45-A

Load-Frequency Control, Load Shedding and Static Frequency Relay

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

45.1. INTRODUCTION TO SYSTEM FREQUENCY CONTROL

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

Method of Frequency Control

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

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

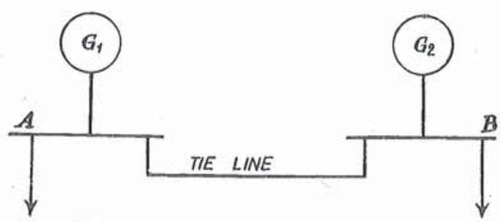


Fig. 45.1. Parallel operation of station A and B.

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

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

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

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

45.2. LOAD-FREQUENCY CHARACTERISTICS OF ROTATING MACHINES

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

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

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

45.3. PRIMARY LOAD-FREQUENCY CONTROL

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

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

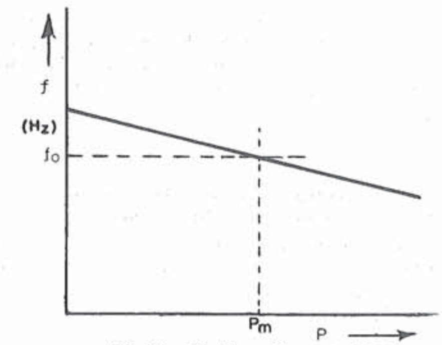
The frequency control by the action of the mechanical governor is called the 'primary control'. The governor admits more steam turbine or more water in hydro turbine. Thereby the electrical output of the generator is also increased. To avoid hunting, the governors are designed to remain stable at a speed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

45.4. SECONDARY LOAD FREQUENCY CONTROL

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

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

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



(Machine : Turbine = Generator Unit)

f_o = Rated frequency P_m = Machine output at frequency.

Fig. 45.2. Machine load frequency relation.

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

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

45.5. LOAD-FREQUENCY CONTROL OF A GRID

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

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

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

— Improve compensation of load fluctuations.

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

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

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

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

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

45.6. LOAD SHEDDING

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

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

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

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

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

where ΔF = change in frequency

ΔP = Power deficit

H = Inertia constant of network.

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

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

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

— Behaviour of system voltage before and after load shedding.

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

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

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

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

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

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

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

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

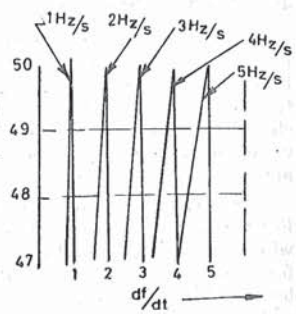


Fig. 45.3. Stability of a frequency relay with respect to df/dt and f.
(*Courtesy* : Brown Boveri, Switzerland)

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

The frequency relay for load shedding has three operating criteria,

— The frequency is below the set release frequency.

— The gradient df/dt is greater than setting.

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

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

45.8. STATIC FREQUENCY RELAY

(*Courtesy* : Brown Boveri, Switzerland)

The following basic requirements are satisfied by static frequency relays :

(*i*) high reliability

(*ii*) accuracy

(*iii*) high measuring speed.

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

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

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

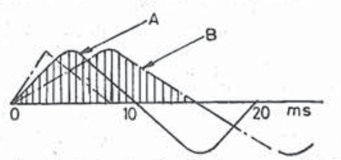


Fig. 45.4. Number of counts during half a cycle increases with reduced frequency.
A = Normal frequency waveform B = Reduced frequency waveform (exaggerated)

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

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

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

45.8.1. Turbine Frequency Capability and Under-frequency Limits

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

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

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

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

1. A reduction in frequency of one per cent to 59.4 Hz would not have any effect on blade life.

2. A reduction of frequency of two per cent to 58.8 Hz for about 90 minutes could result in damage.

3. A reduction in frequency of three per cent to 58.2 Hz for about 10 to 15 minutes could result in damage.

4. A reduction in frequency of four per cent to 57.6 Hz for a period of one minute could result in damage.

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

Steam-Turbine Generator Under-frequency Protection

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

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

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

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

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

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

UNDERFREQUENCY PROTECTION CO-ORDINATION

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

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

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

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

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

45.9. NETWORK ISLANDING

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

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

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

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

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

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

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

45.11. LOAD DISPATCHING AND NETWORK CONTROLLER

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

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

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

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

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

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

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

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

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

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

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

where e = Input variable of load frequency controller

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

$\Delta F = F - F_o$

K = Constant MW/Hz

P_{io} = Target power transmission [MW]

P_i = Tie–lineup power [MW]

F_o = Target frequency

F = Actual frequency

n = Number of supply points.

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

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

where C_p = Proportionality constant

T_N = integral action time constant.

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

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

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

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

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

— economy of generator — safety

— operational requirements.

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

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

SUMMARY

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

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

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

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

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

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

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

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

QUESTIONS

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

45-B

Voltage Control and Compensation of Reactive Power

CAPACITORS FOR SHUNT COMPENSATION AND SERIES COMPENSATION

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

45.12. VOLTAGE CONTROL IN NETWORK (POWER SYSTEM)

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

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

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

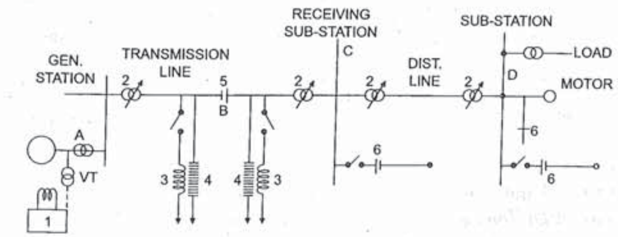


Fig. 45.5. Methods of voltage control in network.

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

45.13. PERMISSIBLE VOLTAGE VARIATION

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

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

REDUCED VOLTAGE ⟷ HIGH LOAD
INCREASED VOLTAGE ⟷ LOW LOAD
NORMAL VOLTAGE ⟷ NORMAL LOAD

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

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

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

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

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

45.14. METHODS OF VOLTAGE CONTROL

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

— *Excitation Control* and voltage regulators in generating stations.
— Use of *Tap-Changing transformers at sending*-end and receiving- end of transmission lines.
— Switching in *shunt reactors* during low-loads or while energizing long EHV lines. Un-switched shunt reactors.
— Switching-in *shunt-capacitors* during high loads or low p.f. load.

(Ref. Fig. 45.5)

— Use of *series capacitors* in long EHV transmission lines, (distribution lines in certain cases of fluctuating loads).
— Use of tap-changing transformers in factory, sub-stations, distribution sub-stations, transmission substations.
— Use of *static shunt compensation* having shunt capacitors and thyristorised control for step-less control of reactive power and voltage. (This method is used instead of synchronous condensers).
— Use of *synchronous condensers* in receiving sub-stations for reactive power compensation.

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

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

(A) Excitation Control and Voltage Regulations of Generators :

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

$$V = E - IX$$

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

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

Time span of AVR response is of a few seconds.

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

(B) Tap-Changing Transformer

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

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

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

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

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

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

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

Time Spans of Various Voltage Control Means

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(C) **Shunt Reactors :**

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

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

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

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

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

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

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

(E) **Static Shunt Compensation**

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

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

(F) **Synchronous Condenser**

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

(G) **Series Capacitors**

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

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

where V_R = Receiving-end voltage

V_S = Sending-end voltage

I = Current

$X_L = 2\pi fL$ of line

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

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

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

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

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

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

— Controllable shunt compensation (SVS)

Thyristors are controlled by feed-back control system.

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

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

45.15. COMPENSATION OF REACTIVE POWER

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

$$S = P \pm jQ$$

where S = Apparent power, kVA

P = Real Power kW

Q = Reactive Power, kVAr

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

By present AIEE Convention :

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

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

1. **INDUCTIVE LOADS**

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

2. **CAPACITIVE LOADS**

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

In complex notations :

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

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

consider $S = EI*$

$$S = P + jQ$$

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

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

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

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

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

Let P = Power transfer watts per phase

Q = Reactive Power Transfer VARs per phase

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

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

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

$R_{+ j} X$ = Series impedance of line/ph.

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

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

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

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

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

The power angle δ between V_R and V_S is proportional to

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

if $X \gg R$, angle δ *depends mainly on P*

Thus,

Voltage is mainly controlled by reactive Power flow power-angle δ is mainly controlled by real power flow. For voltage control, the flow of reactive power through the transmission line should be controlled. The flow of reactive power is controlled by injecting required VAr into the system by means of

— **Static shunt Capacitors/reactors (SVS)**

— **Synchronous Condensers (Compensators).**

45.17. SERIES CAPACITORS

Series capacitors are connected in series with the line conductors. They reduce the effect of inductive reactance between the sending-end and the receiving-end of the line.

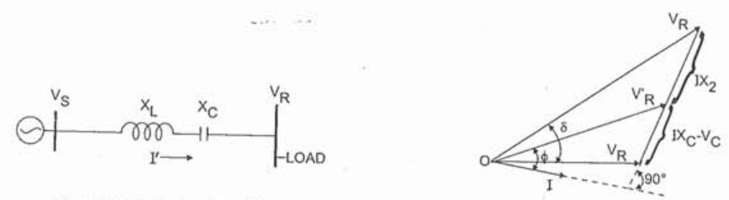


Fig. 45.7 (*a*). Series Capacitor. (*b*) Vector Diagram for (*a*).

Ref. Fig. 45.7(*a*), (*b*). The load current flowing through the transmission line produces voltage-drop ($\Delta V = IX_L$) in the line.

$$\Delta V = I\,(X_L) \text{ ... without series capacitor}$$

$$\Delta V = IX = I\,(X_L - X_C) \text{ ... with series capacitor.}$$

Thus with series capacitors in the circuit the voltage drop ΔV in the line is reduced and receiving-end voltage V_R on full load is improved.

Series capacitors improve the power transfer ability *i.e.*

$$P = \frac{|V_S| \cdot |V_R|}{X_L - X_C} \sin \delta$$

hence series capacitors are used for long EHV transmission system to improve power transfer ability (Stability Limit) as δ is reduced [Refer Fig. 45.7(*b*)].

Vector Diagram. Ref. Fig. 45.7 (*a*) and (*b*) explaining the principle of series capacitor, I is the load current flowing through the transmission line. IX_L is the voltage drop in series inductive reactance of the line. IX_C is the voltage drop across series capacitor. V_R is the receiving voltage with series capacitor in the circuit. Due to the effect of series capacitor the receiving-end voltage will be VR^1 instead of V_R. Angle δ between V_S and V_R is also reduced giving higher stability.

Series Capacitor Installation Scheme. (Ref. Fig. 45.8). Series Capacitors are installed either at both ends of the transmission line (in sending-end and receiving-end sub-station) or in an intermediate switching sub stations. Fig. 45.8 illustrates the scheme of *one* pole of a three bank. Fig. 45.16 illustrates the location of Fig. 45.8.

During normal operation, isolator (1) is open isolator (2.2) are closed; circuit-breaker (3) is open and the line current (I) flows through the capacitor bank (5).

Since the capacitors and its connections are at extra-high voltage (corresponding to the line voltage) the equipment are installed on a raised platform supported on post insulators of adequate insulation level.

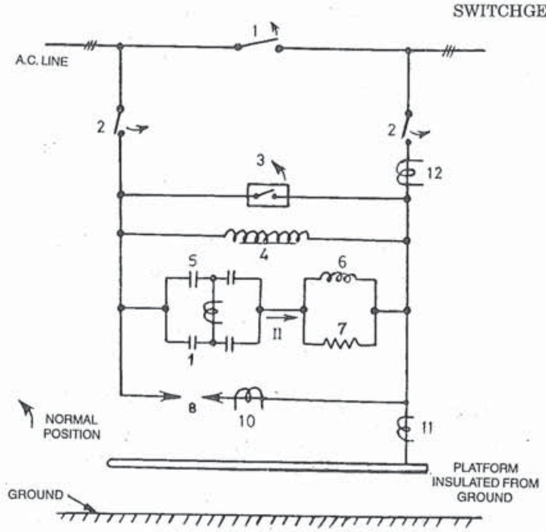
Series capacitor bank (5) comprises capacitor units connected in series, parallel combination to give desired capacitive reactance and MVA capacity.

Damping circuit (6, 7) limits the frequency and peak of inrush currents through the capacitor bank when capacitor is switched in or by passed by closing of the circuit breaker (3).

Circuit-breaker (3) is closed, first wherever the capacitor-bank is to be bypassed. Bypass isolator (1) is closed after closing the breaker (3). Thus the series capacitor bank can be bypassed and normal line current flows through the isolator (1).

Over-current protection is provided by overcurrent relays connected on secondary side of CTs (9.12). Earth-fault protection is provided by relay connected to CT (11). Discharge reactor (4) provides a path for discharging the capacitor after its switching off.

During external fault on the line fault current (I) passes through series capacitor (5) causing excessive voltage IX_C resulting in damage to capacitors. To protect the capacitors from such a failure; a spark gap (8) is provided. When voltage across (5) increases, the spark-gap is triggered. The CT (10) gets



1. Bypass Isolator 2. Series Isolator 3. Bypass breaker
4. Discharge Reactor 5. Damping Reactor 6. Damping Resistor
7. Protective Spark-gap 9-12. Protective Current Transformers

Fig. 45.8. Series-Capacitor Installation Scheme.

current and is arranged to *close the bypass circuit-breaker (3), is closed.* This is an unusual and special application of the circuit-breaker.

The line fault should be cleared by circuit-breaker at sending-end and receiving-end of the transmission line.

APPLICATIONS OF POWER CAPACITORS IN ELECTRICAL NETWORK

45.18. APPLICATIONS OF POWER CAPACITORS IN ELECTRIC POWER SYSTEMS

There are four distinct applications of capacitors in electric power system :

1. *Shunt Capacitors* connected near load points/receiving sub-stations for power factor improvement and voltage control during his load period (Discussed here). These are applied in low voltage/medium/high voltages.

2. *Series Capacitors* used in EHV and UHV transmission lines to improve power transferability.

3. *Surge Suppressor* connected between line and earth near terminals or rotating machines or circuit-breakers (Refer Sec. 18.12).

4. *Coupling Capacitors* used for connection between carrier current equipment and high voltage line (Refer Sec. 30.18).

5. *Capacitor voltage-transformer* used for EHV applications, (Refer Sec. 36.6)

6. In HVDC circuit-breakers.

7. In A.C. circuit-breakers for voltage grading.

(A) **Capacitor.** Comprises conductors separated by insulation capacitance C of a parallel plat capacitor is given by

$$C = \frac{\varepsilon A}{d} \text{ ... farads.}$$

where C = Premittivity of dielectric medium
$= \varepsilon_0 \varepsilon_r$
ε_0 = Premittivity of vacuum
$= 8.85 \times 10^{-12}$ farads/metre
ε_r = Relative permittivity of dielectric.

Capacitors have following important attributes.

— Voltage across capacitor cannot change instantaneously. Hence it acts like a surge suppressor.

— It stores electrical energy in static voltage form. Energy stored in a capacitor is given by

$$W_C = \frac{1}{2} CV^2 \text{ ...... joules.}$$

where C = Capacitance in farads
V = Voltage across C in volts
W_C = Energy stored in capacitance.

In alternating current circuit, the capacitance give capacitive reactance $X_C = \frac{1}{2\pi f C}$ ...... ohms, and takes leading power factor currents, *i.e.* current leads voltage.

In other words, the capacitors supply leading volt-amperes reactive and Q is negative.

$$Q_C = I_C V = V^2 \omega C$$

$$= \frac{V}{X_c} \cdot V = \frac{V^2}{X_C} \text{ Voltamperes reactive}$$

where Q_C = Voltamperes reactive
V = Voltage Volts
$X_c = \frac{1}{2\pi f C}$ .... ohms
Q_C = Apparant or Reactive Power supplied by a capacitor of C farads and charged to voltage V.

(B) **Standard Capacitor Units Available Commercially***.

Indoor Type Unit			*Outdoor Type Units*		
Rated Voltage Volts	*Number of Phases*	*kV Ar of Unit*	*Rated Voltage, Volts*	*Number of phases*	*Rated kV Ar*
230	1	5, 7.5	230	1	1, 2.5, 5, 7.5
440	1 and 3	10 and 15	440	1 and 3	5, 10, 15
660	1 and 3	10 and 15	660	1 and 3	5, 10, 15
2400	1 and 3	15 and 25	2400	1 and 3	5, 10, 15
3600	1 and 3	15, 25	3600	1 and 3	10, 15, 25
7200	1	15, 25	7200	1	10, 15, 25
10500	1	50, 75, 150	10500	1	50, 75, 150
12500	1	50, 75, 150	12500	1	50, 75, 150
13800		Upto 200	13800	1	Upto 200

* Table gives typical ratings of capacitor units for reference. For application aspects, please consult the manufacturers.

(C) Standard Rating of Shunt Capacitor Banks*

Rated Voltage 3-phase kV phase to phase	*Total Rating of Shunt Capacitor Bank (having series + parallel combination of units)*
0.420	20, 30, 50, 100, 125, 150, 180, 250, 300, 500, 750, 1000 kV Ar
3.3	Upto 5 MV Ar.
6.6	Upto 10 MV Ar.
11	Upto 15 MV Ar.
33	Upto 25 and 50 MVAr.
66	Upto 50 and 100 MVAr.
132	100, upto 200 MVAr.

(D) Shunt Capacitors and Power Factors Improvement

The function of shunt capacitors applied in the form of a single unit or a bank (comprising a group of units in series parallel combination) is to supply capacitive volt-amperes to the system at the point of connection.

The shunt capacitors compensate the lagging kVAr absorbed by the inductive loads such as induction motors transformers/welding sets.

The shunt capacitors improve the power factor and thereby reduce the total kVA demand. Hence the $I^2 R$ losses through line are reduced and the voltage regulation is improved. This is illustrated in the well-known Fig. 45.10.

Shunt capacitors are as a rule, connected near the load end and also receiving sub-stations.

When used in the sub-station, the shunt capacitor banks should be provided with switching device. *So that during low loads, capacitors are switched off and voltage does not rise above specified limit.* When used with loads, the capacitor units may be non-switched type (*e.g.* with induction motors). Recently thyristorised (Static) control has been introduced to provide shunt compensation.

The shunt capacitor banks (groups) comprise standard capacitor units of 20 kVAr connected in series/parallel combination. Such banks are used factory-sub stations, distribution-sub-stations. The all kVAr ratings of the banks are 15 MVAr at 12kV; 50 MVAr at 36 kV recently).

(E) Advantages of Shunt Capacitor Banks connected at load/reving end.

1. Reduced lagging-current through supply circuit. Reduced I^2 Rt losses supply line. Improve power factor. Energy Saving; Economy.

2. Increased voltage at load-end during full load. Reduced Voltage fluctuations at load end.

3. **Improved voltage regulation if capacitor units are properly switched.** If not properly switched, the voltage rises during low load and no load periods resulting in overessing the transformer insulation.

4. **Reduced kVA demand, hence same transformer and distribution circuit having certain rated kVA can deliver higher kW. (This is called "Release" of capacity of** supply circuit).

5. Reduced kVA demand, hence lesser charges to be paid to the electricity board for the same consumption of electrical energy. The tarrif generally two part tariff with certain charges for maximum kVA demand; This component reduces due to use of shunt capacitors at load end.

(F) Disadvantages of Low Power Factor (PF)

An electrical plant or sub-station operating at a low power factor has following demerits :

— Reduced kW capacity; over loading of cables, transformers, lines for same kW load. Increased kVA demand for same kW load.

* The size is limited by circuit breaker capacity also.

— Reduced voltage level due to increased IX_L drop in supply circuit. Poor efficiency of motors due to reduced voltage.

— Poorer illumination of lamps due to required supply voltage.

— Increased power losses due to higher currents drawn during low power factor.

— Increased cost of power due to high kVA demand.

(G) kVA, kVAr, kW, Cos ϕ

Refer Fig. 45.10. Power factor is defined as the ratio of active power W to the total apparent power (kVA).

$$\text{P.F.} = \frac{\text{kW}}{\text{kVA}} = \cos\phi \qquad \ldots(1)$$

Hence,

$$\text{kW} = \text{kVA} \times \text{P.F.} = \text{kVA} \times \cos\phi$$

In a 3-phase circuit,

$$\text{kVA} = \sqrt{3}\,\frac{VI}{1000} \qquad \ldots(2)$$

where V = line to line volts

I = Amperes

$$\text{kW} = 3\,\frac{VI\cos\phi}{1000} \qquad \ldots(3)$$

ϕ = Angle between I and V

In case of capacitors I leads V

In case of inductive loads I lags behind V.

Summarising for 3-phase circuits : Fig. 45.9.

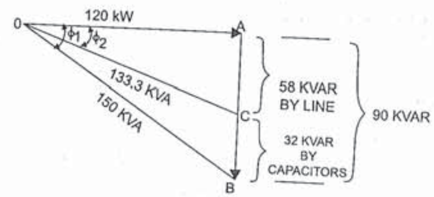


Fig. 45.9.

$$\text{kW} = \sqrt{3}\,\frac{VI\cos\phi}{1000} = 1.73\,\frac{VI\cos\phi}{1000}$$

$$\text{kVAr} = \sqrt{3}\,\frac{VI\sin\phi}{1000}$$

$$\text{kVA}^2 = \text{kW}^2 + \text{kVAr}^2 \qquad \ldots(4)$$

$$\text{kVA} = \sqrt{3}\,\frac{VI}{1000} \qquad \ldots(5)$$

$$\cos\phi = \frac{\text{kW}}{\text{kVA}}$$

$$\text{kW} = \text{kVA} \times \cos\phi$$

$$\tan\phi = \frac{\text{kVAr}}{\text{kW}}$$

$$\sin\phi = \frac{\text{kVAr}}{\text{kVA}}$$

$$\cos\phi = \frac{\text{kW}}{\text{kVA}}$$

$$\text{h.p.} = 746\ \text{W} = 0.746\ \text{kW} \qquad \ldots(6)$$

Example 45. kW, kVA, kVAr cos ϕ

A 3-phase 460 V, system having current 200 amp, total power 120 kW. Determine power-factor, kVA, kVAr, cos ϕ.

Solution.

$$\text{kVA} = \sqrt{3}\,\frac{VI}{1000} = \frac{1.73 \times 460 \times 200}{1000} = 159.2$$

$$\text{kW} = 120 \text{ (given)}$$

$$\cos\phi = \frac{\text{kW}}{\text{kVA}} = \frac{120}{159.2} = \mathbf{0.55} \quad \textbf{Ans.}$$

$$\text{kVAr} = \text{kVA}^2 - \text{kW}^2 = 159^2 - 120^2 = 104$$

or

$$\text{kVAr} = \frac{3VI\,[1 - (\cos\phi)^2]}{1000} = 159.2\,[1 - 0.752] = 104 \quad \textbf{Ans.}$$

(H) **Supply of kVAr, Absorption of kVA** according to presently accepted terminology.

— Inductive loads take lagging currents and *absorb* kVAr, Q is positive.

— Capacitors take leading currents and *supply* kVAr.

— Synchronous condensers take lagging p.f. currents and absorb kVAr when under-excited. They take leading p.f. currents and supply kVAr when overexcited. Hence they are used for step-less p.f. control in receiving sub-stations. Alternatively static shunt compensation has reactors connected at load by means of thyristors. Capacitor current is increased to supply kVAr during heavy loads, inductor current is increased to absorb kVAr during light loads.

(I) **Loads of Poor Power-factor**

Induction motor, induction melting and refining furnaces, welding sets, fluorescent lights etc. take supply currents of lagging p.f. Refer cable C-3.

Examples 45-B-2. P.F. of Group Load

A factory sub-station supplies power to three loads as follows :

— Synchronous motors total 75 kVA at 0.8 p.f. leading.

— Induction motors total 150 kVA at 0.8 p.f. lagging.

— Lighting load filament lamps, 50 kVA at unity p.f.

Calculate overall power-factor of sub-station.

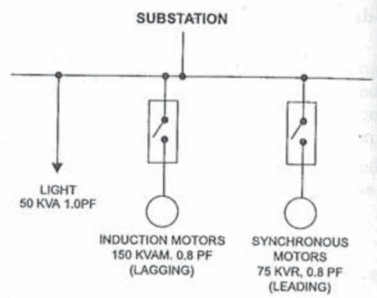


Fig. 45.10. Combined power factor of a group of loads with different PFs'.

Solution.

Method of Solution. Calculate total kW by algebraic sum of component kW's. Calculate total kVAr by summing up component kVAr's. From total kW's and total kVAr's, calculate P.F.

Thus

$$\text{P.F.} = \frac{\text{kW}}{\text{kVAr}} = \frac{\text{kW}_1 + \text{kW}_2 + \text{kW}_3}{(\text{kVAr} - 1) \times (\text{kVAr} - 2) + (\text{kVAr} - 3)}$$

Note. Overexcited synchronous motor acts like a capacitor and supplies kVAr. The power factors of individual loads are used for calculating the power-factor of a group of loads as explained in example below.

Numerical Solution.

Subscript 1, 2, 3 for component loads.

Synchronous motor (1)

$$\text{kVA}_1 = 75 \text{ at p.f. } 0.8 \text{ load (given)}$$

$$\text{kW}_1 = \text{kVA}_1 \cos\phi_1 = 75 \times 0.8 = \mathbf{60\ kW}$$

$$\textbf{kVAr}_{-1} = \text{kVA}_1 \sin\phi_1 = 75 \times 0.6 = 45 \text{ kVAr } [-]$$

(This is negative *i.e.* opposite, that of kVAr of induction motor).

Induction motor (2)

$$\text{kVA}_2 = 150 \text{ at lagging P.F. of } 0.8 \text{ (given)}$$

$$\text{kW}_2 = \text{kVAr}_2 \cos\phi_2 = 150 \times 0.8 = 120 \text{ kW}$$

$$\text{kVAr}_{-2} = \sqrt{\text{kVA}_2^2 - \text{kW}_2^2}$$

$$= \sqrt{150^2 - 120^2} = 90 \text{ kVAr } (+)$$

Lighting Load (3)

$$\text{kVA}_3 = 50 \text{ at unity P.F. (given)}$$

$$\text{kW}_3 = \text{kVA}_3 \cos\phi_3 = 50 \times 1 = 50 \text{ kW}$$

$$\text{kVAr}_{-3} = 0$$

Total $\quad \text{kW} = \text{kW}_1 + \text{kW}_2 + \text{kW}_3$

i.e. $\quad \text{kW} = 60 + 120 + 50 = 230 \text{ kW}$

Total $\quad \text{kVAr} = \text{kVAr}_1 \pm \text{kVAr}_{-2} \pm \text{kVAr}_{-3}$

i.e. $\quad \text{kVAr} = -45 + 90 + 0 = 45 \text{ kVAr}$

$$\text{kVA}^2 = \text{kW}^2 + \text{kVAr}^2 = 54925$$

$$\text{kVA} = 54925 = 234$$

Power-factor of sub-station

$$= \frac{\text{kW}}{\text{kVA}} = \frac{230}{234} = \mathbf{0.982.} \quad \textbf{Ans.}$$

Example : Power Factor Improvement

Example 45-B-3. The power factor of a 120 kW group load is 0.8 and 120 kW group load is 0.8 lag. This p.f. is to be improved to 0.9 by means of shunt capacitors. Calculate kVAr of capacitors required.

Solution.

Draw kVA triangle (Fig. 45.9) as follows :

For $\quad \cos\phi_1 = 0.8.$ Draw triangle OAB

$$OA = \text{kW}_1 = 120 \text{ (given)}$$

$$OB = \text{kVA}_1 = \frac{\text{kW}}{0.8} = \frac{120}{0.8} = 150$$

$$\text{kVAr}_{-1} = \sqrt{\text{kVA}_1^2 + \text{kW}_1^2} = \sqrt{150^2 - 120^2} = 90$$

or

$$\text{kVAr}_{-1} = AB = OA \tan\theta_1 = 120 \tan\theta_1$$

For $\cos\phi_2 = 0.9$

$$\text{kVA}_2 = \frac{\text{kW}}{\text{p.f.}} = \frac{120}{0.9} = 133.3 \text{ kVA}$$

$$\text{kVAr}_{-2} = \sqrt{\text{kVA}_2^2 + 120^2} = 58 \text{ kVAr}_{-2}$$

Note. For p.f. 0.9 kVA is only 133 for same kW of 120. The kVAr to be supplied by the shunt capacitors.

$$\text{kVAr}_{-1} - \text{kVAr}_{-2} = 90 - 58 = 32 \text{ kVAr.} \quad \textbf{Ans.}$$

Note. Capacitors provide kVAr opposite to the kVAr required by inductive loads. Hence a common terminology is the inductive loads absorb the kVAr and capacitors supply the kVAr.

Economic aspects of capacitor installation based on cost of capacitor installation and sub-station.

The cost of capacitor installation can be calculated as follows :

The cost of Installation = Total cost of capacitors + cost of protective and switching devices + cost of installation and commissioning.

Suppose the cost of capacitor installation is K Rs/kVAr (*e.g.* Rs. 100 per kV Ar) cost of sub-station is S Rs./kVA. (*e.g.* a 1200 kVA sub-station costing Rs. 480,000 will have

$$S = \frac{480,000}{1200} = \text{Rs. } 400 \text{ kVA}$$

Most economic p.f. considering cost of kVA released by the capacitors is given by

$$\text{P.F.} = 1 - \left(\frac{K}{S}\right)^2$$

Example 45-B-4. A sub-station costs Rs. 400 per kVA and capacitor installation cost Rs. 100/kVA.

Calculate the economical p.f.

Solution.

Most economical P.F. is given by

$$\text{P.F.} = 1 - \left(\frac{K}{S}\right)^2 = 1 - \left(\frac{100}{400}\right)^2 = \mathbf{0.955} \quad \textbf{Ans.}$$

Another approach to decide the most economic P.F. is *on the basis of kVA maximum demand.*

Let the capacitor installation be Rs. K per kVA (chargeable for a certain period). Let the charges for kVA maximum demand be Rs. M per kVA (chargeable for the same period).

The most economical p.f. is given by

$$\text{P.F.} = 1 - \left(\frac{K}{M}\right)^2.$$

Example 45-B-5. The tariff of electricity is Rs. 72 per kVA maximum. The charges of capacitor installation are Rs. 12 per kVA calculated for the same period. Calculate the most economic power factor.

Solution. $$\text{P.F.} = 1 - \left(\frac{K}{M}\right)^2 = 1 - \left(\frac{12}{72}\right)^2 = 0.98 \text{ (lag)}$$

Example 45-B-6. Mixed Load.

An industrial sub-station is supplying power to following mixed loads :

1. A 150 h.p., induction motor 1 having efficiency of 89% and p.f. 0.9 lag.
2. A 200 h.p. induction motor 2 having efficiency of 90% and p.f. 0.8 lag.
3. A synchronous motor rated 500 h.p. having efficiency of 93% and p.f. 0.707 lead.
4. Unity p.f. lighting load of 100 kW.

Calculate the p.f. of the sub-station. Calculate kW taken by the sub-station.

Solution. Subscripts 1, 2, 3, 4 are as in the same example. Refer example C-2, proceed in similar way.

Let η = efficiency

$$\text{kW}_1 = \frac{\text{h.p.} \times 0.746}{\eta} = \frac{150 \times 0.746}{0.89} = \mathbf{125.7}$$

$$\text{kW}_2 = \frac{\text{h.p.} \times 0.746}{\eta} = \frac{200 \times 0.746}{0.9} = \mathbf{165.9}$$

$$\text{kW}_3 = \frac{\text{h.p.} \times 0.746}{\eta} = \frac{500 \times 0.76}{0.93} = \mathbf{401}$$

$$\text{kW}_4 = 100$$

$$\text{kWAr}_{-1} = \text{kW}_1 \tan \phi_1$$

$$\phi_1 = \cos^{-1} 0.9 = 25° \, 50'$$

$$\tan \phi_1 = 0.484$$

$$\text{kVAr}_{-1} = 125.7 \times 0.484 = 60.8 \text{ (inductive)}$$

Similarly, $\text{kVAr}_{-1} = 1244$ (inductive)

$\text{kVAr}_{-3} = -401$ (capacitive)

$\text{kVAr}_{-4} = 0$

$$\text{Combined p.f. angle } \theta = \tan^{-1}\left(\frac{\Sigma\, kVAr}{\Sigma\, kW}\right)$$

$$= \tan^{-1}\left(\frac{60.8 + 124.4 - 401 + 0}{125.7 + 165.9 + 401 + 100}\right) = 15° \, 14'$$

$$\cos \phi = \mathbf{0.965 \text{ Leading.}}$$

Since the load is predominantly capacitive.

45.19. INSTALLATION OF SHUNT CAPACITORS

Capacitors are installed at every distribution voltage level (415 V, 3.3 kV, 11 kV, 33 kV, 66 kV, 110 kV). The capacitors are connected to provide :

(*a*) Localised p.f. improvement, or (*b*) Group p.f. improvement

Several technical and economic aspects should be considered before deciding the location of capacitors in industrial electrical scheme distribution system. The main technical aspects include :

(*i*) Variations in load (*ii*) Type of motors/other loads
(*iii*) Load distribution (*iv*) Circuit diagram
(*v*) Length circuits (*vi*) Voltage conditions
(*vii*) Cost aspects.

Localised P.F. Improvement. This is made by placing capacitors near motor/small feeder feeding the load.

To obtain maximum advantage, capacitors should be connected near the load or near the end of feeders. This reduces losses in supply circuit and improves voltage near load point.

Localised power factor for improvement can be with switched capacitors or unswitched capacitors depending upon the voltage rise during low load period.

Fig. 45.11 illustrates locations of capacitors in industrial electrical scheme, C_4, C_5 indicate localised p.f. correction. C_1, C_2, C_3 indicate group correction.

C_1 is capacitor bank installed 36 kV or 66 kV network.

Group Power Factor Improvement. This is made at the primary or secondary side of supply transformer (C_1 in Fig. 45.11) or near main switchgear for motor control centre (C_2 and C_3 group p.f. correction is used when load shifts suddenly between feeders. Group correction is also used when they are several small capacity loads mixed with medium capacity loads.

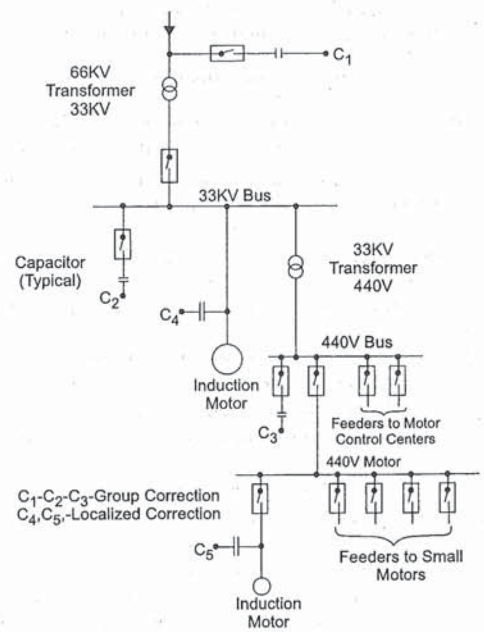


Fig. 45.11. Location of Capacitors in Industrial Scheme.

Capacitors near Motor Terminal. Capacitors are generally installed across terminals of the induction motors when connected in this way, the kVAr should be limited to such a value that the voltage rise near motor terminals is within safe limits when the breaker is open. Refer Table 45-B for reference values of capacitor rating for motors.

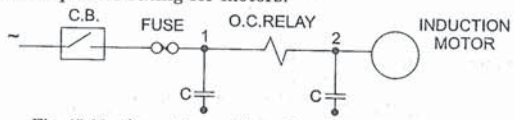


Fig. 45.12. Alternative positions of capacitor connected to motor.

When capacitors are switched along with motor, attention should be paid towards setting of overcurrent relay. Refer Fig. 45.12 explaining alternative position of capacitor with reference to position of over current relay. When capacitor is on supply side (1), capacitor current is not seen by over-current relay. Hence, over current-relay setting is unchanged.

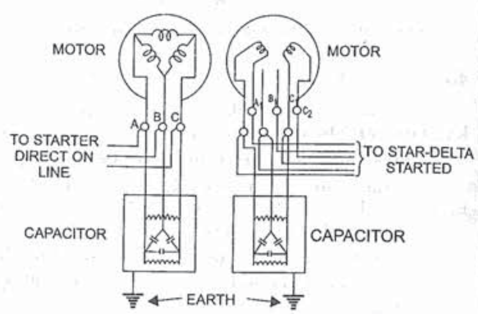


Fig. 45.13. Connections of Capacitor to Induction Motors.

When capacitors are switched along with motor with over-current-relay on supply side (position 2) the over-current relay on supply side (position 2) the over-current relay will see lesser current. Hence lower setting required. For example line current for full load operation of motor with improved power-factor is given by the following expressions :

$$\text{Line current} = \text{Motor full load current} \times \frac{\cos \phi_1}{\cos \phi_2}$$

where, $\cos \phi_1$ = Full load P.F. without capacitors

$\cos \phi_2$ = Improved P.F. with capacitors.

This aspect should be considered when O.C. relay is on supply side as shown in position 2, Fig. 45.12. Fig. 45.13 illustrates typical connections of capacitors for direct connections with motor.

Installation of 33 kV shunt Capacitor Bank. Fig. 45.14 illustrates a typical scheme. The capacitor bank is connected in star and its neutral is *not* grounded. The circuit breaker should be suitable for capacitor switching. It should not re-strike while capacitor current breaking.

While closing parallel capacitor banks, one bank discharges into the other giving high frequency in rush currents. Series reactor shown in Fig. 45.14 is of such reactance that the frequency *fn* of L.C. circuit is within specified limits of breaker capability of closing operation.

Vacuum circuit-breakers are suitable for capacitor switching, because

— They can perform repeated operations without need for maintenance.

— They can open large capacitor banks without restrike due to rapid rate of rise of recovery voltage.

— They can withstand high amplitude of inrush currents of higher frequency.

Refer Fig. 45.14 giving essential protections. Lightning arrestors provide protection against over-voltage.

Over-current and earth fault relays provide respective protection to capacitor bank.

Residual voltage transformer (RVT) gives protection against unbalanced loading due to blowing of individual unit fuse. Fuses with capacitor units give short-circuit protection to individual capacitor units.

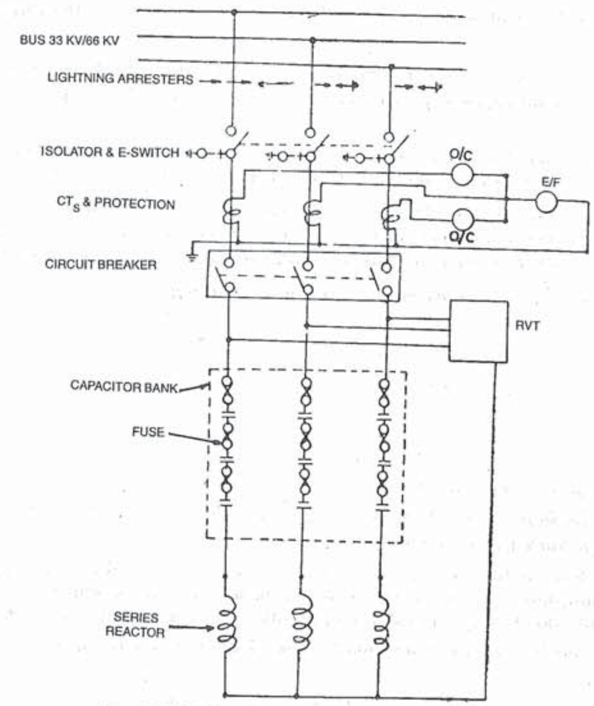


Fig. 45.14. Star connected H.V. capacitor bank.

45.20. REACTIVE POWER REQUIREMENTS AND VOLTAGE REGULATION OF EHV/UHV A.C. LINES. SURGE IMPEDANCE LOADING

The reactive power requirements of long EHV/UHV lines pose a serious problem in voltage regulation.

The voltage variation occurs along the length of line and with charging load. Refer Sec. 48.13.

Let E = Series inductance phase, henry

C = Shunt capacitance, phase to n, Farads

V = Phase to neutral voltage, Volts

I = Line current

$\omega = 2\pi f = 314, \quad f = 50$ Hz

Reactive power *produced* by shunt capacitance of the line (Q_C) is given by :

$$Q_C = VI = V, V/X_C = V^2/X_C$$

$$= \omega CV^2 \quad \text{Volt amperes reactive/phase } (-)$$

Q_C for a given line will depend on voltage of line. Reactive power *Absorbed* by series inductance of the line (Q_1) is given by

$$Q_L = \omega L I^2 \quad \text{Volt ampere reactive/phase, } (+)$$

Q_L for a given line will depend upon line current I. [As per convention, Q_C is negative and Q_L is positive].

By shunt compensation at receiving end, the line current I is reduced and the reactive power absorbed by the line is reduced, *i.e.* $[Q_L = \omega L I^2]$ is reduced by switching-in shunt capacitors at receiving-end.

The compensation requirements of the EHV line depends on line loading is generally expressed in terms of Surge Impedance Loading (P_n) as a multiple of P_n. (Say 1.2 P_n or 0.9 P_n).

If the load on the line is such that (the load current I is such that) the reactive power produced by the line (Q_C) is equal to the reactive power supplied by the line (Q_L) the load impedance is called Surge Impedance (Z_S). The line is said to have natural load or unit Surge Impedance Load.

Thus for unit *surge impedance loading, or natural loading*

$$Q_C = Q_L$$

$$\omega C V^2 = \omega L I^2$$

Hence $$C V^2 = L I^2$$

i.e., $$\frac{V}{I} = \left(\frac{L}{C}\right)^{\frac{1}{2}} = Z_s$$

(This has a unit of impedance).

Hence the load impedance which gives Q_C produced by the line equal to Q_L absorbed by line is called surge impedance (Z_S) of the line.

Surge impedance of line depends on L and C parameters of the line and is independent of line length. Surge impedance of a single conductor overhead line is about 400 Ω and with twin bundled conductors about 300 Ω. Surge impedance of oil filled cables is of the order of 25 Ω.

Power carried by the line when load is equal to (Z_S) and it carries current I such that $V/I = Z_S$ is called

Surge impedance loading or Natural loading. It is given by

$$P_n = VI = \frac{V^2}{Z_s} \text{ Watts.}$$

where P_n = Natural load or Surge impedance loading

Z_s = Surge impedance of line = $\sqrt{\dfrac{L}{C}}$ ohms

V = Rated voltage of line = Volts

Hence for Surge Impedance Loading.

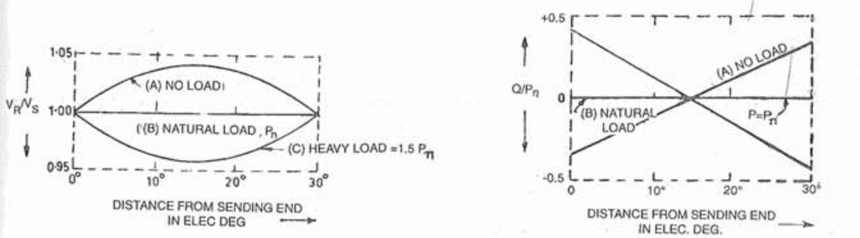
$$I_n = \frac{P_n}{V} \text{ ...... Amperes}$$

Since Z_S for a given line is independent of line length, and depends mainly L and C of line, typical values can be mentioned.

Rated Voltage of Line, kV	132	220	400	765
Surge impedance loading, MW (Natural Load P_n)	40	125	500	1700

Surge impedance loading gives approximate idea of loading of line.

Ref. Fig. 45.15 illustrating the variation of voltage along a line carrying a load (a) No load (b) Natural load and (c) Heavy load.



(a) Voltage variation along length of a long line. (b) Reactive power Active power ratio for a long line.

Fig. 45.15.

When line is carrying natural load ($P = P_n$) the magnitude of voltage is the same everywhere along the line.

In Fig. 45.15, the line length has been expressed in terms of electrical degrees. This is obtained as electrical angle θ,

where $\theta = l\sqrt{LC}$

l = length of line actual, metres

L = series inductance of line per metre per phase

C = shunt capacitance of line per metre per phase

If the line voltage V is to be regulated within say 105% and 95% throughout the line for both low loads and heavy loads, compensation of reactive becomes necessary when power transferred P through line becomes equal to P_m.

$$P_m = P_n \sec\theta$$

where $\theta = l\sqrt{LC}$

P_n = Natural load of line.

Above $P = 1.5\ P_n$ the reactive power requirement increases rapidly.

From curve B in Fig. 45.15, to maintain constant voltage throughout the length of line.

— Reactive Power should be absorbed during low loads, *i.e.* shunt reactors should be switched-in.

— Reactive power should be supplied during heavy loads, *i.e.* shunt capacitors should be switched-in.

— Reactive power requirement increases as the length of line increases.

Reactive power compensation requirements of transmission line varies with line loading.

The transmission line loading based on thermal ratings of conductors is much higher than $P = 1.5\ P_n$. But the increased requirements of compensation and voltage regulation problems set a limit of power transfer to about 1.3 P_n.

Long EHV transmission lines need an intermediate switching sub-station to enable installation of series capacitors and shunt reactors. A typical scheme is illustrated in Fig. 45.16.

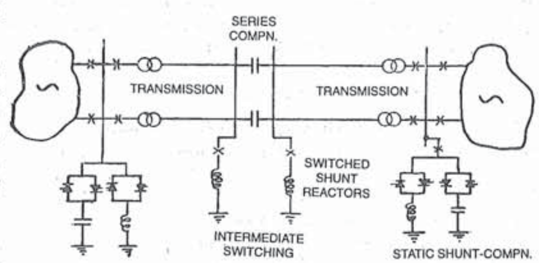


Fig. 45.16. A typical EHV/UHV AC Transmission Line indicating series compensation and shunt compensation.

Summary

Voltage of various sub-stations buses should be held within specified limits, the variation allowed is ± 10%.

Whereas the active power flow (P) determines directly the frequency (f) it does not affect the voltage significantly.

Voltages are affected significantly by the flow of reactive power (Q).

$$\Delta V = \frac{QX}{|V_R|}$$

where $|V_R|$ = Receiving end voltage of the line

Q = Reactive power flow through the line

X = Series reactance of line

ΔV = Voltage drop in line = $|V_S| - |V_R|$

Voltages are controlled by supplying reactive power Q called compensation.

Generator voltage is regulated by automatic voltage regulator and excitation system.

Transmission line voltage is regulated by tap-changing transformer, shunt capacitors, shunt reactors, series capacitors, SVS.

Tap-changing transformers are widely used for network transformers distribution transformers and transformers in the industrial electrical schemes. Off-load tap-changers are used for seasonal voltage variation, on-load tap-changers are used for daily voltage variation. Tap-changers have tap selector, diverter switch and motor drive unit voltage measuring relay having two sets of contracts.

— "raise" and "lower" sends command to the tap-changer. Tap changer operates automatically. Change in voltage ratio is achieved by change in turns ratio.

Shunt capacitors are connected near load point, in factory sub-stations, distribution and sub-stations, receiving stations. They improve power factor, reduce kVA demand, reduce line current and line losses.

Shunt capacitors should be switched in during low voltage, heavy load and switched off during high voltage, low load.

Series capacitors are used for long EHV transmission lines for voltage control and stability improvement. During high load, the reactive power loss in the line reactance is compensated by kVAr supplied by series capacitors.

Flexible AC Transmission (FACT) combines the controllable series capacitors and SVS to achieve control of voltage, power, swing angle (δ).

Voltage control in transmission system is influenced by reactive power flow. By appropriate action in each sub-station, the voltage control is achieved.

Voltage control methods are of three different types : (1) Slow and steady state (2) Medium fast (3) Very fast for transient voltage stability improvement.

45.21. REACTIVE POWER MANAGEMENT

1.0. As we now know that, reactive power compensation improves power factor, stabilizes and maintains the voltage. Series compensation is suitable for transmission line while shunt compensation is used at the distribution sub-station and at the load. For lower capacities, synchronous condenser may be employed which gives smooth control of reactive power, while for larger capacities, static capacitors are employed. Shunt reactors are required to compensate for charging reactive power under light load conditions. Self adjustment in the reactive power is possible by Static VAR Compensators (SVC) which also damps the system oscillations.

2.0. In an integrated power system, efficient management of active and reactive power flows is very important. Quality of power supply is primarily judged from the frequency and voltage of the power made available to the consumer. Keeping in view of the safety, security, quality and

economic considerations, reactive power (VAR) has to be supplied by utilities, as certain loads like Induction Motors, Arc furnances, Welding Machines etc. can not function without reactive power. Further-more, there are statutory limitations of voltage & power factor variation in every country and these are required to maintained within specified limits under all operating conditions. Voltage and reactive power are interrelated fields. Voltage levels are index to measure of balance of generation and consumption of reactive power. In India, the load curve shows wide fluctuations at various hours of the day. The variation is different in various regions of the country. At light load condition, there is excess reactive power available in the system, this causes rise in the system voltage (leading power factor condition). When load demand is heavy, more reactive power is consumed and there is low voltage (lagging p.f. condition). During both the conditions reactive power is to be minimized.

3.0. Disadvantage of Reactive Power

In the peak demand hours, due to inductive or lagging p.f. loads in the system e.g. Fluroscent lamps, Arc Furnances, Agricultural pumps, Traction Motors etc. voltage is less and thus leading VAR demand is more. It has got the following effects :

(*i*) *Effect on Load :* It is extremely important that a consumer gets a constant stable voltage as all the equipments are rated for a constant specific voltage. This results into reduction in the output or in some equipments current drawn increases i.e. IR loss is more and due to heating equipments may get damaged for voltage consumers use voltage Regulators etc which is again a drain on the resources & cause of unnecessary load & harmonics.

(*ii*) *Effect on Transformers :* For the same power to be transmitted over the line, it will have to carry more current at a low power factor. As the line is to carry more current, its cross sectional area will have to be increased, which increases the capital cost of the lines. Also increased current increases the line loss, or the efficiency of the line is lowered, and the line drop is also increased.

(*iii*) *Effect on Generators :* With the low power factor the KVA as well as KW capacities are lowered. The power supplied by the Exciter is increased, as well as the Generator copper losses are increased, so their efficiency is decreased.

(*iv*) *Effect on Prime Movers :* When the p.f. is decreased, the Alternator develops more reactive KVA or the watt less power generated is more, but a certain energy is required to develop it which is supplied by the Prime Mover. This is, the part of the Prime Mover capacity is idle and represents dead investment. Working at low p.f. also decreases the efficiency of Prime Mover.

(*v*) *Effect on Grid :* Due to poor p.f. loads, voltage will be far behind from the rated value. To boost up load bus voltage additional reactive power will be supplied by the Generators. Due to over load Generator/Generators may trip.

(*vi*) *Effect on Switchgear and Bus Bars :* The cross-sectional area of the bus bar, and the contact surface of the Switchgear must be enlarged for the same power to be delivered at low p.f.

(*vii*) In the off-peak hours, due to minimum inductive loads (leading p.f. situation) in the system, system runs in leading VAR (i.e. leading p.f.) condition, which causes high voltage in the system because of which equipments get damaged.

4.0. Advantages of Compensation

(*i*) A greater load can be carried before system reinforcement becomes necessary. An improvement in p.f. from 0.65 to 0.90 increases the system capacity by 30%.

(*ii*) Due to reduction in the current drawn, additional load can be met without additional rating of equipments i.e. loading capacity of the power distribution system is increased.

(*iii*) Because of less heating, the ageing of the insulation becomes slow and thus the life of cable/equipment increases.

(*iv*) Switchgear wear and tear is minimised because of lesser arcing energy dissipation.

(*v*) The KW capacity of Prime Movers/Generators/Transformers & Lines are increase i.e. efficiency is more.

(*vi*) The overall cost per unit is lower.

(*vii*) The voltage regulation of the line is improved.

(*viii*) Reduction in power-cuts, due to reduced demand.

(*ix*) User gets reduction in 'KVA demand' charges, avoidance of penal rate for low p.f. and rebate for higher p.f.

(*x*) Reduced depreciation charges on capital outlay and less capital investment.

5.0. Sources of Reactive Power/Var Compensating Devices

(*i*) Generating Units	(*ii*) Synchronous Condensers
(*iii*) Extra high voltage lines	(*iv*) Reactors
(*v*) Series Capacitors	(*vi*) Shunt Capacitors
(*vii*) Static VAR Compensators (SVC)	(*viii*) Phase Advancers

5.1. Various Var Compensating Devices

(*i*) *Generating Units :* The Generating Units are the major sources to generate as well as to absorb reactive power at different load conditions. An under-excited Generator absorbs reactive power whereas an over-excited Generator will generate it. The terminal voltage of the Generator is regulated by its automatic voltage Regulator (AVR). By setting appropriate reference values in AVR and adjusting field current, reactive power can be generated or absorbed within limits. To maintain rated voltage in the bus in case of heavy load/peak demand VAR generated by the Machine as the system voltage is less and in case of less load/lean demand hours VAR absorbed by the Machine as the system voltage is more.

(*ii*) *Synchronous Condensers :* It is a Synchronous Motor working at over excitation or under excitation mode with no load.

Its advantages :

— It can be operated either over excited mode to compensate for reactive power lost during the heavy load periods (lagging VAR condition) or under excited during light load periods to absorb reactive power generated by the Capacitance of the Transmission Line (leading VAR condition).

— By suitable control of excitation it is also possible for the Synchronous Condenser to improve the stability of the Grid during transient fault.

— Fine control of voltage and/or reactive output.

— High speed response by using static excitation system.

— Synchronous Condenser has an inherently sinusoidal wave form and the harmonics in the voltage do not exist.

— Short time overloading is possible.

— Wide continuous operating range, from an over-excited reactive generation of 100% to an under-excited reactive absorption of approximately 60%. Usually Units between 10-100 MVA are generally considered for the purpose.

Its disadvantages :

— Flexibility of installation is more difficult compared to Capacitor Bank.

— Increase of rating is not possible without installation of a major Unit.

— Losses vary between 1.5 to 4% which are more than Capacitor Bank.

— Costly compared to Capacitor Bank.

— Due to rotating parts, wear & tear is more compared to static Capacitor Bank.

(*iii*) *Extra High Voltage Lines :* 400 KV, 220 KV EHV/Transmission Lines are a potential source of high voltage/leading VAR. In the off-peak hours EHV Lines are some times switched off to avert high voltage. For example, the charging capacity of one circuit at 400 KV, 1000 KM long, is 500 MVAR. So, in peak demand hours, all the EHV circuits should be in service, to provide VAR support in the Grid.

(*iv*) *Reactors :* In extra high voltage networks, capacitive generation often creates problems during operation at low loads; switching operations and disturbances. The severity of such problems increases with the increase in system voltage and increase in line length. Shunt Reactors are a radical means of decreasing the excessive capacitance effects associated with the switching on and off of long lines. They also help to distribute the voltage along the line, decrease the active power losses and the internal over voltages & also enhances system stability under transient fault. The number, size and location of Reactors depend on technical and economic considerations. In case of 400 KV Circuit, Shunt Reactors are connected at both end of the line and at 400 KV Sub-Stations according to need shunt type Bus Reactor is provided. Some times Bus Reactors are also connected in the Tertiary winding of the Transformer. They are all passive elements. In the peak demand hours, Bus Reactors are switched off to avoid low voltage. Generally 60 to 75% of reactive compensation is considered satisfactory, the remaining reactive power being required for the load itself. Under certain load conditions, the number of Reactors connected to the line is varied so as to regulate the transmission voltage and flow of reactive power.

(*v*) *Series Capacitor :* Construction wise, Shunt & Series Capacitors are identical. The two types differ in their method of connection. They are also passive elements like reactors. The voltage on a shunt installation remains constant but the drop across series bank changes instantaneously with load. Series Capacitor is connected in series with the line. A Series Capacitor compensates for the drop or part of, across the inductive reactance of the feeder. The effect of this compensation is valuable in two classes of application. One, on radial feeders to reduce voltage drop and two on tie feeders to transfer power. Series Capacitors are suited particularly to radial circuits where lamp flicker is encountered due to rapid and repetitive load fluctuations, such as frequent Motor starting, varying Motor loads, Electric Welding and Electric Furnaces.

Its advantages :

— The principal application for Series Capacitor is to reduce the effective length of Transmission Lines employed for long distance power transfer, so that the line loading can still approach the Surge Impedance Level (SIL) without encountering problems of transient stability. In other words, it provides increased Line capacity which, in certain cases, obviates the need for constructing additional Transmission circuits.

— The compensation employed in practice is 50 - 60%. For example, the power transfer capability of a Line with 50% compensation is approximately equal to the power transfer capability of two parallel Lines of the same length and voltage. Thus, for example in Russia, by using Series Capacitors on two 850 KM long 400 KV Lines, the capacity has been increased from 450 MW per circuit to 700 MW, obviating the need for a third circuit.

— Enhances transmitting capacity and stability.

— Improved voltage regulation and reactive power balance.

— Elegant and simple.

— The benefit of Series compensation is that the reactive power is self regulating i.e. when more current (varies square of the load current) flows through the Line under load conditions, both, lagging and leading reactive power increases.

Its disadvantages :

— Relay co-ordination aspect

— With the introduction of Series Capacitors, problem of sub-synchronous resonance (SSR) problem arises. The SSR problem comprises of :

(*i*) Self excitation involving resonance of electrical system.

(*ii*) Torsional interaction involving both electrical and mechanical systems.

(*iii*) The transient torque problems occuring during fault and switching operations. For example, when an Induction Motor is started through a Series Capacitor, the Motor may lock in and continue to rotate below normal or synchronous speed. This condition is known as sub-synchronous resonance. It is caused by the Capacitor whose capacitive reactance in conjunction with inductive reactance of the circuit and Motor establishes a resonant circuit at a frequency that of supply.

(*iv*) The cost of Series Capacitor per KVAR is higher than that of Shunt Capacitor.

(*v*) Series Capacitor carry full load current, therefore, the current rating of the Capacitor must be at least as high as load current and preferably, greater than load current to cater future growth.

(*vi*) Under fault conditions, full fault current passes through the Capacitor and voltage across the Capacitor may exceed the permissible limit and may damage the Capacitor. Hence, series Capacitors will have to be provided with special protection schemes devices to take care of fault conditions.

(*vii*) On energisation, a Transformer Bank drawn high transient magnetizing current. If a Series Capacitor is there in the circuit, it may create a resonant condition known as Ferroresonance, and consequent demages.

(*viii*) Shunt Capacitors : Shunt Capacitors are installed in parallel with the inductive load. They are generally distributed at various load points in the Distribution System. The reactive power supplied by Shunt Capacitor varies as square of the voltage applied. In peak demand hours, this should be kept on to generate leading VAR and off-peak hours this should be kept off to avoid high voltage. Shunt Capacitors are normally connected in the 33/11/.415 KV Bus.

Its advantages :

— Static Shunt Capacitors are the most economical means of generation of reactive power.
— Less costly than Synchronous Condenser.
— Lesser Losses (1.5% or less)
— Simple Installation.
— Rating can be increased easily be adding more Units.
— Less maintenance is required.

Its disadvantages :

— Due to harmonic voltage generation, resonance may occur.
— Supply of lagging reactive current not possible.
— Short service life of 10 to 15 years.
— It is difficult to repair a damaged Capacitor.
— They break down easily at voltage exceeding 1.1 times the rated voltage.

(*ix*) Static VAR Compensators (SVC) : In a power system, load varies with the time. In India, there is a considerable fluctuation in the load throughout 24 hours. Over and above matching the supply and demand of active power, reactive power also should be managed continuously to result into reduction in KVA demand, maintaining voltage etc. When demand on the system is more, power factor is less and vice versa.

If fixed Capacitors are employed, on heavy load conditions during peak hours, reactive power compensation may not be achieved fully, while under light load conditions, voltage may shoot up. This is because, when fixed type Capacitors are installed, KVAR is based on average load so that over voltage may not take place under light load conditions.

By employing automatic switched Capacitors, reactive power compensation can be achieved according to changing load. There may be three or four steps. During light load conditions, Capacitors can be switched off. With fixed Capacitors KVA demand reduces but p.f. fluctuates. It is observed that when SVC are used, KVA demand reduces and p.f. & voltage are maintained almost constant. By reducing the peaks, it helps to smoothen the load curve. The SVC is a parallel combination of

Thyristor controlled VAR absorption components (Reactors) and VAR generation components (Capacitor Banks). This provides automatic reactive power control.

Its advantages :

— Reliable, fast acting and maintenance free as compared to Synchronous Condenser.
— It has low losses
— Improves p.f. and regulates voltage, & also damps the system oscillations.
— It also increases power handling capacity and transient stability of the system.
— It has a high degree of reliability and is cost effective.

(*x*) Phase Advancers (PA) : Most of the Motors used as drives are Induction Motors. Phase Advancers improve p.f. of an Induction Motor (IM). The induction Motor has low p.f. as stator winding draws magnetizing current which lags behind the supply voltage by 90°. If the magnetizing ampere turns can be provided from some other source, stator winding will be relieved of the magnetizing current and the p.f. can be drastically improved. A PA is an a.c. excite connected in rotor circuit of an IM, which provides the magnetizing Ampere turns at slip frequency. In IM the rotor frequency is much less than that of the stator so it is desirable to supply the magnetizing Ampere turns from the rotor at slip frequency rather than from the stator at supply frequency. The IM may operate at a leading p.f. if magnetizing Ampere turns provided are more than that required, PA may be of following types :-

(*i*) Leblanc's Exciter
(*ii*) Schebious Phase Advancer
(*iii*) Walker Phase Advancer
(*iv*) Kepp Vibrator

Main advantage with PA is that as compared to Synchronous Condenser, they have small output. However, they are economical only for large capacity Induction Motor.

QUESTIONS

1. Explain the methodology of voltage control in electrical power system.
2. State whether the following statements are right or wrong. Write correct statements.
   (*a*) Shunt capacitors are switched off during low load.
   (*b*) Series capacitors is generally used for power factor improvement.
   (*c*) Voltage control in power system is achieved by changing load.
   (*d*) Load shedding is used when voltage falls below specified limits.
   (*e*) Synchronous condensers are installed in generating stations.
   (*f*) Voltage control is possible from load control centre.
3. Explain the function of shunt capacitors. State the various locations of shunt capacitors.
4. Illustrate the electrical scheme of a typical 33 kV shunt capacitor installation. Explain the function of each component.
5. Explain the function of series capacitor for EHV transmission. Draw a schematic diagram of a series capacitor installation. State the function of circuit-breaker.
6. Fill in the gaps :
   (*a*) Capacitor bank is switched ... when load increases and is switched... when load decreases.
   (*b*) Over excitation of synchronous motor causes current of ... P.F.
   (*c*) Series capacitors are generally used for transmission lines rated ... kV.
   (*d*) Capacitors take current of ... P.F.
   (*e*) Induction motor has P.F. of the order of ....
7. Explain the relation between voltage and reactive power of a transmission line. Explain the use of :
   1. Shunt capacitor 2. Series capacitors 3. Shunt reactors.
8. Fill in the blanks :
   (*a*) Shunt capacitors are installed in ...

(*b*) Typical ratings of shunt capacitor banks for

11 kV sub-station one ... MVAr and
33 kV sub-station one ... MVAr.

(*c*) Typical rating of a shunt capacitor for a 5 kW motor is ... kVAr.

(*d*) Series capacitors are usually used for transmission lines of rated voltage ....

(*e*) Series capacitors improve the ...

9. State the various methods of voltage control in electrical network.

10. Explain the methods of voltage control in a 220 kV/132 kV sub-station.

11. Explain the co-relation between reactive power flow and voltage regulation of a transmission line.

12. With the help of neat schematic diagrams explain the following (*any one*).

1. Layout of a 33 kV Shunt Capacitor Bank.
2. Layout of one pole of an EHV Series Capacitor Bank.
3. Static Shunt Compensation Scheme.

45-C

Voltage Stability of Electrical Network

Introduction — Voltage Instability — *Vr/Pr* and *Q/V* characteristics — Voltage Collapse Occurances and their time-spans — Preventive Measures against Voltage Collapse — Terms and definitions.

45.22. INTRODUCTION TO VOLTAGE STABILITY STUDIES

The traditional *Steady State Stability Studies* and *Transient Stability Studies* take into account the active power flow P and power angle δ, and assume constant receiving and sending end bus-voltages. The *reactive power flow* Q and voltage fall during heavy current flow are neglected. This approach could not explain the several power system black-outs in USA, Europe, Japan etc. during the last quarter of the twentieth century. The black-outs were due to the voltage collapse. Voltage collapse phenomena are of more frequent occurance in rapidly growing interconnected power systems in India and other developing countries where reactive power management is inadequate.

The voltage collapse incidents have occured under high lagging load currents, stalling of induction motors, inadequate shunt compensation at receiving end, sudden tripping of a generator unit or a bulk-power transmission line, heavy HVDC power flow without adequate shunt capacitors at inverter, a line fault or bus fault, starting of a large induction motor, sudden or gradual increase in distribution load up to limiting power flow through transmission lines, etc. During voltage collapse, the *bus voltage starts falling* and as a result the power transfer P through the transmission lines *starts reducing* resulting in ultimate voltage collapse and loss of system stability of entire Network.

The term *voltage instability* was introduced in 1982. The Voltage Stability Studies have received more attention after 1982 and have acquired a vital place in power system studies (1995). The loss of power system stability due to fall of voltage (voltage collapse) is called Voltage Instability. Voltage stability is one of the several type of Stabilities (Ref. Sec. 44.24). Voltage stability is of three types depending on the time span (t) of voltage collapse :

— Short-term Voltage Instability ($t < 1$ to 10 seconds). (Also called transient voltage instability.) This corresponds to rotor angle oscillations in transient state stability.

— Mid-term Voltage Stability

— Long-term Voltage Stability

45.23. EXPLAINING VOLTAGE INSTABILITY

We recall from Sec. 45.16 that the voltage drop ΔV in the transmission line and receiving voltage $|V_r|$ of a transmission line are closely related with reactive power Q and line reactance X and the relationship is given by

$$\Delta V = |V_s| - |V_r| = \frac{XQ}{V_r} \qquad ...(45.2)$$

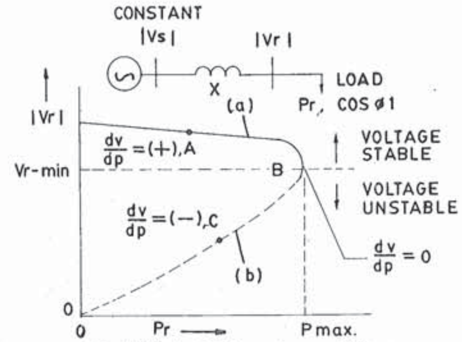


Fig. 45.17. Explaining voltage stability.
(Receiving Voltage Characteristics of an AC transmission line with constant sending end voltage $|V_s|$ and increasing load P_r at power factor cos 1.)

Assuming constant sending end voltage $|V_s|$, the receiving voltage $|V_r|$ reduces with increasing lagging power factor load. Fig. 45.17, gives typical graphs of $|V_r|$ versus active power P_r, *with sending end voltage* $|V_s|$ *constant.*

The characteristic are U curves with axis parallel to P coordinate. Any point A on the upper half (a) of the curve has negative dV/dP where increase in P gives drop in voltage, hence condition of stable voltage. Any point C on lower half (b) of the curve has positive dV/dP, where increase in P gives increase in voltage, hence an unstable voltage. Point B at the tip of the V curve corresponds to P_{max} and $dV/dP = 0$ represents Steady State Voltage Stability Limit. If MVA load with constant p.f. is increased beyond P_{max}, voltage collapses and it is not possible for the transmission line to feed the increasing power demand, P_r start reducing and Voltage Stability is lost. The reason for voltage instability is understood from Eqn. 45.2 above. The voltage drop ΔV in the line is due to reactive power Q_r demanded by the load. If this reactive power is not supplied at the receiving end of the transmission line, the voltage drop ΔV increases and receiving end voltage $|V_r|$ falls. *The reactive power cannot be conveyed through the transmission line,* it must be supplied by capacitors at receiving end. The real power flow is proportional to $\left[\,|V_s| \times |V_r|\,\right]$. Fall of $|V_r|$ results in reduction in P_r. The P_r also falls progressively due to fall in $|V_r|$ resulting in Voltage instability.

45.24. INCREASING VOLTAGE STABILITY LIMIT BY SUPPLY OF REACTIVE POWER

Refer Fig. 45.18, which gives curves of receiving end voltage $|V_r|$ plotted against P_r of various power factors achieved by supply of reactive power Q_r by switching in capacitor banks in steps. Curve 1 is for load p.f. 0.8 with shunt capacitor bank 1 in circuit. The corresponding long term stability limit is P_{m1}. Curve 2 is with shunt capacitor banks 1 and 2 in circuit and corresponding stability limit is P_{m2}; Curve 3 with capacitor bank 1, 2, 3 in circuit has stability limit P_3 and so on. We observe that the Voltage Instability occurs at higher active power with increased supply of reactive power Q_r at load end. By supplying Q_r at receiving end, the voltage drop ΔV in transmission line is reduced and receiving end voltage $|V_r|$ is held in the nearly flat portion of upper half of voltage curve $|V_r|$ vs P_r. The generators become unstable for leading p.f. load supply. Hence the power factor at sending end should be held lagging, slightly below unity.

The dynamic performance is not shown in Fig. 45.17 and 18. It can only be visualised by dashed line of trajectory for short term stability shown in Fig. 45.18.

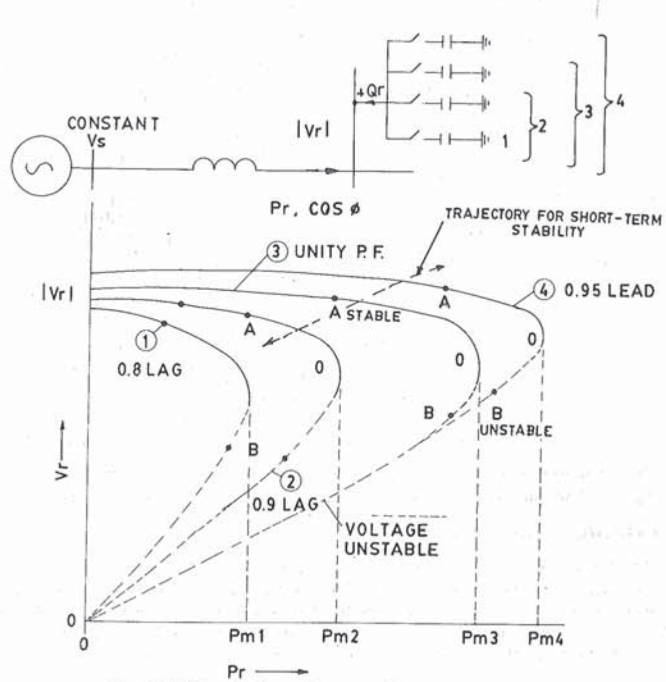


Fig. 45.18. Supply of reactive power Q_r at receiving end by switching on Capacitor Banks.

45.25. SEQUENCE OF SWITCHING-ON AND SWITCHING-OFF SHUNT CAPACITOR BANKS

The receiving end bus voltage should be held constant between specified V_{r-min} and V_{r-max} corresponding to rated nominal bus voltage V_r during regular load variation in power system. For mid-term steady state variation of few minutes this voltage control is achieved by switching-on capacitor banks during fall in voltage and switching on capacitor banks during rise in voltage. Refer Fig. 45.19, curves 1, 2, 3, 4 correspond to receiving end voltage V_r is plotted against P_r for various power factors of P_r.

Curve 1 is for load p.f. 0.8 with shunt capacitor bank 1 in circuit. At point A on curve 1, the voltage has reached V_{r-min} corresponding to permissible lower system voltage. Capacitor bank B is switched on. Point shifts to point a on curve 2. At point B, capacitor bank B is switched in and operating point shifts to b on curve 3, and so on. With load increasing, the capacitor banks are switched on in steps to maintain voltage above V_{-min} and to avoid voltage collapse. During decreasing load P_r, the voltage would tend to rise above V_{r-max}. Capacitors are switched-off in reverse order, at highest permissible system voltage V_{r-max}.

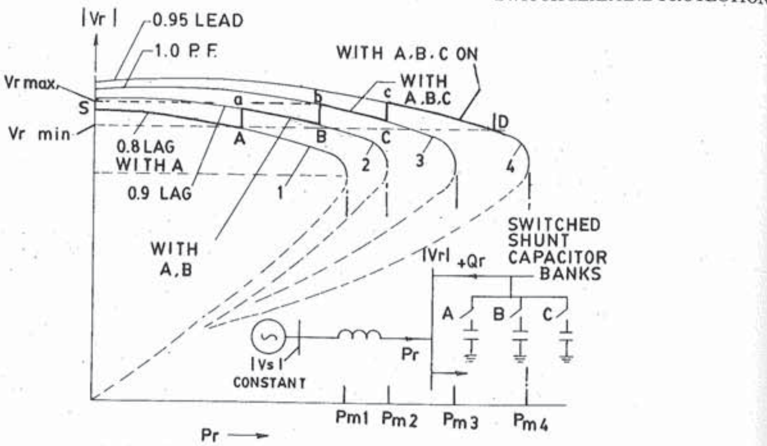


Fig. 45.19. Switching sequence for capacitor banks for voltage stability.

V_{r-min} = Specified Minimum system voltage, Capacitor bank switched in during increasing load

V_{r-max} = Specified Maximum system voltage, Capacitor bank switched off during decreasing load.

45.26. Q—V CHARACTERISTICS

Fig. 45.20 shows how the receiving voltage V_r varies with variable Q_r. The operating point moves along constant power curve. By supplying capacitive reactive power (+ Q), the voltage of operating point increases. By absorbing inductive reactive power (– Q), the operating point comes down resulting in fall of voltage. Fig. 45.21 illustrates effect of switching in the shunt capacitor banks 1 and 2, on voltage at operating point along constant power curve P_1.

The shunt capacitor banks provide compensation $Q_c = V^2/X_c$, which is proportional to square of voltage and is represented by curves 1 and 2. The operating point a corresponds to intersection

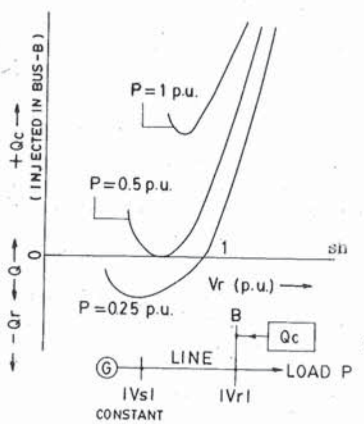


Fig. 45.20. $Q - V_r$ curves for constant

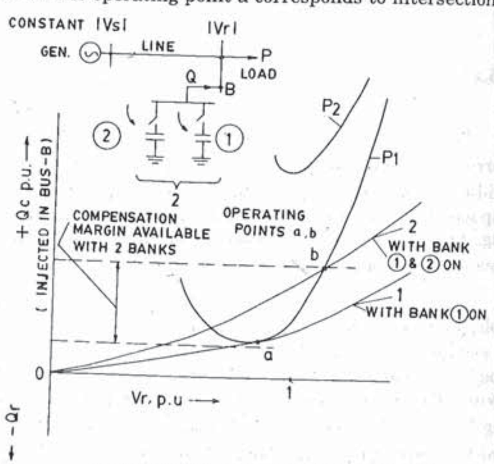


Fig. 45.21. $Q_C - V_r$ curve with curve 1 and 2 for reactive power supply.

point of load curve P_1 and the curve for 1 Bank 1. Likewise, point b is for Bank (1 and 2) in circuit and load P_1. By making Bank 1 and 2 on in steps, the voltage V_r is raised to V_a and V_b respectively.

By thyristor control of shunt capacitor current + Q_r is varied, the operating point on P_1 line could be moved steplessly from a to b and voltage could be raised steplessly from V_a to V_b.

45.27. VOLTAGE COLLAPSE OCCURANCES, AND THEIR TIME-SPANS

Voltage stability is of three types depending on the time span of voltage collapse :

— Short-term Voltage Instability ($t < 1$ to 10 seconds). (Also called transient voltage instability.)

— Mid-term Voltage Stability ($t < 10$ sec to 3 minutes)

— Long-term voltage stability ($t > 3$ min. to an hour)

Voltage collapse can occur due to several individual incidents or sequential combination of incidents occuring under unfavourable load generation and reactive power compensation situations.

	STVS	MTVS	LTVS
1. Gradual increase on line load,			*
2. Gradual increase in Distribution Load			*
3. Inadequate Shunt compensation at Receiving End			*
4. Starting of Large Induction Motor	*	*	
5. Step increase in Export of Power	*		
6. Fault on Line, Busbar, Equipment	*		
7. Tripping of Local Generator/Feeder	*		
8. Inadequate Shunt Compensation of HVDC AC bus			*

STVS — Short-term Voltage Instability ($t < 1$ to 10 seconds). (Also called transient voltage instability.) The time corresponds to oscillations in rotor angle during power swings.

MTVS — Mid-term Voltage Stability ($t < 10$ sec to 3 minutes)

LTVS — Long-term voltage stability ($t > 3$ min. to an hour)

These time spans are approximate and for classification of voltage stability.

Fig. 45.22 illustrates various possible causes described below.

1. *Gradual Increase in Load with Poor P.F.* (> P, < cos ϕ)

The load may be combination of distribution load and subtransmission line load. The time span of such occurance is a few tens of minutes to a few hours near peak load hours on daily load cycle. Station operators can take manual action for increasing turbine settings and increasing power supply. The switched capacitor banks can be switched in. The Voltage Stability comes under *Long Term Voltage Stability*. As the load approaches P_m the stability limit is reached. The value of P_m is very low for poor lagging p.f.

2. *Inadequate Supply of Reactive Power to Loads*

The AC bus voltage starts falling with increasing lagging p.f. load. If reactive power compensation is inadequate, the operating point on V_r/P_r curve goes beyond V_r-min resulting in Loss of Voltage Stability. The occurance comes under Long Term Voltage Instability and takes several tens of minutes.

The reactive power can be despatched through transmission line. It should be supplied directly into receiving end/load bus appropriate shunt compensation. If this is not done, the voltage of receiv-

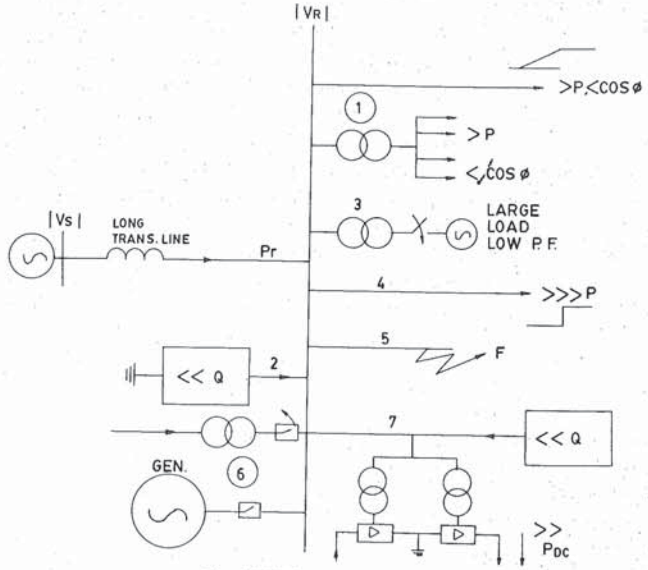


Fig. 45.22. Occurances leading to voltage collapse and their time spans.

ing bus falls gradually resulting in ultimate loss of voltage stability. This comes under *Long Term Voltage Stability.*

3. *Slow staring and Stalling of a Large MV Induction Motor direct on line, during peak load.* The voltage dips and motor takes longer time to start. If motor circuit breaker does not pick-up, motor bus voltage collapses. This has cascade effect on substation bus voltages and voltage collapse may occur. The occurance takes several seconds upto a minute and comes under "short term voltage stability and mid term voltage stability."

4. *Sudden Step-power import by Remote Substation.* The operating point on V_r/P curves shifts beyond stability limit under "Transient instability condition." The occurance is called Short term Voltage Instability or Transient Voltage Instability. The time span is less than 10 seconds.

5. *Fault on Busbar or Transmission Line.* The voltage collapses, power is diverted to fault. Voltage Stability is lost within a few seconds, and the incidence is under Short Term Voltage Stability Regime.

6. *Tripping of Generating Unit or Parallel in-feed transmission Line.* This has an effect on sudden increase in P_r supplied by the Transmission Line, beyond its Stability Limit P_{max} and increased voltage fall below $V_{r-\min}$ due to loss of local generation/infeed support. The category of such occurance is under Short Term Voltage Stability.

7. *Sudden Increase in Pdc through HVDC Line without Corresponding Increase in Supply of Reactive Power Q at inverter terminal.*

When the bus is connected to HVDC Convertor, the voltage support is provided by additional shunt capacitors/AC filter capacitors. Total MVAr drawn by HVDC Inverter from AC bus is of the order of 60% P_{dc}. If the reactive power supplied to HVDC Inverter AC bus is not increased, the reactive power is drawn from the incoming AC transmission lines and the receiving end voltage

$|V_r|$ falls. The load on HVDC line should be reduced to avoid collapse of AC bus voltage, at inverter end to ensure : "Long Range Voltage Stability".

45.28. PREVENTIVE MEASURES AGAINST VOLTAGE COLLAPSE

The preventive measures against voltage instability are taken simultaneously at load points, distribution level, sub-transmission level and main transmission level. The methods are listed in Table 45-D.1.

Table 45-D.1. Preventive Measures Against Voltage Collapse

Method	*Time*	*Application*				
		Generation	*Main Trans.*	*Sub Trans.*	*Distri.*	*Load*
AVR	(ST)	*				
OLTC	(MT, LT)		*	*	*	*
Shunt Reactor Unswitched			*			
Shunt Capacitor	(MT, LT)			*	*	*
SVS	(ST)			*	*	*

Ref. Ch. 45A and Ch. 46.

45.29. DEFINITIONS

Voltage Stability is a type of Power System Stability and the terms covered in Sec. 44.24 are suitably applied.

The difference between Long Term and Short Term Voltage Stability are on *time frame of disturbance/change in load.* The Mid-term voltage instability is applicable for time zone in between short term and long term voltage stabilities.

Steady State (Long Term) Voltage Stability. A power system is steady state voltage stable if following a small *slow* disturbance or increase in load, the system voltages regain steady state equilibrium values without voltage collapse.

Long-term voltage stability refers to behaviour of system which takes 3 minutes to several minutes. The means available for voltage control over long term are voltage relays and tap changing transformers, switched shunt capacitors, switched shunt reactors, load shedding, HVDC interconnection, etc.

Mid-term Voltage Stability refers to behaviour of the system lasting for about 10 to 30 seconds. The means available for improving mid-term voltage stability improvement are : Switched shunt capacitors, Switched shunt reactors, Tap changing transformers.

Short Term Voltage Stability. A power system is short term voltage stable if following a *sudden aperiodic* disturbance or increase in load, the system voltages regain steady state equilibrium values without voltage collapse.

Short-term Voltage Stability refers to behaviour of the system for a few seconds. For short term voltage stability improvement available means are : Excitation system control and AVRs of synchronous machines, thyristor controlled shunt compensation, tap changing of transformers, FACT systems, unswitched shunt capacitors and shunt reactors, series capacitors.

Voltage security. It is the ability of the power system to operate stably with voltages within permissible limits following a disturbance or load increase.

Load-frequency control is carried out simultaneously from generating stations and distribution systems to match total generation systems to match total generation with total prevailing load to maintain frequency within specified limits. However this is not enough. Voltage Stability must also be maintained to ensure system stability.

QUESTIONS

1. Explain the phenomena of voltage collapse during high lagging power factor load on receiving end of long AC transmission line.
2. Describe the procedure of switching in of shunt capacitors to prevent voltage collapse.
3. Define Short term voltage instability and long term voltage instability. Give examples of occurances of voltage instability in short term and long term range.
4. State the various methods of maintaining steady state and short term voltage stability.

45-D

Automatic Voltage Regulators, Voltage Control and Stability of Synchronous Generators

Introduction —Operation of Synchronous Generator—EMF and No Load terminal voltage, Saturation curve—Significance of Field Current I_f— Terminal Voltage of an Isolated Generator with constant field current and without AVR —Synchronous Generator in parallel with the Grid —Types of Excitation Systems and AVRs—Terms and definitions on AVR and Excitation Systems—Excitation Systems and AVR (Synchronous Machine Regulators)—Steady state performance Excitation Systems and AVRs— Transient Performance of AVRs-Excitation System Voltage Response— Generator Capability Curves—Protective Limiters—V/Q Diagram— Power System Stabilizer—Protective, Regulating and Limiting Features.

45.30. INTRODUCTION

The voltage control and reactive power flow control of various Network-busses is carried out simultaneously from load-substations, distribution substations, transmission substations and generating substations; by means of OLTCs, SVS, Shunt Capacitors and AVRs. The bus voltages and reactive power supply in generating stations are controlled by and the Excitation Systems and Automatic Voltage Regulators (AVR) of synchronous generators. The modern term for the Automatic Voltage Regulator is *Synchronous Machine Regulator.*

We will use the term Generator for Synchronous Generator (Alternator) and AVR for Synchronous Machine Regulator.

The variable associated with generator are :

— Frequency f — Induced emf E_a,

— Stator armature current I_a, — Terminal voltage V_t,

— Power factor cos ϕ, — Field current I_f, (DC)

— Apparent power S MVA, Active power P MW and Reactive power Q MVAr

$$S = P + jQ$$

— Rotor speed N_s and Power angle δ between vectors $\mathbf{E}_a$ and $\mathbf{V}_t$.

These variables are *interdependent.* MW output, Speed and frequency are controlled by Governor of Prime Mover and load MW. Voltage, MVAr and power factor are controlled by the AVR in Excitation System under steady state and dynamic state and compensation of reactive power at load bus. The load conditions and/or Grid condition also influence the operating characteristics.

Mechanical Active power P_m is supplied by prime mover and converted to electrical Active Power P (MW) by Generator. AVR does *not* control active power MW, speed N_s and frequency f.

AVR controls the terminal voltage V_t and, power factor cos ϕ, and the Reactive Power supply MVAr by generator.

In addition to voltage control and reactive power control, the AVR performs steady and transient stability functions, limiting functions and protective functions.

Reactive power MVAr and power factor of armature current are closely associated with the *magnetic field* in the generator air gap which is resultant of (1) rotor magnetic field due to field current of generator and (2) armature reaction due to current and its power factor. Net reactive power demanded by the load from the generating station bus, is equal to [Load MVAr ± Shunt Compensator MVAr]

Neglecting losses, with *subscripts* : pm for prime mover, g for generator, L for load and sc for shunt compensator)

1. Active Power $P_{pm} = P_g = P_L$. for constant speed N_s

Controlled by Governor to Prime Mover and input to prime mover

2. Reactive Power $Q_g = Q_L \pm Q_{sc}$ for constant p.f.

Controlled by Excitation System and its AVR.

Three phase, 50 Hz, AC Synchronous generators (Alternators) supply Active Power P (MW), Reactive Power Q (MVAr) and resultant Apparent power MVA. Power factor cos ϕ = MW/MVA.

Under normal steady state load conditions the terminal voltage should be held within specified limits and the power factor should be between 0.85 lag and 0.95. Generators are not stable under leading power factor as the armature reaction has magnetising effect and voltage rises with leading load current and excitation current looses control.

During disturbances in the Network such as sudden increase/decrease of load, faults, switching of loads, starting of large motors, in the network, etc. the generator should remain stable. The rotor angle swing should be damped. The terminal voltage should be recovered within few seconds for maintaining stability. This is achieved by field forcing (high field current) and fast excitation response (fast rate of change in excitation) characteristics of Excitation Systems and AVR.

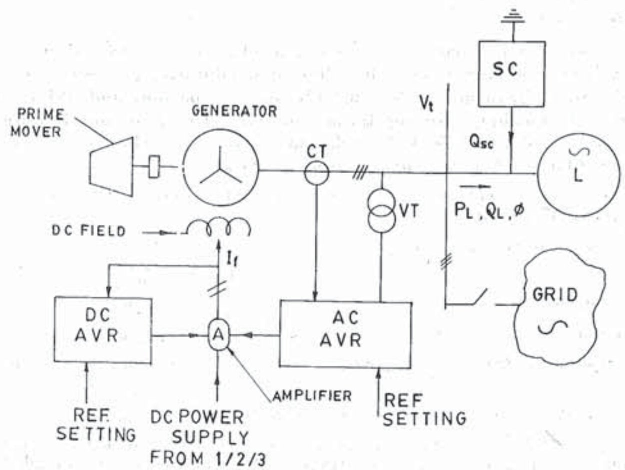


Fig. 45.23. Schematic of a Generator unit, load and AVR.

1. DC Generator 2. Controlled Thyristor Rectifier 3. Uncontrolled Diode Rectifier

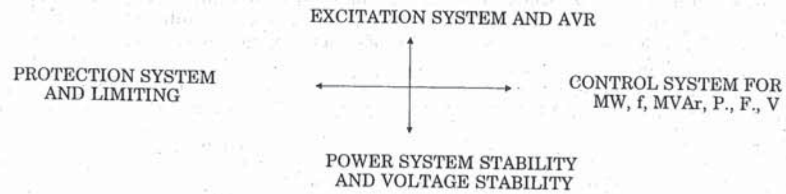
SC = Shunt Compensation *REF* = Reference setting
A = Amplifier *CT* = Current Transformer
VT = Voltage Power Transformer not shown for simplicity.

Note. DC AVR senses DC field voltage. AC AVR senses AC voltage and AC current. Actual configuration varies with design philosophy of AVR of particular manufacturer. Power Supply DC is either from DC Generator—Amlidyne combination or from Rectifier mounted on generator shaft or Static Rectifier receiving power from auxiliary source or the Generator itself.

The Automatic Voltage Regulators (AVR)(Synchronous machine regulator) in the excitation system play a very vital role for voltage control, controlling reactive power supply, emf, voltage and power factor of generator, and also maintaining power system dynamic stability, and in protection of alternators by imposing several limits on generator variables.

Modern term for Voltage regulator is *Synchronous Machine Regulator (1986-IEEE Std.).* It is defined as "The regulator that couples the output variables of a synchronous machine to the input of the exciter through a feed back and feed forward control elements for controlling the synchronous machine output variables."

The active mechanical power supplied by prime mover to shaft is equal to active power supplied by generator to load plus losses in the generator. *AVR does not change the active power P of generator; nor does it change the frequency and speed.* However the AVR influences the power angle δ between the revolving stator plus and revolving rotor flux, both locked up synchronously at N_s.



Excitation system has a strong **interface** with the generator protection, generator control and power system stability as indicated above.

The functions of an AVR (Synchronous machine regulator) and the Excitation System are :

1. *Regulation of Terminal Voltage automatically.* To regulate the terminal voltage within specified limits of the generator *automatically* under steady state operating condition of varying load/p.f. This is done by controlling field current by means of a feedback system involving Voltage Transformer and Automatic Voltage Regulator.

2. To facilitate reactive power load sharing with other generators operating in parallel.

3. *To regulate the voltage and load angle δ under abnormal conditions and transient disturbing conditions* such as faults, power swings, sudden switching in of large loads, etc. and ensuring higher transient stability limit. This is ensured by rapid control of excitation current during disturbance.

To ensure transient and dynamic stability of the generator and the power station by rapid and automatic control of reactive power supply and to ensure that the synchronous machine does not fall out of step and trip under emergency condition.

4. *To damp swing and electromagnetic oscillations in load angle* δ under abnormal conditions and transient/dynamic disturbing conditions rotor oscillations of synchronous generators and to ensure transiently and dynamically stable operation.

5. *To ensure protection of generator* and excitation system by giving tripping command under appropriate abnormal conditions of variables.

To arrange tripping and rapid field discharge during generator stator faults.

6. *Limiting Features.* To inhibit the tripping of the generator unit by the protection system under permissible swings in active power and reactive power. AVR operates in close liason with the generator protection system and raises the operating limits for ensuring generator service during disturbances.

Choice of features, rated characteristics and complexity of an Automatic Voltage Regulator of a generator may vary from simple manual control with protection interface to a very complex automatic control and improved dynamic stability features and performance limiting features, depending upon application, size and importance of the generator duty.

The terminal voltage characteristics of a synchronous generator depend on following three distinct operating conditions :

1. Single generator is operating in isolation and supplying stand alone load (without supply from the Grid.)

— Terminal voltage varies with Excitation Current, $(V_t \propto I_f)$

— Power factor of generator stator current is equal to load current power factor.

— Reactive power supplied by the generator depends on the reactive power demand by the load, and load power factor.

2. Two or more generators operating in parallel and supplying stand alone load (without supply from the Grid). The terminal voltage depends on the operating conditions of parallel machines and the load conditions.

3. Generator connected to Infinite Bus (Grid or several Generators operating in parallel)

— Terminal voltage is constant and equal to grid voltage.

— Terminal voltage does not vary with excitation current.

— Power factor of generator stator current and Reactive Power Q shared by the generator varies with the excitation current.

Under steady state conditions, the terminal voltage of a generator connected to *infinite bus* bar (Grid or a large power system) is constant and is determined by the prevailing Grid Voltage and not by the generator field current. The power factor of armature current is decisively influenced by the excitation current.

The demands made on AVR performance depend on the load characteristics and the load p.f. The various applications of synchronous generators are represented in Fig. 45.24.

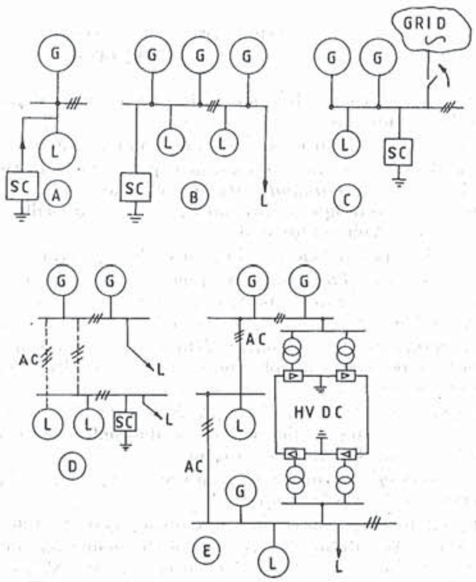


Fig. 45.24. Applications of synchronous generators.
SC = Shunt Compensation L = Load G = Generators

Note : Specifications and type, characteristic features etc. of Controller differ significantly for A to E due to difference in load characteristics/p.f. and protection/control and stability requirements.

A. Single generator feeding a isolated local load.

B. Two or more generators in parallel, feeding a local load and a distribution line.

C. Two or more generators with local load and operating in parallel with the Grid.

D. Two or more generators in parallel, feeding a remote load centre via long AC transmission lines.

E. Two or more generators in parallel, feeding a remote load centre via a long AC transmission line in parallel with a HVDC line.

45.31. OPERATION OF SYNCHRONOUS GENERATOR

A synchronous generator (alternator) has a 3-phase distributed AC armature winding on *stator* and a DC excitation main field winding on the *rotor*.

The rotor is driven at synchronous speed by prime mover (Steam turbine/Hydro turbine/Gas turbine, Diesel engine etc.). The main excitation field winding on rotor of the alternator is supplied DC voltage by the *Exciter*. The main alternator excitation field current. It is increased or decreased by changing Exciter Voltage by Automatic Voltage Regulator and its feedback control system. Rotating magnetic field of DC excitation field of rotor induces 3 phase AC emf in stator armature winding. Flow of stator armature current Ia produces induced revolving magnetic field in the air-gap, revolving at synchronous speed and locked with the rotor magnetic field. The angle between the stator field and rotor field is the load angle δ which increases with load and which undergoes oscillation during disturbances.

The *Main Exiter* provides DC Field voltage to the rotor field winding of the Generator. The exiter-terminal voltage decides the Excitation current (Field current of the generator. The AVR controls exciter terminal voltage and alternator excitation rotor field current to regulate Generator terminal voltage. The pilot excitor (if any) feeds power to the field winding of main exciter.

The generator supplies active power P (MW) at voltage V_t (kV) and power factor cos ϕ, and stator current I_a, (kV), where :

$$P = 3\, V_t\, I_a \cos\phi$$

Consider an isolated generator-load operating mode (without grid connection). The power factor cos ϕ is decided by the load power factor. Magnitude $|V_t|$ is decided by Excitation Current and its control by the AVR.

In case of Parallel operation with the Grid, terminal voltage $|V_t|$ is decided by the Grid Voltage in parallel operation with grid. In that case the power factor of generator armature current Ia is decided by the Excitation Current. I cos ϕ will be get adjusted to required power level, as V_t is constant corresponding to Grid voltage.

The generator also supplies reactive power Q (MVAr)

$$Q = 3\, V_t\, I_a \sin\phi$$

where, I_a = Armature current, V_t = Terminal voltage, and ϕ = Power factor angle

In isolated generator-load operating mode (without grid connection) the Reactive Power Supplied by the generator is equal to Reactive Power demand by load side (Load + Compensator). In that situation, the power factor cos ϕ is decided by the power factor of (load + Compensator). By providing separate shunt compensation to load, the Generator is relieved of reactive power burden to that extent.

The characteristics of generator depend on the net active and reactive power load on the generator.

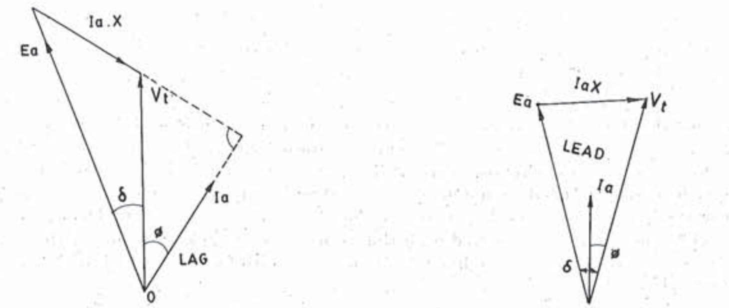
The apparent power is $S = (P + jQ) = 3\, V_t\, I_a$ Voltamperes

Power Factor $\cos\phi = P/S = MW/MVA$

The power angle δ between the two revolving magnetic fields increases with increasing load. During sudden changes in active load or reactive load, the power angle δ undergoes a *swing*. The conditions are studied under transient and dynamic stability studies. In vector diagram, the power angle δ is represented by angle between vectors emf $\mathbf{E}_a$ and voltage $\mathbf{V}_t$. With increase in power P_a, δ should increase.

The vector relationship between emf $\mathbf{E}_a$, terminal voltage V_t and power factor cos ϕ is given by $[\mathbf{V}_t = \mathbf{E}_a - \mathbf{I}_a X.]$

The vector diagram is given in Fig. 45.25. The terminal voltage V_t is equal to vector difference between emf E_a and voltage drop in armature winding ($I_a \cdot X$ drop). Resistance is neglected. $\mathbf{I}_a \cdot X$



Lagging p.f. (Overexcited, $\gg E_a$) Leading p.f. (Under excited, $\ll E_a$)

Fig. 45.25. A, B. Vector diagram of a synchronous generator.

V_t = Terminal voltage E_t = E.M.F. excitation emf or induced emf

I_f = Field current (rotor current) I_a = Armature current (stator current)

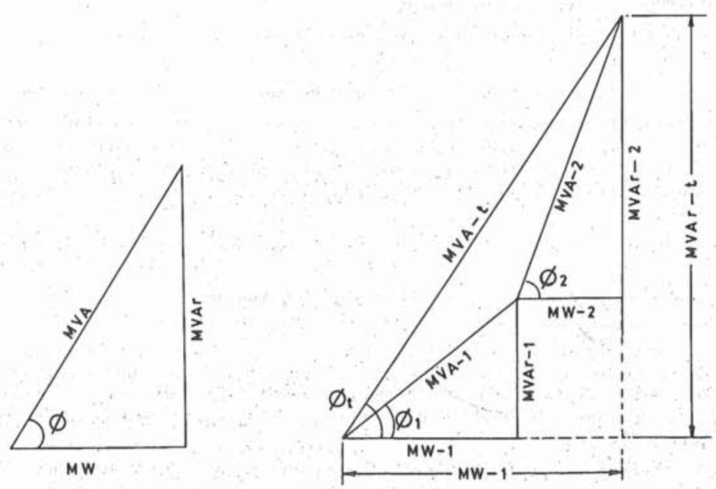
$\cos \phi$ = Armature current p.f., ϕ angle between V_t and I_a

δ = Power angle, Load angle, angle between E_t and V_t

[$I_a \cdot X$ drop is perpendicular to $I_a \cdot E_a$ is proportional to I_f. $I_a \cdot \cos$ is proportional to P_a]

is perpendicular to I_a. The angle δ between $\mathbf{E}_a$ and V_t increases with active load P_a. The armature current I_a is at certain p.f. angle ϕ with respect to voltage V_t.

The lagging p.f. armature current in generator stator has a demagnetising effect on magnetic flux. Hence the excitation current should be increased to maintain the terminal voltage constant. This is called overexcited condition. The *leading p.f. armature current* in generator stator has a



A Single generator B Two Generators in Parallel

Fig. 45.26. MVA, MW, MVAr and ... relationship.

magnetising effect on magnetic flux. Hence the excitation current should be reduced to maintain the terminal voltage constant. This is called underexcitation condition.

In *isolated operation of generator-load combination,* the power factor of load is same as that of the generator. Hence the net reactive power required by load is supplied by the generator.

In *parallel operation of two or more generators feeding isolated load* without grid connection, the net reactive power demanded from the bus bars by the load-compensator combination is supplied by all the generators operating in parallel. These generators share the reactive power in accordance with their excitation levels and rated MVA.

Two or More Synchronous Machines in Parallel

Synchronous generators operating in parallel have tendency to remain in synchronism with each other.

Terminal voltages of machines operating in parallel are the same total active power generation is equal to total active load on the power plant. Active power supplied by the generator is equal to the active power input to its prime mover.

The total reactive power supplied to load is equal to reactive power supplied by the generator units operating in parallel. The reactive power shared by the generator depends on the excitation current.

The vector difference between emfs in the two generators produces a synchronising current in the local circuit of the two generators operating in parallel.

With grid connection, the terminal voltage V_t remains constant and emf and p.f. of generator is determined by the emf/excitation current level of the generator and the load power factor at generator bus. The latter changes with load/network/bus/compensation conditions.

45.32. EMF AND NO LOAD TERMINAL VOLTAGE, SATURATION CURVE AND AIR LINE

The induced emf of generator depends on the excitation field current. The terminal voltage V_t and power factor $\cos \phi$ depend on other conditions prevailing at bus side depending on operating mode and active plus reactive power load.

Induced electro motive force (emf) varies with excitation current in accordance with the no-load characteristics emf Ea versus field current I_f. This characteristic is called *saturation curve.* The extended straight line is called the *air gap characteristic.* At no load voltage drop in synchronous reactance ($I_a \cdot X$ drop) is zero and the no-load, terminal voltage V_t is equal to emf.

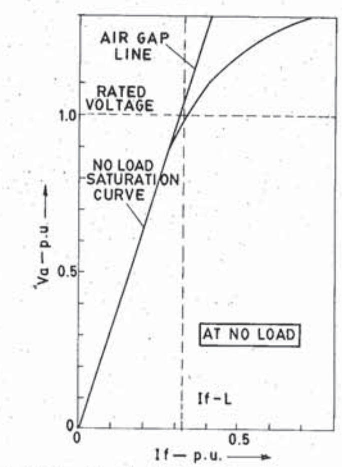


Fig. 45.27. No load terminal voltage V_t against Field Current (Saturation characteristics) of a synchronous generator. V_t on no load = *EMF* that is proportional to I_f.

45.33. TERMINAL VOLTAGE OF AN ISOLATED GENERATOR WITH CONSTANT FIELD CURRENT AND WITHOUT AVR

If field current is held constant, the terminal voltage of an isolated generator (not connected to the grid) would drop with increasing lagging p.f. load current due to $I_a X$ voltage drop in the generator stator winding and demagnetising effect of armature reaction on lagging currents. If the field current is held constant, the terminal voltage of an isolated generator (not connected to the grid) would rise with increasing leading p.f. load current due vector addition of $I_a X$ voltage in the generator stator winding and magnetising effect of armature reaction of leading p.f. current.

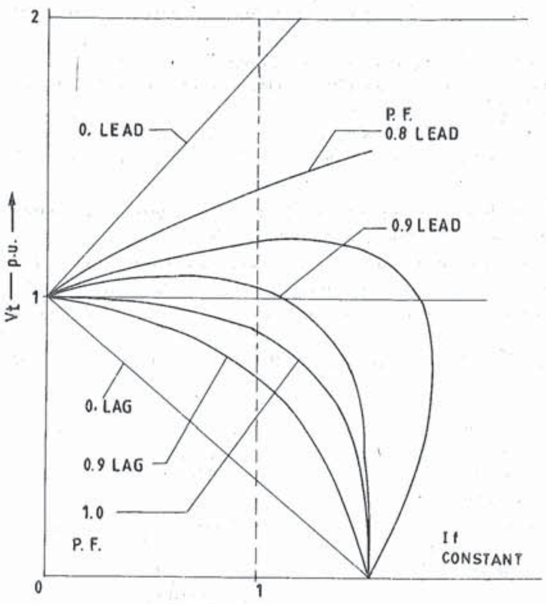


Fig. 45.28. Terminal voltage V_t against Armature current I_a, at constant field current I_f in Islanded operation. (Not connected to Grid)

(Note : I_f constant corresponds to constant emf E_a)

Constant Terminal Voltage -V Curves

The well known *V-Curve,* for a synchronous generator is the graph of MVA load on Y axis and Field current on X axis, *for constant terminal voltage.* Each V curve is for a particular level of active power P_a. The power factor curves are also plotted on the same graph. The unity p.f. curve is at the center of the V. The right side is for lagging p.f. loads and the left side is for leading p.f. load.

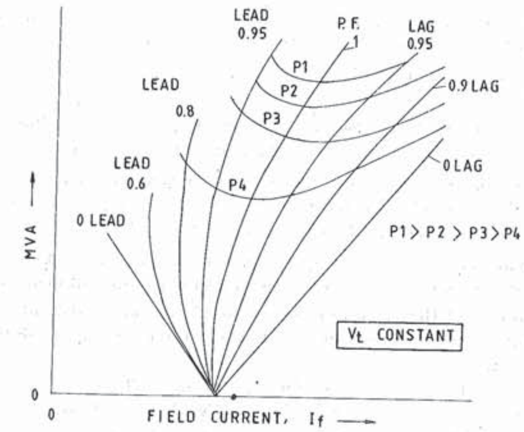


Fig. 45.29. V-curves for synchronous generator.

45.34. TYPES OF EXCITATION SYSTEMS AND AVRs

Automatic Voltage Regulators are a part of Excitation System of Synchronous Machines. Over the past decades the Excitation Systems and AVRs have been developed into several different versions and designs. The principal differences in configuration are in the equipment for supply of DC excitation current and method of feed back from generator output.

As per American Practice, the Excitation System has

1. DC Regulator, DC Regulator is optional in some versions.
2. AC Regulator.

In AC Regulators, the current and voltage supplied by the Synchronous Generator to busbars is measured by the Current Transformers and Voltage Transformers. The reduced secondaries are connected to the AC Voltage Regulator. The AVR compares the actual current and voltage with the desired reference value and gives feed back to the input side of excitation system via an Amplifier. The Amplifier receives DC Power from an Auxiliary Source or the Main Generator and Feeds DC Power to Generator Field as per feed back signal from AVR.

In DC Regulators, the DC field voltage supplied by the Exciter to Field Winding of Synchronous Generator is fed to the DC Voltage Regulator. The DC Voltage Regulator compares the actual DC Field voltage with the desired reference value and gives feed back to the input side of excitation system via an Amplifier. The input is in the form of DC voltage across the field winding of main Synchronous machine.

A. Before 1970s, the earlier versions of Excitation Systems, were with DC Generators and Rotating Amplifier. The DC current required for field was obtained from a DC generator with commutator and brushes. The types of such excitation systems with DC Generators are :

1. DC Generator—Commutator Exciter with Rotating Amplifier The DC generator may be motor driven or generator-shaft driven.
2. DC generator—commutator Exciter with Static amplifier.
3. DC generator—commutator Exciter with Noncontinuously acting Rheostatic Regulator.

B. During 1970s. the of Solid State Devices (Diodes and Thyristors) and Rectifiers were successfully developed and were introduced gradually in the Excitation Systems. The modern Excitation Systems are with Diode Rectifiers (Uncontrolled) or Thyristor Rectifiers (controlled).

With the availability of semiconductor diodes and thyristors, the DC commutator generator excitors are no more used in new installations. The types of modern Excitation systems are :

1. Brushless Excitation System : Alternator—Rectifier Exciter employing Rotating Diode Bridge Rectifier.

2. Alternator—Exciter, employing Stationary Noncontrolled Diode Rectifier.

3. Alternator—Exciter, employing Stationary Controlled Thyristor Rectifier.

Under steady state conditions, the *terminal voltage* of an *isolated generator* (without any other machine or grid in parallel) is decided by the (1) Field Current I_f (excitation current) (2) Armature current (I_a) which in turn depends on load current and (3) Power factor of I_a.

With lagging p.f. load, the terminal voltage tends to drop and the field current should be increased. The load p.f. must be improved by providing shunt capacitors in load side.

With the leading p.f. load the terminal voltage tends to rise and field current should be decreased and the load p.f. should be brought near unity or high lagging by adding shunt reactors in the load side.

Fig. 45.28 shows how the terminal voltage will vary *without* voltage regulator for various power factor loads. However, in practice the terminal voltage of Synchronous Generator bus must be regulated within specified limits *i.e.* rated voltage with tolerance ± 1%.

As per standard specifications of Synchronous Machines, the permissible variation in generator voltage is ± 5%. The AVRs ensure voltage variation within ± 1%.

In case of isolated generator-load, the terminal voltage is regulated by increasing the field current during increasing lagging p.f. load, manually by the operator or automatically by AVR. Likewise, during increasing leading p.f. load current, the excitation current is reduced manually or automatically to reduce emf and regulate the terminal voltage.

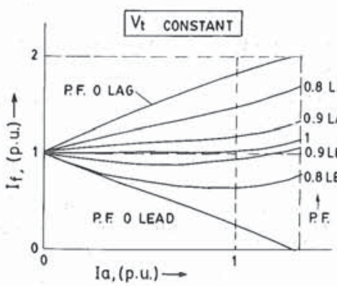


Fig. 45.30. Field current I_f versus Armature current I_a for constant terminal voltage V_t.

For stand-alone (isolated load) synchronous generator the DC field current (excitation) is varied to regulate the terminal voltage. The field current may be varied by manual control by intervention of the control room operator or by Automatic Voltage Regulators in the feed back control system in the excitation system of the generator.

Lagging p.f. load requires higher field current of generator (over excitation), leading p.f. load requires less field current (under excitation. The leading p.f. load current has a magnetising effect on the stator magnetic field and therefore there is a lower limit imposed on the value of load current.

For lagging p.f. higher load, higher field current is necessary to maintain the terminal voltage within specified limits.

Alternatively the shunt capacitors on load side may be switched on to improve load p.f. and relieve the excitation system from overcurrent and heating. Power factor of armature current I_a. The power factor of armature current is decisively influenced by the power factor of the load current and not by the excitation current.

45.35. SYNCHRONOUS GENERATOR IN PARALLEL WITH THE GRID (INFINITE BUS)

Generator operating in parallel with the grid has a tendency to remain in synchronism (in step with) the grid. Grid can be considered. Infinite Bus having constant voltage and constant frequency. With generator in synchronism with the infinite bus (grid), the terminal voltage V_t is controlled by

the prevailing Grid Voltage which is constant. The terminal voltage of the generator does not change by change in its field current (unlike in the case of generator operating on isolated load). The change in field current of the generator affects the power factor of the generator armature current and reactive power shared by the generator. Active power shared by the generator remains unaffected.

The synchronous machine connected to infinite bus (Grid) operates as generator or motor or condenser (compensator) depending upon the power input to generator shaft and electrical power delivered by the synchronous machine.

For generator operation mechanical power input is more than electrical output and δ is considered to be positive, and we get

$$V_t + I_a X = E_t$$

For motor operation, electrical power input is more than the mechanical power output and δ is considered to be negative, we get,

$$V_t - I_a X = E_t$$

For compensator operation, the electrical power is equal to mechanical shaft power and δ is zero, $V_t = E_t$.

The amount of field current of the synchronous machine connected to grid determines mainly the machine-power factor and to lesser extent the load angle. The load angle is determined by the electrical load on generator terminals and the mechanical power input to the shaft. If mechanical shaft input power is stopped, the machine continues to rotate in motor mode taking electrical input from grid.

The V-curves shown in Fig. 45.30 illustrate the characteristics of the synchronous generator operating at constant terminal voltage achieved by changing field current I_f.

Table 45D.1
Types of Excitation Systems and Source of Excitation Power

Exciter Category	*Type of Exciter*	*Exciter Power Source*	*Initial Response*
DC	DC Generator commutator Exciter	Motor-Generator set or Syn. Machine Shaft	Slow
AC	Alternator-Stationary Non-controlled Diode Rectifier	Syn. Machine Shaft	Slow
AC	Alternator-Rotating Non-controlled Diode Rectifier Brushless Exciter	Syn. Machine Shaft	Fast
AC	Alternator-Stationary Controlled Thyristor Rectifier	Syn. Machine Shaft	Fast
St	Potential Source Controlled Rectifier	Synch. machine voltage or Aux. Bus Voltage	Fast
St	Compound Source Non-controlled Diode Rectifier	Synch. machine voltage and Current	Slow
St	Compound Source controlled Thyristor Rectifier	Synch. machine voltage and Current	Fast

45.36. TYPES OF AVR AND EXCITATION SYSTEMS

A1. DC Generator-Commutator Exciter with Amplidyne Voltage Regulator

Fig. 45.31 shows a simplified schematic of a typical earlier excitation system. The DC generator (Main Excitor) was driven by a separate motor or was mounted on main generator shaft through

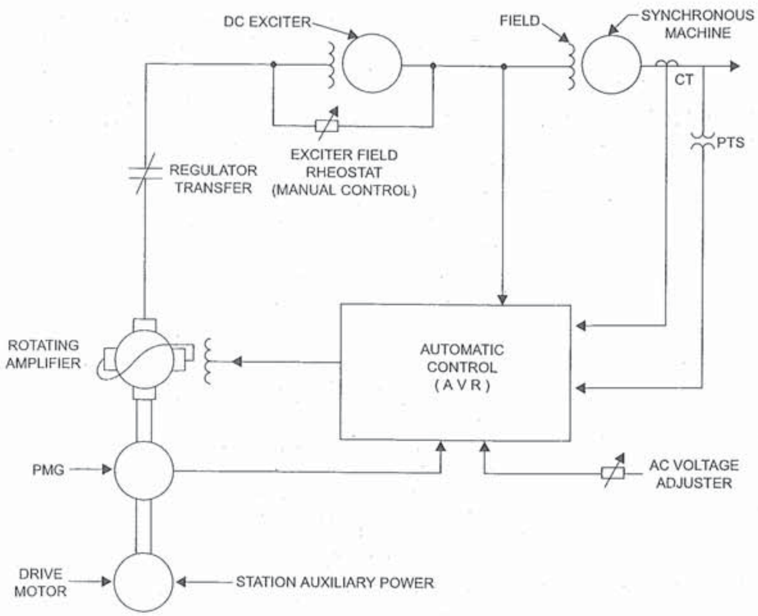


Fig. 45.31. Schematic of excitation system with DC generator-commutator exciter with rotating amplifier.

gear arrangement for speed change. The feed back signal was amplified in Amplidyne (DC Rotating Amplifier). The field current for Main Excitor DC generator was supplied by Pilot Excitor (a permanant magnet DC generator PMG).

The DC generator may be motor driven or generator-shaft driven.

The DC Generator Exciter System had achieved a high degree of reliability and was well accepted universally upto mid 1970s. However the modern Excitation systems are with Diode or Thyristor rectifiers, lesser weight/size, having superior characteristics and lesser maintenance.

B. Brushless Excitation System

Fig. 45.32 gives a schematic of a Brushless Excitation System with Rotating Noncontrolled Diode Rectifier Excitation System.

It consists of an AC Exciter and a rotating diode bridge mounted on generator shaft. A small permanant magnet generator (PMG) provides excitation current to the stator AC exciter field. The excitation current supplied to stator of AC Exciter field is controlled by stationary AVR by manual control or Automatic control.

Brushless excitation systems have no brushes/slip rings/commutators. The AC Exciter-rotor and, Rotating Diode Rectifier Bridge are mounted on the generator shaft without the need of brushes. Alternator field winding is connected to the two terminal plates of Rotating Diode Rectifier Bridge. The rotating rectifier bridge receives 3 phase input from AC Exciter Rotor and gives DC output to alternator field. The AC Exciter Stator has DC winding which receives DC power from Permanant Magnet Generator (PMG) through AVR Control.

The *flow of excitation power* is as follows :

Main field of Generator ← Diode Bridge on Rotor Shaft of Gen. ← Three phase rotor winding of AC Exciter on Gen shaft

↑

Field current for stator of AC exciter from PMG through AVR (PMG has rotating Poles and Stationary DC winding)

AVR The brushless excitation system is preferred for alternators where the control requirements are not very stringent or where sparking at brushes or commutators is not permissible due to chemically explosive environment (*e.g.* mines).

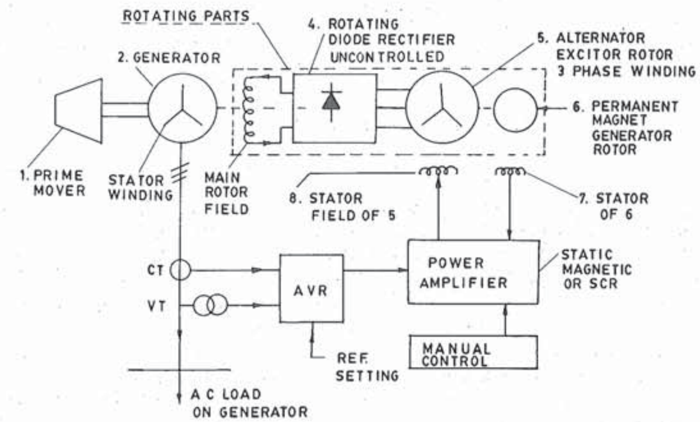


Fig. 45.32. Simplified schematic of brushless excitation system with rotating Noncontrolled diode rectifier.

Note : Design configurations may differ, the above figure illustrates a typical example.

C. Alternator-Exciter with Stationary Noncontrolled Diode Rectifier

The excitation power is supplied by Alternator Exciter. The Alternator Exciter is a direct coupled AC generator driven by main generator shaft. The Alternator-Exciter has a stationary 3 phase armature winding and rotating DC field winding. The 3 phase stator winding supplies AC power to stationary uncontrolled diode rectifier bridge. The output of this rectifier bridge is supplied to the Main Generator rotor field through two slip rings.

The rotor DC field of Alternator Exciter is supplied current through stationary controlled thyristor rectifier bridge. The firing angle of thyristor bridge is controlled by AC Regulator or DC Regulator.

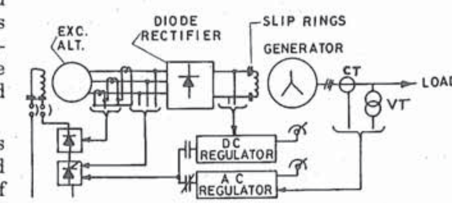


Fig. 45.33. Excitation system with "Alternator-Exciter employing stationary uncontrolled diode rectifier bridge".

Note : Design configurations may differ, the above figure illustrates a typical example.

The power for excitation is derived from the Power CT and Power VT whose primaries are connected in the main power circuit between Alternator Exciter and Stationary Rectifier Bridges.

D. **Alternator-Exciter Employing Stationary Controlled Thyristor Rectifier**

Like in the C above with a difference that the Stationary Rectifier feeding DC to Main Generator field is a controlled *Thyristor Rectifier Bridge* supplying DC Field current, the excitation power is supplied by Alternator-Exciter. The control of thyristor bridge firing angle is by Regulators.

The Alternator Exciter is a direct coupled AC generator driven by main generator shaft. The Alternator-Exciter has a stationary 3 phase armature winding and rotating DC field winding. The 3 phase stator winding supplies AC power to stationary controlled thyristor rectifier bridge. The output of this thyristor-rectifier bridge is supplied to the Main Generator Rotor Field through two slip rings.

The rotor DC field of Alternator Exciter is supplied current through stationary controlled thyristor rectifier bridge. The firing angle of thyristor bridge is controlled by AC Regulator or DC Regulator.

The power for excitation is derived from the Power CT and Power VT whose primaries are connected in the main power circuit between Alternator Exciter and Stationary Rectifier Bridges.

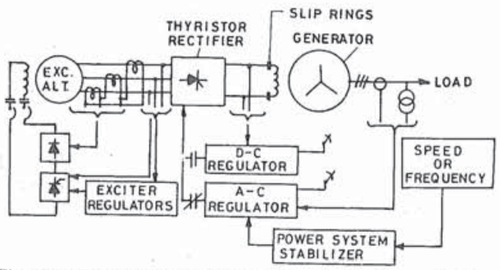


Fig. 45.34. Excitation system with "Alternator-Exciter employing stationary controlled thyristor rectifier bridge".

Note : Design configurations may differ, the above figure illustrates a typical example.

E. **Voltage Source Controlled Exciter**

The excitation power is supplied by the generator through Voltage-Power Transformers.

F. **Compound Source Controlled Exciter**

The excitation power is supplied by the generator through compounded output of Voltage-Power Transformers and Current Power Transformer.

45.37. TERMS AND DEFINITIONS ON AVR AND EXCITATION SYSTEMS (Ref. IEEE Std. 1986, BS Std. 1987)

1. **Excitation System.** The equipment for providing field current (excitation current) to a synchronous machine. The equipment includes all power/control/regulating and protective elements.

2. **Regulated Voltage.** The voltage which is held within specified band or zone during steady or gradually changing load conditions within specified range of load.

3. **Band or Zone of regulated Voltage** is expressed as percenta of rated value of rated voltage. (*e.g.* + 3 per cent of rated V_t).

4. **Exciter.** The equipment providing field current for excitation of a synchronous machine.

5. **Pilot Exciter.** The equipment providing field current to the exciter field.

6. **Automatic Voltage Regulator.** A subsystem of the excitation system for regulating the terminal voltage of synchronous machine automatically.

7. **Voltage regulator** is a hystoric term. Modern term is Synchronous machine regulator. (1986)

8. **Synchronous Machine Regulator.** The regulator that couples the output variables of a synchronous machine to the input of the exciter through a feed back and feed forward control elements for controlling the synchronous machine output variables.

9. **Rated field current.** Direct current in the field winding of the synchronous machine operating at rated : voltage, current, power factor.

10. **Rated field voltage.** Direct voltage required across the terminals of the field winding of the synchronous machine under rated continuous load conditions with its field winding at specified temperature. (*e.g.* 75°C)

11. **Excitation system nominal response.** Rate of increase of excitation system output voltage divided by rated field voltage. (Ref. Sec. 45.40) Rate of increase of excitation system output voltage is determined from excitation system nominal response curve. Fig. 45.36.

12. **Exciter voltage response time.** Time in seconds for exciter voltage to reach 95% of the (difference between ceiling voltage and rated load field voltage) under specified conditions.

13. **Excitation system Ceiling Voltage.** The maximum DC voltage which the excitation system can supply to the generator field winding for a specified short time.

Excitation system Ceiling Current. The maximum DC current which the excitation system can supply to the generator field winding for a specified short time.

14. **Field forcing.** The control function that rapidly forces the field current in the synchronous machine in positive or negative direction.

15. **Voltage Regulating Adjuster.** A device associated with the Regulator by which the adjustment in terminal voltage of synchronous generator can be made.

16. **Limiter.** An element in the excitation system which acts to limit a variable under certain predetermined conditions. *e.g.*

(*a*) **Under Excitation Limiter :** Prevents the voltage regulator from lowering field current below specified limit.

(*b*) **Over Excitation Limiter :** Prevents the voltage regulator from raising field current above specified limit.

(*c*) **Volts per hertz Limiter :** Acts through voltage regulator to limits V/f ratio within specified limits and takes corrective action to make V/f normal.

16. **Manual Control.** The control of terminal voltage of synchronous generator by operators action, *e.g.* by adjusting field rheostat, controlling angle of firing the thyristors of controlled rectifier.

17. **De-Excitation.** Removal of excitation (field current) of main exciter or pilot exciter. For example by opening field circuit and discharging the field by means of Field Discharge Circuit Breaker.

18. **Field Forcing.** Control function that rapidly increases or decreases the field current of the synchronous machine.

19. **Power System Stabiliser.** A group of elements in the excitation system that supplement the voltage regulating function and provide additional regulating function to improve the dynamic performance of power system.

20. **Types of AVRs (Synchronous Machine Regulators).** In the past, the DC current required for field was obtained from a DC generator with commutator and brushes. The types of such excitation systems are :

(*a*) DC Generator—Commutator Exciter with Rotating Amplifier. The DC generator may be motor driven or generator-shaft driven.

(b) DC generator—Commutator Exciter with Static amplifier.

(c) DC generator—Commutator Exciter with Noncontinuously acting Rheostatic Regulator.

With the availability of semiconductor diodes and thyristors, the DC commutator generator excitors are no more preferred. The types of modern Excitation systems are :

(d) Alternator—Rectifier Exciter employing Brushless Rotating Noncontrolled Diode Rectifier.

(e) Alternator—Rectifier Exciter employing Stationary Noncontrolled Diode Rectifier.

(f) Alternator—Rectifier Exciter employing Stationary Rectifier.

(g) Voltage source supplied controlled/uncontrolled Exciter.

(g) Compound Voltage and Current supplied controlled source controlled Exciter.

21. **DC Regulator** senses DC Voltage from field winding terminals and uses it for control of field voltage. DC Regulator is in addition to AC Regulator.

22. **AC Regulator** senses AC Voltage and Current from generator terminals and uses them for control of field voltage.

23. **Slip Rings with Brushes.** DC current is transferred from stationary terminals to rotating winding via the Slip rings on rotor and brushes in stator. Brushes provide a sliding contact.

45.38. EXCITATION SYSTEMS AND AVR (SYNCHRONOUS MACHINE REGULATORS)

Synchronous Machine Regulator (AVR) regulates voltage and reactive power generated by the synchronous machine. The controlled variables received by AVR are generator stator current I_a from CT secondary, generator stator voltage V_t from secondary of VT and DC field voltage. These variables are measured by the AVR against set reference value and corrective feed back signal is given to Amplifier. The Amplifier amplifies the signal and corrected DC voltage is supplied to Generator Field. The feedback control system controls the variables (V_t and MVAr). AVR is a part of the excitation system.

The excitation system consists of mechanically and electrically coordinated components which together perform the following functions

1. Power Source. 2. Rectification. 3. Cooling 4. Control and stabilising function. 5. Protective function.

1. **Power Source.** The required excitation power is supplied by the power source. The required power may be derived from the main generator-turbine shaft or an auxiliary bus, or a special electrical machine mounted on the generator turbine shaft, or from special winding in the, main generator, or from main generator terminals via power transformer.

2. **Rectification.** In earlier excitation systems of 1960s, DC current for excitation was obtained from Rotating—Commutator type DC Generators. Todays excitation systems without exception use Diode Rectifier or Thyristor Rectifier to obtain DC current from AC Supply derived from main generator output.

3. **Cooling System.** In the earlier designs, air cooling is used for cooling the components of excitation system. For compact and optimised designs of large size, gas cooling or liquid cooling is preferred in modern designs.

4. **Control Functions.** The voltage of generator under wide range of load variation is held within permissible narrow limits by adjusting field current manually or automatically by generator voltage regulator. The generator voltage regulator is a controller in the excitation system. The automatic voltage regulator controls the terminal voltage during normal load conditions and also during abnormal conditions causing sudden voltage change.

In addition to voltage regulation, following control functions are usually incorporated in the modern excitation system depending upon application requirement.

Improved Stability. Improvement in Steady State, Transient Stability Limits of Generators with respect to Power system by continuous, fast control of excitation current to match the requirements of generator and power system. During steady state operation of generator, excitation current is adjusted continuously to maintain the terminal voltage of generator at rated value. Thus the steady state stability limit of generator is improved and generator can be loaded to higher limit.

During transient state, the excitation current is rapidly increased or decreased by field forcing to ensure voltage recovery within minimum time. Thus ensuring synchronous operation during transient disturbances.

When the generator voltage overshoots during sudden load throw-off, the controller forces the field in negative direction and reduces the terminal voltage within a few seconds by fast response.

When the generator voltage falls during sudden loading, the controller forces the field in positive direction and increases the terminal voltage within a few seconds by fast response.

Dynamic Stability. The fast acting voltage regulators provided with power system stabilising features, improve the dynamic performance of the power system by rapid damping of oscillations in load angle O. With such a feature the loading on transmission line outgoing from the generating station can be increased.

Power System Stabiliser. A control function added to the Automatic Voltage Regulator for improving power system stability is called the Power System Stabiliser. The power system stabiliser may utilise signals from shaft speed, frequency, power or other variable. The dynamic performance of the power system is improved by rapid damping of system oscillations.

Reactive Power Compensator. The controllers for generators operating in parallel in the same power plant may be provided with additional feature for sharing reactive power in proportion to their rating (or some other assigned ratio).

Line Drop Compensation. When a generating station is feeding a remote load via a transmission line, the terminal voltage may be controlled such that the voltage at some point on the line length is held constant (instead of the terminal bus voltage constant). Such control function is called lone drop compensation or active and reactive compensation.

Limiter. The excitation system is provided with several limiters which acts to limit a variable under certain predetermined conditions. *e.g.*

— **Under Excitation Reactive Ampere Limit (URAL) :** Limits the under excited reactive MVA that the generator can supply so that adequate steady state stability margin is available with respect to powersystem and the generator, and safe operating conditions are not crossed.

— **Over Excitation Limiter** : Prevents the voltage regulator from raising field current above specified limit.

— **Volts per hertz Limiter** : Regulate V/f ratio for protection of the generator and the associated transformers to limits V/f ratio within specified limits and takes corrective action to make V/f normal.

— **Other limiter include** : Stator current limiter, Load angle limiter. Ref. Fig. 45.42.

5. **Protective Functions.** AVR has a strong interface with the generator protection system (Ch. 33) The coordination between protective relay characteristics and AVR characteristics permits maximum loading of generator excitation system under steady state condition and transient condition. Protection system acts to remove faulty parts from the rest of the system. If short circuit occurs in generator stator winding, the excitation current is reduced rapidly and the field is discharged by means of Field Discharge Circuit Breaker and Field Discharge Resistor. Various Limiters provided in the excitation system protect the Generator and power system equipment against over heating, excessive mechanical stresses and yet allow the machine to operate at higher MW output.

45.39. STEADY STATE PERFORMANCE EXCITATION SYSTEMS AND AVRs

During normal operation of synchronous machine, the excitation system should automatically provide an adjustment in generator field current to maintain terminal voltage within cloase limits and ensure sharing of reactive power properly. This means that the excitation system should be capable of supplying a wide range of DC current to generator field.

The Range of Permissible Steady State Generator Voltage V_t and Frequency f Variation

The synchronous machines are designed for continuous rated output, at rated power factor; at rated voltage with tolerance ± 5% and rated frequency with tolerance ± 2%. The combination of operating voltage and operating frequency is of importance with reference to overheating of excitation winding and overfluxing of power transformers of the generator unit. Fig. 45.35 gives the operating range of V and f combination recommended by *the standard of synchronous machines.* (However, in practice the terminal voltage of Synchronous Generator bus must be regulated within specified limits *i.e.* rated voltage with tolerance ± 1% by the Automatic voltage regulator.)

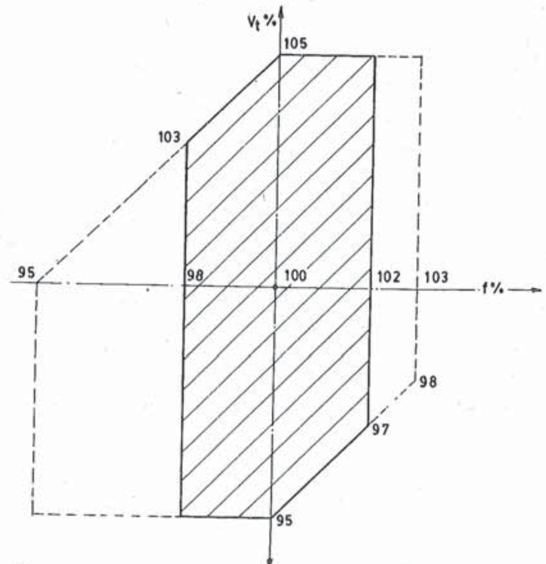


Fig. 45.35. V_t and f operating range for steady state operation of synchronous generators.

For isolated generator-turbine unit, the voltage is controlled by the Automatic voltage regulators and the frequency is controlled by the turbine-governor and voltage by the Automatic Voltage Regulator. For grid connected Generator unit, the voltage and frequency is decided by Bus voltage and bus frequency respectively.

High V/f is harmful for unit transformer and Auxiliary transformer as the core gets heated due to overfluxing. V/f limiter in excitation system prevents V/f above permissible limit. (Usually 1.1 pu.)

45.40. TRANSIENT PERFORMANCE OF AVRs

System faults, sudden load throw-off, sudden loading, switching, etc. produce transient disturbances in the power system. These disturbances are of short term time duration in several cycles or long term duration of several seconds.

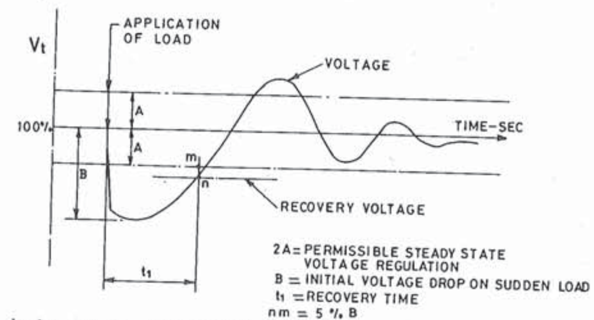


Fig. 45.36. Typical voltage response characteristic of generator on application of sudden load on generator. (95% of difference between ceiling voltage and rated load field voltage is attained in time t_1)

During transient disturbance in the Network, the excitation system of generators should rapidly respond so as to maintain the stability of the generators and the power system. Thus, during voltage dip, the excitation current must be rapidly increased and during voltage rise, the excitation current should be rapidly reduced.

The excitation current must then be brought to normal after the disturbance has subsided.

Modern excitation systems have provision of *Field forcing* by which the controller acts rapidly to (1) increase the field current to ceiling current level during fall in terminal voltage, (2) decrease field current during rise in terminal voltage.

Two important transient characteristics of the excitation system—Excitation System Ceiling voltage—Excitation Response.

These two characteristics are important in evaluating the effectiveness of Excitation systems and AVRs in maintaining transient stability.

Excitation system Ceiling Voltage. The maximum DC voltage which the excitation system can supply to the generator field winding for a specified short time under defined conditions.

45.41. EXCITATION SYSTEM VOLTAGE RESPONSE

Under sudden disturbances, load fluctuations, faults, Switching, etc. the AVR forces the field current in positive or negative direction such that field current is changed rapidly to recover terminal voltage within a few seconds and the stability is maintained.

Consider sudden application of load. As the sudden load occurs, there is a sudden fall in terminal voltage of the generator. The AVR is called upon to operate rapidly and increase the exciter terminal voltage and thereby the generator field current exciter. The field being inductive, the DC current in field winding cannot rise instantaneously. Hence the exciter current rise slowly and the generator voltage is recovered slowly. By field forcing, the exciter voltage is increased rapidly for a short duration to *almost twice normal exciter voltage,* thereby the terminal voltage of the generator is recovered rapidly.

Earlier Definition of Excitation Response. The rate of increase or decrease of exciter terminal voltage when change in voltage is demanded.

Exciter voltage response time. Time in seconds for exciter voltage to reach 95% of the (difference between ceiling voltage and rated load field voltage) under specified conditions.

For a turbo generator exciter, exciter response was of the order of 200 V/sec with nominal voltage of 400 V. The required excitation response of hydro generators was much higher due to possible overspeeding of hydro turbines.

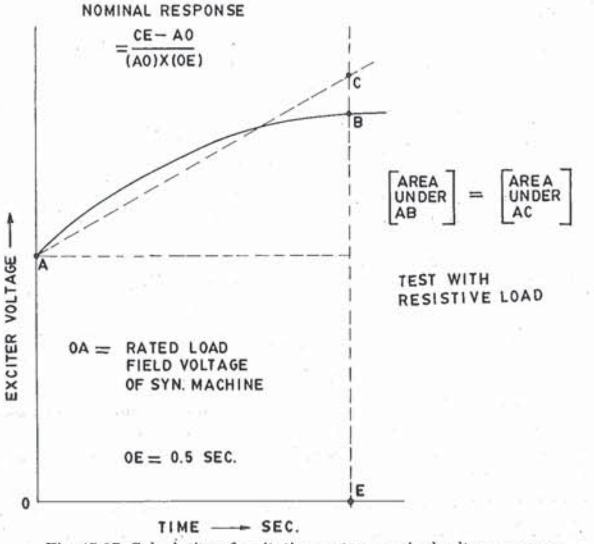


Fig. 45.37. Calculation of excitation system nominal voltage response.
(For testing excitation system with resistive load equal to field winding resistance).

Excitation system nominal response. Rate of increase of excitation system output voltage divided by rated field voltage. (Ref. Sec.) Rate of increase of excitation system output voltage is determined from excitation system nominal response curve.

The Nominal Response is calculated as shown in Fig. 45.38. Initially the exciter voltage is at rated value, *i.e.* rated field voltage of synchronous generator. The exciter is loaded with resistance equal to resistance of synchronous machine field winding. The exciter voltage is increased rapidly to the exciter ceiling voltage by introducing command through feed back loop.

The excitation voltage response defined as above adequately describes the performance of various conventional old type AVRs. But it is not adequate to describe the performance of many faster AVRs in use today having *high initial response.*

High Initial response (IEE Standard). For the high performance fast acting Excitation Systems, 95% of difference between Ceiling voltage and rated load field voltage is attained within 0.1 sec.

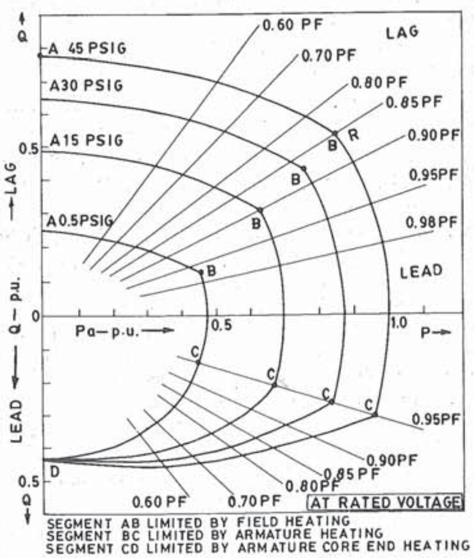


Fig. 45.38. Generator capability curves at rated voltage.

45.42. GENERATOR CAPABILITY CURVES

The capability of the generator terms of Active Power P and Reactive Power Q is usually represented in the form of the Generator Capability Curves (Fig. 42.38). Any point on the curve has certain P MW-p.u. and certain Q MVAr p.u. Inclined lines are the Power factor lines. The diagram has three segments, each segment represents limit imposed by most adversely influenced generator component. *Segment AB* in the upper part of the diagram is for overexcited lagging p.f. condition during which limit on generator capability is imposed by heating of field winding. For segment *AB*, the field current is at rated value.

Since the field current should not exceed rated value, segment AB is the limit imposed by maximum field current. With power factor below 0.6 lag, the active power capability of generator is reduced below 0.5 p.u. MW.

Referring to Fig. 45.38, the *segment BC* the power factor range is from rated p.f. 0.85 lag to leading p.f. 0.95; the generator is giving maximum output MW and the limit is set by the rated stator current heating. Maximum rated nameplate current shall not be exceeded. The protection is provided by Stator Overcurrent Protection.

The *segment CD,* the power factor range is in Leading p.f. from 0.95 lead at C to leading 0 p.f. lead at D.

In this range, the generator field is underexcited. The armature current magnetic flux has a predominantly magnetising effect which adds to the main field flux. The rotor core is at right angles to the stator laminations. The stator flux causes excessive heating of rotor core and stator end laminations. The active power capability reduces rapidly below 0.5 p.u. MW for leading power factors below 0.7. The generator output is reduced drastically. The limitation is provided by Under Excitation Reactive Ampere Limiter. Secondly, the leading power factor stator currents provide magnetic field of their own in air gap and excitation currents loose control over terminal voltage. The generator becomes Voltage Unstable in leading p.f. stator current range. *Hence Stability considerations are imposed in addition to heating limitations shown by segment CD.* Active power P MW should be reduced to ensure stable operation of Generator feeding leading power factor loads (*e.g.* night load in Megacities of distribution cable network with p.f. improvement compensators not disconnected and lighting load of unity p.f. in Mega cities). In the underexcited condition, the synchronising torque is less and stability is adversely affected.

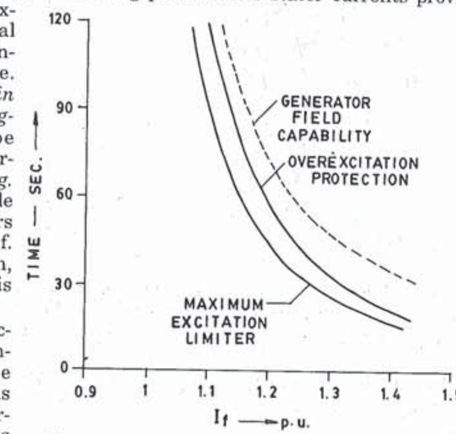


Fig. 45.39. Coordination of field capability curve with overexcitation protection and overexcitation limiter.

In practice, the reactive power, power factor, terminal voltage and cooling system, ambient temperature influence permissible loading of generators. The protection systems and limiters provide safeguards. The Generator Operators should be provided guidelines regarding generator capabilities under poor p.f. loads and adverse operating conditions of voltage and poor cooling.

Fig. 45.40 shows the time versus Field Current I_f characteristics of Generator Field Capability Curve and corresponding Protection Curve and Over Excitation Limiter Curve.

Table 45.D.2. Generator Armature an Field Overload Capabilities

Time sec	10	30	60	120
Armature current % of rated I_a	226	154	130	116
Field Voltage % of rated V_f	208	146	125	112

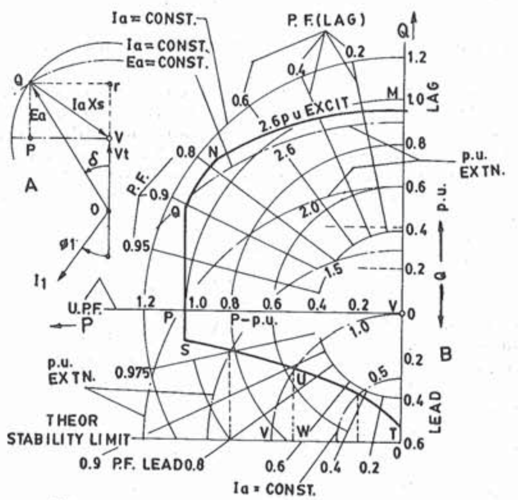
45.43. ELECTRICAL LOAD DIAGRAM OF A SYNCHRONOUS GENERATOR OPERATING IN PARALLEL WITH THE GRID (VT CONSTANT)

By plotting p.f. lines and constant excitation circles on the P-Q diagram, we obtain the Generator Loading Diagram (Fig. 45.41).

For grid connected generator, the terminal voltage remains constant.

The relationship between active power P_g, reactive power Q_g for various excitation currents I_f and power factors is plotted and is called Electrical Load Diagram. The limits of excitation current, active power, reactive power and armature current are drawn as dark curve on the same electrical load diagram.

Active power shared $V_t\,I_a$ cos depends on input to prime mover. Neglecting active power loss, the X coordinates give active power.



E_t = E.M.F. which depends on excitation current I_f

V_t = Terminal voltage, which depends on grid voltage, constant

o = Load angle between E_t and V_t

P_g = Active power

Q_g = Reactive power

Fig. 45.40. Typical electrical load diagram of a synchronous machine in parallel with the grid.

Active Power of Generator P_g = Active power of Prime Mover

In electrical load diagram, the Y coordinate of operating point represent active power P_g and X coordinate represents reactive power Q_g supplied by the Generator to busbars. The reactive power Q_g shared by the generator depends on Power Factor of armature current and Excitation Current. The Y coordinates give reactive power.

The vector diagram on the corner of Fig. 45.41 shows the relationship between E_t, I_a, load angle o and power factor angle. The load diagram is an extension of the vector diagram.

Fig. 45.29 illustrates a typical Load Diagram for a synchronous machine operating in parallel with the Grid.

The dashed circles represent constant p.u. excitation circles with origin 0' (0.5, 1.0, 2.0, 2.5, 2.6 p.u. Exc.). The firm curve circles with origin 0 correspond to p.u. armature current. The inclined lines represent power factors. The dark **line represents generator capability segments.**

45.44. CONTROL AND PROTECTIVE CIRCUITS OF AN EXCITATION SYSTEM

Additional protective, controlling and limiting systems in the Excitation System serve as regulators, Limiters and Protective Elements. Proper coordination between these elements and the Generator Protection System permits maximum short time overloading of the Excitation System under normal and emergency conditions thereby improving service continuity of the Generator.

Limiter. The excitation system is provided with several limiters which acts to limit a variable under certain predetermined conditions. *e.g.*

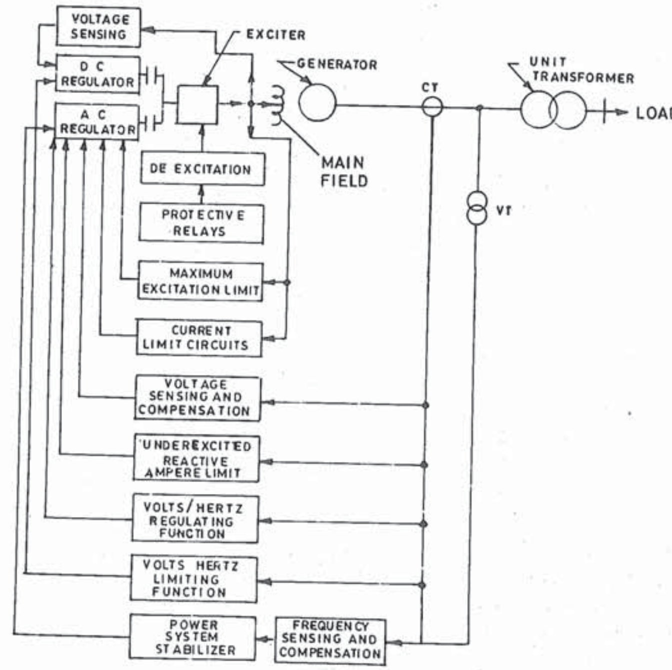


Fig. 45.41. Additional Protective, Regulating and Limiting Features in Excitation System.

— **Under Excitation Reactive Ampere Limit (URAL) :** Limits the under excited reactive MVA that the generator can supply so that adequate steady state stability margin is available with respect to powersystem and the generator and safe operating conditions are not crossed.

— **Over Excitation Limiter :** Prevents the voltage regulator from raising field current above specified limit.

— **Volts per hertz Limiter :** Regulate V/f ratio for protection of the generator and the associated transformers to limits V/f ratio within specified limits and takes corrective action to make V/f normal.

— **Other limiter include :** Stator current limiter, Load angle limiter. Rotor current limiter, Stator current limiter etc. Ref. Fig. 45.42.

45.45. VOLTAGE-REACTIVE POWER CHARACTERISTIC FOR CONSTANT POWER

Consider a Generator connected to Network (Grid). The voltage V_t remains almost constant and is determined by the Grid voltage. Hence the operating characteristic is very flat line on V_t versus Q diagram. The characteristic is similar to that for SVS. (Ch.)

The flat characteristics indicates, a small change in grid voltage *necessates* a large change in the reactive power output of Generator. Thus the operating point P moves along line AB with change in generator field current with Terminal voltage Vt determined by the Grid. The limits by Field current, Armature Currents and Rotor Angle are imposed on the operating range.

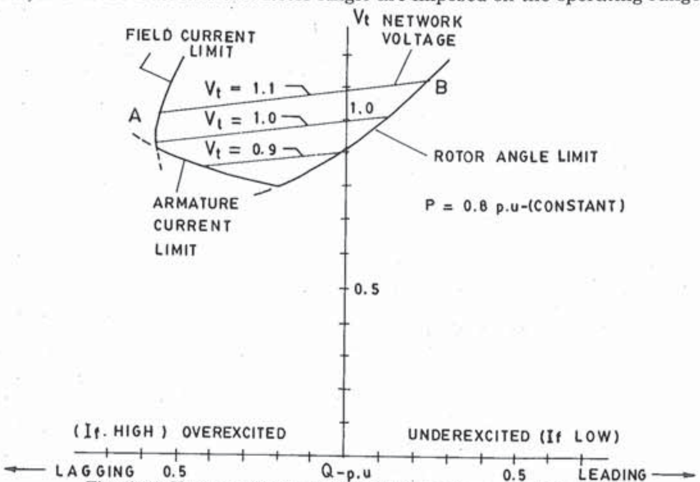


Fig. 45.42. V_t versus Q characteristics for Generator connected to Grid.

Power System Stabiliser

The Power System Stabiliser is an additional feature provided in the Excitation System for improving dynamic performance and rapid damping of system oscillations. The signal is taken from rotor shaft speed or rotor angle or frequency. The excitation voltage is rapidly controlled to damp the oscillations in load angle o.

SUMMARY

Excitation Systems and Voltage regulators of Generator regulate the terminal voltage within + 1% during normal load variation and improve transient stability during disturbances. Additional limiting and controlling, protective, stabilising features are also provided within Excitation Systems and AVR.

During terminal voltage fall, the excitation current is rapidly increased by Field Forcing. During voltage rise, the excitation current is rapidly reduced by Field Forcing. Two important features the ceiling voltage (app. 200% rated exciter voltage), and Excitation Response. The rated terminal voltage of generator is recovered within a few seconds to ensure transient stability.

The types of Excitation Systems are : DC Generator Amplidyne Exciter, Brushless Exciter, Alternator—Stationary Diode Rectifier Exciter, Alternator Stationary Thyristor Exciter etc. The source of excitation power is the Min generator/Auxiliary Station Supply/Aux. Motor Generator Set.

Under lagging power factor load, generator must be overexcited. The field current sets the upper limit. Under leading power factor load, the heating of rotor core end and stator magnetic

circuit set a limit. Under normal p.f.) 0.85 lag to 0.95 lead, stator armature heating sets the limit of loading. Excitation system has several limiters for protection of excitation system and the generator. Generator Excitation System and AVR control the voltage and improve the stability.

QUESTIONS

1. With the help of a schematic diagram, explain the configuration of a typical Brushless Excitation System. Define the terms "Excitation Voltage Response, Ceiling Voltage."
2. With the help of a simple Voltage versus time Graph, show how an AVR helps in rapid recovery of voltage after sudden loading on Generator.
3. Explain how the power factor of stator currents of a synchronous generator influence the limit of Active Power Supply in case of Lagging Power Factor Loads.
4. Explain the various Limiting Features in the Excitation System of a synchronous generator and their significance.
5. Explain the difference in terminal voltage of a Synchronous generator operating with its load in isolated operation (without grid connection) and that in parallel with the grid, with reference to changing its Excitation Current.
6. Why does the Leading Power Factor Current pose a limit on the active power load on Synchronous generator.
7. Explain a P/Q Capability Diagram of a Generator. Explain the Limits imposed by Overexcitation, Armature Load and Underexcitation.
8. What happens if V/f of Generator exceeds 2 P.U.?
9. (A) What happens to the field current of Generator on Full MW load at 0.4 p.f. lag ?

   (B) What happens to the field current of Generator on Full MW load at 0.1 p.f. lead ?

   (C) What happens if full excitation current is given to generator field with rotor speed at half the rated Synchronous Speed and generator stator is connected to Unit Transformer and Auxiliary Transformer.
10. Explain the need of improved load power factor of load for better Generating Unit output MW.
11. Draw and Explain V_t versus Reactive power Q characteristic of a synchronous generator connected to Grid voltage. Draw the limiting characteristics. Explain why a small change in Grid voltage produces a large change in MVAr of the generator.
12. Explain Stabilising Features provided in excitation system of a Generator.