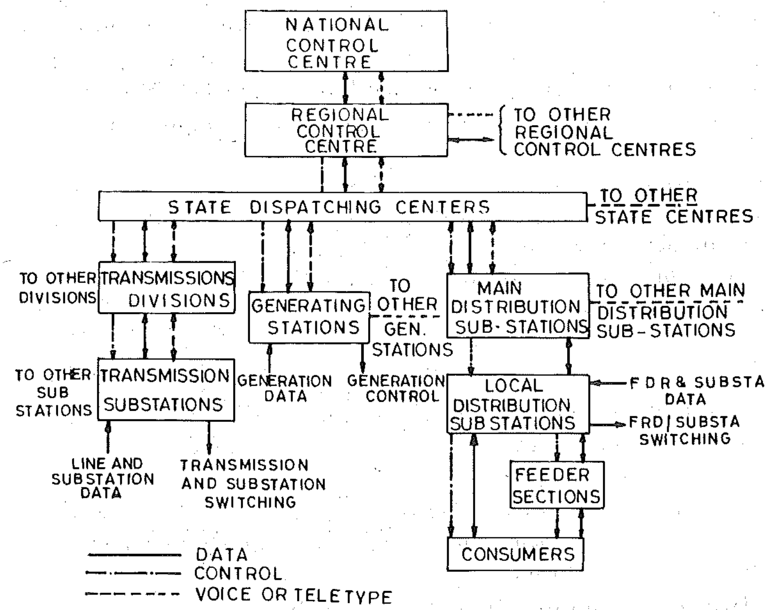


Fig. 50.2. (*a*) Communication between control centres in SCADA system.

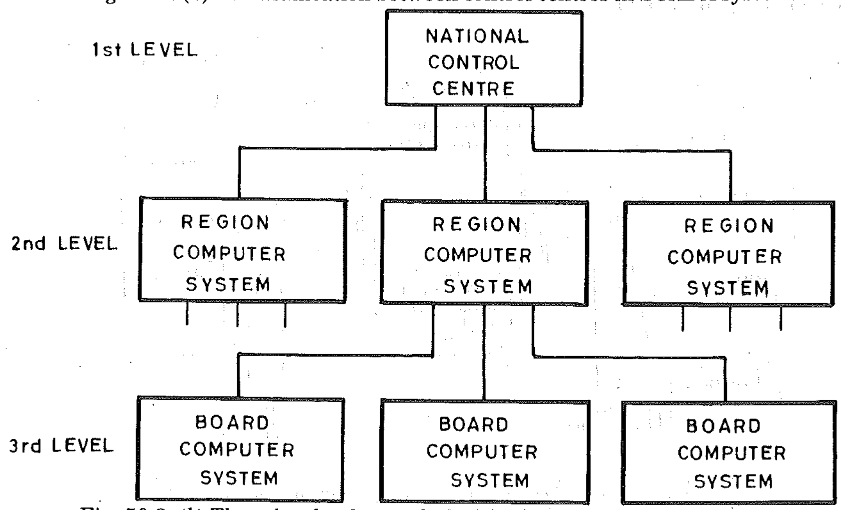


Fig. 50.2. (*b*) Three levels of control of SCADA system and control system.

systems have become acceptable in commercial installation. These automatic SCADA systems provide integrated approach to power system protection, operation control and monitoring, automatically with least intervention of the control room operator.

With the microprocessor based control and automation, the microprocessor are located in the master station, generating stations and sub-stations. The microprocessor in transmission sub-stations and distribution sub-stations provide control and protection decisions locally where the data is located. The action is reported to the operator "by exception". The operator retains the option of taking intervening action of overriding or initiating of his own.

Various types of the microprocessor based SCADA systems are installed for various centres including small centres, small distribution system, small power plants to very large interconnected power systems. The functions and architecture of SCADA system is selected in accordance with the functional requirements and size of the power system. Table 50.1 gives a summary of functions of various alternatives SCADA systems.

Table 50.1
Various types of computer-based Supervisory Control and Data Acquisition Systems (SCADA)

Functions	*System type 1*	*System type 2*	*System type 3*	*System type 4*
Application / functions	*Small Distribution Systems small hydro stations, HVDC Links*	*Medium sized power systems, power stations HVDC links distribution systems*	*Regional control centre, Distribution systems in large Urban areas, several hydropower stations with cascade control*	*National and Regional control centres, distribution systems in large urban areas, several hydro stations, with cascade control*
(1)	*(2)*	*(3)*	*(4)*	*(5)*
Interative studies security assessment, Network modeling.	—	—	—	Operators Loadflows (OLF) Training Simulator (TL) Security Assessment calculations Contingency Analysis (CA) State Estimation (SA)
Generation control.			Automatic generation control (AGC)	Automatic generation control (AGC) Economic dispatch calculation (EDC). Load forecasting (LF). Unit commitment (UC)
Calculations	—	—	User-oriented calculation language (CAL) Energy balance. Status calculations.	User-oriented calculation language (CAL). Interchange scheduling and accounting. Status calculations.
Monitoring	Status/indication changes, Control operations. Limit values	Status/Indication changes. Operational commands. Limit values.	Status/indication changes. Control operations. Limit values, 4 limits + gradient limit. Event classification.	Status/indication changes. Control operations. Limit values, 4 limits + gradient limit. Event classification.
Logging	Events. Hard copies or Screen display on printer.	Energy reports max/min reports. Events. Printout copies of screen displays.	Statics, Post-mortem reviews (PMR). Sequential events recording. Event reports. Time tagged date (TTD). Printouts of screen displays.	Statics, Post-mortem reviews (PMR). Sequential events recording. Event reports. Time tagged data (TTD). Printouts of screen displays.
Data acquisition	Status/indications. Measured values. Upto 500 signal points from 16 RTUs and 40 STUs.	Status/indications. Measured values. Energy values, Upto 3000 signal points from 30 RTUs and 100 STUs.	Status/indications. Measured values. Energy values. Up to 7000 signal points from 50 RTUs.	Status/indications. Measured values. Energy value Upto 30000 signal points from 150 RTUs.
Control	ON/OFF commands RAISE/ LOWER regulation.	ON/OFF commands RAISE/ LOWER regulation. Set point values.	OF/OFF commands. RAISE/ LOWER regulation. Set point values. Sequential control.	ON/OFF commands. RAISE/ LOWER regulation Set point values. Sequential control.
Display	Monochromatic display and printer.	Color display and printer.	Color display, mimic diagram and printer.	Color display, minic diagram and printer.

50.4.1. Division of Tasks between various control centres

National Load Control Centre

— To decide generation allocation to various regions and to decide exchange between regions on overall economy and energy policy/reserves.
— Load-frequency control of entire grid by matching total generation with total load.

Regional Load Control Centre

— To decide generation allocation to various generating stations within the region on the basis of equal incremental operating cost considerating line losses are equal.
— Frequency control in the region.

Plant Load Control Room

— To decide allocation of generation of various units in the plant on the basis of equal incremental operating costs of various units.
— To minimize reactive power flow through lines so as to minimise line losses and maintain voltage levels.
— Frequency control in the plant.

Sub-Station Control Room

— To minimise reactive power flow through transmission lines by compensation to minimise line losses and to maintain voltage levels.
— Load shedding as per agreed plan or instructions of load control centre.
— Synchronizing and system restoration.

The primary objectives of the various levels are :

— Load frequency control
— Voltage Control
— Economic load despatch

Large sub-stations perform assigned functions via their control rooms. The basic functions at sub-station level include :

— Maintain the voltage level of sub-station buses within specified limits by tap-changing and reactive power compensation.
— Frequency monitoring and load shedding.
— Network segregation (islanding) during system frequency drop and fluctuations.
— Synchronizing and system restoration.

The load shedding is generally performed at a smaller distribution sub-stations as per the automatic load shedding programme by means of co-ordinated frequency relays or in accordance with instructions from control room of large sub-stations feeding smaller sub-stations.

The 'architecture' of SCADA system at each of the above control centre/control room differs with reference to the required functional tasks.

50.4.2. Functions of SCADA systems

Supervisory control and data acquisition system (SCADA) are arranged to perform one or more of the following functions :

The following functions are common to all types of SCADA systems (type 1 to 4 Table 50.1).

1. Monitoring
2. Alarm
3. Control and Indication of Production Automatic Generation Control (AGC)
4. Data logging
5. Data acquisition
6. Control ON/OFF, RAISE/LOWER
7. Display

The following additional functions are provided with SCADA systems for National Load Control Centres :

— Interactive studies
— Security assessment calculations contingency
— Training simulator
— Network modelling
— Energy Management Systems (EMS)

50.4.3. Common features of all SCADA systems (Fig. 50.3)

The SCADA systems are arranged to perform the following tasks :

— Data Collection (Data Acquisition)
— Data Transmission (Telemetry)
— Scanning, Indication, Monitoring, Logging.
— Execution of operating, commands : ON/OFF, RAISE/LOWER
— Network supervision, alarms and report any uncommon change-of-state.
— Control and indication.
— Ensure sequential events.
— Data presentation, display, reporting.

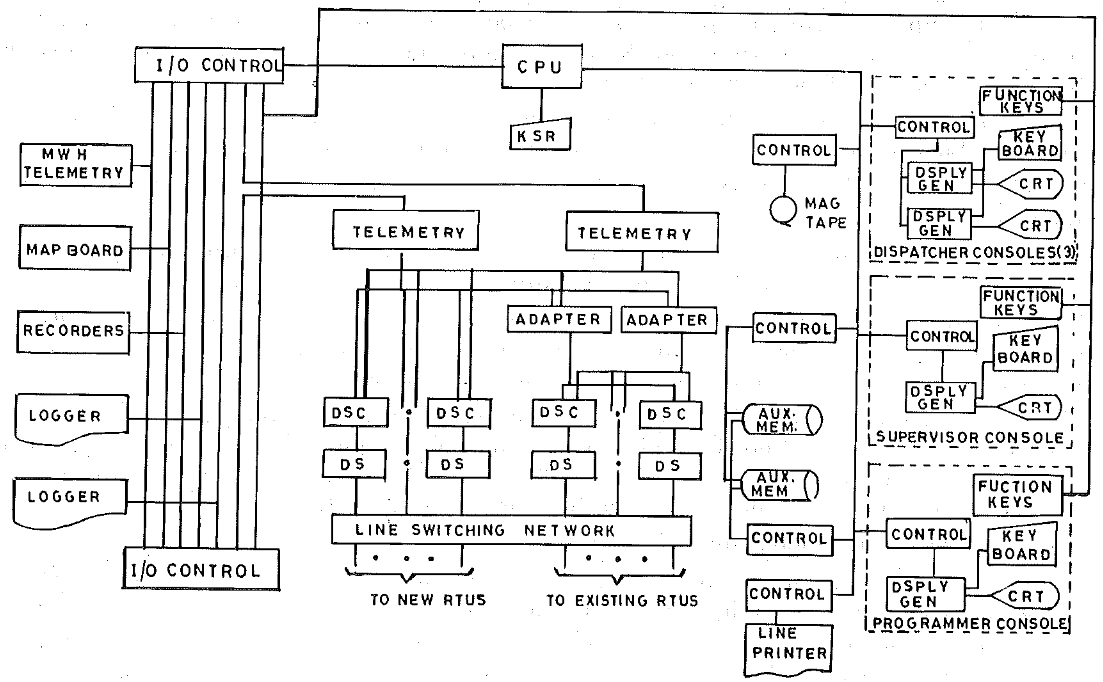


Fig. 50.3. Features of a SCADA system.

Refer Sec. 46.3 regarding SCADA functions. These have been further elaborated in the following paragraphs :

The Data. The data consists of electrical and mechanical variables, on/off states, analogue quantities, digital quantities, change of state, sequence of event, time of occurrence and several other data which the control room operator would like to know.

Data Collection (Acquisition). The data is acquired by means of a CTs VTs, transducers and other forms of collecting information. The process to be supervised has a very large number of electrical and mechanical and other data (information) transducers convert the data into electrical form to enable easy measurement and transmission. Data originates in the main process and is collected at the point of origin. Data may be collected at low level (5 mA) or high level (5 V). The data amplified in signal amplifier and conditioned in data signal conditioner.

Data Transmission. The data is transmitted from the process location to the control room, and from the control room to the control centre. (Refer Sec. 46.5).

Data Processing and Data Logging. The large number of electrical/mechanical/other data are scanned at required interval, recorded and displayed as per the requirements. Some of the data is converted from Analogue to Digital form by A/D convertors (Sec. 31.25).

The *Data Loggers* perform the following functions :

— Input scanning	— Signal amplification
— A/D conversion	— Recording
— Display	— Programming

Fig. 46.2 gives a block-diagram of a programmable data logger.

The input scanner is generally a multiway device which selects input signals at regular periodic intervals in a sequence. (Table 46.3/4/5). The rate of change of input data (*e.g.* 20 seconds, 1 minute, 1 hour etc.). Slow varying quantities are scanned with a longer period of intervals of scanning, fast varying quantities are scanned at shorter intervals of time.

The scanning gives necessary data regarding values of various input variables. The decision regarding follow up actions (e.g. change in input) can be taken according to the program. Automatic control necessitates a series of scans and checks at regular intervals, scanning provides indication has to when appropriate follow action can be initiated.

Output of scanner is given to A/D convertor. Digital signals are given to microprocessor or digital computer. Logic operations are performed rapidly by on-line micro computer.

The electrical signals (A/D) are transmitted (telemetered) to a remote control pannel through control cables.

The analogue or digital signals are received in control room. These are processed for measurement, recording, display, control by the instrumentation system in the control room.

The operator in the control room needs information regarding parameters and network configuration. CRT display (cathode ray tube) provides the operator with these informations whenever he want (when he presses an appropriate button on control desk).

Remote Terminal Units (RTU). A typical modern supervisory control system has remote terminal units (RTUs). The function of RTU is to record and check signals, measured values and meter readings, before transmitting them to control station and in the opposite direction, to transmit commands, set point values and other signals to the switchgear and actuators.

The RTU is capable of following functions :

— Acquisition of information (measured values, signals, alarms, meter readings), including features such as plausibility checks and filtering.

— Output of commands/instructions (binary pulse-type or continuous commands, set points, control variables), including their monitoring (as a function of time, l out of n).

— Recognition of changes in signal input states, plus time data allocation for sequential recording of events by the master control station.

— Processing of information transmitted to and from the telecommunication equipment (data compression, coding and protection).

— Communication with master control stations.

Presentation (CRT Display). CRT is a short form for Cathode Ray Tube. CRT display is made available in the control room. CRT display provides the operator with the information about input

quantities whenever he wants. (When he presses appropriate push button on the control desk). CRT display is located in the control room of Generating Stations, Sub-stations, Control Centre.

Two types of display are available :

— Tabulated values of parameters, measured values and computed characteristics.

— Graphical display representing status of equipment in the form of mimic diagrams.

CRT display include the following :

1. **Alpha-numeric Displays.** These give direct reading of measured parameters. Name of the parameter and numerical value is displayed.

2. **Single Parameter Displays.** For certain parameter several measured numerical data are required in a tabular form. These are displayed.

3. **Mimic diagram display.** In this display, the single line diagram of the circuit with position of C.B's and isolator is displayed. The power flow is indicated.

4. **Displays with threshold blackout.** Threshold means on the border. In threshold blackout display the threshold values of quantity is displayed.

5. **Graphical displays.** This displays graph of quantities.

6. **Histogram displays.** Histogram refers to graphical representation of a distribution of quantity. The quantity can be illustrated vertical lines or horizontal lines representing the parameter values.

7. **Pictorial displays.** Pictorial displays can be used as small mimic diagrams. Line diagram of a plant indicating positions of equipment.

8. **Analogue displays.** These are useful to show continuously varying parameter.

9. **Alarm displays.** These are displayed on control board for attention of the operator.

The main criterion of CRT display system is the number of independent displays required for some simultaneous viewing.

Display selector switches are provided for following duties :

1. Display unit selection2. Clear tube

Common display requirements of sub-station control room, generating station, control room, control entire control room are markedly different.

Typical display in a *Generating Station Control* room includes :

— Tabulated values of various process parameters (Refer Table 46.3 and 46.4)

— Mimic diagram indicating the position of ON/OFF of circuit breakers, isolators, earthing switches and stations of operating units, tap position of tap-changers.

Typical display in sub-station control room includes :

— Tabulated values (*e.g.* Table 46.5)

— Electrical layout indicating ON/OFF condition of circuit breakers, tap position.

Typical display in Regional Control Centre, Control Room includes the following :

— Configuration of the system in the form of Mimic Diagram

— Alarm and logging

— State of system : Normal, Alert, Emergency

— Tabulated Data (Table 50.2)

— Transmission system status.

Table 50.2. Data in Regional Load Control Centre

System Data	*Unit*	*Input Interval and or Check Interval*
1. Generating station status	MW	15 min
2. Spinning reserves	MW	15 min
3. Tie line status	MW	30 min
4. Frequency	f	20 sec
Rate of change	df/dt	20 sec
5. Transmission system status		
— Voltages	kV	1 min
— Active Power	MW	1 min
— Reactive power	MVAr	1 min
6. Emergency condition Data		20 sec.

50.4.4. Alarm Functions (Ref. Sec. 46.4, 25.1)

The operator in control room receives on alarm in the form of Audio Visual indication. The alarm indicates dangerous condition calling for supervisors immediate attention and intervention, if necessary.

The alarms are arranged for electrical/mechanical/other parameters and are included in the configuration of Data Logger (Fig. 46.2 – Alarm and Annunciation Block in the output portion). The variables and scanned at regular intervals. When scanned value exceeds certain limit, and alarm is sounded.

50.4.5. Integration of Measurement Control and Protection Functions by SCADA Systems

With recent revolution in the static relays, microelectronics, microprocessor and digital computers, several functions of measurement instrumentation, data logging, supervision, monitoring alarm control, protection and automation are integrated with the help of SCADA systems. The total system becomes compact, economical and versatile.

Instrumentation deals with measurements, recording, display and infeed to control and protection systems, data acquisition, data transmission, data monitoring, data logging etc.

Control deals with sensing the controlled quantity, comparing with reference quantity to bring the controlled quantity with in targeted limits. In a open loop control system, the input influences output directly the output is not fed back to input.

Protection deals with protecting the system and its sub-systems from harmful effects of abnormal quantities, such as over-current, undervoltage, temperature rise, etc.

Monitoring means checking the performance by measuring at regular intervals.

Closed loop control systems have a provision of comparing output and changing the input to achieve the necessary corrections. Adaptive control systems are able to tune themselves to the changing environment.

On line control deals with real time (second to second) control of the system variables.

The above tasks are dealt by SCADA systems. The SCADA system supplements the control system and protection system to form an integrated system.

50.5. AUTOMATIC SUB-STATION CONTROL

The electrical energy is transferred from large generating stations to distant load centres via various sub-stations. In every sub-station certain supervision, control and protection functions are necessary. Every sub-station has a control room. The relay and protection panels and control panels are installed in the control room. The various circuit breakers, tap changers and other devices are controlled by corresponding control-relay panels. In a small independent sub-station, the super-

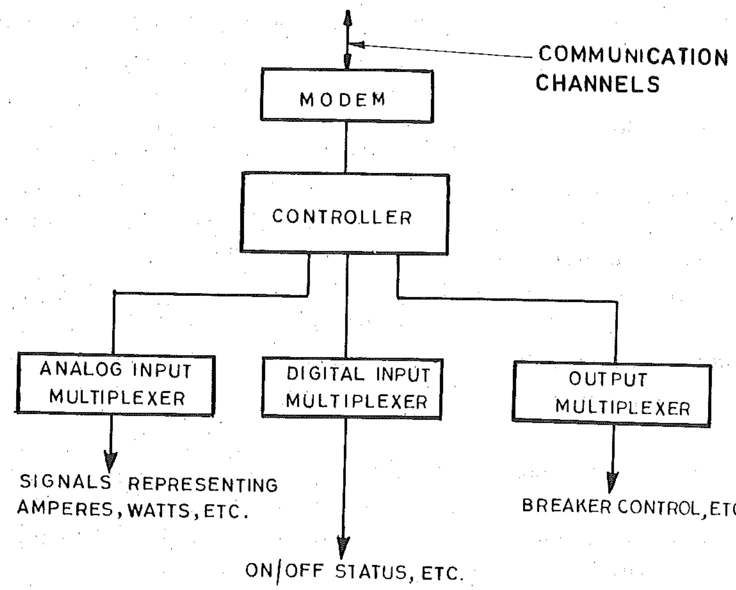


Fig. 50.4. SCADA system in sub-station.

vision and operation for normal service can be carried out by the operator with the aid of analogue and digital control systems in the plant. The breakers can be operated by remote control from the control room. During faults and abnormal conditions, the breakers are operated by protective relays automatically. Thus, the primary control in sub-station is of two categories.

1. Normal routine operation by operators command.
2. Automatic operation by action of protective relays and control systems.

Two Sub-systems in Sub-stations. The control equipment in a sub-station are to be treated as two sub-systems :

1. Control System 2. Protective System.

For many reasons, it is desirable to have two separate systems as above.

The relay protection system should acquire the data independently, process it, evaluate it and take action to perform protective tasks (tripping).

The different event are reported to the control system as well as protective system. Both the systems must, therefore, co-operate closely with one another.

In modern sub-station, these functions are realised with relays, static processing devices and micro-computers.

The tasks of protective systems include sensing abnormal condition, annunciation of abnormal condition alarm, automatic tripping, back-up protection, protective signalling etc.

The tasks of control systems in sub-station include data collection, scanning, event reporting and recording ; voltage control, power control, frequency control, other automatic and semi-automatic controls etc. The two systems work in close-co-operation.

Two Hierarchical Levels in a sub-station. The control equipment are generally arranged it two hierarchical levels. From the higher (sub-station) level, the entire sub-station is controlled and supervised. From the lower (unit) level, the lines, transformers etc. are controlled and supervised. The equipment on unit level is divided into a number of independent 'units'. This division improves the operating reliability and simplifies future extensions such as additional lines.

Inter-level Communication. Information is transferred between the two control levels primarily via a series bus, where the sub-station level computer controls the traffic by cyclic scanning the other units connected to the bus.

Sub-station level. The following main functions are arranged on sub-station level :

— Ordinary man-machine communication system of the sub-station.

— Remote control inter-face.	— Synchronising
— Disconnector inter-locking	— Busbar Protection (Relay Protection) System
— Fault annunciation	— Automatic network restoration
— Automatic switching sequences	— Load shedding/Load re-connection
— Voltage control	— Compiling of energy and other reports
— Disturbance reconditioning/recording	— Sequential events recording.

Most of these functions are integrated as softwares in the substation level computer. This software is of modular design, which facilitates addition of new functions.

The man-machine communication system of a sub-station consists of the following :

(*i*) Video Display Unit (VDU)	(*ii*) Functional key-board
(*iii*) Typewriter	(*iv*) Indication pannel.

These units replays the control board of conventional control system. The VDU is used to display indication and events that have occurred in the power system.

The function of key board is to enable the operator to operate high voltage apparatus and automation systems. The typewriter is used to present events as they occur.

Unit level. The entire sub-station is divided into certain 'units' (Similar to protective zones). Each unit includes one or two major equipment such as line, bus-bar section, transformer, etc.

The function relating to particular unit include the following :

— Line Protection, Breaker Failure Protection etc.

— Auto-reclosing

— Synchronising check

— Energy metering

— Acquisition and time tagging of events

— Acquisition of position indication and measured values

— Execution of commands from sub-station-level computer

— Back-up control.

Sub-station Control Functions arranged through SCADA systems. These include the following :

1. **Alarm Functions**

To sound alarm/annunciation regarding dangerous, uncommon events such as abnormal values of process parameters, fire, illegal entry in premises, over temperatures, low voltage of auxiliary supply, unusual happening etc. Alarms are obtained from data logger and are for alerting the operator in the control room.

2. **Control and Indication**

2.1. Control of two position devices such as circuit-breakers, isolators, earthing-switches, starters.
Indication of ON/OFF state of the devices on control board/mimic diagrams.

2.2. Control of position of devices having positions (closed, middle open) *e.g.* values, input settings, indication of position on control panels.

2.3. Control positions of multi-position device *e.g.* tap changer, indication of position on control panels.

2.4. Indication without control.

2.5. Control without indication : *e.g.* raise or lower control of generator load by automatic load frequency control.

2.6. Set-point control to provide set point to a controller located at remote sub-station.

3. Data collection, recording, display.

4. Sequential operation of devices with predetermined time and conditions for operation of various devices *e.g.*

1. Auto-reclosing of circuit-breakers operation O-CO-Time-CO
2. Operation of circuit-breaker, isolator and earthing switch in a particular sequence during opening of circuit and another sequence during closing of circuit.

By means of SCADA system, the operator in control centre can cause operations in a remote sub-station. The possible remote operations include :

— Opening and closing of switching devices

— Tap-changing of transformers (voltage control)

— Switching of capacitor banks (voltage control)

— Load shedding (load frequency control)

Some of the remote operations are made automatic by one-line computer based system without human intervention *e.g.* Net work islanding, Backup protection. The automatic control function are segregated into :

1. Interconnection functions
2. Transmission line automatic function (Table 50.3)
3. Distribution system automatic functions (Table 50.4).

Table 50.3

Automatic Function in Transmission Sub-station with SCADA System	
Protective Functions	
— Sequential events — Auto-reclosing — Bus protection — Fault distance reporting — Backup protection	— Line protection — Transformer protection — Reactor protection — Synchronising checks
Control and Monitoring Functions	
— Voltage control VAr flow control — Automatic bus sectionalising — Synchronising checks — Sub-stations transformer load monitoring — Data collection, monitoring alarm, display, logging.	— Load frequency control, load shedding, islanding — Sequential events — Monitoring — Power flow monitoring

Table 50.4

Automatic Function in Distribution Sub-station with SCADA Systems	
Protective Functions	
— Underfrequency protection — Conductor fail protection — Transformer protection — Bus bar protection	— Earthfault protection — Feeder protection and autoreclosing — Breaker failure protection — Backup protection
Control and Monitoring Functions	
— Feeder Sectionalizing — Voltage control, VAV control	— Feeder deployment switching — Data collection, monitoring status, loading, display.

50.6. SCADA CONFIGURATIONS

Fig. 50.5 (*a*) represents the simplest SCADA configuration employing a single computer.

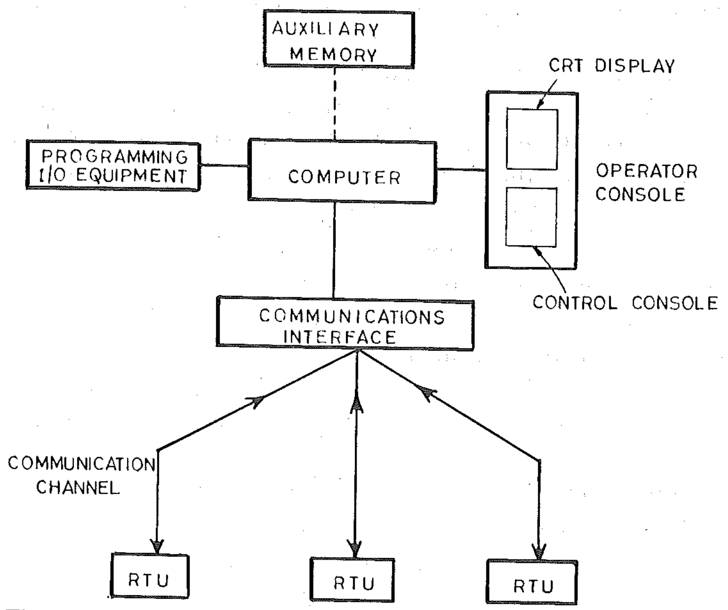


Fig. 50.5. (*a*) Remote Terminal Units RTU and interfaces with computer. Simple SCADA system with single computer.

Computer receives data from RTUs via the communication interface.

Operators control base one or more CRT terminals for display. With this terminal it is possible to execute supervisory control commands and request the display of data in alpha numerical formats arranged by geographical location and/of type.

The programming input/output is used for modifying the supervisory software. In the basic SCADA system, all the programmes and the data is stored in the main memory. The more sophisticated version of SCADA has additional auxiliary memories in the form of magnetic disc units.

Redundant SCADA System. For more important applications, to satisfy the reliability criteria the SCADA systems may have built in redundancy. Main computer, auxiliary memory, communication interface may be duplicated. In the event of a failure of one of the elements, the SCADA function is carried out by its duplicate elements.

The system is designed to continuously monitor its own operation. In the event of malfunctioning, the change-over to the duplicate system automatically.

Fig. 50.5(*b*) illustrates a more sophisticated system which has two computers one failures can be sustained without interruptions.

50.7. ENERGY MANAGEMENT SYSTEMS (EMS)

The Energy Management System (EMS) for a large inter-connected system have following hierarchical levels :

1. System control centre
2. Area control centre
3. Remote Terminal Units (RTU's)

Many energy management systems are similar to the structure shown in Fig. 50.2 (*a*) in which

— System control centre controls and co-ordinates a transmission system. The generated power is injected into the transmission system and the centre is also a charge of generation control and co-ordination.

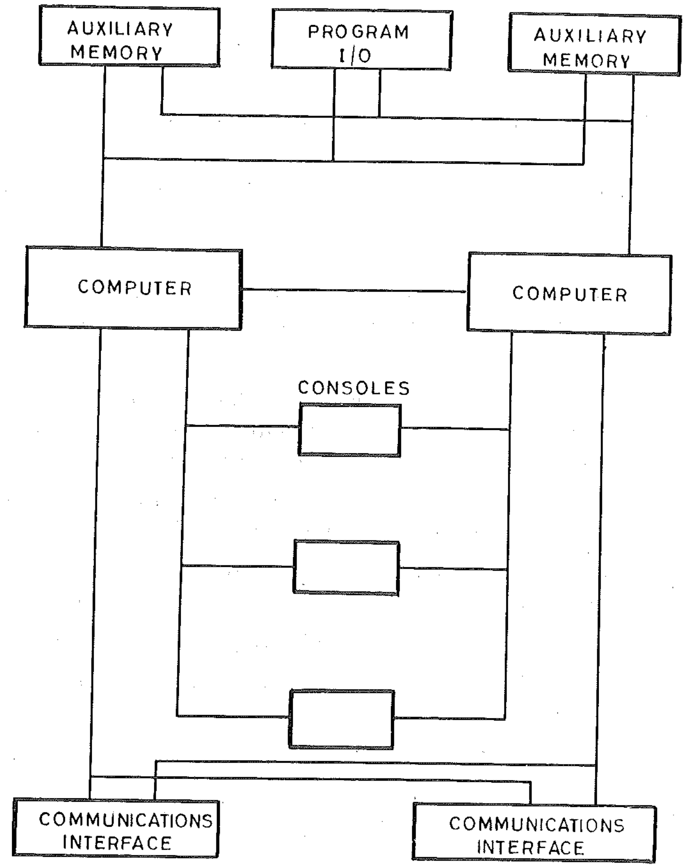


Fig. 50.5. (*b*) Redundant (Duplicate) Computer system, sophisticated SCADA system.

— Area control centres monitor and the transmission equipment and the supply points to the distribution systems in their areas. These centres are also responsible for performing the controls that area issued by the system control centre. If necessary these centres may issue controls directly.

— Remote terminal units which primarily acts as the data acquisition units for telemetry and provide the means of executing the instructions received from the control centres.

In such an arrangement, the typical objectives of the *system control centre* include :

— Building and maintaining a model of the steady state situations of the power system. This model will be used for control, optimization and operational planning.

— Providing means of reacting to power system events in an optimum and secure manner so that the system frequency and interchange are maintained at specified values.

— Providing means of maintaining voltage levels with optimum allocation of reactive power in systems with a centralized voltage control policy.

— Examining the effect of possible power system faults on the current operating state of the system in real time. Monitoring the produced fault levels and checking for availability of adequate circuit beaker capacity. Monitoring the post fault situation and checking for any violations in the system steady state.

— Supporting the operator by providing him with (*a*) The tools to extract the most critical information about the operating state of the system. (*b*) The tools to examine the effects of his commands in an accurate and fast way before actually issuing them. (*c*) The analytical tools to calculate the optimum states and schedules under a given situation.

Tools for integration

The job of managing and integrating an Energy Management (EM) system is large and complex. Fig. 50.3 illustrates the software functions of EMS.

To achieve it within reasonable time scales and budget require a good software support tools. Essential tools are :

— Database management
— Display compiler
— Source of control
— Database query programme
— Task manager

While these tools should be adequate for the system development and integration needs, they should not compromise the requirements of the on-line operation of the system control centre.

Database Systems

An EM system has three major sources of data; telemetered data, network parameters and generation parameters. This data is organized and managed by a common database system which has many of the features of structured and relational database.

The facilities of the database system are used as tools for defining as well as accessing the data structures required by SCADA, generation and network applications.

The structure and discipline imposed by the database system allows various tools to be developed to manage this data, one of the most important being a display compiler.

The features that have aided development and integration phases are :

— Ease of scheme modification to cater for specific contract requirements.
— Ease of re-dimensioning.
— Capability to dump and re-load into a newer version where the scheme has been modified.
— The capability of the database to provide means of grouping together the data which have the same characteristics, (*e.g.* same purpose of use, same life time).

Integration

The system database is divided into the major areas of the SCADA database, the network database and the generation data base. These database are built using the facilities of the database manager and the database compilers which are specific to individual application areas.

The defined databases each form a logical independent description, from which any application may draw the required data. For example the network database describes the power network and supports all the network applications. The correspondence between the different databases is built in an off-line mode but updated in real time, if necessary.

In the energy management task organization of Fig. 50.6 each solid box is a task. Each broken box includes a set of tasks that operate on the same database and is referred to as an application.

The applications normally divide into the two areas of real time and study. The real time set runs automatically on a cyclic basis or on a power system event.

A typical network sequence is ; topology processing, state estimation and contingency analysis. Some systems also include short circuit analysis. The generation applications form a second on-line sequence of tasks.

Fig. 50.6 shows the data communications between the applications. Inter-application communication falls into three groups.

— From real time to study applications or between study applications.
— Between real time applications in the same analysis sequence (*e.g.* estimator to short circuit analysis).
— Between real time applications with different database structure (*e.g.* SCADA to estimator).

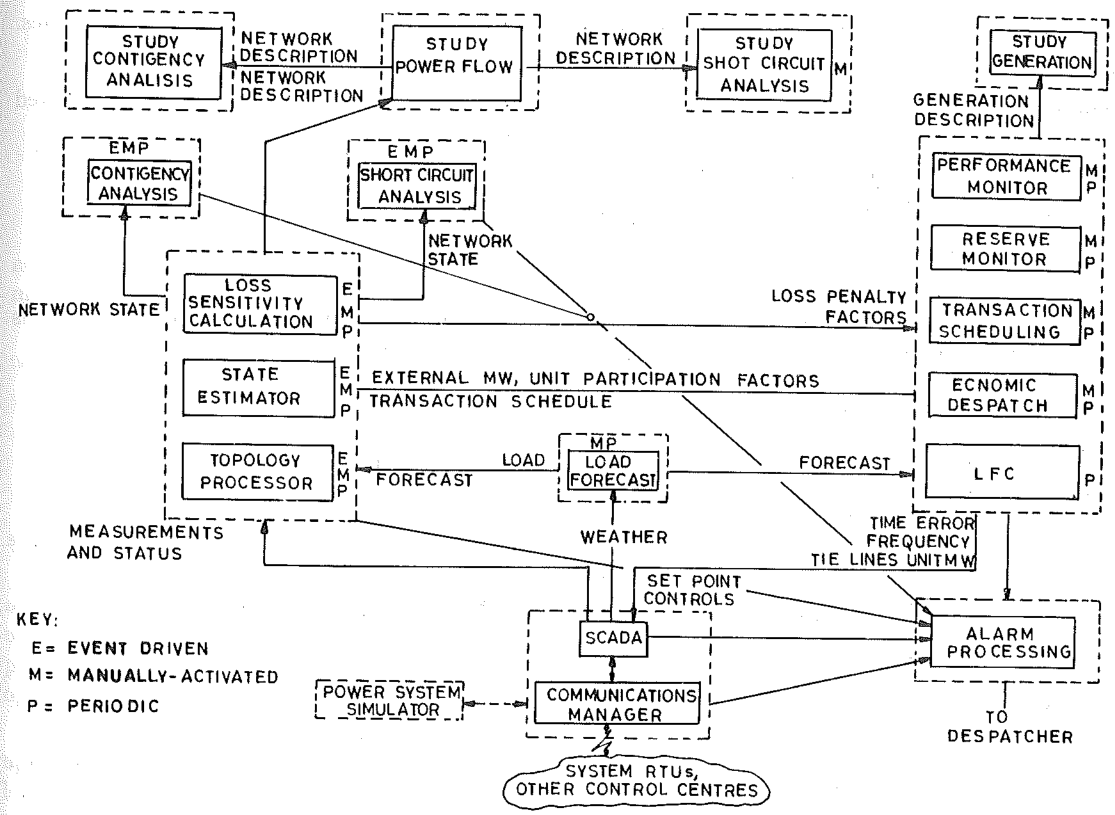


Fig. 50.6. Software in energy management system (EMS).

The facilities of the database and task management system are used interfacing the EM applications. These interfaces are capable of

— Transferring the data to the receiving application in time, without causing any deadlocks.
— Transferring enough information so that the receiving application can carry out its analysis.
— Supporting an inter-machine application interface.

50.8. SYSTEM OPERATING STATES

For the purpose of analysis and for achieving appropriate on line control actions, the operating states of power system are classified into the following categories (Fig. 50.7).

— Normal state (Secure State)
— Alert state (Insecure state)
— Emergency state
— In Extremis state (Islanding)
— Restoration state.

50.8.1. Normal State (Secure State)

The power system is in the normal (secure) state when frequency, currents voltages are of normal value and no likely contingency would cause on emergency condition to exist.

50.8.2. Alert State (Insecure State)

The power system is in the alert (Insecure) state when one or more like contingencies would cause an emergency condition. The border line between the Normal and Alert States depends upon what contingencies are considered likely. Generally all single contingencies are used as a basis for security analysis and a condition for Alert State.

Outage of a large unit; outage of a transmission path etc. are examples of single contingencies.

50.8.3. Emergency State

The power system is in the emergency state when critical operating constraints being violated and thereby the integrity of the system is adversely effected.

Examples of such critical operating constraints include :

— Thermal loading limits of transmission lines, transformers
— Line loading based on transient stability limit or voltage collapse limit
— Voltage limits of sub-station buses.

In emergency state the above constraints are being violated but the integrity of the system is still continuing and the system is supplying power to the consumers.

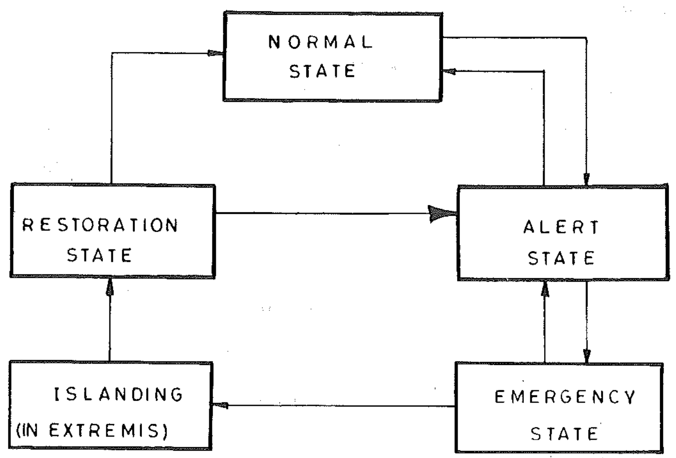


Fig. 50.7. Transition of operating states in a power system.

50.8.4. Islanding (In Extermis) State

This is an emergency state in which the system integrity is lost either by load shedding or by network islanding. In islanding condition, the inbalance between generating and load exists within each island resulting in frequency excursions, further load scheduling and tripping of generators. Thus islanding state is associated with black-out of some portion of the interconnected system.

50.8.5. Restoration State

By bringing the Islanding state under control, the system is brought in Restoration State. The generating units are restarted, the loads are reconnected, the interconnection are established.

Overall operation for reliability means to operate the system is Normal State. This means to generate enough power to meet area load and area net interchange demand, no overloading or machines/apparatus/lines, and the effect of contingencies are minimum. If the power system departs from the above conditions for any reason, the attempts should be to restore the above conditions in minimum time.

50.9. SYSTEM SECURITY (Refer Ch. 55)

Power system security may be defined as ability of the power system to operate in the normal state even with occurrence of specified contingencies. The system shall remain in normal state by means of fast acting automatic control systems following a contingency without allowing the system to pass to emergency state.

For steady state security analysis the following contingencies are generally considered :

1. Loss of one generating unit
2. Sudden tripping of a large load
3. Sudden change of tie-line power flow
4. Sudden outage of a major transmission line
5. Outage of one large transformer
6. Outage of one shunt reactor or one shunt capacitor bank.

50.9.1. Security Control (Refer Ch. 55)

The system state is continuously monitored by means of one line computer system. The data acquisition is through SCADA system. Fast computations of the security status are made. Command signals are sent to remote terminals regarding corrective actions to be taken.

Continuous monitoring of security and appropriate corrective actions for improving security is called security control.

System security function is generally broken down into following three major functions :

1. System monitoring 2. Contingency analysis 3. Corrective action analysis

System monitoring provides up-to-data information about conditions in the power system.

State Estimation based on system monitoring data produces best estimate of latest power system condition (state).

Contingency Analysis allows the system to be operated defensively. Many of the problems which occur in the power system can cause serious trouble within a very short time that the operator could not take any fast action. Therefore, modern computers are equipped with contingency analysis programmes, which model the power system and are used to study outage events and alert the operators of potential overloads or over voltages.

The third major function of the security is *Corrective Actions*. It allows the operator to take appropriate corrective action in the event of a contingency such as certain outage or certain overload. A simple form of corrective action involves shifting generation from one station to another station. Such a shift causes flow to change and this can bring about change in the loading overloaded lines.

Modern power systems have evolved the following guide lines :

— To operate the power system such that the power is delivered reliability.
— Within constraints of reliability, the system shall be operated economically.

50.10. STATE ESTIMATION

The state estimation is the process of estimating the 'state' of the power system.

It is based on statistical approach. The process involves acquiring data about system variables based on imperfect measurements and estimating the system state based on statistical criteria.

In a power system, the state variables are ; the voltage magnitudes and relative phase angles of system nodes. Measurements are required in order to estimate the power system performance and real time for the following :

— System security control — Constraints on economic despatch.

The inputs to an estimator are selected. These include imperfect power system measurements of the following for the various modes :

— Voltage — Power flow
— VAR flow

The estimator is designed to produce the best estimate of the system voltages and phase angles with understanding that there are errors in measured quantities and there is redundant data.

The output data of state estimates is used by system control centres for implementing :

— System security control — Constraints on economic load despatch.

50.11. EXPERT SYSTEMS USING ARTIFICIAL INTELLIGENCE FOR POWER SYSTEM OPERATION

Consider an emergency situation in a *large interconnected power system* during a cascade tripping of breakers accompanied by a large scale black-out. The load despatcher starts getting several alarms, the indications, print-outs etc. from the control panel does not know what to do. He finds himself in a helpless situation. In such situations digital computer aided artificial intelligence systems called 'expert systems' come to his rescue. The expert system tells him within seconds the probable location of the line fault and suggests steps to be taken for restoring the system.

Consider a complex thermal plant having many units and auxiliaries, several parameters are being scanned periodically. Some are within safe limits and some trouble is likely to develop. What are the actions to be taken in advance to overcome the trouble and to avoid tripping of a unit? An Expert System can give the possible solutions quickly and suggests actions which may be taken. Such *Expert Systems* are now beginning to emerge as practical tool for helping the operation and maintenance personnel to deal with increasingly complex power systems. The Expert Systems enable to acquire and preserve the knowledge of its best experts and keeps it always readily available. By encoding critical domains of human expertise for computer manipulation, an expert system can quickly sort through enormous amount of data to provide a system despatch/power plant operator/maintenance engineer/testing engineer with provisional diagnosis of problems and printout a list of possible corrective actions to be taken.

Expert Systems are not designed to calculate exact solutions to specific mathematical problem or technical problem, in the manner of conventional computer programs. The Expert Systems imitate human logic by applying a series of 'If-then' rules based on past experience.

50.11.1. What is an Expert System?

Expert Systems (like robotics, spoken language interpretation, visual object recognition) is a major branch of Artificial Intelligence (AI), a branch of computer science that enable the machines to perform like human beings in limited ways.

50.11.2. Components of Expert System

Each Expert System has three essential components :

1. **Knowledge Base.** This contains specific *facts* about application and the rules that apply under various situations.
2. **Interface Engine.** This controls the problem of solving by selecting and *executing the rules* and determining when the solution has been found.
3. **User Interface.** This provides a convenient format for entering additional data and for describing possible *solutions* or *scenarios.*

50.11.3. Example of an Expert System's Working

Suppose the on line data coming from a turbo-generator unit shows the temperature of a critical component to be 320°C. The *knowledge base* contains the information indicating that the safe temperature is 280°C. One rule coded in the *Interface engine* might be. "If the temperature exceeds 300°C then sound an alarm". After executing this rule, the *user interface* might provide a message saying "70% probability that hydrogen cooler is blocked. Suggest check the hydrogen cooler before shutting down the unit". The operator gets this message on control panel VDU and takes necessary corrective action.

The expert system have different approach than conventional computer programme solution in following respects.

1. Expert Systems use Artificial Intelligence (AI) language which makes it easier to encode "If—, them—" rules.

2. The programming time of AI language is lesser.
3. New rules and facts can be incorporated without the need of complete reprogramming.
4. The problem solving by Expert System is mainly probabilistic and intutive approach. The vast experience of experts, research studies, earlier case histories, probability theory etc. is used effectively.

In the above example the expert system has told the operator on the basis of past experience that blocked hydrogen cooler is the most likely cause of the abnormal temperature rise in the generator. Conventional computer would do several lengthy and irrelevant calculations to solve such a problem.

The importance of Expert Systems comes from their ability to imitate human reasoning process in specific ways, providing answers to problems that may be less precise than those calculated by conventional computer programs but which are more relevant and easy to understand. The search of solution is based on 'thumb rules' which can be updated with further experience.

Structurally, the process permits separation of rules, data, system control, user interface into different modules as shown in Fig. 50.8.

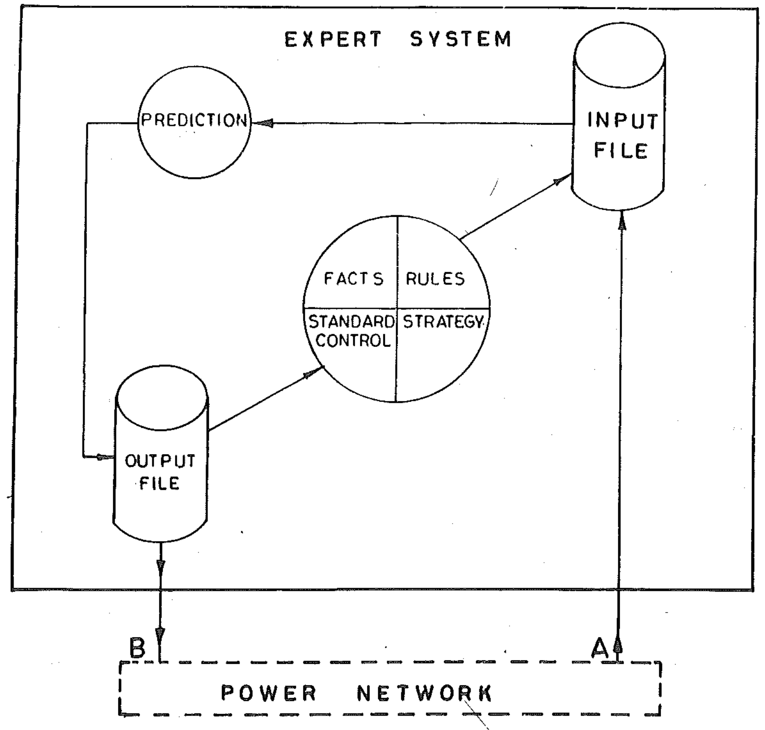


Fig. 50.8. Principle of Expert System applied for Network Restoration. [Customer Restoration and Fault Testing (CRAFT)].

50.11.4. Applications in Power Systems

Expert Systems have opened new era in power systems by integrating the following :

— Protection — Controls

— Diagnostics — Computers

— Accumulated human knowledge, etc.

Commercial applications of AI based on-line or off-line Expert System are being introduced by Electrical Power Research Institute (EPRI), USA.

Westinghouse, USA and other Electrical Manufacturing/Research/Power Supply companies in several areas of power systems. Following Expert Systems are now commercially available (1989).

1. **Generator Expert Monitoring System (GEMS).** It is a diagnostic tool for improving the generator's operation, reliability and availability on the basis of available monitoring information. GEMS can be installed with any generator unit by means of installation advisor module.

2. **Customer Restoration and Fault Testing (CRAFT).** CRAFT identifies and isolates faulted section in multi-tapped transmission lines. It is an effective means available at the Load Control Centre of a large interconnected AC system.

3. **On-line Diagnostic System for Emergency Diesel Generators.** It is a microcomputer based system to help the plant engineer in identifying operating trends and problem areas before complete failure of emergency power supply system.

4. **Plant Systems Inspection (PSI).** It is an expert system for maintenance engineer for inspection of the plant. The PSI inspects the plant periodically and performs predictive and preventive maintenance.

5. **On-line Monitoring System (OMS).** Such a systems collects and interprets data and advises operator about possible failures and advises corrective actions.

Many more Expert Systems are under development. Expert Systems are becoming an essential complement to switchgear protection, control, maintenance, testing, trouble-shooting etc.

In traditional protective systems the protection is not actuated until the abnormal condition (such as a fault) develops. The conventional protective system does not prevent a fault. Conventional protective system does not assist the operator in finding solution regarding actions to be taken. These limitations are overcome by the Expert Systems.

50.12. CENTRALISED DIAGNOSTIC EXPERT SYSTEM USING ARTIFICIAL INTELLIGENCE

Courtesy : Westinghouse, USA.

As the data can be transmitted from the plant to its control room, the data from several control rooms can be transmitted to the Central Master Controller. Thereby several plants can be watched from the Central Control. One example of such a system is described here.

Westinghouse, USA has installed (1988) On-line Expert System in Centralized Turbine-Generator Monitoring located in the load control centre at Orlando, Florida USA. The remote power plants are being monitored from the centralized system.

Commercial application of artificial intelligence (AI)-based, on-line diagnostics puts the combined diagnostic knowledge of turbine/generator experts in the hands of utility personnel so they can have a better continuous understanding of the health of their equipment.

From a central diagnostic centre, it is possible to monitor any power plant in the on-line, around the clock-and diagnose turbine generator conditions as they develop. The centralized diagnostic centre is connected to power plant data centres through telephone lines and packet switching network to transmit digital data.

The data centres receive data signals from hundreds of sensors located on the turbine/generator being diagnosed. This data is stored in the data centre's computer, then transmitted to the diagnostic centre. There, the data is analysed, and the resulting diagnosis is sent to power plant and displayed for use of operating personnel.

This is one of the few practical commercial applications of artificial intelligence. In particular, this is an application on the one branch of AI called Expert Systems.

Process diagnosis system. The process diagnosis system (PDS) is an Artificial Intelligence tool. It can be used for the *on-line* diagnosis of a wide variety of complex equipment, not just turbine generators.

PDS is a forward-chaining, rule-based system. It is an "empty" expert system ; that is, it defines a generic set of concept such as *sensors, rules and hypotheses for representing expert knowledge.* The knowledge engineer uses these concepts to create a rule base which contains the expert knowledge for diagnosing a specific process.

Once a rule base is defined, the PDS *inference-engine software* will use the rule base and the sensor inputs to compute the actual *diagnosis.* The representatives and propagation of belief are similar to that found in MYCIN, a medical expert diagnostic system.

For each rule, there are schemata describing each constituent part of the rule's antecendent (or evidence) a schema describing the rule's consequent (or hypothesis), and a schema describing relationship between the rule's evidence and hypothesis.

In most applications, it is just as important for the expert system to question the "truthfulness" of the data it receives as it is to perform a diagnosis on the equipment itself.

The correct diagnosis of any equipment condition requires knowledge of the condition and accuracy of the sensors themselves. If a sensor is known to be completely failed (*e.g.* an open circuit thermocouple), its reading should be ignored. Or a sensor may be slowly deteriorating so that its reading is still useful, but to a reduced extent (*e.g.*, a drifting sodium monitor).

PDS provides a method for handling both situations. The knowledge engineer can write rules which will determine a sensor's present condition. These rules can be based on redundant sensing, physical or logical tests, or on expert knowledge of the behaviour of a failed or failing sensor.

These are called sensor diagnosis rules and are executed before the set of rules perform the actual equipment diagnosis.

Another special class of rules exists, called *Parameter alternation rules*, that will dynamically alter the equipment diagnosis rules according to the results of the sensor diagnosis.

System Configuration of On-line Diagnostic System

Fig. 50.9 shows the system configuration. It comprises of :

1. **Diagnostic Centre.** The expert system computer is located at the *diagnostic centre* and not at individual power plant sites. The centralized approach allows the expert system to improve its knowledge based on experience gained from all power plants using the system.

The diagnostic centre consists of three functional areas :

Two artificial intelligence laboratories are used to facilitate the transfer of knowledge from experts to the knowledge engineer who is putting the knowledge into the computer.

The system takes advantage of the synergy of using multiple experts to create the knowledge base. The knowledge is put into the computer and then the experts are called back to verify that the diagnosis is in agreement with their judgement and experience.

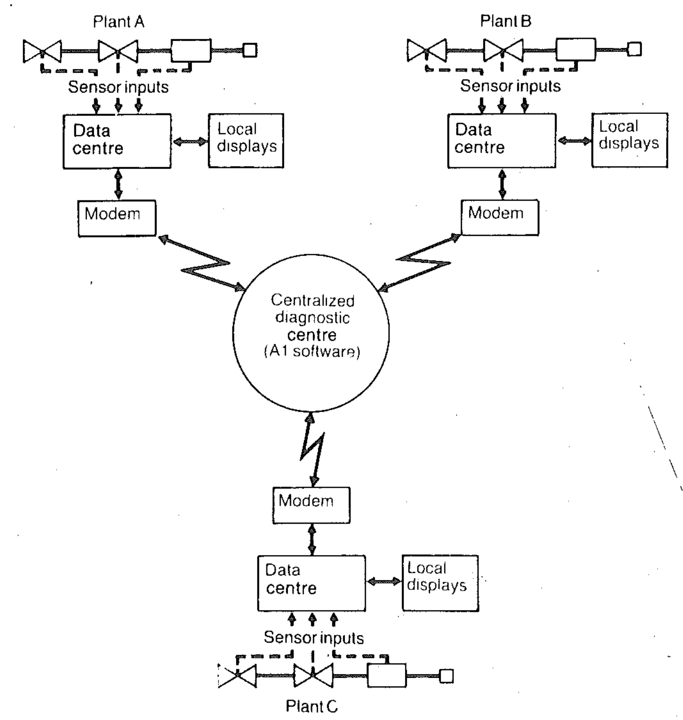


Fig. 50.9. Configuration of On-line Diagnostic System (*Courtesy* : Westinghouse, USA).

The knowledge to allow the computer to supply confidence factor values is obtained from the experts in the form of necessity and sufficiency functions. Thus if the human experts who provided the knowledge were given the same data as the computer, they should diagnose the same conditions with approximately the same confidence factors.

The rules can be tested using internal functions that allow the manual entry of sensor values and the setting of specific contexts in lieu of actual data. An edit function allows the study of the effects of small modifications in sensor values on the *propagation-of-belief* process.

2. **Monitors and data centres.** At the user end of the system are the monitors and data centre located within the power plant. Monitors contain the primary means of variable measurement. Typical monitors are the generator condition monitor for detection of particulation from overhead coils, radio frequency monitor for identifying arcing, and the fibre optics generator end turn vibration monitor. The fibre optics vibration monitor is interesting because of its ability to measure the magnitude of vibration of the end turns of the stator winding in the presence of high magnetic and electrostatic fields. High amplitude vibration is indicative of future problems with the stator winding and its detection allows operational changes which can extend the life of the windings.

50.13. SCADA SYSTEMS FOR POWER SYSTEM

The basic job of a SCADA (Supervisory Control And Data Acquisition) system is to supervise the working of various processes and to provide to the operator, the requisite information & the facility and means to control the working of the system and the outputs of the process.

Hardware. There is a main server computer (often with an identical twin, to provide redundancy), which runs the basic software of the SCADA system. There may be other associated servers to undertake specific functions. The main job of this system is to acquire the process data, and present it to the operator in suitable formats to enable him to take decisions as well as recognize any maloperations. The operator works via the HMI (Human Machine Interface). There is at least one HMI acting as a client to the server. For every small application, the HMI may be operative on the main-server.

While it is usual in a hydro power station to interface the PLC system to the SCADA system for data acquisition purposes, in some other application, this work may be entrusted to a Remote Terminal Unit (RTU) system. A block diagram of the digital control system for a hydro power plant is given in Fig. 50.10.

Software. The software enables reading in of the process information. Thereafter, the information is stored, transformed and displayed for supervision by the operator. In case the operator so decides, his instruction is forwarded to the process for execution. The resultant changes in the process are again displayed to the operator so that he may check out the effects of his command.

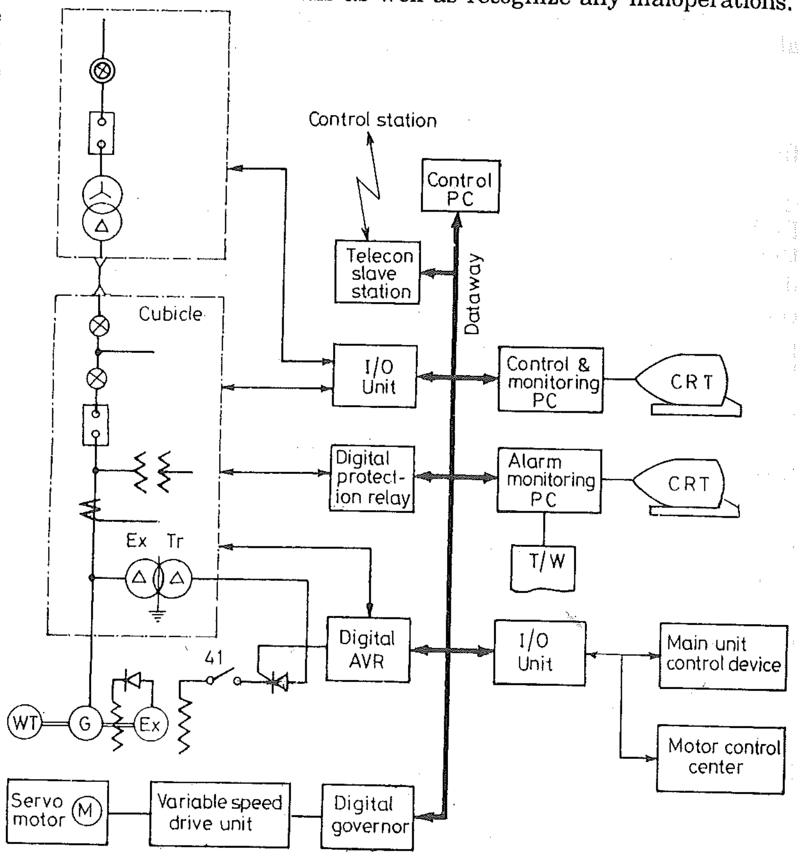


Fig. 50.10. Typical Block diagram of the digital control SCADA system for a Hydro Power Plant.

There are many sub-functional modules in the software. Each module has a specific function. The following are the common functions of the software :

— Analog value processing
  Converting the binary coded value into a standard value
— Binary value processing
  Getting the status of the represented element, checking its plausibility.
— Counted value processing
  Converting the counts into numeric value of (energy).
— 1-of-n value processing
  Locating which option has been selected.
— Time stamp processing
  Converting time to normal representation, storing the variable as per the given time.
— Data base operations
  Storing information in a suitable detabase and retrieving the correct information on query.
— Events logging
  Keeping and retrieving the events in the given chronological order, printing them on the logging device.
— Alarms logging and acknowledgement
  Similar to events. But the operator acknowledgement has to be applied on the stored alarms.
— Station diagrams
  Display Single Line Diagrams of individual locations with all the relevant data filled in.
— Reports display
  Create the desired report using the correct template and the right variables, for display on the screen.
— Reports printing
  Same as above, however, the output is added to the print queue.
— Events/alarms based actions (reports, storage of information)
  On occurrence of the defined event/alarm, initiate the predefined action.
— Trends/bar charts
  Take the initial data from the database and create the desired graph. Update it on receiving fresh information.
— Limits processing
  The analog values and the counted values may be subject checking for limits. The limits are operator defined. Crossing of limits leads to alarm.
— 'Rate of change' processing
  Here the limit is set on the first derivative of the value.
— Status evaluation
  Checking the current status of any variable. The processing of the variable could change depending on its current status. e.g. if a value is not being received from the process, there is no point in checking the value for limits.
— Plausibility check
  Any value, when received, is checked for being what it represents. Wrong or invalid entries are to be discarded.
— Command outputs
  Check the validity of the command for authorization, background status, correct state, etc.
— Manual inputs

If the operator doubts the current value of the variable, he may decide to replace it with his estimate.

— Valid/invalid check

Any value declared invalid shall not be used for further functions.

— System configuration

All system modules (Hardware & Software) are monitored for proper functioning. Any significant deviation leads to a change in the system to enable uninterrupted but correct operation.

— Hot-standby function (Dual servers)

Duplication of hardware is done to increase system availability. Duplication also enables a fully functional identical server, which shadows the main server and, hence can ensure continuation without interruption, in case of a switchover. It is also useful in case of any significant changes in the system, which are tested on the standby system first.

— Switch-over

The various supervisory functions within the SCADA system at Hardware and Software level will signal a switchover to the back up or standby system, in case any serious fault or error is observed.

— Archive

A very important part of the SCADA system is its storage of process related data. As an extension there to it stores data pertaining to some past time-points as well. This enables a proper comparison of any status or value. It also permits trending of data for later analysis. The same data can also be used by other systems, such as, the Higher-level functions.

— Database access for other programs

This is the gateway to enable other interested systems to use the stored data for their specific function. The same gateway may be used to transfer the data to any other site.

The software has many built-in functions to check the validity of the data received. This prevents misinterpretation of data.

HMI (Human Machine Interface)

There may be one or more HMI logically connected to the main server. The operator gets the process data as visualization on the screen of the HMI. The functionality of the HMI is capable of drawing operator's attention towards any mishap in the system. The operator issues his command over the HMI and the system, in turn, informs him of the validity of his action and later, the result of his action.

Together, the HMI's and the servers constantly keep check on the health of the SCADA system. If any error is detected, the whole system reconfigures itself in the most logical way, to continue operation.

Video screens are provide to display an overview of the process i.e., the Network diagram or combined SLDs. Typically the screen has space to display an interconnecting diagram of all the important stations along with space for additional information, e.g., alarms. Such a screen is a big help for the operator. A change would be depicted by switching on or by blinking of the corresponding lamp. The operator's attention is drawn to this change and he may now check up details on the monitor of the HMI.

A video screen device is very similar to a video projector. Technically, it is similar in working to a monitor of a computer (HMI). Hence, the symbols and other graphics look the same as any other diagram on the HMI screen. Any graphic constructed for display on normal monitor can also be displayed on the Board. With the use of 'windows', we can project many pages on the Board at the same time. Hence the looks and feel of the Board is very similar to the computer monitor, making it simple to configure and operate. To construct a large board, we can combine a number of devices vertically and horizontally. In this case, a special electronic unit is required, which splits

the original diagram in to a number of part diagrams, each of which is displayed on to the corresponding unit. So the combined face of the units reproduces the original diagram. Making a change is as simple as editing the diagram and using the changed diagram thereafter. No hardware change in required.

Add-on functions

Since the SCADA system stores a whole lot of process information, the same is available to carry out other useful functions. The more important among these are :

— Load-Frequency Control — Generation Scheduling
— Load Forecasting — Machine Parking
— Condition Monitoring based maintenance scheduling
— Asset Management — Spinning Reserve
— Multi Tariff Billing — Power System Modelling
— Water Inflow Prediction — ABT Reporting

Expert Systems incorporating Artificial Intelligence are being introduced to assist the control room operator/plant engineer/testing engineer/maintenance engineer, etc. An Expert System incorporates computer programs based on AI-language and 'If..then..' rules. Expert System provides quick possible clues regarding problem and likely solution.

51

Power System Planning

Scope — Significance — Computer Programmes — Generation Planning — Transmission Planning.

51.1. SCOPE OF POWER SYSTEM PLANNING AND DESIGN

Planning and designing has become important and continuous activity. Older equipments and systems are being replaced by the new. The overall planning and designing is divided into the following categories :

— Energy resources and generation planning considering alternative sources of energy.
— Transmission planning including planning of interconnections.
— Distribution planning including planning of load centres.

Planning and design activities are influenced by the following aspects:

— Changing requirements of consumers, increasing loads over large geographical area away from generating stations.
— Changing pattern of energy resources of generation methods.
— Feedback of *System studies* and experience leading to better design of systems and equipments.
— New software.
— Availability of new, superior technologies, *e.g.* HVDC, Fibre-optic data transmission, FACT, SVS.
— Obsolescence of old products and systems, *e.g.* small isolated generating stations; bulk oil breakers, electro-mechanical relays.
— Increasing use of power electronics.
— Increasing use of microprocessor, digital computer based, programmable systems for protection, control and automation.
— Increasing use of SCADA, AGC, DAC systems.*

51.2. SIGNIFICANCE OF SYSTEM PLANNING AND DESIGN

Good system planning and design has the following objectives :

— Sufficient, continuous supply of electrical energy to all the consumers over wide geographical area at lowest possible cost at specified voltage and frequency.
— Highest possible security and reliability of supply.
— Most economic generation, transmission and distribution.
— Optimum use of energy resources.

*SCADA	:	Supervisory Control and Data Acquisition.
AGC	:	Automatic Generation Control.
DAC	:	Distribution Automation and Control.
ES	:	Expert System.
AI	:	Artificial Intelligence.

These are difficult due to the following :

— Decision regarding choice of equipment have long term effect (15 to 30 years) and equipments may become obsolete in less time (2 to 10 years)
— Sources of energy for generation of electrical power are scattered away from load centres and there are many alternatives : *e.g.*

e.g. coal for thermal plants, water resources for hydroplants, nuclear, geothermal, wind, solar, tidal, waste, etc.

— Electrical energy cannot be stored in large quantities economically some new techniques such as pumped storage; battery and fuel cell systems, compressed air systems etc. are used upto a few MW.
— Alternative forms of transmission are available *e.g.* AC, HVDC. SF_6 Gas Insulated Cables (GIC) underground cables etc.
— Economic analysis has uncertainties regarding cost of fuels, escalations in capital cost of future projects, interest rates etc.
— Planning decisions are influenced by load management techniques.

51.3. COMPUTER PROGRAMMES FOR PLANNING

The planners formulate several alternatives especially for generation planning and transmission system planning. Each alternative has lengthy and complex formulations. The following computer programmes are used for expansion planning and simulation. These programmes may be used separately or with any other programme as per requirement of the problem.

1. Load growth and load shape Model Programme.
2. Generation Growth Programme.
3. Transmission Growth Programme.
4. Investment costing.
5. Generation Production Costing.
6. Organisation Financial model programme.

Local Growth and Load Shape Model Programme accepts the hour by hour load data of earlier years and gives predicted, tabulation of load shape during a day for all the days of a year. These predictions are used for simulation of generation growth programme.

General Growth Programme compares the installed generating capacity with the predicted load growth. The risks of capacity shortage are predicted. Alternative generation growth strategies are formulated by using different alternatives.

Transmission Growth Programme is used for determining the voltage levels, routes, required year of installation for various future transmission lines and sub-stations.

The output of transmission growth programme are used for planning expansion of back bone transmission network underlying main transmission network to match the planned generation growth.

Investment Costing Programme is used for predetermining the investments for the generation growth and transmission growth.

Generation Production Costing Programme simulates the fixed and running costs on the basis of present rates and likely price-rise and computes the future production costs. The results of investment costing programme are also considered.

Organisation's Financial Model Programme is used for predicting the influence of investment decisions on the overall balance sheet, cash-inflow and cash-outflow predictions.

For the Organisation's Financial Model needs the following inputs : generation and transmission costs of every year, details of the organisation financial structure, accounting data, management information reports.

The organisation financial model programme can simulate the monthly basis and the necessary capital investment for generation and transmission growth for that month can be predicted.

Table 51.1 gives the details about Generation Planning.

Table 51.2 gives details about Transmission Planning.

Table 51.1. Aspects About Generation Planning

Basic Questions	*Inputs*	*Remarks*
1. How much installed capacity during next 20, 10, 5, 1 years. How much shall be the excess capacity ?	— Load forecasts — Prediction of outages : Planned and unplanned Maintenance schedules	— Generation growth programme — Planned Capacity should be in excess of predicted requirements.
2. What shall be unit size, type of unit? (*e.g.* 200 MW, 500 MW)	— Loss-of-load probability (LOLP) analysis.	— Prediction of LOLP for various sizes, types of units and comparison of their outage characteristics.
3. What type of generation ? — Steam (thermal) — Hydro — Nuclear	— Available natural resources and technology. — Further capital investment cost of different types of generating stations. — Future running cost (fuel, efficiency) — Future reliability, outage possibility. — Environment factors.	— Decision based on predicted one year cost considering capital and running cost.
4. What should be scheduled generation of Hydro and Thermal Stations.	— Data regarding hydro reserves throughout the year — Cost of hydro and thermal generation	— Hydro thermal co-ordination based on available energy resources, optimum utilization and economic generation.
5. What should be generation commitment of a station, an area and the Total System	— Load frequency control as first priority. — Economic generation as second priority.	— National local control centre decides total generation and instruct scheduled interchange to each area. — Individual area decides total required generation of that area for meeting its load/frequency and committed interchange.

Table 51.2. Aspects About Transmission Planning

Basic Questions	*Inputs*	*Remarks*
1. Configuration of Transmission, system Which new circuits ? Which new tie-lines ? Which new sub stations ?	— Existing network data — Locations and magnitudes of all future generating stations — Locations and magnitudes of all future load centres. — Annual study of generation growth and load growth — Short and long range plans of generation and load.	— Existing network used as starting point. — Long range planning. — Short-term planning of transmission. — Alternative expansion plans of transmission. — Matching transmission growth with load growth and generation growth.
2. What voltage levels ?	— Length and power of transmission line — Economical voltage level — Power handling capacity required per circuit — Existing voltage levels.	— Voltage levels are standardised for 1. Backbone transmission network 2. Primary transmission 3. Secondary transmission 4. Special cases such as very long lines

Basic Questions	*Inputs*	*Remarks*
3. EHV-AC or HVDC ?	— System studies and requirements — Economic studies.	— EHV-AC used for backbone net work primary transmission : — HVDC used for long high power lines and interconnections
4. Technique for Compensation Reactive power Planning.	— Load flow studies — Dynamic stability studies	— SVS used at various substation buses.
5. Which inter connections	— Overall policy — Geographical locations of adjacent independently controlled AC Networks — Load cycles of networks and available capacity for interchange — Agreement between the organisations.	— Interconnections are either EHV-AC/HVDC/HVDC back to back. — Interconnections are planned on the basis of long range transmission plants.
6. What should be location of sub-stations and types of sub-stations	— Location selected on the basis of locations of load centers, generating stations, transmission routes.	Types : — Outdoor open terminal — Indoor SF_6 insulated GIS — HVDC — Indoor metal clad for medium voltages.
7. What should be the communication chemicals	— Telephones — Power-line carrier — Radio link.	
8. What should be controlled strategy.	— Fully automatic unmanned — Semi-automatic...only control supervisors.	

Summary

The load, generation and transmission grow continuously. The long-range and short-term planning are essential for :

— Planning of generation.

— Planning of transmission and distributions.

The planning should aim at excess capacity *i.e.*, installed capacity should be more than predicted demand. Various aspects about generation planning, transmission planning and system studies have been summarised in Tables 51.1 and 51.2.

52

Improving Dynamic Stability by Flexible AC Transmission System (FACT) and HVDC Systems

Inter-relationship between P, Q, V. δ — Concept of Dynamic Stability — Tasks in Power System Operation — Network phenomena and associated problems — Methods of Improvement — Dynamic Stability — Power Swings — First Swing — Oscillations — Damping Control — FACT Systems. HVDC Systems with Damping Control Feature.

52.1. INTER-RELATIONSHIP BETWEEN VOLTAGE, ACTIVE POWER, REACTIVE POWER, POWER ANGLE, OSCILLATIONS AND VARIOUS TYPES OF STABILITIES

Various types of stabilities have been defined in Sec. 44.21. Voltage control and reactive power compensation has been covered in Chapter 45-B. Static VAr Sources (SVS) and their application for dynamic compensation has been covered in Sec. 48.28. We will now take an overall integrated view of various methods being used presently and in near future for improving voltage profile and the dynamic stability of power system.

52.1.1. Review of Concepts of Power System stability and Basic Equations

Power system stability is generally explained by means of the following well known power equations :

1. **For a Single Machine against Infinite Bus :**

$$P = \frac{EV}{X_S} \sin \delta \qquad \text{...(1)... Ref. Eqn. (44.3)}$$

2. **For AC Transmission System :**

$$P = \frac{V_S \cdot V_R}{X} \sin \delta \qquad \text{...(2)... Ref. Eqn. (44.1)}$$

where, E and V, V_S, V_R are magnitudes in rms volts

From these equations the co-relation between the following variables is identified.

For Single Machine System

P = Active power flow from generator to infinite bus
E = Induced e.m.f., rms Volts.
V = Terminal voltage, rms Volts
δ = Phase angle between E and V, are called power angle or load angle.
X_S = Synchronous reactance.

For AC Transmission System :

P = Active power flow from V_S to V_R
V_S = Sending-end voltage, rms Volts.
V_R = Receiving-end voltage, rms Volts.
X = Series reactance of the line
δ = Load **angle or power angle, the angle between vectors V_S and V_R.**

During dynamic operating conditions P, V_S, V_R, δ undergo violent swings and stability is endangered.

In the above equations, the term reactive power flow (Q) is not appearing. However, the voltages V, V_S, V_R are influenced by the reactive power flow (Q) as visualised from the following equations :

Complex power S is given by :

$$S = P + jQ \qquad \text{...(3)}$$

Power angle δ between V_S and V_R of a transmission line is given by approximate equation

$$\delta = \frac{XP - RQ}{|V_R|} \qquad \text{...(3) ... Ref. Sec. (45.15)}$$

If $X \gg R$,

$$\delta = \frac{XP}{|V_R|} \qquad \text{...(4) ... Ref. Sec. (45.15)}$$

In equations (1) to (4) the voltages at the buses of generation station, sending and receiving-ends of transmission lines are influencing the load angle δ and the power flow P. Hence the magnitude difference ΔV between sending-end voltage V_S and receiving-end voltage V_R of a transmission line is given by the equation.

$$\Delta V = |V_S| - |V_R| = \frac{XQ}{|V_R|} \qquad \text{...(5) ... Ref. Sec. (45.16)}$$

Hence reactive power flow Q determines the voltage difference ΔV between the sending-end bus and the receiving-end bus.

52.2. PARAMETERS FOR DYNAMIC CONTROL

By co-relating Equations (1) to (5) given above we can visualise the following :

1. **Active Power Flow P.** This determines the load angle δ and *vice versa.* As the voltage must be maintained within specified limits, no much variation in active power flow can be achieved by varying voltages.

Instead, the phase angle (δ) between voltages is varied to change P.

2. **Load Angle** δ. The load angle δ between generator e.m.f. E and generator bus voltage V is increased by increasing the input to the turbines.

The load angle δ between sending-end voltage $|V_S|$ and receiving-end voltage $|V_R|$ of a transmission system is varied by increasing the generation or by reducing the load.

Other methods to achieve the change in power flow through a tie-line include

1. Use of phase shifting transformer in series (Sec. 49.15).
2. Use of Flexible AC Transmission (FACT) (Fig. 52.2).
3. Use of HVDC Transmission (Sec. 47.2.10).

3. **Bus Voltages and Reactive Power Consumption.** Various methods of controlling the bus voltages have been reviewed in Table 45-B-1. Bus voltages are controlled by controlling reactive power Q, and by tap-changing transformers. *Voltage Stability* is related with bus voltages and reactive power compensation. (Ch. 45 C) *Generator Stability* improvement by AVR and Excitation System is covered in Ch. 45 D.

4. **Steady State Stability Limit and Transient Stability Limit.** Various methods are described in Ch. 44.

5. **Oscillations in Power Angle δ and Power Swings.** Refer Sec. 44.21 – Clause 13. During disturbance the power angle δ oscillates. The first swing is generally largest. By various means, the swing of δ is minimised.

6. **Dynamic Stability.** The instability caused by insufficient damping torque is called *Oscillatory instability.*

A transmission system is said to be *Dynamically stable* if it recovers its normal stable condition following a sudden specified minor disturbance.

7. **Transient stability.** A transmission system is said to be transiently stable if following a sudden *large disturbance,* it regains its normal stable condition. Various methods of improvement in transient stability have been reviewed in Ch. 44.

52.3. FUNDAMENTAL REQUIREMENTS OF AC TRANSMISSION SYSTEM

— Voltages at sending and receiving ends should be within specified limits and should not be allowed to collapse during steady state, transient state; under the various conditions of dynamic stability. This is called voltage stability. Voltage instability occurs due to reactive power unbalance. SVS systems are necessary to avoid voltage instability.
— Stability should be maintained under steady, transient and dynamic conditions.
— Power flow through transmission lines should be controllable. This is particularly required for an interconnected line due to the reasons described in Sec. 49.9.

52.4. TIME RANGES OF ABNORMAL CONDITIONS AND DISTURBANCES

The disturbance and damping are related with time-rate of change of variables. The abnormal conditions and disturbances may occur during sub-transient, transient, or steady-state periods (Ref. Sec. 3.5). Some very fast transient may be within a period of a few microseconds. Table 52.1 gives the time ranges of various phenomena.

Table 52.1. Time Range of Power System Phenomena, Disturbances and Abnormal Conditions

Phenomenon or Happening	*Time-Range (Approximate)*
1. Lightning surges	10 μs — 100 μs
2. Very fast switching surges	2 μs — 10 μs
3. Switching surges	100 μs — 3000 μs
4. Line faults and fault clearing primary back-up (Ref. Table 44.1)	1 — 2 cycles 2 — 3 cycles
5. Transient stability and Dynamic Stability	40 millisce — 40 sec
6. Steady State Voltage control	20 cycles — 1 min
7. Steady state stability	20 cycles — 1 min
8. Load-frequency disturbance and prime-mover response.	3 sec — 1 hr
9. Load cycle and Thermal Overloads	5 min — 24 hrs

Note : 1–3 Sub-transient state happening.
4–5 transient state happening.
6–9 Steady state happening.

52.5. ENTER THYRISTOR CONTROL

Traditionally the only means available for protective and control switching operations of circuit-equipments such as reactors, lines, capacitors etc. were circuit-breakers which operate under transient state (Fig. 3.7) and require approximately 3 cycles (60 milli-sec.). Thyristors used for power switching operate within a few milli-seconds including control time. During 1980's the rate

and capabilities of thyristors have increased manyfold. Single thyristors are now available for rated forward current upto 4000 A and rated voltage upto 1.5 kV. A thyristor can be triggered by a short-duration pulse (100 μs) of a few milli-ampere gate current. When used in AC circuits, the gate current pulses can be phased so as to fire the thyristor at desired phase angle within each positive half-cycle thereby producing phase control. Several thyristors can be connected in series to form a 'Valve' for high voltage convertors.

By means of power thyristors, and associated controls it has been possible to obtain switching of power circuits components within a few milli-seconds during every cycle, thus giving effective means of dynamic control.

This application has been successfully used for

— HVDC Convertors (Sec. 47.5)
— Flexible AC Transmission (FACT)
— Excitation Systems and AVR.
— SVS Systems (Sec. 48.28)
— AC harmonic filters.

52.6. FIRST SWING PERIOD AND OSCILLATORS PERIOD

Fig. 52.1 illustrates the oscillations in P, V_R and δ during a sudden disturbance in a transmission system or connected AC networks.

The *first swing* period refers to the time for the first half oscillation of the rotor angle(s) or synchronising power swing(s) following a large disturbance such as a fault or a small disturbance such as opening a line. *Typical time range of first swing period is 0.5 to 1 sec.* In this period the synchronous machines are characterised by constant flux linages behind machines transient reactance. First swing period is usually critical for maintaining transient stability.

Oscillatory period follows the first swing period. *During oscillatory period, significant cyclic variation in voltage, currents, active and reactive power flow, power angle δ take place.* Synchronizing power swings caused by synchronous machine rotor angles may last for 3 to 20 sec after a severe fault.

By adopting SVS, FACT, HVDC System with damping control, fast response excitation systems of synchronous generators, first swing peak is reduced and subsequent oscillations are damped. Dynamic stability is improved.

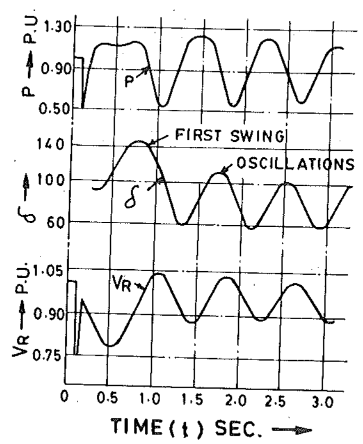


Fig. 52.1. First Swing and Subsequent Oscillations in an AC Transmission System (Without dynamic oscillation.)

For improving transient stability and dynamic stability the flow of reactive power and damping of voltage oscillations is helpful. This technique is possible by using the following means :

— SVS Systems
— FACT Systems*
— HVDC transmission with damping control*.

52.7. REVIEW OF POWER SYSTEM PROBLEMS AND METHODS FOR IMPROVEMENT

Switchgear, Protection, Power System, Automation and Controls perform the tasks by a teamwork of various equipments and associated controls.

Table 52.2 gives the review.

* Refer book 'EHV-AC and HVDC TRANSMISSION PRACTICE.'

Table 52.2. Review of Power System Problems and Methods/Equipments for Improvement

Tasks ↓ Methods →	Increase transmission voltage	Increase No. of Lines in parallel	Transformer Tap-changing	Slow AV Control	Fast AV Control	Fast turbine valving	Rapid line switching operations, reclosing of circuit breakers	Breaking resistors	Shunt reactor (switched/ unswitched/linear/non-linear	Shunt Capacitor	Series reactor	Series capacitor	Synchronous condenser	Thyristor controlled reactor	Thyristor switched capacitor	Static VAr sources (SVS)	Short circuit limiting coupling (or Fault current limiter)	Flexible AC Transmission (FACT)	HVDC System with Damping Control
1. To improve steady-stage stability	*	*		*								*	*	*	*	*		*	*
2. To improve dynamic stability					*								*	*	*	*		*	*
3. To improve transient stability	*	*			*	*	*					*	*	*	*	*		*	*
4. To limit rapid voltage decline					*		*			*			*	*	*	*		*	
5. To limit slow voltage decline			*	*						*			*	*	*	*		*	
6. To limit rapid voltage increase					*		*		*				*	*	*	*		*	
7. To limit slow voltage increase			*	*					*				*	*	*	*		*	
8. To limit fast wavefront overvoltages due to lightning, switching etc.								*	*					*		*			
9. To give reactive power support at dc converter terminals										*			*	*	*	*			
10. To increase short circuit level												*	*						
11. To decrease short circuit level										*	*						*		*

Table 52.3 gives the comparison of various methods. In traditional protective systems the protective and control functions are almost independent. In recent microprocessor based protective and control devices the functions are integrated.

Table 52.3
Comparison of Various Methods
for Improving Voltage, Reactive Power Flow, Dynamic Stability

	Method	*Advantages*	*Disadvantages*
1.	Shunt reactor (Switched)	Simple principle and construction	Fixed in value. Switching of large reactors is difficult, gives transients.
2.	Shunt capacitor (Switched)	Simple principle and construction, can be arranged in Banks.	Fixed in value. Switching takes about 3 cycles.
3.	Series capacitor (Fixed)	Simple principle. Performance relatively insensitive to location. Improves steady state stability limit.	Requires overvoltage protection and subharmonic filters. Limited overload capability. Power flow cannot be changed.
4.	Synchronous condenser	Has useful overload capability, Fully controllable. Low harmonics. Step-less control.	High maintenance cost. High initial cost. Slow control response. Performance sensitive to location.
5.	Thyristor-controlled reactor (TCR). Gives shunt compensation.	Fast response. Fully controllable. No effect on fault level. Can be rapidly repaired after failures.	Generates harmonics. Perfomance sensitive to location. Requires harmonic filters
6.	Thyristor-switched capacitor (TSC). Gives shunt compensation.	Can be rapidly repaired after failures. No harmonics.	No inherent absorbing capability to limit overvoltages. Complex buswork and controls. Low frequency resonances with system. Performance sensitive to location.
7.	Static VAr Source (SVS)	Stepless control. Combination of 5, 6.	Requires harmonic filters. Combination of 5, 6 above
8.	Flexible AC Transmission (FACT).	Less costly and simpler than HVDC. Damps oscillations and improves dynamic stability. Power Flow can be controlled. Improves transient and dynamic stability.	Needs intermediate substations at an interval of 250 to 350 km along the long line. In initial stage of development.
9.	Fast circuit breakers, Protective relaying, Auto-reclosing.	Improves the transient stability limit.	Does not help in damping oscillations and improving the dynamic stability.
10.	HVDC System with Damping Control	Power flow can be controlled rapidly. Power Flow can be reversed rapidly. Damping of power swings effective.	Very costly Very complex.

The various techniques are reviewed in following paragraphs :

1. **Switched Shunt Reactors.** Shunt reactors are connected to long transmission lines at sending-end, receiving-end and in intermediate sub-station. Large shunt reactors are difficult to switch-off due to high inductive energy and current chopping in circuit-breakers. Hence fixed unswitched shunt reactors are being used presently for EHV-Transmission systems. Shunt reactors provide *fixed* shunt compensation to line capacitance to earth.

2. **Switched Shunt Capacitors.** These are used at receiving end, in intermediate substation and near load points. They are switched on during heavy loads and switched-off during low loads for voltage control. Modern SF_6 and vacuum circuit-breakers have overcome the problems of restrike phenomena and the switching overvoltages occurring with earlier oil circuit-breakers. However circuit-breakers cannot be operated repeatedly and their operating time is about 3 cycles.

3. **Series Capacitors** are used for long EHV-Transmission systems for improving power transfer ability and stability limit. They are located in sending-end, receiving-end and intermediate substations. They compensate the inductive series reactance of long transmission lines. They have inherent limitations of subsynchronous resonance and limited overload capacity.

4. **Synchronous Condensers.** These are used in receiving substations and give controllable shunt compensation as well as additional short-circuit level. Recently (1980's) they have been replaced by SVS systems.

5, 6, 7. TCR, TCC, SVS. They provide controllable shunt compensation. Thyristors can be controlled rapidly to vary the shunt reactive power compensation. The bus voltage can be dynamically controlled. SVS system give improvement in dynamic stability by rapid variation of reactive power compensation.

52.8. FLEXIBLE AC TRANSMISSION (FACT)

This is a recent development (1986). These systems are likely to be used for AC interconnecting lines and long AC lines.

Fig. 52.2 (*a*) shows a long Flexible AC Transmission system (FACT). It has intermediate substation at an interval of 250 to 350 km. 1, 1... are controllable series capacitors and 1′, 1′ are controllable SVS.

In a typical FACT system, controllable series capacitor installation is achieved by means of bypass Thyristors switch [Fig. 52.2(b)]. By controlling the bypass current I_B through the thyristor controlled switch (TCS) the current I_C through series capacitor (SC) and the amount of series compensation is varied.

$$P = \frac{|V_S| \cdot |V_R|}{X_L - X_{CF}} \sin \delta$$

By controlling X_{CF}, the power flow P is controlled.

where X_L = Series reactance of the long transmission line

X_{CF} = Controllable series reactance of series capacitor of FACT system.

By controlling X_{CF} by means of bypass, thyristors switch, the power transfer P is controlled. The phase control of bypass thyristor switch gives the control over the power transfer P and the power angle δ. The basic limitation of AC transmission line and series compensation had been the lack of controllability. This limitation has been overcome by controllable series capacitors of FACT system. In addition to the controllable series capacitor; the FACT incorporates controllable shunt compensation by means of SVS. Thereby the voltage at the sending-end and receiving-end is controlled by dynamically. This gives voltage stability and improves dynamic stability of the transmission link.

In a typical FACT system, controllable series capacitors and controllable SVS combinations are installed at an interval of approximately 250 km along a long AC line. By controlling series.

Description of a FACT system

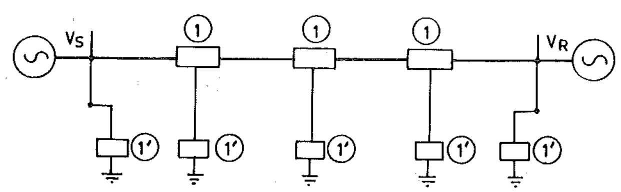
Various configurations are being tried. A likely configuration Fig. 52.2 (*a*) shows a single line diagram of a long AC transmission line incorporating FACT principle.

Controllable series capacitor (1) and controllable shunt compensation (1′) are installed at an interval of 250 to 350 km.

Fig. 52.2 (*b*) shows schematic diagram of the details of controllable series capacitors (1). All the equipments of (1) are installed on *insulating platform* (*IP*). The control unit senses the phase to ground voltage (*V*) at the location of (1) and adjusts phase angle of TCS. Bypass current I_B is controlled.

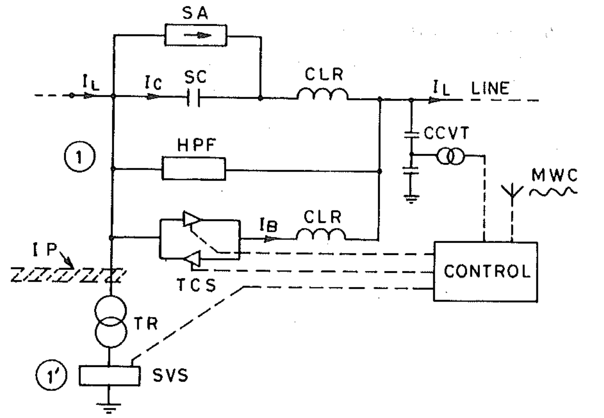
$$I_L = I_C + I_B$$

By varying $\boldsymbol{I_B}$, $\boldsymbol{I_C}$ is varied. This results in variable series compensation which can be controlled from load control centre *via* compensation, the power flow is controlled. By controlling the SVS, the voltages at sending-end, receiving-end and at intermediate substations are controlled.



V_S = Sending-end voltage
V_R = Receiving-end voltage
1 = Controllable series compensation
1′ = Controllable shunt compensation (SVS).

Fig. 52.2 (*a*) Single line schematic diagram of a Flexible AC Transmission System (FACT) (Controllable AC Power Link – CPL)



IP = Insulating platform for (1).
SC = Controllable series capacitor bank with current I_C.
TCF = Thyristor control switch with bypass current I_B.
HPF = High pass harmonic filter to suppress harmonic generated by operation of TCS.
SA = Zinc-oxide Surge Arrester for protection of SC against overvoltages.
CLR = Current Limiting Reactor.
TR = Auxiliary transformer for SVS.
SVS = Static VAr source.
CCVT = Coupling capacitor, voltage transformer.
MWC = Microwave communication channel.

Fig. 52.2 (*b*) Details of controllable series compensation in the FACT installation (only one phase shown).

Series and shunt compensation are controllable and control is fast and over wide range. Hence, FACT gives improvement in the dynamic stability of AC transmission system.

By simultaneous control of 1, 1 ... and 1′, 1′ ... the power flow *P*, voltages V_S and V_R and power angle δ between V_S and V_R are controlled. The oscillations in *P*, *V*, δ are damped by means of control of 1 and 1′.

9. **The Microwave Communication Channel.** By simultaneous control of (1) and (1′), the power flow, power angle and voltages are controlled dynamically.

10. **Fast Circuit-breaker and Protection Systems.** Effect of fast circuit-breakers, Auto-reclosing etc. has been covered in Ch. 41. Circuit-breakers cannot be operated in time less than about 40 milliseconds. Protective relays take approximately 20 milliseconds. Circuit-breakers are not suitable for repeated operations which are necessary for damping control.

These limitations are not present in thyristor controlled devices like SVS, FACT.

Hence circuit-breakers are used for tripping faulty lines, and SVS/FACT systems are used for improving dynamic stability and for damping control.

52.9. DAMPING OF OSCILLATIONS IN AC NETWORKS BY MEANS OF HVDC DAMPING CONTROL

HVDC Transmission links in the form of long distance overhead line/submarine cable/back-to-back coupling station interconnect two (or more) AC Networks.

Asynchronous HVDC interconnection has no parallel AC lines.

Synchronous HVDC interconnection has parallel AC lines(s).

$$Pd = Vd \cdot Id$$
$$= Vd \left[\frac{Vd_1 - Vd_2}{R} \right]$$

Due to small value of R ; Id can be controlled quickly and easily. Therefore, the Power flow (Pd) through an HVDC link can be controlled quickly, precisely in direction and magnitude by means of phase control of thyristor-valves at rectifier and inverter ends (Ref. Ch. 47). This ability is utilized for improving the transient stability and dynamic stability of :

1. Connected AC Networks at terminals.
2. AC transmission lines parallel to HVDC link
3. Adjacent AC transmission systems connected to AC Buses of HVDC system.

During disturbance such as a fault in a transmission line, the power angles of buses experience a swing and oscillations. *By modulating the power flow through HVDC links, the swing is reduced and the oscillations are damped. This is a major advantage of HVDC transmission and with damping control added to HVDC system control the line loading of adjacent/parallel AC Transmission lines can be increased.*

Feedback loop of Δf or $\Delta\delta$ or both is added to the power controller of HVDC pole control. Thereby power flow is modulated to damp the oscillations in AC Networks. Stability of AC Networks/lines is improved.

ASYNCHRONOUS HVDC LINK FOR IMPROVING STABILITY OF AC SYSTEMS

52.10. STABILISATION OF ADJACENT AC LINES

Asynchronous HVDC link has no parallel AC lines. (Ref. Fig. 52.3). The prevailing frequencies of two AC Networks are different and the two AC Networks are not in synchronism.

Consider a transmission system shown in Fig. 52.3 consisting of three AC lines between AC networks 1 and 2 and one bipolar HVDC link from busbar 2 to infinite bus 3. HVDC link has no parallel AC lines. Hence the HVDC link (2-3) is *asynchronous.*

The bipolar HVDC link transfers power (Pd) from busbar 3 to busbar 2. The asynchronous HVDC link connects AC Networks 2 to infinite bus 3. AC Network 3 (infinite bus) is very large and there is no limit on power exchange ($\pm Pd$) between AC Network 2 and Infinite bus 3.

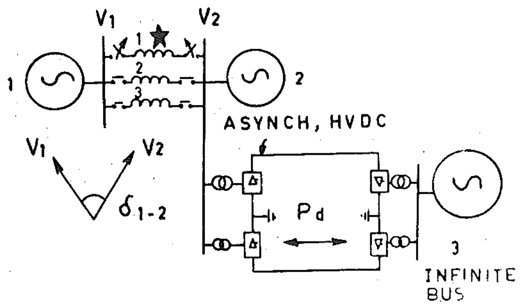


Fig. 52.3. Asynchronous HVDC link 2-3 has no parallel AC lines. Pd is modulated to improve Dynamic Stability of 1, 2.

[Opening an AC line 1 causes oscillations in power angle δ, These are damped

DC power flow $\pm Pd$ can be controlled with modification such that

$$\Delta Pd = \text{function } (\Delta f \text{ or } \Delta\delta)$$

By introducing such a control parameter to the power controller of the HVDC link, the oscillations in power angle δ in AC links between Networks 1 and 2 can be damped. Thus the control of HVDC link can be suitably modified for damping the oscillations in adjacent AC transmission lines (not parallel with the HVDC link). Fig. 52.4 shows oscillations in power angle between 1, for various control modes in DC links 2-3.

Fig. 52.4, Curve 1, shows increasing oscillations leading to dynamic instability. Such curve is obtained if HVDC system 3 is without damping control.

Curve 2 shows damped oscillations obtained by adding damping control feature in HVDC power control.

The stability and swing curves during a disturbance (such as opening and AC line) is influenced by the method of control adopted for HVDC link (3).

Curve : 1. Constant DC power control.
2. Constant power angle δ control.
3. Constant Pd plus control of Δf.
4. Constant δ and control of Δf.

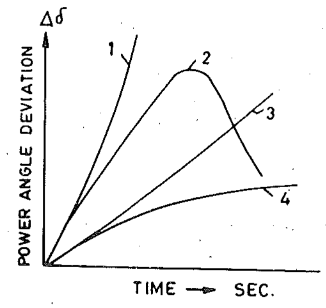


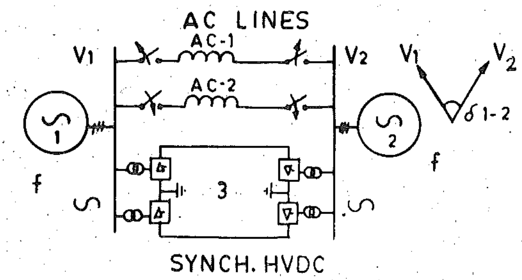
Fig. 52.4. Oscillations in Power Angle δ for phase angle difference $\Delta\delta$ produced by opening on AC line in Fig. 52.3 for various conditions of control.

Fig. 52.4 shows the first swing curve in terms of $\Delta\delta$ versus t, for various types of controls of HVDC link $\Delta\delta$ refers to deviation in power angle δ during the swing.

SYNCHRONOUS HVDC LINK FOR IMPROVING STABILITY OF AC SYSTEMS

52.11. DAMPING OF AC NETWORKS OSCILLATIONS WITH DIFFERENT CONDITIONS OF DC CONTROL FOR SYNCHRONOUS HVDC LINK

Fig. 52.5 shows an HVDC Link 3 which is in parallel with AC lines 1 and 2 and all the lines connect AC Network 1 and 2 synchronously. The terminal AC Networks are at the same frequency and in synchronism. Hence the name *'Synchronous'.* If line AC-1 is opened, the voltage vectors V_1 and V_2 experience a swing and subsequent oscillations.



[Line 1 opened, oscillations in δ_{1-2} being analysed for various controls of HVDC link].

Fig. 52.5. Synchronous HVDC Link.

By modifying the HVDC control, the swing in power angle δ can be reduced and the oscillations can be damped. Thereby the transient stability of AC Network 1, 2 and AC transmission lines 1 and can be improved.

The power flow through the HVDC link (3) can have different control criteria, for example constant power Pd or constant power plus damping control. Accordingly, the swing curve and oscillations in δ get modified.

Fig. 52.6 (A) shows the effect of damping control of HVDC link on oscillations in power angle δ_{1-2} of Fig. 52.5.

With only AC lines, stability would have been lost as shown in curve 3 of increasing δ. With HVDC link with modified control (constant Pd plus damping control) the first swing is reduced and the oscillations are damped (curve 1, 2).

Power through HVDC link (Pd) between 1 and 2 can be quickly modulated by damping control. For critical damping high DC power flow is required [curve 1 – Fig. 52.6 (B)]. For under critical damping of oscillations in δ $\sin_{1-2}$ lesser DC power would be required (curve 2).

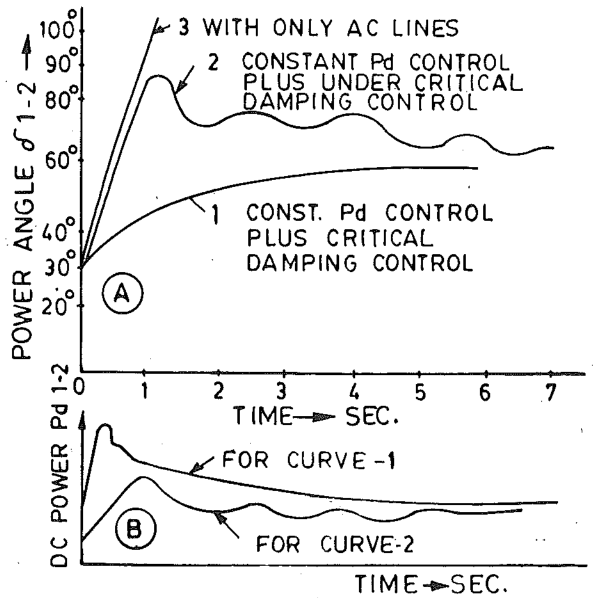


Fig. 52.6 (A). Swing curves for various types of controls applied to HVDC link 3 in Fig. 52.5.
(B) DC Power through synchronous HVDC link 3.

Power through HVDC link can be quickly increased/decreased/modulated in such a way that the power angle swing of δ is not allowed to reach its prospective peak an the oscillations in δ are damped. Thereby the Dynamic Stability of connected AC Networks and parallel/adjacent AC lines is improved.

Methods of HVDC Control for Improved Transient Stability various possibilities of DC control have different effects on the oscillations as illustrated in curve 1 to 4 in Fig. 52.4. The improved transient stability is achieved by reducing the swing angle δ before it reaches unsafe value.

Curve 1 (Fig. 52.4) Constant DC Power Control. In curve 1, the swing curve is steep and angle deviation Δδ overshoots, the safe limits faster indicating severe unstable condition, (worse than curve 2 for three AC lines).

As seen later, constant *Pd* control gives progressive increase in the amplitude of oscillations and this is called *dynamic instability*. Hence constant *Pd* control is not suitable from stability considerations. Power control of HVDC must be modified.

Curve 2 (Fig. 52.4) Constant Power Angle δ Control of HVDC Link (*i.e.* Constant phase angle. In this type of DC control, the control signal for DC power flow is *modulated* such that the power transfer *Pd* is varied to achieve constant power angle δ between two AC Networks vectors V_1 and V_2.

Since measurement of phase angle δ between V_1 and V_2 for long distance is difficult one of the following two parameters are generally used.

$$\frac{d\delta^2}{dt^2} = \text{Angle acceleration}$$

$$= \frac{d}{dt}(\Delta f) = \text{Time derivative of frequency difference between two AC Networks}$$

In this type of control the DC line responds to control like an AC link as shown by curve 2 (Fig. 4). No much improvement is obtained in improving transient stability of AC lines/Networks.

Curve 3 (Fig. 52.4). With Constant Power (Pd) and additional control parameter proportional to the frequency difference (Δ*f*). The frequency deviation Δ*f* is low. Load angle difference Δ*f* increases *more slowly* as shown by curve 3 giving more time to auto-reclosing.

Curve 4 (Fig. 52.4). Constant δ between V_1 and V_2 and additional control parameter proportional to frequency difference Δ*f*.

In this type of control, both Δ*f* and Δδ are limited quickly. Δ*f* is brought down to zero and δ is stabilised to new value critically. *The AC circuit breaker can be reclosed without difficulty.*

Time Delay of control signals. The control signals have inherent time delay of the order of a few tens of m sec. This affects the degree of damping provided by DC control.

Conclusion. With synchronous HVDC link, when a parallel AC line is opened the resulting oscillations of power angle δ in connected AC Network can be damped satisfactorily by choice of suitable control signals added into the HVDC power control. Constant power control with additional control parameter proportional to frequency difference Δ*f* gives minimum swing and brings back the frequency deviation Δ*f* to zero quickly and parallel AC line can be reclosed.

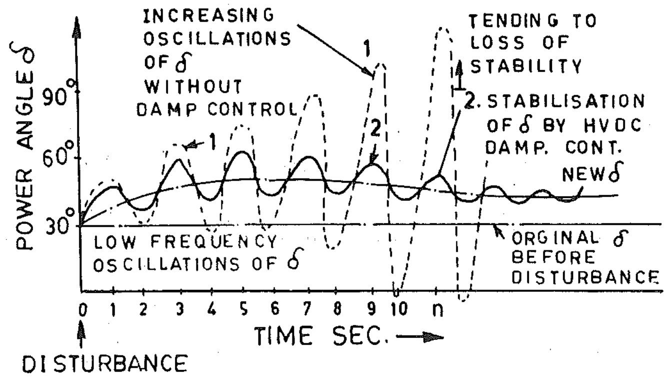


Fig. 52.7. Damping of oscillations in power angle δ_{1-2} of Fig. 52.3 for various types of controls of Asynchronous HVDC link. Curve 2 shows effective damping of oscillations in power angle δ.

Fig. 52.7 shows typical oscillations of power angle δ_{1-2} between vectors V_1 and V_2 of a asynchronous HVDC link shown in Fig. 52.3. Curve 2 shows that Dynamic Oscillations of δ_{1-2} can be damped effectively by modulation of power flow through adjacent HVDC link. Thereby adjacent AC transmission can be made dynamically stable.

SUMMARY

The concepts of stability have undergone gradual changes during last 70 years. Now four important stabilities are defined as

— Steady state stability
— Transient stability
— Voltage stability
— Dynamic stability

Means available for improving transient stability and dynamic stability include : use of SVS, FACT and HVDC transmission, fast AVRs in Excitation System of Synchronous generators with stabilizing features (Ch. 45 D)

Means available for improving voltage stability are : SVS, Tap-changer control, synchronous condensers.

FACT systems incorporate controllable series compensation-plus SVS systems. FACT systems are likely to be used for several long AC lines and interconnecting lines.

HVDC system control can be modified with constant Δδ control or constant Δ*f* control so as to damp the oscillation in δ and limit the maximum swing in δ. Thereby transient and dynamic stability of AC Networks and transmission systems is improved.

HVDC systems can also be used for controlling frequency (f_2) of smaller network interconnected to a large network. The power flow from large network to small network is modified with frequency deviation Δ*f*, where $\Delta f = f_n - f_2$

P_d = Function (Δ*f*)

P_d = Power flow from large network to small network

Δ*f* = Frequency of deviation of small network.

$= f_n - f_2$

f_n = Rated frequency

f_2 = Actual frequency of small network.

53

Computer Aided Power System Studies

Objective of CAE — Purpose and need — Basic power system studies — List of studies — Main aspect of studies — Preparation — Software programs — Simulation of power system — Network planning system — Means of power system studies.

53.1. COMPUTER AIDED ENGINEERING (CAE) FOR POWER SYSTEM STUDIES

To ensure *high availability* and *operational reliability* of electrical power networks, their *steady-state* and *dynamic behaviour* must be known in detail. Highly advanced computer programs are used which allow a wide range of alternative configurations and operating conditions to be realistically simulated in a short time and at a lower cost. The data provided by Computer Aided Engineering (CAE) studies is essential to meet the growing needs of power system studies and the equipment.

Today's power system engineer needs high-performance personal computers and CAE environments at his disposal for planning, engineering, documentation (such as single-line diagrams) and cost-effectiveness.

The earlier experience and data in the development and application of power system engineering packages is also useful. The main topics covered in CAE studies include :

— Load-flow calculation
— Stability investigations
— Harmonic frequency analysis
— Short-circuit studies
— Transient analysis
— Reliability planning.

With various highly advanced tools, at his disposal, today's power systems planning engineer can quickly identify and solve even complex problems. Thus, operational disturbances can be reduced to a minimum and system failures, such as blackouts, prevented.

53.2. PURPOSE AND NEED OF SYSTEM STUDIES

The purpose of system studies is to assist in evaluation of present and future system performance, reliability etc. Such evaluation is essential for design, expansion, planning and operation of power systems.

Following objectives of both technical and economical aspects are fulfilled by Computer Aided Engineering (CAE) :

— Formulation of objectives :
  What is to be achieved ?
  What are the objectives ?
— State evaluation and sensitivity analysis :
  How was the problem handled till now ?
  What influence do certain parameters have ?
— Looking for alternative sources :
  To improve or extended the present system ?
  A new concept and/or replacement of certain components.

53.3. BASIC POWER SYSTEM STUDIES*

A wide variety of power systems engineering problems are solved by means of CAE. Some typical examples are given here. The ultimate goal is to have the application programs and know-how necessary to solve every power system problem which could arise during planning or operation. The same specialized engineering support is also available from specialised companies and research institutions.

Quasi-steady-state load-flow calculation. The quasi-steady state load-flow calculation is one of the most common, but also most important calculations performed when analyzing and planning power systems. Tasks the power system engineer performs with the help of load-flow simulation, for example, typically concerns reactive-power compensation and voltage-level control.

Transient stability studies. To secure reliable and economic operation it must be known how the power system will react to disturbances and system failures. The transient stability problems a traditional. The stability limits for the system are to be determined for various conditions. In many cases the stability of a power system can be considerably improved by installing static shunt compensators or series capacitors, etc. Programs have been developed to simulate the power system behaviour, and to solve stability or reactive power balance problems.

Analysis of electromagnetic transients. A detailed analysis of the transient phenomena due to switching or other causes, either internal or external, is often essential for insulation co-ordination studies. Only an in-depth knowledge of the very fast processes involved, reproduced by high frequency models which cover the travelling-wave range, allow suitable precautionary measures to be taken for the overvoltages occurring.

Reliability planning. The series reliability of a modern power supply system is of vital importance, and as such has to be taken into consideration during the *project engineering*. Reliability Analysis are therefore essential to system planning. Alternative designs have to be compared and that design selected which best conforms requirements while still complying with economic constraints. The aim is to achieve 99.99% *availability*.

Project Studies. These include feasibility studies for new projects, design calculations for various subsystems, main circuit parameters, control criteria etc.

Before finalising the design specifications of new transmission projects,

— Load flow
— Load shedding
— Harmonic filtering
— Insulation coordination
— Reactive power balance
— Transient overvoltages
— Economic feasibility
— Reliability

Expanding and upgrading large supply system for Industries

When system studies have to be carried out for expansion of large supply networks to industries, the following aspects may have to be considered :

— Evaluation of short circuit levels
— Projection system coordination
— Steady-state stability
— Load-frequency and load shedding
— Starting of motors
— Motor Stability
— Extension planning
— Component and system reliability
— Simulation of special operating events and disturbances.

Studies of this kind and performed to determine weak points in the power system and to obtain detailed recommendations for possible system improvement. The final goal is always to raise the reliability and availability of the power supply.

Likewise there are several areas of applications of CAE. Table 53.1 gives a list with remarks.

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* *Courtesy* : ABB, Sweden.

Table 53.1. System Studies Associated with Transmission Planning

Type of study	*Remarks*
1. Load flow studies	To determine bus voltage magnitude and phase angles, Real Power and Reactive Power through lines for steady condition, for various buses.
2. Stability studies under various states of control	To determine the transient stability limits for various conditions.
3. System Dynamic Studies	To determine system behaviours under dynamic condition considering generation, transmission and load characteristic.
4. Switching overvoltage studies	To determine switching over voltages under various switching conditions for EHV, HV, MV.
5. Lightning performance studies.	To determine effect of lightning on shield wire, conductor, tower etc.
6. METIFOR optimisation studies.	Metrologically Integrated Forecasting based on hourly weather observations and lightning outage rate.
7. Voltage Level Studies.	Carried out before introducing new voltage level for expansion, new lines.
8. Reactive Power Studies.	Carried out on the basis of load flow studies and voltage regulation requirements.
9. Short-circuit studies.	Carried out for determining short-circuit currents at various points for equipment specifications, protection settings.
10. Studies of abnormal operations and protection planning and relay co-ordination.	Based on network phenomena analysis equipments withstand levels and protection system capabilities.
11. Reliability studies and security studies.	Aim at keeping the system and normal state of operation, demands are met, no apparatus is overloaded.

53.4. PREPARATION FOR SYSTEM STUDIES

The background required for system studies includes : familiarity with fundamentals. Thevenin's equivalent circuit, phasor representation, Fourier series, symmetrical components, etc.

Equivalent circuits of the system are prepared with assumptions acceptable in the particular study. Basic system data is collected before proceeding with the preparation of the program or simulation.

System modelling is an essential requirement in the power system studies. The system to be analysed is represented by its equivalent model. Modelling involves choosing swing bus and infinite bus, nodes, and branches (line and transformers), balanced three phase network, single line diagram impedance diagram etc.

After these preparations, the computer program or simulation on Network Analyser is arranged. Computer programming involves programming language and associated computation method. The type and capabilities of the computer to be used should be considered before preparing the programs.

53.5. SOFTWARE PROGRAMMES ON POWER SYSTEM ENGINEERING*

The summary of key software tools which are available to the power system engineers is given below. All the programs are routinely updated and upgraded so that they are always up-to-date. The listed programs are used in various electric utilities, consulting engineers and industrial companies, and also some of them by universities for educational purposes.

Simulation of Power System (SPS) and Network Planning System (NPS) are generally the mainframe packages for investigating load flows, short circuits, dynamic stability and harmonic propagation. The programs are used for solving problems in large to very large utility networks

* *Courtesy* : ABB, Sweden.

with complex HVDC transmission and static VAr compensators as well as in the small or medium-size power networks installed in industrial plants.

The programs features enhanced data management and facilities for graphics, *e.g.* Single-line networks containing the computed results and can be run on main frame computers or workstations (IBM, VAX, APOLLO, etc).

The majority of the programs are written in FORTRAN and can be customized for special tasks. Program modules for different analysis functions can be combined as required or run as independent programs.

Table 53.2. Main Aspects of Power System Planning and Calculation

Power system operation	*Reactive load compensation and voltage control*	*Evaluation of special phenomena and disturbances*	*Determination of system component stresses*	*System planning and dimensioning*	*Insulation coordination and transient overvoltages*
Calculation of load and short circuit currents	Use of shunt reactors, capacitors and static phase shifters	Analysis of harmonic and flicker problems	Circuit-breakers Transformers	Reliability planning and coordination	Calculation of internal and external over voltage
Load forecast and unit commitment	Control of generators and transformers	Interference in telephone and other transmission systems	Electrical machines	Earthing problems	
Evaluation of losses and their minimization	Determination of load-frequency over-voltages.	Effect of voltage fluctuation on operation of electrical machines	Lines and cables Compensators Surge arresters	Planning and coordination of protection systems Installation layout.	Analysis of switching operations
Investigation of dynamic stability problems	Use of capacitive series compensation for improved stability and increase in transmission capability	Resonance problems	Insulators	Extension planning Evaluation of alternative concepts	Insulation coordination Use of surge arresters
Evaluation of system behaviour during and after disturbances		Switching operations in power systems			

Courtesy : ABB, Sweden.

The main functions of the SPPS and/or NPS systems are :

— Load flow
— Optimal load flow
— Dynamic stability
— Load flow graphics
— Short-circuit graphics
— Harmonic frequency analysis
— Machine transients and subsynchronous resonance (SSR)
— Steady-state short-circuit calculations in accordance with IEC 909 or using the superposition method.
— Steady-state stability and eigen value analysis.

SPS and/or NPS *allow power systems planning* personnel to benefit from the following enhanced facilities.

— Automatic voltage regulators and turbine governor systems.
— Implementation of control systems by means of a dedicated macro language.
— Investigation of symmetrical or unsymmetrical network conditions, such as simultaneous occurrence of faults at different locations.
— Phasewise-controlled static VAr compensators.
— Different machine models.
— Transformers with automatic load tap changers.
— Different relay representations.

53.6. TOOLS FOR POWER SYSTEM STUDIES

For planning, designing and analysing power systems, various means are used. These are called the tools for analysis. Important tools, available today include the following :

1. DC Calculating Board
2. AC Calculating Board (Network Analyzer)
3. HVDC Simulator (Ref. Ch. 47)
4. Transient Network Analyser (TNA)
5. Special High Frequency Models.
6. Digital Computer (Sec. 24.5)

Transient Network Analyser (TNA0 is used for Transient analysis and simulation of AC Networks. Due to non-linearit and varying machine characteristics, some problems of AC systems cannot be solved by digital computer. TNA is a useful tool in which the AC Network can be closely represented.

The response of AC Networks to fast switching transients, lightning transients etc. is simulated on special *high frequency models.*

Problems on HVDC systems are analysed on *HVDC simulator.*

SUMMARY

Power system studies are generally aid to control room engineer, planning engineer, design engineer. The power system studies are carried out by means of Transient Network Analyser (TNA), HVDC Simulator, Digital Computer. The Network is represented by an equivalent physical or mathematical model. The studies include (1) steady state studies (2) Transient studies and also (1) Static studies (2) Real time studies.

54

Power System Reliability Studies

Reliability — Quantitative Evaluation — Terms and Definitions — Rliability Indexes — Procedure of Evaluation — Service interruptions — Failure Mode and Effect Analysis FMEA — Types of Failures — Availability — Schedules Outage — Forced Outage — Summary

54.1. INTRODUCTION

The term 'reliability' is closely associated with *'outages', interruptions', 'failure', 'availability'* etc. and the reliability is closely associated with switchgear, protection and control. Absolute 100% reliability and availability of generating systems, transmission systems and distribution systems cannot be guaranteed. However, a very high level (99.99%) is aimed at and is being achieved in developed countries. High reliability (more than 99.8%) is possible with

— Availability of generation, transmission and distribution systems.
— Reserve capacity (margin) between installed capacities and expected maximum load.
— Design and quality aspects,
— Operation and Maintenance aspects.

An important aspect of power system studies involves *quantitative evaluation* or reliability, availability, security etc.

1. As required by the load.
2. To be supplied by the supply company ; proposed generating/transmission/distribution system.

Quantitative evaluation calls for precise definitions of terms, reliability indices, computer programs etc. the studies are based on set theory probability theory, combination analysis etc.

For quantitative evaluation, the *reliability performance* of constituent 'components' of the system should be known.

Alternative designs and alternative choice of components is considered while evaluating the service reliability. The choice of the following is based on the studies of reliability.

— Service reliability and cost of alternative components.
— Service reliability and cost of alternative system configuration.
— Maintenance requirements of components and subsystems.
— Operating practices and policy.
— Switching and protective schemes.

54.2. TERMS AND DEFINITIONS*

1. **Adequacy.** To have sufficient margin between generating capacity and maximum load.

2. **Availability.** A term which applies either to the performance of individual components or to a system. Availability is the long-term average fraction of time that a component or system is in service satisfactorily performing its intended function. An alternative and equivalent definition for availability is the steady-state probability, that a component or system is in service.

* *Courtesy* : IEEE.

3. **Component.** A piece of equipment, a line or circuit, or a section of a line or circuit, or a group of items which is viewed as an entity for purposes of reliability evaluation.

4. **Interruption.** The loss of electric power supply to one or more loads.

Interruption frequency. The expected average number of power interruptions to a load per unit time, usually expressed as interruptions per year.

5. **Outage.** The state of a component or system when it is not available to properly perform its intended function.

Repair time. The clock time from the time of component failure to the time when the component is restored to service, either by repair of the failed component or by substitution of a spare component for the failed component. It is not the time required to restore service to a load by putting alternate circuits into operation. It includes time for diagnosing the trouble, locating the failed component, waiting for parts, repairing or replacing, testing, and restoring the component to service. The terms *repair time* and *forced outage duration* can be used synonymously.

6. **Scheduled outage.** An outage that results when a component is deliberately taken out of service at a selected time, usually for purposes of construction, maintenance, or repair.

7. **Scheduled outage duration.** The time period from the initiation of a scheduled outage until construction, preventive maintenance, or repair work is completed and the affected component is made available to perform its intended functions.

8. **Scheduled outage rate.** The mean number of scheduled outages per unit of exposure time for a component.

9. **Switching time.** The period from the time a switching operation is required because of a component failure until that switching operation is completed. Switching operations include such operation.

10. **Expected interruption duration.** The expected, or average, duration of a single load interruption event.

11. **Exposure time.** The time during which a component is performing its intended function and is subject to failure.

12. Failure. Any trouble with a power system component that causes any of the following to occur.

1. Partial or complete plant shutdown, or below-standard plant operation.
2. Unacceptable performance of user's equipment.
3. Operation of the electrical protective relaying or emergency operation of the plant electrical system.
4. Deenergization of any electric circuit or equipment.

A failure on a public utility supply system can cause the user to have either of the following :

1. A power interruption or loss of service.
2. A deviation from normal voltage or frequency of sufficient magnitude or duration.

A failure on an in-plant component causes a forced outage of the component, that is, the component is unable to perform its intended function until repaired or replaced. The terms *failure and forced outage* are often synonymous.

13. **Failure rate (forced outage rate).** The mean number of failures per unit of exposure time for a component. Usually *exposure time* is expressed in years and *failure rate* is given in terms of failures per year.

14. **Failure Mode Effect Analysis (FMEA).** (Ref. Sec. 54.4).

15. **Forced unavailability.** The long-term average fraction of time that a component or system is out of service as a result of failures.

16. **Mean Time to Failure : MTTF**

Mean Time Between Failure : MTBF

17. **Reliability.** The term describes the ability of continuous service without outages/failure/interruptions. It is expressed as

$$\text{Reliability Index} = \left(\frac{\text{Total Service Hours} - \text{Interruption Hours}}{\text{Total Service Hours}}\right) \text{Per year.}$$

18. **Security.** Ability of the power system to continue to operate normally even with specified failures ; without cascade tripping and overall blackout.

19. **System.** A group of components connected or associated in a fixed configuration to perform a specified function of distributing power.

20. **Unavailability.** The long-term average fraction of time that a component or system is out of service caused by failures or scheduled outages. An alternative definition is the steady-state probability that a component or system is out of service. Mathematically, unavailability = (1 – availability).

54.3. RELIABILITY INDEXES

Various *Indexes have been considered in the past. Two types have proven useful for quantifying Reliability of Power Supply Systems.*

1. Loan interruption frequency.
2. Extended duration of load interruption events.

After computing these indexes for a supply system, the following other indexes are also computed.

1. Total expected average interruption time per year.
2. System availability or unavailability as measured at load supply point under consideration.
3. Expected energy demanded but not supplied, per year.

The disruptive effects of interruptions on the consumer are often non-linear with respect to the duration of interruption. Hence it is often desirable to compute :

1. Overall interruption frequency.
2. Frequencies of interruptions categorized by appropriate durations.

A typical example of simple Reliability Index for power supply at consumer's premises is given below :

Reliability Index of power system

$$= \left[\frac{\text{Total Hours} - \text{Interruption Hours}}{\text{Total Hours}}\right] \text{Per year.}$$

54.4. PROCEDURE OF SYSTEM RELIABILITY EVALUATION

The procedure for system reliability evaluation is described below :

1. Assess the service reliability requirements of the loads and processes supplied and determine appropriate service interruption definition or definitions.
2. Perform a failure mode and effects analysis (FMEA) identifying and listing those component failures and combinations of component failures which result in service interruptions and constitute minimal cut-sets of the system.
3. Computer interruption frequency contribution expected interruption duration, and the probability of each of the minimal cut-sets of (2).
4. Combine results of (3) to produce system reliability indexes.

54.5. SERVICE INTERRUPTION

The *service interruption* should be assessed as a first step in reliability studies. The clear definitions of service interruptions with respect to reduced voltage level (voltage dip) duration of voltage dip, loss of supply etc. should be determined in advance.

To simplify the analysis 'continuity' of supply or service, is used as a measure to calculate services interruptions. *Interruption in service continuity is generally used in computations of Reliability Indexes.*

54.6. FAILURE MODE AND EFFECT ANALYSIS (FMEA)

The failures or outages of *'component'* or *'combination of components'* (see Defn. 54.2.3.) is analysed and is called FMEA component outages are categorized as

1. Forced outages or failures
2. Scheduled (maintenance) outages
3. Overload outages.

Forced outages may be temporary outages or permanent outages. Permanent forced outages require repairs or replacements before restoration of service continuity. Temporary (transient) outages imply no permanent damage and no need for repairs/replacement.

In addition, component failure can be classified by physical mode or *type of failure.* This type of failure classification is important for switchgear and protective devices.

1. Faulted, must be cleared by back-up breaker
2. Fails to trip when required
3. Trips falsely
4. Fails to reclose when required. Each of the type will have different impact on service continuity and system performance. FEMA is a useful tool in reliability studies.

54.7. Availability

Availability means the equipment/plant/supply system is functioning satisfactorily and is in service. (Defn. 54.2.2.) Overall availability of generating, transmitting and distribution system depends on whether any part is out of service, due to any of the following :

1. Scheduled outage (for maintenance)
2. Forced outage (Due to fault or accident)

The *probability* of any plant or equipment being out of service as a result of (1) or (2) can be computed from statistical data of performance of existing plant and equipment.

54.8. Scheduled Outage

Planned preventive maintenance is carried out to avoid forced outage the plant and equipment.

Maintenance of switchgear and protection-gear consists of periodic checking of proper operation, condition of contacts and operating medium of circuit-breakers etc. Recent microprocessor based protective relays have self-checking feature or self-monitoring feature. The trend is towards maintenance free circuit-breakers and reliable protective gear.

54.9. Forced Outage

Statistical probability of any component of supply system being forced out of service due to its own failure is defined as proportion of a given period (exposure time) during which it is forced out of service.

$$\text{Forced Outage Rate } p = \frac{\text{Period of Forced Outage}}{\text{Given Period}}$$

$$\text{Given Period} = \text{Period of Forced Outage} + \text{Period Available for Service}^{*}$$

* (Excluding Scheduled outage).

The corresponding probability of the same component being 'available' for service is called 'Service Probability' or 'Service Rate'.

$$\text{Service Rate } q = \frac{\text{Period Available for Service}}{\text{Given Period}}$$

Note that $p + q = 1.$

SUMMARY

Reliability refers to continuing service without failure or outage. Reliability is calculated in terms of Reliability Indexes. Reliability of each component and group of components should be known before assessment of Reliability of Power System. In developed countries Reliability of 99.99% is generally achieved.

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1. IEEE Standard 493-1980, Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems.
2. IEEE COMMITTEE REPORT, Report on Reliability Survey of Industrial Plants, Part 1 : Reliability of Electrical Equipment, *IEEE Transactions on Industry Applications,* pp. 213-235, March/April 1974.
3. IEEE COMMITTEE REPORT, Reliability of Electric Utility Supplies to Industrial Plants, Conference Record 1975 & CPS Technical Conference , pp. 131-133.
4. ANSI/IEEE Standard 399, 1988, Recommended Practices for Power System Analysis.

55

Power System Security and Optimum Load Flow

Definition — Significance — Case studies — Monitoring — EMS software functions — Alarm conditions — Action by operator — Contingency Analysis — Optimum Load Flow — Summary — Conclusions.

55.1. POWER SYSTEM SECURITY

"The ability of a power system to operate in normal state even with occurrence of specified contingencies" is called power system security. Ref. Sec. 50.9.

Another definition of power system security is *"the ability of the power system to keep operating in stable condition during and after specified failures without cascade tripping and overall blackout"*.

Failures of equipment in power system cannot be eliminated completely. The principle reasons of failures are insulation failure, auxiliary failure, equipment failure, mechanical failure, thermal overload failure etc.

Protection and switchgear are arranged to take the faulty equipment out of service quickly and automatically. However, such an action invariably results in diversion of power flow through remaining healthy paths resulting in their overloading and likely tripping due to overloads. Failures and isolation of a faulty equipments result in overloading of adjacent *healthy equipment.* The overload protective relays of these healthy adjacent equipment are set for overload protection of respective equipment. Hence without security measures, the adjacent healthy parts may also trip. Hence overloads in healthy parts of the system must be quickly eliminated by appropriate operating means at the disposal of control operator. For this the overload must be quickly diverted to other paths which are underloaded.

The control room operators decisions affect the further course of events as seen from the following case studies.

Case 1 : Tripping of a Generating Unit (single outage).

When the generator unit is taken out of service, the remaining generators in parallel must take up the overloads due to the loss of generation. However, if there is insufficient remaining generation, the frequency drop can be of so severe that recovery is impossible. Operators must therefore be sure to commit enough generation so that the loss of any generating units will still leave enough generating capacity to restore the frequency safely.

Case 2 : Tripping of a Transmission Line (single outage)

When a transmission line trips, the current flowing through it will redistribute on the remaining adjacent circuits. If the new load flows on the remaining circuits cause one or more of them to be over-loaded, their relay protection will operate, resulting in further more redistributions of currents. This process, if it continues, is called *a cascading failure* and can result in a blackout on large parts or all of the system.

A large scale blackout occurred in USA and Canada during Nov. 1964 due to a similar cause.

55.2. PURPOSE OF SECURITY ANALYSIS

Primary purpose of 'Power System Security' is to keep the power system operation continuing such that failures do not lead to cascade trippings and overall blackout. Time available to ensure, appropriate actions is limited. Control room operator must take advance actions such that the system security is not lost during a single failure. Contingency analysis indicates which actions are to be taken by the operator in advance.

To achieve high power system security the control room should-have data collection system and computerised power system security analysis program software. Such system are called Energy Management Systems (EMS).

55.3. EMS CONFIGURATION AND SECURITY ANALYSIS

An EMS generally has a *Centralised* Digital Computer System connected to Remote Terminal Units (RTUs) *via* communication channels. The computer software includes a variety of programs (Fig. 50.6).

Various types of Data is collected periodically from various parts of the system. Data includes status *on/off*, Analog Measurements (AM) ; MW flow, MVA flow, Bus kV etc from various power stations and substations. Such data are *monitored* with the help of computer system. When the quantity tends to go beyond safe limits, alarm is sounded in the control room indicating the position of likely trouble. The control room operator sends commands to respective substation or generating station to take appropriate action *e.g.* open/close certain circuit-breakers ; increase/decrease MW ; change Tap-position ; Switch-in/off shunt capacitors etc. Such commands are sent *via* communication channel *e.g.* Power Line Carrier , Microwave, Telephone Wire, Fibre-optic cables etc.

The Control Room Operator takes various types of actions to maintain adequate power system security.

Table 55.1
Actions by Control Room Operator for Maintaining System Security

Action by Operator	*Variables to be adjusted*
Generation commitment	Generator on/off status
Generation dispatch	Generator megawatt output schedule
Generator bus voltage	Unit exciter setting
Network configuration	Substation circuit breaker open/close
Load shedding	Distribution feeder circuit breaker
On-Load tap changing transformer	Tap position
Phase-shift transformer	Tap position
Tie-line system interchange	Interchange schedule

55.4. POWER SYSTEM MONITORING AS ESSENTIAL PART OF SECURITY IMPROVEMENT

Power system monitoring is an essential part of maintaining system security. Monitoring System has several software programs. Ref. Fig. 50.6 and Table 55.2.

Courtesy : Modern Power Systems.

Table 55.2
Power System Monitoring Functions in EMS Software (Fig. 50.6)

Function	*Function performed*
Data acquisition	To process message from RTUs To check analogue measurements against limits To check status values against normal value To send alarm conditions to alarm processor
Alarm processor	To send alarm messages To transmit messages according to priority
Status processor	To determine status of each substation for proper connection To determine status of network for equipment out of service, islanding, To send alarm messages to alarm processor
Reserve monitor	To check generator megawatt output on all units against unit limits To send alarm if insufficient reserves
State estimator	To determine system state variables using measured values and network model To detect presence of bad measured values To identify location of bad measurements To initialize network model for other application programs

Sec. 46.3 describes the Data Acquisition System and Table 46.3, 4 give the data to be monitored from control room.

The first job of control room operator responsible for system security is monitoring the system. (Ref. Sec. 25.6.2.) The values of substation and power station variables are scanned periodically and are transmitted to the EM system through the RTUs and note is taken of any out-of-limit or other unusual conditions. However, with thousands of status and analog values, this is a humanly impossible task and is therefore usually handled by *the computer system.* Each value is checked as it comes into the system. Changes in status and out-of-limits analog values are brought to the operator's immediate notice through *alarm messages* on the console displays.

The abnormal or unusual values are known to the control room operator through EM system.

The functions incorporated in the monitoring system of EM software are listed in Table 55.3.

Table 55.3. Important Programs in the EMS Software for Improving Power System Security (Ref. Fig. 50.6).

Software	*Description*
Alarm Processing	Part of monitoring system. Alarms are given in advance so that operator can take advance action to improve security.
Topology Processor (Status Processor)	Identifies of prevailing network configuration (topology) as to which units and lines are connected.
State Estimator	Calculates on the basis of mathematical model of prevailing network. Results can be compared with actual data to identify bad measurements
Contingency Analysis	Calculates effect of hypothetical outage on the system security
Performance Monitor	Monitors performance and suggests improvements

55.5. SOFTWARES IN ENERGY MANAGEMENT SYSTEM

For achieving maximum security, several programs are available in the EM software for the control room operator.

Table 55.3 gives a list.

Fig. 50.6 gives the block diagram. Some blocks are described below.

55.5.1. Alarm Processing

When some of the variables in power stations or substations are out-of-limit, the operator gets corresponding *alarm message.*

The operator receives the alarm signals. By virtue of past experience and human reasoning, the control room operator determines the cause of trouble and takes appropriate follow-up action to ensure system security.

The knowledge of single alarms by themselves is often insufficient, and the operator must be able to draw conclusions from knowing the *status* and values of many other *variables.* In the case of breaker status values, the operators are provided with *one-line display diagrams* have graphic indications of breakers, busbars, switches, transformers, etc. Further, the breaker positions are shown so that a quick accurate assessment of a switching action can be obtained by looking at the display.

Table 55.4. Alarm Indications in Monitoring System

Monitored Quality	*Alarm indication and Sounding*
Voltages of buses	Bus kV above/below limit
Load flow through lines	Megawatt, MVA, MVAr, I above/below limits.
System frequency	Above/below target limits
Load	MW, MVAr above limit
Load shedding equipment	Load/shed/load restore/Islanding
Generator status	On/off line
Generator unit	MW, MVAr, kV above limit
Network transformers	Temperature above or below limit
Tele-communications channel to RTU	Normal/failure
Protective relay communication channel	Normal/failure
Circuit-breaker status	Open/close
Circuit-breaker (SF_6)	Normal/low pressure

55.5.2. Topology Processor. (Status Processor)

When a switching action affects more than one substation, the computer system can analyze the transmission system network using a topology processing program (Fig. 50.6). This program requires a complete description of the transmission system stored in the computer. When supplied with the telemetered status values, the status processor analyzes the topology of each substation and then the entire network to see which buses are connected together and which lines are in service and whether the system is connected or has been switched into electrical islands. Often the output of the status processor is sent to indicators on large graphic diagrams of the electrical system placed on a wall in the control room.

Reserve Monitor

Another information required by the control room operator for maintaining system security is the generation reserves.

Energy Management System has a program which calculates the generation reserves and compares this amount to established reliability criteria. The reserve monitoring program *provides* the operator with a display of present reserves as well as gives alarm messages when insufficient reserves are reached.

55.5.3. State Estimation Program

The software of Energy Management System includes state Estimation Program. The principle of state estimation has been described in Sec. 50.10.

The actual measurements may be doubtful due to errors in transducers, poor data transmission etc. The operator has to depend within the framework of such doubtful measurements. Sometimes, the telemetry fails and the operator has to depend on estimated values. State Estimation Program provides such values to the control room operator/EM system. The state estimator takes a *mathematical model of the power system* using the output of the *status processor* plus measured *analog values* and calculates a *best estimate* of the state variables for the system. The basic state variables are the voltage magnitudes and phase angle at each bus in the network. If there are more measured values than states, the quality of the estimate improves. Once the voltage magnitude and phase angle are available, the state estimator can calculate the load flows in all transmission lines in the network. In addition, if sufficient redundant measurements are available, the presence of a doubtful measurement can be detected and identified so that repair action can be taken. The state estimator uses the mathematical model of the prevailing system. Hence it also provides base for modelling contingencies.

55.5.4. Contingency Analysis (Security Analysis)

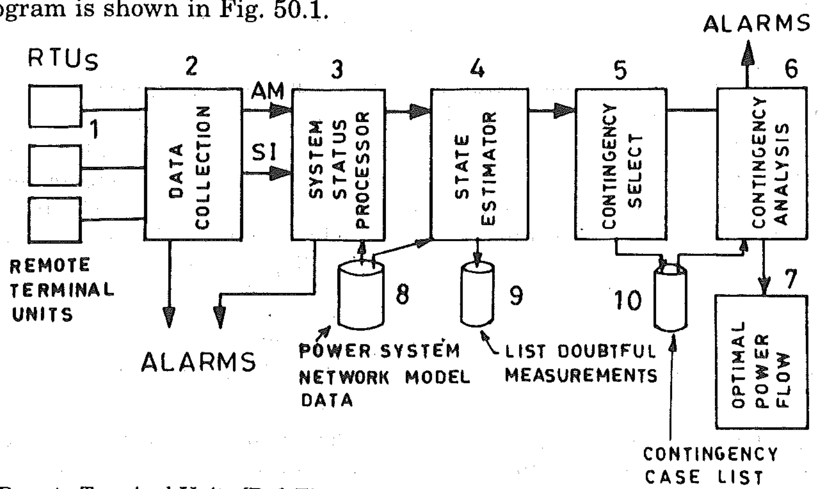
Refer Sec. 50.9.1. During one or two failures, the system security should not be lost. However, in modern networks the time available to control room operator is too short to take corrective actions immediately. Many problems occurring on power system cannot be corrected quickly and system security is difficult to be maintained unless the operator takes advance actions.

Contingency Analysis or Security Analysis refers to the process of studying the prevailing power system for hypothetical failure.

The contingency analysis mathematical model is based on actual configuration of the power system. Outages in generating unit or transmission line or both are assumed.

The model of Network for contingency analysis consist of admittance matrix which is built from the information given by the *status processor*.

The P and Q for each bus comes from the *state estimator*. The P and Q and voltages are computed on an ac load-flow program. The ac load-flow solves two simultaneous quadratic equations (one for the real power and the other for reactive power) for each bus in the network. By keeping the bus loading conditions as determined by the state estimator and then altering the admitttance matrix to reflect the outage, the contingency analysis program can calculate the effects of the outage and alarm the operator. The basic flow of information from the power system to the contingency analysis program is shown in Fig. 50.1.



1. RTUs Remote Terminal Units [Ref. Fig. 50.5 *a*]
2. Data Collection [Ref. Sec. 46.4]
3. System Status processor [Topology Processor]
4. State Estimator [Ref. Sec. 50.9.1]
5. Contingency Select
6. Contingency Analysis
7. Optimal Power Flow.

Fig. 55.1. Block diagram of Sequence in Power System Security Program.
(This is a part of EMS – Fig. 50.6)

Contingency Analysis programs calculates the effects of hypothetical outages and gives alarm to the operator.

Fig. 55.1 shows the interrelationship and data flow from the Remote Terminal Units to the Contingency Analysis Program in Energy Management System (Ref. Fig. 50.6).

The power system changes continuously with change in load flows, switching of units, lines etc. Hence contingency analysis should be repeated for present conditions in the power system.

The AC load-flow calculation can take a long time to perform, especially if the network being modeled is large. Typical *contingency analysis models* can encompass several thousand buses. In modern Energy Management Systems, and this may take anywhere in the range of 15 s to several minutes to solve contingency program depending on the capability of the computers in the energy management system. If, for example, the execution time of the ac load flow took 2 min for each outage and several hundred were to be tested, the operators might not know all the results for a few hours — which is much too long. In order to solve the contingency analysis in a reasonable time, three methods are applied (1) Contingency selection (2) Faster load-flow calculation techniques (3) Expert Systems.

After a failure, the operator does not have enough time to think about alternatives. Hence, contingency analysis is carried out periodically in advance and is made available to the operator. Appropriate actions are taken in advance to ensure system security.

Contingency Selection

Out of various substation and generating station failures only a *few failures* result in loss of system security. Therefore it is a practice to *select only such* contingencies for contingency analysis and neglect all other failures. For contingency selection, two methods are used in practice.

1. To use screening technique by calculating partial load-flows for various failures (outages) and identify potential cases which are heading towards trouble. For such cases full load flow results are computed.
2. Use a *single calculation* based on performance index of system loading conditions and obtain an approximate ordering instruction for *each* possible network outage. *e.g.* outage of one unit or outage of one line. Table 55.3 gives the comparison of the two methods for selection of contingency.

Table 55.5. Description of Contingency Selection Methods

Method of contingency selection	*Description method*
Contingency screeing method	Based on calculation of partial AC load flow calculations If partial load flow indicates possible limit surpassing, then remainder of load flow is run and limits checked and alarm are sent. Time to perform screening is equal to twenty pecent of time for AC load-flow for each possible contigency event. Can select contingencies for bus voltage and line/transformer flow-limit surpassing.
Single calculation method	Makes use of performance index of network loading. Calculates ordered list of contingency event (ordered with most severe contingency at top of list) Full AC load flows computation are run on top members of list and limits checked and alarmed Time to calcualte list equal to run time for one to two full AC load flows Present technology does not include ordering based on out-of-limit bus voltages Time is much shorter than contingency Screening method.

55.6. OPTIMAL LOAD FLOW

The term load flow refers to the flow of power from one or more sources, through available paths, to the loads consuming the energy.

In load flow studies, the direction and amount of real power and reactive power flowing through various paths is indicated on the system single-line diagram.

Load Flow Studies is an important branch in power system analysis. For complex AC power systems, the load flow studies are carried out by means of a computer program. By means of load flow program, the P, Q and V at various substation buses and generating station buses can be quickly computed.

Load flow studies and useful in EMS and security planning.

Optimum Load Flow refers to load flow which gives maximum system security by minimising the overloads. The optimal load flow aims at minimum operating costs and minimum losses. Optimal load flow should be based on operational constraints.

Table 55.6 gives the limits and objectives on load flow planning.

Table 55.6. Optimum Load Flow — Objective and Limits

Objectives (only one in use at one time)	*Limits and Constraints*
Minimize system operating cost (Rs/hr) Minimize system megawatt losses (MW) Minimise overloads (ΔI, ΔMVA)	*Generation* Generator unit megawatts within limit Generator unit megawatts within limit *Interconnection* Area interchange within limit Transmission substations Transformer tap position within limit Bus voltage magnitude within limit Transmission line megawatts, MVA, or amperes within limit Flow over groups of circuits within limit AC load-flow conditions met at all buses.

Methods of Optimum Load Flow

Two methods are used to calculate the proper adjustments to a power system to relieve overloads and voltages beyond limits. The first method makes use of linear programming and solves a decoupled model much as in the decoupled load-flow calculation. In the linear-programming routine, the objective is to minimize operating cost for any given supplied load while meeting a variety of constraints such as circuit flows and bus voltages.

The second method solves a completely coupled AC load-flow model and uses megawatt losses or operating cost as the objective function. Generally the same constraints are used as in both the methods.

The load flow studies are carried out with the help of a model of power system. The model is in form of an admittance matrix built for the particular network topology. The quadratic equations for P and Q are solved simultaneously to obtain P, Q, V at each of the bus.

SUMMARY

Power system security deals with continuity of service even with certain outages. The power system security program is incorporated in Energy Management System Software. The power system security programs prove their economic worth many times in preventing costly system blackouts. In addition, the power system security programs also allow operators to operate the system closer to its limits, thus giving better economic operation. Large AC networks are managed optimally by means of EMS. The cost of EMS is justified by the major benefits such as (1) Prevention of major outages (2) Better loading of plants and lines (3) Energy saving.

With the help of contingency analysis program in power system security management, the operator can decide in advance how to react to certain hypothetical failure and what actions can be taken to prevent the cascade trippings in the network. Necessary steps can be taken by control room operators to improve power system security.

Conclusions

Modern Power system are large interconnected systems.

Power system studies are useful and essential for proper operation, planning, design. *Modern*

Power System Operation aims at maximum reliability, availability, and security. These objectives are achieved by means of modern Energy Management Systems.

Microprocessor based combined protection, monitoring and control relays form an essential play a vital role in the Energy Management.

In EMS, the central load control centre is connected to Remote Terminal Units (RTUs) *via* communication channels. Functions such as contingency analysis, optimal load flow, security analysis expert systems, etc. are centrally located. Data from various generating stations and substations is received by the central computer. The software in the EMS analyses the off-circuit and real time data and sends appropriate instructions to various substation control rooms and generating station control rooms. Appropriate actions are taken and maximum reliability, availability and security is ensured.

For special requirements Expert Systems based on Artificial Intelligence are being developed and used. Several new techniques such as FACT, HVDC, SVS have been introduced during 1980's to improve the controllability of large power systems and to minimise the operating costs.

The Computer Aided Engineering (CAE) and computer Aided Automation (CAA) is of vital importance in todays power system operations.

56

Renewable and Conventional Energy and Power Plants

56.1. ENERGY RESOURCES AND FORMS OF ENERGY

Primary energy resources are those available in nature in raw form. (Coal, Petroleum-Oil, Natural Gas, Fire-wood, wind, water and high level, solar-irradiation, Geothermal, Ocean-waves, Ocean thermal, Ocean tides nuclear fuels etc.)

Secondary energy sources are those supplied to the user for consumption (electrical energy); steam, hot water, gas in cylinders or pipe-lines, petroleum Oils, fire-wood etc.).

Fossil Fuels (Coal, Petroleum, Natural Gas are organic matters formed from plant/animal fossils under temperature, pressure by biological and chemical decomposition over past several centuries.

Non-renewable energy resources are those which do not get replenished after their consumption, *e.g.* coal once burnt is consumed without replacement, of the same (Fossil fuels, Nuclear fission fuels).

Renewables are those which are renewed by the natural again and again and their supply is not affected by rate of consumption. (Wind energy ; solar-energy, Geothermal energy , Ocean wave ; Hydro-energy etc.).

Alternative energy sources are those which are non-traditional. They are *alternatives* to the conventional energy resources.

Table 56.1. Conventional and Renewable Resources for Electrical Power Generation

Conventional	*Alternative, Renewable*
Coal	Wind power
Petroleum oils	Solar power
Natural Gas	Geothermal
Hydro	Ocean waves
Nuclear fission fuels	Oean tide
Chemical cells	— Bio-mass fuels — Waste-fuels — Bio-gas — Synthetic gases — Nuclear fusion fuels — Fuel cells — Fire-wood.

Conventional energy resources are those which have been used traditionally for several decades before 1970s. After the oil energy crisis in 1973, the non-conventional energy resources have received high priority all over the world. Cost of various energy resources is increasing steeply. This has affected the overall national economy, the standard of living and the progress of various developing and developed nations.

*For further reading : "Energy Technology-Renewable and Conventional" —S. Rao and B.B. Purulekar, Khanna Tech. Publications, Delhi, 1995.

Electrical Energy is most widely accepted form of energy all over the world. Electrical Energy is supplied by the utilities (Electrical Supply Companies) to the consumers at all times. The consumers convert the *electrical energy* to several other forms such as mechanical (drives), heat (furnaces, ovens), light (lighting), high frequency waves etc. Energy supply and electrical powers supply are intimately related.

56.2. UNITS OF ELECTRICAL ENERGY

Joule = Watts × Seconds   kWh = Kilo-watt × Hours

MWh = Mega-watt × Hours

Units of Electrical Power : Watts, kW, MW, MWe represents electrical MW rating to distinguish from thermal rating.

56.3. ELECTRICAL LOAD AND DEMAND

Customers 'demand' certain MW and this 'demand' acts as a 'load' on the power plants. Hence 'load' and 'demand' are similar terms.

The *connected load* is the MW rating of the installed load. A residential building may have a connected load of 2.5 kW.

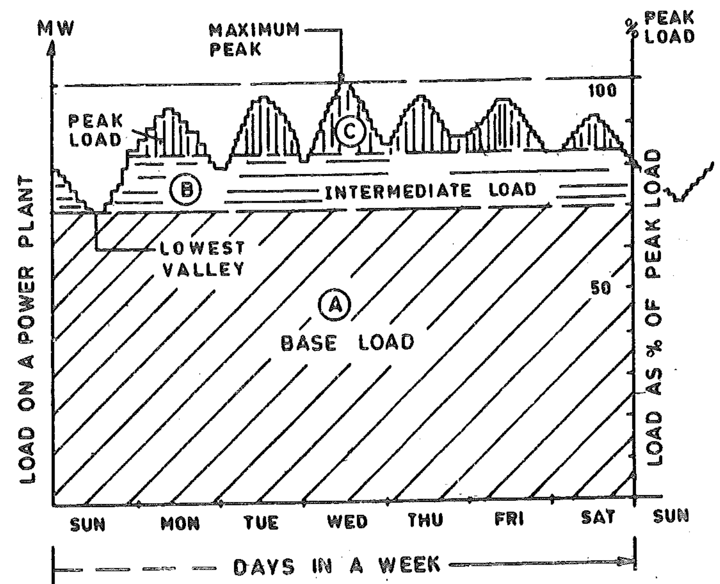
Actual demand (load) is the MW or kW power drawn by the particular user at prevailing time (say at 9 AM) *e.g.* the residential building mentioned above may have prevailing demand of 1 kW at 9 A.M. The prevailing *demand* of individual consumer, group of consumers, a locality, a city and a group of cities goes on varying during the day and during the week, during the seasons etc. This *demand* is a *load* on a power station or a group of power stations.

The *greatest problem for a power supply company is varying load.* The generation should be matched with the load constantly.

56.4. LOAD CURVES AND PEAK LOAD

Cronological time is plotted on X-axis and load in MW on a particular plant or a group of plants if plotted on Y-axis. A *load curve* is drawn for (*i*) 24 hours of a day (Daily Load Curve), (*ii*) 7 days of a week (weekly load curve) or (*iii*) 12 months of an year (Yearly Load Curves).

Fig. 56.1 shows a weekly load curve. The daily variation has a certain repetitive cyclic depending upon life-style, business hours, industrial hours etc. The load line touching the highest peak



A = Base Load stations operation period
B = Intermediate stations operation period
C = Peaking station operation period.

Fig. 56.1. Weekly Load Curve.

gives *Peak Load.* The total installed capacity of a plant (or a group of plants) should be more than the peak load with adequate surplus margin for steady state stability limits of generators, planned outages, single or twin contingency due to forced outages etc.

Instead of increasing installed capacity for peak load ; the region may import power through *interconnected line* as per scheduled exchange. Peak loads in two regions are generally displaced in time.

56.5. BASE LOAD, INTERMEDIATE LOAD AND PEAK LOAD

Lowest line parallel to X-axis and touching the minimum load is called the *Base Load Line.* This load is present at all the time.

The line parallel to X-axis at the base of the rising peaks is called Intermediate Load Line. In Fig. 56.1. (*A*), (*B*), (*C*) show the demarkation.

Note. During peak loads all the three categories (*A, B , C*) generate power. There should be some spare capacity for contingency.

56.6. LOAD DURATION CURVE

From daily load curve, corresponding daily load duration curve is plotted as shown in Fig. 56.2 (*a*), (*b*). The *Y*-axis is of MW load and *X*-axis is number of hours for which the load prevailed (Duration of MW).

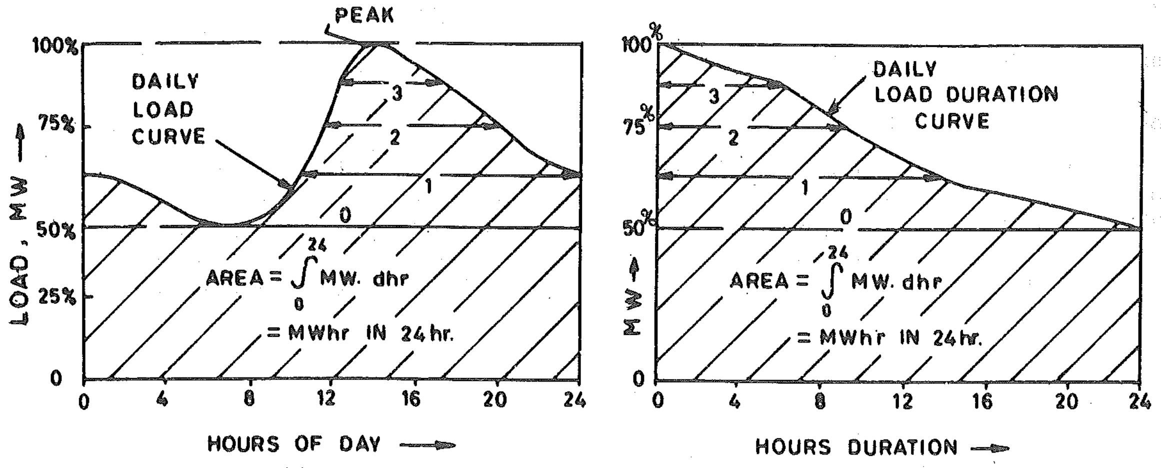


Fig. 56.2 (*a*) Daily load curve (*b*) Corresponding load duration curve.

Fig. 56.3 shows the load duration curve with markings for base load, intermediate load and peak load. **Note.** Area under the curve gives MWhr supplied.

Area under the daily load curve and corresponding daily load duration curve is given by

$$\text{Area} = \int_0^{24} \text{MW} \cdot \text{dhr} = \text{MWhr}$$

Thus area under these curves represents *electrical energy* supplied during 24 hours.

From the well known law of conservation of energy.

Total MWhr Energy Generated = Total MWhr Energy Consumed + Total MWhr Losses
Also Total MW being Generated = Total MW Prevailing + Total MW Losses

Some generating units may have lesser efficiency and higher generating cost (Rs./MWh). Such units are used for intermediate loads (*B*) Efficient units with lower generating cost are used for Base Load (*A*). Units with quick start/loading/stop are used for peaking (*C*) even though their fuel costs may be higher.

The scheduling of 5 units in a station or 5 stations in a regional grid is indicated on the left side of Fig. 56.3.

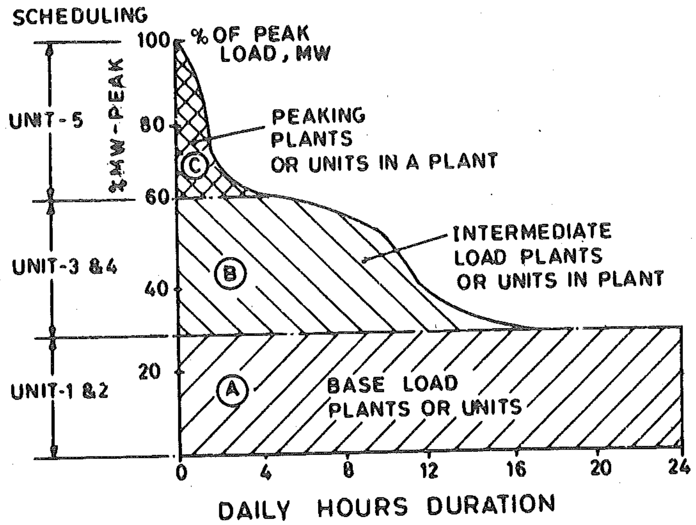


Fig. 56.3. Daily load duration curve with demarkation (*A*) Base load (*B*) Intermediate load (*C*) Peak load.

56.7. TYPES OF GENERATING UNITS FOR BASE LOAD, INTERMEDIATE LOAD AND PEAKING LOAD

Basic requirements of the generator, turbine, primary energy convertor (boiler) differ for Base load/Intermediate load/Peak load units.

Base Load Stations/Units are with :

— Continuous load with high load factor
— No frequent starting, rapid loading, rapid load throw-off
— Large reserves of primary energy resources.
— High efficiency
— Lowest generation cost (Rs./MWhr)

Intermediate Load Station / Units are in between the base load and peaking load.

Peak Load Station / Units are loaded for a few hours in a day. They should be :

— Quick to start, pick-up load, unload, stop
— Relatively lesser MW rating
— Cost of generation Rs./MWhr may be higher but is justified due to lesser MWhr produced by the peaking station/unit.

Table 56.2. Types of Power Plants for Base Load, Peaking Load

Category of Load	*Type of Station*	*Remarks*
Base Load	— Coal Fired Steam Thermal Power Plant — Nuclear Steam Thermal PP. — Geothermal Steam Thermal — Large Hydro-Electric — Combined Cycle Power Plant	— Operated at all times. — Influence overall cost of generation Rs./MWhr.
Intermediate Load	— Combined Cycle PP — Hydro-electrical PP. — Less efficient steam thermal units	— Operated at above base load line
Peaking Load	— Gas Turbine PP. — Combined Cycle PP. — Hydro-electric PP — Pumped storage PP — Diesel Electric PP	— Operated during peak loads only
Energy Displacement Plants	— Wind power, — Solar power, — Tidal power, etc	— Whenever Renewable Energy Source is available near load centres.

Energy Displacement Power Plants. Solar power plants and wind power plants generate electrical energy only during favourable natural conditions of sun-light and wind. During favourable conditions, they are allowed to generate full power and the other intermediate power plants are relieved of equal power generation. The energy consumption of non-renewable is displaced by corresponding amount of MWhr.

Hybrid of Renewable and Storage Plants. Energy displacement plants may operate in liaison with a conventional diesel electric plant and battery-energy storage to form Hybrid solution. Hybrid power plants introduced commercially are :

— Solar-Battery-Diesel — Wind-Battery-Diesel.

During favourable conditions of sun/wind, the storage batteries are charged. During unfavourable natural conditions the battery-back supplies energy *via* a suitable power conditioning unit (DC to AC).

When stored energy in battery-bank reduces, diesel-generator sets are started to supply the power.

Table 56.3
Operation of Renewable — Battery-Diesel Hybrid Power Plants

During favourable solar/wind Hours	→	Primary energy from renewable source converted to electrical
During unfavourable solar/wind hours — with batteries fully charged	→	Battery-pack supplies electrical energy *via*. conditioner.
— with battery charge exhausted	→	Diesel-Generator gives power.

56.8. PLANT FACTORS AND RESERVES

For economic operation of power plants and the energy supply system; load factor should be high, Diversity, Factor should be high. From the regular pattern of the daily load curves, advance preparations of the various 'reserves' are maintained.

Boilers, steam turbines, combustion processes, gas turbines etc. have different starting and loading characteristics.

Load Factor $= \dfrac{\text{MWh generated in a given period}}{\text{Maximum Demand} \times \text{Hours of operation in given period}}$

$= \dfrac{\text{Average Demand}}{\text{Maximum Demand}}$

Diversity Factor $= \dfrac{\text{Sum of individual consumers Maximum demands}}{\text{Maximum load on the station}}$

Plant Capacity Factor $= \dfrac{\text{MWhr produced}}{\text{MW capacity} \times \text{Total hours}}$

$= \dfrac{\text{MWhr. Produce}}{\text{MWhr. could be produced}}$

Plant Use Factor $= \dfrac{\text{MWhr. produced}}{\text{MW capacity} \times \text{Hours of operation}}$

Firm Power = Power which should always be readily available even during emergency state.

Cold Reserves = Reserve generating capacity available but not in operation

Hot Reserves = Reserve capacity available with thermal process in operational readyness.

Spinning Reserves = Operating capacity connected to bus and ready for taking load.

56.9. POWER PLANTS WITH CONVENTIONAL ENERGY RESOURCES

Fig. 56.4 shows the present alternatives on cost basis. The type of generating plants in a country or a region will mainly depend upon :

— natural (primary) energy resources available locally and their present and future supplies.
— Energy resources which could be transported by sea, rail, road upto the plant sites.
— Technology available/imported.
— Relative costs
— Ecological and Environmental clearances.

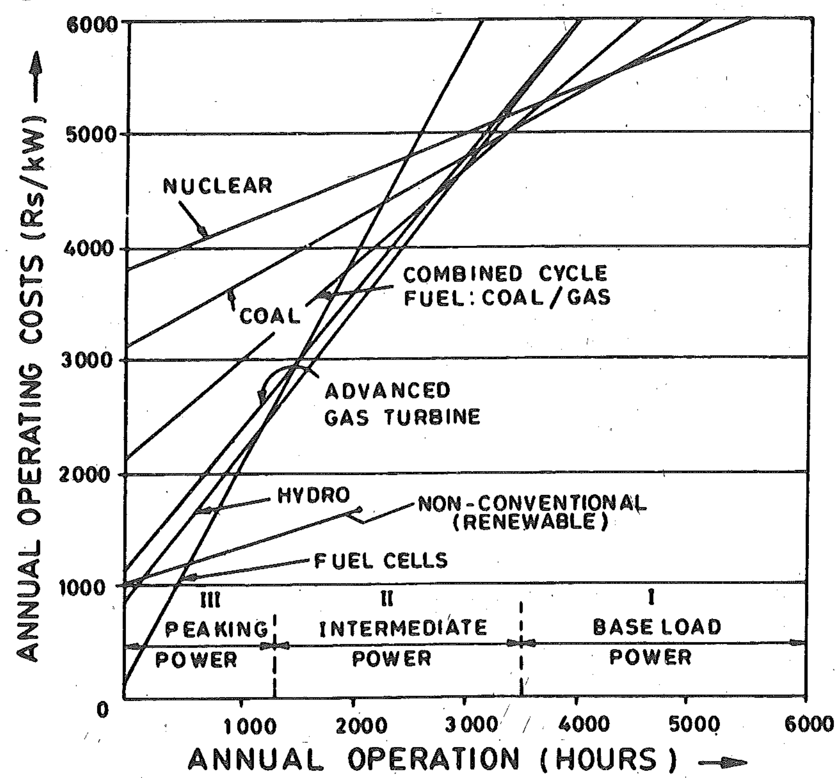


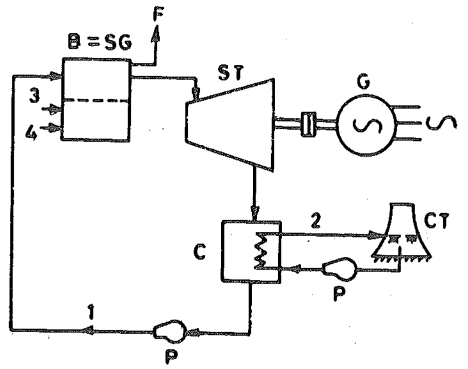
Fig. 56.4. Comparison of Generation Cost for Power Plants with different energy resources.

Conventional Power Plants of importance are :

1. Coal Fired Steam Turbine Power Plants
2. Hydro-Turbine Power Plants
3. Nuclear Reactor Power Plants
4. Gas-turbine and Combined Cycle-Power Plants. (Gas Turbines plus Steam Turbines)
5. Diesel-Engine driven Gernerator Plants

56.10. COAL FIRED STEAM-TURBINE POWER PLANTS

Refer Fig. 56.5. Pulverised Coal (powered coal) (3) and preheated air (4) are supplied to the Boiler — steam generator. Chemical energy in coal is converted into heat by *combustion.* The flue



1 = Feed water
2 = Cooling water
3 = Pulverised coal
4 = Preheated Air
B = SG Boiler Steam Generator
C = Condenser
ST = Steam-Turbine
G = Generator
CT = Cooling Tower
P = Pump
F = Flue gases

Fig. 56.5. Schematic of a Boiler — Steam Turbine Generator Unit.

gases (*F*) are sent out through stack (Chimney) after removal of fly-ash, SOx, NOx, CO etc.

Superheated high pressure steam is admitted into *steam-turbine inlet. Steam-turbine* is the prime-mover of generator-rotor. A steam turbine has series of nozzles on stator and series of buckets (Blades) on rotor. Steam *expands* from high pressure to low pressure and drives rotor blades. Steam is condensed in the condenser (*C*) at vacuum level. The condensate is recirculated as feed water (*I*).

Turbine-generator-exciter are mounted on a single shaft. The *Generator* is as a rule of 3 phase. AC, 50 Hz. Synchronous generator operating in parallel with other generators, and in synchronism with busbar/system frequency $f = N_s P/120$).

The generator units for steam turbine plants must be of higher MW rating for economical generation. Hence steam turbine generator units are generally of unit rating of 200 MW, 300 MW, 400 MW, 500 MW, 600 MW ... upto 1300 MW.

In India following unit ratings have been standardised for steam-turbine generator units :

Rated voltages	:	12 kV to 22 kV rms, ph to ph
Rated frequency	:	50 Hz ± 1%
Rated MW	:	200 MW, 237 MW (Nuclear)
		500 MW (Coal fired and Nuclear)
		800 MW (Next likely size).

Synchronous generators operate in synchronism with the other synchronous generators in the station and the network.

Coal Fired Power Plants in India. About 66% of installed MW capacity in India is by coal-fired steam turbine power plants. This percentage will be retained for about a century. India has vast reserves of coal. Estimated reserves are around 160 billion-tons with present mining rate of about 160 million-tons. India will have coal age for next hundred years (2000-2100). The coal in Indian mines is of high ash content, low heat value and low sulphur content.

Table 56.4. Indian Coal Composition Range

Ash content	25 to 50%
Sulphur content	< 1%
Heat value	12 to 16 million J/kg. 3000 to 4000 kcal/kg

India's coal reserves are in Bihar, UP, Maharashtra, Madhya Pradesh, Orissa, Andhra Pradesh, Tamil Nadu.

Present coal fired power plants are with unit sizes of 200 MW and 500 MW. The average national load factor is 58%.

Flue gases from coal fired power plants create environmental pollution by emitting fly ash (particulates). SOx, NOx, CO etc. Most of the earlier coal fired plants in India are without any Electro Static Precipitators (ESP) for controlling fly ash ; or SOx scrubbers, NOx treatment plants. Hence India's coal technology and power plant technology needs revision (1990).

56.10.1. Fluidised Bed Combustion Chamber Boilers

Coal pieces or some (other solid fuel pieces like wood chips, rice husk, wheat husk, sugar cane skins, etc.) are introduced in the furnace having a bed of ash and calcium carbonate. High velocity air through nozzles is swirlded in the furnace bed. The particles get heated by collusion and fuel burns at relatively low temperature. Water is boiled and used for steam turbines. Flue gases are cleaned and let into atmosphere or Heat Recovery Steam Generator.

Fluidised Bed Boilers are manufactured in smaller capacities (10 MW to 50 MW). They can be designed to accept a variety of solid fuels.

56.11. INTEGRATED COAL GASIFICATION COMBINED CYCLE POWER PLANTS (ICGCC)

Coal is Gasified in coal gasifier. Gasified coal is used as the primary fuel for a gas turbine of combined cycle power plant having (*i*) Gas Turbine (*ii*) Heat Recovery Steam Generator (*iii*) Steam Turbine.

ICGCPP have been recently introduced in Europe ; USA.

The main purpose is *reduction* of emission products like fly ash, SOx, NOx from combustion of the gasified coal as compared with burning of pulverised coal.

56.12. HYDRO ELECTRIC POWER PLANTS

The *potential energy* is stored water in the reservoir with high head is converted into kinetic energy is the flowing *water.*

The flowing water converts the energy into mechanical rotary energy in the hydro turbine. Hydro-turbine drives the rotor of hydro-electric generator.

The hydro-electric power plants are located near dams or river-barrages generally away from load centres. The types of hydro-turbines and power plants are classified as high head, medium head and low head power plants. The choice of turbine depends on head *H* and flow rate *Q*. There are three types of turbines (Table 56.5).

Table 56.5. Types of Hydro-Turbines

Type	*Head* *H, m*	*Flow rate* $Q, m^3/s$
Impulse (Pelton)	High 100 to 1000	2 to 100
Reaction (Francis)	Medium 5 to 30	5 to 500
Kaplan	Low 2 to 100	5 to 100

India's hydro-electric potential is about 100,000 MW mostly located in northern, Himalayan region. Present installed capacity of hydro plants is 15000 MW and is likely to be doubled to 30,000 MW by the year 2000.

Environmental problems include earthquakes, deforestation, submergence of villages/agricultural lands etc.

Financial problems include high civil-works cost, long construction periods, long transmission lines etc.

Considering the continuing supply of hydro-energy as a *primary renewable*, hydro electric power will have 20 to 30% share of the total installed capacities in India during 1990 to 2050.

Pumped Hydro Plants. During off-peak, the electrical machine operates as a motor and hydraulic machine operates as a pump. Water from lower head is pumped to higher head reservoir for *storage of energy*.

During peak loads, the higher head water flows down and drives the hydraulic machine operating in turbine mode and the electrical machine in generating mode.

There may be one or two separate hydro-machine and one electrical machine on same shaft.

Two pumped hydro plants have been commissioned in India.

56.13. NUCLEAR FISSION REACTOR POWER PLANTS

Some heavy uranium isotopes U235, U238, PU 233 etc. are used as primary fuels in a *nuclear reactor*.

Nuclear Fission is the process of splitting of a nucleus into two almost equal fragments accompanies by heat.

Fission Chain Reaction is a self-sustained continuing sequence of nuclear fission in a controlled manner.

Nuclear Reactor is a plant which initiates, sustains, controls, maintains, nuclear chain reaction and provides shielding against the radio active radiation.

Fissile Materials are materials which can give nuclear fission *e.g.* U 235.

Fertile materials are these which by certain processes get converted into fissile material (*e.g.* U238 gets converted to U235).

Nuclear Power Plant has a nuclear reactor, heat exchanger and steam turbine generators along with other auxiliaries.

There are several types of nuclear reactor power plants with names based on (*i*) Fuels (*ii*) Moderators (*iii*) Method of Heat removal (4) Patented Process etc.

India's nuclear uranium fuel resources are located in West Bengal.

Nuclear power generation is being perused regoriously in India with self dependence in engineering and technology. Presently, India has seven Pressurised Heavy Water Reactor Plant (PHWR) with 210 MW and 235 MW size steam-turbine generator units. Six 500 MW units are being installed (1990-2000). Present installed capacity of Nuclear Power Plants is 7000 MW (1991). This would grow to 10000 MW by the year 2000 AD. Thorium Cycle Plants will be introduced after 2000 AD.

Research projects for smaller nuclear fission power plants are in progress. Success has been reported in 1996.

56.14. GAS TURBINE POWER PLANTS

Fuels. Natural gas; Petroleum oils of various grades ; gases from blast furnace ; Synthetic gases ; gasified coal etc. are used as primary fuels for both (*i*) Gas Power Plant and (*ii*) Combined Cycle Power Plant.

The Gas Power Plant has the following (Ref. Fig. 56.6).

1. Air compressor
2. Fuel Combustor
3. Gas Turbine
4. Synchronous generator driven by Gas Turbine.

Gas-turbine generator units are produced in standard sizes in the range of 10 MW to 150 MW (recently 250 MW). *In simple open cycle gas-turbine power plant. The exhaust is let into atmosphere. Therefore, heat in exhaust is wasted and thermal efficiency is very poor (20%).*

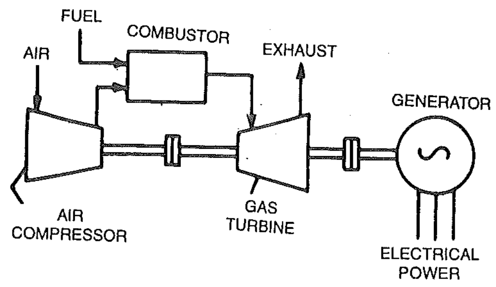


Fig. 56.6. Simple, open cycle Gas Turbine Power Plant.

Gas turbine power plants are easy to install ; have low capital cost ; quick to start ; quick to load ; quick to stop, with modular construction, with least pollution hazards etc. They are ideally suited for (*i*) peaking power plants, (*ii*) Emergency power plants (*iii*) Standby power plants (*iv*) *Supply of auxiliary power during peak loads etc.*

Due to increasing fuel costs and importance of energy conservation simple open cycle gas power plants are not favoured. The combined cycle power plants are preferred.

56.15. COMBINED CYCLE POWER PLANTS

Fig. 56.7 shows the schematic with one unit of gas turbine generator and one unit of steam-turbine generator. In practice there are two or four gas turbine generators and one steam turbine generator. *Combine Cycle Plant has a combination of (i) Gas Turbine Generators and (ii) A Steam Turbine Generator. Hence the name 'combined cycle'.*

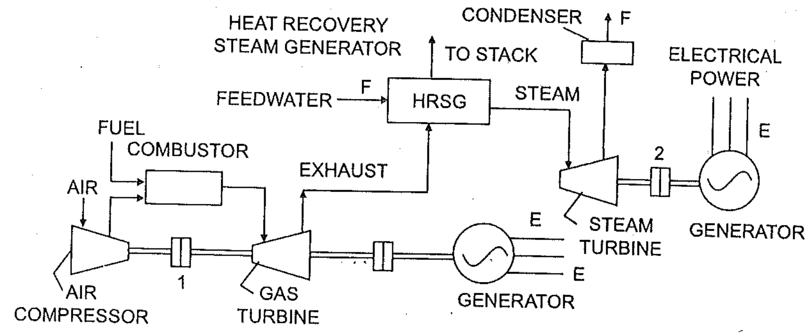


Fig. 56.7. Schematic of a Combined Cycle Power Plant Combination of
1. Gas-turbine Generator 2. Steam-turbine Generator.

Main equipment include :

1. Gas Turbine Units
   — Air Compressor — Combustor
   — Gas Turbine — Synchronous Generator
2. *Heat Recovery Steam Generator* (HRSG)
3. *Steam-Turbine Generator Unit*
   — Steam Turbine — Synchronous Generator

The flue gases from HRSG have low heat and low emission products.

56.15.1. Integrated Coal Gasification Combined Cycle Plants

Coal is gasified and used as an input fuel in the gas plant of the combined cycle plant.

India's known recoverable sources are as follows :

Crude-oil reserves	500 million-ton
Natural Gas	490 billion m^3.

Oil reserves are insufficient even for transportation sector and India is an importer of oil.

Ten 112 MW Gas Power Plant have been commissioned with total installed capacity of 896 MW (1996). Estimated potential is 1300 MW by year 2000. The gas reserves are expected to last upto 2015.

56.16. DIESEL ELECTRIC POWER PLANTS

The diesel (a petroleum oil) is primary fuel. Its energy is converted into mechanical rotary energy in a diesel engine generator units. The ratings range between a few kW to a few MW.

Diesel Engine Plants can be started quickly (a few seconds) and are preferred for

1. Peaking power plants
2. Remote, stand-alone power plants of smaller ratings where steam power plants or gas turbine power plants are not economical.
3. Hybrid of solar battery diesel.
4. Hybrid of wind-battery diesel.
5. Captive power plants for continuous process industry with uninterrupted power plants.

56.17. AGE OF RENEWABLE AND ALTERNATIVES

Fossil Fuel age is expected to span only 1000 years of human civilization (1700 AD to 2700 AD) with ever increasing population and fuel consumption rates ; and increase in petroleum product, prices ; the energy starvation is felt by every developing and developed country.

After 1973 petroleum price rice, the attention of planners, decision makers, engineers and technologists has been focussed on alternative, renewable energy resources and power plants. The alternative energy power plants have been built on commercial basis in several advanced countries developing countries have also initiated ambitious projects for harnessing the renewables. Table 56.7 gives the summary.

Present installed capacities of renewable energy plants (except hydro) in India are negligible. By the year 2000, about 250 MW installed capacity of renewables is expected in India. Present emphasis is to consume available fossil fuels. The renewable technology is under the development. It is costly and requires very high capital cost for a relatively small capacity power plants.

Table 56.7. Alternative and Renewable Energy Power Plants

Type	*Remarks*
1. Solar-Thermal Steam Power Plant or Solar Photo-Voltaic Cell Panel Power Plant	— Boiler installed on tall central tower gets reflected solar irradiation from sun-tracking mirrors on ground level. — Steam from boilers drives steam turbine-generators — Solar PV cell panels connected in series/parallel
2. Wind-Turbine-Generator Power Plant	— Large wind-turbine with three blades, horizontal axis, installed on nacelle on a tall tower. The wind turbine-gears-rotate generate shaft. — Several wind-turbine-generator units. (50 kW to 300 kW) installed in one wind-farm.
3. Geo thermal-steam Themral Power Plant or Binary Cycle Power Plant	— Heat inside earth extracted in form of dry steam/wet steam/hot brine through hot deep well (1.5 to 3 km deep) — Heat used for steam turbine or NH_3 turbine. — Turbine drives generator — Large base load power plants rated 200 MW to 1000 MW
4. Ocean Thermal Energy Conversion Power Plant (OTEC)	— Heat in upper layer of water used for driving steam turbine/gas turbine on shore or in floating power plant. — Cold water from bottom of ocean used for condenser.
5. Ocean Wave Energy Power Plant	— Power plants are located in locations with high waves (2 to 4 m) — Waves drive hydro-turbine in cyclic manner during onward wave or during forward/reverse waves. — Bulb Turbine-generators installed within penstocks located inside long barrages across the ocean-shore
6. Ocean Tidal Energy Power Plant	— During high tide, water is accumulated in upper reservoir. During the low tides, the water from upper reservoir flows to lower level and drives the hydro-turbine generators
7. Waste Incineration Power Plants	— Located in large sites. — Combustible waste from the city (paper, rags, wood chips, wood dust, residence-waste etc.) is used as fuel. — The combustion of fuel gives heat. Steam turbines drive generators rated a few MW — Flue gases cleaned before letting into atmosphere.
8. Bio-Fuels Power Plants	— Wood, Rice husk, wheet husk, special farms with fuel-crops raised in three months, etc. are burnt and heat used for steam-turbine generators.
9. Fuel Cells Power Plants	— Chemical Liquids, Gases used as fuels and oxidants Ratings a few kW to a few MW.
10. *Nuclear fusion Power plants*	— *Likely to be introduced by 2010. Presently research and development work is in progress.* — *Combining (fusion) of some nuclei gives heat.* — *Likely to serve as major energy resource in future.*
11. *Magneto Hydro Dynamics (MHD) Power Project*	— *Hot gases are seeded to form ionized gases. These are passed through strong magnetic field-Electrodes held in perpendicular plane collect the current.* — *Direct conversion from heat to electricity 14 MW plant built in India as prototype* — *100 MW, 200 MW plants built in USSR.*

Wind Energy. India's wind energy potential is of 20,000 MW. Wind farms would be located in sea-shores, shallow sea water, windy areas.

Wind-farms with unit rating of 50 kW to 200 kW have been installed in Gujarat, Tamil Nadu. Total installed capacity is 120 MW and projects of 200 MW capacities are under installation.

Solar Energy is being used for heating water. 50 kWe solar thermal electric plant has been installed in Gwalpheri, Haryana. Solar power plants rated 30 MWe with parabolic through collectors, steam turbine generators are being planned. First station will be built in Jodhpur.

Ocean Tidal Potential in Gujarat and West Bengal states is about 10,000 MW Kutch in Gujrat and Sunderban in West Bengal are selected as locations for ocean tidal power plants.

Ocean-thermal Power Plants rates 100 MW each are envisaged in Kulasekarpatnam, Marakkanam, Pondicherry, Cuddalore. (Tamil Nadu). Totally 6 plants of 100 MW each are being considered.

New and Renewable Sources of Energy (NRSE). Schemes under Ministry of Non-conventional Energy. India has planned following by 2000 AD.

Biomass	6000 MW
Agricultural waste	2000 MW
Solar systems	5000 MW

The share of installed capacity would be increasing rapidly after 2000 AD due to depleting fossile fuels, increasing cost of fossile fuels, established infra-structurer for alternative energy power plants. Fig. 56.8 illustrates the likely trends.

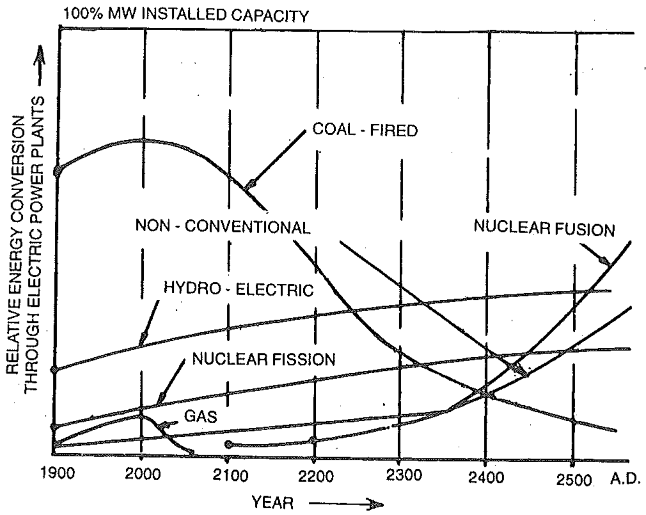


Fig. 56.8. Trends in energy resources for power generation.

56.18. ENERGY STORAGE PLANTS

It is uneconomical to increase installed capacity for meeting peak demand of few minutes or an hour or so. Energy storage plants are designed to store energy during off-peak periods and supply it during peak load periods. Following types of plants have been built in advanced countries.

— Pumped hydro (2 plants in India)
— Compressed Air (or Nitrogen) Energy Storage
— Thermal Energy Storage
— Superconducting Magnet Energy Storage (1/2 Li^2 in superconducting coal)
— Secondary cell energy storage
— Fuel-cell Energy storage (in form of fuels and oxidants derived during off-peak periods)
— Ocean tidal power plants.

56.19. POWER QUALITY

With use of digital devices, microprocessors, digital computers, plants management systems, EDP etc. the quality of electric supply has received more attention. New terms are being defined and standardised. Agreements between users and utilities with legal and political implications are envisaged particularly in advanced countries.

Power Quality is defined in terms of parameters of supply voltage and includes specified values and permissible tolerances for voltage, waveform, frequency, balance in three phase, continuity and disturbances. The *load parameters* affecting power quality include power factor ; starting currents, starting duration, load fluctuations, load unbalance, load power-factors (reactive power drawn), maximum kVA demand etc. While some terms have been defined and specified the others are not.

Table 56.8. Parameters of Power Supply Quality and Load Quality

Parameters	*Range or Limit*
1. Supply AC Voltage	Nominal, Highest, Lowest Voltages Specified
2. Voltage Disturbance — Transient overvoltages — Momentary under-voltages — Temporary under-voltages	 < 0.2 ms + 150% to 200% 4 to 20 ms with – 100% < 0.5 sec – 25% to – 30%
3. Voltage harmonic Distortion	3% to 5%
4. Electrical Noise	Not defined
5. Supply Frequency	India 50 Hz ± 3% USA 60 Hz ± 1%
6. Rate of change of frequency	1 Hz/sec.
7. 3 phase voltage unbalance in supply	2.5% to 5%
8. Load 3 phase unbalance	5% to 20% for any one phase
9. Load Power Factor	0.8 to 0.9
10. Peak Load demand	0.75 to 0.85 of connected load

Categories of Disturbances in Power Quality. These could be in terms of duration and magnitude of disturbance. Table 56.9 gives and example.

Table 56.9. Categories of Disturbances in Voltages

	Disturbance	*Duration*	*Range of Magnitude*
1.	Harmonic Distortion	Steady State to few seconds	Upto 1 percent
2.	Power Supply outage	Hours to millisecond	0 power
3.	Voltage Dips of short duration	0.5 to 50 cycles	1 to 0.5 pu
4.	Temporary overvoltages	0.5 to 50 cycles	1 to 1.75 pu
5.	Fast voltage transients (Noise, Notches, spikes in waveform	< 10 ms	up to 6 kV

The power quality encompasses several topics related with switchgear and protection. Assuring good power quality is the aim of electric power supply company and require understanding and cooperation between supply companies , users, system designers, system analysts and operating staff.

56.20. INTERCONNECTED POWER SYSTEM

Fig. 56.9 is a conceptual diagram of a National Grid (N) knowing five regional grids (*A, B, C, D, E*). Each regional grid covers the consumers in certain geographical area. Each regional grid has certain installed generating capacity (MW) of conventional/renewables and certain connected loads (Σ MW). Some interconnections are EHV-AC and some are Back-to-back HVDC coupling substations for quick, accurate power exchange and damping of system disturbances automatically.

Fig. 56.10 shows a regional grid having a variety of conventional and non-conventional power plants and the transmission and distribution networks.

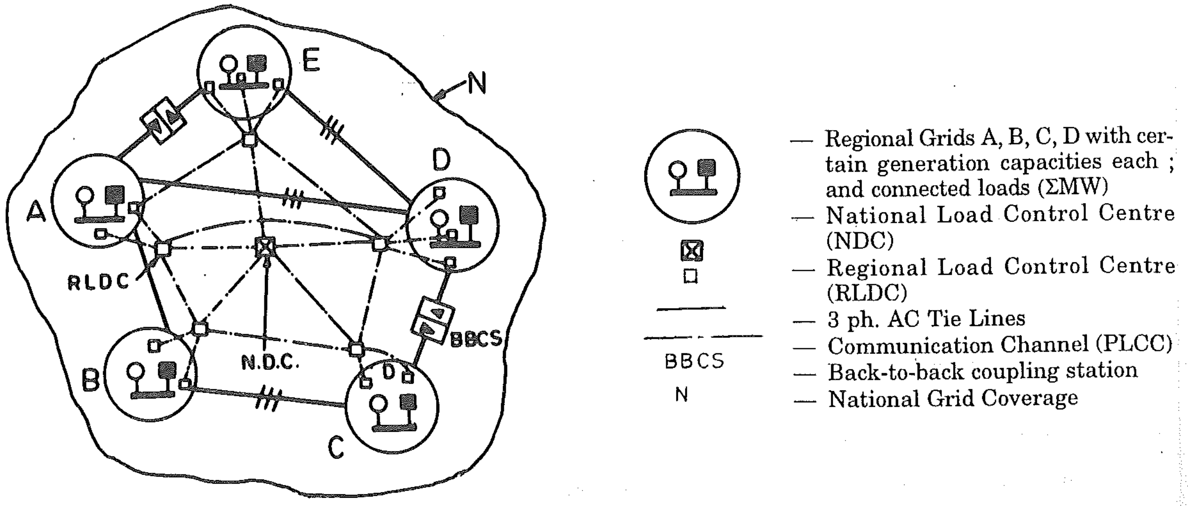
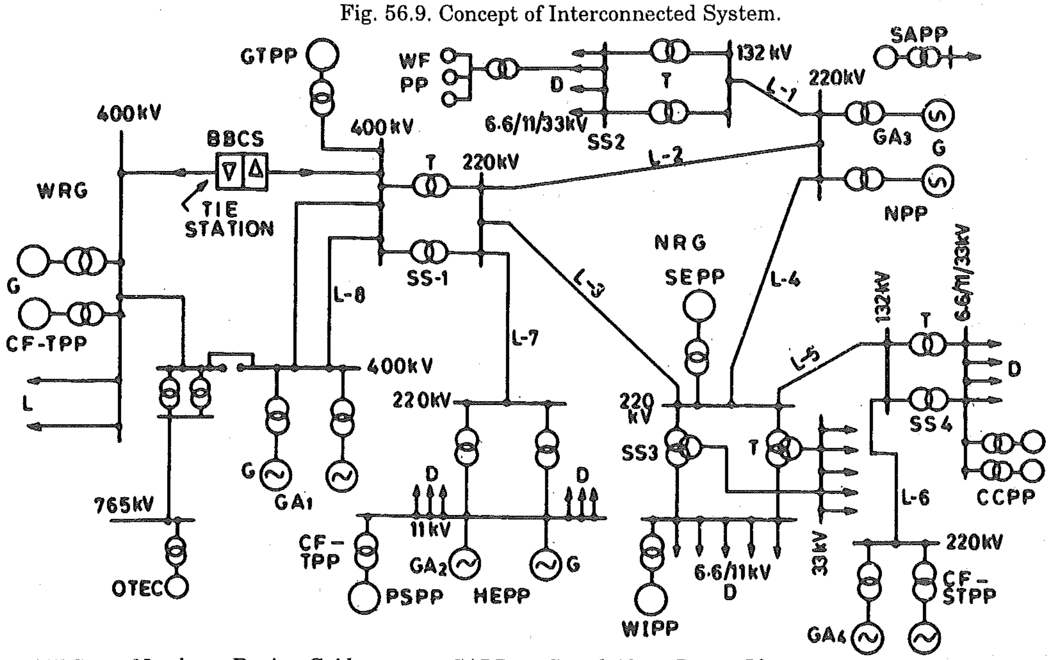


Fig. 56.9. Concept of Interconnected System.



NRG	= Northern Region Grid	SAPP	= Stand Alone Power Plant
WRG	= Western Region Grid	SEPP	= Solar Energy PP
BBCS	= Back-to-back HVC Coupling Station		
PSPP	= Pumped Storage PP	CCPP	= Combined Cycle Power Plant
WIPP	= Waste Incineration PP	CFTPP	= Coal Fired Steam Thermal PP
WFPP	= Wind Farms PP	GTPP	= Geo Thermal Power Plant
G	= Generator	HEPP	= Hydro Electric Power Plant
L	= Transmission Line	NPP	= Nuclear Power Plant

Fig. 56.10. Conceptual single line diagram of a Regional Grid.

56.21. PROJECTED GROWTH OF ENERGY SUPPLY SYSTEM INDIA

Present installed capacity is app-85,000 MW. The National Grid of Indian envisages additional 50,000 MW installed capacity during ninth plan (1996-2000). The total capacity would be about 135,000 MW by 2000 AD.

The *generation* responsibility is with National Thermal Power Corporation. (NTPC); National Hydro Power Corporation, (NHPC); State Power Corporation, State Electricity Boards etc.

With present population of 85 crores the per capita installed capacity is about 100 watts.

The EHV-AC and HVDC transmission responsibility is of newly formed Power Grid Corporation Limited (PGCL) and State Electricity Boards. The "National Power Transmission Plan 1990-2000" envisages additional 50,000 ckt km of 400 kV AC lines, 500 ckt km of 765 kV AC lines, 4000 Ckt km of HVDC lines, Five Back-to-back HVDC coupling substations between adjacent Regional Grids. Several Renewable and Conventional Power Plants would be added to achieve the target.

56.22. SIGNIFICANCE OF SWITCHGEAR PROTECTION AND POWER SYSTEM AUTOMATION

Electrical form of energy is an important link between the primary energy resources and energy forms for ultimate utilization.

Energy and power science and technology has developed to ensure continuous supply of electrical energy of good power quality without disturbing ecology and environment. The growth, prosperity, advancement of civilization is influenced by the capability of handling the energy from resources to final consumption. Per-capita installed capacity and power capita energy consumption have become accepted measures for economic progress. Modern Energy Supply Sytems are dependant on switchgear protection and power system automation for supplying quality power to all the consumers at all times in present and future.

57-A

Power Flow Calculations — Part I

Introduction to Power Flow Studies — Variables — Admittance Calculations — Equivalent Sources — Network Nodal Current Equations — Y- bus Matrix — Interation Procedure — Simple Two Node AC System — Multibus System — Types of Buses — Load Flow Equations — Gauss Interative Method — Gauss Seidel Interative Method — Acceleration Factors used in Gauss Seidel Interative Method — Newton Raphson Interative Method — *Solved Examples* — Significance of Power Flow Studies — HVDC Load Flow — Summary.

57.1. INTRODUCTION TO POWER FLOW CALCULATIONS

In 3 phase AC power system, active and reactive power flows from generators to loads *via* various Network Buses and Branches (Transmission Lines). The flow of active and reactive power is called *Power Flow or Load Flow.* The voltages of buses and their phase angles are affected by the power flow and *vice versa. Power flow studies deal with calculations of bus voltages, their phase angles, active and reactive power flow through various branches, generators and loads under steady state conditions.*

Active power P and reactive power Q is supplied by generators at generator buses. Active power is drawn by loads from load buses. Reactive power Q is supplied or drawn from the load buses by shunt compensation elements (shunt capacitors, shunt reactors, SVS).

The various loads draw active and reactive power from the load buses. The AC power system has tens/hundreds of Generating stations and hundreds/thousands of branches and load buses. Calculations of Power flow (Load flow) through various buses, bus voltages and phase angles, etc. are carried out by *interative process* using. Digital Computer.

The method of power flow calculations has been explained in this chapter with the help of simple networks having a few generator buses and a few load buses. The same method is applicable to a multibus system.

Refer a simple Network shown in *Fig. 57.1.* The base variables for each buses are : V_k, $\angle \delta_k$, P_k and Q_k, where k is bus number 1, 2, 3 ...N. Variables for each of the six branches are active power P, reactive power Q through the branch. Current I and power factor cos ϕ. etc in generator, load and branches can be calculated from the base variables.

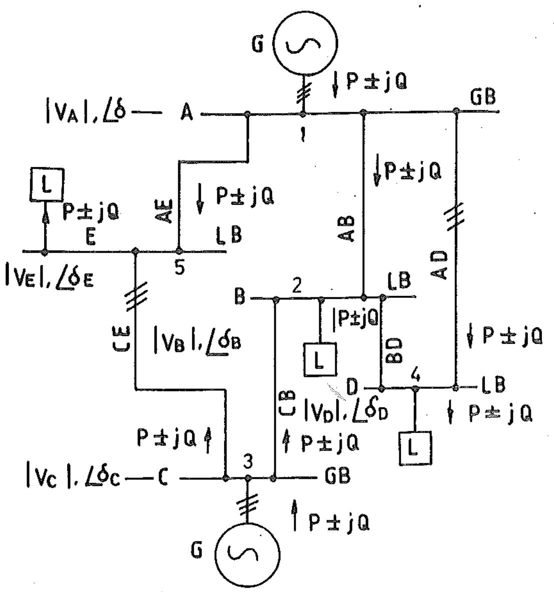


Fig. 57.1. Simplified representation of a 3-phase AC Network for Power Flow Study.

Ref. Fig. 57.1.	*Known (Specified)*	*Unknown* (To be calculated)*
Generator Buses : A, C	V, P	$\angle\delta, Q$
Load Buses : B, D, E	P, Q	$V, \angle\delta$
Branches : AE, CE, AB, CB, BD, AD		Flow : P, Q

*The objective of Power flow (Load flow) studies is to determine these unknowns for each bus.

Nature of Load Flow Problem

Electrical energy in form of 3 phase AC power flows from various *generating station buses* to various *connected load buses via* various *branches* of the transmission network. Each branch has certain admittance Y (reciprocal of impedance Z).

The power flow in a branch of a two bus network is easy to calculate as it depends on sending end bus voltage, receiving end bus voltage, load angle δ between voltage vectors V_s and V_r and the branch admittance Y (reciprocal of impedance Z). The analysis of a two bus system gives understanding about relationships between $|V_s|$ and $|V_r|$, $\angle\delta$, P and Q. Two bus system has only 2 equations which can be solved by calculator. But a total power system has thousands of buses and several thousand variables. Hence interative procedure and digital computer are essential to solve the thousands of simultaneous equations.

Power System Network has certain configuration. The bus voltages, are influenced by the power flow ($P \pm jQ$) through various branches, branch admittances and generator voltages. The flow of active and reactive power through various buses branches influences the bus voltage magnitude and their phase angles. Change in load ($P \pm jQ$) at any bus affects all the other variables of other buses and branches.

The principal variables $|V|$, $\angle\delta$, P and Q of all the buses and branches in the Network related with each other by circuit laws and can be evaluated only by solving *Simultaneously nodal current equations* for given conditions by the interation process applied to load flow equations. In Fig. 57.1, if load on bus D changes, voltage V, phase angle $\angle\delta$, P and Q at all the four network buses and six branches will change simultaneously. The objective of Power Flow Study of Network in Fig. 58.1 will be to determine the unknown variables.

Power flow studies give a systematic mathematical approach to determine the various bus voltages, their phase angles, active and reactive power flow through various branches for given *steady state conditions of the Network* and given network configuration. The power flow through the branches is known only from the printout of the successful run of Load Flow Program. Table 57.1 gives a simple example. *Power flow study of a power system deals with calculations of steady state variables for buses and branches including Voltage |V|, Phase angle of V, Active Power P, Reactive Power Q, Apparent Power S, Current I, Power factor cos φ, etc power and associated variables for steady state conditions in Network.*

Table 57.1. Example of Computer Print-out* Report of a Power Flow Study

Karnatak State Electricity Board, Banglore

Report on Power Flow Calculations for No. 2 Hubli Zonal Circle Bus Data

Bus No.	*Bus Name*	*Bus Volts*	*Bus Angle*	*Generation*		*Load*	
				P MW	*Q MVAR*	*P MW*	*Q MVAR*
1.	Belgaum	1.02	0	65	33	00	00
2.	Dharwar	0.955	– 3.9	00	00	61	30
3.	Hubli	1.04	2.0	100	48	00	00
4.	Karwar	0.923	– 8	00	00	40	10
5.	Chickodi	0.993	– 2.1	00	00	60	20
	Total Zonal Circle			165	81	161	60

End of Power Flow Program Run
No. of Interations 25

* Only for study project, not for planning and design.

57.2. NEED OF POWER FLOW STUDIES

Power flow studies are essential and very important for

— Designing a power system
— Planning of power system
— Expansion of power system
— Providing guidelines for optimum operation of power system
— Providing base data for various power system studies Refer Sec. 57.24 for further details.

57.3. OUTLINES OF THE PROCEDURE OF POWER FLOW STUDY

The Power Flow Calculations involve the following steps :

1. Single line diagram of the system is drawn.

2. The *Nodal Admittance Diagram* is drawn. The network is represented in form of its Admittance Model.

3. The *Bus Admittance Matrix* is constructed.

The steady state model of the network is presented in form of *Bus Admittance Matrix Equation* based on modal current equations and Kirchoff's current laws. The bus admittance matrix of a large network is *large and sparse.* The bus admittance matrix can be constructed as per simple building blocks procedure.

4. The *Network Buses are classified* and are given a number. The three classes are : Generator Buses, load buses and a slack bus (swing bus). Each bus is given a number $k = 1, 2, \dots N$.

5. To begin with, the known and unknown variables are noted for each bus.

6. **Power Flow Equations** are written in terms of $P, Q, V, \angle\delta$ for kth bus. $k = 2, 3, \dots. N$.

Subscript k denotes the bus number.

7. These equations are solved by any one of the suitable interation procedure on a digital computer. The interation procedure consists of assuming certain values for the unknown variables to begin with and solving the equations to obtain the yet another revised value of the unknown variables for each bus. Interations are repeated till the *difference* between consecutive results of the same variables for each bus are within acceptable small value. At that stage the interations are stopped and final values are noted.

Superscript r denotes the interation number.

For given conditions of generation and load and power flow through various branches and voltages/phase angles of various buses are calculated by solving N number simultaneous nonlinear equations for N buses by *Interative method and digital computer solution of load flow equations.* N number bus system, to begin with, $2N$ variables are known and $2N$ are to be determined.

	Known (Specified)	*Unknown* (To be calculated)*
Generator Buses :	V, P	$\angle\delta, Q$
Load Buses :	P, Q	$V, \angle\delta$
Slack Bus (Swing Bus)+ :	$V, \angle\delta$	P, Q

* The objective of power flow (load flow) studies is to determine these unknowns for each bus under steady state condition.

+ Slack bus (with bus) is any one selected generator bus for which P and Q are not specified to begin with. Voltage magnitude and phase angle are specified. This provides for accounting for transmission losses in the branches which will be known at the end of computer run.

8. Presently one of the following two methods are preferred for solving Power Flow Equations by interation process :

— Gauss-Seidel Method — Newton-Rhapson Method

The relative merits are covered in Sec. 57.21

8. Solution of Power Flow Equations by any of the above two methods gives values of unknown principal variables for each of the N network buses. The basic variables for each bus are : Voltage magnitude $|V|$, phase angle of voltage vector : $\angle\delta$; active power P and reactive power Q.

— Out of these four principal variables for *each* bus two are known (given) and remaining two are calculated by load flow calculations.

For given conditions of generation and load, the power flow through various branches and voltages/phase angles of various buses are calculated by solving N number simultaneous nonlinear equations for N buses by *Interative Method and Digital Computer Solution of Load Flow Equations.*

— From the solution to power flow study the value of the two unknown variables for each bus are obtained and thus all the four variables for each bus are then known at the end.

— The other derived variables for the buses and branches such as current I, power factor of I, MVA etc. can then be calculated for each branch from the four principal variables of each terminal bus by applying fundamental circuit equations.

BRANCH ADMITTANCE EQUATIONS

57.4. BRANCH ADMITTANCE AND SOURCE TRANSFORMATION

In normal circuit calculations impedance Z is used, $I = V/Z$. Power flow load calculations are generally made with admittance Y parameter. $I = VY$. [Admittance Y = 1/Impedance Z]

Calculations with computer solution of power flow equations are easy with admittance parameters. [The impedance parameter calculations are used generally for short circuit calculations and are rarely used for load flow calculations.] In the following sections the Admittance form has been used for load flow calculations.

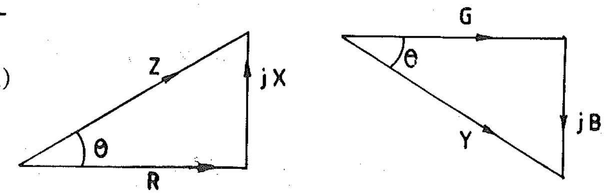
57.5. ADMITTANCE FORM OF CALCULATIONS

Reciprocal of impedance Z is called admittance Y. We have impedance triangle and admittance triangle as shown in Fig. 57.2 Y and Z are complex quantities.

$$Z = R + jX \text{ ohm} \quad Y = G + B \text{ mho} \quad \dots(57.1)$$

$$Z = \frac{1}{Y} \qquad Z = \frac{V}{I} \text{ ohm}$$

$$Y = \frac{1}{Z} \qquad Y = \frac{I}{V} \text{ mho}$$



Z = R ± jX Y = G ± jB

Fig. 57.2. **Impedance** triangle and Admittance triangle.

Voltage drop V_a in impedance Z_a (or admittance Y_a) by current I_a is given by :

$$V_a = IZ_a \quad I = V_a/Z_a \quad I = V_a Y_a$$

Example 57.1. *Branch Admittance and Branch Current in a two node one branch circuit shown in Fig. 57.3B, the branch impedance Z_a 3 + j4 ohm. Voltage drop in the branch (a) is $V_a = 100 \angle 0°$ V. Calculate (1) Branch current (2) Branch admittance.*

Solution.

Branch Current : $$I_a = \frac{V_a}{Z_a} = \frac{100\angle 0°}{3+j4} = \frac{100\angle 0°}{5\angle 53°} = 20\angle -53°.$$

Branch Admittance $$Y_a = \frac{1}{Z_a} = \frac{1}{3+j4} = \frac{(3-j4)}{(3+j4)(3-j4)}$$

$$= \frac{3-j4}{3^2+4^2} = \frac{3}{25} - j\frac{4}{25} = 0.12 - j0.16 \text{ mho}$$

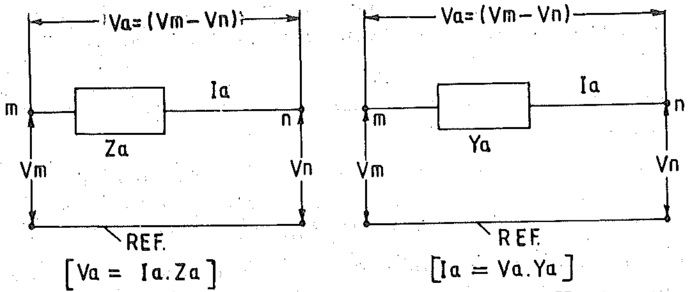


Fig. 57.3A. Branch Representation by Z or Y.

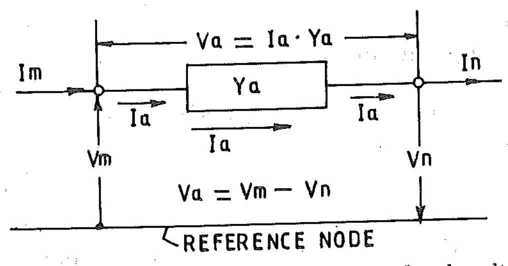


Fig. 57.3B. Branch admittance Y, Branch current I and node voltage V_m and V_n.

$$|Y_a| = \sqrt{0.12^2 + 0.14^2} = 0.2 \text{ mho}$$

$$[\angle \tan^{-1}(-0.16/0.12)] = \angle -53°$$

Check : $$I_a = V_a\, Y_a = 100\ \angle 0° \times 0.2\ \angle -53° = 20\ \angle -53°$$

Example 57.2. $Z = 3 + j4$ calculate Y

$$Y = \frac{1}{3+j4} = \frac{1\,(3-j4)}{(3+j4)\,(3-j4)} = \frac{3-j4}{3^2+4^2} = \frac{3-j4}{25}$$

$$= 0.12 - j0.16 = \sqrt{0.12^2 + 0.16^2} = 0.2 \text{ mho}$$

57.6. BRANCH ADMITTANCE

Ref. Fig. 57.3A. Network branch and be represented either by a branch impedance Z_a or by a branch admittance Y_a.

In Fig. 57.3B the node voltages of the terminals of branch (a) with respect to the reference node are V_m and V_n.

The current in the branch (a) is given by :

Impedance form	*Admittance form*	
$I_a = \dfrac{V_a}{Z_a}$	$I_a = V_a\, Y_a$	
$= \dfrac{(V_m - V_n)}{Z_a}$	$I_a = (V_m - V_n)\, Y_a$	...(57.2)

57.7. SOURCE TRANSFORMATION : CURRENT SOURCE —VOLTAGE SOURCE

In impedance form of representation, and active voltage source (generator) can be represented by a circuit having emf E_a in series with internal impedance of surface Z_a. The terminal voltage V_a is given by

$$E_a = V_a - I_a\, Z_a \qquad \text{...(57.3)}$$

Dividing both sides by Z_a,

$$\frac{E_a}{Z_a} = \frac{V_a}{Z_z} - \frac{I_a\, Z_a}{Z_a} \qquad \text{...(57.4)}$$

But we know, $1/Z_a = Y_a$ and $V_a/Z_a = V_a\, Y_a$. Let $E_a/Z_a = I_s$

$$\frac{E_a}{Z_a} = V_a\, Y_a - I_a \qquad \text{...(57.5)}$$

We call $E_a/Z_a = I_s$

$$\frac{E_a}{Z_a} = I_s = V_a\, Y_a - I_a \qquad \text{...(57.6)}$$

Comparing Eqns. 57.3 and 57.5, we observe that the voltage source E_a in series with Z_a can be transformed into an *equivalent* current source I_s in parallel with admittance Y_a without changing load voltage or load current. This is called source transformation.

Fig. 57.4 illustrates the source transformation. The variables on the load side shall remain unchanged.

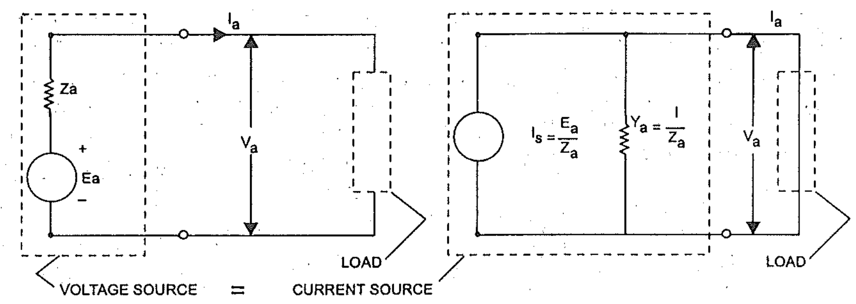


Fig. 57.4. Source transformation Current source ↔Voltage source.

Voltage source in series with source impedance = Equivalent current source in parallel with source admittance. Load current and load voltage remaining unchanged.

57.8. BUS NODAL CURRENT EQUATIONS FROM KIRCHOFF'S CURRENT LAW

Kirchoff's current law states that : "The sum of currents entering the bus from the sources, is equal to the sum of currents leaving the bus."

By applying Kirchoff's current law, the N number Bus-Nodes, N Nodal Current Equations are written for a N-bus system. These N current system. These N current equations are useful in load flow studies for formulating bus impedance matrix Y bus.

Refer a four bus network shown in Fig. 57.5. Bus number N are 1, 2, 3, 4. Branch admittances are $y_{12}, y_{23}, y_{34}, y_{24}$. Next step is to draw the Nodal Admittance Network (Fig. 57.6)

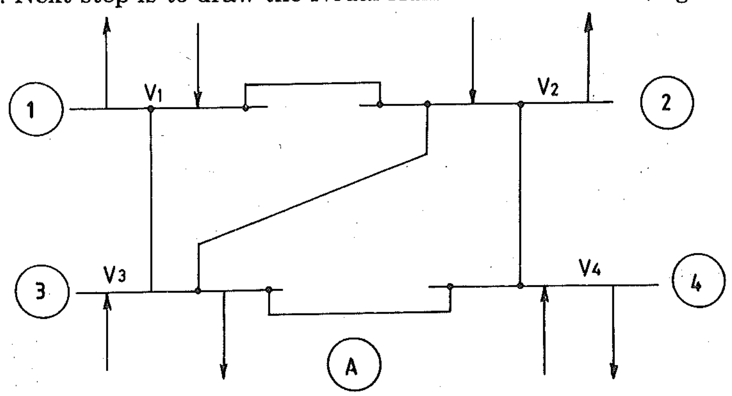


Fig. 57.5. Four bus network for nodal current equations.

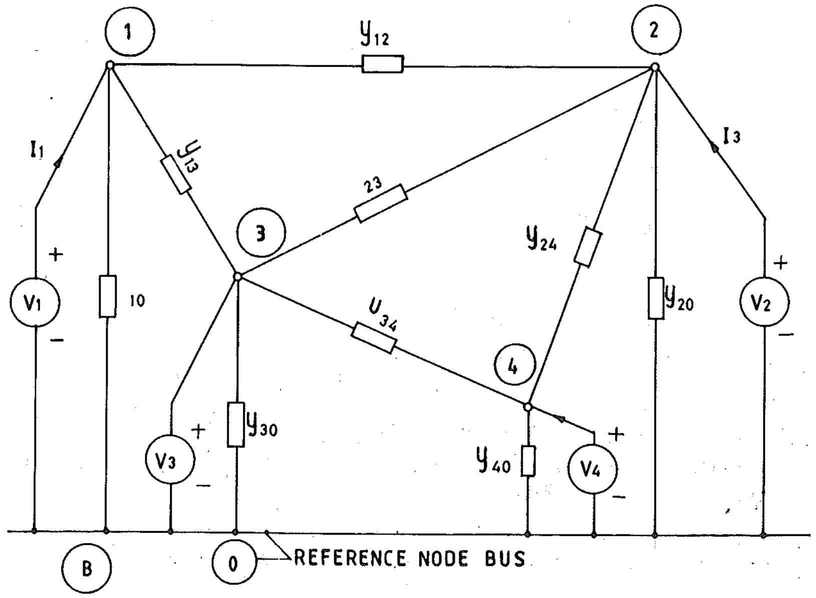


Fig. 57.6. Admittance network of the four bus network.

Next step is to write systematic Bus Current Equations and then write Bus Admittance Matrix. For bus 1, we get nodal current equation by equating current entering the bus equal to current leaving the bus are :

$$I_1 = V_1 y_{10} + (V_1 - V_2)\, y_{12} + (V_1 - V_3)\, y_{13} \qquad \text{...(57.7)}$$

Likewise current equations are written for bus 2, 3, 4 and we get four simultaneous equations as follows :

$$\begin{aligned}
I_1 &= V_1 y_{10} + (V_1 - V_2)\, y_{12} + (V_1 - V_3)\, y_{13}\\
I_2 &= V_2 y_{20} + (V_2 - V_1)\, y_{12} + (V_2 - V_3)\, y_{23} + (V_2 - V_4)\, y_{24}\\
I_3 &= V_3 y_{30} + (V_3 - V_1)\, y_{13} + (V_3 - V_2)\, y_{23} + (V_3 - V_4)\, y_{34}\\
I_4 &= V_4 y_{40} + (V_4 - V_2)\, y_{24} + (V_4 - V_3)\, y_{34}
\end{aligned}$$

Rearranging these equations and rewriting them in matrix form, we get :

$$\begin{bmatrix} I_1\\ I_2\\ I_3\\ I_4 \end{bmatrix} = \begin{bmatrix} y_{10}+y_{12}+y_{13} & -y_{12} & -y_{13} & 0\\ -y_{12} & y_{20}+y_{12}+y_{23}+y_{24} & -y_{23} & -y_{24}\\ -y_{13} & -y_{23} & y_{30}+y_{13}+y_{23}+y_{34} & -y_{34}\\ 0 & -y_{24} & -y_{34} & y_{40}+y_{24}+y_{34} \end{bmatrix} \begin{bmatrix} V_1\\ V_2\\ V_3\\ V_4 \end{bmatrix} \qquad \text{...(57.8)}$$

The admittance terms on RHS are redesignated as :

Self Admittances	*Mutual Admittances*
$Y_{11} = y_{10} + y_{12} + y_{13}$	$Y_{12} = Y_{21} = -y_{12}$
$Y_{22} = y_{20} + y_{12} + y_{23} + y_{24}$	$Y_{13} = Y_{31} = -y_{13}$
$Y_{33} = y_{30} + y_{13} + y_{23} + y_{34}$	$Y_{14} = Y_{41} = -y_{14} = 0$
$Y_{44} = y_{40} + y_{24} + y_{34}$	$Y_{23} = Y_{32} = -y_{23}$
	$Y_{24} = Y_{42} = -y_{24}$
	$Y_{23} = Y_{43} = -y_{34}$
General term : Y_{ii}	General term : Y_{ik}

Matrix equation 57.8 is written in terms of self bus admittance Y_{ii} and mutual bus admittances Y_{ik} as :

$$\begin{bmatrix} I_1\\ I_2\\ I_3\\ I_4 \end{bmatrix} = \begin{bmatrix} Y_{11} & Y_{12} & Y_{13} & Y_{14}\\ Y_{21} & Y_{22} & Y_{23} & Y_{24}\\ Y_{31} & Y_{32} & Y_{33} & Y_{34}\\ Y_{41} & Y_{42} & Y_{43} & Y_{44} \end{bmatrix} \begin{bmatrix} V_1\\ V_2\\ V_3\\ V_4 \end{bmatrix} \qquad \text{...(57.9)}$$

The above equation is re-written as

$$[I] = [Y_{bus}]\, [V] \qquad \text{...(57.10)}$$

where $[I]$ is node current matrix, $[V]$ is node voltage matrix and $[Y_{bus}]$ is bus admittance matrix.

In general, for an N-Node network, the Y bus matrix is

Y_{bus} Matrix =

$$Y_{bus} = \begin{bmatrix} Y_{11} & Y_{12} & \dots & Y_{1N}\\ Y_{21} & Y_{22} & \dots & Y_{2N}\\ \dots & \dots & \dots & \dots\\ Y_{N1} & Y_{N2} & \dots & Y_{NN} \end{bmatrix} \qquad \text{...(57.11)}$$

Y_{bus} matrix has self bus admittance terms Y_{ii} along diagonal and mutual bus admittances terms Y_{ik} as nondiagonal.

57.9. SELF AND MUTUAL ADMITTANCE OF THE BUSES

In equation 57.11 each of the admittances Y_{ii}, $(i = 1, 2, 3, 4)$ are called self admittance of the bus or driving-point admittance of the bus. It is the algebraic sum of all the admittances terminating in that bus *e.g.*

$$Y_{11} = y_{10} + y_{12} + y_{13} \qquad \text{...(57.12)}$$

Mutual admittance between two buses

In equation 58.11 each of the admittance Y_{ik}, $(i, k = 1, 2, 3, 4)$ is called mutual admittances or transfer admittances between bus i and k. It is the negative of sum of all the admittances connected between those two buses. We note that $(Y_{ik} = Y_{ki})$. For example, from Eqn. 57.

$$Y_{13} = Y_{31} = -y_{13} \qquad \text{...(57.13)}$$

57.10. BUS ADMITTANCE MATRIX

General equation for N-bus network based on Kirchoff's current laws and admittance form is :

$$[I] = [Y_{bus}] * [V] \qquad \text{...(57.14)}$$

where, $[I]$ is the N-bus current matrix, $[V]$ is the N-bus voltage matrix and, $[Y_{bus}]$ is called bus admittance matrix and Eqn. 57.14 is written as

$$\mathbf{I} = \mathbf{Y_{bus}}\,\mathbf{V}$$

where

$$\mathbf{Y}_{bus} = \begin{bmatrix} Y_{11} & Y_{12} & \dots & Y_{1N}\\ Y_{21} & Y_{22} & \dots & Y_{2N}\\ \dots & \dots & \dots & \dots\\ Y_{N1} & Y_{N2} & \dots & Y_{NN} \end{bmatrix} \qquad \text{...(57.15)}$$

is called the *bus admittance matrix,* and **V** and **I** are the N-element *node voltage matrix* and *node current matrix,* respectively.

Y_{bus} matrix for N-bus network has N rows and N columns. Each of the Y terms in the rows and columns has two subscripts :

— The first subscript refers to the bus number on which the current is expressed.

— The second subscript refers to the bus number whose voltage has caused that current component.
— The terms on diagonal are self-admittances.
— All the non-diagonal terms are mutual admittances. It is seen that the current entering bus k is given by :

$$I_k = \sum_{n=1}^{N} y_{kn} V_k \qquad ...(57.16)$$

Meaning of Self Admittance and Mutual Admittance Elements

Self Admittance of the Node

The terms Y_{ii} (i = 1, 2, 3, 4) are *self admittances* of respective nodes and represent the *algebraic sum of all the admittances terminating at that node.* Each diagonal term in the Y_{bus} matrix is a self admittance term.

If we short all the other nodes except node i with the reference bus and inject current I in the particular node i bus and measure the voltage V across that node i and the reference bus the ratio I/V gives the self admittance of that node.

Thus, self admittance of nodes 2 is (i = 2)

$$Y_{22} = \frac{I_2}{V_2} \left| \begin{array}{l} V_2 \text{ not} = 0 \\ V_1 = V_3 = V_4 = \ldots\ V_N = 0 \end{array} \right. \qquad ...(57.17)$$

Mutual Admittance between two nodes

The mutual admittance terms (Transfer Admittance terms) are the terms Y_{ik} in Y_{bus} Matrix. All the non-diagonal terms in the Y_{bus} matrix are mutual admittance terms. Y_{ik} (i ; k = 1, 2, 3, 4, ... N)

Mutual admittance between two buses is the negative of the sum of all the admittances connected directly between those two buses.

Also, $Y_{ik} = Y_{ki}$

For measuring the mutual admittance between the two nodes, all the other nodes except one of the two nodes (i, k) are shorted with the reference bus. Current I is injected in the shorted node and the voltage V across the two nodes is measured. The ratio I/V gives the mutual admittance between the two nodes. Thus,

Mutual admittance between node 1 and 2 is : $Y_{12} = Y_{21}$

$$Y_{21} = \frac{I_2}{V_1} \left| \begin{array}{l} V_1 = \text{not} = 0 \qquad (V_1 \text{ is not shorted}) \\ V_2 = V_3 = V_4 = \ldots = V_N = 0 \end{array} \right. \qquad ...(57.18)$$

INTERATION METHOD EXPLAINED

57.11. INTERATION PROCESS

The method of solving simultaneous equations by starting with assumed values of unknown variables and obtaining successive better values of the same variable by repeated cycles of solution is called method of interation.

Starting from some *assumed values* of unknown variables and other given values of known variables, the algorithm equations are solved to obtain *new better values* of the same unknown variables.

These new better values of unknowns are again substituted in the same equations (Algorithms) to get yet another set of new revised values. The process of calculations of the new revised values of variables (*e.g.* Bus Voltages) by using earlier result is called *"an interation".* Interation process is continued till the difference in results between consecutive values is too small and below certain predetermined acceptable criterion.

Consider an example in which the unknown variable is bus voltage V and, ΔV is the difference in values of V from two consecutive interations. If ΔV reduces with every next interation, the process is said to be *Convergent.* When ΔV reduces below accepted criterion, (c), the interation process is stopped.

Let c = 0.0001V. Then in the following table, the convergence is reached at 5th interation *e.g.* in the example solved below :

Interation	1	2	3	4	5
V pu	0.9125	0.9135	0.9138	0.9137	0.9137
ΔV		0.001	0.0003	0.0001	0

Interation stopped at the end of 5 of the interation.

If ΔV increases during successive interations, the interation is *divergent.* The interation process should be stopped and reasons for divergence should be reviewed. Start newly and check for convergence.

The repeated procedure of calculation by substituting the previously obtained value in the next set of calculations in the same set of equations is called Interation Process. The interation process is stopped when the difference ΔV in values from two consecutive interations is smaller than the selected convergence criterion (c).

when $\quad c < \Delta V \quad$ Interation is stopped ...(57.19)

In load flow studies, from the solution of the Nodal equations, voltage V_k, phase angle and current are known for given steady state power system conditions. From these solution values P_k, Q_k can be calculated for each bus (k = 1 to N)

The interations are repeated till sufficiently accurate values are obtained and further interations are not giving next better values, *i.e.* covergence is reached.

Most widely used interative methods for Load Flow Calculations are (1) Gauss-Seidel method (2) Newton Raphson method.

The digital computers are used for obtaining the solution given equations and system conditions.

The equations to be solved are formulated such that they are amenable to interative solution on digital computer. The general equations used for interation are called the Algorithm.

STEPS IN INTERATION PROCESS

57.12. STEPS IN INTERATION

1. To begin with, for the First Interation, *estimated value* (V) is assigned to the unknown bus voltage. (V) ; r = 0.

2. Equations (Algorithm) are solved in *First Interation* by using the assumed values (V) of unknown bus voltage say (V) ; r = 0. In the calculation, the other known bus variables (P, Q) are substituted. Equations are solved to obtain the new updated value of voltage called (V) ; r = 1.

3. The new values of bus-voltages (V) ; r = 1 obtained from the first Interation (r = 1) are used for the *Second Interation*

The equation is solved again in the second interation (r = 2) and yet new values of bus voltage (V) ; r = 2 is obtained.

Each set of calculations of the new values of the variable (e.q. bus voltages) by using earlier result is called "an interation".

The interation process is repeated (r = 1, 2, 3, 4, 5 ...) until the change (ΔV) between consecutive **resulting values of V at each bus are less than the specified** ***convergence criterion (c).***

Possibility of Convergence

— Convergence may be achieved after several tens or hundreds of interations.

— Convergence may not be achieved at all, if the solution does not exist or if the interation process is Divergent.

Example 57.3. *2-bus System solved by Interation process.*

Refer Fig. 57.7 for a 2-bus system. Procedure is explained in following equations are obtained.

$$S_2 = V_1 I^* \qquad V = S/I^* \qquad \text{...(57.19)}$$

$$V_2 = V_1 - ZI = V_1 - Z\,\frac{S_s^*}{I_2^*}$$

$$= V_1 - Z\,\frac{S_2^*}{(V_2^{(k-1)})^*} \qquad \text{...(57.20)}$$

Procedure

1. Assume value of V_2 for the start of *first interation* and call it as ; (V_2) ; $r = 0$.

2. Substitute this *(assumed)* starting value of (V_2) in the right hand side of the Equation 57.21 and solve for (V_2). Call this V_2 obtained as a result of the first interation as (V_2) ; $r = 1$.

3. Then substitute this resulting value (V_2) ; $r = 1$ of first interation again on right hand side of the Eqn. and obtain yet new value of (V_2) $r = 2$, of the second interation $r = 2$.

4. Substitute (V_2) ; $r = 2$ in the same Equation and obtain (V_2) ; $r = 3$. (V_2) ; $r = 3$ is the result of third interation (r = 3), and so on.

5. Calculate the difference (ΔV) between values obtained from consecutive interations ; s $[(V_2)$; $r = p + 1 - (V_2)$; $r = p]$ and compare with the accepted convergence criterion.

6. The interation is continued till the convergence to desired precision is achieved. Let us call this interation as $r = X$. At interation $r = X$, the covergence criteria is reached and the interation process is stopped.

7. The interative process used is described by the General Equation called *the Algorithm. e.g.* Eqn. 57.20 ;

$$V_2^k = V_2 - \frac{Z\,S_2^*}{(V_2^{(k-1)})^*} \qquad \text{...(57.21)}$$

8. Last Interation is when the resulting V satisfies :

$$\Delta V = \left\{[(V_2)\,;\, r = p+1] - [(V_2)\,;\, r = p]\right\} < 0.00001 \text{ P.U} \qquad k = 1, 2, \ldots N, \text{ bus Number}$$

Interation number $\quad p = 1, 2, \ldots (p+1) = X$

At interation $r = X$, the covergence criteria is reached and the process is stopped, computer print out is obtained. From the basic variables of the buses, the remaining variables for the buses and the branches are then calculated. The above procedure is now applied in Example 57.4.

Example 57.4. *Load Flow Calculations for 2-Bus System by Interation Procedure., A simple 2-Bus System with a short transmission line between the sending end and the receiving end shown in Fig. 57.7 has the following given data, all values in P.U. : $V_1 = 1\angle 0°$; $Z = 0.05 + j\,0.02$; $S = P + jQ = 1.06 \mid j\,0.6$.*

Determine V_2 by interation method. Convergence criterion $c < \Delta V$ when Interation is stopped. Given c = 0.00005 pu.

Solution. We use the procedure explained earlier.

Algorithm (Eqn. for the Interation Process) is

$$V_2^k = V_1 - \frac{Z\,S_2^*}{(V_2^{(k-1)})^*} \qquad \text{...(57.21)}$$

1. Assume value of V_2 for the start of first interation (int = 1) and call it as (V_2) ; $r = 0$. Let $V_2 = 1\angle 0°$ p.u.

Substituting assumed $V_2 = (V_2)$; $r = 0 = 1\angle 0°$ on RHS of the Algorithm :

$$V_2^k = V_1 - \frac{Z\,S_2^*}{(V^{(k-1)^*})}$$

$$V_1 = 1\angle 0° \qquad \text{...(given)}$$

$$V_2^k = 1\angle 0° - \frac{(0.05 + j0.02)\,(1.0 + j\,0.6)}{1\angle 0°}$$

$$V_2 = (1 - 0.05 + 0.012) - j\,(0.030 + j0.02)$$

$$V_2 = 0.962 - j\,0.05 \quad \text{... result of interation 1.}$$

This new value is used in RHS for the *next interation* to obtain yet updated V_2. Procedure is repeated

The following results are of successive interations :

Used Value of V_2 in Interation	*Interation Number r*	*Resulting value of, V_2*
Assumed Value : $V_2 = 1 + j0$	1	$0.962 - j\,0.05$
$0.962 - j\,0.05$	2	$0.963 - j\,0.054$
$0.963 - j\,0.054$	3	$0.9635 - j\,0.054$
$0.9635 - j\,0.054$	4	$0.9635 - j\,0.054$
	Interation Stopped,	$r = 4$

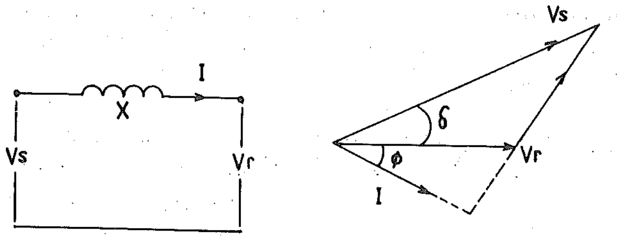
In the interation Process of this example, the acceptable convergence $\Delta V = (V_2)_4 - (V_2)_3 = 0$ has been achieved within 4 interations.

Interation	1	2	3	4
V pu	0.9625	0.9635	0.9638	0.9638
Δ V		0.001	0.0003	0

POWER FLOW IN TWO-NODE AC SYSTEMS

57.13. POWER FLOW IN A TWO BUS AC SYSTEM (SINGLE BRANCH)

Power flow study of a simple *two node AC system* gives understanding of the fundamental relationship between variables, $|V|$, $\angle\delta$, P, Q. The basic relationship are important as they apply to every branch in a multi-bus system. Let the sending end bus by subscript be (s) and receiving end bus by subscript be (r). Each node has four variables, namely P, Q, $|V|$, δ only two variables are known for each bus and the other two are unknown.



(A) Single line diagram (B) Phasor diagram

Fig. 57.7. Two node system with a short AC transmission line (Flow P_{ac} is decided mainly by $\sin \delta$)

$|V_s|$ and $|V_r|$ magnitudes are held within narrow specified limits.

The per phase, per unit quantities are :

V_s = Sending-end voltage phasor	V_r = Receiving-end voltage phasor
V_1^* = Complex conjugate of V_s	V_r^* = Complex conjugate of V_r
$\|V\|$ = Absolute value of phasor	δ = Phase angle of phasor V
I = Sending-end current phasor	I = Receiving-end current phase
I^* = Complex conjugate of I	V^* = Complex conjugate of V
P_s = Sending end Real Power	Q_s = Sending end Reactive Power
S_s = Sending end Complex Power $= P_s + j\,Q_s$	S_r = Receiving end complex Power $= P_r + jQ_r$
S_s = Complex conjugate of S_s	S_r = Complex conjugate of S_r

δ = Power angle, angle between phasors V_s and V_r

X = Series Reactance of transmission line = $2\pi f_L$

R = Resistance of transmission line

Complex Power S, in general is given by :

$$S = P + jQ = VI^* \quad \text{voltamperes, } VA \qquad ...(57.22)$$

where, I^* is complex conjugate of phasor I ; and V is phasor voltage.

For Sending-End, we have,

$$S_s = P_s + j\,Q_s = V_s\,I^* \;\; VA \qquad ...(57.23)$$

Quantities are per phase, per unit basis. From Fig. 57, we get

$$I = \frac{1}{jX}(V_s - V_r) \qquad ...(57.24)$$

Therefore,
$$I^* = \frac{1}{-jX}(V_s^* - V_r^*) \qquad ...(57.25)$$

Substituting I^* from Eqn. 57.25 in Eqn. 57.23, we get

$$S_s = \frac{V_s}{-jX}(V_s^* - V_r^*) \qquad ...(57.26)$$

From phasor diagram of Fig. 57, we get

$$V_r = |V_r| \angle\delta°, \quad \text{therefore, } V_r = |V_r|^*$$

and,
$$V_s = |V_r| \angle\delta°$$

Thus, Eqn. 57 becomes
$$S_s = \frac{|V_s|^2 - |V_r|\;|V_s|\;e^{i\delta}}{-jX} \qquad ...(57.27)$$

$$S_s = \frac{|V_s|\;|V_r|}{X}\sin\delta + j\frac{1}{X}\Big[|V_s|^2 - |V_r|\;|V_r|\cos\delta\Big]$$

After simplifying,

$$P_s = \text{Real Part of } S_s = \frac{1}{X}\Big[|V_s|\;|V_r|\sin\delta\Big] \text{...Watts} \qquad ...(57.28)$$

$$Q_s = \text{Imaginary Part of } S_s = \frac{1}{X}\Big[|V_s|^2 - |V_s|\;|V_r|\cos\delta\Big] \text{...VAr} \qquad ...(57.29)$$

Similarly, for Receiving End, we get

$$S_r = P_r + j\,Q_r = V_r\,I^* \qquad ...(57.30)$$

and
$$P_r = \text{Real Part of } S_r$$

$$P_r = \frac{1}{X}\Big[|V_s|\;|V_r|\sin\delta\Big] \text{...W} \qquad ...(57.31)$$

The transfer of real power through the line is mainly due to load angle δ between voltage vectors. Power transfer is not much dependent on magnitudes of voltages.

$$Q_r = \frac{1}{X}\Big[|V_s|\;|V_r|\cos\delta - |V_r|^2\Big] \text{...VAr} \qquad ...(57.32)$$

Reactive power will flow from higher voltage to lower voltage. For $\delta = 0$, the average reactive power flow through the line is

$$Q_{av} = \frac{1}{2}[Q_s + Q_r] \text{ VAr} \qquad ...(57.33)$$

$$= \frac{1}{2X}\Big[|V_s|^2 - |V_r|^2\Big] \text{...VAr} \qquad ...(57.34)$$

The transfer of reactive power through the line is from higher voltage to lower voltage and is strongly dependent on voltage magnitudes.

Line Losses in AC Lines (P_{line}) :

If we consider line losses,

$$P_{line} = |I|^2 R \text{ ...watts} \qquad ...(57.35)$$

Coming back to Equation 57

$$I^* = \frac{P + jQ}{V} \quad I = \frac{P - jQ}{V^*} \qquad ...(57.36)$$

Thus,
$$II^* = |I|^2 = \frac{P^2 + Q^2}{|V|^2}$$

Therefore, Eqn. 57.35 becomes,

$$P_{line} = \frac{(P^2 + Q^2)\,R}{|V|^2} \text{...watts} \qquad ...(57.37)$$

The line losses are due to I^2R losses caused by flow of both real power and reactive power. Hence it is important to minimise reactive power flow through the line. To minimise line losses, the reactive power flow should be minimised by providing compensation of Q at load end.

SOLVED EXAMPLES ON TWO BUS AC SYSTEM LOAD FLOW

Example 57.5. *Load Angle. The sending end voltage $|V_s|$ for a line is 1 pu. The receiving end voltage $|V_r|$ is also 1 pu. Line reactance is j 0.05 pu. Real power flow through line is 10 pu. Calculate power angle δ between V_s and V_r vectors.*

Solution. We know,
$$P = \frac{|V_s|\;|V_r|}{X}\sin\delta \qquad ...(57.38)$$

Hence
$$\sin\delta = \frac{P}{|V_s|\;|V_r|/(X)} = \frac{10}{1 \times 1/(0.05)} = 0.5$$

Power Angle
$$\delta = \sin^{-1}(0.5) = \angle 30° \quad \textbf{Ans.}$$

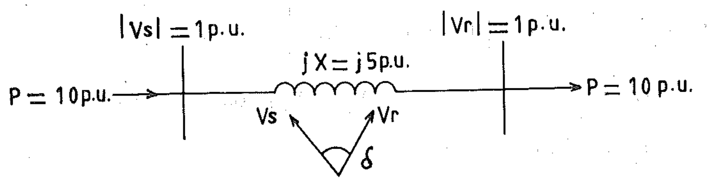


Fig. 57.8. Figure of example 57.6 and 57.7.

Example 57.6. *Active and Reactive power Flow. The sending end voltage $|V_s|$ and the receiving end voltage $|V_r|$ for a line is 1 pu. The line reactance is j 0.05 pu. Resistance is neglected. Real power flow through line is 10 pu. Calculate reactive power flow through the line state the complex power flow through the line.*

Solution. We know, $P = \frac{|V_s|\ |V_r|}{X} \sin \delta$

Hence $\sin \delta = \frac{P}{[|V_s|\ |V_r|]/(X)} = \frac{10}{1 \times 1/(0.05)} = 0.5$

Power Angle $\delta = \sin^{-1}(0.5) = \angle 30°$

Reactive power flow at sending end through the line is given by

$$Q_s = \frac{|V_s^2|}{x} - \frac{|V_s|\ |V_r|}{X} \cos \delta$$

$$= \frac{1^2}{0.05} - \frac{1 \times 1}{0.05} \cos 30° = +2.68 \text{ pu}$$

Reactive power flow at receiving end through the line is given by

$$Q_r = \frac{|V_s|\ |V_r|}{X} \cos \delta - \frac{|V_s|^2}{X}$$

$$= \frac{1 \times 1}{0.05} \cos 30° - \frac{1^2}{0.05} = -2.68 \text{ pu}$$

Reactive power flow through the line

$$Q_s - Q_r = 2.68 - (-2.68) = 5.36 \text{ pu}$$

Complex power flow through line $P + jQ = 10 + j\,5.36$ pu. **Ans.**

Example 56.7. *Load Angle and Power Flow in Two Bus AC System. The sending end voltage $|V_s|$ and the receiving end voltage $|V_r|$ of an AC transmission line is also 1 pu. Line reactance is j 0.05 pu resistance of line is neglected. The power angle between V_s and V_r vectors is 30 elec. Calculate the p.u. active power flow through the transmission line.*

Solution.

We know, $P = \frac{|V_s|\ |V_r|}{X} \sin \delta = \frac{1 \times 1}{0.05} \sin 30° = \frac{0.5}{0.05} = 10$ pu.

Example 57.8. *The reactance of a short transmission line is j 0.06 pu. The load current at receiving end is 1+ j0.6 pu and receiving end voltage is 1 ∠0° pu. Calculate (1) sending end voltage and (2) Average reactive power flow in line.*

Solution.

Sending end voltage = (Receiving end voltage) + (*IZ* drop)

$$V_s = V_r + IZ = 1\ \angle 0° + (1 + j0.6)\ (j0.6)$$

$$= 1 + j0 + j0.6 - 0.36 = 0.64 + j\,0.6 = 0.96\ \angle 3.56°$$

$$Q_{av} = \frac{1}{2}[Q_s + Q_r] = \frac{1}{2X}\left[|V_s|^2 - |V_r|^2\right]$$

$X = j\,0.06$, Sending and voltage $|V_s|$ are calculated above = 0.96 pu Receiving end voltage (given) = 1 pu

$$Q_{av} = \frac{1}{2\,(0.06)}[0.96^2 - 1^2] = -0.65 \text{ pu}$$

Example 57.9. *Complex power If $V = 1\ \angle 0°$ pu and $I = 1.188\ \angle -28.6°$ pu, calculate complex power S, real power P and reactive power Q.*

Solution. $S = VI^* = P + jQ \quad I = 1.88\ \angle -28.6°$ pu

$I = I = 1.188\ \angle +28.6°$ pu

$S = VI^* = (1\ \angle 0°)\ (1.188\ \angle +28.6°)$ pu

$= 1.188\ \angle +28.6°$ pu

$= 1.188\ (\cos 28.6 + j \sin 28.6)$

$S = 1.043 + j\,0.569 = P + jQ$

Equating real part from each side, Real Power $P = 1.043$ pu Equating Imaginary part from each side, Reactive power $Q = 0.569$ pu Complex power $= P + jQ = 1.043 + j\,0.569$.

57-B

Power Flow Calculations — Part II

Gauss Seidel Method and Newton Raphson Method for Multibus AC system—Power Flow through bipolar HVDC Link.

57.14. INTRODUCTION

The principles of AC network power flow calculations by interative procedures have been covered in the earlier chapter. Various methods of power flow calculations differ from each other in respect of (1) Algorithm used (2) proceedings of the interations.

Following methods are used in power flow studies

— Gauss Seidel methods (GSM)

— Gauss Seidel methods employing acceleration factors (successive over relaxation method).

— Newton Raphson Method (NRM)

The procedure of solving Power Flow Equations of Multibus System by these methods are covered in this chapter. The procedure of power flow calculations for bipolar 2 terminal HVDC have also been explained.

57.15. POWER FLOW IN A MULTI-BUS AC SYSTEM

Consider a Nodal Admittance Model of a N-bus Network. Each bus has a corresponding node a number k [$k = 1, 2, ... N$]

— The node voltages with respect to reference node are $|V_2|$, $|V_3|$, ... V_N. The phase angles of the bus voltage are $\delta_2, \delta_3, ..., \delta_N$.

The current entering the node k is I_k.

$k = 1$ is for reference bus. The subscript denotes the node number.

The N node network can have N number of Kirchoff's nodal equations in terms of node current, node voltages *Branch Admittances.* These N equations are simplified and written in terms of *Bus Admittance Matrix.* These N equations are solved by the *Interative Procedures.* The interation number is denoted by *superscript r e.g.* V_k^r denotes the voltage of bus k obtained from interation r. $V_k^{(r+1)}$ denotes the voltage of bus k obtained from interation $(r + 1)$.

1. *Initial data* for a typical power flow study is

(1) Given network configuration and branch admittances

(2) Voltage levels of generator buses

(3) Generation active power and reactive power levels

(4) Active and reactive power to load buses

2. **Objective.** To determine the voltages and their phase angles for all the network buses and to calculate the unknown variables P and Q for each bus. From these calculated results the various

other quantities for buses and branches are to be calculated for steady state power flow and voltage conditions.

Initially, we draw a single line diagram of the given system and identify the generator buses and load buses.

Thus,

	Known (Specified)	*Unknown* (To be calculated)*
Generator buses	P, $\mid V \mid$	$\angle\delta$, Q
Load buses	P, Q	$\mid V \mid$, $\angle\delta$
Slack bus (Swing bus)$^+$	$\mid V_1 \mid$, $\angle\delta_1$ = Ref.	P_1, Q_1

* The objective of power flow (Load flow) studies is to determine these unknowns for each bus under steady state condition.

+ Slack bus (Swing bus) is any one selected generator bus for reference voltage and reference phase angle, P and Q are not specified to begin with.

3. The *basic variables* associated with *each of the N buses are*

— Voltage magnitude $|V_k|$,

— Phase angles of voltage phasors (δ_k),

— Real power P_k,

— Reactive power Q_k

A typical *Load flow study* (power flow study, load flow calculations) gives mainly values of the following variables for specified *normal steady state* operating conditions of generation and load :

— Phasor voltages of various network buses, $V_k = |V_k| \angle\delta_k$, $k = 1$ to N for an N Bus system

— Phase-angles of bus voltage phasors ($\angle\delta_k$)

— Real power P_k, reactive power Q_k, at various network buses ($k = 1$ to N) and through branches of the electrical power system.

For each bus out of the above four variables two variables are known (given) and remaining two are unknown and are to be determined by load flow studies.

3. The *Derived Variables* are Branch current I, branch power, power factor cos ϕ of branch current, MVA etc. are calculated from the Principal Variables of terminal nodes obtained from the end results of the interation.

4. **Classification and types of Buses.** [Fig. 8.(*b*)]

In load flow studies, the network buses are classified according to the known and unknown *variables* into following three categories :

— Generator buses (P, $|V|$) or (Voltage controlled buses)

— Load buses (P, Q) Buses

— Slack bus [$|V|$-Bus or Swing bus or reference bus]. It is a bus selected for reference voltage.$^+$

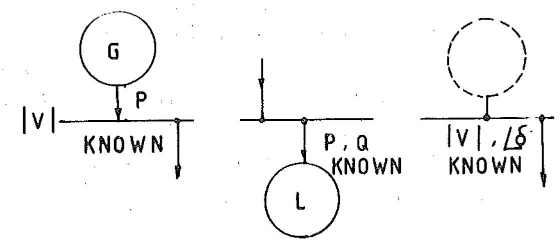


Fig. 57.8B. Types of Buses

Out of the 4 basic variables (P, Q, $|V|$, δ) for each bus, two are specified (known) variables and the other two are unknown variable (to be calculated from the power flow study). Accordingly, we have by convention real power entering the bus is positive ; real power leaving the bus is negative.

	Known *(Specified)*	*Unknown** *(To be calculated)*
Generator buses :	$P, \|V\|$	$\angle\delta, Q$
Load buses :	P, Q	$\|V\|, \angle\delta$
Slack bus (Swing Bus)+	$\|V_1\|, \angle 0 = \text{Ref.}$	P_1, Q_1

* The objective of power flow (load flow) studies is to determine these unknowns for each bus under steady state condition.

+ Slack bus (Swing bus) is any one selected generator bus for reference voltage and reference phase angle. P and Q are not specified to begin with. In the further text, $k = 1$ is for slack bus.

Table 57 B.1. Classification of network buses for the power flow study

Generator Bus (P, $|V|$ Bus), (Voltage controlled Bus)

Generator bus is the bus for which the generated real power P and magnitude of generated voltage $|V|$ magnitude are known. For a generator bus real power P is injected into bus and therefore positive. The reactive power Q and the phase angle of bus voltage is to determined by solving N simultaneous equations of power flow.

Load Buses (P-Q Buses)

Load bus (PQ bus) is the bus for which real power (Active power) P and reactive power Q are specified and known and bus voltage magnitude $|V|$ and its phase angle δ are to be found. For a load bus the outgoing real power P is taken as negative

Swing bus ($|V|$ Bus) : (Reference Bus) or (Slack Bus).

It is one of the selected Generator bus at which $|V|$ and $\angle\delta$ are specified. P and Q are to be determined.

For convenience the swing bus is taken as reference with

$$V/\delta = 1\angle 0°, \text{ i.e. } |V| = 1 \text{ pu and } \delta = 0°$$

For a swing bus : $V = 1 + j\,0$ pu.

The transmission losses in total network remain unknown till the solution to load flow is obtained. For this reason one of the generator bus is assumed to supply for the transmission losses of real power.

57.16. PROCEDURE

- Draw single line diagram and the Admittance network. Identify the buses and branches by numbers. (Ref. Fig. 57.5 and Fig. 57.6)
- Write the power flow equations for the given network in suitable form.
- The procedures for writing power flow equations differ with the GS method and *NR* method.
- The equations are converted to the algorithm for interative solution. The procedures for writing algorithm differ with the *GS* method and *NR* method.
- Solve the equations by interative method by substituting known quantities of some variables and assumed quantities of variables under interation.
- If interation is converging, continue. If diverging, investigate the cause and take corrective action and then proceed further with interations.
- Interations are continued till the desired convergence is reached.
- Calculate derived quantities for various buses, branches.
- Analyse the results and use them.

57.17. EQUATIONS FOR POWER FLOW IN GAUSS METHOD AND GAUSS SEIDEL METHOD FOR MULTI-BUS SYSTEM

These equations co-relate the variables P, Q, V and I of various Network buses. Nodal Admittance form is preferred as it is more amenable for computer solution by interative process.

Both the Gauss and Gauss Siedel use the same power equations but the algorithms for voltage are slightly different.

57.18. GAUSS METHOD

In Gauss Method, the same values of bus voltages are used in the entire interation. The newly calculated value of bus voltage say v the next bus voltage in the *next interation.*

In this book we have used subscript k for bus number and superscript r for interation number, N is total number of buses. Thus, V_k^r would mean voltage of kth bus and rth interation. (Various text books use different subscripts and superscripts for the bus numbers and interation numbers. Applied logic should be understood for writing the Algorithm correctly.)

For the kth node (of N node network), nodal current is

$$I_k = \sum_{n=1}^{n=N} Y_{kn} V_n \quad \text{...(57.39)}$$

which can be written as,

$$V_k = Y_{kk} V_k + \sum_{\substack{n=1 \\ n \neq k}}^{n=N} Y_{kn} V_n \quad \text{...(57.40)}$$

N = Total number of nodes I_k = Current in k'th node

Solving for Y_k, we get

$$V_k = \frac{I_k}{Y_{kk}} - \frac{1}{Y_{kk}} \sum_{\substack{n=1 \\ n \neq k}}^{n=N} Y_{kn} V_n \quad \text{...(57.41)}$$

N = Total number of nodes

Y_k = Bus admittance of kth node

But we have, $V_k^* I_k = S_k = P_k - jQ_k$ ...(57.42)

Hence, $$I_k = \frac{P_k - j\,Q_k}{V_k^*} \quad \text{...(57.43)}$$

Equations 57.42 and 57.43 are applied to N nodes and a set of N nonlinear simultaneous equations are obtained as :

$$V_k = \frac{1}{Y_{kk}}\left[\frac{P_k - jQ_k}{V_k^*} - \sum_{\substack{n=1 \\ n \neq k}}^{n=N} Y_{kn} V_n\right] \quad \text{...(57.44)}$$

for $k = 1, 2, 3, 4 \ldots N$

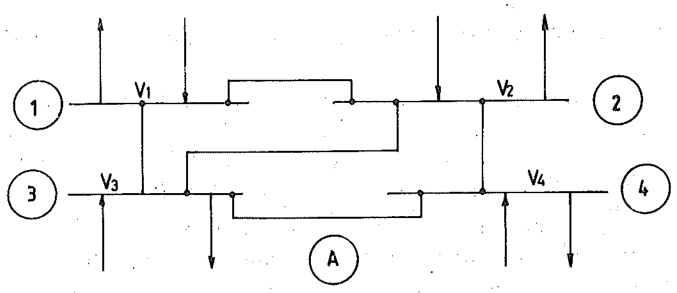
$k = 1$ is a swing bus with specified V. Hence in above eqn.

V_1 is taken as specified.

The set of N Equations 57.44 are called the *Power Flow Equations.*

Example 57.10. *Write load flow equations for a 4-Node network shown in Fig. 57.9A.*

Solution. In Gauss Siedel Method, the newly calculated value of bus voltage say V immediately replaces the previous value of the same bus. The newly calculated value is then used for calculating the next bus voltage in the *same interation.*



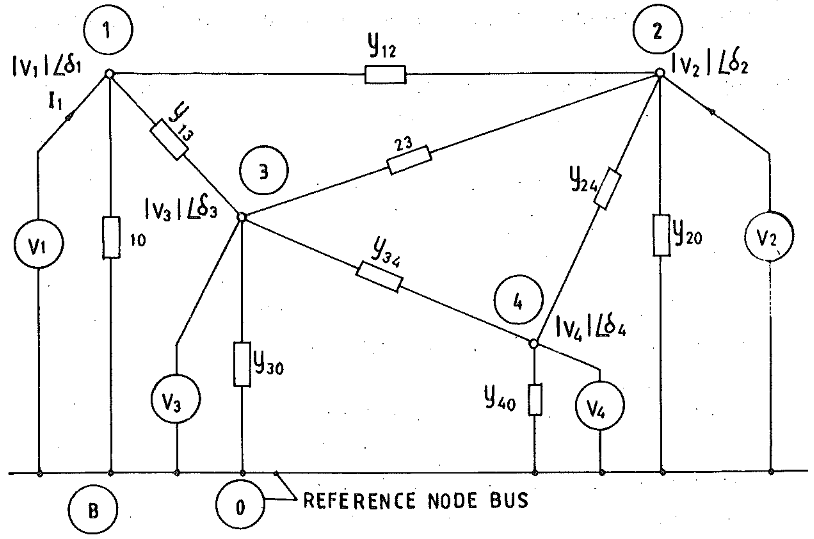


Fig. 57.9A. Single line diagram of a 4 Bus Network.
Fig. 57. 9B. A 4-Node admittance diagram for load flow study.

Algorithm from Equation 57.44 is

$$V_k = \frac{1}{Y_{kk}}\left[\frac{P_k - jQ_k}{V_k^*} - \sum_{\substack{n=1 \\ n \neq k}}^{n=N} Y_{kn} V_n\right] \quad ...(57.45)$$

for $k = 2, 3, 4, \ldots$ N

$k = 1$ is the swing bus with known V.

k = (subscript). Bus Number $\quad V_k^*$ = complex conjugate of V_k

N = Total number of buses $\quad N$ = Total number of simultaneous nonlinear equations

P_k = Real power flow from k'th bus $\quad Q_k$ = Reactive power flow from k'th bus

r (Superscript) = Interation number, $r = 1, 2, 3, \ldots X$

At $r = X$, the specified convergence is achieved and interation is stopped.

For bus $k = 1$: Reference bus $V_1 = (1 + j\,0)$ Specified

$N = 4$. Simultaneous Non linear load flow equations got from algorithm 57.46 are :

For bus $k = 2$, $V_2 = \dfrac{1}{Y_{22}}\left[\dfrac{P_2 - jQ_2}{V_2^*} - (Y_{21} V_1 + Y_{23} V_3 + Y_{24} V_4)\right]$

For bus $k = 3$, $V_3 = \dfrac{1}{Y_{33}}\left[\dfrac{P_3 - JQ_3}{V_3^*} - (Y_{31} V_1 + Y_{32} V_2 + Y_{34} V_4)\right]$

For bus $k = 4$, $V_4 = \dfrac{1}{Y_{44}}\left[\dfrac{P_4 - jQ_4}{V_4^*} - (Y_{41} V_1 + Y_{42} V_2 + Y_{43} V_3)\right]$

57.19. SOLUTION OF POWER FLOW EQUATIONS BY GAUSS-SEIDEL METHOD

The *Algorithm* of Gauss-siedel method is obtained by modifying the power flow equation 57.44 to get the algorithm :

$$V_k = \frac{1}{Y_{kk}}\left[\frac{P_k - jQ_k}{V_k^*} - \sum_{\substack{n=1 \\ n \neq k}}^{n=N} Y_{kn} V_n\right] \quad ...(57.45)$$

for $k = 2, 3, 4, \ldots N$

$k = 1$ is for slack bus with known voltage.

Superscript r of V_k denotes the interation number. V_3^{15} would mean voltage of bus 3 obtained from 15th interation. Algorithm 57.45 is used in for Gauss Seidel method. Note that the V_k begins with $k = 2$, as the slack bus ($k = 1$) has known voltage, so we begin the calculation with bus $k = 2$.

Proceedings of Interations by Gauss Seidel Method. The quantities on right hand side (RHS) of the Algorithm 57.45 are either initially specified quantities or initially estimated quantities. We observe that the quantity V_k for the bus voltage is on RHS and on LHS of the equation.

Initially known quantities and *assume quantities* are substituted on the RHS of the equation for interation 1. The solution of the interation gives the new corrected value of the unknown quantity V. The newly calculated corrected quantity from the interation will differ from the earlier estimated quantity used in the preceding interation. *i.e.*

$$V_k^{(r+1)} \neq V_k^r$$

where subscript k denotes bus number and superscript (r) denotes the iteration number.

The new corrected value of the corrected quantity $V_k^{(r-1)}$ is then used on RHS of the next interation to obtain yet new corrected value of V_k^r Thus, we proceed to calculate step by step the following.

Interation r	1	2	3	r
Quantity used on RHS for solving the Eqn.	V_k	V_k^1	V_k^2	V_k^{r-1}
Quantity obtained from the solution of interation	V_k^1	V_k^2	V_k^3	V_k^r

The agreement between V_k^{r-1} and V_k^r would be reached after several interations. When V_k^{r-1} is in agreement with V_k^r, the more accurate value of V_k is estimated.

Refer power flow equations for the 4 bus system shown in Fig. 57.9

Subscript $\quad k$ = bus number, $\quad k = 1, 2, 3, 4, 5, 6 \ldots N$

Superscript $\quad r$ = Interation number, $\quad r = 1, 2, 3, \ldots X$

$k = 1$ is the swing bus with known V

N = Total number of buses

N = Total number of simultaneous non linear equations.

P_k = Real power flow from k'th bus

Q_k = Reactive power flow from k'th bus

At $r = X$, the convergence is specified achieved and interation is stopped.

1. For bus $k = 1$: Reference bus $V_1 = (1 + j\,0)$ Specified
2. Computation starts with bus 2. ($k = 2$)

For 4-Bus system, $N = 4$, general equation is :

$$V_k = \frac{1}{Y_{kk}}\left[\frac{P_k - jQ_k}{V_k^*} - \sum_{\substack{n=1\\n\neq k}}^{n=N} Y_{kn} V_n\right] \quad ...(57.44)$$

For $k = 2$,

$$V_2 = \frac{1}{Y_{22}}\left[\frac{P_2 - jQ_2}{V_k^*} - \sum_{\substack{n=1\\n\neq 2}}^{n=N} Y_{2n} V_n\right] \quad ...(57.44)$$

Expanding RHS for the 4 Bus Network

For bus $k = 3$,

$$V_3 = \frac{1}{Y_{33}}\left[\frac{P_3 - jQ_3}{V_3^*} - (Y_{31} V_1 + Y_{32} V_2 + Y_{34} V_4)\right] \quad ...(57.45)$$

Likewise for $k = 4$,

$$V_4 = \frac{1}{Y_{44}}\left[\frac{P_4 - jQ_4}{V_4^*} - (Y_{41} V_1 + Y_{42} V_2 + Y_{43} V_3)\right]$$

The quantities on RHS are either initially specified quantities or initially estimated quantities. By substituting these quantities, the solution to Eqn. 57.44 may be obtained to get value of V_k.

Estimated value of V used on right hand side will differ from that calculated of from the interation. *i.e.* $V_k^{r-1} \neq V_k^r$.

The agreement between V_k^{r-1} and V_k^r would be reached after several interations. When V_k^{r-1} is in agreement with V_k^r, the more accurate value of V_k is ėstimated.

For $k = 2$, this correct value of voltage of bus 2 is used for calculating the corrected voltage of bus 3.

Equation similar to 57.45 may be written for each bus. The interation $r + 1$ is carried out by using estimated values and known values of quantities on RHS and corrected value of V obtained in the earlier interation (r). Thus,

Substituting V_k^r

$$V_k^{(r+1)} = \frac{1}{Y_{kk}}\left[\frac{P_k - jQ_k}{V_k^r} - (Y_{k1} V_1^r + Y_{k2} V_2^r + Y_{k3} V_3^r + ...\right]$$

The interation process is repeated to get correct value of $V_k^{(r+1)}$.

The interation process is repeated again and again to get specified covergence.

In this method called the *Gauss Seidel Method,* the calculated value of a kth bus voltage from rth interation is used immediately for calculation of next bus voltage in the rth interation itself.

Example 57.11. *Load flow calculation of 2 bus system by Gauss Seidel interative method.*

Fig. 57.10 gives a 2-bus system with following given data :

Bus 1 : $V_1 = 1.1\ \angle 0°$ pu, *Load* $L = 1.1 + j\,0.4$ pu

Bus 2 : $V_2 =$ *To be determined, Load* $L = 0.5 + j\,0.3$ *pu*

Bus admittance : $Y_{11} = Y_{12} = 1.6\ \angle -80°$ *pu*

$Y_{12} = Y_{12} = 102 \angle 100°$ *pu*

Determine the voltage and phase angle at Bus 2 by Gauss-Seidel Method.

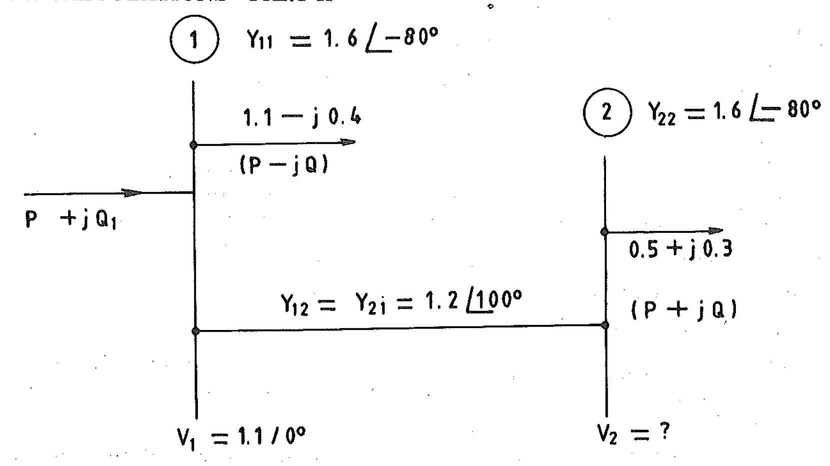


Fig. 57.10. Two bus systems of examples 57.

Solution.

Power entering the bus is positive. Power leaving the bus is negative.

Complex Power S *into* the bus 1 is

$$S_1 = (P_1 + jQ_1) - (1.1 + j\,0.4)$$
$$= (P_1 - 1.1) + j\,(Q_1 - 0.4) \text{ pu}$$

Complex power S_2 into the Bus is $S = -(0.5 - j0.3)$ p.u.

Algorithm for Gauss Seidel, from Eqn. 58.45 :

$$V_2^{(r+1)} = \frac{1}{Y_{22}}\left[\frac{P_2 - jQ_2}{(V_2^r)^*} - Y_{21} V_1\right] \quad ...(1)$$

with the given data,

$$V_2^{r+1} = \frac{1}{1.6 \angle -80°}\left[\frac{(-0.5 + j0.3)}{(V_2^0)^*} - (1.9 \angle 100°)(1.1 \angle 0°)\right]$$

$$= 0.625 \angle 80°\left[\frac{0.583 \angle 149°}{(V_2^0)^*} - 2.09 \angle 100°\right] \quad ...(2)$$

Interation 1, To Begin. Assume $V_2^0 = 1 \angle -10°$ pu.

$$V_2^1 = 0.625 \angle 80°\left[\frac{0.583 \angle 149°}{(1 + \angle + 10°)} - 2.09 \angle 100°\right] \quad ...(2)$$

$$= (0.625 \angle 80°)\ [(0.583 \angle 139° - 2.09 \angle 100°]$$
$$= 1.047 \angle -12.6° \text{ pu.}$$

The Second Interation. Substitute V_2^1 obtained from interation 1 on RHS of Eqn. 1 to get yet new value of V_2

$$V_2^2 = 0.625 \angle 80°\left[\frac{0.583 \angle 149°}{(1.047 \angle -12.06°)^*} - 2.09 \angle 100°\right] \quad ...(2)$$

$$V_2^2 = 1.047 \angle -8.6° \text{ pu.} \quad \textbf{Ans.} \quad ...(3)$$

Difference $\Delta V_2 = 1.047 - 1.047 = 0$, hence further interation is not required and the final result is given by (3) equation.

57.20. TREATMENT TO VOLTAGE CONTROLLED BUSES IN GAUSS-SEIDEL METHOD

We recall that the Generator Bus is Voltage controlled bus and for Generator Buses

Known	*To be determined*
P, V_k,	$\angle\delta, Q$

We have to treat the Generator buses differently for solving the unknowns. The Algorithm 57 is for solution of V_k which is not applicable to the generator bus with known voltage. We must arrive at a suitable Algorithm.

We write the equation for kth bus as

$$Q_k = -I_m \left[V_k \sum_{n=1}^{n=N} Y_{kn} V_n \right] \quad \text{...(57.48)}$$

The algorithm for the same equation is :

$$Q_k^r = -I_m \left\{ V_k^{(r-1)^*} \left[\sum_{n=1}^{k-1} Y_{kn} V_n + \sum_{n=k}^{N} Y_{kn} V_n \right] \right\} \quad \text{...(57.49)}$$

where, I_m is imaginary part of the expression in the bracket ; superscripts r indicate number of interation, subscript indicates bus number.

Q_k^r is calculated from Eqn. 57.49 for best previous value of the buses from Eqn. 57.49. This value of Q_k is used for obtaining the new value of V_k from Equation 57.45 for voltage V_k.

57.21. ACCELERATION FACTORS (α) FOR GAUSS SEIDEL METHOD OF INTERATION

With routine interation by Gauss Seidel Method, the convergence criteria is achieved after very many interations. This results in excessive computer time. If the correct values obtained from the preceeding interation are increased by using an Acceleration Factor before substituting in the next interation, the interation proceedings are accelerated and the convergence is achieved in lesser number of interations.

The factor by which the best corrected voltage result obtained from the preceding interation is multiplied before substituting the values in the next interation are called the Acceleration Factor. For example a acceleration factor $\alpha = 1.6$ may be used for real and imaginary components for calculated voltage. *Acceleration Factor is always less than 2.*

$$V_{2\,acc}^{(1)} - v_2^{(0)} + \alpha \left[V_2^{(1)} - V_{2\,(acc)}^{(0)} \right] \quad \text{...(57.50)}$$

α is called the Acceleration factor. Algorithm for Equation 57.50 is : For example, for interation r, for bus k :

$$V_{k\,(acc)} = V_{k\,(acc)}^{(r-1)} + \alpha \left[V_k^r - V_{K\,(acc)}^{(r-1)} \right] \quad \text{...(57.51)}$$

where, V_k^r = Resulting best voltage of bus k, from interation r, before applying Acceleration factor α

$V_{k\,(acc)}^r$ = Modified value of best voltage of bus k, from interation r, after applying Acceleration factor α, for using in interation $(r + 1)$.

Example 57.12. *Acceleration Factors in Gauss Seidel Method Assumed Value : assumed value of V for first interation was $V_2^0 = 1 + j0$.*

The best result of interation 1 by Gauss Seidel Method for bus 2 was $V_2^1 = 0.983664 - j\,0.032316$.

The Acceleration Factor to be used as 1.6.

Calculated the modified $V_{2\,(acc)}^1$ to be used for next interation.

Solution.

From $$V_{2\,(acc)}^1 = V_2^0 + \alpha\,(V_2^1 - V_2^0) \quad \text{...(57.52)}$$

Let $\alpha = 1.6$. Substituting $V_2^0 = 1$ pu and $V_2^1 = 0.983564 - j\,0.32356$

$V_{2\,(acc)}^1 = 1 + 1.6\,[(0.983564 - j\,.03316) - 1]$ p.u.

$V_{2\,(acc)}^1 = 0.973703 - j\,0.051706$ p.u

We use this Modified Accelerated New value for next interation instead of the earlier $V_2^1 = 0.983564 - j\,0.032316$.

NEWTON-RHAPSON METHOD

57.22. INTRODUCTION AND COMPARISON BETWEEN GAUSS SEIDEL METHOD AND NEWTON RAPHSON METHOD

The comparison between these two most widely used methods is given in the following table.

Table 57.B2. Comparison between Gauss Seidel and Newton Raphson Method

Gauss Seidel Method	Newton Raphson Method
— Well Established, Simple	— Recent
— More number of Interations	— Less number of interations
— More Computer Time	— Less Computer Time
— High Computation Cost	— Less Computation Cost
— Convergence uncertain	— Convergence certain
— Acceleration Factors used for rapid convergence	

Gauss Seidel is a simple interative method of solving N number power flow equations by interative method. There is no need of partial derivatives. The Newton Raphson Method is based on *Taylor's Series* and partial derivatives.

The Newton Raphson Method is recent, requires less number of interations to reach convergence, takes less computer time hence computation cost is low, and the convergence is certain. Today, System Study Groups of Utilities and Power System Planning Sectors prefer the Newton Raphson Method.

The Newton Raphson Method is based on *Taylor's Series* of function with two or more variables and their partial derivatives.

To begin with let us study the two equations with two variables x_1 and x_2. Thereafter the procedure may be extended to power flow equations having several variables.

57.23. TAILORS SERIES FOR TWO EQUATIONS WITH TWO VARIABLES

Consider the two functions of variables are x_1 and x_2 related by equations by following two equations

$$f(x_1\,;x_2) = C_1 \quad \text{...(57.53)}$$

$$f(x_1\,;x_2) = C_2 \quad \text{...(57.54)}$$

where, C_1 and C_2 are constants.

Solutions to these equations give values of x_1 and x_2. Let the *initial estimates give values of* x_1 and x_2 *be* x_1^0 *and* x_2^0.

Let the initial estimated solution differ from the final correct solution by $(\Delta\,x_1^0)$ and $(\Delta\,x_2^0)$.

i.e. correct solution—initial estimated solution = Δx

$$f_1 (x_1^0 + \Delta x_1^0 ; x_2^0 + \Delta x_2^0) = C_1 \quad ...(57.55)$$

$$f_2 (x_1^0 + \Delta x_1^0 ; x_2^0 + \Delta x_2^0) = C_2 \quad ...(57.56)$$

The Left Hand Side of these two equations is expanded by *Taylor's Series*, to get :

$$f_1 (x_1^{(0)}, x_2^{(0)} + \Delta x_1^{(0)} \left.\frac{\delta f_1}{\partial x_1}\right|_{x_1^{(0)}} + \Delta x_2^{(0)} \left.\frac{\partial f_1}{\partial x_2}\right|_{x_2^{(0)}} + ... = C_1 \quad ...(57.57)$$

$$f_2 (x_1^{(0)}, x_2^{(0)} + \Delta x_1^{(0)} \left.\frac{\partial f_2}{\partial x_1}\right|_{x_1^{(0)}} + \Delta x_2^{(0)} \left.\frac{\partial f_2}{\partial x_2}\right|_{x_2^{(0)}} + ... = C_2 \quad ...(57.58)$$

Partial derivatives of second and higher order are neglected. The results are written in matrix form as :

$$\begin{bmatrix} C_1 - f_1 (x_1^{(0)}, x_2^{(0)}) \\ C_2 - f_2 (x_1^{(0)}, x_2^{(0)}) \end{bmatrix} = \begin{bmatrix} \dfrac{\partial f_1}{\partial x_1} & \dfrac{\partial f_1}{\partial x_2} \\ \dfrac{\partial f_2}{\partial x_1} & \dfrac{\partial f_2}{\partial x_2} \end{bmatrix}_{x_1^{(0)}, x_2^{(0)}} \begin{bmatrix} \Delta x_1^{(0)} \\ \Delta x_2^{(0)} \end{bmatrix} \quad ...(57.59)$$

The problem is to solve $x_1^{(0)}$ and $x_2^{(0)}$. The terms $\partial/\partial x_1$, $\partial/\partial x_2$ indicate that the partial derivative is evaluated for the estimated values of $x_1^{(0)}$ and $x_2^{(0)}$. Other partial derivative terms are also evaluated similarly. The Equation 57.59 is conveniently written as

$$\begin{bmatrix} \Delta C_1^{(0)} \\ \Delta C_2^{(0)} \end{bmatrix} = J^{(0)} \begin{bmatrix} \Delta x_1^{(0)} \\ \Delta x_2^{(0)} \end{bmatrix} \quad ...(57.60)$$

In Eqn. 57.60, ΔC^0 and ΔC^0 are the differences as appearing on the LHS of Eqn. 57.59.

In Equation 57.60, the Square Matrix of the partial derivatives on RHS is called the Jacobian J_0 (of the initial Estimates $x_1^{(0)}$ and $x_2^{(0)}$).

$$J_0 = \begin{bmatrix} \dfrac{\partial f_1}{\partial x_1} & \dfrac{\partial f_1}{\partial x_2} \\ \dfrac{\partial f_2}{\partial x_1} & \dfrac{\partial f_2}{\partial x_2} \end{bmatrix}_{x_1^0 ; x_2^0} \quad ...(57.61)$$

And the Equation 57.61 is written in short as :

$$\begin{bmatrix} \Delta C_1^0 \\ \Delta C_2^0 \end{bmatrix} = J_0 \begin{bmatrix} \Delta x_1^{(0)} \\ \Delta x_2^{(0)} \end{bmatrix} \quad ...(57.62)$$

The solution of the matrix equation 57.62 gives $x_1^{(0)}$ and $x_2^{(0)}$. The better estimates of the solution is given by

$$x_1^{(1)} = x_1^{(0)} + \Delta x_1^{(0)} \quad ...(57.63)$$

$$x_2^{(1)} = x_2^{(0)} + \Delta x_2^{(0)} \quad ...(57.64)$$

Repeating the process of interations, with these values, we get yet better estimated values. The Δx_1 and Δx_2 becomes smaller and smaller with every interation and finally the interation process is stopped when Δx_1 and Δx_2 are lesser then the pre-selected convergence criterion c.

To apply the Newton-Raphson Method described above to a Load Flow Problem, P_k and Q_k are specified for all the buses except the swing bus.

C_1 corresponds to Specified P_k of Buses ... except for swing bus.

C_2 corresponds to Specified Q_k of Buses ... except for swing bus.

Calculated P's of buses corresponds to $f_1 (x_1^0, x_2^0)$

Calculated Q's of buses corresponds to $f_2 (x_1^0, x_2^0)$

ΔP and ΔQ correspond to Δx and Δx and Δx. The details are described in the next section.

57.24. NEWTON RAPHSON METHOD APPLIED TO LOAD FLOW PROBLEM

Consider an N Bus Power System for load flow problem, by NR Method.

Let the,

kth bus have the phasor voltage $V_k = |V_k| \angle\delta_k$
N buses have phasor voltages $V_n = |V_n| \angle\delta_n$
The bus admittance of kth bus is $Y_{kn} = |Y_{kn}| \angle\theta_{kn}$

From Eqns. 57.39 and 57.43 ;

$$P_k - jQ_k = \sum_{n=1}^{N} |V_k V_n Y_{kn}| \underline{/\theta_{kn} + \delta_n - \delta_k} \quad ...(57.65)$$

$$P_k = \sum_{n=1}^{N} |V_k V_n Y_{kn}| \cos (\theta_{kn} + \delta_n - \delta_k) \quad ...(57.66)$$

$$Q_k = \sum_{n=1}^{N} |V_k V_n Y_{kn}| \sin (\theta_{kn} + \delta_n - \delta_k) \quad ...(57.67)$$

where, P_k = Real part of RHS in Eqn. 57.65

$$P_k = |V_k V_n Y_{kn}| \cos (\theta_{kn} + \delta_n - \delta_k) \quad ...(57.66)$$

Q_k = Imaginary part of RHS in Eqn. 58.65

$$Q_k = |V_k V_n Y_{kn}| \sin (\theta_{kn} + \delta_n - \delta_k) \quad ...(57.67)$$

For the swing bus, $|V|$ and δ are specified and are omitted from the interative solution.

We first estimate V and δ for each bus except the swing bus. The specified P and Q correspond to C_1 and C_2 in Eqn. 57.57, 57.58 and 57.59.

The calculated P's and Q's represent $f_1 (x_1^0, x_2^0)$ and $f_2 (x_1^0, x_2^0)$. Let subscript k_s be for k'th bus and *specified value.* (of P or Q) and subscript k_c be for k'th bus and *calculated value* (of P or Q).

Having P and Q specified for every bus (except a swing bus) corresponds to knowing C_1 and C_2 in (57.59). We first estimate V and δ for each bus except the swing bus, for which they are known. We then substitute these estimated values, which correspond to the estimated values for x_1 and x_2, in (57.66) and (57.67) to calculate P's and Q's that correspond to $f_1 (x_1^{(0)}, x_2^{(0)})$ and $f_2 (x_1^{(0)}, x_2^{(0)})$.

Further we compute,

$$\Delta P_k^{(0)} = P_{ks} - P_{kc}^{(0)} \quad ...(57.68)$$

$$\Delta Q_k^{(0)} = Q_{ks} - Q_{kc}^{(0)} \quad ...(57.69)$$

Where subscripts s and c for attached to bus subscript k represent *specified* and *calculated.* These correspond to the LHS of Eqn. 57.60 [ΔC_1 ΔC_2]

Matrix Equation for a 3-Bus System corresponding to Eqn. 57.59 and Eqn. 57.60, omitting Swing Bus 1 :

$$\begin{bmatrix} \Delta P_2^{(0)} \\ \Delta P_3^{(0)} \\ \Delta Q_2^{(0)} \\ \Delta Q_3^{(0} \end{bmatrix} = \begin{bmatrix} \dfrac{\partial P_2}{\partial \delta_2} & \dfrac{\partial P_2}{\partial \delta_3} & \dfrac{\partial P_2}{\partial |V_2|} & \dfrac{\partial P_2}{\partial |V_3|} \\ \dfrac{\partial P_3}{\partial \delta_2} & \dfrac{\partial P_3}{\partial \delta_3} & \dfrac{\partial P_3}{\partial |V_2|} & \dfrac{\partial P_3}{\partial |V_3|} \\ \dfrac{\partial Q_2}{\partial \delta_2} & \dfrac{\partial Q_2}{\partial \delta_3} & \dfrac{\partial Q_2}{\partial |V_2|} & \dfrac{\partial Q_2}{\partial |V_3|} \\ \dfrac{\partial Q_3}{\partial \delta_2} & \dfrac{\partial Q_3}{\partial \delta_3} & \dfrac{\partial Q_3}{\partial |V_2|} & \dfrac{\partial Q_3}{\partial |V_3|} \end{bmatrix}_{\substack{\Delta\delta_2^{(0)},\, \Delta\delta_3^{(0)} \\ \Delta V_2^{(0)},\, \Delta V_3^{(0)}}} \begin{bmatrix} \Delta\delta_2^{(0)} \\ \Delta\delta_3^{(0)} \\ \Delta\,|V_2^{(0)}| \\ \Delta\,|V_3^{(0)}| \end{bmatrix} \qquad \text{...(59.70)}$$

The Square Matrix of Partial Derivatives is the Jacobian. The elements of the Jacobian are determined by taking partial derivatives of P_k and Q_k and substituting there in the voltages assumed for the first interation *or* the voltages calculated from the previous interation.

The Equation 57.70 can be solved by inverting the Jacobian.

$$\begin{bmatrix} \Delta\delta_2^{(0)} \\ \Delta\delta_3^{(0)} \\ \Delta\,|V_2^{(0)}| \\ \Delta\,|V_3^{(0)}| \end{bmatrix} = \begin{bmatrix} \dfrac{\partial P_2}{\partial \delta_2} & \dfrac{\partial P_2}{\partial \delta_3} & \dfrac{\partial P_2}{\partial |V_2|} & \dfrac{\partial P_2}{\partial |V_2|} \\ \dfrac{\partial P_3}{\partial \delta_2} & \dfrac{\partial P_3}{\partial \delta_3} & \dfrac{\partial P_3}{\partial |V_2|} & \dfrac{\partial P_3}{\partial |V_3|} \\ \dfrac{\partial Q_2}{\partial \delta_2} & \dfrac{\partial Q_2}{\partial \delta_3} & \dfrac{\partial Q_2}{\partial |V_2|} & \dfrac{\partial Q_2}{\partial |V_3|} \\ \dfrac{\partial Q_3}{\partial \delta_2} & \dfrac{\partial Q_3}{\partial \delta_3} & \dfrac{\partial Q_3}{\partial |V_2|} & \dfrac{\partial Q_3}{\partial |V_3|} \end{bmatrix}_{\substack{\Delta\delta_2^{(0)},\, \Delta\delta_3^{(0)} \\ \Delta V_2^{(0)},\, \Delta V_3^{(0)}}} \begin{bmatrix} \Delta P_2^{(0)} \\ \Delta P_3^{(0)} \\ \Delta Q_2^{(0)} \\ \Delta Q_3^{(0} \end{bmatrix}$$

Equation (57.71) is solved to get values of $\Delta\delta_k^{(0)}$ and $\Delta\,|V^{(0)}|$. The values determined for $\Delta\delta_k^{(0)}$ and $\Delta V_k^{(0)}$ are added to the previous estimates of V and δ to obtain *new estimates with which the next iteration is started. The interation process is repeated until the values in either column matrix are as small as desired convergence.*

The resulting values of $\Delta\,\delta_2^{(0)}$ and $\Delta\,V_k^{(0)}$ are added to the previously estimated values of V and δ to obtain yet new estimated values of V and δ. With which the next interation is started. The process is repeated until the values in either column matrix are as small as the selected convergence criteria.

Example 57.13. Newton Raphson Method. *A three bus system shown in Fig. 57.11 has following bus admittance matrix :*

$$Y_{bus} = \begin{bmatrix} 24.23\,\angle{-75.95^\circ} & 12.13\,\angle{104.04^\circ} & 12.13\,\angle{104.04^\circ} \\ 12.13\,\angle{104.04^\circ} & 24.23\,\angle{-75.95^\circ} & 12.13\,\angle{104.04^\circ} \\ 12.13\,\angle{104.04^\circ} & 12.13\,\angle{104.04^\circ} & 24.23\,\angle{-75.95^\circ} \end{bmatrix} p.u.$$

The per unit bus voltage of Bus 1 and 2 are indicated in the Figure. Per unit power flows into/from the buses are indicated by arrows. Calculate Voltage of Bus 2 by the Newton Raphson Method.

Solution.

The unknown quantity is the voltage of Bus 2. Let the initial estimate of V be $V = 1 + j0$ pu. Then from Eqn. 57.66 , we get $P_2^{(0)}$ as

$$P_2^{(0)} = |V_2^{(0)}|\;|V_1^{(0)}|\;|Y_{21}|\,\cos(\theta_{21} + \delta_1^{(0)} - \delta_2^{(0)}) + |V_2^{(0)}|^2\,|Y_{22}|\,\cos\theta_{22}$$
$$+ |V_2^{(0)}|\;|V_3^{(0)}|\;|Y_{23}|\,\cos(\theta_{23} + \delta_3^{(0)} - \delta_2^{(0)})$$

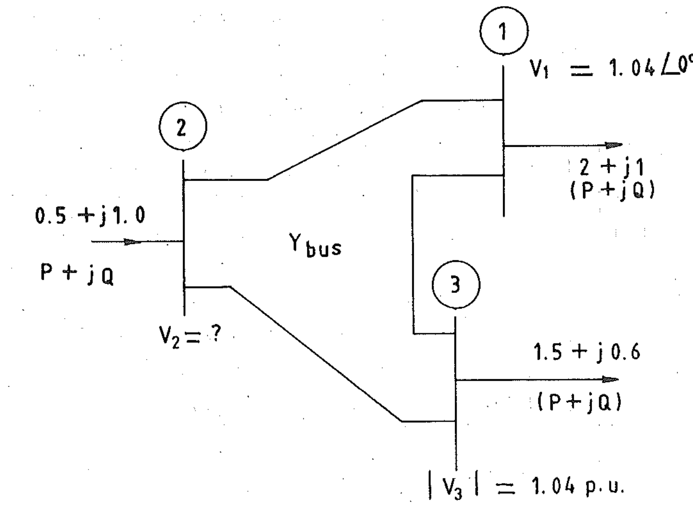


Fig. 57.11. Load flow of 3 bus network by NR method.

$$= (1)\,(1.04)\,(12.31)\cos 104.04^\circ + (1)\,(24.23)\cos(-75.95^\circ)$$
$$+ \mid (1)\,(1.04)\,(12.31)\cos 104.04^\circ = -\,0.34 \text{ pu.}$$

Likewise, $P_3^{(0)} = |V_3^{(0)}|\;|V_1^{(0)}|\;|Y_{31}|\,\cos(\theta_{31} + \delta_1^{(0)} - \delta_3^{(0)}) + |V_3^{(0)}|\;|V_2^{(0)}|\;|Y_{32}|$

$$\times \cos\left(\theta_{32} + \delta_2^{(0)} - \delta_3^{(0)} - \delta_3^{(0)}\right) + |V_3^{(0)}|^2\,|Y_{33}|\,\cos\theta_{33}$$
$$= (1.04)\,(1.04)\,(12.31)\cos 104.04^\circ + (1.04)\,(12.31)\cos 104.04^\circ$$
$$+ (1.04)^2\,(24.23)\cos(-75.95^\circ) = 0.026 \text{ pu}$$

Likewise from Eqn. (57.67) we get Q as,

$$Q_2^{(0)} = -\,|V_2^{(0)}|\;|V_1^{(0)}|\;|Y_{21}|\,\sin(\theta_{21} + \delta_1^{(0)} - \delta_2^{(0)}) - |V_2^{(0)}|^2\,|Y_{22}|\,\sin\theta_{22}$$
$$-\,|V_2^{(0)}|\;|V_3^{(0)}|\,\sin(\theta_{23} + \delta_2^{(0)} - \delta_3^{(0)})$$
$$= -\,(1)\,(1.04)\,(12.31)\sin 104.04^\circ - (1)\,(24.23)\sin(-75.95^\circ)$$
$$-\,(1)\,(1.04)\,(12.31)\sin 104.04^\circ = -\,1.34 \text{ pu.}$$

From (57.68), $\Delta P_2^{(0)} = 0.5 - (-\,0.34) = 0.82$ pu

$\Delta P_3^{(0)} = -\,1.5 - 0.026 = -1.526$ pu

Similarly, from (57.69) $\Delta Q_2^{(0)} = 1 - (-\,1.33) = 2.33$ pu

For the given three-bus system (with V_3 known), (Eqn. 57.70) becomes

$$\begin{bmatrix} \Delta P_2^{(0)} \\ \Delta P_3^{(0)} \\ \Delta Q_2^{(0)} \end{bmatrix} = \begin{bmatrix} \dfrac{\partial P_2}{\partial \delta_2} & \dfrac{\partial P_2}{\partial \delta_3} & \dfrac{\partial P_2}{\partial |V_2|} \\ \dfrac{\partial P_3}{\partial \delta_2} & \dfrac{\partial P_3}{\partial \delta_3} & \dfrac{\partial P_3}{\partial |V_2|} \\ \dfrac{\partial Q_2}{\partial \delta_2} & \dfrac{\partial Q_2}{\partial \delta_3} & \dfrac{\partial Q_2}{\partial |V_2|} \end{bmatrix} \begin{bmatrix} \Delta\delta_2^{(0)} \\ \Delta\delta_3^{(0)} \\ \Delta\,|V_2^{(0)}| \end{bmatrix} \qquad \text{....(A)}$$

Differentiating P_k from Eqns. 57.66 and 57.67 and substituting numerical values in Eqn. A above gives.

$$\begin{bmatrix} 0.83 \\ -\,1.526 \\ 2.33 \end{bmatrix} = \begin{bmatrix} 24.27 & -\,12.23 & 5.64 \\ -\,12.23 & 24.95 & -\,3.05 \\ -\,6.11 & 3.05 & 22.54 \end{bmatrix} \begin{bmatrix} \Delta\delta_2^{(0)} \\ \Delta\delta_3^{(0)} \\ \Delta\,|V_2^{(0)}| \end{bmatrix} \qquad \text{....(B)}$$

We recall the Matrix Inversion principles to three Matrices

$$A = BC \quad \text{then } B^{-1}A = C$$

By applying this principle Eqn. B re-written as,

$$\begin{bmatrix} \Delta\delta_2^{(0)} \\ \Delta\delta_3^{(0)} \\ \delta\,|V_2^{(0)}| \end{bmatrix} = \begin{bmatrix} 24.47 & -12.23 & 5.64 \\ -12.23 & 24.95 & -3.05 \\ -6.11 & 3.05 & 22.54 \end{bmatrix}^{-1} \begin{bmatrix} 0.83 \\ -1.526 \\ 2.33 \end{bmatrix} \quad ...(C)$$

This gives (C) as

$$\begin{bmatrix} \Delta\delta_2^{(0)} \\ \Delta\delta_3^{(0)} \\ \Delta\,|V_2|^{(0)} \end{bmatrix} = \begin{bmatrix} 0.05179 & 0.02653 & -0.00937 \\ 0.02666 & 0.05309 & 0.00051 \\ 0.01043 & -0.00001 & 0.04176 \end{bmatrix} \begin{bmatrix} 0.83 \\ -1.526 \\ 2.33 \end{bmatrix} \quad ...(D)$$

Solving for $\Delta\,|V_2^{(0)}|$, the solution of Eqn. gives

$$\Delta\,|V_2^{(0)}| = (0.01043)\,(0.83) + (0.00001)\,(1.526) + (0.04176)\,(2.33) = 0.106 \text{ pu}$$

Thus, $\quad |V_2^{(1)}| = 1 + 0.106 = 1.106$ pu

This procedure is repeated until convergence is reached.

Finally, we get $\quad V_2 = 1.081 \angle -1.36°$ pu. **Ans.**

57.25. IMPORTANCE AND OBJECTIVES OF POWER FLOW STUDIES

The Power Flow Studies. (Load Flow Studies) are the essential and most important part of power system studies. Power system engineers need data about the bus voltage, active and reactive power flowing though the branches under steady state. Such data is obtained from load flow study. Load flow studies are extremely important and essential for Power System Planning, Designing, Expansion design and for providing guidelines to Control Room Operating Engineers in following activities.

— Load flow studies are the basis for power system planning, designing and expansion and providing operating instructions to control room operators. (Ref. Ch. 53)
— Evaluation the operating performance of a power system under normal-steady state.
— Providing operating instructions to generating station and substation control rooms for loading, reactive power compensation, relay settings, tap-setting, and switching sequence. Selecting the optimum settings of Over Current Relays.
— Analysing the effect of rearranging the circuits on the load flows, bus voltages.
— Preparing software for on line operation, control and monitoring of the power system.
— Analysing the effect of temporary loss of generating station or transmission path on the load flow.
— Determining the effect of compensation of reactive power on bus voltages.
— Calculation of line losses for various load flow conditions.
— Planning expansion of Network. Introducing HVDC line, interconnection, EHV AC line.
— *Obtaining initial input data for various other power system studies* such as : Economic Load Despatch, Reactive power and voltage control, State Estimation, Fault Calculations, Generation Planning, Transmission Planning, etc.

POWER FLOW THROUGH TWO TERMINAL HVDC LINK

57.26. POWER FLOW THROUGH A BIPOLAR TWO TERMINAL HVDC LINK

The power flow calculation for an HVDC Link is quite different from that for an AC Link. Refer Fig. 57.12.

Let, U_d = DC voltage, pole to ground at the mid point of line pole, kV, DC

U_{d1} = DC voltage, pole to ground at Rectifier—End of line pole, kV, DC

U_{d2} = DC voltage, pole to ground at Inverter—End of line pole, kV, DC

Then, $U_d = (U_{d1} + U_{d2})/2$ ... kV DC, pole to ground corresponding pole to pole voltage is $(2\,U_k]$ ...kV DC

Same current I_d flows through the pole 1 and Pole 2 line conductors.

I_d = Current in DC line pole, kA

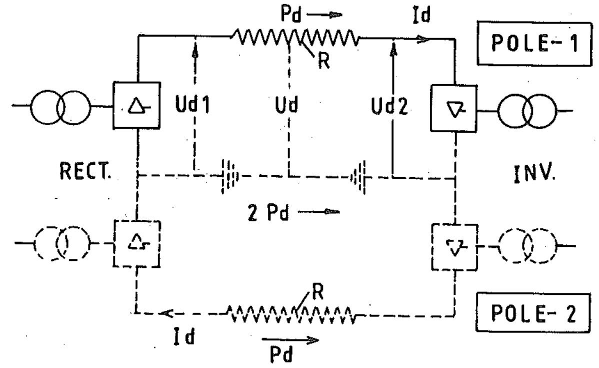


Fig. 57.12. Power flow through a bipolar 2-terminal HVDC link [Flow P_{dc} is dictated mainly by $(U_{d1} - U_{d2})/R$].

Then average DC power P_d flowing through one line pole is

$$P_d = U_d \times I_d = \frac{U_{d1} + U_{d2}}{2} \times I_d \text{ ...MW/pole} \quad ...(57.74)$$

Bipolar power $\quad = 2 \times P_d$ ...MW $\quad ...(57.75)$

Rectifier (Sending) End power : $P_{dr} = U_{d1} \times I_d$ ...MW pole

where U_{d1} is rectifier end DC voltage, pole to ground, kV DC, pole to Ground

Inverter (Receiving) End Power : $P_{d1} = U_{d2} \times I_d$

where U_{d2} is rectifier end DC voltage, pole to ground, kV

$$U_{d1} - U_{d2} = \text{Voltage drop in one DC line pole}$$

$$P_{dr} - P_{di} = P_{loss} = \text{ line loss in one DC line pole.}$$

$$P_{loss} = (Id)^2\,R$$

Bipolar line loss $\quad = 2 \times P_{loss} = 2\,(I_d)^2\,R$

where R = line pole resistance of one line conductor.

$$U_{d1} - U_{d2} = \text{Voltage drop in DC line pole} = I_d \cdot R \text{...kV DC.}$$

where, I_d is in kA and R in ohm.

Note. In power calculations U_{dc} in kV and I_{dc} in kA gives P_{dc} in MW.

Example 57.14. Power Flow through Bipolar 2-Terminal HVDC Line

Ref. Fig. 57.12. A 840 km long bipolar 2 Terminal Rihand Delhi HVDC link has following operating conditions ;

— Sending end DC pole voltage (Rihand), $U_{d1} = 520$ kV DC, Pole to earth.
— Receiving end DC Pole Voltage (Delhi), $U_{d2} = 490$ kV DC, Pole to earth
— Current in the line pole conductor, $I_d = 1$ ...kA DC

Both the line poles are transferring equal power at equal voltage conditions. *Calculate* the following :

1. Power Flow per pole from Rihand to Delhi $\qquad$ 2. Bipolar power flow

3. Line Loss per pole in bipolar line
4. Bipolar line loss
5. Reactive power flow through the DC line.

Solution.

DC line pole voltage at middle of line length :

$$U_d = \frac{U_{d1} + U_{d2}}{2} = \frac{510 + 490}{2} = 500 \ldots \text{ kV DC pole to ground}$$

$$I_d = \text{Current in a HVDC pole = given as 1 kA}$$

The power flow *per pole,* through line pole at mid point of line

$$P_d = U_d \times I_d \ldots \text{ MW} \qquad \ldots(1)$$

$$= 500 \times 1 = 500 \ldots \text{ MW per pole}$$

where, P_d = Power flow per pole through the HVDC link, MW

U_d = Average of pole to ground sending—end voltage U_{d1} and receiving end voltage U_{d2}, kV

$$\text{Bipolar power flow} = 2 \times P_d = 2 \times 500 = 1000 \text{ MW} \qquad \ldots(2)$$

R = DC resistance of HVDC line pole between sending end and receiving end, ohm

$$\text{Given : } I_d = 1 \text{ kA} = \frac{U_{d1} - U_{d2}}{R} = \frac{510 - 490}{R} = \frac{20}{R} = 1 \ldots \text{ kA}$$

$$R = 20/1 = 20 \text{ ohm}$$

$$\text{Line loss per pole } P_{loss} = (I_d)^2 R \ldots \text{ MW per pole} \qquad \ldots(5)$$

$$= 1 \times 1 \times 20 = 20 \text{ MW per pole}$$

$$\text{Total Bipolar line loss} = 2 \times (I_d)^2 R \ldots \text{ MW for 2 poles} \qquad \ldots(6)$$

$$= 40 \text{ MW for 2 poles}$$

Sending-end power per pole :

$$P_{dr} = U_{d1} \times I_d = 510 \ kV \times 1 \text{ kA} = 510 \text{ MW/pole}$$

Receiving-end power per pole :

$$P_{di} = U_{d2} \times I_d = 490 \text{ kV} \times 1 \text{ kA} = 490 \text{ MW/pole}$$

$$\text{Line loss per pole} = P_{dr} - P_{di} = 510 - 490 = 20 \text{ MW (Check)}$$

Steady state reactive power flow through HVDC line = 0

Since, I_d and V_d are with same phase angle along the line length.

Example 57.15. Load flow through Bipolar 2-Terminal HVDC Line.

A bipolar 2-terminal HVDC link delivers 1000 MW DC at ± 500 kV at receiving end. The line losses in 2 poles are 60 MW.

Calculate following :

1. Sending end power
2. Power in the middle of line
3. Line resistance per pole
4. Sending end DC voltage
5. Receiving end DC voltage
6. DC voltage in the middle of line.

Solution.

Rectifier (sending) end bipole power

= Inverter (Receiving) end bipole Power + bipole line loss

$$2 P_{dr} = 2P_{di} + 2P_L$$

$$= 1000 + 60 = 1060 \text{ MW}$$

$$\text{Power in the middle of bipole line} = [P_{dr} + P_{di}]/2$$

$$= [1060 + 1000]/2 = 1030 \text{ MW}$$

Rectifier end DC voltage = Rectifier DC power/DC current

DC line current is same at rectifier end to inverter-end. Inverter end DC current is

$$I_d = P_d/U_d = 1000/1000 = 1000 \text{ A} = I_{dr}$$

Rectifier sending end bipolar DC voltage

$$= P_d/I_d = 1060/1000 = 1060 \text{ kV DC}$$

Rectifier sending end bipole DC voltage = 1060 kV DC pole to pole

Rectifier sending end DC pole to ground voltage

$$= \pm 530 \text{ kV DC pole to pole}$$

DC voltage in middle of line pole to ground

$$= [530 + 500]/2 = 515 \text{ kV DC}$$

Line resistance per pole

$$= (U_{dr} - U_{di})/I_d = (530 - 500)/1 = 30/1 = 30 \text{ ohm}$$

Note. In power calculations U_{dc} in kV and I_{dc} in kA gives P_{dc} in MW.

57.27. IMPORTANT CONCLUSIONS ABOUT POWER FLOW THROUGH AC AND HVDC LINKS

1. Operation and Control principles of AC Link and HVDC Link are quite different. In AC line power transfer is due to power angle δ between V_s and V_r phasors. The increase in load brings about increase in δ automatically. However no precise and fast control of power is possible through a particular AC line in an AC network.

In an *HVDC Link* the power flow is

$$P_d = U_d \times I_d = \frac{U_{d1} + U_{d2}}{2} \times I_d \ldots \text{ MW} \qquad \ldots(57.74)$$

$$P_d = U_d \times \frac{U_{d1} - U_{d2}}{R} \ldots \text{ MW} \qquad \ldots(57.75)$$

In these Eqns. U_d in kV, I_d in kA and P_d in MW.

Since R is small, a small variation in $(U_{d1} - U_{d2})$ gives a significant change in DC power flow. DC power flow can be controlled precisely and rapidly by controlling $(U_{d1} - U_{d2})$, by tap changers of converter transformers (slow control 10 seconds) and by control of phase angles of converter valves firing simultaneously from both the ends of the HVDC Link Rapid control (tens of milliseconds). Power flow can be set at precise level. Power flow through a particular DC link can be changed at a rate of 30 MW/min over a wide range (*e.g.* 200 MW to 1500 MW).

2. Transfer of Real Power P_s (watts) through a branch of an AC network dependent mainly on power angle δ, between V_s and V_r phasors. The angle *o* is therefore called *Power angle or Load angle.* This angle increases with flow of *P* through the branch. In an AC line, power flow through a branch *does not* depend much on the magnitude difference $|V_s| - |V_r|$.

Power Flow in *HVDC line* however *depends* mainly on the magnitude difference $|U_{d1}| - |U_{d2}|$, and there is no question of load angle δ in case of HVDC lines.

3. Maximum power transfer (steady state stability limit) of an AC line occurs when power angle δ = 90°. Neglecting line losses,

$$\text{for } \delta = 90^\circ \ldots, \qquad P_{max} = \frac{|V_s| \ |V_r|}{x} \angle \ldots \text{W} \qquad \ldots(57.9)$$

Beyond P_{max} the transmission link stability is lost. HVDC transmission link has no such limit based on power angle. Maximum HVDC power is usually dictated by thermal limit of thyristor-converter and converter transformers.

4. In AC lines, the reactive power Q flows in the direction from higher voltage to lower voltage. In HVDC line there is no continuous flow of reactive power.

5. HVDC line losses are less than 5% of power transfer ; HVDC line has no I_R line losses due to reactive power flow. Hence line losses are less than equivalent AC line carrying same power.

Whereas losses in AC line are about 15 to 20% high transmission losses in AC line are due to additional reactive power flow.

57.28. POWER FLOW THROUGH AC LINE AND PARALLEL HVDC LINE

Refer Fig. 57.12B illustrating the power flow through HVDC line and parallel AC line.

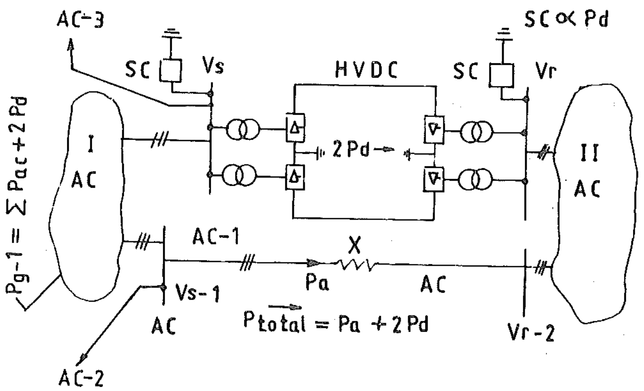


Fig. 57.12. B Power flow through HVDC line and parallel ac line.

Total power transfer from AC-1 to AC-2 is the sum of P_a and $2P_{dc}$.

$$P \text{ total} = P_a + 2\,P_d$$

where, P_a = power flow through AC line $= \dfrac{|V_{s1}| \cdot |V_{r2}|}{X} \sin \delta$,

P_a cannot be easily and rapidly changed.

δ = Phase angle between V_{s-1} and V_{r-2} vectors

$2P_d$ = Power trough Bipolar HVDC line $= 2U_d \times I_d$

U_d = pole to ground voltage and i_d = DC pole current

$2P_d$ can be easily and rapidly changed.

Power flow $2P_d$ from AC network 1 to AC Network 2 *via* bipolar DC line can be precisely controlled by means of HVDC Link.

Power flow P_a from AC Network 1 to AC Network 2 *via* AC line cannot be changed easily and rapidly as increased generation in Network 1 would result in increased power flow trough various AC lines such as AC 1, AC 2, AC 3. The increase in power flow is shared by various outgoing lines in accordance with the loads at receiving ends and resulting phase power angles δ_1, δ_2, δ_3 of the AC lines.

Voltage control. As the power $2P_d$ through DC line is increased, the Leading shunt compensation (SC) at receiving end should be increased to regulate V_r. Amount of shunt compensation required is about 60% of $2P_d$.

Total power generator. When AC Network 1 is sending power to other parts of the Network, the general equation is :

$$P_{g-1} = \sum P_{ac} + 2P_{dc} \qquad ...(57.76)$$

where, P_{g-1} = The total power generated in Network 1

ΣP_{ac} = Total power transmitted through various AC lines

$2P_{dc}$ = Total power transmitted through bipolar HVDC line

$$P_{ac} = P_g - 2\,P_{dc} = P_{ac1} + P_{ac2} + P_{ac3}$$

where, P_{ac1}, P_{ac2} are the power flow through various AC lines.

The increase or decrease in $2P_{dc}$ can be independently achieved by HVDC control. This is a unique advantage of HVDC Link over AC link. Neglecting the losses, the total power generated is equal to total power transmitted, P_g remaining the same, the increase in P_{dc} results in corresponding decrease in ΣP_{ac}. The power flows through various AC lines (P_{ac1}, P_{ac2} etc) are determined by means of power flow calculations for the total network.

Example 57.16. Parallel AC line and HVDC line. *A super thermal power plant is generating 6000 MW power. Out of the total generation, the Bipolar HVDC line transmits 2000 MW to a remote load centre and the remaining power is transmitted through four AC lines. The power flow through the three AC lines is 1000 MW each. Calculate the power flow through the fourth AC line.*

Solution.

$$P_{g-1} = \Sigma P_{ac} + 2P_{dc}$$

where, P_{g-1} is total generation, ΣP_{ac} is total power flow through all the AC lines and $2P_{dc}$ is bipolar HVDC power flow.

$$P_{g-1} = 6000 = \Sigma P_{ac} + 2000 \text{ MW}$$

Therefore,

$$\Sigma P_{ac} = 6000 - 2000 = 4000 \text{ MW}$$

$$\Sigma P_{ac} = P_{ac-1} + P_{ac2} + P_{ac-3} + P_{ac4}$$

$$\Sigma P_{ac} = 4000 \text{ MW} = P_{ac1} + P_{ac2} + P_{ac3} + P_{ac4}$$

$$= 1000 + 1000 + 1000 + P_{ac4}$$

$$P_{ac4} = 1000 \text{ MW} \quad \textbf{Ans.}$$

Example 57.17. Parallel AC line and HVDC line. *A super thermal power plant is generating 6000 MW power. Out of the total generation, the Bipolar HVDC line transmits 4000 MW to a remote load centre and the remaining power is transmitted through four AC lines equally. What would be the power flow through each of the four AC lines, assuming they share the load equally.*

Solution. $\Sigma P_{ac} = P_{g-1} - 2P_{dc}$

where P_{g-1} is total generation, ΣP_{ac} is total power flow through all the AC lines and $2P_{dc}$ is bipolar HVDC power flow.

$$P_{ac} = 6000 - 4000 = 2000 \text{ MW}$$

Power flow through each AC line = 2000/4 = 500 MW.

SUMMARY

The calculation of steady state P and Q flow through various branches of the Network and the resulting bus voltages and their phase angles is called *Power Flow Study* or *Load Flow Study*.

The *Principal variables* associated with *each of the N buses* are :

— Voltage magnitude $|V_k|$,

— Phase angles of voltage phasors (δ_k),

— Real power P_k,

— Reactive power Q_k

(subscript k for the bus number, k = 1, 2, 3, ... N for an N bus system. The *Derived Variables* for branches are current I. Power Factor cos ϕ, MVA etc., these are calculated from the Principal Variables obtained from the end results of the interation).

For each bus generally two of the above four principal variables are specified and other two are to be determined from Load flow calculations. The two unknown variables for each of the N buses are calculated by solving N simultaneous non-linear load flow equations co-relating P_k, Q_k, V_k for $k = 1$ to N bus number.

— Gauss seidel interative method (GS Method)
— Successive over relaxation method. (GS method employing acceleration factors)
— Newton-Raphson interative method. (NR method)

The power flow calculations of an N-Bus system involves solution to N number of simultaneous nonlinear power flow equations, with generally two unknowns for each of N Busses. The solution should satisfy network power flow equations. Modern load flow studies are performed by solving the network power flow equations by *Interative Procedure and use of Digital Computer/Personal Computer.*

Starting from the *assumed values* of unknown variables and given values of other variables, the load flow equations are solved to obtain new better values of the same unknown variables.

These new better values of unknowns are again substituted in the same equations (Algorithms) to get yet an another set of new revised values. The process of calculations of the new revised values of variables (*e.g.* Bus Voltages) by using earlier result is called *"an interation"*.

The interations are repeated till sufficiently accurate values are obtained and further interations are not giving next better values, *i.e.* convergence is reached. The equations used for interative solution are called *Algorithm.* The Gauss Seidel Method and Newton Raphson Method are used for interative solution of load flow problems.

Power flow calculations are essential for system design, system expansion, relay coordination, power system analysis and operation guidelines, and for input data for Stability Studies.

Power flow through HVDC link can be controlled precisely, rapidly and to required level through particular HVDC Link. *The increase or decrease in $2P_{dc}$ can be independently achieved by HVDC control.* This is a unique advantage of HVDC Link over AC link. Neglecting the losses, the total power generated is equal to total power transmitted, P_g remaining the same, the increase in P_{dc} results in corresponding decrease in ΣP_{ac}.

QUESTIONS

1. Explain the meaning of bus admittance matrix Y bus, with the help of a 3 bus network.
2. Distinguish between Load Bus, Generator Bus and Slack Bus in a Power Flow Study. State the known variables and unknown variables for each of the type of bus.
3. Write a general equation for voltage V_k of kth node of a N node power system, in terms of P_k, Q_k, Y_{kk}, V_k and Y_{kn} and V_n. Write the 3 equations for voltages of V_2, V_3 and V_4 a 4 Bus Network considering V_1 as Slack bus voltage.
4. In a 2 bus system, bus 1 is supplied by generator G_1 and bus 2 by generator G_2. The real power supplied by G_1 is 5.0 pu and by G_2 is 5.0 p.u., $|V_1| = 1.0$ pu. ; $|V_2|$ is 1.1 pu.

   Each bus has complex local load, equal to $S_1 = S_2 = 3 + j\,4$ pu. The two buses are connected by branch 1-2 having series reactance of 0.08 p.u. Calculate the total complex load on each bus.

   Ans. $8 + j\,5.7$ pu.
5. Explain the Gauss Seidel interation method for power flow solution.

6. Explain the information obtained from a typical power flow study and the significance of power flow studies.
7. Give comparison between Gauss siedel method and newton Raphson method of power flow studies.
8. Explain the significance of following equations for a branch in an AC network with respect to control of power flow through a branch of an AC network. How can the power through the branch be increased ?

$$P_s = \frac{1}{2}\,|V_s|\;|V_r|\,\sin\delta$$

9. Derive expression for power flow through a pole of a 2 terminal bipolar HVDC system having sending end DC voltage U_{d1} per pole, receiving end DC voltage U_{d2} per pole, line resistance r per pole and current in pole conductor I_d. Derive expression for P_d at sending end, P_d at receiving end and power loss in line pole.

   A bipolar 2 terminal HVDC line pole has resistance of 10 ohms, DC current in line pole is 1000 A, receiving end DC voltage is 400 kV DC pole to ground. Calculate : Line loss per pole, sending end DC power per pole, Sending end DC voltage per pole and bipolar DC power at middle of the HVDC line length.
10. A generating station generates 5000 MW. The power is transmitted through one bipolar HVDC line and three AC lines. The HVDC line transmits total 3000 MW. The two AC lines transmit totally 1500 MW. Calculate the power transmitted through the third AC line.

    Explain why HVDC line is preferred to AC line for better power flow control.

58

Applications of Switchgear

58.1. LOW-VOLTAGE INSTALLATIONS

58.1.1. Switchgear apparatus

Low-voltage switchgear is used for switching and protecting electrical equipment. The various devices are selected according to their required function, e.g. isolating, disconnecting loads, short-circuit breaking, switching motors, protecting against overloads and danger to human life. The switching functions can also be performed by a combination of several devices. Fig. 58.1 gives some of the devices used for low voltage switchgear.

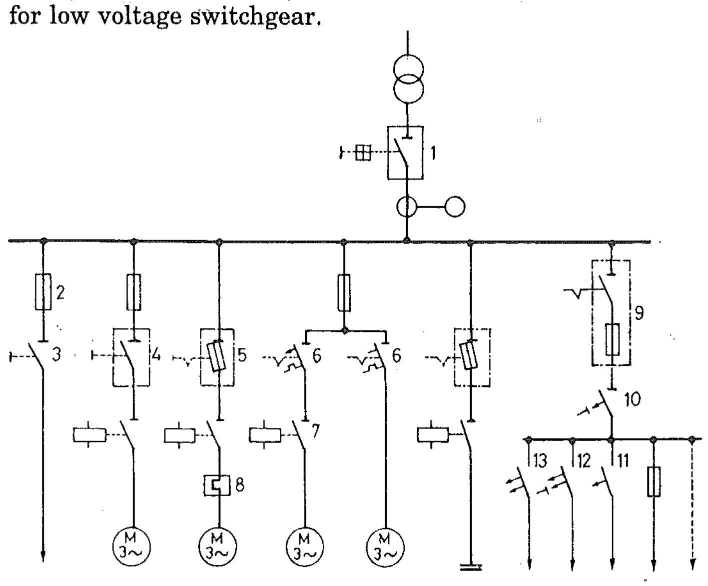


Fig 58.1 : 1 Circuit-breaker, 2 Fuse, 3 disconnector, 4 Loadback switch, 5 Fused switch-disconnector, 6 Motor starter (motor protection switch), 7 Contactor, 8 Overload relay, 9 Switch-disconnector with fuses, 10 Residual current circuit-breaker (r.c.c.b.), 11 Miniature circuit-breaker (MCB), 12 Residual current circuit-breaker with overcurrent trip, 13 miniature circuit-breaker, MCCB.

58.1.2. Technical Requirements of Various devices

1. Circuit-Breakers. Circuit-breakers must under normal operating conditions be able to make, carry and break currents and, under specified abnormal conditions up to a short circuit, be able to make the current, carry it for a defined length of time and interrupt it. Circuit breakers with instantaneous overload and short-circuit trips are used for routine switching and for overload protection of apparatus and parts of systems having a low operating frequency. Circuit-breakers without overcurrent releases, but with a special open-circuit shunt release (0.1 to $1.1 \times U_N$) are employed as "network protectors" to prevent reverse voltages.

Circuit-breakers are available for dependent or independent manual actuation and also for actuation by dependent power or energy-storage devices (operation by motor, electromagnetic,

electropneumatic). The breakers can be opened manually, electrically by a motor or electromagnet, or by releases e.g., open-circuit, overcurrent, undervoltage, reverse power or reverse current. Circuit-breakers are classified according to their design principle i.e. "current-zero breakers" and "current limiters".

Current-zero breakers interrupt the switching arc at the natural zero transition of the a.c. current. The current paths are arranged so that during the peak short-circuit current the contact pressure is reinforced by the electrodynamic forces, and the contacts do not separate until the short-circuit current has settled. These switches and all subsequent parts of the system must be able to carry the full peak short-circuit current. Current limiters are fast-acting circuit-breakers which operate before the current maximum is reached. The peak short-circuit/s is limited to a cut-off current l_p, thus reducing the mechanical and thermal stresses on the system which would occur if the short-circuit current were not restricted.

2. Contactors. Contactors are remote-controlled switches with restoring force which are actuated and held by their operating mechanism. They are used mainly with high operating frequencies for switching equipment under fault-free conditions. Including normal overloads. Contactors are not always suitable for isolating function and they must be preceded by a protection device to guard against short circuits.

Besides the widely used electromagnetic operating mechanism, contactors are also actuated pneumatically or electropneumatically.

To prevent thermal overloading of motors, contactors are fitted with current-dependent protection devices. To guard against motor overload or failure of a phase conductor, e.g., a wire breaks or only one fuse blows, the overcurrent relays are set to the rated current of the motor. Modern overcurrent relays have a temperature-compensating facility which offsets the influence of different ambient temperatures on the tripping times of the bimetal releases.

The contactor must be able to work satisfactorily within the limits of 85% and 110% of the nominal control voltage (with the control current flowing).

If the control lines are long, it is possible that the contactor will not respond to a command on closing because the voltage drop is too large (a.c. and d.c. actuation). or on opening because the capacitance of the line is too high. A voltage drop of 5% max is permitted for calculating the length of control lines.

3. Motor starters. The term motor starter are the devices necessary for starting and stopping a motor. These are provided with appropriate overload protection.

Motor starters, are also called motor protection switches if these are suitable for switching short-circuit currents.

Motor starters can be operated by hand or motor, electromagnetically, pneumatically or electropneumatically. They can be used in conjunction with open-circuit shunt releases, undervoltage relays or undervoltage releases, time-delay overload relays, instantaneous overcurrent relays and other relays or releases.

The rated operational current of a motor starter depends on the rated operational voltage, the rated frequency, the rated duty, the application and the type of enclosure.

4. Other switchgear apparatus

(*a*) **Disconnectors (isolators).** A switch which for safety purposes when open provides isolating distances (safety clearances) in compliance with specified requirements. A disconnector can open and close a circuit only if the current to be disconnected or connected is negligible, or if there is no perceptible voltage difference between the two contacts of each current path. For a defined length of time it can carry service currents under normal conditions, and also higher currents under abnormal conditions, e.g. short-circuit currents. Disconnectors can also have a certain making and/or breaking capacity.

Negligible currents can be capacitive currents occurring at bushings and busbars and very short cables, and also the currents of voltage transformers and dividers used for measuring purposes.

No perceptible voltage difference exists, for example, when induced voltage regulators or circuit-breakers are shunted.

(*b*) **Switch-disconnector.** A switch which in the open position satisfies the isolating requirements.

(*i*) *Switches (load switch).* A switch which under normal conditions, where specified also certain overload conditions, is able to connect, carry and interrupt currents and which under defined abnormal conditions such as short circuits, can carry these currents for a specified length of time. It has a short-circuit making capacity, but not a short-circuit breaking capacity.

(*ii*) *Fuse combination unit.* A switch, disconnector or switch-disconnector and one or more fuses assembled as a unit.

(*iii*) *Disconnector-fuse.* An integral assembly of a disconnector and fuses where a fuse is connected in series with the disconnector in one or more current paths.

(*iv*) *Fuse-disconnector.* A disconnector in which a fuse line or fuse carrier with fuse link constitutes the moving contact.

(*v*) *Fuse-switch.* A switch in which a fuse line or a fuse carrier with fuse link constitutes the moving contact.

(*vi*) *Switch-fuse.* An integral assembly of switch and fuses in which a fuse is connected in series with the switch in one or more current paths.

5. Protective switchgear for wiring systems. The switchgear protecting lines/cables apparatus and people are now available in modular construction. These are either snap-mounted (channel mounted) or fastened with screws. They are used for wiring,. switching, control and measuring in building installations and commercial and industrial plants. The various devices used in such switchgear include :

(*a*) **Miniature circuit-breakers.** Miniature circuit-breakers are manually operated, current-limiting switches with permanently set, undelayed electromagnetic releases and delayed thermal releases. They automatically disconnect the circuit from the network if the specified current is exceeded.

Miniature circuit-breakers for line protection are available in one, two and three-phase form, and also in one- and three-phase versions with connected neutral, together with auxiliary switches if required. Current ratings for voltages of 415 VAC and 440 VDC extend up to 63 A, the commonest ratings being 6, 10, 16, 20, 25, 32, (35).

(*b*) **Residual current-operated circuit-breakers (leakage current).** Residual current-operated circuit-breakers are used for protecting people, livestock and property (fire) against alternating and pulsating direct fault currents. They trip within 0.2 s if a defined fault current is exceeded, e.g., due to damaged insulation. They are usually protected against short circuits by an overcurrent device.

Residual-current breakers are available in two-and four-phase versions for 500 V a.c. and current ratings up to 63 A. Common rated currents are 16, 25, 40 and 63 A for nominal fault currents $l_{\Delta n}$ of 10, 30, 100, 300 and 500 mA.

(*c*) **Residual-current circuit-breakers with overcurrent trip.** These-breakers are with switch combinations which automatically disconnect all phases from the supply network, irrespective of mains and auxiliary voltages, if the values set for fault, overload or short-circuit current are exceeded.

(*d*) **Miniature circuit-breakers with differential trip.** Such breakers are combinations of switches which automatically disconnect the circuit from the supply if the set values for overcurrent or differential current are exceeded. The differential current trip can be independent of mains or auxiliary voltages. Versions in two- three- and four-phase (3 or 4 protected phases) and single-phase breakers with continuous neutral for fixed installation and two-phase breakers for plug connection with a rated differential current of 10 mA for current ratings of 10 and 16 A are available.

58.1.3. Selectivity of devices

There are a number of overcurrent protective devices between the power source and an item of equipment requiring protection against short circuits. These devices must respond selectively in order to restrict any fault as far as possible to the affected part of the system. For this proper selection of the device & the area to be covered under the protection has to be made to ensure that :

— routine current spikes do not cause disconnection

— when operating properly, only the protective device nearest to the fault in the supply direction responds.

— if this device fails, the one next to it in sequence comes into action.

The selectivity of protective devices can be established by comparing their time/current characteristics. Attention has to be paid to the following :

— zone of overcurrents: long tripping times, effective range of thermal overcurrent release.

— Zone of small short-circuit currents : short tripping times, effective range of electro- magnetic release.

— Zone of large short-circuit currents : tripping time within one half-wave, effective range of current limitation.

Various examples of selectivity are :

(*i*) **Vity fuse.** Fuses generally function selectively if their time/current characteristics do not overlap. With large short-circuit currents it is no longer sufficient to merely state the melting time. In this case selectivity is assured only if the critical value $l^2 . t_a$ of the smaller fuse is lower than the value $l^2 . t_s$ of the preceding fuse. This condition is normally satisfied by grading the fuse current ratings in a ratio 1 : 1.6.

(*ii*) **Circuit-breaker.** Selective short-circuit protection is not possible by grading the response values of the electromagnetic releases, but requires additional time grading independent of current. The total break time t_A of the downstream breaker must be shorter than the minimum command time t_m of the upstream breaker. The grading times between two breakers are 100 ms approx.

58.2. LOW-VOLTAGE SWITCHGEAR ASSEMBLIES

The term low-voltage switchgear assemblies covers all configurations with rated voltages up to 1000 VAC at frequencies up to 1000 Hz or 1500 VDC, except for small distribution boards. Also included are combinations of electromechanical and electronic equipment and also construction with solely electronic equipment.

For the same level of safety, a distinction is made between

"Type-tested switchgear assemblies" and

"Partially type-tested switchgear assemblies".

The manufacture can choose the manner of testing on grounds of production or economy.

Type-testing must demonstrate the following :

— Adherence to upper limit temperature

— Dielectric strength

— Short-circuit strength

— Flawless connection between parts of switchgear assembly and protective conductor by inspection or resistance measurement.

— Short-circuit strength of protective conductor

— Creepage distances and clearances

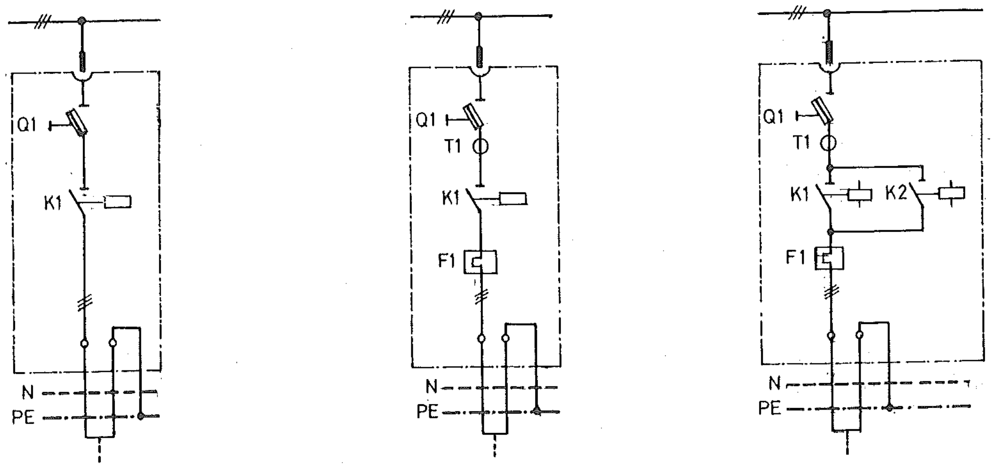
— Mechanical functioning

— IP protection class.

58.3. LOW-VOLTAGE SWITCHGEAR INSTALLATIONS AND DISTRIBUTION BOARDS

Low-voltage switchgear installations and distribution boards are used for power distribution, motor control centres and as combinations of these. They contain equipment for protecting, switching, converting, controlling and measuring. Different constructions and combinations are required for the widely varied applications and requirements, and from operation by the unskilled to locked electrical premises. The switchgear is Suitable for Surface-mounting flush-mounting, without removable cover or without door, with removable cover or with door.

Distribution boards for mounting in hollow walls are also available. Small distribution boards can include meter positions also examples of different available switchgear assemblies are given in Fig. 58.2 (*a*), (*b*), (*c*).



(*a*) (*b*) (*c*)

Fig. 58.2. Examples of standard assemblies with circuit diagrams (draw-out units with fuse switch-disconnectors) (*a*) without thermal protection, (*b*) with thermal protection, one direction, (*c*) with direction reversal

58.4. MEDIUM-VOLTAGE INSTALLATIONS

Switchgear apparatus is basically more or less the same except that characteristics, technical parameters are different.

1. Disconnectors. Disconnectors used in medium-voltage installations are mainly of the knife-contact type (Fig. 58.3). Special attention must be paid to the pivoting movement of the isolating blades when deciding the cubicle dimensions, to ensure the required clearances. Switchgear cubicles with knife-contact disconnectors require more mounting depth than those with slide-in disconnectors.

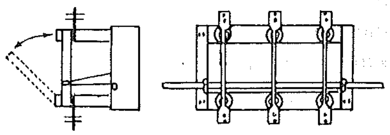


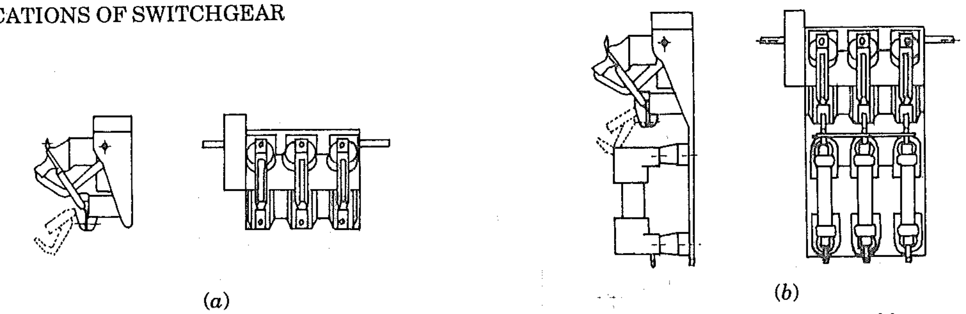
Fig. 58.3. Medium-voltage knife-contact disconnector

The blades of knife-contact disconnectors mounted standing or suspended have to be appropriately prevented from moving spontaneously under their own weight.

Disconnectors with rated voltages of up to 36 kV are usually operated by hand. In remote-controlled installations they are actuated by a motor or compressed air. Earthing switches can be fitted, including those with full making capacity.

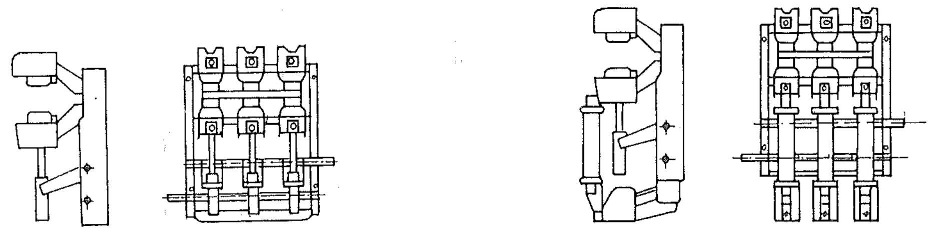
Disconnectors rated voltages of up to 36 kV must satisfy the test conditions according IEC 129 (DIN VDE 0670 Part 2)

2. Switch-disconnectors. Switch-disconnectors are increasingly being used in medium-voltage switching stations. Switch-disconnectors have full making capacity and can handle all fault-free routine switching operations. Switch-disconnectors are load-break switches with visible isolating distances.



(*a*) (*b*)

Fig. 58.4. Knife-contact switch-disconnector : (*a*) without and (*b*) with fuse assembly



(*a*) (*b*)

Fig. 58.5. Slide-in type switch-disconnector : (*a*) without and (*b*) with fuse assembly

Knife-contact switch-disconnectors and slide-in type switch-disconnectors can be operated in two ways.

(*a*) Snap-action mechanism. With this form of operating mechanism, a spring is tensioned which is released shortly before the switching angle is completed, and its force is used to move the contacts. The procedure is employed for both closing and opening.

(*b*) Stored-energy mechanism. This system has one spring for closing and a second spring for opening. During the closing operation the opening spring is tensioned and latched. The stored energy for the opening operation is released by means of a magnetic trip or H.V. (H.R.C.) fuse.

3. Earthing switches. Depending on the construction of the switching installation, earthing switches are mounted separately ahead of the switchgear, e.g., in the cable basement (Fig. 58.6 c) or contained in the base of the switch disconnector (Fig. 58.6 a) or factory-assembled immediately underneath the circuit-breaker (Fig. 58.6 b). Earthing switches are disconnectors or switch-disconnectors (with full making capacity). Knife-contact and slide-in types are available. For safety reasons - e.g. accidental closure of the earthing switch on a live incoming or outgoing feeder earthing switches with full making capacity are recommended for conventional switching installations.

4. H.R.C. fuse links. The protection of capacitors and transformers must include provision for inrush currents. In capacitor installations. The rated current of the fuse link must be at least 1.6 times the capacitor current rating, to take into account the possible network harmonics and voltage rise.

When selecting fuse links for protecting high-voltage motors, attention must be paid to the motors starting current and starting time. The frequency of starting must also be considered if this is so high that the fuses cannot cool down in between. Fuse links are available with rated voltages and currents graded for fuse-bases of different sizes.

Current-limiting capacity. The maximum current that a fuse will let through depends on its rated current and on the prospective short-circuit current. The fuse's melting characteristics is indicated by the manufacturer for the range of breaking currents, for each rated current one can read off the peak value of the let-through current to which the fuse limits a symmetrical short-circuit current. Plotted on the horizontal axis are the r.m.s. symmetrical short-circuit current occurring when a fuse is shunted out. At a symmetrical short-circuit current of 40 kA, for example, with

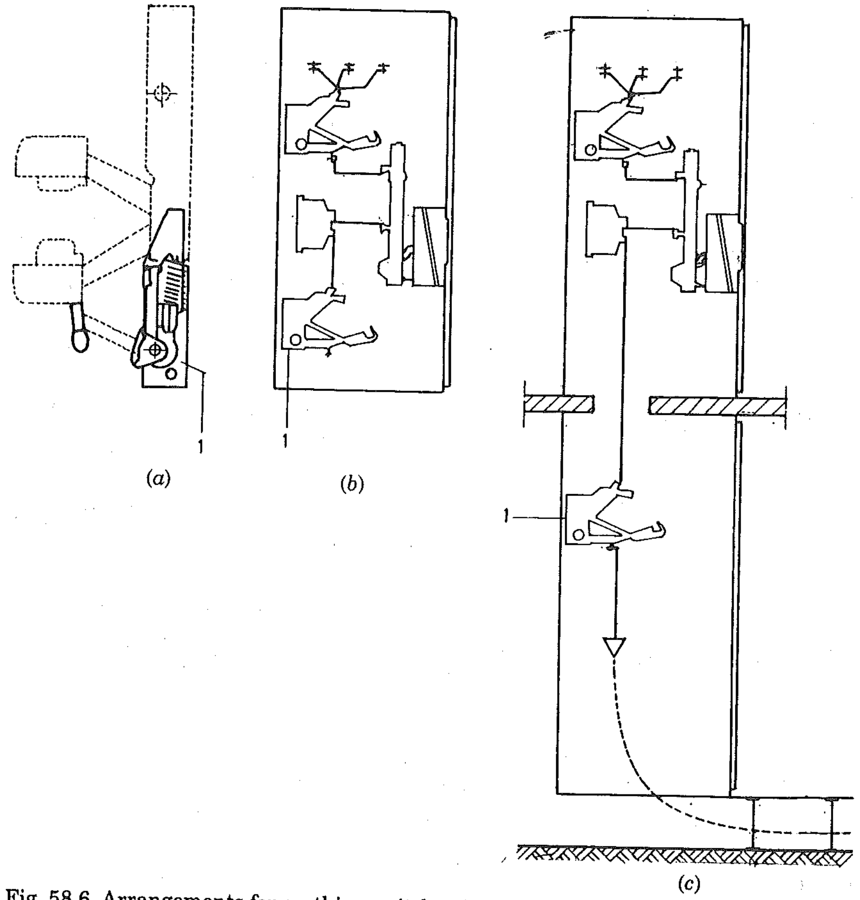


Fig. 58.6. Arrangements for earthing switches (1) : (a) mounted on switch-disconnector ; (b) in cubicle underneath of circuit-breaker and (c) in cable basement/compartment

a 16 A link the let-through current is only 3 kA as against a prospective impulse short-circuit current of about 100 kA with full asymmetry. This current limitation effectively protects the installation against damage due to thermal and dynamic stresses.

5. Peak current I_s limiters. Peak current I_s limiters are switching devices which interrupt circuits very quickly after tripping, commutate the current to a special quartz fuse arranged in parallel, and there extinguish it. As can be seen in Fig. 58.7. The I_s limiter consists of an insulating housing (3) containing two pieces of tube (1) provided with lengthwise slits and having one end connected to the terminals while the other ends are soldered together. Inside these tubular contacts is a detonator (2) which is fired with an igniter by discharging a capacitor.

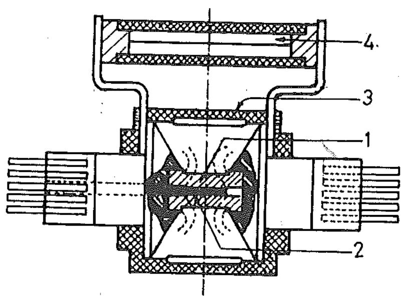


Fig. 58.7. Design of an I_s limiter, 1 Contact pieces, 2 Detonator, 3 Insulating housing, 4 Fuse

The high pressure caused by the detonation spreads the contact fingers, so interrupting the main circuit. The fuse (4), which is designed for a small rated current, limits and quenches the computated short-circuit current while it is still rising. Since the opening time of the I_s limiter is well below 1 ms, its let-through current is small, making it a very effective current-limiting device (Fig. 58.9)

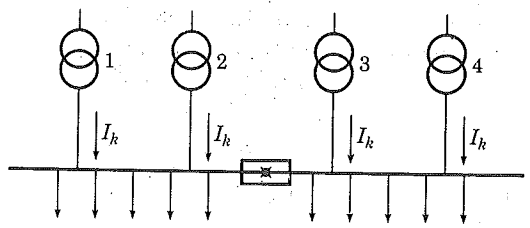


Fig. 58.8. Two switching stations coupled through an I_s limiter (a) to limit the short-circuit current

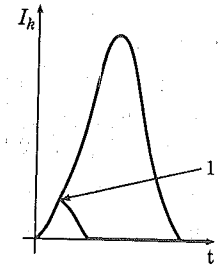


Fig. 58.9. Limitation of short-circuit current (1) by melting of fuse link

I_s limiters are used in medium-voltage installations up to 36 kV. They are employed for quickly sectionalizing busbars in installations with high-fault powers (Fig. 58.8), for re-connecting short-circuited current-limiting reactors and for directly disconnecting faulted circuits.

I_s limiters are manufactured for the rated voltages and currents shown in the Table below :

Rated voltages and currents for I_s limiters.

For higher current ratings the limiters can be connected in parallel.

Rated voltage kV	*Rated current A*		
12	1000	2000	3000
24	1000	1600	2000
36	1000	2000	

6. Circuit-breakers. Circuit-breakers for medium voltages are nowadays mainly of the oil-free type. Breakers with current ratings of 400 A to 3150 A are available for voltage ratings of 7.2 kV to 36 kV and rated short-circuit breaking currents up to 40 kA. They are either fixed or truck-mounted together with the appropriate interlocks. Draw-out breakers on extending rails are also available in standard forms for rated currents up to 1250 A.

Circuit-breakers conform essentially to IEC Publication 56-2.

Compared with minimum-oil designs, oil-free circuit-breakers (vaccum, SF_6) have the advantages of being largely maintenance-free and having a high long-term breaking capacity. Construction features, merits/demerits of each type have been covered separately.

7. Vaccum Contactors. Vaccum contactors are particularly suitable for the routine switching of motors which start and stop frequently, e.g. medium-voltage motors for pumps, compensators, capacitors or fans. Short-circuit protection for the motor feeders is provided by current-limiting h.r.c. fuses, or by a circuit-breaker.

Vacuum contactors have generally a life expectancy of 1×10^6 switching cycles and can handle switching frequencies of up to 1200 on/off operations per hour.

Rated voltage	*kV*	*3.6*	*7.2*	*12*
Rated current	A	450	450	250
for motors up to	kW	1500	2000	4000
for capacitors up to	kVar	2000	4000	4000

8. Switchgear with fully-insulated busbar. Medium-voltage installations with high power rating connections for currents of up to 5000 A because of the limited space fully phase-insulated, capacitor-controlled busbar connections are manufactured and especially where the busbar system has to meet stringent thermal and dynamic requirements.

They are generally suited for :

— connecting transformers is switchgear assemblies for voltages 0.4 to 72.5 kV
— coupling busbars for duplex switching stations
— section ties between switching stations and busbars
— incoming connection to inverter installations

Construction of such a bus-bar is given in Fig 58.10.

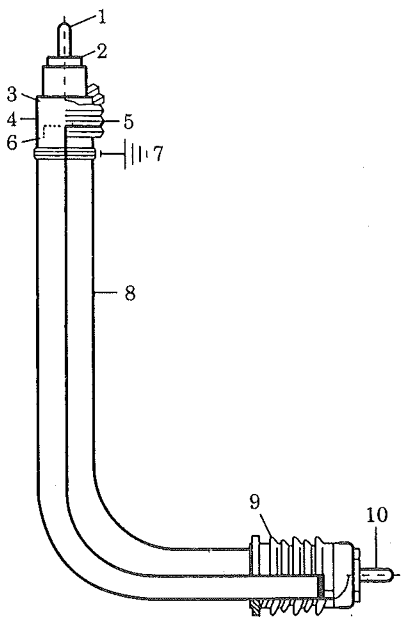


Fig. 58.10. Construction of insulated busbar for indoor or outdoor application : 1 indoor connection, 2 Conductor, 3 insulation, 4 Busbar termination with standard creepage distance, 5 Busbar termination with increased creepage distance, 6 Earth potential layer, 7 Earth connection, 8 Surface design for indoor; without protection cover, optional with protection tube, for outdoor; with protection tube, 9 Porcelain insulating cover, 10 Outdoor connection.

9. High-Current Switchgear associated with a generator.

Generator circuit-breakers are switching devices in the high-current connection between generator and main transformer. The main applications and the resulting advantages are listed below.

Function	*Advantages*
Isolate generator from station services infeed	Station services fed via generator transformer. No need for starting transformer and associated switchgear and change-over facilities (see Fig. 9-1a).
Synchronize on low-voltage side of main transformer	Eliminates voltage transformers on h.v. side of main transformer. Possibility of connecting two generator to one over-head line via 2 separate transformers or a three-winding tranformer.
Efficient power plant layout (particularly hydro plants)	Possibility of connecting two or more generators to a two or three-winding transformer and thence to an overhead line (see Fig. 9-1e).
Isolate fault in generator transformer or in station service transformer	Effects of fault very much less than with rapid de-excitation as disconnection takes less than 100 ms.
Isolate fault in generator	Station services remain continuously connected to network, thus increase of availability.
Isolate fault on line from power plant to next transformer or switching station	No need for high-voltage breaker in generating station.
Use in nuclear power stations.	Considerably improves security of no break station services power supply.
Use in pumped storage plants.	Straightforward switching between pump and generator mode.
Power plant automation.	Only 1 switching operation to synchronize or disconnect the generator, instead of 5-7 operations when synchronizing on the HV side.

Fig. 58.11 shows examples of unit-connected arrangements with generator breakers. The various alternatives show that with large units having several generator and station services transformers, these breakers ensure to a very high degree that the service supply remains available in the event of a fault.

Generator breakers are ideal for use in conventional and nuclear power plants with high unit ratings and stringent requirements as regards safety and availability.

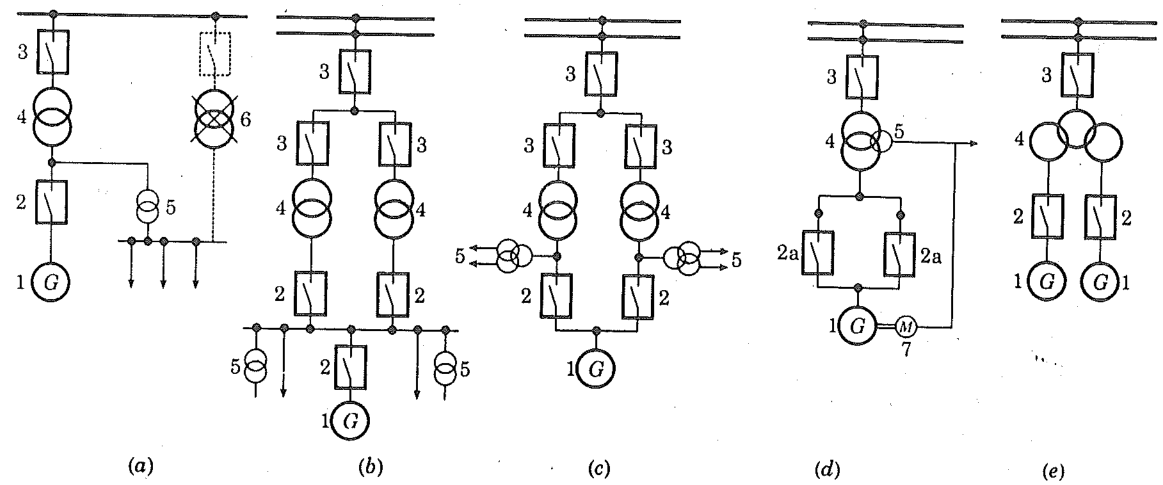


Fig. 58.11. Unit connection arrangements in power stations
(*a*) Basic diagram, (*b*) and (*c*) Large generators with part-load transformers,
(*d*) Pumped storage unit, (*e*) Hydro plant :
1 Generator, 2 Generator breaker, 2a 5-pole generator breaker for switching between motor and generator mode,
3 High-voltage circuit-breaker, 4 Main transformer, 5 Station services transformer,
6 Starting transformer, 7 Starting motor

There are three types of generator Circuit Breaker :

***(i)* SF_6 generator circuit-breakers.** The type SF_6 generator breaker is designed for generator ratings from 50 MVA to about 400 MVA. The breakers are of three-phase construction, either single-phase enclosed or unenclosed for the 24 kV voltage class. It can be installed in metal-enclosed or open high-current busducts. Unenclosed generator breakers of type are installed in a room which can be locked or surrounded by an aluminium enclosure to prevent touch contact.

The basic model has 1 extinction chamber. It can be extended on the modular principle by 1 disconnector, 1 or 2 earthing switches and 1 or 2 current transformers, all mounted on the same baseframe.

***(ii)* Air-blast generator circuit-breakers.** *(a) Closed Type Busbars.* Breakers of this type are intended for unit ratings of about 400-2000 MVA and above. The breaker is operated by compressed air. It incorporates a separate isolating distance, for which compressed air is the quenching medium. The necessary high-quality compressed air is produced in a self-contained compressor station.

This type of generator breakers are of single-phase metal-enclosed construction and can be incorporated directly into the high current busduct. Both the breaker enclosure and the active parts are connected to the busduct by flexible copper straps.

The series covers load-break switches and circuit-breakers of modular construction, so providing a range of models using the same basic components and suitable adapted cooling systems.

(b) Open Type Bus-bars. This type of air-blast breaker is preferably used in open, unenclosed busbars. These breakers are available in single or 3-phase versions, depending on their size.

Such generator circuit-breakers should be installed in a room which can be locked. Alternatively, the breakers can be surrounded by an aluminium enclosure or grille to protect against contact.

Breakers standing directly on the floor do not need any lifting gear : built-in castors enable them to be moved in any direction.

Their open construction, with the isolating distance visible, makes them particularly easy to check and service.

58.5. HIGH-CURRENT ISOLATED PHASE BUSDUCTS (GENERATOR BUSDUCTS)

The high-current isolated phase busducts and their branches are an important part of the electrical installation in a power plant.

The high-current busducts and switchgear are connected as shown in (Fig. 58.12): The purpose & function of such bus-ducts are :

— Connection between generator and the main transformer (s), including the generator neutral.

— Branch connections to station services transformer, excitation transformer and voltage transformer cubicle,

— Mounting and connection of measuring, signalling and protective devices for current, voltage and other parameters,

— Installation and connection of switching devices such as generator breakers, high-current disconnectors and earthing switches.

— Additional facilities relating, for instance, to protective and maintenance earthing, pressure-retaining systems or forced cooling.

Modern generator design, with rated voltages up to 27 kV and powers up to 1600 MVA, gives rise to service currents of up to 36 kA. For the high-current busduct this means that it has to withstand the temperature rise in conductor and enclosure and also the effects of substantial magnetic fields in the installation and its surroundings.

Unit capacities of this magnitude in conjunction with the high network powers can result in short-circuit currents of up to about 750 kA in the busducts and switchgear. Short-circuit currents of more than 1000 kA can occur in the branches. Furthermore, the safety and availability of a high busduct must conform to the high standard of the other station components.

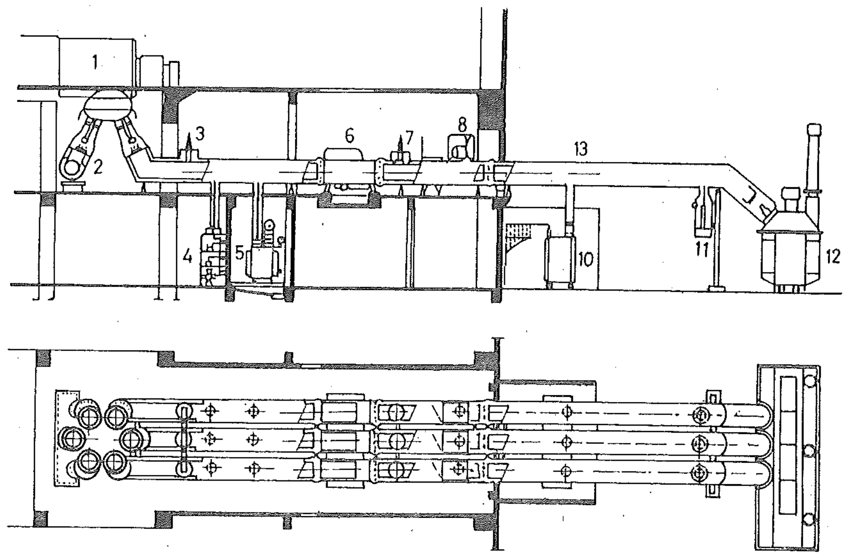


Fig. 58.12. High-current switchgear installation, 1 Generator, 2 Generator neutral, 3 Earthing switch with short-circuiter, 4 Voltage transformer cubicle, 5 Excitation transformer, 6 Generator circuit-breaker, 7 Earthing switch (optional), 8 Voltage transformer and capacitor compartment, 9 Expansion joint, 10 Station services transformer, 11 Lightning arrester, 12 Main transformer, 13 High-current busduct.

High-current busducts have to satisfy the following requirements :

— Adherence to specified temperature limits,

— Adequate short-circuit strength (thermal and mechanical strength in the event of short circuits),

— Adequate magnetic screening,

— Safe insulation, i.e., protection against overvoltages, moisture and contamination.

58.5.1. Types & Constructional features

Up to about 5 kA the generator connections are generally shaped like ordinary busbars. The simplest form consists of flat or U-section aluminium or copper bars (sometimes also tubes, but only Al). Exposed bars are used only with small generator ratings, because the area then has to be locked. On the other hand, placing the bars in a common square aluminium duct (nonsegregated phase busduct) protects them against contact and contamination. Added protection is provided by partitions between the phases (segregated phase busduct), thus preventing phase-to-phase short circuits and reducing the dynamic forces ; For higher ratings, isolated phase bus-ducts (each phase in separate enclosure) is provided.

Both the conductor and the enclosure arranged concentrically round it are in the form of aluminium tubes and are insulated each other by air and moulded-resin insulators.

Three insulators construction is commonly used for higher ratings as shown in Fig 58.13 for lower ratings, single insulator type bus-ducts are used.

An important technical feature is that the enclosures of each phase are short-circuited across the three phases at both ends. The current flowing in the enclosure-in the opposite direction to the conductor current-attains some 95% of the conductor current, depending on the system configuration and the impedance of the short-circuit connection between the enclosures (Fig. 58.13).

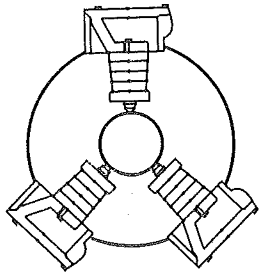


Fig. 58.13. (a) BBC high-current isolated-phase busduct, single-phase arrangement

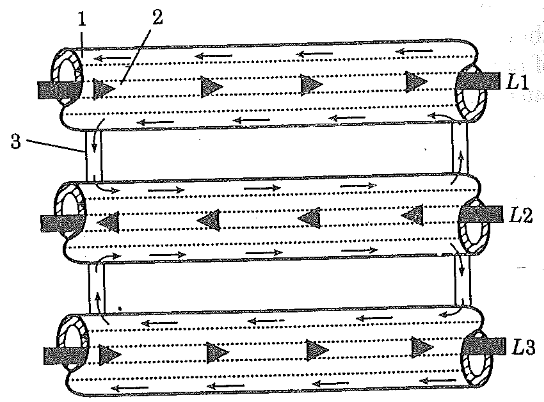


Fig. 58.13. (b) Principle of high-current busduct with electrically continuous enclosure : 1 Enclosure current. 2 Conductor current, 3 Short-circuit connection between enclosures.

The magnetic field outside the enclosure is almost completely compensated, so eliminating losses to the surroundings.

This design has the following important features :

— Proof against contact, so locked electrical premises are unnecessary.
— Protection against dirt and moisture, maintenance is limited to visual inspection,
— No magnetic field outside the enclosure (no inductive losses in nearby conducting material, such as grilles, railings, concrete reinforecements, pipes, etc.),
— Less likelihood of earth faults and short circuits.
— Single-phase high-current breakers can be incorporated in each busduct.

58.5.2. Design Considerations

The design of a high-current isolated-phase busduct is based on :

— Rated voltage
— Current
— Insulating level
— Short-circuit current
— Operating temperatures
— Climatic conditions
— Other requirements concerning components and ancillaries

Dielectric strength (rated power-frequency any lightning impulse withstand voltages) is provided by standard type sizes with air clearances between conductor and enclosure conforming to the minimum clearances specified in IEC 71.2, and by standard insulators complying with IEC and the respective voltage levels with test voltages to IEC 694/298.

58.5.3. Construction

Conductor and enclosure are generally of Al 99.5% rolled aluminium sheet into tubes and submerged-arc. The prefabricated assemblies can be up to 12 m long. Their length depends on transport and site lonstrain.

Each support consists of three post insulators—four in exceptional cases—which are mounted from outside. Sliding surfaces or fixed pins on all insulators of each support, and as spring arrangement on one of them, allow relative axial movement between conductor and enclosure.

The bearing elements for the enclosure are arranged independently of the conductor supports. They are of sliding or fixed type and bolted direct to the base structure. The tubular shape allows foot supports at distances of 10-20 m, depending on the system.

All connections to generator, transformers and switchgear not only provide sure electrical contact but also allow adjustment, the accommodation of thermal movement and access to the junction

points. Careful construction of the enclosure in particularly important in the vicinity of the generator terminals, owing to the small space between them. With small and medium-sized installations, three-phase terminal and neutral compartments with hatches and windows enable the connections to be reached and inspected. At higher current ratings, only the isolated-phase busduct construction provides adequate magnetic-field compensation, avoids eddy currents and so ensures controlled temperature conditions.

Flexible pressure-welded copper straps are used to bolt the conductors to the generator and switchgear terminals. Strong and highly resilient washers ensure the necessary contact pressure and so prevent excessive heat build-up. The contact surfaces are silver-coated if the maximum permitted conductor temperature so warrants.

Current tranformers for measurement and protection are of the bushing type of annular core type integrated into the busduct at a suitable place. To install or remove them, detachable connections have to be provided along the duct. Voltage transformers can be incorporated in the busduct or contained in separate instrument cubicles connected by way of suitable branches. The same applies to protective capacitors for limiting capacitively transmitted voltages.

Surge arresters protect busduct and generator in the event of flashover in the transformer, but are then usually stressed beyond the resealing voltage. Personnel and equipment can be safeguraded by using explosion-proof arresters and a suitably designed and tested arrester housing with means of pressure relief.

The earthing system of the isolated-phase busduct utilizes the enclosures of the three phases as an earth conductor. The other earth connections needed are restricted to connecting the enclosure to the earth terminals of the generator and the transformers, and coupling to the station earth.

58.5.4. Earthing Switch

Short-circuit-proof earthing switches and short-circuiting devices are necessary in the vicinity of high-current busducts, for safety reasons. With small unit ratings, manually fitted jumpers and straps can be used. For higher unit ratings it is advisable to employ motordriven earthing switches.

Fig. 58.14 shows the basic diagram of a high-current busduct with earthing switch.

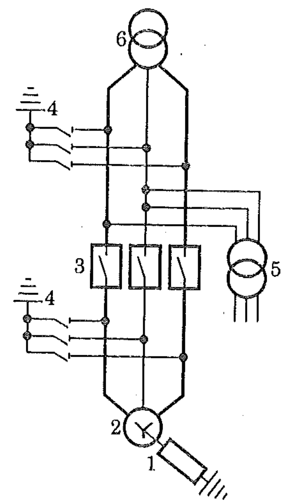


Fig. 58.14. Basic diagram of high-current busduct 1 Neutral earth, 2 Generator, 3 Generator breaker, 4 Earthing switch type E 36.150, 5 Station services transformer, 6 Main transformer.

58.5.5. Switchgear Installations

A switchgear installation contains all the apparatus and auxiliary equipment necessary to ensure reliable operation of the installation and a secure supply of electricity. High-voltage switchgear installations with operating voltages up to 800 kV are used for distributing electricity in towns and cities, regions and industrial centres, and also for power transmission. The voltage level employed is determined by the transmission capacity and the short circuit capacity of the power system.

Distribution networks are operated predominantly up to 132 kV. Power transmission systems and ring mains round urban areas operate with 33, 66, 132, 220, or 400 kV rated voltage, depending on local conditions. Over very large distances, electrical power is transmitted at 765 or 800 kV or by high-voltage direct-current systems.

Switchgear installations can be placed indoors or outdoors. SF_6 gas-insulated switching stations have the important advantage of taking up little space and being unaffected by pollution and environmental factors.

Indoor installations are built both with SF_6 gas-insulated euipment for all voltage ratings above 36 kV and also with conventional, open euipment up to 132 kV. SF_6 technology, requiring very little floor area and building volume, is particularly suitable for supplying load centres in cities and industrial complexes. This kind of equipment is also applied in underground installations.

Outdoor switching stations are used for all voltage levels from 33 kV to 765 kV. They are built outside cities, usually at points along the cross-country lines of bulk transmission systems. Switchgear for HVDC applications is also predominantly of the outdoor type.

Transformer stations comprise not only the h.v. equipment and power transformer but also medium-and low-voltage switchgear and a variety of auxiliary services.

Depending on the intended plant site, the construction of a switchgear installation must conform to IEC requirements of particular national codes, like BIS in our country.

The starting point for planning a switchgear installation is its single-line diagram. This indicates the extend of the installation, such as the number of busbars and branches, and also their associated apparatus.

The brief summary of Technical Particulars of HV switchgear is given subsequently for reference of both students as well as practising engineers.

58.6. HIGH-VOLTAGE SWITCHGEAR

58.6.1. Definitions and electrical characteristics for HV switchgear apparatus

Disconnectors are mechanical switching devices which in the open position provide an isolating distance. They are able to open or close a circuit if either a negligible current is switched or if no significant change occurs in the voltage between the terminals of the poles. Currents can be carried for specified times in normal operation and under abnormal conditions (*e.g.* short circuit). Negligible current have values $\leq$ 0.5 A; they include the capacitive charging currents of bushings, busbars, connections, very short lengths of cable and the currents of voltage transformers.

Isolating distances are gaps of specified dielectric strength in gases or liquids in the open current paths of switching devices; as protection for people and equipment they must satisfy special conditions and their existence must be clearly perceptible when the switching device is open.

Load switches are switching devices a switching capacity equivalent to the electrical stresses occurring when connecting and disconnecting equipment and sections of installations in the fault-free condition.

Load disconnectors are load switches which in the open position provide a visible isolating distance.

Circuit-breakers are switching devices able to close on the current occurring in a circuit under specified normal and abnormal conditions, to carry them for a specified time, and interrupt them.

Earthing switches are mechanical switching devices for earthing and short-circuiting circuits: they are able to carry currents for a specified time under abnormal conditions.

Fuses are switching devices in which the circuit is interrupted by the melting of specified parts under the influence of heat generated within the device when the current exceeds a given value for a specified time.

Auxiliary switches, auxiliary circuits. Auxiliary switches must be designed for a continous current of at least 10 A and be able to interrupt the current in control circuits. Details must be started by the manufacturer. If this information is not available, auxiliary switches must be able to interrupt at least 2 A at 220 V d.c. with a minimum time constant of the control circuit of 20 ms. The terminals and wiring in auxiliary circuits must be designed for a continuous current of at least 10 A.

58.6.2. Electrical characteristics

Making current. Peak value of the first large half-wave of the current in one pole of a circuit-breaker during the transient reaction after current starts to flow on closing.

Peak current. Peak value of the first large half-wave of the current during the transient occurrence after current begins to flow which a switching device withstands in the closed position under specified conditions.

Breaking current. Current is one pole of a circuit-breaker at the instant the arc occurs during an opening operation.

Making capacity. The value of the maximum prospective peak current which at a given voltage a circuit-breaker can interrupt under specified conditions; for load switches the value of the prospective service current.

Short-line fault. A short circuit on an overhead line at a short, not negligible distance from the terminals of the circuit-breaker.

Switching capacity (Making or breaking) under asynchronous condition. Making or breaking capacity when synchronism is lost or absent between the network sections before and after the circuit-breaker under specified conditions.

Normal current. The current that the main current path of a switching device can carry continuously under specified conditions. For standardized rated normal currents, see below.

Short-time current. The rms value of the current which a switching device in the closed position can carry for a specified short time under specified conditions. For standardized rated short-time currents. see below.

Rated voltage. The maximum voltage of a network for which a switching device is designed. For standardized rated voltages, see below.

Applied voltage. The voltage between the terminals of a circuit-breaker immediately before making of the current.

Recovery voltage. The voltage occuring between the terminals of a circuit-breaker after the current is interrupted.

Opening time. The time interval between the beginning of the opening time of a circuit-breaker and the end of the arcing time.

Closing time. The time interval between commencement of the closing movement and the instant at which current begins to flow in the main current path.

Rated value. The value of a characteristic quantity used to define the operating conditions for which a switching device is designed and built, and which the manufacturer must guarantee.

Withstand value. The maximum value of a characteristic quantity that a switching device will tolerate with no impairment of function. The withstand value must be at least equal to the rated value.

Standard value. A value defined in official specifications on which the design of a device is to be based.

Standardized rated voltages. 3.6, 7.2, 12, 17.5, 24, 36, 52, 72.5, 100, 123, 145, 170, 245, 300, 362, 420, 525, 765 kV.

Standardized rated normal currents. 200, 400, 630, 800, 1250, 1600, 2000, 2500, 3150, 4000, 5000, 6300 A.

Standardized rated short-time currents. 8, 10, 12.5, 16, 20, 25, 31.5, 40, 50, 63, 80, 100 kA.

Rated power-frequency withstand voltage. The value of the power-frequency voltage which the insulation of a device must withstand for a time of 1 minute.

Rated lightning impulse withstand voltage. The value of the unipolar standard 1.2/50 μs impulse voltage which the insulation of a device must withstand.

Rated switching impulse withstand voltage. The value of the unipolar standard 250/2500 μs switching impulse voltage which the insulation of a device with a rated voltage of 300 kV and above must withstand.

NOTE :

1. Under the new standards, the isolating distances of disconnectors for rated voltages of 300 kV and above are tested by applying the power-frequency voltage to one terminal and, when the peak value is reached, applying to the other terminal the reversed-polarity lightning or switching impulse voltage. This bipolar test is called the bias test.

   Table 10-1 below lists the dielectric values for disconnectors, switches, earthing switches and circuit-breakers for the respective rated voltages. In the case of circuit breakers, tests are conducted across the contact stroke in the open position with the voltages in columns 2, 4 and 6.
2. Up to 72.5 kV one can choose between list 1 (which covers equipment in networks and industrial installations not connected to overhead lines, or through transformers) or list 2 (in all other cases or if increased security is required).

   At the higher voltages the related values are selected from the same line.

Table 58-1

Standardized* values for disconnectors, load switches, circuit-breakers and earthing switches.

Rated voltage (rms value)	*Rated power-frequency withstand voltage 50 Hz / 1 min (rms value)*		*Rated lightning impulse withstand voltage 1.2 / 50 μs (peak value)*	
	To earth	*Across isolating distance*	*To earth*	*Across isolating distance*
(kV)	*(kV)*	*(kV)*	*(kV)*	*(kV)*
1	*2*	*3*	*4*	*5*
—	—	—	List 1 List 2	List 1 List 2
3.6	10	12	20 — 40	23 — 46
7.2	20	23	40 — 60	46 — 70
12	28	32	60 — 75	70 — 85
17.5	38	45	75 — 95	85 — 110
24	50	60	95 — 125	110 — 145
36	70	80	145 — 170	165 — 195
52	95	110	250 — 250	290 — 290
72.5	140	160	325 — 325	375 — 375

* Minor variations in various standards exist.

Table 58-1 (Continued Figures in brackets are peak values of the power-frequency voltage applied to the opposite terminal.

Rated voltage (rms value)	*Rated power-frequency withstand voltage 50 Hz / 1 min (rms value)*		*Rated lightning impulse withstand voltage 1.2 / 50 μs (peak value)*		*Rated switching impulse withstand voltage 250 / 2500 μs (peak value)*		
	To earth	*Across isolating distance*	*To earth*	*Across isolating distance*	*To earth*	*Across isolating distance Class A*	*Class B*
(kV)	*(kV)*	*(kV)*	*(kV)*	*(kV)*	*(kV)*	*(kV)*	*(kV)*
1	*2*	*3*	*4*	*5*	*6*	*7*	*8*
100	150	175	380	440	—	—	—
	185	210	450	520			
123	185	210	450	520			
	230	265	550	630			
145	230	265	550	630			
	275	315	650	750			
170	275	315	650	750			
	325	375	750	860			
245	360	415	850	950			
	395	460	950	1050			
	460	530	1050	1200			
300	380	435	950	950 (+170)	750	850	700 (+ 245)
			1050	1050 (+170)	850		
362	450	520	1050	1050 (+205)	850	950	800 (+295)
			1175	1175 (+205)	950		
420	520	610	1300	1300 (+240)	950	1050	900 (+345)
			1425	1425 (+240)	1050		
525	620	760	1425	1425 (+300)	1050	1175	900 (+430)
			1550	1550 (+300)	1175		
765	830	1100	1800	1800 (+435)	1300	1550	1100 (+625)
			2100	2100 (+435)	1425		

58.7. DISCONNECTORS AND EARTH SWITCHES

Various types of disconnectors/isolators are :

1. Rotary disconnectors.

(a) Two-column rotary disconnectors. These are general-purpose disconnectors for voltages from 72.5 to 420 kV, used mainly in small substations or larger switchyards as incoming-feeder or sectionalizing disconnectors. Earthing switches can be mounted on either side.

As can be seen in Fig. 58.15, the two rotating bases are mounted on a sectional-steel frame and linked by a braced tie-rod. The post insulators are attached to the rotating bases and at the top carry the swivel heads with their arms and high-voltage contacts. When actuated, both arms turn through 90 degrees. In the open position, two-column centre-break disconnectors create a horizontal isolating distance.

The rotating bases are weather-proofed and are provided with roller bearings. The insulators are mounted on stay bolts which allow precise adjustment of the contact system once the lines are rigged, and also take care of the insulator tolerances.

The swivel arms are of welded aluminium construction with non-corroding contact pieces, so minimizing any long-term change in resistance. An interlocking device (pawl and pin) prevents the arms from separating in the event of high short-circuit currents. Current transfer to the rotating heads, which are fully protected and need no maintenance, is by way of contact fingers arranged in tulip shape round two contact pins or, for service currents > 2500 A, via tapered roller contacts. The high-voltage terminals can turn through 360 degrees, enabling the tube or wire runs to be connected in any direction. The contact system is a composite copper/steel construction with separately sprung contact fingers (none of them exposed), it has permanent dry lubrication, and thus needs minimum maintenance.

Both disconnector and earthing switch have an operating mechanism with a deadcentre interlock. This prevents them from changing service position under extreme circumstances such as short circuits, earthquakes or high winds.

Disconnector and earthing switch have separate operating mechanisms. One mechanism operates the two- or three-pole group, the individual poles of a group being mechanically linked by a connecting rod.

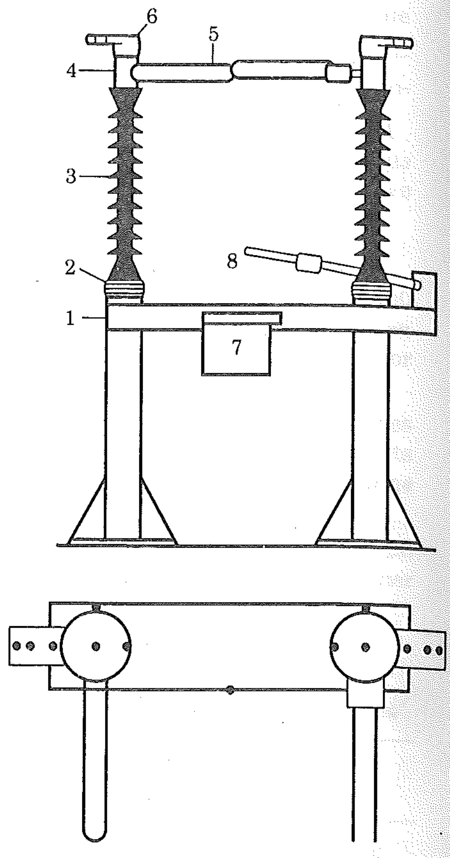


Fig. 58.15. Two-column rotary disconnector type SEF 123 kV. 1 Rotating base, 2 Frame, 3 Insulator, 4 Rotating head, 5 Swivel arm, 6 High-voltage terminal, 7 Actuator, 8 Earthing switch

The actuating force from the drive is transmitted to one rotating base, and turns it through 90 degree; at the same time the tie-rod rotates the second base. When opening and closing, the contacts of the disconnector both rotate and execute a sliding movement, so easily break even severe icing.

The force of the operating mechanism is passed to the shaft of the earthing switch. When the disconnector closes, the arm of the earthing switch swings up and engages the earthing contact on the swivel arm.

(*b*) *Three-column rotary disconnectors*. These disconnectors are used usually for lower voltages. Compared with two-column disconnectors they allow smaller distances between phases and higher static terminal pull.

The two outer insulators are fixed to the baseframe and carry the contact system (Fig. 58.16). The middle insulator stands on a rotating base and supports the one-piece arm which, when operated, turns through about 60 degrees and engages the contact systems on the outer insulators.

The contacts for the earthing switches, which can be mounted on either side, are located at the fixed contact system.

2. Single-column (pantograph) disconnectors. In installations for higher voltages and multiple busbars, the single-column disconnector (also pantograph or vertical-reach disconnector) shown in Fig. 58.17 are provided. These require, less ground area than other kinds of disconnector. It is widely used for this reason and because of the clear station layout.

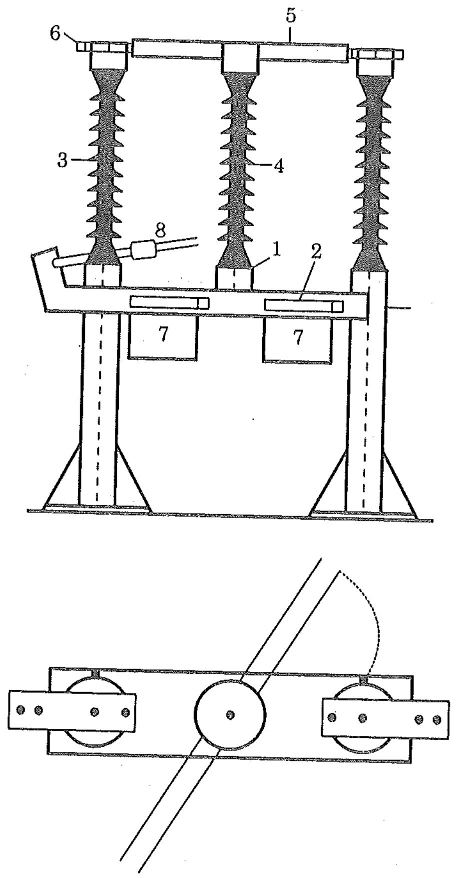


Fig. 58.16. Three-column rotary disconnector type TDA, 145 kV, 1. Swivel base, 2 Frame, 3 Fixed insulator, 4 Rotating insulator, 5 Contact arm, 6 High-voltage terminal, 7 Operating mechanisms, 8 Earthing switch.

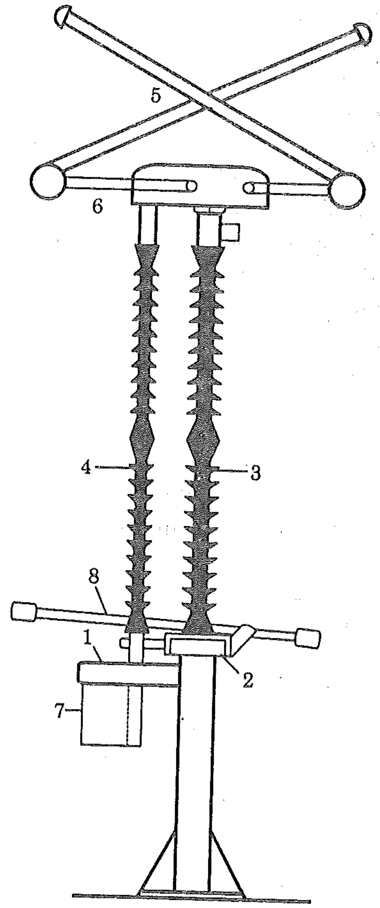


Fig. 58.17. Single-column insolator 245 kV. 1 Rotary bearing, 2 Frame, 3 Post insulator, 4 Rotating insulator, 5 Pantograph, 6 Gearbox, 7 Operating mechanism, 8 Earthing switch, 9 Suspended contact.

The base of the disconnector is the frame on which is installed the post insulator carrying the head piece with the pantograph and gearbox. The actuating force is transmitted to the gearbox by a rotating insulator. The suspended contact is mounted on the busbar situated above the disconnector. On closing it is gripped between the pantograph arms. The feeder line is connected to the high voltage terminals on the gearbox.

If desired, each disconnector pole can be equipped with a rotary/linear earthing switch as described under single column earthing switch.

The frame with its attached rotary bearing for transmitting the actuating force from the operating mechanism to the gearbox is fastened to the support by four stay bolts. These allow exact adjustment of the disconnector relative to the suspended contact, an advantage when installing and servicing. Any slight discrepancies in the foundation heights can be compensated by adjusting the stay bolts.

The pantograph assembly is a welded aluminium construction (the same for all types up to peak currents of 200 kA) which is fixed and pinned to the pantograph shaft in the gearbox. This unit is thus unable to shift. It also ensures consistently high contact pressure between the upper ends of the pantograph arms and the stirrup contact. The contact pressure of 70-150 kp (according to design) not only guarantees efficient current transfer, but also helps to break even severe icing. Contact between the gearbox and the pantograph arms and also from the lower to the upper arms is provided by flexible, multi-layer links of silver-coated copper strip or tapered roller contacts.

The contact bars at the top of the arms and also the suspended contact are of silver-plated copper, or with an inlay of high-purity silver for heavy duty or special cases. Contact erosion is therefore slight, ensuring good current transfer and long servicing intervals.

Disconnectors for high short-circuit currents have a damping device between the arm joints. In the closed position these limit the distance between the two arms to prevent any reduction in contact pressure and damping any vibration of the contact arms caused by a short-circuit current.

Single-column disconnectors have a dead-centre interlock in the gearbox, so that their position does not alter spontaneously. The setting is retained even if the rotating insulator breaks or extreme vibration due to earthquakes or short-circuit forces occurs. Anti-corona fittings at the tips of the arms act as a stop for the suspended contact if it moves vertically. The stirrup remains firmly held in the contact zone even when subject to high tensile forces due to a short circuit.

The assembly comprising pantograph and gearbox is mechanically set in the factory, greatly reducing on-site erection time.

A compensating spring in the gearbox assists the actuating force on closing, while on opening it returns the arms to the folded position.

Special versions of the single-column disconnector have been in use for many years in high-voltage direct-current (HVDC) installations.

Each disconnector pole has its own operating mechanism.

When the disconnector closes the pantograph arms execute a wide catching movement and so are sure to engage the suspended contact. The forces acting on one point and the high contact pressure together ensure reliable current transfer and can also overcome severe icing. The anti-corona fittings at the ends of the pantograph arms prevent the stirrup contact from slipping out of their grip.

Special Technical Consideration. In outdoor switching stations, a change of busbars without interruption of current supply gives rise to commutation currents during the switching operation, and these can cause increased burning at the disconnector contacts and at the fixed contact. How high these currents are depends on the distance of the switching location from the infeed or the manner of changeover, i.e., busbar or switching bay, the latter producing the higher stress.

Commutation phenomena occur both on closing and opening. Closing gives rise to bouncing between disconnector arms and stirrup contact which result in little arcing and hence slight contact wear. On opening, however, an arc is drawn between the separating arm contacts and this persists until the inverse voltage needed to extinguish the arc has been generated. Since at first the contacts move slowly this can take several cycles, severely damaging the disconnector contact elements. High-power 420 kV switchyards can experience commutation voltages up to 300 V and commutation currents up to 1600 A.

The suspended commutating contact developed by some manufacturers for single-column disconnector has two enclosed auxiliary switching systems which act independently of each other. This ensures proper operation every time, regardless of which pantograph arm is first to touch or last to leave the suspended contact. The principal components are shown in Figs. 58.18 (*a*) and (*b*). The auxiliary switch system is contained in an anti-corona hood and consists esssentially of a snap contact (coupled to the auxiliary contact bar by a toggle lever) and a deion arc-quenching device. The snap contact opens and closes regardless of switching speed when the auxiliary contact bar is in a particular position.

Since on opening th arc duration lasts only about 25 ms, wear on the snap contact system is slight and the current is safely interrupted before separation of the disconnector contact bar. By separating the main and auxiliary contact systems, no forces are exerted on the latter in the event of a fault. Short-circuit testing has demonstrated an impulse withstand strength of 200 kA. Each

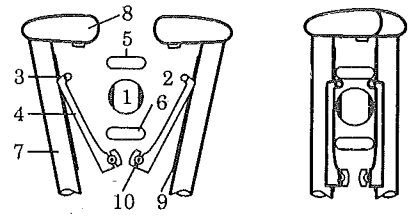


Fig. 58.18. (*a*) Commutating suspended contact, operating principle of guide strips, 1 Main contact support, 2 Main contact bar, 3 Auxiliary contact bar, 4 Toggle lever, 5 Upper guide strip, 6 Lower guide strip, 7 Pantograph arm, 8 Catch device, 9 Pantograph contact piece, 10 Insulated pivot with resetting spring.

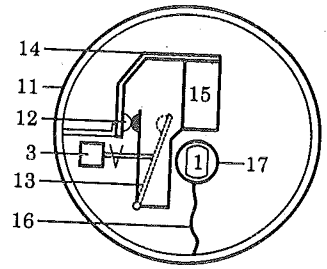


Fig. 58.18 (*b*). Commutating suspended contact, schematic of auxiliary switching chamber, 1 Main contact support, 3 auxiliary contact bar, 11 Anti-corona hood, 12 Fixed contact, 13 Snap contact, 14 Arc-deflecting baffle, 15 Deion arc-quenching plates, 16 Flexible bonding connection, 17 Rotary bearing

switching system can perform at least 350 switching cycles with commutation currents of up to 1600 A and commutation voltages up to 330 V.

Installing commutating suspended contacts thus provides the system operator with flexibility and reliability. Also these contacts can be fitted to upgrade existing installations.

3. Two-column vertical centre-break disconnectors. Higher voltages mean large isolating distances & thus long contact arms. The vertical centre-break disconnector with two-piece contact arms for voltages ≥ 400 kV is a better choice in case of space constraints.

As shown in Fig. 58.19, the two post insulator-column are mounted on a frame, Attached to them are the gearboxes with the contact arms and the high-voltage terminal Rotating insulators link the rotary bearings in the frame to the top bearings in the gearboxes. Below the frame centre, the operating mechanism is provided, the force of which is transmitted to the two rotary bearings by tie-rods.

Either side of the disconnector can be fitted as required with a rotary-linear earthing switch. The earthing contacts are mounted on a holder between the post insulator and the gearbox.

Advantages & other Technical features : The vertical centre-break disconnector requires less force to operate than types with one-piece contact arms. The strain substation portals need not be so high and

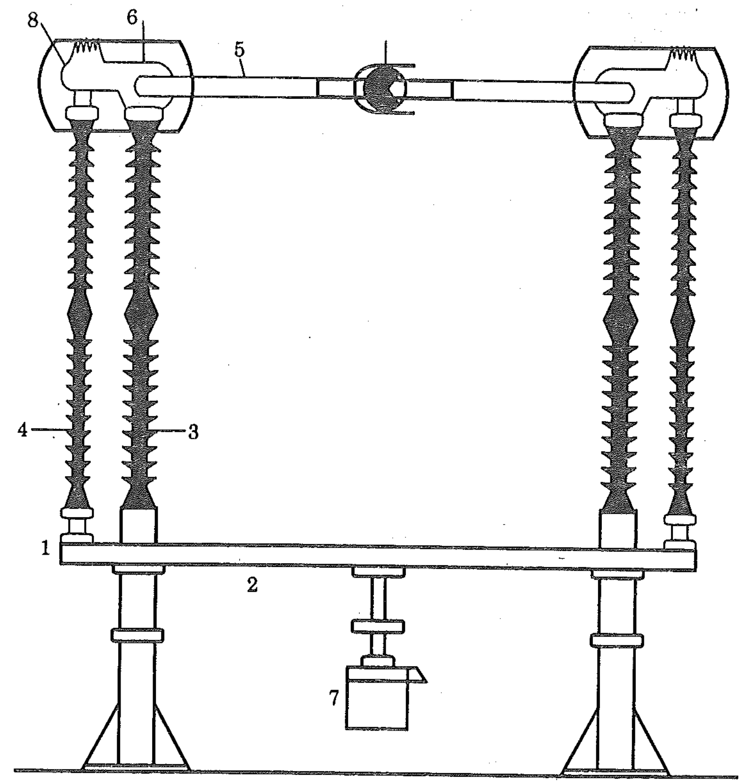


Fig. 58.19. Vertical centre-break disconnector for HV. 1 Rotary bearing, 2 Frame, 3 Post insulator, 4 Rotary insulator, 5 Contact arm, 6 High-voltage terminal, 7 Operating mechanism, 8 Gearbox.

so the fundation costs are lower. The mechanical construction of the disconnector is simple because the current arms rotate only in a vertical plane without additional rotary movement to achieve the necessary contact pressure.

Like the other kinds of disconnector, the post insulators stand on stay bolts which, after the lines are rigged, allow precise adjustment of the contact arms and compensation for insulator tolerances. The rotary insulators have universal bearings at the gearbox end, and tramsmit the actuating force without distortion. Gearbox and contact half-arm form a mechanical assembly unit.

The contact arms are made up of components from the range of two-column rotary disconnectors, a welded aluminium construction with only a few bolted joints. Tapered roller contacts transfer the current in the weatherproof, cast aluminium gearbox. Dry, permanent (and maintenance-free) lubrication is used for the separately sprung, copper/steel composite contact fingers. Low contact pressures also reduce wear at the contact points. An interlocking device prevents the contact arms from separating in response to high short-circuit currents and ensures trouble-free operation even under extreme conditions.

Diagonal tie-rods transmit the actuating force from the operating mechanism to the two bottom bearings and via rotary insulators to the bearings in the gearboxes. The diagonal tie-rods and the actuating rods at the gearbox pass through a dead-centre point shortly before reaching the open position, and block the current arms in this position. Each contact arm rotates vertically through 90 degrees. In the open position they point vertically upwards, creating a horizontal isolating distance.

4. Single-column earthing switch. In outdoor switchyards earthing switches are required not only directly at the disconnectors but also at other positions, e.g., for earthing individual busbar sections. The single-column earthing switches employed for this duty can also be used as supports for tubular busbars.

Earthing switches for mounting on disconnectors or separately on a single column have the same components. The only exceptions are the frame and support for the earthing contact.

A baseframe containing the operating mechanism supports the insulator (Fig. 58.20), to which are attached the contact holder and the earthing contact.

Two types of such switches are manufactured are available, to meet different requirements : (a) vertical-reach earthing switches for low rated voltages and peak currents, (b) rotary/linear earthing switches for higher voltages and peak currents. The differences lie in the design of the operating mechanism, and hence in the movement executed by the contact arm.

The contact arm of the vertical-reach earthing switch is able to swivel on a shaft and executes only a rotary movement with an angle of about 90 degree. In the closed position the earthing contact lies between the contact fingers, and these in turn against a spring stop. The mechanics of the rotary/linear earthing switch allow increased performance: the contact arm at first rotates, but towards the end of this rotation moves in a straight line into the earthing contact. The contact blade mounted on the contact arm is thus fixed in the earthing contact, making a joint which can withstand high peak currents.

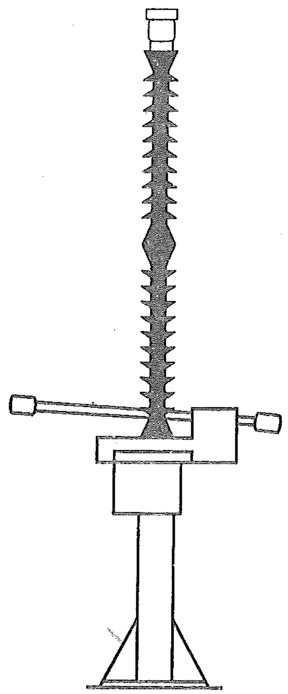


Fig. 58.20. High-voltage single-column earthing switch 420 kV

Disconnectors and earthing switches can be actuated by motor-driven, compressed-air or manual operating mechanisms. Air-powered mechanisms are now used only where a source of compressed air is already available. Motorized systems are usually simpler and less costly to install and connect.

The operating mechanism is generally mounted direct on the baseframe of the disconnector or earthing switch. However, disconnector situated well of the ground, e.g., on a portal, can also have the operating mechanism positioned within reach. The actuator unit then requires a bearing and additional like rods. Emergency manual operation is possible with all operating mechanisms if the power source should fail, or for making adjustments.

The operating mechanisms also incorporate annunciator switches for indicating the switching position and for control and interlock purposes: motor-driven units also include contactors and control devices. The control system is arranged so that only one switching pulse is needed and the actuators switch off automatically when the end-position is reached. In the event of emergency manual operation a safety contact interrupts the motor circuit so that simultaneous actuation from the control room is not possible. Motor-driven systems can also be equipped for local and remote control.

To prevent maloperation the operating mechanisms of disconnectors and earthing switches can be interlocked relative to each other: motorized systems electrically, compressed-air systems electro-pneumatically and manual systems mechanically. Manual and motorized systems can also be equipped with a locking solenoid which when the interlock voltage is dead prevents actuation by hand. Local operation is then possible only if the interlock voltage is present and the specified interlocking conditions are satisified. For instance, a disconnector can only be closed or opened if its related circuit-breaker is open. Various kinds of key-operated interlocks are also fitted.

The actuating systems of disconnectors and earthing switches have a dead-centre interlock so that the switching position cannot change spontaneously under extreme conditions such as short circuit, earthquakes or hurricane.

5. Load switches. High-voltage load switches are mechanical switching devices which are able to make carry and break the currents - which may also include a specified operating overload-occurring in the network under normal conditions, and also to carry currents under specified abnormal system conditions, e.g., short circuits, for a certain time. A load switch may also be able to close on short-circuit currents, but not interrupt them.

Load switches are designed for both indoor and outdoor installation. According to their switching function or application, these switches are classified as :

— general-purpose switches — transformer off-load switches

— single-capacitor-bank switches

Also used are switch-disconnectors with a visible isolating distance in the open position.

Load switches are increasingly being used in gas insulated switchgear installations.

58.7.1. Circuit Breakers Function

High-voltage circuit-breakers are mechanical switching devices able to make, continuously carry and interrupt currents under normal circuit conditions and also for a limited time under abnormal circuit conditions e.g. short circuits. Circuit-breakers are used for switching overhead lines, cable branches, transformers, reactors and capacitors. They are also used in bus and section-ties in multiple-busbar installations so that power can be transmitted from one bus bar to the other.

Specially designed breakers are used for specific duties such as railways, where in 16 2/3 Hz networks they have to extinguish longer-burning arcs, (longer half-wave).

Breakers for use with melting furnaces operate frequently and so require smaller actuating forces and lower breaking capacity. They therefore experience less wear, despite the high switching rate, and so servicing intervals are long.

(*b*) **Selection.** The principal points to consider when selecting circuit-breakers are :

— maximum operating voltage at location

— height of installation above sea level

— maximum operating current occurring at location

— maximum short-circuit current occurring at location

— system frequency

— duration of short-circuit current

— switching cycle

— particualr operational and climatic conditions (*c*) **Selection.** Rated values can be selected with the aid of Tables 10-1 and 10-2.

(*d*) **Reference standards.** Important national and international standards for circuit breakers are :

IEC	VDE
56-1	0670 Part 100/2.78 General and definitions
56-2	0670 Part 102/2.82 Classification
56-3	0670 Part 103/2.78 Design and construction
56-4	0670 Part 104/11.78 Type and routine testing
56-5	0670 Part 105/3.79 Selection
56-6	0670 Part 106/3.79 Information in enquiries, tenders and orders
56-7	0670 Part 107/7.80 Testing under asynchronous conditions
427	0670 Part 108/5.79 Synthetic testing
	0670 Part 1000/8.84 Common clauses for HV switchgear and controlgear

ANSI (American National Standards Institution)

C 37.04	— 1979 Rating structure
C 37.06	— 1979 Preferred ratings
C 37.09	— 1979 Test procedure
C 37.010	— 1979 Application guide
C 37.011	— 1979 Application guide for transient recovery voltage
C 37.012	— 1979 Capacitance current switching
C 37.11	— 1979 Requirements for electrical control

Table 1.
Table for coordinating rated values of circuit-breakers to DIN VDE 0670 Part 102, IEC 56-2

Rated voltage	*Rated short-circuit breaking current*	*Rated operating current*				
kV	*kA*	*A*				
123	12.5	800	1250			
	20		1250	1600	2000	
	25		1250	1600	2000	
	40			1600	2000	
145	12.5	800	1250			
	20		1250	1600	2000	
	25		1250	1600	2000	
	31.5		1250	1600	2000	3150
	40			1600	2000	3150
	50				2000	3150
170	12.5	800	1250			
	20		1250	1600	2000	
	31.5		1250	1600	2000	3150
	40			1600	2000	3150
	50			1600	2000	3150
245	20		1250	1600	2000	
	31.5		1250	1600	2000	
	40			1600	2000	3150
	50				2000	3150

Rated voltage	*Rated short-circuit breaking current*	*Rated operating current*				
kV	*kA*	*A*				
300	16	1250	1600			
	20	1250	1600	2000		
	31.5	1250	1600	2000	3150	
	50		1600	2000	3150	
362	20			2000		
	31.5			2000		
	40		1600	2000	3150	
420	20		1600	2000		
	31.5		1600	2000		
	40		1600	2000	3150	
	50			2000	3150	4000
525	40			2000	3150	
765	40			2000	3150	

Table for coordinating rated values of circuit-breakers to ANSI C 37.06.1979

Rated voltage	*Maximum rated voltage*	*Rated short-circuit breaking current*	*Rated operating current*			
kV	*kV*	*kA*	*A*			
34	38	22	1200			
69	72.5	37				
115	121	20	1200		2000	
		40		1600	2000	3000
		63				3000
138	145	20	1200			
		40		1600	2000	3000
		63			2000	3000
		80				3000
161	169	16	1200			
		31.5		1600		
		40			2000	
		50			2000	
230	245	31.5		1600	2000	3000
		40			2000	3000
		63				3000
345	362	40			2000	3000
500	550	40			2000	3000
700	765	40			2000	3000

(*e*) **Design.** The main subassemblies of HVCB include : operating mechanism, insulators, extinction chamber, capacitor and resistor.

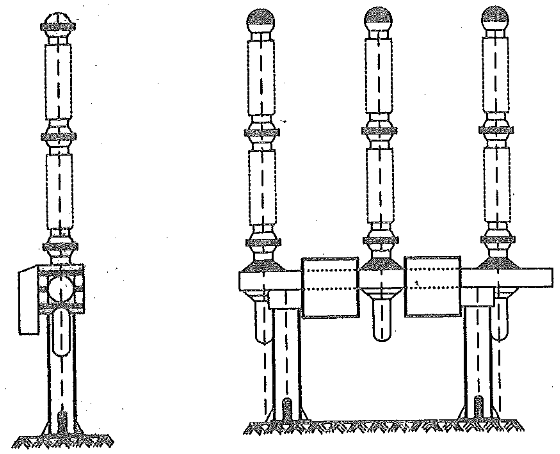
HV circuit-breakers are built on the modular principle. The number of interrupting chambers is increased to cope with higher voltages and capacities.

Single-chamber breakers are used for voltages up to 245 kV and breaking currents of 40 kA. Multiple-chamber breakers are preferred for higher currents within this voltage range.

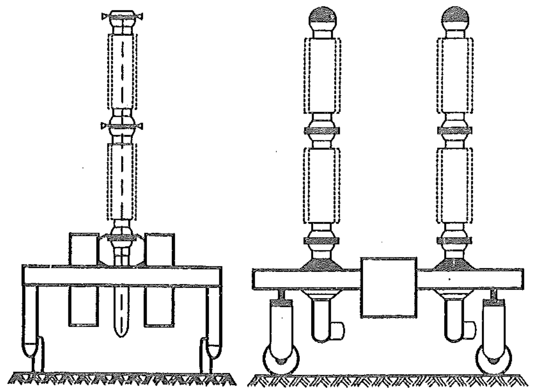
Only multiple-chamber breakers are used for voltages ≥ 245 kV. Up to 525 kV and a breaking current of 50 kA they have two chambers. With higher voltages or capacities the number of chambers can be four or more.

All breakers can be installed as individual poles, each with its own operating mechanism. For the lower voltages and three-phase auto-reclosure the 3 poles are best mounted on a common frame. HV circuit-breakers can also be mounted on trolleys with sprocket-type or plain wheels.

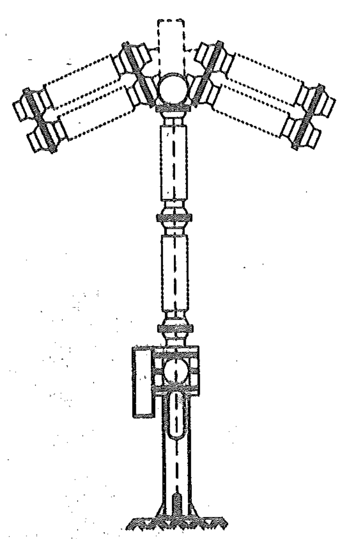
Typical arrangement of various voltage rating breaker is given in Fig. 58.21.



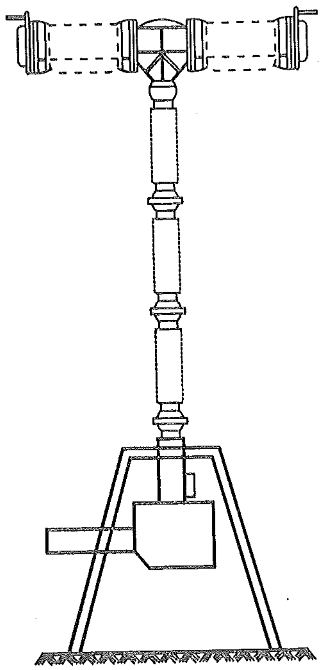
(a) 132 kV Three-pole arrangement



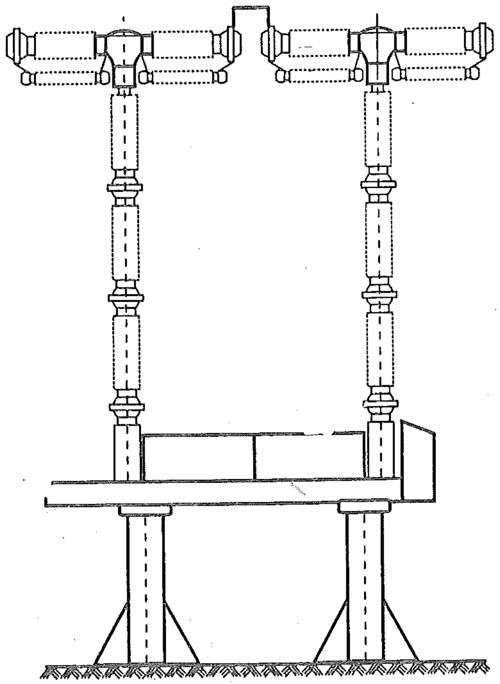
(b) 132 kV two-pole with trolley



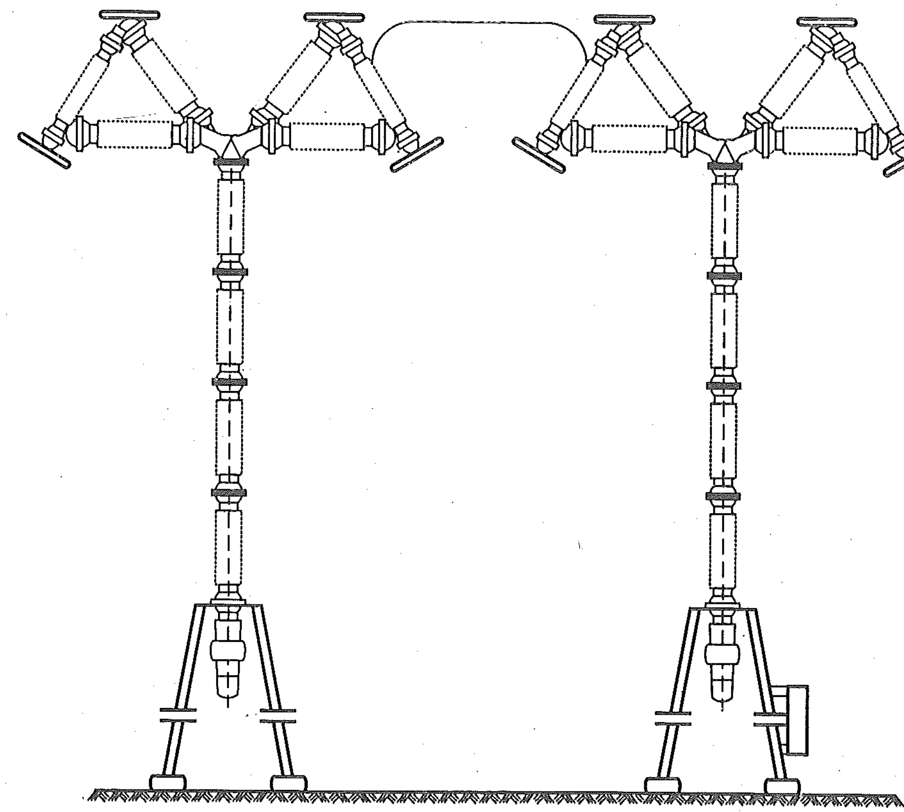
(c) 245 kV Single-pole



(d) 420 kV Two chamber



(e) 420 kV 4-chamber A without Pre-Insertion resistors



(f) 800 kV 4 chamber with closing resistors
Fig. 58.21

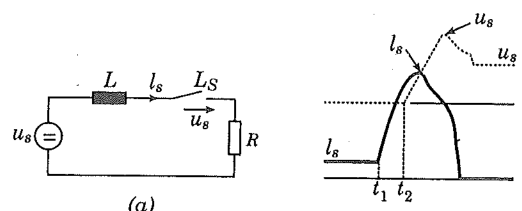
Typical arrangements of Various rating SF6 Outdoor Circuit breaker

Brief Arc extinction process of a cricuit Breaker

The arc-extinction process can take two basic forms.

Direct-current extinction, Fig. 58.22.

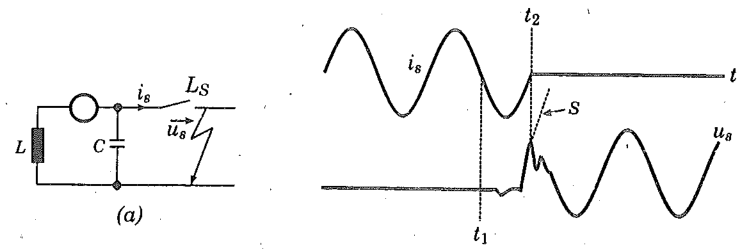
A d.c. arc can be extinguished only when the arc voltage U_s is greater than the voltage present at the breaker LS. A sufficiently high arc voltage can be built up - at reasonable measures — only in low and medium-voltage d.c. circuits (magnetic blowout breakers). To extinguish the d.c. arc in d.c. high-voltage circuits the voltage must be lowered accordingly and/or artificial current zeroes must be created by inserting a resonant circuit.



(a) (b)

Fig. 58.22 Direct-current extinction, (a) simplified equivalent circuit, (b) curves of current I_s and arc voltage U_s, t_1 initiation of short-circuit, t_2 contact separation

Alternating-current extinction, Fig. 58.23 a.c. arcs are extinguished at each current zero. In high-voltage circuits, and without extra measures the arc re-ignites after passing current



(a)

Fig. 58.23 Alternating-current extinction, (a) simplified equivalent circuit, (b) curves of short-circuit current i_s and recovery voltage U_s, t_1 contact separation, t_2 arc extinction, S rate of rise of recovery voltage zero, and so continues to burn. In high-voltage breakers, the arc plasma is intensively cooled in the extinction chambers thus reducing its electrical conductivity at current zero so the recovery voltage is insufficient for re-striking.

Voltage stresses on the breaker. While Interrupting different types of loads :

(*a*) On interrupting an inductive load (Fig. 58.24 a) the breaker voltage oscillates to the peak value of the recovery voltage. The breaker must be able to cope with the recovery voltage's rate of rise and its peak value. The dielectric strength between the arcing contacts must built up faster than the recovery voltage rises, if re-striking is to be prevented.

(*b*) When interrupting a purely resistive load (Fig. 58.24 b) current zero and voltage zero coincide. The recovery voltage at the breaker rises sinusoidally with the service frequency. The gap between the contacts has sufficient time to recover.

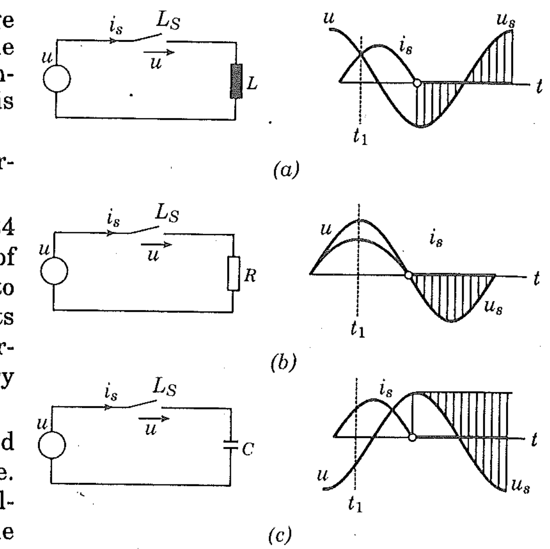


Fig. 58.24. Recovery voltage U_s when interrupting (*a*) inductive load, (*b*) resistive load, (*c*) capacitive load

(*c*) When switching a capacitive load (Fig. 58.24 c) following interruption of the current the supply-side voltage (infeed C.B. terminal) oscillates at system frequency between ± μ, while the breaker terminal on the capacitor side remains charged at + μ.

Different Switching Conditions for which breaker has to be designed/developed. Depending on their location, circuit-breakers have to cope with a variety of conditions which in turn impose different requirements on the breaker. *e.g.*

(*i*) **Terminal fault (symmetrical short-circuit current).** Fig. 58.25. A terminal fault is a short circuit on the consumer side of a breaker in the immediate vicinity of the breaker terminals. The short-circuit current is symmetrical if the fault takes place at the voltage maximum. The recovery voltage settles to the value of the driving voltage. Rate of rise and amplitude of the transient voltage are determined by the network parameters.

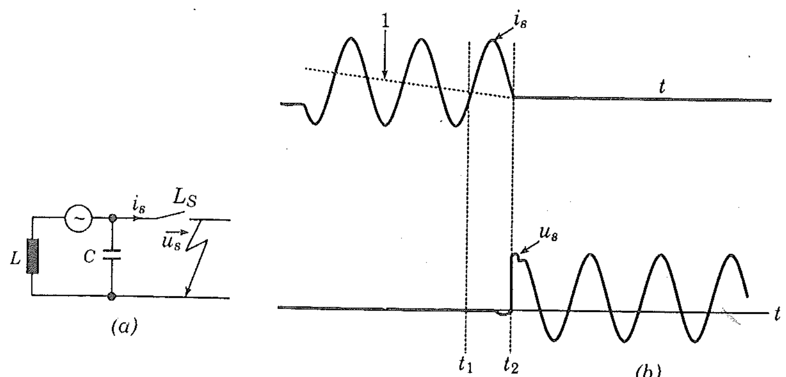


Fig. 58.25. Terminal fault, (*a*) simplified equivalent circuit, (*b*) curves of recovery voltage U_s and short-circuit

(*ii*) **Terminal fault (asymmetrical short-circuit current).** In addition to the symmetrical short-circuit current, a d.c. component also has to be interrupted, its magnitude depending on the breaker's mechanical opening time. The d.c. component of the short-circuit current depends on the moment of short circuit initiation (max. at voltage zero) and on the time constants of the network's supply-side components such as generators, transformers, cables and h.v. lines.

(*iii*) **Short-line fault, Fig. 58.26.** Short-line faults are short circuits that occur on overhead lines not far (a few kilometres) from the breaker. They impose a particularly severe stress on the breaker because two transient voltages are superimposed: the transient voltage of the feeder network and the transient voltage on the line side. The cumulative effect is a particularly steep rate of rise of voltage, with only a minor reduction in the short-circuit current. The critical distance of the short-circuit depends on current, voltage and arc-quenching medium.

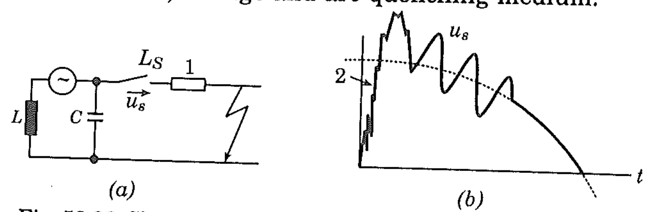


Fig. 58.26. Short-line fault, (*a*) simplified equivalent circuit, (*b*) recovery voltage U_s across breaker, 1 Line, 2 Sawtooth shape of U_s

(*iv*) **Phase opposition.** The (power frequency) voltage stress is severe if the phase-angles of the systems on either side of the breaker are different (system components fall out of step or generator breakers incorrectly synchronized).

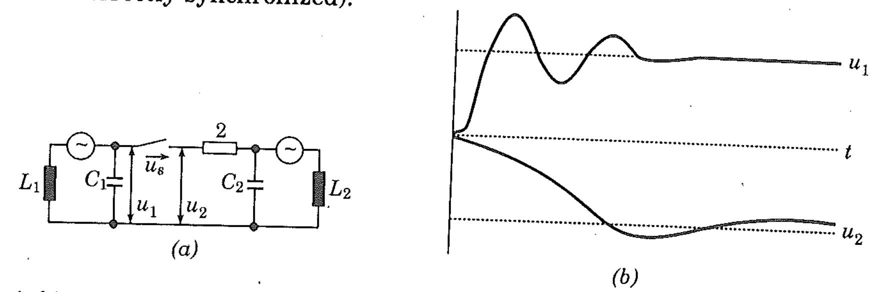


Fig. 58.27 Switching with phase opposition, (*a*) simplified equivalent circuit, (*b*) voltage stress on circuit-breaker

(*v*) **Interruption of small inductive currents, Fig. 58.28.** Depending on network configuration, the interruption of small inductive currents, such as reactors or transformer magnetizing currents, can cause a rapid rise of recovery voltage and also high overvoltages as a result of current chopping (forced extinction) before the natural zero passage.

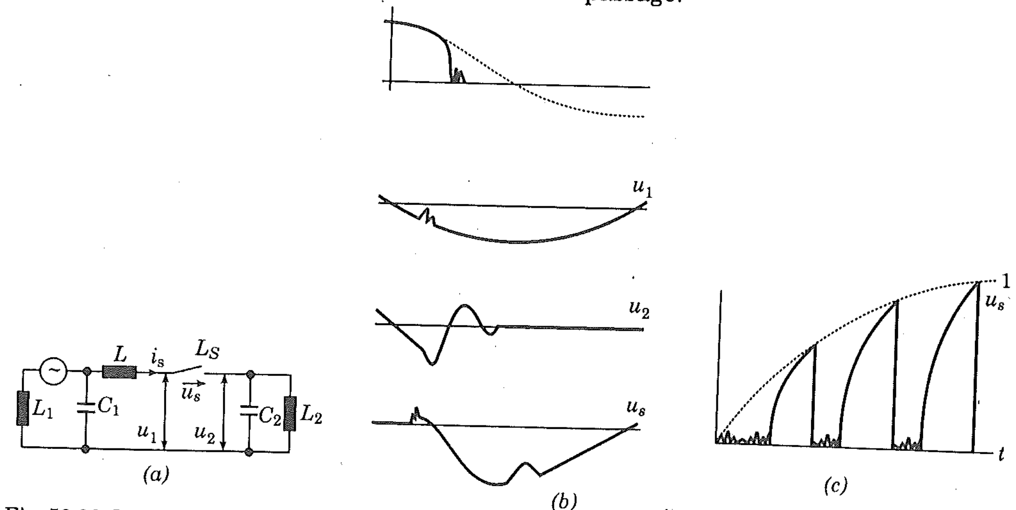


Fig. 58.28. Interruption of small inductive currents, (*a*) simplified equivalent circuit, (*b*) curves of current and voltages with current chopping without re-striking, (*c*) curve of voltage in response to re-striking

(*vi*) **Switching capacitive currents, Fig. 58.29.** This situation imposes no severe stresses, as breakers that prevent re-striking are generally available (Fig. 58.29). Theoretically, however, repeated re-striking can increase the voltage stress to a multiple peak value of the driving voltage.

Switching of open-circuit lines and cables :

The capacitance per unit length of line or cable imposes similar conditions as to the switching of capacitors.

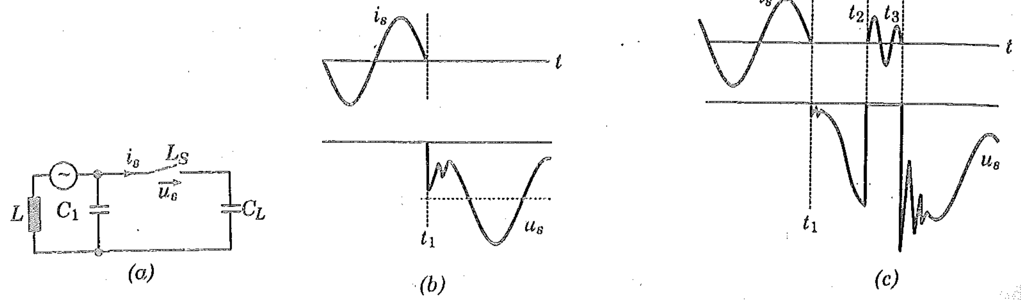


Fig. 58.29. Switching of capacitive currents, (*a*) simplified equivalent circuit, (*b*) curves of current and voltage, (*c*) curves of current and voltage when re-striking occurs

(*vii*) Stresses on contacts when connecting an inductive circuit, see Fig. 58.30.

Closing on inductances and capacitances can produce overvoltages of up to 100%. Circuit-breakers for high voltages and very long lines (approx. 300 km) are therefore fitted with closing resistors.

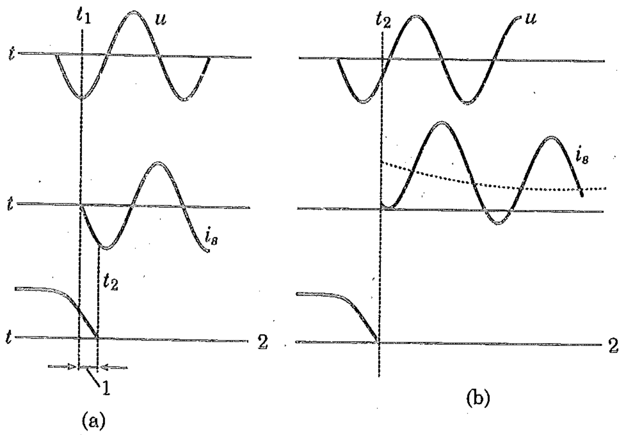


Fig. 58.30. Contact stress when connecting an inductive circuit: (*a*) with pre-arcing (*b*) without pre-arcing

58.7.2. Quenching Medium and Operating Principle for Different Insulating & Quenching Medium

(*i*) SF_6 **gas.** Circuit-breakers using SF_6 gas as the insulating and quenching medium have been operating successfully throughout the world for a number of years. This gas is particularly suitable as a quenching medium because of its high dielectric strength and high thermal conductivity.

Fig. 58.31 shows the design and operating principle of the extinction chamber of a SF_6 circuit-breaker. The extinction unit consists of the fixed contact and the moving contact with its blast cylinder. During the opening movement the volume of the blast cylinder diminishes steadily and hence the pressure of the gas inside it increases until fixed and moving contacts separate. Separation of the contacts causes an arc to be drawn which further raises the pressure of the SF_6 gas in the blast cylinder. When the pressure is high enough the compressed gas is released and blows the arc, so depleting its energy and causing it to extinguish. The nozzle shape of both contacts results in optimum flow and quenching characteristics.

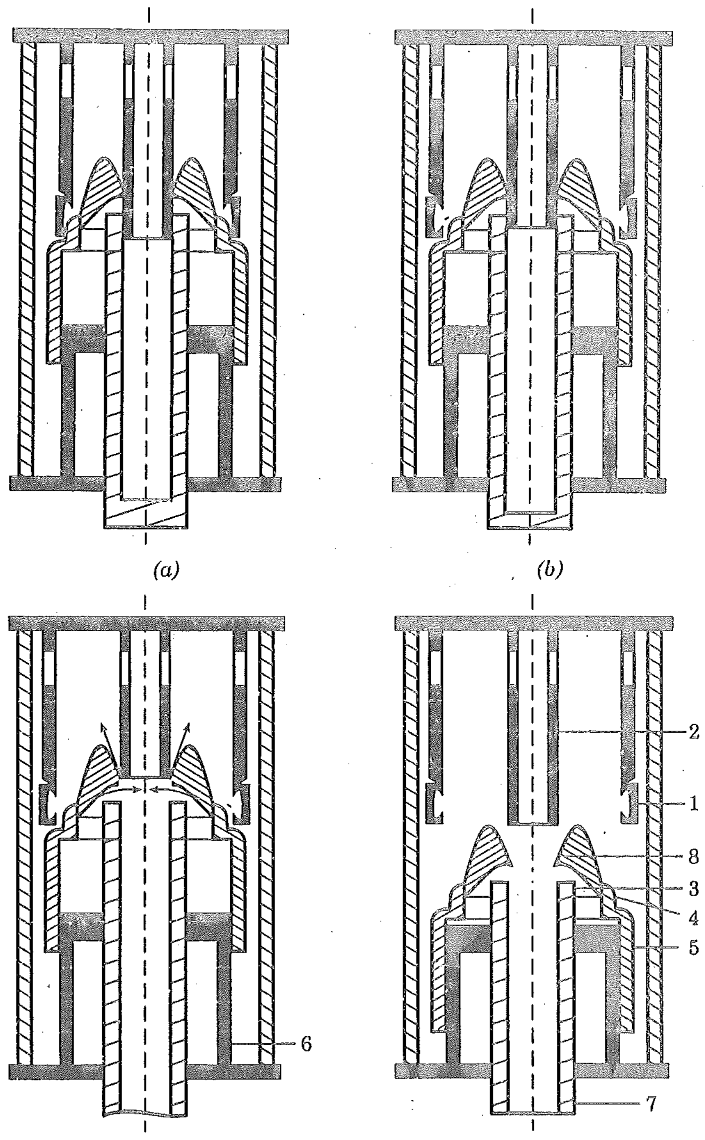


Fig. 58.31. Principle of SF_6 breaker for outdoor installation, 4 positions of opening process, (*a*) closed position, (*b*) opening movement begins, (*c*) arc contacts separate, (*d*) open position.
1 Fixed continuous current contact, 2 Fixed arcing contact, 3 Moving arcing contact,
4 Moving continuous current contact, 5 Compression cylinder, 6 Compression piston,
7 Actuating rod, 8 Quenching nozzle

(*ii*) **Oil.** Up to about 1930 high-voltage breakers were of the bulk-oil type. The oil was used as insulation and to extinguish the arc. The arc heats the oil in its vicinity, so causing it to flow and extinguish the arc. The bulk oil breaker, which contains a large amount of oil, was gradually replaced by the minimum-oil breaker in which the extinction chamber contains a small volume of oil. With these breakers, too, the arc heats the oil and so brings about its own extinction. When switching small currents, quenching of the arc is assisted by a pump effect.

(*iii*) **Compressed air.** Air-blast breakers using compressed air as the quenching, insulating and actuating medium were widespread up to the end of the seventies. Here the quenching medium is held in an air receiver at pressures up to some 30 bar, and inside the breaker. As the contacts separate, compressed air is blown through the nozzle-shape contacts, so quenching the arc and establishing the insulating gap. Air compressor, storage and distribution systems provide air-blast breakers with clean, dry, compressed air.

58.7.3. Different types of Operating mechanisms of HV, CB

(*i*) *Spring-powered operating mechanism.* The spring-operated mechanism is a mechanical system in which energy is stored by a powerful spring. The spring is tensioned with an electric motor and held ready by a latch arrangement. When the breaker trips, a magnet releases the latch and the force of the spring is used to move the contact.

(*ii*) *Hydraulic spring operating mechanism.* The hydraulic spring mechanism is a combination of hydraulic and spring systems. Energy is transmitted by an incompressible medium, usually oil, and stored with the aid of a spring. A pump feeds oil into a high-pressure cylinder in which a piston tensions a strong spring. Solenoid pilot valves allow the oil to pass to the master valve and from here to the actuator cylinder for closing, or to the low-pressure tank for opening. All dynamically stressed seals are between the high and low-pressure volumes. In the event of a leak, therefore, oil can pass only into the low-pressure volume, but not to the outside.

The principle of the hydraulic spring operating mechanism is given in Fig. 58.32.

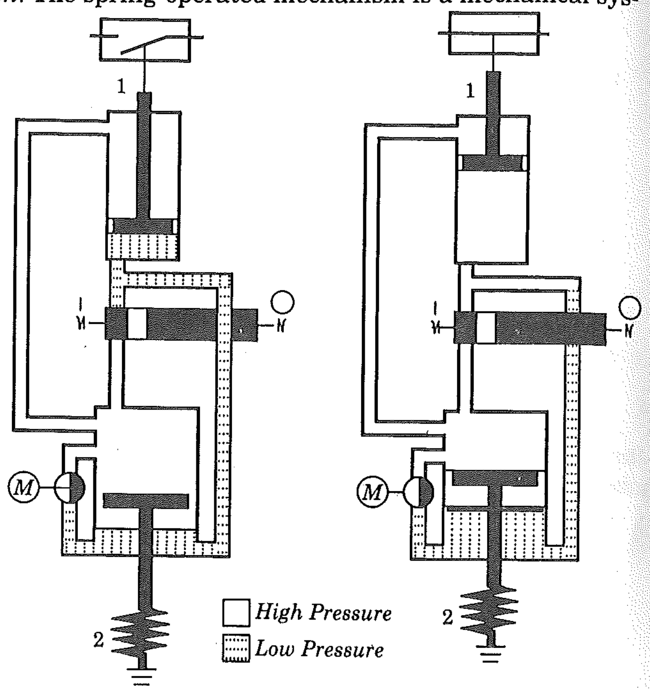


Fig. 58.32 Principle of hydraulic spring operating mechanism, (*a*) OPEN position, (*b*) CLOSED position, 1 Breaker actuating rod. 2 Disc-spring column .

The system works on the differential piston principle. The OPEN (piston rod) side is smaller than the CLOSED (piston face) side by the cross-section area of the piston rod. The piston rod side is permanently under system pressure. The piston face side, on the other hand, is subjected to system pressure on closing, and relieved on opening.

(*iii*) *Pneumatic operating mechanism.* The pneumatic system uses compressed air contained in a receiver directly on the breaker. Solenoid valves allow the compressed air to pass to the actuator cylinder (on closing) or to atmosphere (on opening).

58.7.4. Electrical control of H.V. Circuit breakers

(*a*) *Phase-discrepancy monitoring for breakers with single-pole actuation.* If a TRIP circuit of a breaker pole is disturbed, this pole does not respond to an TRIP command, and the three breaker poles adopt different positions. The phase-discrepancy monitoring system detects this difference and after a preset waiting time of 2 s actuates the joint OPEN operation of all three breaker poles.

Breakers with three-pole auto-reclosure do not need phase-discrepancy supervision because the three poles are mechanically linked and so cannot achieve different positions.

(*b*) *Anti-pumping control.* Anti-pumping control prevents repeated, undesired operation of one or more breakers if an existing OPEN command is followed by repeated CLOSE commands. The breaker must then close no more than once, followed by lock-out, *i.e.* it must stay in the OPEN position, regardless of whether control commands are applied, or for how long.

(*c*) *Non-stop motor operation.* Depending on the system design and the switching cycle performed, the pump or compressor requires a certain time to restore the energy expended. If there is a leak in the pressure system the motor starts more often or runs continuously. Non-stop running is interpreted as a disturbance and signalled.

(*d*) *SF_6 gas monitoring.* The breaking capacity of a circuit-breaker depends on the density of the gas in the breaking chamber, and this is measured with a temperature-compensated pressure gauge. An alarm is given if the gas density falls to a preset value, and if it falls further to a specified minimum the breaker is blocked.

(*e*) *Local/remote control.* To allow work to be done on the breaker, it can usually be controlled from the local cubicle; control can be set from remote to local by means of a selector-switch.

(*f*) *Pressure monitoring.* Control and supervision of pressure is required particularly with pneumatic and hydraulic operating mechanisms that use nitrogen to store energy. A multipole pressure switch performs the following functions:

— close replenishment valve, *i.e.* stop pump or compressor
— open replenishment valve, *i.e.* start pump or compressor
— interlock auto-reclosure if pressure is insufficient
— interlock CLOSE operation, prevents breaker closing if it then cannot open because pressure is insufficient
— interlock OPEN operation, prevent breaker opening if pressure is insufficient

Hydromechanical operating mechanisms are controlled by means of a gate system. These mechanisms depend not on pressure, but on travel.

(*g*) *Auto-reclosure.* Single or three-pole auto-reclosure is selected according to the kind of system earth, the extent of network interconnection, the length of the lines and the amount of infeed from large power plants. Tripping commands from the network protection system (overcurrent and line protection) are accordingly evaluated differently for the respective circuit breakers.

In circuit breakers for single-phase auto-reclosure each pole has a separately controlled operating mechanism. Any pole can thus be tripped independently. However, all three poles close together, and the auxiliary power system for the three poles is supplied from a single unit. The clearance of transient faults can then be limited in time and location, without taking out larger parts of the network. Single-phase tripping improves system stability; the network remains in synchronism. The three poles of breakers with single-phase auto-reclosure can also be controlled so that they open and close together.

Circuit-breakers for three-phase auto-reclosure have a single actuator cylinder for all three poles. The three poles are mechanically linked to each other and to the operating mechanism. They can therefore only be closed and opened all together. In stable networks (where loss of synchronism is unlikely) breakers with three-phase auto-reclosure shorten possible outage times.

58.7.5. Instrument transformers for switchgear installations.

Instrument transformers to transform high voltages or currents to values which are unified or can be measured safely, while incurring low internal losses. In the case of current transformers the primary winding carries the operating current, while with voltage transformers it is connected to the operating voltage. The voltage or current of the secondary winding is identical to the value on the primary side in phase and ratio, except for the error of the transformer. Current transformers operate under almost short-circuit conditions, while voltage transformers operate at no-load. Primary and secondary sides are nearly always electrically independent and insulated from each other as required by the operating voltage.

Instrument transformers are used either for measuring purposes when connected to measuring instruments, meters and the like, or for protection purposes, in which case they are connected to protective devices.

Instrument transformers are divided into classes according to their accuracy of measurement. Their applications are summarized in Table.

Table Applications and classes of instrument transformers

Application	*VDE class*	*IEC class*	*ANSI class*
Precision measurements and calibration	0.1	0.1	0.3
Accurate power measurement, tariff metering	0.2	0.2	0.3
Tariff metering, accurate measuring instruments	0.5	0.5	0.6
Industrial meters: voltage, current, power, etc.	1	1	1.2
Ammeters or voltmeters, overcurrent or voltage relays	3	3.5	1.2
Protection cores of current transformers	5 P, 10 P		C, T

Definition according to DIN VDE 0414

1. Current transformers :

— Primary and secondary rated current are the primary and secondary currents stated on the nameplate.

— Rated transformation ratio is the ratio of the primary rated current to the secondary rated current.

— Burden is the impedance of the secondary circuit expressed in terms of its modulus and power factor cos β.

— Rated burden is the burden to which specifications regarding error limits are referred.

— Rated output is the apparent power in VA at rated secondary current and rated burden.

— Current error is the deviation in percent of the secondary current, multiplied by the nominal transformation ratio, from the primary current.

— Phase displacement is the difference in phase angle of the secondary current relative to the primary current.

— Composite error of a current transformer is the ratio in per cent having as divisor the rms value of the primary current and as dividend the rms value taken over one cycle of the difference between the instantaneous values of the secondary current multiplied by the rated transformation ratio and the instantaneous values of the primary current.

$$F_g = 100\,\frac{\sqrt{\frac{1}{T}\int_0^T (K_N \cdot i_2 - i_1)^2\,dt}}{I_1}$$

Here : F_g Composite error in %,
T Duration of one cycle in s,
K_N Rated transformation ratio,
I_1 rms value of primary current in A,
i_1 Instantaneous value of primary current in A,
i_2 Instantaneous value of secondary current in A.

— Primary rated accuracy limit current is a current at which at rated burden the composite error specified for instrument transformers for protection purposes is not exceeded and at which the composite error for instrument transformers for measuring purposes is greater than 15%.

— Rated accuracy limit factor is a defined number by which the primary rated current must be multiplied to obtain the primary rated accuracy limit current.

— Rated continuous thermal current is 1.2 times the rated current, and 1.5 or 2 times this current in the case of current transformers with extended range.

— A current transformer with extended range is a transformer whose rated continuous thermal current is greater than 1.2 times the rated current and which complies with the specified error limits.

— Rated short-time thermal current (I_{th}) is stated on the nameplate as the rms value of the primary current of one second duration which the current transformer can withstand without suffering damage when the secondary winding is short-circuited.

— Rated dynamic current (I_{dyn}) is the value of the first current crest the related forces of which a current transformer can withstand without damage with the secondary winding short-circuited.

2. Voltage transformers :

— Primary rated voltage is the value of the primary voltage stated on the nameplate. In the case of phase-insulated transformers connected in three-phase networks between phase and earth it is stated in the form $U/\sqrt{3}$, U being the voltage between the phase conductors.

— Secondary rated voltage is the value of the secondary voltage stated on the nameplate, also stated as $U/\sqrt{3}$. In the case of earth-fault detection windings it is stated in the form $U/3$.

— An earth-fault detection winding for three-phase networks consists of a set of three phase-isolated transformers.

— Rated transformation ratio is the ratio of the primary to the secondary rated voltage.

— Burden is the admittance of the secondary circuit expressed in terms of its value and burden power factor cos β.

— Rated burden is the burden to which the specifications regarding error limits are referred.

— Rated output is the apparent power at secondary rated voltage and rated burden.

— Voltage error of a voltage transformer at a given primary voltage is the difference in per cent between the secondary voltage, multiplied by the rated transformation ratio and the primary voltage. The voltage error is taken to be positive if the actual value of the secondary voltage is greater than the desired value.

The voltage error of a voltage transformer is :

$$F_u = 100 \cdot \frac{U_2 \cdot K_N - U_1}{U_1}$$

Here : F_u Voltage error in %, U_1 Primary voltage in V,
U_2 Secondary voltage in V, K_N Rated transformation ratio.

— Error angle is the phase displacement of the secondary voltage relative to the primary voltage.

— Rated long-duration current is the current in an earth-fault detection winding which this can withstand for 4 or 8 hours in the event of an earth fault at 1.9 times the primary voltage and with the other windings simultaneously connected to rated burden, without the permitted temperature rise being exceeded by more than 10°C.

— Short-time load rating is determined by the rated voltage factors and duration of the load at elevated voltages.

58.7.6. Current transformers

The primary winding is incorporated in the line and carries the current flowing in the network. It is provided with various secondary cores. The purpose of current transformers is to transform the primary current in respect of magnitude and phase angle within prescribed error limits. The main source of transformation errors is the magnetizing current. So that this and the transformation errors remain small, all current transformers are equipped with high-grade core magnets. The cores are made of silicon-iron or high-alloy nickel-iron. Fig. 58.33 shows the magnetizing curves of different core materials. In special cases cores with an air gap are used in order to influence the core's behaviour in the event of transients.

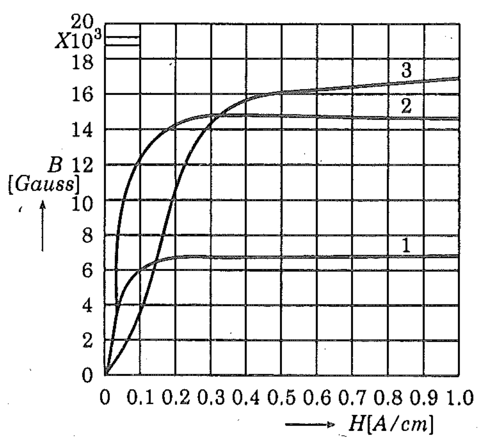


Fig. 58.33. Magnetizing curves of different core materials. Material 1 is used mainly for measuring cores, and material 3 for protection cores. H = field strength [A/cm], B = peak flux density [gauss], 1 = nickel-iron with approx. 75% Ni, 2 = nickel-iron with approx. 50% Ni, 3 = mill-patterned cold-rolled silicon-iron.

Current transformers are divided in single-turn transformers and wound-type transformers depending on the construction of the primary winding. Single-turn transformers are made in the form of outdoor inverted-type transformers, straight-through transformers, slipover and bar transformers. Wound-type transformers can be bushing transformers, post-type and miniature transformers and also outdoor post-type and tank transformers with oil-paper insulation. Fig. 58.34 shows the basic construction of an inverted-type transformer (Fig. 58.34 a) and a tank-type transformer (Fig. 58.34 b).

The different designs of current transformer according to insulating medium are shown in Table 10-5.

Table 10-5 Design of current transformers

Insulation	*Type*	*Voltage range*	*Application*
Dry	Slipover, wound and cable-type transformers	Low voltage	Indoors
Cast resin	Post-type and bushing transformers	Medium voltage	Indoors and SF_6-installation
Oil-impregnated paper/porcelain	Tank and inverted-type transformers	High and very high voltage	Outdoors

If required, current transformers can be provided with reconnecting facilities for two or more different primary currents. The following versions are possible :

Primary changeover. Changeover takes the form of switching two or more partial primary windings in series/series-parallel or parallel. The rated output and rated overcurrent factor remain unchanged. The rated thermal short-time current and rated dynamic current decrease in direct proportion to the primary current.

Secondary tappings. Changeover is performed with the aid of tappings on the secondary winding.

When the primary rated current is reduced in this way, the rated output in classes 0.1 to 3 decreases approximately as the square of the reduction in primary current, and in protection classes 5 P to 10 P roughly in direct proportion to this reduction.

The absolute values of the thermal rated short-circuit current and rated dynamic current also remain the same for all ratios.

Selection of current transformers. The factors determining the choice of current transformers are the values of the primary and secondary rated currents, the rated outputs of the different cores for a given accuracy class, and the rated overcurrent factor. The rated current of the transformer has to be adapted to suit the operating current.

According to DIN VDE 0414, current transformers can be continuously overloaded by 20%. With an operating current of 120 A, for example, this means a transformer for 10% A can be used. Current transformers for wide-range use can be loaded continuously the 1.5. I_N (ext. 150%) or 2.0 . I_N (ext. 200%).

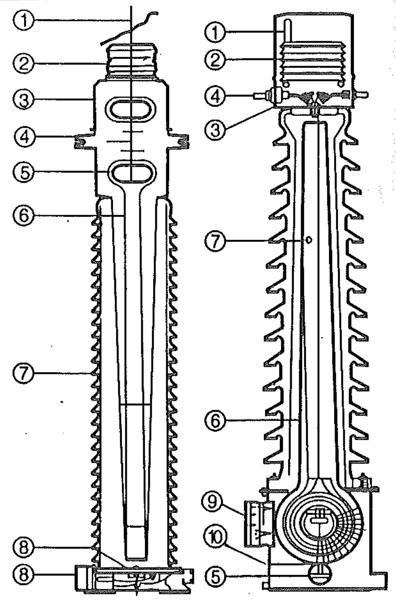


Fig. 58.34 (*a*) Inverted-type current transformer AOK for 300-525 kV, 40-6000 A, (*b*) Tank-type current transformer AOT for 300-765 kV, 40-4000 A, 1 Oil level indicator, 2 Bellow, 3 Terminal head, 4 Primary terminals, 5 Cores with secondary winding. 6 Core-and-coil assembly with main insulation, 7 Insulator. 8 Base plate, 9 Terminal box, 10 Tank

Determining the output of a current transformer. The sec. output of a current transformer is governed by the number of ampere-turns the core material and the construction of the core. The output varies approximately at the square of the number of ampere-turns (roughly linear with

protection cores). However, it also decreases roughly as the square of the difference between operating current and the rated current of the transformer (approximately linearly in the case of protection cores), so that with a transformer rated 30 VA and loaded with half the rated current, the output is reduced to a quarter, *i.e.* to about 7.5 VA.

The rated output of a current transformer is the product of the nominal burden Z and the square of the rated secondary current I_{2N}, i.e.: $S_N = XZ\, I_{2N}^2$ in VA. A current transformer with a secondary current of I_{2N} = 5A and a connected burden of 1.2 Ω thus has a rated output of 1.2. 5^2= 30*VA*. The transformer may be loaded with the rated output stated on the nameplate, without exceeding the limits of error. This means that a series-connected current paths of measuring instruments, meters and protective relays in the secondary circuit, including the resistance of their associated connection wires and cables, must not in total exceed this nominal burden (Table 58.6).

Table 58.6
Rated outputs and nominal burdens of current transformers (for 50 Hz)

Rated output in VA	5	10	15	30	60
Nominal burden at 5 A in Ω	0.2	0.4	0.6	1.2	2.4
Nominal burden at 1 A in Ω	5	10	15	30	60

For 162/3 Hz the transformer output must be multiplied by a factor of approximately 0.33 and for 60 Hz by 1.2.

When selecting current transformers, attention must be paid to the rated overcurrent factor, as well as to the output. The rated overcurrent is stated on the nameplate.

For measuring and metering cores, the rated overcurrent factor should be as small as possible, *e.g.* M 5 or M 10, to protect the connected measuring instruments from excessive overcurrents or short-circuit currents. Since the rated overcurrent factor is valid only for the nominal burden, while the actual overcurrent factor increases roughly in inverse proportion to the decrease in burden or transformer loading, care must be taken to ensure that the operating burden of the connected measuring instruments, including the necessary connecting wires and cables, is as close as possible to the nominal burden of the transformer, to prevent the instruments from being damaged. Otherwise, an extra burden should be included in the secondary circuit.

Example 58.1. Current transformer to 100/5 A, 30 VA class 0.5 M 5

Power requirement :	1 ammeter	...	2.5 VA
	1 wattmeter	...	3 VA
	25 m cable of 2.5 mm^2	...	4.5 VA
	Total power requirement	...	10 VA

Since the product of the core output and rated overcurrent factor is almost constant, in the example we have 30 VA . 5 = 150. With a burden of only 10 VA this then gives an overcurrent factor of 150 : 10 = 15. The measuring instruments are then insufficiently protected. If a transformer of only 15 VA is selected, the overcurrent factor is 7.5. The transformer output could thus be even smaller, or an additional burden would have to be provided.

Protection cores for connection to protective relays must unlike measuring cores, be so chosen that, depending on the settings of the relays, their total error in the region (short-circuit currents) where the relays have to function reliably, *e.g.* between 6 and 8 times the rated current, is not too large. The protection core must therefore be so designed that the product of rated output and rated overcurrent factor is at least equal to the product of the secondary circuit power requirement at rated current and the necessary rated overcurrent factor. This must be considered especially if verification of the thermal short-circuit stress indicates an enlarged conductor cross-section on the primary side. In this case one can either choose a current transformer for a higher rated current, whereupon the number of primary turns will be smaller (but so will the output because the operating current is lower than the rated current), or one can use a special transformer.

Example 58.2.

Current transformer for 400/5 A, 15 VA class 5 P 10

Power requirement:	overcurrent relays	...	8 VA
	differential relays	...	1 VA
	cable	...	3 VA
	Total power requirement	...	12 VA

The overcurrent factor is then $\dfrac{15VA\,.\,10}{12VA} = 12.5$

i.e. the transformer has been chosen correctly.

An overcurrent relay set to 8 I_N will trip because in the present case the current rises in direct proportion to the primary current, up to 12.5 × rated current.

In the event of a fully displaced short-circuit current, the d.c. component occurring at the beginning of the short circuit gives rise to transmission errors owing to saturation of the core. This can be remedied by using linearized cores with a high rated overcurrent factor (*e.g.* 200), or by selecting a high transformation ratio for the protection core.

The above selection criteria relate as well to current transformers in metal-enclosed switching installations.

The selection of current transformers in accordance with international standards (IEC) and the major foreign standards (*e.g.* ANSI) is generally based on similar criteria. The following short summary and Tables 10-7 to 10-11 are intended to assist in selecting transformers to the above standards.

Definitions and standard ratings to IEC Publication 185 (1966)

Measuring cores Rated output : 2.5 – 5.0 – 10 – 15 – 30 VA ; Burden power factor cos $\beta = 0.8$

Classes : 0.1 – 0.2 – 0.5 – 1 valid between 25% and 100% of rated power.
0.25 – 0.5 only for 5 A secondary current
3 – 5 valid between 50% and 100% of rated power

Designation Measuring cores are designated by a combination of rated output and class, *e.g.*
15 VA class 0.5
15 VA class 0.5 ext. 150% (wide-range transformer).

Table 58-7
Error limits for measuring cores

Class	*± Current error in % referred to per cent of rated current*					*± Phase displacement referred to per cent of rated current*							
						Minutes				*Centiradiant*			
	10	*20*	*50*	*100*	*120*	*10*	*20*	*100*	*120*	*10*	*20*	*100*	*120*
0.1		0.2	—	0.1	0.1	10	8	5	5	0.3	0.24		
	0.25											0.15	0.15
0.2	0.5		—	0.2	0.2	20	15	10	10	0.6	0.45	0.3	0.3
		0.35											
0.25; 0.5		0.2	—	0.2	0.2	—	—	—	—	—	—	—	—
	0.35												
0.5	1.0		—	0.5	0.5	60	45	30	30	1.8	1.35	0.9	0.9
		0.75											
1	2.0	1.5	—	1.0	1.0	120	90	60	60	3.6	2.7	1.8	1.8
3	—	—	3	—	3	—	—	—	—	—	—	—	—
5	—	—	5	—	5	—	—	—	—	—	—	—	—

Current transformers of classes 0.1 – 1 are also defined as wide-range transformers for 120%. 150% and 200% of rated primary current.

Phase displacement limits are not defined for classes 3 and 5.

Protection cores Rated output : preferred 10 – 15 – 30 VA

Classes : 5 P and 10 P; here the numbers denote the maximum permitted composite error at the error limit current; the letter P stands for protection.

Error limit factor : 5 – 10 – 15 – 20 – 30

Table 58-8
Error limits for protection cores

Class	*Current error in % at rated primary current*	*Phase displacement at rated primary current Minutes Centirad.*		*Composite error in % at error limit factor*
5 P	± 1	± 60	± 1.8	5
10 P	± 3	—	—	10

Designation : The rated output and class is followed by the error limit factor, *e.g.* 30 VA class 5 P 10.

58.7.7. Inductive voltage transformers

Inductive voltage transformers are low-power transformers in which the secondary voltage is for all practiced purposes proportional to and in phase with the primary voltage. The purpose of voltage transformers is to transform network voltage to be measured into a secondary voltage which is fed to measuring and protective devices. The primary and secondary windings are galvanicly separated from each other.

Inductive voltage transformers are manufactured in the following forms :

1. Voltage transformers with two-phase insulation for connection between two phases, ratio 6000/100 V, for example. Two voltage transformers in vee connection are normally used for measuring power in three-phase networks.
2. Voltage transformers with single-phase insulation for connection between one phase and earth, ratio *e.g.* $110\ 000/\sqrt{3}/100/\sqrt{3}$ V.

   For measuring power in three-phase networks one needs three voltage transformers connected in star. If single-phase insulated voltage transformers include an auxiliary winding for signalling earth faults, in three-phase networks this winding must be sized for 100/3 V. The "open triangle" in the three-phase set can also be provided with a fixed resistor to damp relaxation oscillations (caused by ferroresonance in insulated networks with small capacitances).
3. Three-phase voltage transformers with the measuring windings connected in star and an auxiliary winding on the 4th and 5th limb for signalling earth faults. In the event of an earth fault the auxiliary winding has a voltage of 100 V.

Inductive voltage transformers are selected according to the primary and secondary rated voltages and also the accuracy class and rated output of the secondary windings so as to meet the requirements of the devices they are connected to.

If there is a winding for detecting earth faults, its rated long-duration currents must be stated. For the short-time load rating it is necessary to state the rated voltage factor and the duration of stress at elevated voltage.

58.7.8. Capacitive voltage transformers

For higher system voltages up to 765 kV it is also possible to use voltage transformers that work on the capacitive divider principle. Capacitive voltage transformers can be connected to all customary measuring instruments and protection relays; they are also authorized for tariff metering purposes.

The basic diagram of a capacitive voltage transformer is shown in Fig. 58.35. Capacitive transformers also provide a reliable supply to system protection relays with transistorized circuitry for very short switching times, especially if the transformers are provided with an electronic damping device which very quickly attenuates any transient oscillation of the transformer.

Capacitive voltage transformers have the added advantage that they can be used for coupling high-frequency power-line carrier systems, *e.g.* for telephony, telecontrol, and so on. The necessary additional components (reactor, lightning arrester) can be contained in the terminal box.

The essential features to consider when selecting voltage transformers are the primary and secondary rating, rated frequency, rated output and class. However, account must also be taken of the rated long-duration current of any earth-fault detection winding, rated voltage factor and the duration of stress at elevated voltage.

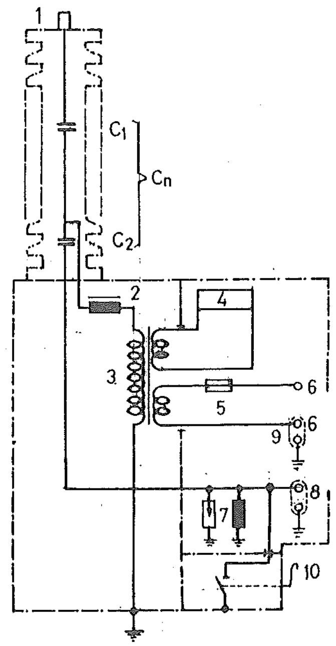


Fig. 58.35. Basic diagram of a capacitive voltage transformer

1 High-voltage terminal, 2 Medium-voltage choke, 3 Transformer, 4 Protection device, 5 Fuses (optional), 6 Secondary terminals, 7 Earthing reactor and lightning arrester (optional), 8 PLC terminal, 9 Earthing strap, 10 PLC earthing switch (optional), 11 Earthing terminal, C_n, C_1, C_1 capacitive voltage divider

Capacitive voltage transformers are selected in the same way as inductive types, except that the rated capacitance must also be defined. An example of determining the main technical data of a capacitive voltage transformer is given below :

Rated primary voltage	$\frac{110.000}{\sqrt{3}}$ V
Rated secondary voltage of measuring winding	$\frac{110}{\sqrt{3}}$ V
of earth-fault detection winding	$\frac{100}{3}$ V
Rated output	75 VA, Kl, 0.5
Rated voltage factor	1.9 U_N, 4h
Rated long-duration current of earth-fault detection winding	9 A, 4h
Rated capacitance	4.400 pF ± 10%
Rated frequency	50 Hz

With capacitive transformers the rated capacitance and behaviour under transient conditions (interaction with network protection system) are also important.

Inductive and capacitive voltage transformers are used in SF_6-insulated switching stations. They are described more fully in Section 11.2.4.

58.8. SURGE ARRESTERS

58.8.1. Types of Surge arresters

(*i*) Arresters with plate-type spark-gaps and silicon carbide (SiC) resistors (valve-type arresters) are used in distribution systems with overhead lines. They provide a relatively high protection level against atmospheric overvoltages.

(*ii*) Arresters with magnetically blown spark-gaps and SiC resistors (also valve-type arresters) afford protection at lower levels. Their energy absorption capacity is about 3 times higher than that of plate-type arresters. They are used in high-voltage networks and at central points in distribution systems.

(*iii*) Surge arresters with no spark gap and using non-linear metal-oxide resistors (MO-arresters) usually, Zno are suitable for all voltage levels.

58.8.2. Application and selection

Surge arresters are used to protect costly and critical equipment and installations (especially power transformers HV cables etc.) against atmospheric overvoltages and switching overvoltages. They are selected according to the rules of insulation coordination. Valve-type arresters are selected according to their resealing voltage, the rules of insulation coordination, surge (discharge) current, line discharge class and short-circuit strength. For gap-less metal oxide arresters, the criteria are: maximum permitted continuous operating voltage, surge current, strength against transient overvoltages, line discharge class and short-circuit strength.

The resealing voltage is the voltage across the arrester at which the follow current is still definitely interrupted after sparkover. According to DIN VDE 0675 it is chosen equal to, or greater than, the maximum permissible continuous power-frequency voltage at the arrester. Account must be taken of the most unfavourable conditions. For phase arresters (connected between phase and earth) the resealing voltage is governed by the maximum phase-to-earth voltage. This is calculated as the product of the maximum power-frequency voltage and the earth-fault factor c_E.

With metal oxide arresters the maximum continuous operating voltage U_c is the highest power-frequency voltage that the arrester can withstand permanently. The strength T against transient overvoltages is the maximum temporary increase in the power-frequency voltage, referred to U_c for time t.

Selection of U_c for MO arresters: In networks with insulated or inductively earthed neutral the continuous operating voltage U_c is chosen the same as the maximum operating voltage U_m.

If networks with insulated neutral are provided with earth-fault protection, lower values of U_c are permissible: $U_c \geq U_m/T$.

Strength T as a function of time t for which the transient overvoltage persists is a characteristic of the arrester design and is usually represented in a diagram.

With non-earthed transformers the neutral is normally brought out. & an arrester is used to protect this neutral.

Strength T against transient overvoltages can be called upon when MO arresters are used for the neutral point. The continuous operating voltage U_c is selected in terms of the highest possible neutral-point voltage divided by T. Factor T depends on the type of arrester and will be found in the appropriate literature.

58.8.3. Typical values of surge arresters for the major voltage ratings

Recommended values of valve-type arresters for the principal voltages are summarized given in Table 58.13.

With gap-less MO arresters the continuous operating current U_c must be selected according to the earth-fault c_E. Table 14 shows typical values for low impedance-earthed networks ($c_E = 1.4$) and non-earthed systems ($c_E = \sqrt{3}$) without any other transient overvoltage.

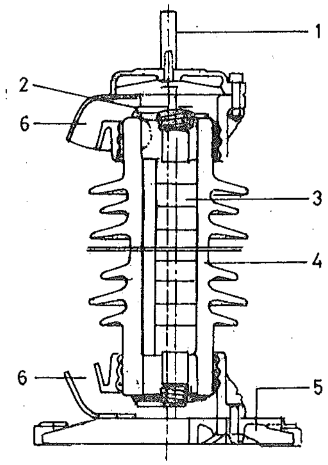
Table 58.13.
Recommended values for valve-type arresters

Rated system voltage U_m *kV*	*Treatment of system neutral*[1)]	*Phase arrester Resealing voltage* U_1 *kV*	*Neutral arrester Resealing voltage* U_1 *kV*
10	f, l	12	—
20	f, l	24	—
30	f, l	36	—
110	n	120	85
110	l	132	85
138	e	128	60
220	e	216	120
220	e[2)]	234	120
345	e	321	151
380	e	360	195
380	e[2)]	420	175
500	e	467	219

1 f system with insulated neutral
l system with earth-fault compensation
e system with low impedance-earthed neutral, earth-fault factor ≤ 1.4
n 110 kV system with low impedance-earthed neutral, earth-fault factor ≤ 1.7
2 for generator transformers

Table 10-14.
Selection of MO arresters
for maximum permitted continuous operating voltage U_c
(assuming that no other transient overvoltages occur)

Rated system voltage	*Phase arrester*		*Neutral arrester*	
U_m kV	U_c for $c_E = 1.4$ kV	U_c for $c_E = \sqrt{3}$ kV	U_c for $c_E = 1.4$ kV	U_c for $c_E = \sqrt{3}$ kV
10	—	12	—	—
20	—	24	—	—
30	—	36	—	—
110	71	123	34	71
138	84	—	41	—
220	142	—	68	—
345	209	—	102	—
380	243	—	116	—
500	304	—	147	—



Metal oxide surge arrester
1. Primary terminal,
2. Pressure relief device,
3. Stack of MO resistors,
4. Insulator,
5. Earth-side terminal,
6. Pressure relief exhaust

Fig. 58.36. Construction of MO arrester.

Arresters for up to 30 kV in distribution networks (*e.g.* for tower-mounted transformers) are usually designed for a rated surge current of 5 kA; arresters for 10 kA are used in networks seriously at risk due to thunderstorms. A rated surge current of 10 kA must always be selected for arresters before cable runs.

Arresters for voltages above 30 kV always have rated surge currents of 10 kA.

Under extreme fault conditions it is possible for lightning arresters to be overloaded. In such cases, e.g. a voltage rise from one level to the next, a single-phase earth fault occurs in the resistor assembly of the arrester. The pressure relief system prevents the porcelain housing from exploding. The system earth-fault current at the arrester's location must be smaller than the guaranteed current of the arrester's pressure relief device.

Lightning arresters are fitted in parallel with the object protected, generally between phase and earth. Because of their limited spatial protected zone, the arresters must be connected as close as possible to the protected item, e.g. a transformer.

Table 10-15
Approximately values of Protected zone of lightning arresters, reference values

Maximum voltage of equipment U_m *kV*	*Protected zone* I_{max} *m*	*Length of lead to arrester* a *m*
≤ 36	8	2
123	15	5
245	20	10
420	20	15

In medium-and high-voltage installations with cable entry, overvoltages due to reflection must be taken into account, despite limitation of the travelling wave by the cable. The arresters must therefore be located as close as possible to the transformer.

Surge counters are used to monitor lightning arresters. These are connected in the earth-wire of the arrester; the arresters are therefore, insulated against earth.

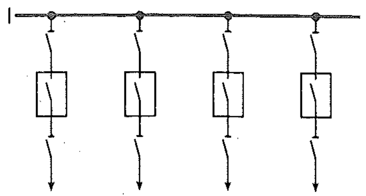
58.8.4. Circuit configurations for high- and medium-voltage switchgear installations

The circuit configurations for high- and medium-voltage switchgear installations are governed by operational considerations. Whether single or multiple busbars are necessary will depend mainly on how the system is operated and on the need for sectionalizing, to avoid execessive breaking capacities. Account is taken of the need to isolate parts of the installations for purposes of maintenance and also of future extensions.

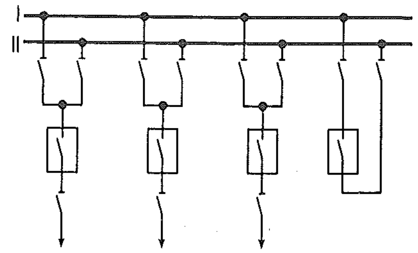
When drawing up a single line-diagram a great number of possible combinations of incoming and outgoing connections have to be considered. The most common ones are as described below.

(*i*) *Single busbars.* Suitable for smaller installations. A sectionalizer allows the station to be split into two separate parts and the parts to be disconnected for maintenance purposes.

(*ii*) *Double busbars.* Preferred for larger installations. Advantages: maintenance without interrupting supply. Separate operation of station sections possible from bus I and bus II. Busbar sectionalizing increases operational flexibility.



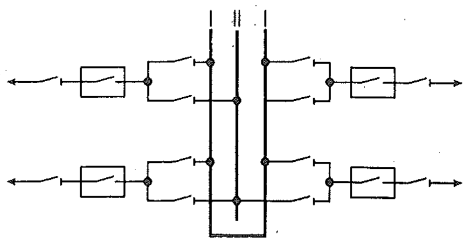
Single busbars



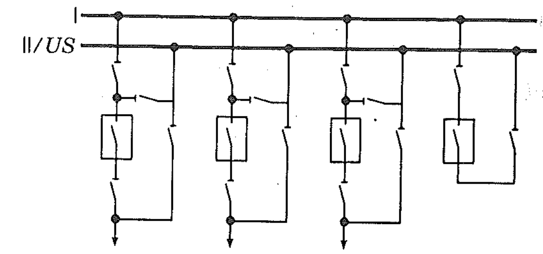
Double busbars

(*iii*) *Double busbars in U connection.* Low-cost, space-saving arrangement for installations with double busbars and branches to both sides.

(*iv*) *Composite double bus / bypass bus.* This arrangement can be adapted to operational requirements. The station can be operated with a double bus, or with a single bus plus bypass bus.



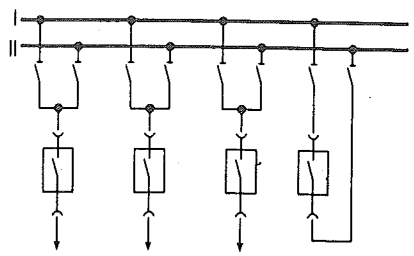
Double busbars in U connection



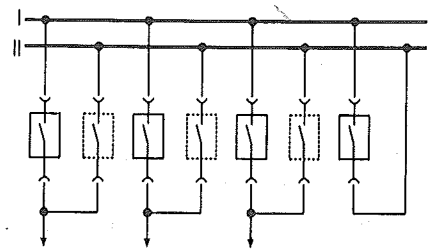
Composite double bus/bypass bus

(*v*) *Double busbars with draw-out circuit-breakers.* In medium-voltage stations, draw-out breakers reduce downtime when servicing the switchgear; also a feeder isolator is eliminated.

(*vi*) *Two-breaker method with draw-out circuit-breakers.* Draw-out circuit-breakers result in economical medium-voltage stations. There are no busbar isolators or feeder isolators. For station operation the draw-out breaker can be inserted in a cubicle for either bus I or bus II.



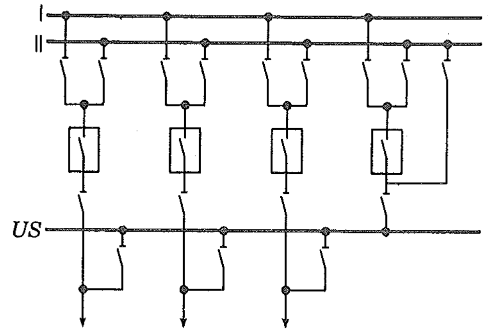
Double busbars with draw-out circuit-breakers.



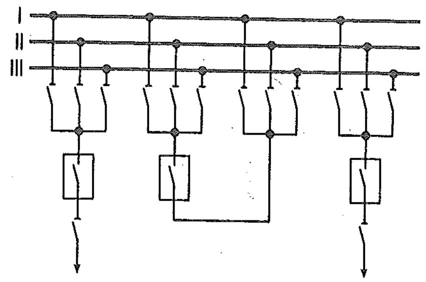
Two-breaker method with draw-out circuit-breakers.

(*vii*) *Double busbars with bypass busbar.* The bypass bus is an additional busbar connected via the bypass branch. Advantage; each branch of the installation can be isolated for maintenance without interrupting supply.

(*viii*) *Triple (multiple) busbars.* For vital installations feeding electrically separate networks or if rapid sectionalizing is required in the event of a fault to limit the short-circuit power. This layout is frequently provided with a bypass bus.



Double busbars with bypass busbar

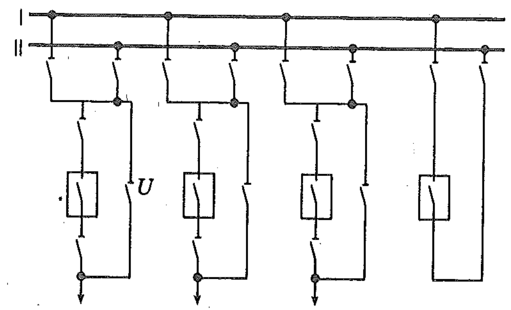


Triple (multiple) busbars.

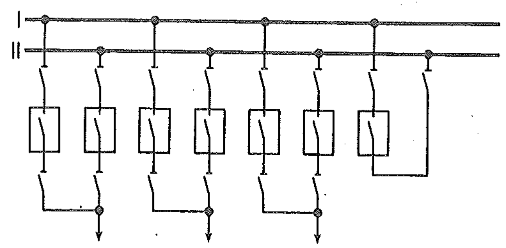
(*ix*) *Special configurations.*

(*a*) *Double busbars with shunt disconnector.* Shunt disconnector "U" can disconnect each branch without supply interruption. In shunt operation the tie breaker acts as the branch circuit-breaker.

(*b*) *Two-breaker method with fixed switchgear.* Circuit breaker, branch disconnector and instrument transformers are duplicated in each branch. Busbar interchange and isolation of one bus is possible, one branch breaker can be taken out for maintenance at any time without interrupting operation.



Double busbars with shunt disconnector

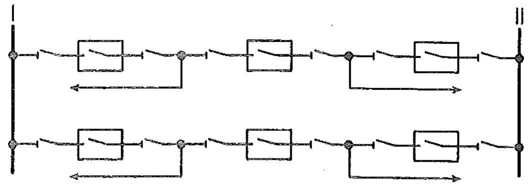


Two-breaker method with fixed switchgear

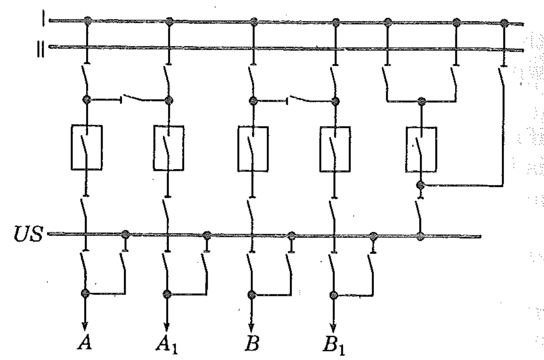
(*c*) *1 1/2-breaker method.* Fewer circuit-breakers are needed for the same flexibility as above. Isolation without interruption. All breakers are normally closed. Uninterrupted supply is thus maintained even if one busbar fails.

(*d*) *Cross-tie method.* With cross-tie disconnector "DT" the power of line A can be switched to branch A_1, bypassing the busbar. The busbars are then accessible for maintenance.

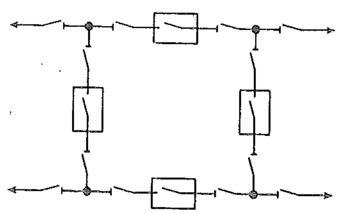
(*e*) *Ring busbars.* Each branch requires only one circuit-breaker, and yet each breaker can be isolated without interrupting the power supply in the outgoing feeders. The ring busbar layout is often used as the first stage of 1 1/2-breaker configurations.



1 1/2-breaker method

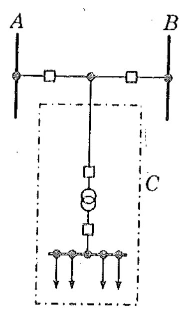


Cross-tie method

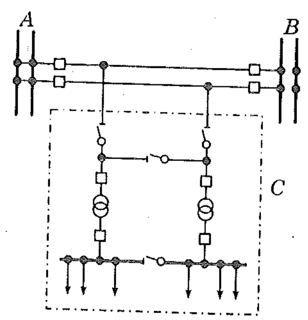


Ring busbars

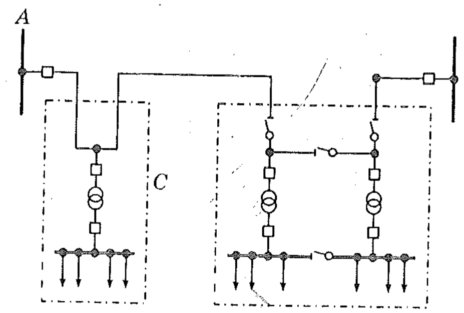
(*x*) *Configurations for load-centre substations.* A and B = Main transformer station, C = Load-centre substation, □ = Circuit-breaker or load disconnector. The use of load disconnectors instead of circuit-breakers imposes operational restrictions.



Single-feed station



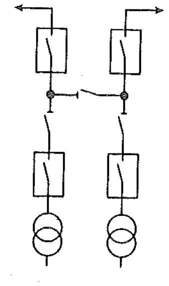
Double-feed station



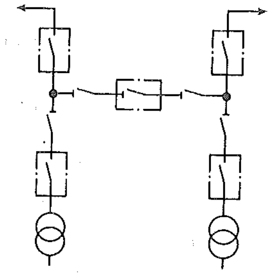
Ring stations

A and B = Main transformer station, C = Load-centre substation, □ = Circuit-breaker or load disconnector. The use of load disconnectors instead of circuit-breakers imposes operational restrictions.

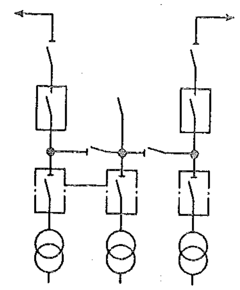
Load disconnectors are frequently used in load-centre substations for line/cable branches or transformer feeders. Their use is determined by the operating conditions and economic considerations.



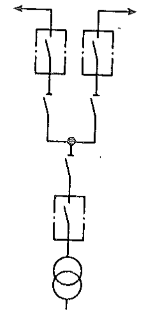
H connection with circuit-breakers



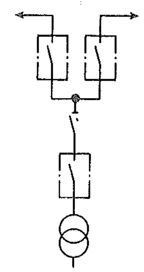
H connection with load disconnectors



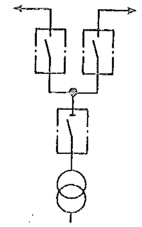
H connection with 3 transformers



Ring main cable connection allowing isolation in all directions

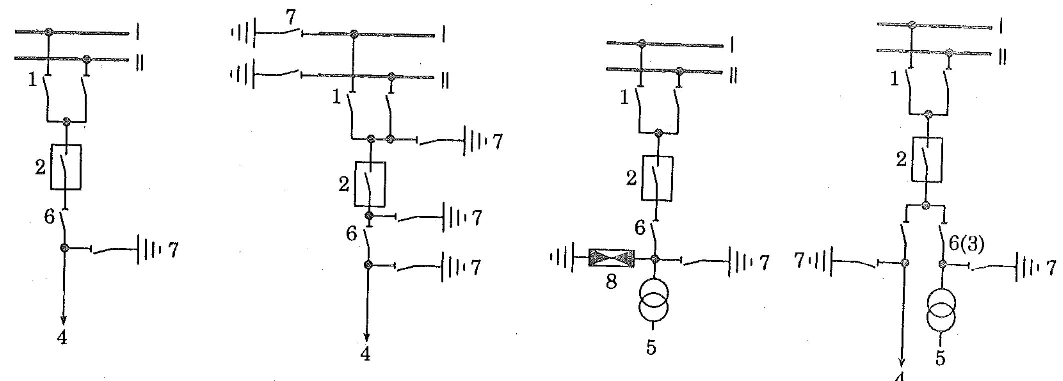


Simple ring main cable connection



Cable loop

(*xi*) *Branch connections, variations (a) to (d)*



(*a*) (*b*) (*c*) (*d*)

1. Busbar disconnector, 2. Circuit-breaker, 3. load disconnector, 4. Overhead-line or cable branch, 5. Transformer branch, 6. Branch disconnector, 7. Earthing switch, 8. Surge arrester

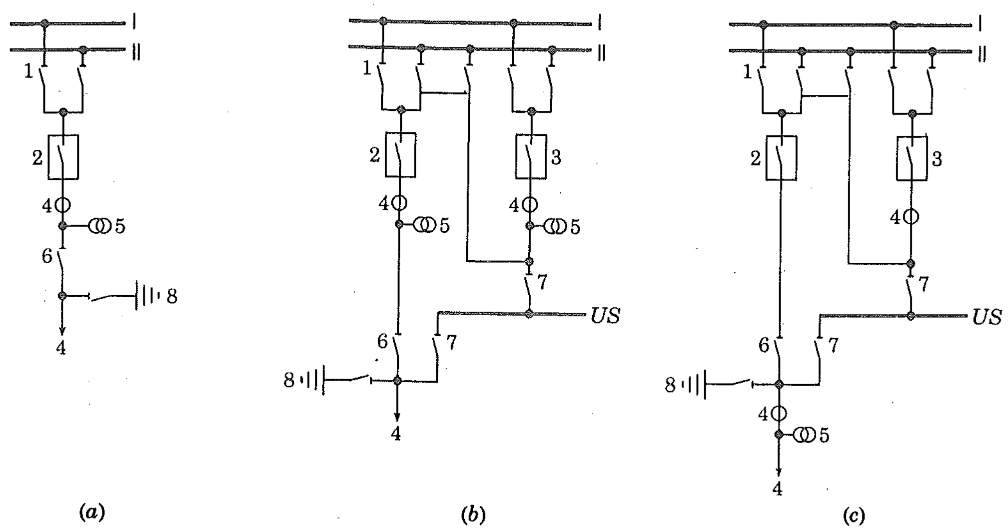
(*a*) *Overhead-line and cable branches.* Branch disconnector 6 allows circuit-breaker 2 to be isolated for maintenance purposes, even in installations with feedback voltage. Earthing switch 7 eliminates capacitive charges and provides protection against atmospheric charges on the overhead line.

(*b*) *Branch with unit earthing.* Station earthing switches 7 are made necessary by the increase in short-circuit powers and (in impedance-earthed systems) earth-fault currents.

(*c*) *Transformer branches.* Feeder disconnectors can usually be dispensed with in transformer branches because the transformer is disconnected on both h.v. and l.v. sides. For maintenance work an earthing switch 7 is recommended.

(*d*) *Double branches.* Double branches for two parallel feeders are generally fitted with branch disconnectors 6. In load-centre substations, by installing load disconnectors 3 it is possible to connect and disconnect, and also through-connect, branches 4 and 5.

(*xii*) *Connections of instrument transformers, variations*



1. Busbar disconnectors, 2. Branch circuit-breaker, 3. Bypass circuit-breaker, 4. Current transformers, 5. Voltage transformers, 6. Branch disconnector, 7. Bypass disconnectors, 8. Earthing switch

(*a*) *Normal branches.* The instrument transformers are usually placed beyond the circuit-breaker, 2. with voltage transformer 5 after current transformer 4. This is the correct arrangement for synchronizing purposes. Some kinds of operation require the voltage transformer beyond the branch disconnectors, direct on the cable or overhead line.

(*b*) *Station with bypass busbar.* Instrument transformers within branch. The instrument transformers cease to function when the bypass is in operation. Line protection of the branch must be provided by the instrument transformers and protection relays of the bypass. This is possible only if the ratios of all transformers in all branches are approximately equal. The protection relays of the bypass must also be set for the appropriate values. Maintenance of the branch transformers are used which also act as coupling capacitors for a high-frequency telephone link, this link is similarly inoperative in the bypass mode.

(*c*) *Station with bypass busbar.* Instrument transformers outside branch.

In bypass operation the branch protection relays continue to function, as does the telephone link if capacitive voltage transformers are used. It is only necessary to switch the relay tripping circuit to the bypass circuit-breaker 3. Servicing the transformers is more difficult since the branch must then be out of operation.

The decision as to whether the instrument transformers should be inside or outside the branch depends on the branch currents, the protection relays, the possibility of maintenance and, in the case of capacitive voltage transformers, on the h.f. telephone link.

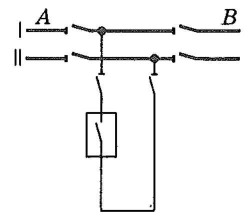
Busbar coupling connections

A and B = Busbar sections, LTR = Busbar sectioning disconnector

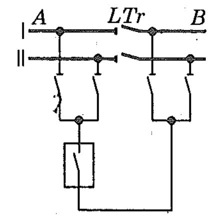
More complex coupling arrangements are usually needed in order to meet practical requirements concerning security of supply and the necessary flexibility when switching over or disconnecting. This greater complexity is evident in the layouts for medium and high-voltage installations.

Division into two bays is generally required in order to accommodate the equipment for these tie-breaker branches.

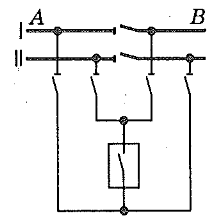
Double busbars



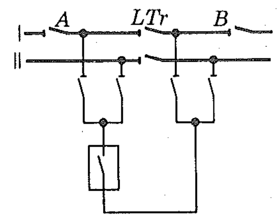
Bus coupling I/II for A or B



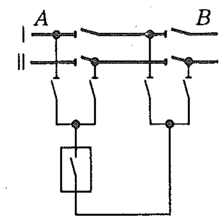
Section coupling for A-B Bus coupling I/II via disconnector LTR



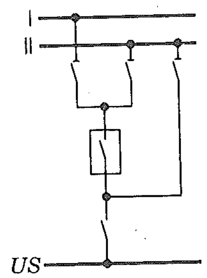
6-tie coupling Section coupling for A-B Bus coupling I/II for A or B



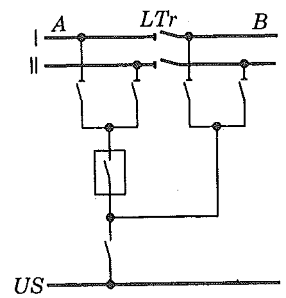
Section coupling for A-B Bus coupling I/II for A or B via tie-breaker bus II



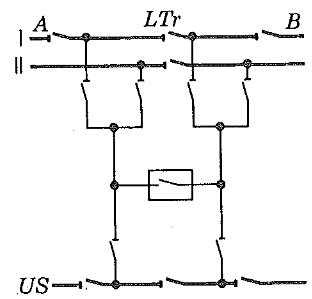
8-tie coupling Section coupling for A-B Bus coupling I/II for A or B



Bus coupling I/II Bypass (US) coupling I or II to bypass

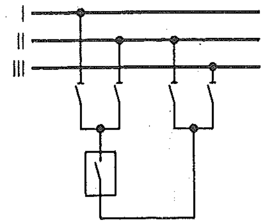


Section coupling for A-B Bus coupling I/II via LTR Bypass coupling A direct. B via LTR to bypass

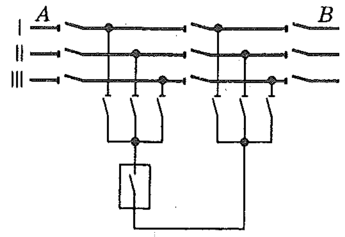


13-tie coupling Most flexible method of section, bus and bypass coupling

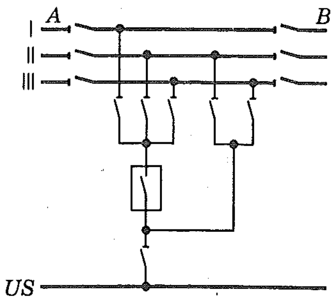
Triple busbars



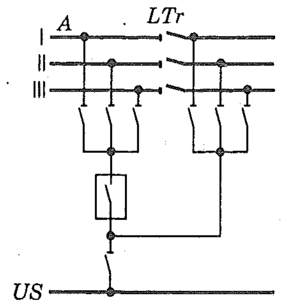
Bus coupling I/II/III



Section- and bus coupling for all possible ties between the 6 sections A-B



Bus coupling I/II/III for A or B Bypass coupling I/II/III to bypass (US) for A or B



Section coupling for A-B. Bus coupling I/II/III via LTR. Bypass coupling A I/II/III to bypass. Bypass coupling B bypass via LTR.

59

Electrical Safety

59.1. INTRODUCTION

While electricity has made life full of comfort and ease, it has also the potential to create heavy destruction if adequate precautions against its potential dangers are not taken care of. This brings into focus the safety to be exercised in the entire process of generation, transmission, distribution and the end use of electrical energy. Safety management & monitoring system has to ensure:

— Safety to self
— Safety to fellow workman
— Safety to consumer
— Safety to the public
— Safety of equipment apparatus & buildings
— Continuous and reliability of supply.

The concept of electrical safety as applied to the present day environment has taken deep roots so as to evolve as a discipline in itself in which specialists from all essential walks of life contribute towards devising ways and means to ensure safety in dealing with electrical energy. Safety includes safety of the equipment as well as the safety of the personnel. It is rather difficult to visualize any well-designed electrical system where these two aspects have not been taken into consideration. The safety of the equipment is generally provided by the use of protective devices such as switchgear and controlgear, fuses, relays etc. Safety of the personnel is ensured not only by employing protective devices but also by educating them about the safety precautions and practices that are required for installation, maintenance and operation of the electrical equipment. In addition, requirements to ensure a safe design of the equipment coupled with the reliability are specified in its product specification at the time of formulation of the relevant standard. For ensuring safety, a suitable statutory & institutional mechanism has been provided.

59.2. REQUIREMENTS FOR ELECTRICAL SAFETY

Personnel involved in the electrical work are normally called for to attend to installation and maintenance work, be it in a substation or in the factory premises or in commercial or domestic dwelling where electrical energy is being put to use. It is essential for these personnel to be conversant with Indian Standard and Codes of practices dealing with procedures for use of electricity and for various maintenance activities of electrical installations. The safety codes specify the precautions to be taken in ensuring safe use of electricity for the personnel working on them. In the Standards on personnel safety, various requirements on design and constructional details of the equipment have been laid down with a view to ensure protection from shock as well as protection from fire hazards under abnormal conditions. For ensuring a safe electrical environment, it is essential that the product conforms to these specified requirements and the instructions and guidelines laid down in Standards codes are known and practiced at all times by all concerned. The safety instructions are to be regarded as normal routine and not as involving extra and laborious efforts. Some of the important factors against which safety is ensured and requirements laid down in the Standards are:

(*i*) **Protection Against Electric Shock.** Safety against electric shock is ensured by specifying the following parameters in the Standard :

(*a*) Permissible leakage current (*b*) Insulation resistance
(*c*) Accessibility of live parts (*d*) Clearance and creepage distances
(*e*) Provision for earthing

(*ii*) **Protection Against Mechanical Hazards.** Protection against mechanical hazards to the personnel is ensured by the following requirements:

(*a*) Design and constructional features (*b*) External surfaces
(*c*) Accessibility of moving/rotating parts

(*iii*) **Protection Against Other Hazards.** Requirements for other kinds of hazards as given below are also specified:

59.3. RELEVANT INDIAN STANDARDS

The equipment used in the electrical installation should function satisfactorily not only at the time of commissioning but also it should continue to function reliably ensuring a safe working environment throughout its life period. The electrical safety requires that equipment should be able to withstand the electric stresses in normal and abnormal conditions and also at the same time providing no hazards to the persons handling the equipment. BIS has formulated Indian Standards and Codes of practices for installation and maintenance of entire range of electrical works and equipment like domestic appliances, wiring, earthing, transformers, power cables, switchgears, fuses, induction motors, motor-starters, lighting etc. A list of the same has been given at the end for reference of readers.

The scope and contents of some of the important standards is given below:

(*a*) **IS 302 Series: Safety of Household and Similar Electrical Appliances**

On the electrical safety of personnel, the most important Standard relates to general and safety requirements for household and similar electrical appliances (IS 302 series). In this Standard, constructional details of appliances have been laid down with a view to ensure protection from shock as well as protection from fire hazards under abnormal conditions beside the safety aspects. These Standards form the basis for development of more than 50 specifications dealing with the safety requirements of different electrical appliances. In addition there are about 30 specifications dealing with performance requirements for electrical appliances.

Indian Standards on electrical appliances permit a leakage current of only 300 micro amperes (Peak) against a maximum value of 700 micro amperes (peak) permitted in European countries where ambient conditions are dry and it was realized that this value may not be suitable for a tropical country like India where the ambient temperature and humidity are comparatively high. The difference in the living conditions was also taken into account to consider not only a safe current but that the level should be such that it should not cause discomfort to the user. Based on extensive study tests carried out all over the country, it was established that for India 300 microamperes (peak) should be the safe permissible leakage current. This value has been accepted by International Electrotechnical Commission also for tropical countries.

(*b*) **IS 5216 (Part 1 & 2): 1982 Guide for Safety Procedures and Practices in Electrical Work**

This is another important Standard on safety which deals with safety procedures and practices that should be followed for all major installations such as generating stations, sub-stations, industrial establishments, transmission and distribution lines and cable network. This guide also deals with safety instructions for working on low, medium, and high voltage machines and apparatus, methods to deal with accidents and fire fighting, first aid and resuscitation treatment for electric shock.

(*c*) **IS 732:1989, Code of Practice for Electrical Wiring Installations**

This Standard covers the essential requirements, which govern installations of electrical wiring in buildings with particular reference to safety and good engineering practices. It specifies the precautions to be taken regarding wiring in electric installations for ensuring efficient and safe use of electricity including safety from fire and shock. It relates to all electric installations in such locations whether the electric supply is derived from an external source or from a private generating plant.

(*d*) **IS 2309:1989, Code of Practice for the Protection of Buildings and Allied Structures Against Lightning**

This code gives the guidance on the principles and practices in protecting structures against damage from lightning. Guidance is given on how to assess the risk of being struck and in deciding if a particular structure is in need of protection.

(*e*) **IS 3043:1987, Code of Practice for Earthing**

This code gives guidance on methods that may be adopted to earth an electrical system for the purpose of limiting the potential of current carrying conductors forming part of the system.

(*f*) **IS 7689:1989, Guide for the Control of Undesirable Static Electricity**

This Standard covers the recommendations for controlling static electricity generated incidentally by processes, which may present hazards and inconvenience. This standard details the principal methods for safe control and dissipation of static electricity generated by solid objects, persons, liquids, dusts and gases. It contains information about the factors involved in the generation of the static electricity and the danger it can cause in a given environment.

(*g*) **IS 8437:1993, Effects of Current Passing Through Human Body**

This provides basic guidance on the effects of shock currents on the human body for use in the establishment of electrical safety requirements. It specifies the effects of both the types of current ac as well as dc on living organisms.

(*h*) **IS 8828:1996 Specification for Miniature Circuit Breakers**

This standard specifies the requirements of miniature circuit breakers, which ensures the tripping of circuitry in case of overload and short circuit conditions and thus preventing hazards.

(*i*) **IS 12640:1988 Specification for Residual Current Operated Circuit Breakers**

This Specification lays down the requirements of RCCBs/ELCBs which operate and separate the electrical system in the event of any leakage current and thus ensures the safety of the personnel handling the equipment.

(*j*) **IS 13703:1993 Specification for Low Voltage Fuses**

This covers the various types of fuses, which are used in breaking the circuit in the event of overload and short circuit conditions and thus reducing the risk of thermal hazards and fire.

(*k*) **SP (30) : 1986, National Electrical Code**

It is as a document on electrical practices & has been organized in the following parts :—

Part 1 General and Common Aspects
Part 2 Electrical installation in standby y Generating Stations and substations
Part 3 Electrical installation in no-industrial buildings
Part 4 Electrical installation in industrial buildings
Part 5 Outdoor installations
Part 6 Electrical Installations in agricultural premises
Part 7 Electrical Installation in hazardous area

Each part of the National Electric Code covers the requirements relating to electrical installations in specific occupancies. Special considerations & precautions are required for any electrical equipment for use in hazardous areas. Various such features and requirements are given in the next chapter.

59.4. SPECIAL PRECAUTIONS IN DESIGN, INSTALLATION MAINTENANCE OF ELECTRICAL EQUIPMENT IN HAZARDOUS LOCATIONS

The Electrical and Instrumentation equipment to be installed in hazardous locations of chemical and/or Hydrocarbon based processing, manufacturing, storage and/or transportation industry, are to be of special design to ensure that electrical equipment does not become a source of ignition/explosion of the inflammable gases/vapors or volatile liquids and/or dusts/fibers in such areas. There are many types and varieties of inflammable gases, dusts, fibers and liquids and these are grouped together based on their ignition/flash point, relative density and desired concentration of its mixture with oxygen in the air to form combustible source. The arcs/sparks at make-break contacts, and/or the hot surface temperature of electrical equipment can be source of start of ignition of such inflammable elements mixed with air in the atmosphere and which can lead to an explosion.

59.4.1. Elements for Ignition

There are three basic essential elements for ignition to start:

(A) Presence of favorable concentration of inflammable gases/vapours, dust, volatile liquids, fibers, etc.

(B) Arc/Sparks or heated surface temperature enough to ignite.

(C) Oxygen in the air to spread the combustion.

Presence of inflammable elements in Hydrocarbon and chemical process based industry and use of electrical equipment such as Panels, DBs, Junction boxes, Switchgear items, Motors, Generators, Luminaries, Fans, Telephone and Transducers, etc. is invariably required. It is not always practical to install electrical equipment away from hazardous area.) Oxygen is always present in atmosphere. Therefore, only element out of three above, which can be controlled is by the construction and design of electrical equipment to avoid start of ignition/combustion, by ensuring that no arcs/sparks come in direct contact with inflammable elements and equipment surface temperature in continuous as well as fault conditions does not exceed ignition/flash temperature point of inflammable elements. Ignition temperature of a gas/vapor is the lowest temperature at which its ignition occurs under specified condition. Flash point of a liquid is the lowest temperature at which the liquid evaporates and its vapors form inflammable mixture with oxygen in the air to start ignition.

Therefore specially designed electrical equipment have to be installed and maintained with proper care, that its explosion protected features remain always intact, to ensure safety of plant, machinery and personnel in the vicinity of such equipment.

For uniformity in design, construction and testing of such apparatus, Standards and Rules have been formulated in various countries. Independent test houses are established and recognized by statutory bodies to issue a conformity compliance test report to the manufacturer vide relevant Engineering Standards. The statutory approving authorities in each country accord approval, on the application and use of such test certified explosion protected equipment. It is mandatory to use only such test certified approved explosion protected design equipment in the hazardous areas. The development of Ex-protection methods took place around 1905. The first regulation of installation of such equipment in the hazardous areas was published in Germany and USA IN 1934-1935. The European norms for hazardous areas were published by CENELEC in 1972. The Indian Standard IS 2148 was first published in 1962. (Previously India used British Standards.)

Basic concept of explosion protection in various techniques is elimination of arcs/sparks, prompt extinguishing of arcs/sparks (if it occurs) and design the size of enclosure so as to maintain the surface temperature within the ignition limit/flash point of hazardous areas. The explosion protected design is coupled with mechanical design of joints, gaps, openings and inserts, etc. in such a fashion that environmental dust and liquids do not enter inside the enclosure. Care is also taken in the selection of material of construction and/or its painting to prevent corrosion due to acid/alkali fumes, gases and vapors in the vicinity of such apparatus. In such areas the process equipment or systems are also so designed, installed operated and maintained to minimize the release of inflammable elements during working conditions.

59.4.2. Classifications of hazardous areas & its sub-groups

As various explosion protection techniques depend on probability and risk factor of identified hazardous location, European (CENELEC series), British, Indian and standards formulated by IEC are similar on hazardous area classification and gas groups. NEC code of USA has a different classification scheme. NEC also recognizes inflammable dust and fibers as a separate class than gases (vide NEC 500-503). Recently NEC has added Part 505 to make hazardous areas classification in line with EN Series Standards. Vide NEC gases/vapors are Class I, dust as Class II and Fibers as Class III. Whereas vide most of other National standards, gases/vapors/dust/fibers are grouped into 4 Gas Groups only. The differences between NEC of USA and other major standards are—continued non-agreement on division and zone classification, differences in marking scheme on the equipment and differences in wiring and installation methods.

59.5. HAZARDOUS AREAS CLASSIFICATION-ZONES/DIVISIONS

The hazardous areas have been divided into zones take into account to different levels of dangers and likely protection schemes, which take care of both cost and safety.

A. Continuous Hazardous

Areas where Combustible Gas/Vapor/dust/fibers/volatile liquids are continuously present or present for long time. These are normally confined spaces like process vessels, storage tanks or closed containers, etc.

Known as — Zone-0 vide EN-500014, IEC79.1, IS-5572Pt.1 and IS-13346, NEC-505, BS 5501 Pt.1 for Gases/Vapours and Zone-20 vide EN, BS and IEC Standards for Dusts (It is Class-I, Division-1 vide NEC 500 to 503 for Gases and class-II, Division-1 for dusts)

B. Intermittent Hazardous

Areas where inflammable elements may exist under normal working conditions and/or under frequent repair/maintenance operations or where breakdown or faulty operation of process equipment may simultaneously cause failure of electrical equipment.

Known as-zone-1 vide EN 50014 and others as above for Gases/Vapors and zone-21 for Dusts.

(It is Class-I, Division 1 vide NEC 500-503 for Gases and Class-II, Division-1 for Dusts)

C. Hazardous Under Abnormal Condition

Areas where inflammable elements are handled within closed system/enclosures and where its concentration is prevented by the ventilation, *i.e.* areas where hazardous atmosphere occurs only during abnormal operating conditions (simultaneous occurrence of failure of some control system and sparks due to electrical failure). In such areas no danger exists in normal operating conditions. Such areas explosive gas/air mixture occurs for short time only.

Known as zone 2 vide EN 50014 and others as above for Gases/Vapours and Zone-22 for Dusts.

(It is Class-I, Division 2 vide NEC 500-503 for Gases Class-II, Division-2 for Dusts)

Areas adjacent to Zone 1 are also identified as Zone 2 because inflammable Gas/Vapor mixture may occassionally flow into such areas from Zone 1. It is the obligation of process know-how supplier and the process Engineering Consultant who prepare layout of equipment to identify hazardous areas of a Plant/Project in above 3 categories and earmark its boundary limits in both vertical and horizontal plane, around the equipment/area. Exhibit - I may be referred for guidance only for estimation of zones.

Extent of zones is a national division m/km a plant.

59.6. GAS/DUST/FIBRE GROUPS

Inflammable substances can be Gas, Liquid or Solid. Gases are often compound of Hydrogen and Carbon, which require little energy to react with atmospheric oxygen. Inflammable liquids are Hydrogen such as Ether, Acetone and Lighter fuel, which even at room temperature can evaporate to form explosive danger. Other liquids need higher temperature to form vapors.

When liquids are sprayed, a mist consisting of very small droplets with a large overall surface is produced. Such mist also present explosion hazards.

Inflammable solids are in form of dust, fibers and fluff that may react with atmospheric air to produce explosion. Once combustion starts the energy released produces high pressure and temperature.

Different combustible/inflammable elements have been grouped together based on its characteristics like density, flash point/ignition temperature and its lower and upper explosive limit by percentage volume (ratio with oxygen in air). This has been done to standardize the explosion protection technique for a particular gas/dust/fiber group and not design the electrical equipment for each type of gas/vapor/dust, etc. Othere important classification of hazardous areas is its temperature class based on ignition temperature of gas/dust, etc. or flash point of volatile liquids. A representative gas or dust is nominated for each group and design of equipment is based on characteristics of the representative gas/vapor, dust, etc.

Gas Groups : Representative gas name	*Gas group vide EN/IS/IEC/BS and also NEC 505*	*Class vide NEC 500 to 503*	*Group vide NEC 500 to 503*	
Methane*	I	Class I	Group D	(Underground coal mines)
Propane	IIA	Class I	Group D	
Ethylene	IIB	Class I	Group C	(Above ground plants)
Hydrogen	IIC (or IIB + H2 vide NEC 505)	Class I	Group B	
Acetylene	IIC	Class I	Group A	

*Methane in above ground plants (Sewage, LNG) falls under Gas Group II A

Representative dust/fiber name	*Class and group vide NEC 500-503*	*Group Classification vide EN/IEC/IS/BS standards*
Metal dust	Class II Group E	IIA/IIB
Coal dust	Class II Group F	IIA/IIB
Grain dust	Class II Group G	IIA/IIB
Wood/Paper/Cotton (Process fibers)	Class III No sub group	IIA/IIB

59.7. TEMPERATURE CLASS

The temperature rise of electrical products like Light Fitting, Motors, Fans, Generators, MOV, Transformer, etc. is important factor for its suitability in hazardous area. For uniformity and standardization, EN, IEC as well as NEC and IS codes have formulated 6 classes of temperature from T1 to T6, and design of any Ex-protected equipment is tested to determine its temperature class based on maximum surface temperature attained in continuous working. The selection of equipment is such that temperature class must be lower than the minimum ignition point or flash point of explosible elements in that area. The surface temperature attained of an equipment is external surface temperature for Exd type of protection and internal surface temperature for Exe type of protection. Ambient Temperature assumed is normally 40°C and they are suitable for installation in areas of ambient temperature (–) 20°C to (+) 40°C. For areas with ambient temperature higher than 40°C, the product has to be de-rated suitably. If an apparatus is combination of more than one enclosure, the temperature class of the apparatus shall be that of lowest temperature class of various enclosures.

Highest surface temperature of system: Temperature classes are $T1$ – 450°C, $T2$ – 300°C, $T3$ – 200°C, $T4$ – 135°C, $T5$ – 100°C and $T6$ – 85°C vide IEC/EN/IS/BS/NEC Codes. NEC 500-503 has sub-groups in T2 to T6 classes (for cost saving in size of enclosures).

Indian standard 2206 part 1 and B.S. 889 have different system of temperature class for only light fittings. These classes are, X – 125°C, Y – 75°C, and Z – 50°C which is Temperature rise above ambient temperature of 35°C. Therefore temperature class vide these standards for light fittings shall be

$$X\,(125 + 35) - 160°\text{C} \triangleq T3$$
$$Y\,(75 + 35) - 110°\text{C} \triangleq T4$$
$$Z\,(50 + 35) - 85°\text{C} \triangleq T6$$

Temperature classes vide VDE (Germany) are 5 classes, G1 to G5, called ignition groups,

G1 - more than 450°C, G2 - 300 to 450°C
G3 - 200 to 300°C, G4 - 135 to 200°C
G5 - 100 to 135°C

The cable junction boxes (JBs) local and remote control stations, DBs, Panels, Receptacles, Switches and starters, etc. are in general designed for T6 class always by all manufacturers. Temperature rise in electrical apparatus may also be due to insulation failure of wires/cables, Transformers, solenoid valves, Impedance coils, etc which is a condition of temperature rise during fault/breakdown. In motors, generators, and MOV the temperature rise can also be due to overload condition. The temperature class is tested by Test House and recorded in the Type Test Certificate.

59.8. WEATHER PROTECTION

All Ex-Protected equipment design and construction also takes care of environmental protection against ingress of dust/liquids. For the design based on weatherproof protection standards (IP - degree of protection) Exhibit - III gives details of degree of protection. The metallic enclosures are epoxy powder coated to withstand corrosion. In areas where dust accumulation on electrical products cannot be controlled, design has to take care of temperature class due to smouldering temperature of the type of dust in the environment.

59.9. MATERIAL OF CONSTRUCTION, DESIGN CHARACTERISTICS AND CONFORMITY TYPE TEST REPORT

The electrical equipment when in metallic construction has to be of copper free metal alloy to ensure that it does not produce spark when stuck by a metallic tool or hardware dropped on it by accident. Normally Aluminium - Alloy-LM6 is used for above ground installation and Cast Iron for underground coalmines. New trend is to use Moulded Reinforced polypropylene enclosures. For above ground industries only (still not approved vide Indian Standard IS-2148 for zone 1 Areas), design features are according to Engineering Standard to which it is made and tested.

Tests conducted by Test House include study of Detail construction drawings evaluation of materials of construction, Type of joints, Material and size of Hardware, Number and Size of display windows and cable entries, Rating and specification of electrical components. The equipment is actually tested for Explosion test, Flame Transmission test, Over Pressure Test, and IP Test. The detail construction design of manufacturer is also studied and approved by the Test House and the drawing number is recorded in the Type Test Certificate.

The test certificate number is sometimes suffixed by letter U, B, S, or X. If there is no suffix, the product can be used in designated area. The suffix stand for -

U — Test Certificate is not for complete equipment. It is usually for Components or Conduit/Cable accessories (like P.B., I.L., Switches, Meter, Gland, Elbow and other Pipefittings and Blanking plug.

B — Special conditions for installation, which are described in test report.

S — A non Ex-protected apparatus. This apparatus has often Exi circuits, which may be connected, into hazardous areas or this apparatus can be part of Exi circuits.

X — It is a substitute for B and S above, only vide CENELEC standards (EN - Series).

A list of approved Test Laboratories is given in Appendix-IV.

59.10. MARKING ON EX-PROTECTED DESIGN ELECTRICAL EQUIPMENT

Explosion protected design equipment carry a Name plate on cover top to indicate Name of manufacturer, Manufacturer product type number/numbers (in case of Panel, DB, LCS, etc.), Name of Test House, Reference of Standard to which design conforms to, Test certificate Numbers or Numbers, Approval reference of Statutory bodies (as relevant to country of installation) along with type of protection, degree of IP protection and temperature class.

The explosion protection technique is symbolized by letter "Ex" suffixed by type of protection like d, e, i, P, q, O e.g., Ex-d/Ex-e/Ex-P or combination of 2 protection like Ex-ed/Ex-id, as per IS, BS, NEC Standard. Whereas vide European harmonized EN standards the symbol is "EEx" suffixed by type of protection.

This is followed by hazardous zone and Gas group to which equipment has been tested and found suitable by the test House and then by temperature class and last by IP degree of protection. For example, Ex-d IIA/B T4 IP55 or EEx-d IIA/B T4 IP55. The symbol for conformity to EN codes is Ex.

A new scheme (IEC Ex) was published by IEC in Oct'1998 acceptable to all member countries, to minimize multiple testing and certification for a product to be accepted in various countries. It has been declared operative in Sep'1999. Under the scheme a manufacturer obtains an Assessment and Test Report (ATR) from an accepted certification body (ACB) using the work of an IEC Ex Testing laboratory (Ex TL). This ATR is accepted by certification bodies in other countries, when issuing their own national certification. (ACB and Ex TL can be same in many cases) ATR shows evidence of conformity with relevant IEC standards.

Each country when joining IEC Ex scheme is required to declare the differences between its national standard corresponding to IEC standard. On manufacturer request the ATR may include testing and assessment to cover the declared differences. ATR is thus a passport to gain access to different countries. ATR is an IEC Ex certificate of conformity and an IEC Ex marking. At present 19 countries are members (Australia, Canada, China, Korea, Russia, South Africa and 13 European nations) of this schemes. The basis to become member for a country is to get its ACB AND Ex TL approved by IEC Ex scheme governing body after survey of its standards and testing laboratories.

In Europe many EC nations have accepted 'ATEX' Directive (Ref. 94/9/EG) of 1995, which is being used for Ex-protected Equipment marking for zone-2 areas only. Under 'ATEX' manufacturers have option to build and Test Ex-Protection Equipment based on performance testing and not strictly confirming to laid out Engineering Standards. Such ATEX approved equipment is marked 'CE'. Under this scheme manufacturer is responsible for documenting and certifying the equipment. ATEX allows performance testing of product, instead of testing production facilities and construction standards. The 'CE' marking means equipment meet all EC directives. This CE mark and manufacturers declaration of conformity replaces legal testing norms, for zone 2 areas equipment only. Equipment for zone 0 or zone 1 still requires test certificate of approved test lab. ATEX has fixed June 30, 2003 dead line for manufacturers who wish to use CE mark, to have their quality systems in place, before getting approval of ATEX to use 'CE' mark on zone 2 area suitable equipment.

Association of electrical manufacturers of North America (NEMA) and test laboratory 'UL' in USA have standardized enclosure construction for Ex-Protection, to 2 Types only, which are marked on the equipment as relevant (NEMA 7 or NEMA 9, refer Exhibit - III).

59.11. MAINTENANCE OF EX-PROTECTED EQUIPMENT

It is very important that plant owners and Maintenance Engineers/Technicians must know and operate Ex-Protected Equipment in their plants, as per standard Norms and Care.

1. **First principle :**

— De-Energize/Isolate power supply before any opening of cover of Ex-protected Equipment

— Avoid using hammers and sharp tools, which damage flat joint surfaces.

— Always use right size of allen-key only, for cover bolts.

2. **Types of maintenance :**

— Preventive - Routine inspection and checks

— Repairs/replacement

— Statutory audit/inspection

3. **Visual inspection (once in every 4 to 6 months) :**
    1. Check for any Mechanical Damage, Corrosion, Dust collection, Condensate collection, Loose hardware, condition of Connectors and Cables, Tightness of clamps, condition of glass display windows and glass covers of light fitting and any visible cracks on equipment.
    2. Check for Tightness of cover Bolts/Threaded joints. See no cover bolts are missing and are not loose.
    3. To clean exteriors of dust/dirt, Touch up with correct quality of paint.
    4. To Ensure earth connections tight.
    5. To Remove dust/dirt from insulating materials, Check insulators are not discolored or damaged.
    6. Check condition and connection of components in "Exi" circuits, Check and measure open circuit voltage of Exi terminals.
    7. To Check Nameplate data is legible and no deterioration of markings on tag plates. Do not temper with nameplate data.
    8. To See no unused cable entry is blank. Use proper size and test certified blanking plugs with correct type of threads. Check over pressure reading of Ex-p apparatus.
    9. To Check flexible cable of portable equipment, Hand Lamp and Extension receptacle boards, etc., to be intact, properly connected and no extra load of any kind applied on such leads.
    10. To Check dielectric strength of Exi circuits, *i.e.* IR valve between intrinsically and non-intrinsically safe terminals is within limits.
    11. To check there is no undue vibration.
    12. To check oil levels of oil filled protected enclosure and sand level of sand filled protected enclosure.

4. **Routine maintenance (once in every 6 to 12 months) :**
    1. To remove rust/corrosion from joint gaps use CTC/Brush. Do not use files/abrasives. Do not place covers on surfaces that might damage/scratch flat joints.
    2. Topping up of Oil/Sand as relevant in Ex-protection models; To check Electrical and Mechanical Interlocks in Ex-p protected apparatus.
    3. Lamp replacement, removal of condensed water (if any).
    4. Check Emergency light fitting - Check for correct connection, Indicating light, switch and its ON/OFF working.
    5. Check performance of P.B. Actuators, Switch shaft, Limit Switch rollers, MCB, ELCB and O/L relay and resetting knobs, etc., for any malfunction/deterioration etc.

6. Check condition of gaskets for any cracks/deformation. Replace with genuine material and shape of gaskets only.
7. Check condition of Bearing, for leakage, deterioration of oil/grease and replace as desired. Use specified grease only.
8. To check and measure flame-path length and joint gaps with Vernier/Feeler gauges and verify it with standard norms for Exd and/or Exi enclosures.
9. Check aluminium alloy flanges for shape and damage. Clean flange joints of dirt/dust and apply suitable grease. Check that all surfaces that form flame-path are in tact and protected from damage. Check no foreign material in joints or between cover and enclosures. Never use metal tools or abrasives to clean flame-path.
10. Always use proper size and thread type of test certified cable glands. Never try any fresh Drilling/Tapping in Ex protected enclosures OD/UAD Grommets (Bushes) in a gland must be compatible with cable data.
11. When replacing cover bolts/Screws, always use specified size and material. Always use proper size of allen-keys.
12. Always maintain standard gaps when doing re-assembly of Rotors, Shafts and Bearing, etc.
13. Check IR value with megger before assembly after maintenance jobs to maintain integrity of insulation to avoid any accidental sparking or arcs.
14. No maintenance or checking of any sort shall be ever done on live parts.
15. Always take written permission of concerned plant manager before any repair/maintenance job is done in hazardous areas.
16. Check all enclosures and non-current carrying metal parts of fixed and portable equipment is properly grounded after each repair jobs, care is taken to avoid ignition due to static electricity. Cathodic protection system shall be maintained as per standard codes and circuits.

5. **Repair jobs (when required) :**
    1. Replacement parts must be genuine and identical only. (Any modification must be done with Manufacturer consent or by Manufacturer only.) Alterations done without authorization invalidate the Type Test Certificate.
    2. Flame-paths/gaps are measured with Feeler gauges, Vernier and Taps after each repair jobs.
    3. Check operation and function of operating Shafts, Handles, Actuator rods, etc. after reassembly.
    4. Check condition of Gasket (0 or V Shape), Ensure fitting of Gasket in designated groove only after repair jobs. Replace gaskets with specified material and type only.
    5. Dome glass when broken must be replaced with correct specified glass, cemented in metal ring for Exd and with rubber ring for Exe light fittings.
    6. When terminating external cables, ensure cable conductors not subject to any tension. Check all connections are tight.
    7. Check and measure surface temperature of Ex protected apparatus and ensure it is within specified temperature class of the area, after any repair job on Ex protected equipment.
    8. Follow Sr. Nos. 9 to 16 of Routine Maintenance jobs as above after every repair job.
    9. It is important, Plant owner shall keep in their records "AS BUILT" GA Drawings, conformity test certificates, Approvals of statutory bodies wiring diagrams, Reference list of comptible spare parts, Rating, Make and specification of electrical components used in assembly as well as Instruction manuals of the manufacturer. User shall also keep a log book/register to keep record of all repair jobs done as well as any incidents of Fire, Malfunctioning and of Explosion.

6. **Statutory audit/inspection (once in 1.5 to 2 years):**

It should be by chartered certified consulting engineers and/or by Inspector/Controller of explosives as per rules in the country of installation. The frequency of visual/Routine/Statutory Inspections can be revised based on process conditions and environmental conditions or after each fire and explosion.

59.12. DUTIES AND OBLIGATIONS

Manufacturer. To manufacture and sell all equipment strictly in line with certified approved detail construction drawing reference as indicated in conformity test certificates of test house. The test house approved detail construction drawing shall be shown on demand at manufacturer works to the buyer for verification of material of construction, dimensions, thickness of enclosures, special condition of test report (if any), size and openings of display windows, cable entries, Glass Type and thickness, and rating of components including glass, resin and cement/chemicals used in construction. Name plate of product shall also show relevant approval reference of statutory bodies. DIRECTOR GENERAL MINES SAFETY (coal, oil/gas mines), CHIEF CONTROLLER OF EXPLOSIVES (for all chemical and petrochemical industries), DIRECTOR GENERAL FACTORY ADVISORY SERVICES AND LABOUR INSTITUTE (for all industries) and ISI mark license Number issued by Bureau of Indian standards are the relevant approving authorities in India. Each Product shall be supplied with copy of Test house Type Test Certificate and works routine test reports (Hydraulic Test, IR Test, HV Test, Wiring circuit tests and functional tests).

Plant Owner/User. To install the equipment as per guidelines of hazardous areas and electricity rules, the equipment erection and cable termination are to be approved by statutory body in country of installation before commissioning. Copies of conformity test certificates and approvals must be available with user for reference of statutory body. Plant owner/user has to notify the approving statutory body promptly at time of any major/minor explosion or fire in hazardous areas. Routine Maintenance and inspection must be done as per factory/standard norms.

The Ex-protected equipment shall be properly serviced and maintained. A Log Book/Register shall be maintained to record all Maintenance/Repair jobs done and incidents of Sparking, Fire and Explosion, etc. for use in future audit jobs. Any special condition in conformity test certificate of recognized test house must be observed during repair jobs.

59.13. SELECTION OF RIGHT VARIETY OF EX-PROTECTED EQUIPMENT

Electrical and instrumentation equipment for hazardous areas shall be selected based on zone and gas group classification, Temperature class, Environmental protection desired and material of construction as per purchase requisition. Special consideration has to be given for non-hazardous area equipment, which is associated with hazardous area equipment of intrinsically safe design and sometimes of increased safety design also. The equipment shall be of design out of recognized Ex protection techniques with a conformity test certificate issued be a recognized test house vide standards approved and recognized in the country of installation. The explosion protection technique of equipment shall be compatible with hazardous area class, gas group (when relevant) satisfactory to thermal stability and any special condition of Conformity Test Certificate, as well as ambient Temperature, environmental protection desired and external cable sizes as per permissible cable entries in the equipment. Some equipment into which fluids may be introduced during the process (like pressure switch or canned motor pumps, where under fault condition diaphragm can fail and fluid under pressure released inside the apparatus) which is a ignition risk and its installation must be as per conditions in conformity test certificate.

Vide EN and NEC codes, user can assemble test certified enclosure with test certified components (like P.B., I.L., Meters, Switches etc.) In such cases only the test certified components vide standards acceptable in country and area of installation, shall only be selected by the user.

59.14. EXPLOSION PROTECTION TECHNIQUES

A. **Primary Ex-Protection.** It aims at substituting an inert product for inflammable substance or reduces quantity of Air/Oxygen that it does not form explosive mixture. Increase Air circulation or have equipment in open areas to reduce danger. Provide artificial ventilation and use Gas/Smoke detection, which would give alarm and/or shut down the system in case of Air/Gas mixture ratio exceeds set limits. Third element to prevent explosion is avoidance of source of ignition i.e. Electrical sparks (static discharge or when circuits are broken) friction and impact sparks (when castings or enclosure are struck) and hot surfaces (due to heat of Lamp, Brakes, Bearing and coils). Other ignition sources are flames or hot gases, lighting, ionizing, radiation, intense electromagnetic radiation, etc.

B. **Secondary Ex-Protection.** An explosion protected electrical equipment is not necessarily a totally encapsulated or totally sealed unit. There are 7 Known types of protection techniques, which revolve round principles that electrical equipment does not become a source of ignition, *i.e.* parts to which a potentially explosive atmosphere has free access do not become hot enough to ignite explosive mixture. The Protection feature, design construction details and Test acceptance norms are described in relevant Engineering standard of corresponding Ex-Protection scheme.

1. *Type M or type h - hermatically sealed.* It is totally sealed or Encapsulated design, in which parts that can ignite gases/vapors are enclosed (hermetically sealed) with a resin sufficiently resistant to environmental influences. It is mainly used for Miniature motors, Indicating Lamp, Meters, Small Compressors, Limit Switches and Electronic circuit boards. Suitable for zone 0, 1 and 2 areas, any gas group.

2. *Type q - sand filled/powder filled.* The electrical equipment is fitted in an enclosure which is filled with fine granulated sand (Quartz) of size 1.6 mm maximum and having 0.1% by weight of water, so that any arc occurring within the enclosure will not ignite the surrounding atmosphere and arc thus occurring is extinguished in sand itself, so no ignition is caused by flame or excessive temperature of surfaces of the enclosure. It is mainly used for fuse banks, Capacitor Banks, Resistance Banks, Small transformer or electronic circuit boards. The safe filling height of sand is determined by the rating of equipment and type tests. The minimum distance between bare live parts and enclosure wall shall be 5 mm to 10 mm. The enclosure must withstand over pressure test and withstand explosion within. It is suitable for zone 1 and 2 areas. The enclosures can be sheet metal fabricated or of castings.

3. *Type O - oil immersion.* Similar to Type q above, here sand is replaced by Mineral Oil, Minimum oil immersion height is determined by the rating and type tests. The maximum oil temperature shall remain within temperature class of area. High and Low oil level limits are mentioned on the enclosure. It is mainly used for Switching units, Circuit breakers and Transformers. Oil is a fire hazard, so special attention in maintenance and operation of such apparatus. Suitable for zone 2 areas.

4. *Type P - pressurized apparatus.* In this the whole electrical apparatus such as large size Motor, Generator, Instrument Banks, the room itself where DCS system or Power Control Center or MCC is installed is made safe by Pressurization of the enclosure of Motor/Generator or MCC/PCC room with a protective gas at higher pressure than surrounding atmosphere to prevent entry of surrounding gas/vapors into the enclosure. Over pressure can be maintained with or without continuous flow of protective gas (inert gas like N2 or air.) When flow is continuous, it is called purged gas technique, normally used when whole room is protected. In such a case the access door of the room are mechanically/electrically interlocked with power input to electrical apparatus. Also the operation of pressure control valve of the circulating air/N2 is electrically interlocked with power supply input to the electrical apparatus. The enclosure can be of sheet steel or cast metal. This technique is used where it works out economical compared to Ex-d technique or where electrical equipment is used temporarily for short period only. It is suitable for zone 1 or 2 areas.

5. *Type i - intrinsically safe.* It is a circuitry only and not an enclosure for electrical equipment. Concept is based on circuit design such that current and voltage input to the electrical equipment, like Sensor, Transducer, Pilot Valve, Control instruments, Communication equipment, etc. in the hazardous areas shall be within limit of ignition energy (MIC - Minimum ignition current) required to ignite inflammable gases/vapors and Air mixture, under normal or anticipated fault condition either having usable power of the order of one watt, open circuit voltage less than 30 volts and short circuit current up to 200 milliamperes. Open circuit voltage is limited by proper selection of cable capacitance and short circuit current by cable inductance. (V and I limits above are in relation to Ethane gas.) There are 2 categories in design, Ex-ia for connection of equipment in zone 0, 1 or 2 areas up to 2 components and up to 2 concurrent faults, and Ex-ib for connection in zone 1 or 2 areas for up to 1 component and 1 fault only.

Interconnection wiring between hazardous and safe areas is through test certified zener barriers/isolators to ensure cutting off of power input when input V and I limit exceed the design limit of Ex-i circuit. Care is taken to ensure Ex-i wires are not electro-statically and magnetically induced by Non Ex-i wires and proper earth connection are always maintained. Ex-i circuit is test certified for specified condition of a hazardous area and cannot be automatically used in any other location.

Advantages of Ex-i design circuits are - Maintenance and Calibration can be done in 'Hot' circuits and it is very economical compared to other techniques which require a suitable design enclosure to assemble electrical apparatus. It is good even for zone 0 areas and Suitable for zone 1 and 2 areas.

6. *Type e - increased safety design.* It is a technique used for zone 2 areas only (any gas group). In this, electrical apparatus is assembled inside a cast metal (CI or LM-6) or Mould Polypropylene (GRP) enclosure, or fabricated sheet metal. Safety features of Electrical component, like terminals, lamp holders, rotating machines (squirrel cage motors) are enhanced to minimize chances of sparking. It is assumed here that no explosion shall take place inside the enclosure. The enclosure size is determined such as to limit the surface temperature within the planned temperature class under maximum rating and fault conditions. Safety is increased by making lamp holder as enclosed Break Type, cable terminals as vibration-proof anti loosening type and added thermal protection devices in rotating machine to cut-off power if temperature exceeds the limit. The enclosure is made sturdy enough to avoid impact effect and mechanical damage. The enclosure is also designed for specified IP degree of weather protection.

This protection is economical compared to Ex-d protection. The joint lengths, Flame-path and Clearances of enclosure and cover are determined by test and standardized in relevant Engineering standards. Ex-e design light fitting is also complete with Restrictive breathing design for entries and joint gaps. This ensures that influences of external environment is minimum inside the enclosure and explosive atmosphere is unlikely to occur in normal working condition. This technique normally used for light fitting and meters and for cable terminal boxes, etc. Ex-e enclosures can be used with test certified Ex-d components in combined type of protection, Ex-ed suitable for zone 1 areas.

7. *Type d - flameproof (explosion proof) design.* This is most widely used technique. It is suitable for zone 1 areas. In this also the electrical equipment is assembled inside a cast metal (CI or LM-6) or moulded reinforced polypropylene (GRP) enclosure. Concept is that enclosure is sturdy enough to withstand an explosion, if it occurs inside the enclosure and its gaps and joints are such that flame gets cooled and extinguished when it travels within the enclosure, before getting out from the gaps and joints of enclosure. The transmission of flame outside is prevented by toleranced flame-paths, based on maximum emission safe gap (MESG) test for different varieties of gases/vapors. The enclosure design is different for gas group IIA/IIB and for gas group IIC. However, an equipment approved for zone 1, IIC group can be used also in zone 1, IIA/IIB, but vice versa is not true. The enclosure size is determined by planned temperature class of application. The enclosure design is coupled with IP degree of protection and impact resistance as desired for proposed application.

The thickness of enclosure, flame path length, gap width and length, type of joint (Bolted or Threaded or flanged types), the openings for display windows and for Shaft, Bearings, Spindles, etc. are maintained as per standard limit and norms determined by laboratory tests and standardized in relevant Engineering Standards. The Exd design is used for almost all type of electrical equipment, like light fitting, control station, motors, fans, telephones, MOV, solenoid valves, junction boxes, cable conduit accessories, etc. Flameproof concept shall not be related in any way however with fireproof. Also to be noted that Exd or Exe enclosures are not Gas/Air tight. Engineering Standards associated with the various types of protection techniques.

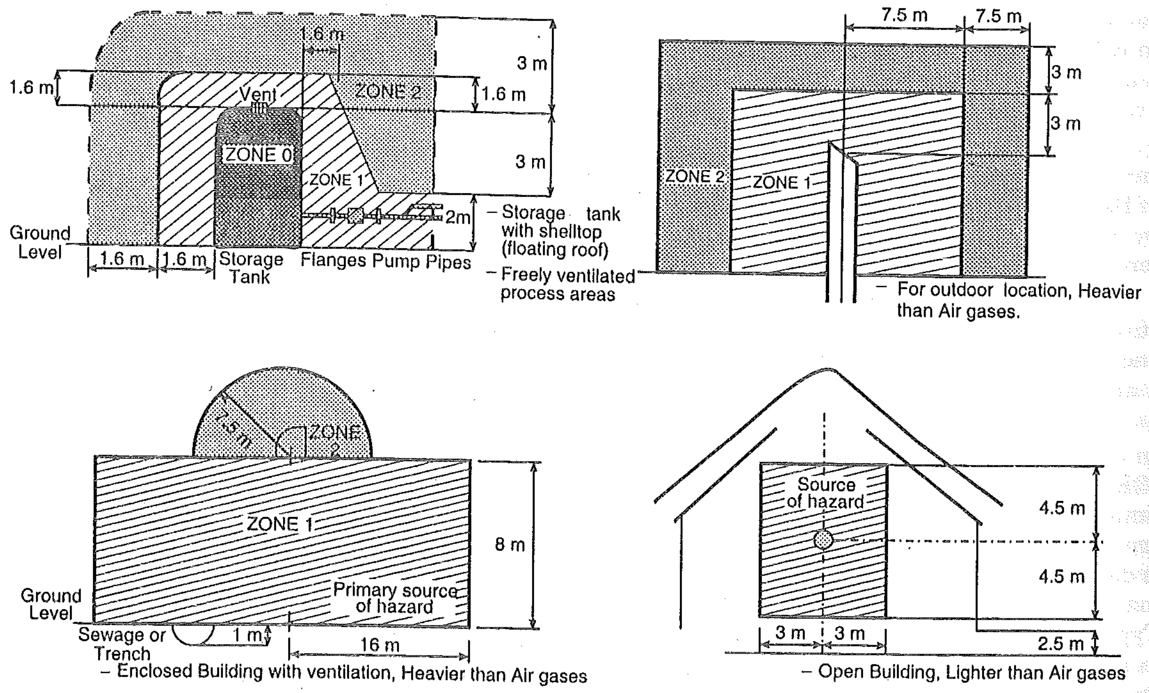


Fig. 59.1. Classification of hazardous area.

59.15 LIGHTNING PROTECTION OF STRUCTURES WITH EXPLOSIVE OR HIGHLY FLAMMABLE CONTENTS

(This is only for information of students - for field application codes & Practices to be followed)

The presence of explosives or highly flammable materials in a structure may increase the risk to persons or to the structure and the vicinity in the event of a lightning stroke. For this reason higher degree of protection is essential for these structures. Protection of a different degree may be secured in the case of both self-protecting and other structures by installation of various types of protection equipment, such as vertical and horizontal air terminations and other means. The recommendations given below should be followed for structures in which explosive or highly flammable solids, liquids, gases, vapours or dusts are manufactured, stored or used or in which highly flammable or explosive gases, vapours or dusts may accumulate.

PRECAUTIONS. Following precautions should be taken for the protection of structures and their contents from lightning.

(*a*) Storage of flammable liquids and gases in all-metal structures, essentially gas-tight,

(*b*) Closure or protection of vapour or gas openings against entrance of flames,

(*c*) Maintenance of containers in good condition, so far as potential hazards are concerned,

(*d*) Avoidance, so far as possible, of the accumulation of flammable air-vapour mixtures about such structures.

(*e*) Avoidance of spark gaps between metallic conductors at points where there may be an escape or accumulation of flammable vapours or gases.

(*f*) Location of structures not inherently self-protecting in positions of lesser exposure with regard to lightning, and

(*g*) For structures not inherently self-protecting, the establishment of zones of protection through use of earthed rods, masts, or the equivalent.

59.16. GENERAL PRINCIPLES OF PROTECTION

For the protection of structures with explosives or highly flammable contents an air termination network should be suspended at an adequate height above the area to be protected. If one horizontal conductor only is used, the protective angle adopted should not exceed 30°. If two or more parallel horizontal conductors are installed, the protective angle to be applied may be as much as 45° within the space bonded by the conductors, but it should not exceed 30° outside that space. The height of the horizontal conductor should be sufficient to avoid all risk of flashover from the protective system to the structure to be protected. The supports of the network should be adequately earthed.

Where this method may be expensive and where no risk is involved in discharging the lightning current over the surfaces of the structure to be protected, a network of horizontal conductors with a spacing of 3 m to 7.5 m, according to the risk, should be fixed to the roof of the structure. If the vertical conductor is separate from the structure to be protected, the minimum clearance between it and the protected structure shall be not less than 2 m; this clearance should be increased by 1 m for every 10 m of structure height above 15 m to prevent side flashes. Also the minimum clearance between the suspended horizontal air termination and the highest projection on the protected structure shall be 2 m.

A structure which is wholly below ground and which is not connected to any services above ground may be protected by an air termination network since soil has an impulse breakdown strength which can be taken into account when determining the risk of flashover from the protective system to the structure to be protected, including its services. Where the depth of burying is adequate, the air termination network may be replaced by a network of earthing strips arranged on the surface.

59.17. TYPES OF LIGHTNING PROTECTION SYSTEM

These are generally of the integral mounted system with the horizontal air terminals running along the perimeter of the roof in all cases except for buildings containing highly sensitive explosives & very small buildings. The following types of protection have been given in various Codes :-

Type of Building	*Recommended Type of Protection*
Building with explosives dust or flammable vapour risk	Integrally mounted system with vertical air terminals 1.5 m high and horizontal air terminals spaced 3 to 7.5 m from each other depending on the type of storage and processes involved
Explosives storage building and explosives workshops	Integrally mounted system with vertical air terminals 0.3 m high and horizontal air terminals spaced 7.5 m.
Small explosives storage buildings	Vertical pole type
Buildings storing more dangerous types of explosives, for example, nitroglycerine (NG) and for initiatory explosives manufacturing	Suspended horizontal air terminations at least 2 m higher than the structure and with a spacing of 3 m.

The earth terminations of each protective system should be interconnected by a ring conductor. This ring conductor should preferably be buried to a depth of at least 0.5 m unless other considerations, such as the need for bonding other objects to it, testing, or risk of corrosion make it desirable to leave it exposed in which case it should be protected against mechanical damage. The resistance value of the earth termination network should be maintained permanently at 10 ohms or less.

59.18. BONDING

All major members of the metallic structure, including continuous metal reinforcement and services, should be bonded together and connected to the lighting protective system. Such connections should be made at least in two places and should, so far as is possible, be equally spaced round the perimeter of the structure at intervals not exceeding 15 m. Major metalwork inside the structure should be bonded to the lightning protective system. Electrical conductors entering a structure of this category should be metal-cased. This metal casing should be electrically continuous within the structure. It should be earthed at the point of entry outside the structure on the supply side of the service and bonded directly to the lightning protective system. Where the electrical conductors are connected to an overhead electric supply line, a length of buried cable with metal sheath or armouring should be inserted between the overhead line and the point of entry to the structure and a surge protective device, for example, of the type containing voltage-dependent resistors, should be provided at the termination of the overhead line. The earth terminal of this protective device should be bonded direct to the cable sheath or armouring. The sparkover voltage of the lightning protective device should not exceed one-half the breakdown withstand voltage of the electrical equipment in the structure. Metallic pipes, electrical cable sheaths, steel ropes, rails or guides not in continuous electrical contact with the earth, which enter a structure of this kind, should be bonded to the lightning protective system. They should be about 75 m away and the other a further 75 m away.

59.19. OTHER CONSIDERATIONS

For a buried structure or underground excavation to which access is obtained by an adit or shaft, extra earthing should be followed for the adit or shaft at intervals not exceeding 75 m.

The metal uprights, components and wires of all fenes, and of retaining walls in close proximity to the structure, should be connected in such a way as to provide continuous metallic connection between themselves and the lightning protective system. Discontinuous metal wire fencing on non-conducting supports or wire coated with insulating material should not be employed.

The vents of any tanks containing flammable gas or liquid and exhaust stacks from process plants emitting flammable vapours or dusts should either be constructed of non-conducting material or be filled with flame traps.

Structures of this category should not be equipped with a tall component, such as spire or flagstaff or radio aerials on the structure or within 15 m of the structure. This clearance applies also to the planting of new trees.

59.20. GROUP CLASSIFICATION OF INFLAMMABLE GAS/VAPOR

(Figure in Brackets is Auto Ignition Temperature in °C)

(A) *Gas Group D of NEC or Group I vide EN/IS/BS/IEC*

1. Methane (537)

(B) *Gas Group C and D of NEC or Group - IIA/IIB vide EN/IS/BS/IEC*

1. Acetaldehyde (175)
2. Amyl Acetate (360)
3. Butadiene (175)
4. N-Butylvaldehyde (218)
5. Carbon Monoxide (609)
6. Isoprene (220)
7. Acetone (465)
8. Ammonia (498)
9. Ethyl chloride (405)
10. ChloraEthylene (350)
11. Butane (288)
12. Benzene (498)
13. Naphtha (288)
14. Ethanol (363)
15. Ethyl Acetate (427)
16. Hexane (225)
17. Methyl Acetate (454)
18. Ethane (472)

19. Methanol (385)
20. Propane (450)
21. Pentane (243)
22. Xylene (464)
23. Di-ethyl Ether (160)
24. Ethylene (450)
25. Ethylene (340)
26. Gaselene (260 - 471)
27. Coke oven gas (250)
28. LPG (Propane+Butane) (205)
29. Hydrazine (23 to 270)
30. Marsh gas (methane) (515)
31. Water gas (H2 + CO) (415)
32. Producer Gas (CO + N2) (455)
33. Ethylene Glycol (238)
34. Natural gas (Methane + Hydrocarbons) (426)
35. Hydrogen Sulphide (260)
36. Town Gas (350 - 500)
37. Ethylamine (380)
38. Ether (60)
39. Toulene (480)
40. Acetic Acid (464)
41. Carbon Disulphide (90)

(C) *Gas Group A and B of NEC or Group IIC vide EN/IS/BS/IEC*

1. Hydrogen (520)
2. Acetylene (305)
3. Ethylene oxide (429)
4. Formaldehyde gas (428)
5. Fuel and Combustible process containing > 20% H2 by volume (200 to 400)

(2) **Group classification of Dust**

(A) Group E of NEC: Metal dusts (Aluminium Alloy, Boron, Calcium, Silicate, Chromium, Magnesium, Thorium, and Titanium.)

(B) Group F of NEC: Coal dusts (Asphalt, Charcoal, lignite coal coke dust)

(D) Group G of NEC: Grain dusts, (cork, almond, cellulose, citrus peel, cocoa, corn, rice bran, sugar, powdered walnut shell, wheat starch, wood flour yeast, drugs, dyes, pigments, intermediate, pesticide, thermoplastic resins and moulding compound, nylon resins, epoxy resins.

(3) Group classification of Volatile liquids - vide IS-5572 Part-1 and Petroleum code of CCE, India, divided into 3 classes based on flash point. It is the lowest temperature at week sufficient quantity of vapors will advise to permit its ignition under laboratory condition.

1. Class A —	for Flash Point up to 25°C Aviation fuel, Gasoline, Benzene, Low F.P. Naphtha, Chlorobenzene
2. Class B —	for Flash Point from 26 to 60°C Kerosene, Diesel, Edible Oil, High Flash Point Naphtha, Styrene, Turpentine
3. Class C —	for Flash Point from 61 to 94°C Furnace oil, Fuel oil, Phenol and heavy petroleum

Notes : (1) The above is not complete exhaustive list of all inflammable elements.

(2) Group 2 above are Gas Group IIA and IIB vide EN/IS standards, class III Group fibers and fluff vide NEC have further no sub groups.

(3) Please refer Engineering Standards, Hand Books or manufacturers manuals for characteristics like Density ignitions point flash point and maximum and minimum gas/air mixture limits of various inflammable elements.

Table

First Digit	Degree of protection against contact and foreign bodies	Second Digit	Degree of protection against water
0	No special protection	0	No special protection
1	No protection against conscious entry, however exclusion of large body surfaces, protected against foreign bodies over 50 mm diameter.	1	Protection against drops of water falling vertically.
2	Exclusion of finger and similar parts protected against foreign bodies over 12-mm diameter.	2	Protection against drops of water falling at 15° to vertical.
3	Exclusion of wires, etc. over 2.5 mm diameter, protected against foreign bodies over 2.5 mm diameter.	3	Protection against water spray falling at 45 to 60° to vertical.
4	Exclusion of wires, etc. over 1 mm diameter, protected against foreign bodies over 1 mm diameter.	4	Protection against water spray from any direction.
N5	Complete protection against contact, protection against harmful dust deposits (Dust Protected).	5	Protection against jets of water from any direction at specified force (size of sets and distance as per standards).
6	Complete protection against contact, protection against the entry of dust (Dust tight).	6	Protection against heavy seas or strong jets of water.
		7	Protection against harmful entry of water when dipped in (submerged in water for long time).
		8	Protected against entry of water when submerged (indefinite immersion).

QUESTIONS

1. Name three important IS related to electrical safety ?
2. The IS which deals with the requirement of Residual Current operated circuit breakers is ?
   (*a*) 13703 (*b*) 12640 (*c*) 8828 (*d*) 732,
   Ans. (*b*)
3. What are the three basic essential elements for ignition to start ?
4. What is the importance of operating temperature limit of electrical equipment in hazardous areas.
5. Discuss (*a*) Primary Ex-Protection (*b*) Secondary Ex-Protection
6. What is meant by Ex-Protected design of Electrical/Electronic Products.
7. What is degree of Protection.
8. N5 degree of protection ensures.
9. Discuss briefly the type of lightning protection of structures/buildings with Explosive or Highly flammable contents.

Appendix-A
Recent Trends and Advances Towards 21st Century

Introduction — Standards and Organisations for Quality Management (QM) — ISO 9000 Certification — BVQI Certificate of Quality Management — Feedback Loop of Site Quality and Interfaces — Interaction between Power Systems, Load, Equipment and Protection/Control/Monitoring/Dignostics — Fault Investigations — Event Recorders — Expert Systems — SCADA — Modern Control Room Facilities for Fault Investigations — *Intelligent Circuit Breakers.* *Electrical Safety Management* and *Safety Aspects* — Unsafe conditions and acts — Safety Procedures. *Intelligent Air Insulated Substations,* (IAIS) Control and Protection Systems with Fiber Optic Cables — Fiber Optic Cables for Data Transmission, Measurement, Protection, Monitoring Systems — Fiber Optic Cables with Transmission Lines — *Digital Optical Instrument Transducer* (DOIT) — Fiber Optic CT — Communication in Power System — *Satellite Communication.*

A.1. INTRODUCTION

The electric power systems, switchgear protection and power system automation have undergone significant advancements during the last quarter of the twentieth century. *Trends* are set for new, versatile, maintenance-free, compact, reliable, safe, user-friendly, automatic equipment. The *reliability* and *availability* of power systems, plants and equipments has gained significance. The power systems, market trends, manufacturing trends are undergoing intense restructing as a result of privatization, economic reforms, energy crisis and market pressures on cost. The significant trends have been reviewed in this concluding chapter*.

A.2. STANDARDS AND ORGANISATIONS FOR QUALITY MANAGEMENT (QM)

Quality certification for plants, equipment and services has gained importance. The following organisations publish the standards related with specifications and quality of equipment, plants and services.

— International Standards Organisations (ISO) Head Quarters : Geneva, Switzerland.
— Indian Bureau of Standards (Former Indian Standards Institution), New Delhi.
— Bureau Veritas Quality International (BVQI).

The list of ISO and IS Standards on Quality is given below. These standards are followed by Manufacturers, Consultants and Customers (users) of electrical plants and equipment.

ISO	*IS*	*Title*
ISO : 9000	IS : 14000	Quality Management and Quality Assurance Standard. Selection and Use : 20 Systems Elements
ISO : 9001	IS : 14001	Level 1 : Design/Development Prodution, Testing in Factory Installation and Servicing
ISO : 9002	IS : 14002	Level 2 : Production and Installation all elements, some less stringent.
ISO : 9003	IS : 14003	Level 3 : Final Inspection and Tests – half the elements, low stringent.
ISO : 9004	IS : 14004	Guidelines : Maximising benefits and minimising costs.

A.3. ISO 9000 CERTIFICATION

ISO 9000 Certification is given to a manufacturer or an organisation as a recognisation of the Quality. The duration of the certificate is 3 years.

* Also refer : Ch. 52, Table 52.2 ; Ch. 43-C, Ch. 46-A Ch. 47, Ch. 48, Ch. 50, Ch. 52 and Ch. 53 for recent advances.