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.*

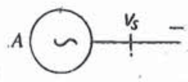
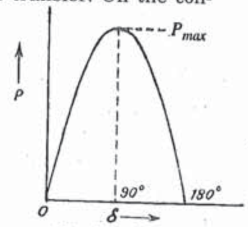


Fig. 44.1 (a). Two-machine system (a.c.).



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

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

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

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 :

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

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

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).

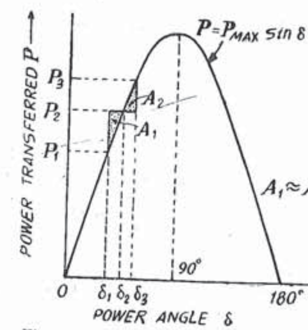


Fig. 44.2. Explaining Transient Stability.

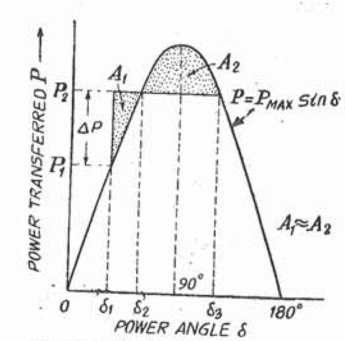


Fig. 44.3. Explaining Transient Stability.

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

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

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 :

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

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.*

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

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

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

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 :*

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

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

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.*

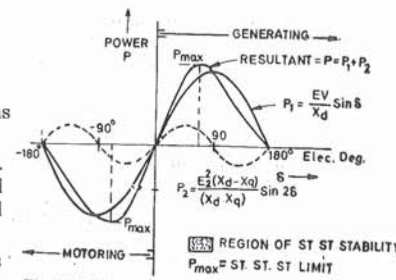


Fig. 44.5. Power angle characteristic of a salient pole Synchronous Machine (P v/s δ).

For salient pole machines

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

for cylindrical rotor machine

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

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 :

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

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

where E, E' = voltage behind reactance
V = Terminal voltage
δ = Angle between E and V.

Consider V as reference vector

$V = V \angle 0°$

$= 1.00 \angle 0 = 1 + j0$

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

= Angle between I and $V = 24.5°$

$$E' = V + j\,IX'_d \qquad \text{...(44.8)}$$

$= (1 + j0) + (1.00\ ° - 24.5°)\ (0.37 \angle 90°)$

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

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

between E' and V at

$t = 0$ is $16.3°$

Power angle curve is given by :

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

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

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.

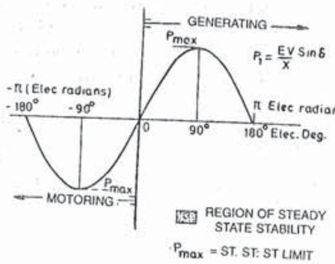


Fig. 44.6. Power angle characteristic of Cylindrical Rotor Synchronous Machine (P v/s δ).

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.

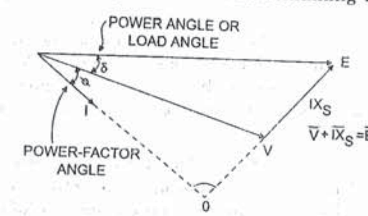


Fig. 44.7. Vector diagram for cylindrical rotor machine operating as generator.

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

Synchronising power P, an angle δ_1 is

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

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,

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

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

J = Moment of Inertia of rotor

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

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

where N = RPM. One Rev. = 2π radians

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

K.E. = Joules

ω = Angular speed of rotor, radian/sec.

If N_s = Synchronous speed rpm

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

$\omega = \frac{2\pi N}{60}$ 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-m² and runs at no load speed of 500 rpm. Calculate the kinetic energy in the rotor.*

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

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

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

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

= 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 $\frac{\text{kg-m}^2 \text{ rad}}{\text{sec}}$ ...(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

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

$$= G \times H \quad \text{...(44.15)}$$

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

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

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

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 :

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

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 50×10^2. 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 m^2

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

[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-metre^2
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, $M = \frac{\text{Megajoules sec}}{\text{Elec. Degree}}$ $\omega = \frac{\text{Elec. Degree}}{\text{Sec.}}$	Megajoules
M	Angular momentum	$M = \frac{GH}{180 f}$ $= \frac{GH}{\pi f}$	$\frac{\text{Mega-joule sec}}{\text{Elec. Degree}}$ $\frac{\text{Mega-joule sec}}{\text{Elec. Radians}}$

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).

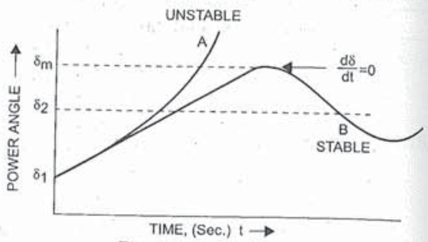


Fig. 44.8. Swing Curve.

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	**M** ... $\dfrac{\text{Mega Joule sec.}}{\text{electrical degree}}$
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 :

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

where P_a = Acceleration Power ... MW

P_s = Shaft Power ... MW

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

We know, from Eq. 44.3

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

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

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

From Eq. 44.4 (*b*),

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

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

$$T_a = T_s - T_e \qquad \text{...(44.13)}$$

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

Accelerating Power	=	Shaft Power	−	Electromagnetic Power
P_a	=	P_s	−	P_e

...(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 $P_a = J\alpha\,\dot{\omega} = (Ja)\,\omega$

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), $P_e = \dfrac{VE}{X}\sin\delta.$

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 $= \dfrac{\text{K.E. (stored)}}{\text{MVA rating}} = \dfrac{200}{50} = 4$

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

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

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

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

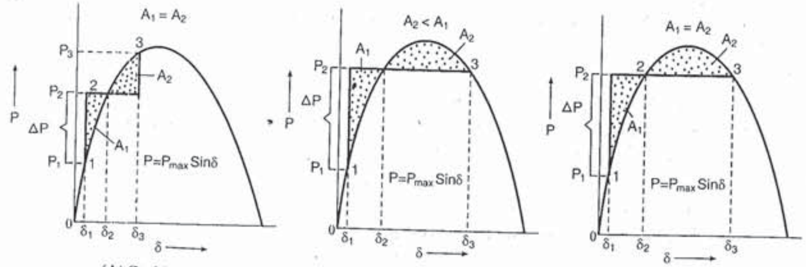
Hence acceleration $$d^2\delta/dt^2 = \frac{2.5}{1.06} = 2.35 \text{ rad/sec.}^2$$

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 :

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

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 $\frac{d}{dt}$

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

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

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

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

Integrating with respect to t,

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

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

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,

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

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

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
$$A_1 - A_2 = \int_1^2 (P_1 - P_2)\, d\delta \qquad ...(44.26)$$

from Eqns. 44.25 and 44.26,

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

$$A_1 = A_2 \qquad \text{...(44.27)}$$

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

$$(\delta_3 - \delta_1) \sin \delta_2 + \cos \delta_3 - \cos \delta_1 = 0 \qquad \text{...(44.28)}$$

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 $\delta = 8°$?

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

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

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

(B) Let initial angle $\delta = 8°$

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

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

$$(\pi - \delta_2 - \delta_1) \sin \delta_2 - \cos \delta_2 - \cos \delta_1 = 0 \qquad \text{...(44.29)}$$

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*.

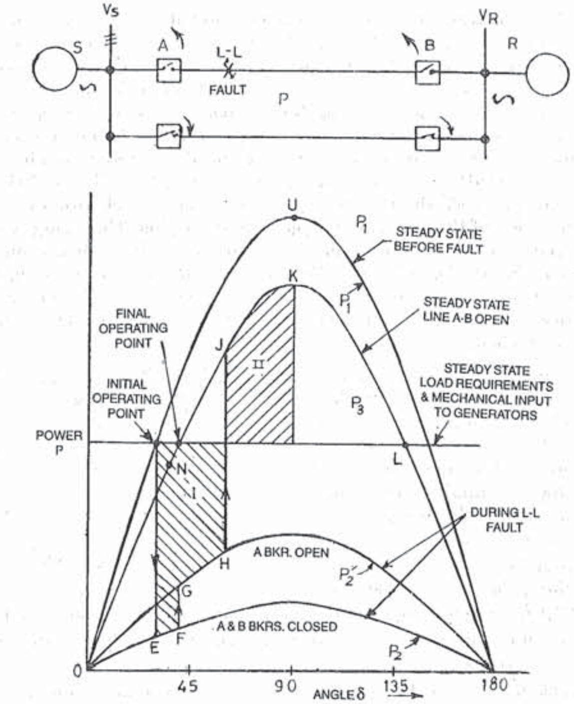


Fig. 44.11. Power transfer curves before, during and after line-to-line fault.

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.

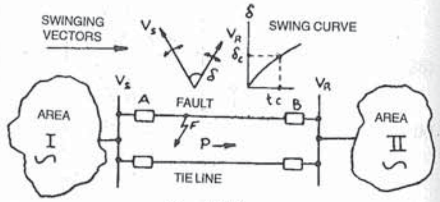


Fig. 44.12.

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.

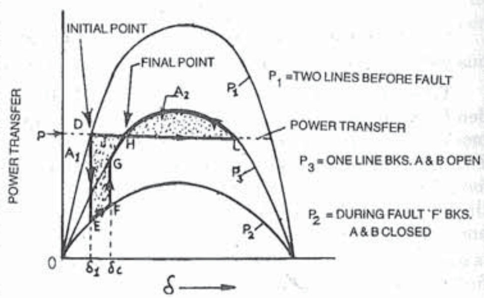


Fig. 44.13.

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.*

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

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

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 $\delta_1 = \sin^{-1}\left(\frac{1}{1.8}\right)$ = 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.

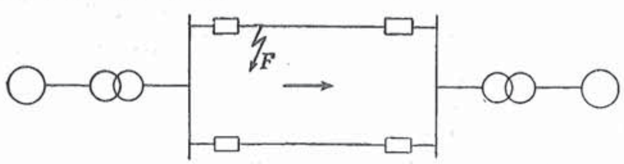


Fig. 44.14 (*a*). The system subjected to fault F at sending end on one of the two lines.

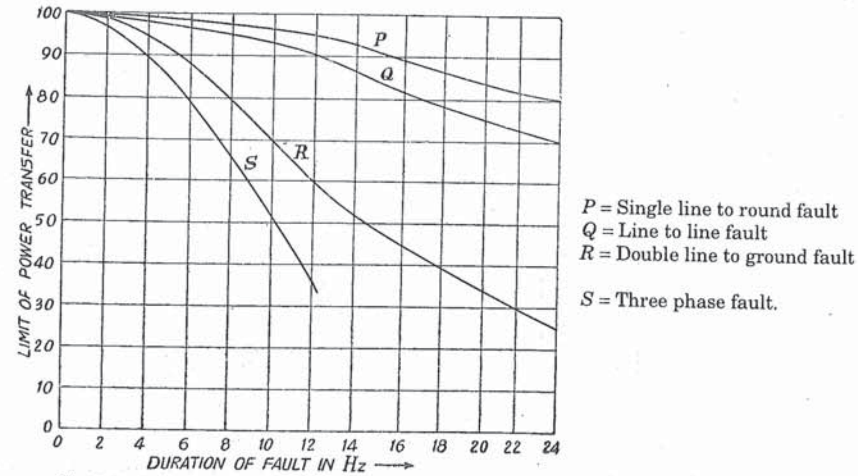


Fig. 44.14 (*b*). Effect of duration of fault on limit of power transfer for various types of fault.

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.

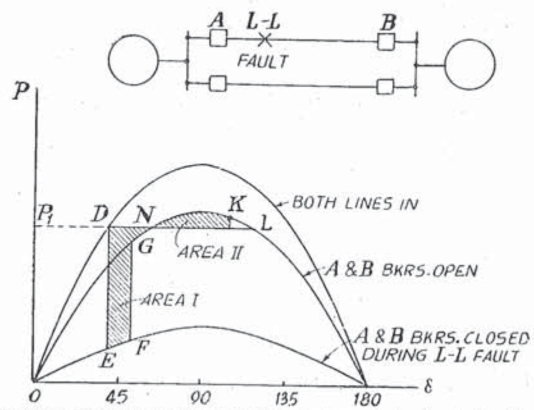


Fig. 44.15. Power angle diagram before, during and after line-to-line fault.

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

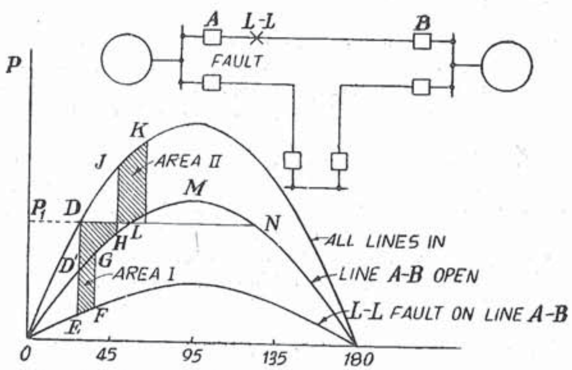


Fig. 44.16. Power angle diagram for L-L fault with rapid reclosing.

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.

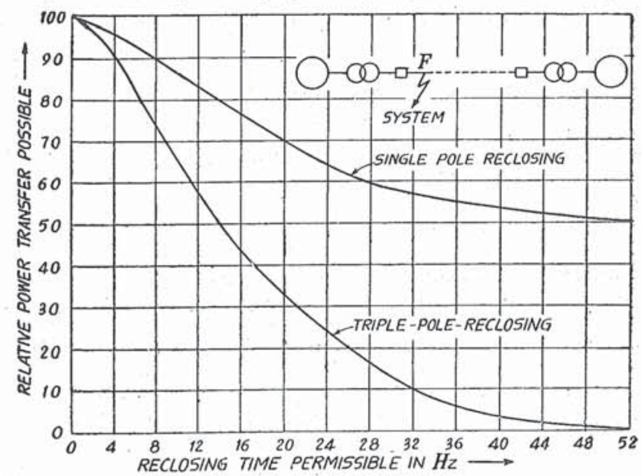


Fig. 44.17. Comparison between three-phase auto-reclosure and single phase auto-reclosure.

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

2*L–G* fault, *L–L* fault — 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.

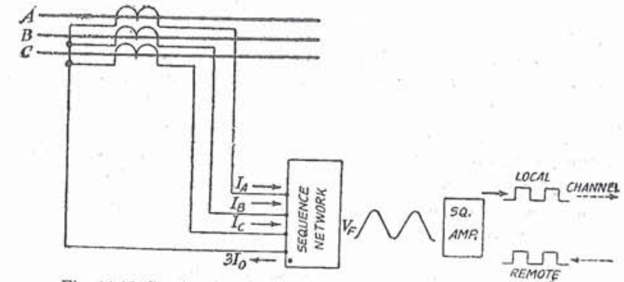


Fig. 44.18. Carrier signals in conventional phase comparison relaying.

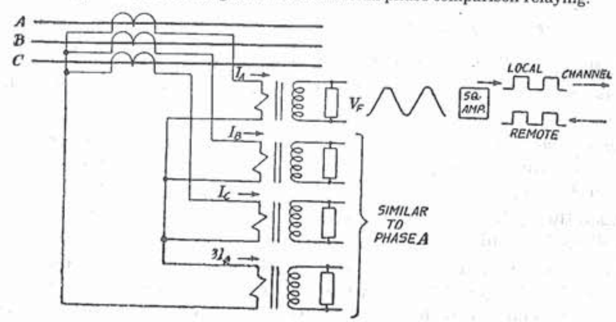


Fig. 44.19. Carrier signals in SPCR.

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).

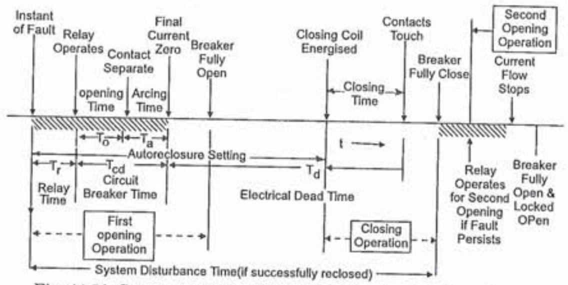


Fig. 44.20. Sequential events in single shot autoreclosing scheme. (Chapter 2 for detailed description)

(*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.

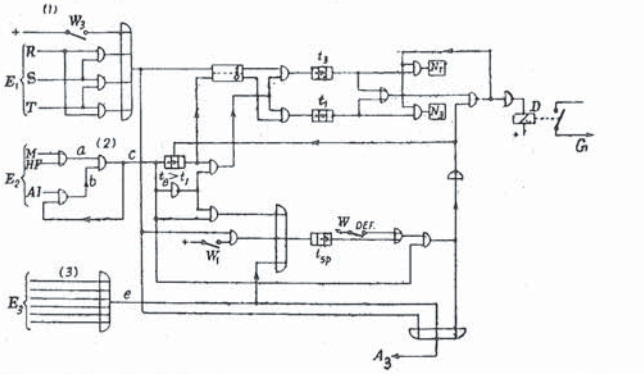
The Distance Protection Scheme provided for long transmission lines are fitted with Autoreclosing Apparatus (Refer Ch. 42).

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

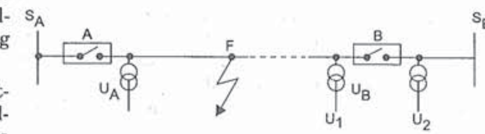
— all three phases trip if a single phase faults occurs while the reclosure is blocked, or
— all three phases trip when three phase tripping is required for all types of faults.

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.

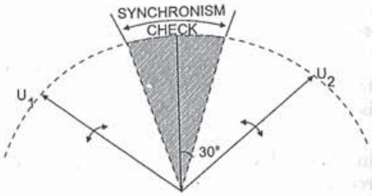


Fig. 44.23. Condition for closure of synchronism monitor contracts.

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 $\pm 30°$ 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.

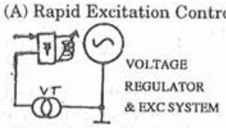
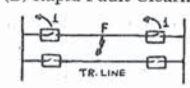
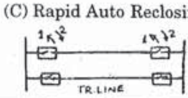
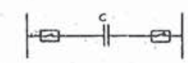
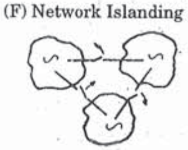
Large motors take high starting currents for a few seconds. The bus-voltage shall not dip below 85% under starting conditions.

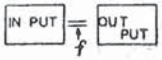
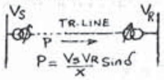
PART F : IMPROVEMENT IN STEADY STATE TRANSIENT STABILITY LIMITS

[*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

$\mathbf{V} = \mathbf{E} - \mathbf{IX}$

$\mathbf{V}$ = 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.

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

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.