Synchronous generators or alternators are synchronous machines that convert mechanical energy to alternating current (AC) electric energy.¹

SYNCHRONOUS GENERATOR CONSTRUCTION

A direct current (DC) is applied to the rotor winding of a synchronous generator to produce the rotor magnetic field. A prime mover rotates the generator rotor to rotate the magnetic field in the machine. A three-phase set of voltages is induced in the stator windings by the rotating magnetic field.

The rotor is a large electromagnet. Its magnetic poles can be salient (protruding or sticking out from the surface of the rotor), as shown in Fig. 31.1, or nonsalient (flush with the surface of the rotor), as shown in Fig. 31.2. Two- and four-pole rotors have normally nonsalient poles, while rotors with more than four poles have salient poles.

Small generator rotors are constructed of thin laminations to reduce eddy current losses, while large rotors are not constructed from laminations due to the high mechanical stresses encountered during operation. The field circuit of the rotor is supplied by a DC current. The common methods used to supply the DC power are

1. By means of slip rings and brushes
2. By a special DC power source mounted directly on the shaft of the rotor

Slip rings are metal rings that encircle the rotor shaft but are insulated from it. Each of the two slip rings on the shaft is connected to one end of the DC rotor winding and a number of brushes ride on each slip ring. The positive end of the DC voltage source is connected to one slip ring, and the negative end is connected to the second. This ensures that the same DC voltage is applied to the field windings regardless of the angular position or speed of the rotor. Slip rings and brushes require high maintenance because the brushes must be checked for wear regularly. Also, the voltage drop across the brushes can be the cause of large power losses when the field currents are high. Despite these problems, all small generators use slip rings and brushes because all other methods used for supplying DC field current are more expensive.

Large generators use brushless exciters for supplying DC field current to the rotor. They consist of a small AC generator having its field circuit mounted on the stator and its armature circuit mounted on the rotor shaft.

The exciter generator output (three-phase alternating current) is converted to direct current by a three-phase rectifier circuit also mounted on the rotor. The DC current is fed to the main field circuit. The field current for the main generator can be controlled by the small DC field current of the exciter generator, which is located on the stator (Figs. 31.3 and 31.4).

31.1
FIGURE 31.1  (a) A salient six-pole rotor for a synchronous machine.  (b) Photograph of a salient eight-pole synchronous machine rotor showing the windings on the individual rotor poles.  (Courtesy of General Electric Company.)  (c) Photograph of a single salient pole from a rotor with the field windings not yet in place.  (Courtesy of General Electric Company.)  (d) A single salient pole shown after the field windings are installed but before it is mounted on the rotor.  (Courtesy of Westinghouse Electric Company.)

FIGURE 31.2  A nonsalient two-pole rotor for a synchronous machine.  (a) End view;  (b) side view.
FIGURE 31.3  A brushless exciter circuit. A small three-phase current is rectified and used to supply the field circuit at the exciter, which is located on the stator. The output of the armature circuit of the exciter (on the rotor) is then rectified and used to supply the field current of the main machine.

FIGURE 31.4  Photograph of a synchronous machine rotor with a brushless exciter mounted on the same shaft. Notice the rectifying electronics, which are visible next to the armature of the exciter.
A brushless excitation system requires much less maintenance than slip rings and brushes because there is no mechanical contact between the rotor and the stator. The generator excitation system can be made completely independent of any external power sources by using a small pilot exciter. It consists of a small AC generator with permanent magnets mounted on the rotor shaft and a three-phase winding on the stator. The pilot exciter produces the power required by the field circuit of the exciter that is used to control the field circuit of the main generator. When a pilot exciter is used, the generator can operate without any external electric power (Fig. 31.5).

Most synchronous generators that have brushless exciters also use slip rings and brushes as an auxiliary source of field DC current in emergencies. Figure 31.6 illustrates a cutaway of a complete large synchronous generator with a salient-pole rotor with eight poles and a brushless exciter.

**THE SPEED OF ROTATION OF A SYNCHRONOUS GENERATOR**

The electrical frequency of synchronous generators is synchronized (locked in) with the mechanical rate of rotation. The rate of rotation of the magnetic fields (mechanical speed) is related to the stator electrical frequency by:

$$f_e = \frac{n_m P}{120}$$
where \( f_e \) = electrical frequency, Hz
\( n_m \) = mechanical speed of magnetic field, \( r/min \) (= speed of the rotor for synchronous machines)
\( P \) = number of poles

For example, a two-pole generator rotor must rotate at 3600 \( r/min \) to generate electricity at 60 Hz.

**THE INTERNAL GENERATED VOLTAGE OF A SYNCHRONOUS GENERATOR**

The magnitude of the voltage induced in a given stator phase is given by:

\[
E_A = K\phi \omega
\]

where \( K \) is a constant that depends on the generator construction, \( \phi \) is the flux in the machine, and \( \omega \) is the frequency or speed of rotation.

Figure 31.7 (a) illustrates the relationship between the flux in the machine and the field current \( I_F \). Since the internal generated voltage \( E_A \) is directly proportional to the flux, the relationship between the \( E_A \) and \( I_F \) is similar to the one between \( \phi \) and \( I_F \) [Fig. 31.7 (b)]. The graph is known as the *magnetization curve* or *open-circuit characteristic* of the machine.

**THE EQUIVALENT CIRCUIT OF A SYNCHRONOUS GENERATOR**

The variable \( E_A \) is the internal generated voltage induced in one phase of a synchronous generator. However, this is not the usual voltage that appears at the terminals of the generator.
In reality, the internal voltage $E_A$ is the same as the output voltage $V_H$ of a phase only when there is no armature current flowing in the stator. The three factors that cause the difference between $E_A$ and $V_H$ are

1. The armature reaction, which is the distortion of the air-gap magnetic field by the current flowing in the stator
2. The self-inductance of the armature (stator) windings
3. The resistance of the armature windings

The armature reaction has the largest impact on the difference between $E_A$ and $V_H$. The voltage $E_A$ is induced when the rotor is spinning. If the generator’s terminals are attached to a load, a current flows. The three-phase current flowing in the stator will produce its own magnetic field in the machine. This stator magnetic field distorts the magnetic field produced by the rotor resulting in a change of the phase voltage. This effect is known as the armature reaction because the current in the armature (stator) affects the magnetic field that produced it in the first place.

Figure 31.8 (a) illustrates a two-pole rotor spinning inside a three-phase stator when there is no load connected to the machine. An internal generated voltage $E_A$ is produced by the rotor magnetic field $B_R$ whose direction coincides with the peak value of $E_A$. The voltage will be positive out of the top conductors and negative into the bottom conductors of the stator.

When the generator is not connected to a load, there is no current flow in the armature. The phase voltage $V_H$ will be equal to $E_A$. When the generator is connected to a lagging load, the peak current will occur at an angle behind the peak voltage [Fig. 31.8 (b)]. The current flowing in the stator windings produces a magnetic field called $B_s$, whose direction is given by the right-hand rule [Fig. 31.8 (c)].

A voltage is produced in the stator $E_{stat}$ by the stator magnetic field $B_s$. The total voltage in a phase is the sum of the internal voltage $E_A$ and the armature reaction voltage $E_{stat}$:

$$V_H = E_A + E_{stat}$$

The net magnetic field $B_{net}$ is the sum of the rotor and stator magnetic fields:

$$B_{net} = B_R + B_s$$
The angle of the resulting magnetic field $B_{net}$ coincides with the one of the net voltage $V_\phi$ [Fig. 31.8 (d)].

The angle of voltage $E_{stat}$ is $90^\circ$ behind the one of the maximum current $I_A$. Also, the voltage $E_{stat}$ is directly proportional to $I_A$. If $X$ is the proportionality constant, the armature reaction voltage can be expressed as

$$E_{stat} = -jXI_A$$

The voltage of a phase is

$$V_\phi = E_A - jXI_A$$
Figure 31.9 shows that the armature reaction voltage can be modeled as an inductor placed in series with the internal generated voltage.

When the effects of the stator windings self-inductance $L_A$ (and its corresponding reactance $X_A$) and resistance $R_A$ are added, the relationship becomes

$$V_\phi = E_A - jX_A I_A - R_A I_A$$

When the effects of the armature reaction and self-inductance are combined (the reactances are added), the synchronous reactance of the generator is

$$X_S = X + X_A$$

The final equation becomes

$$V_\phi = E_A - jX_S I_A - R_A I_A$$

Figure 31.10 illustrates the equivalent circuit of a three-phase synchronous generator. The rotor field circuit is supplied by DC power, which is modeled by the coil’s inductance and resistance in series. The adjustable resistance $R_{adj}$ controls the field current. The internal...
generated voltage for each of the phases is shown in series with the synchronous reactance $X_S$ and the stator winding resistance $R_A$. The three phases are identical except that the voltages and currents are $120^\circ$ apart in angle.

Figure 31.11 illustrates that the phases can be either Y- or Δ-connected. When they are Y-connected, the terminal voltage $V_T$ is related to the phase voltage $V_\phi$ by

$$V_T = \sqrt{3} V_\phi$$

When they are Δ-connected, then

$$V_T = V_\phi$$

![Diagram of generator equivalent circuit](image)

**FIGURE 31.11** The generator equivalent circuit connected in Y (a) and in Δ (b).
Figure 31.14 illustrates the phasor diagrams of generators operating at lagging and leading power factors. Notice that for a given phase voltage and armature current, lagging loads require larger internal generated voltage $E_A$ than leading loads. Therefore, a larger field current is required for lagging loads to get the same terminal voltage, because:

$$E_A = K \Phi \omega$$

where $\omega$ must remain constant to maintain constant frequency. Thus, for a given field current and magnitude of load current, the terminal voltage for lagging loads is lower than the one for leading loads. In real synchronous generators, the winding resistance is much smaller than the synchronous reactance. Therefore, $R_A$ is often neglected in qualitative studies of voltage variations.

Since the three phases are identical except that their phase angles are different, the *per-phase equivalent circuit* is used (Fig. 31.12).

**THE PHASOR DIAGRAM OF A SYNCHRONOUS GENERATOR**

*Phasors* are used to describe the relationships between AC voltages. Figure 31.13 illustrates these relationships when the generator is supplying a purely resistive load (at unity power factor). The total voltage $E_A$ differs from the terminal voltage $V_o$ by the resistive and inductive voltage drops. All voltages and currents are referenced to $V_o$, which is assumed arbitrarily to be at angle $0^\circ$.

Figure 31.14 illustrates the phasor diagrams of generators operating at lagging and leading power factors. Notice that for a given phase voltage and armature current, lagging loads require larger internal generated voltage $E_A$ than leading loads. Therefore, a larger field current is required for lagging loads to get the same terminal voltage, because:

$$E_A = K \Phi \omega$$

where $\omega$ must remain constant to maintain constant frequency. Thus, for a given field current and magnitude of load current, the terminal voltage for lagging loads is lower than the one for leading loads. In real synchronous generators, the winding resistance is much smaller than the synchronous reactance. Therefore, $R_A$ is often neglected in qualitative studies of voltage variations.
A synchronous generator is a machine that converts mechanical power to three-phase electrical power. The mechanical power is usually given by a turbine. However, the rotational speed must remain constant to maintain a steady frequency.

Figure 31.15 illustrates the power flow in a synchronous generator. The input mechanical power is $P_{\text{in}} = \tau_{\text{app}} \omega_m$, while the power converted from mechanical to electrical energy is

\[ P_{\text{conv}} = \tau_{\text{ind}} \omega_m \]

\[ P_{\text{conv}} = 3E_A I_A \cos \gamma \]

**FIGURE 31.15** The power flow diagram of a synchronous generator.
where $\gamma$ is the angle between $E_A$ and $I_A$. The real electric output power of the machine is:

$$P_{\text{out}} = \sqrt{3} V_T I_L \cos \theta$$

or in phase quantities as

$$P_{\text{out}} = 3V_\phi I_A \cos \theta$$

The reactive power is

$$Q_{\text{out}} = \sqrt{3} V_T I_L \sin \theta$$

or in phase quantities as

$$Q_{\text{out}} = 3V_\phi I_A \sin \theta$$

A very useful expression for the output power can be derived if the armature resistance $R_A$ is ignored (since $X_s >> R_A$). Figure 31.16 illustrates a simplified phasor diagram of a synchronous generator when the stator resistance is ignored. The vertical segment $bc$ can be expressed as either $E_A \sin \delta$ or $X_s I_A \cos \theta$. Therefore,

$$I_A \cos \theta = \frac{E_A \sin \delta}{X_s}$$

and substituting into the output power equation

$$P = \frac{3V_\phi E_A \sin \delta}{X_s}$$

There are no electrical losses in this generator, because the resistances are assumed to be zero, and $P_{\text{conv}} = P_{\text{out}}$.

FIGURE 31.16  Simplified phasor diagram with armature resistance ignored.
The output power equation shows that the power produced depends on the angle $\delta$ (torque angle) between $V_\phi$ and $E_A$. Normally, real generators have a full load torque angle of between 15 and 20°.

The induced torque in the generator can be expressed as

$$\tau_{\text{ind}} = k B_R \times B_S$$

or as

$$\tau_{\text{ind}} = k B_R \times B_{\text{net}}$$

The magnitude of the expressed torque is

$$\tau_{\text{ind}} = k B_R B_{\text{net}} \sin \delta$$

where $\delta$ (the torque angle) is the angle between the rotor and net magnetic fields. An alternative expression for the induced torque in terms of electrical quantities is

$$\tau_{\text{ind}} = \frac{3V_\phi E_A \sin \delta}{\omega_p X_S}$$

THE SYNCHRONOUS GENERATOR OPERATING ALONE

When a synchronous generator is operating under load, its behavior varies greatly depending on the power factor of the load and if the generator is operating alone or in parallel with other synchronous generators. Throughout the upcoming sections, the effect of $R_A$ is ignored, and the speed of the generators and the rotor flux will be assumed constant.

THE EFFECT OF LOAD CHANGES ON A SYNCHRONOUS GENERATOR OPERATING ALONE

Figure 31.17 illustrates a generator supplying a load. What are the effects of load increase on the generator? When the load increases, the real and/or reactive power drawn from the

FIGURE 31.17  A single generator supplying a load.
generator increases. The load increase increases the load current drawn from the generator. The flux $\phi$ is constant because the field resistor did not change, and the field current is constant. Since the prime mover governing system maintains the mechanical speed $\omega$ constant, the magnitude of the internal generator voltage $E_A = K\phi\omega$ is constant.

Since $E_A$ is constant, which parameter is varying with the changing load? If the generator is operating at a lagging power factor and an additional load is added at the same power factor, then the magnitude of $I_A$ increases, but angle $\theta$ between $I_A$ and $V_\phi$ remains constant. Therefore, the armature reaction voltage $jX_S I_A$ has increased while keeping the same angle. Since

$$E_A = V_\phi + jX_S I_A$$

$jX_S I_A$ must increase while the magnitude of $E_A$ remains constant [Fig. 31.18 (a)]. Therefore, when the load increases, the voltage $V_\phi$ decreases sharply. Figure 31.18 (b) illustrates the effect when the generator is loaded with a unity power factor. It can be seen that $V_\phi$ decreases slightly. Figure 31.18 (c) illustrates the effect when the generator is loaded with leading-power-factor loads. It can be seen that $V_\phi$ increases.

The voltage regulation is a convenient way to compare the behavior of two generators. The generator voltage regulation (VR) is given by

$$\text{VR} = \frac{V_{nl} - V_{n\ell}}{V_tr} \times 100\%$$

![Diagram](image-url)
where $V_{nl}$ and $V_{fl}$ are the no-load and full-load voltages of the generator. When a synchronous generator is operating at a lagging power factor, it has a large positive voltage regulation. When a synchronous generator is operating at a unity power factor, it has a small positive voltage regulation, and a synchronous generator operating at a leading power factor has a negative voltage regulation.

During normal operation, it is desirable to maintain constant the voltage that is supplied to the load even when the load varies. The terminal voltage variations can be corrected by varying the magnitude of $E_A$ to compensate for changes in the load. Since $E_A = Kf\omega$ and $\omega$ remains constant, $E_A$ can be controlled by varying the flux in the generator. For example, when a lagging load is added to the generator, the terminal voltage will fall. The field resistor $R_F$ is decreased to restore the terminal voltage to its previous level. When $R_F$ decreases, the field current $I_F$ increases. This causes the flux to increase, which results in increasing $E_A$ and, therefore, the phase and terminal voltage. This process is reversed to decrease the terminal voltage.

**PARALLEL OPERATION OF AC GENERATORS**

In most generator applications, there is more than one generator operating in parallel to supply power to various loads. The North American grid is an extreme example of a situation where thousands of generators share the load on the system.

Three major advantages for operating synchronous generators in parallel are

1. The reliability of the power system increases when many generators are operating in parallel, because the failure of any one of them does not cause a total power loss to the loads.
2. When many generators operate in parallel, one or more of them can be taken out when failures occur in power plants or for preventive maintenance.
3. If one generator is used, it cannot operate near full load (because the loads are changing), then it will be inefficient. When several machines are operating in parallel, it is possible to operate only a fraction of them. The ones that are operating will be more efficient because they are near full load.

**THE CONDITIONS REQUIRED FOR PARALLELING**

Figure 31.19 illustrates a synchronous generator ($G_1$) supplying power to a load with another generator ($G_2$) that is about to be paralleled with $G_1$ by closing the switch ($S_1$). If
the switch is closed at some arbitrary moment, the generators could be severely damaged and the load may lose power. If the voltages are different in the conductor being tied together, there will be very large current flow when the switch is closed.

This problem can be avoided by ensuring that each of the three phases has the same voltage magnitude and phase angle as the conductor to which it is connected. To ensure this match, these four paralleling conditions must be met:

1. The two generators must have the same rms line voltages.
2. The phase sequence must be the same in the two generators.
3. The two a phases must have the same phase angles.
4. The frequency of the oncoming generator must be slightly higher than the frequency of the running system.

If the sequence in which the phase voltages peak in the two generators is different [Fig. 31.20 (a)], then two pairs of voltages are 120° out of phase, and only one pair of

![Image of diagrams](image-url)

**FIGURE 31.20** (a) The two possible phase sequences of a three-phase system. (b) The three-lightbulb method for checking phase sequence.
voltages (the \(a\) phases) are in phase. If the generators are connected in this manner, large currents would flow in phases \(b\) and \(c\), causing damage to both machines.

The phase sequence problem can be corrected by swapping the connections on any two of the three phases on one of the generators. If the frequencies of the power supplied by the two generators are not almost equal when they are connected together, large power transients will occur until the generators stabilize at a common frequency. The frequencies of the two generators must differ by a small amount so that the phase angles of the oncoming generator will change slowly, relative to the phase angles of the running system. The angles between the voltages can be observed and switch \(S\), can be closed when the systems are exactly in phase.

**THE GENERAL PROCEDURE FOR PARALLELING GENERATORS**

If generator \(G_2\) is to be connected to the running system (Fig. 31.20), the following two steps should be taken to accomplish paralleling:

1. The terminal voltage of the oncoming generator should be adjusted by changing the field current until it is equal to the line voltage of the running system.
2. The phase sequence of the oncoming generator and the running system should be the same. The phase sequence can be checked by using the following two methods:
   - \(a\). A small induction motor can be connected alternately to the terminals of each of the two generators. If the motor rotates in the same direction each time, then the phase sequence of both generators is the same. If the phase sequences are different, the motor would rotate in opposite directions. In this case, two of the conductors on the incoming generator must be reversed.
   - \(b\). Figure 31.20 \((b)\) illustrates three lightbulbs connected across the terminals of the switch connecting the generator to the system. When the phase changes between the two systems, the lightbulbs become bright when the phase difference is large, and they become dim when the phase difference is small. *When the systems have the same phase sequence, all three bulbs become bright and dim simultaneously.* If the systems have opposite phase sequence, the bulbs would get bright in succession.

   The frequency of the oncoming generator should be slightly higher than the frequency of the running system. A frequency meter is used until the frequencies are close, then changes in phase between the system are observed. The frequency of the oncoming generator is adjusted to a slightly higher frequency to ensure that when it is connected, it will come on-line supplying power as a generator, instead of consuming it as a motor.

   Once the frequencies are almost equal, the voltages in the two systems will change phase relative to each other very slowly. This change in phase is observed, and the switch connecting the two systems together is closed when the phase angles are equal (Fig. 31.21). A confirmation that the two systems are in phase can be done by watching the three lightbulbs. The systems are in phase when the three lightbulbs all go out (because the voltage difference across them is zero). This simple scheme is useful, but it is not very accurate. A synchroscope is more accurate. It is a meter that measures the difference in phase angle between the \(a\) phases of the two systems (Fig. 31.22).
FIGURE 31.21 Steps taken to synchronize an incoming AC generator to the supply system. (a) Existing system voltage wave (one phase only shown). (b) Machine voltage wave shown dotted. Out of phase and frequency. Being built up to equal the system max. volts by adjustment of field rheostat. (c) Machine voltage now equal to system. Voltage waves out of phase, but frequency being increased by increasing speed of prime mover. (d) Machine voltage now equal to system, in phase, and with equal frequency. Synchroscope shows 12 o’clock. Switch can now be closed.
The phase difference between the two $a$ phases is shown by the dial. When the systems are in phase (0° phase difference), the dial would be at the top. When they are 180° out of phase, the dial would be at the bottom.

The phase angle on the meter changes slowly because the frequencies of the two systems are slightly different. Since the oncoming generator frequency is slightly higher than the system frequency, the synchroscope needle rotates clockwise because the phase angle advances.

If the oncoming generator frequency is lower than the system frequency, the needle would rotate counterclockwise. When the needle of the synchroscope stops in the vertical position, the voltages are in phase and the switch can be closed to connect the systems.

However, the synchroscope provides the relationship for only one phase. It does not provide information about the phase sequence.

The whole process of paralleling large generators to the line is done by a computer. For small generators, the operator performs the paralleling steps.

**FREQUENCY-POWER AND VOLTAGE-REACTIVE POWER CHARACTERISTICS OF A SYNCHRONOUS GENERATOR**

The mechanical source of power for the generator is a *prime mover*, such as diesel engines or steam, gas, water, and wind turbines. All prime movers behave in a similar fashion. As the power drawn from them increases, the rotational speed decreases. In general, this decrease in speed is nonlinear. However, the governor makes this decrease in speed linear with increasing power demand.

Thus, the governing system has a slight speed-drooping characteristic with increasing load. The speed droop (SD) of a prime mover is defined by

\[
SD = \frac{n_{nl} - n_{fl}}{n_{fl}} \times 100\%
\]

where $n_{nl}$ is the no-load speed of the prime mover, and $n_{fl}$ is the full-load speed of the prime mover.

The speed droop of most generators is usually 2 to 4 percent. In addition, most governors have a setpoint adjustment to allow the no-load speed of the turbine to be varied. A typical speed-power curve is shown in Fig. 31.23. Since the electrical frequency is related to the shaft speed and the number of poles by

\[
f_e = \frac{n_{nl}P}{120}
\]

the power output is related to the electrical frequency.

Figure 31.23 (b) illustrates a frequency-versus-power graph. The power output is related to the frequency by
The reactive power $Q$ has a similar relationship with the terminal voltage $V_T$. As previously described, the terminal voltage drops when a lagging load is added to a synchronous generator. The terminal voltage increases when a leading load is added to a synchronous generator. Figure 31.24 illustrates a plot of terminal voltage versus reactive power. This plot has a drooping characteristic that is not generally linear, but most generator voltage regulators have a feature to make this characteristic linear. When the no-load terminal voltage setpoint on the voltage regulator is changed, the curve can slide up and down. The frequency-power and terminal voltage-reactive power characteristics play important roles in parallel operation of synchronous generators.

When a single generator is operating alone, the real power $P$ and reactive power $Q$ are equal to the amounts demanded by the loads. The generator’s controls cannot control the real and reactive power supplied. Therefore, for a given real power, the generator’s operating frequency $f_e$ is controlled by the governor setpoints. For a given reactive power, the generator’s terminal voltage $V_T$ is controlled by the field current.

\[ P = S_P (f_{\text{nl}} - f_{\text{sys}}) \]

where $P = \text{power output of generator}$

$f_{\text{nl}} = \text{no-load frequency of generator}$

$f_{\text{sys}} = \text{operating frequency of system}$

$S_P = \text{slope of curve, kW/Hz or MW/Hz}$
The power system is usually so large that nothing the operator of a synchronous generator connected to it does will have any effect on the power system. An example of this is the North American power grid, which is so large that any action taken by one generator cannot have an observable change on the overall grid frequency.

This principle is idealized by the concept of an infinite bus, which is a very large power system, such that its voltage and frequency do not change regardless of the amounts of real and reactive power supplied to or drawn from it. Figure 31.25 illustrates the power-frequency and reactive power-terminal voltage characteristics of such a system.

The behavior of a generator connected to an infinite bus is easier to explain when the automatic field current regulator is not considered. Thus, the following discussion will ignore the slight differences caused by the field regulator (Fig. 31.26).

**FIGURE 31.25** The frequency-versus-power (a) and terminal-voltage-versus-reactive-power (b) curves for an infinite bus.
When a generator is connected in parallel with another generator or a large system, *the frequency and terminal voltage of all the generators must be the same because their output conductors are tied together*. Therefore, a common vertical axis can be used to plot the real power-frequency and reactive power-voltage characteristics back-to-back.

If a generator has been paralleled with the infinite bus, it will be essentially “floating” on-line. It supplies a small amount of real power and little or no reactive power (Fig. 31.27).

If the generator that has been paralleled to line has a slightly lower frequency than the running system (Fig. 31.28), the no-load frequency of the generator would be less than the operating frequency. In this case, the power supplied by the generator is negative (it consumes electric energy because it is running as a motor). The oncoming generator frequency should be adjusted to be slightly higher than the frequency of the running system to ensure that the generator comes on-line supplying power instead of consuming it.

In reality, most generators have a reverse-power trip connected to them. They must be paralleled when their frequency is higher than that of the running system. If such a generator starts to “motor” (consume power), it will be automatically disconnected from the line.

Once the generator is connected, the governor setpoint is increased to shift the no-load frequency of the generator upward. Since the frequency of the system remains constant (the frequency of the infinite bus cannot change), the generator output power increases. The house diagram and the phasor diagram are illustrated in Fig. 31.29 (a, b).
Notice in the phasor diagram that the magnitude of $E_A (= K\phi\omega)$ remains constant because $I_F$ and $\omega$ remained unchanged, while $E_A \sin \delta$ (which is proportional to the output power as long as $V_T$ remains constant) has increased.

When the governor setpoint is increased, the no-load frequency and the output power of the generator increase. As the power increases, the magnitude of $E_A$ remains constant while $E_A \sin \delta$ is increased further.

If the output power of the generator is increased until it exceeds the power consumed by the load, the additional power generated flows back into the system (infinite bus). By definition, the infinite bus can consume or supply any amount of power while the frequency remains constant. Therefore, the additional power is consumed.

Figure 31.29 (b) illustrates the phasor diagram of the generator when the real power has been adjusted to the desired value. Notice that at this time, the generator has a slightly leading power factor. It is acting as a capacitor, consuming reactive power. The field current can be adjusted so the generator can supply reactive power. However, there are some constraints on the operation of the generator under these circumstances.
When \( \dot{f} \) is changing, the power must remain constant. The power given to the generator is \( P_{\text{in}} = \tau_{\text{app}}\omega_n \).

- For a given governor setting, the prime mover of the generator has a fixed-torque-speed characteristic. When the governor setpoint is changed, the curve moves.
- Since the generator is tied to the system (infinite bus), its speed cannot change. Therefore, since the governor setpoint and the generator’s speed have not changed, the power supplied by the generator must remain constant.
- Since the power supplied does not change when the field current is changing, then \( I_A \cos \theta \) and \( E_A \sin \delta \) (the distance proportional to the power in the phasor diagram) cannot change.

The flux \( \phi \) increases when the field current is increased. Therefore, \( E_A (= K\phi \omega) \) must increase. If \( E_A \) increases, while \( E_A \sin \delta \) remains constant, then phasor \( E_A \) must slide along the constant-power line shown in Fig. 31.30. Since \( V_\phi \) is constant, the angle of \( fX_s I_A \) changes as shown. Therefore, the angle and magnitude of \( I_A \) change.
Notice that the distance proportional to $Q (I_A \sin \theta)$ increases. This means that *increasing the field current in a synchronous generator operating in parallel with a power system (infinite bus) increases the reactive power output of the generator.*

In summary, when a generator is operating in parallel with a power system (infinite bus):

- The power system connected to the generator controls the frequency and the terminal voltage.
- The real power supplied by the generator to the system is controlled by the governor setpoint.
- The reactive power supplied by the generator to the system is controlled by the field current.

**SYNCHRONOUS GENERATOR RATINGS**

There are limits to the output power of a synchronous generator. These limits are known as *ratings* of the generator. Their purpose is to protect the generator from damage caused by improper operation. The synchronous generator ratings are: voltage, frequency, speed, apparent power (kilovoltamperes), power factor, field current, and service factor.

**The Voltage, Speed, and Frequency Ratings**

The common system frequencies used today are 50 Hz (in Europe, Asia, etc.), and 60 Hz (in the Americas). Once the frequency and the number of poles are known, there is only one possible rotational speed.

One of the most important ratings for the generator is the voltage at which it operates. Since the generator’s voltage depends on the flux, the higher the design voltage, the higher the flux. However, the flux cannot increase indefinitely, because the field current has a maximum value.

The main consideration in determining the rated voltage of the generator is the breakdown value of the winding insulation. The voltage at which the generator operates must not approach the breakdown value. A generator rated for a given frequency (e.g., 60 Hz) can be operated at 50 Hz as long as some conditions are met. Since there is a maximum flux achievable in a given generator, and since $E_A = K \Phi_0$, the maximum allowable $E_A$ must change when the speed is changed. For example, a generator rated for 60 Hz can be operated at 50 Hz if the voltage is derated to 50/60, or 83.3 percent of its design value. The opposite effect would happen when a generator rated for 50 Hz is operated at 60 Hz.
Apparent Power and Power-Factor Ratings

The factors that determine the power limits of electric machines are the shaft torque and the heating of the windings. In general, the shaft can handle more power than that for which the machine is rated. Therefore, the steady-state power limits are determined by the heating in the windings of the machine. The windings that must be protected in a synchronous generator are the armature windings and the field windings.

The maximum allowable current in the armature determines the maximum apparent power for the generator. Since the apparent power $S$ is given by

$$S = 3V_\phi I_A$$

if the rated voltage is known, the maximum allowable current in the armature determines the rated apparent power of the generator. The power factor of the armature current does not affect the heating of the armature windings. The stator copper losses heating effect is

$$P_{SCL} = 3I_A^2 R_A$$

These effects are independent of the angle between the $I_A$ and $V_\phi$. These generators are not rated in megawatts (MW), but in megavoltamperes (MVA).

The field windings copper losses are

$$P_{RCL} = I_F^2 R_F$$

Therefore, the maximum allowable heating determines the maximum field current for the machine. Since $E_A = K_\phi I_A$, this also determines the maximum acceptable $E_A$. Since there is a maximum value for $I_F$ and $E_A$, there is a minimum acceptable power factor of the generator when it is operating at the rated MVA.

Figure 31.31 illustrates the phasor diagram of a synchronous generator with the rated voltage and armature current. The current angle can vary, as shown. Since $E_A$ is the sum of $V_\phi$ and $jX_S I_A$, there are some current angles for which the required $E_A$ exceeds $E_{A_{\text{max}}}$. If

$$\boxed{|I_A|_{\text{max}}}$$

$$\boxed{|E_A|_{\text{max}}}$$

**FIGURE 31.31** How the rotor field current limit sets the rated power factor of a generator.
the generator is operated at these power factors and the rated armature current, the field windings will burn.

The angle of $I_A$ that results in the maximum allowable $E_A$ while $V_\phi$ is at the rated value determines the generator-rated power factor. The generator can be operated at a lower power factor (more lagging) than the rated value, but only by reducing the MVA output of the generator.

**SYNCHRONOUS GENERATOR CAPABILITY CURVES**

The generator *capability diagram* expresses the stator and rotor heat limits and any external limits on the generator. The capability diagram illustrates the complex power $S = P + jQ$. It is derived from the generator’s phasor diagram, assuming that $V_\phi$ is constant at the generator’s rated voltage.

Figure 31.32 illustrates the phasor diagram of a synchronous generator operating at its rated-voltage and lagging-power factor. The orthogonal axes are drawn with units of volts. The length of the vertical segment $AB$ is $X_S I_A \cos \theta$, and horizontal segment $0A$ is $X_S I_A \sin \theta$. The generator’s real power output is

$$P = 3V_\phi I_A \cos \theta$$

The reactive power output is

$$Q = 3V_\phi I_A \sin \theta$$

The apparent power output is

$$S = 3V_\phi I_A$$

Figure 31.32 (b) illustrates how the axes can be recalibrated in terms of real and reactive power. The conversion factor used to change the scale of the axis from volts (V) to voltamperes (VA) is $3V_\phi/X_S$:

$$P = 3V_\phi I_\phi \cos \theta = \frac{3V_\phi}{X_S} (X_S I_A \cos \theta)$$

$$Q = 3V_\phi I_\phi \sin \theta = \frac{3V_\phi}{X_S} (X_S I_A \sin \theta)$$

On the voltage axes, the origin of the phasor diagram is located at $-V_\phi$. Therefore, the origin on the power diagram is located at

$$Q = \frac{3V_\phi}{X_S} (-V_\phi) = -\frac{3V_\phi^2}{X_S}$$

On the power diagram, the length corresponding to $E_A$ is

$$D_E = \frac{3E_A V_\phi}{X_S}$$

The length that corresponds to $X_S I_A$ on the power diagram is $3V_\phi I_A$. 
Figure 31.33 illustrates the final capability curve of a synchronous generator. It illustrates a plot of real power $P$ versus reactive power $Q$. The lines representing constant armature current $I_A$ are shown as lines of constant apparent power $S = 3V_\phi I_A$, which are represented by concentric circles around the origin. The lines representing constant field current correspond to lines of constant $E_A$. These are illustrated by circles of magnitude $3E_A V_\phi / X_S$ centered at:

$$Q = -\frac{3V_\phi^2}{X_S}$$
The armature current limit is illustrated by the circle corresponding to the rated \( I_A \) or MVA. The field current limit is illustrated by the circle corresponding to the rated \( I_F \) or \( E_A \). Any point located within both circles is a safe operating point for the generator. Additional constraints, such as the maximum prime-mover power, can also be shown on the diagram (Fig. 31.34).

**SHORT-TIME OPERATION AND SERVICE FACTOR**

The heating of the armature and field windings of a synchronous generator is the most important limit in steady-state operation. The power level at which the heating limit usually occurs is much lower than the maximum power that the generator is mechanically and magnetically able to supply.

In general, a typical synchronous generator can supply up to 300 percent of its rated power until its windings burn up. This ability to supply more power than the rated amount is used for momentary power surges, which occur during motor starting and other load transients.

A synchronous generator can supply more power than the rated value for longer periods of time, as long as the windings do not heat up excessively before the load is removed. For example, a generator rated for 1 MW is able to supply 1.5 MW for 1 min without causing serious damage to the windings. This generator can operate for longer periods at lower power levels.
The insulation class of the windings determines the maximum temperature rise in the generator. The standard insulation classes are A, B, F, and H. In general, these classes correspond to temperature rises above ambient of 60, 80, 105, and 125°C, respectively. The power supplied by a generator increases with the insulation class without overheating the windings.

In motors and generators, overheating the windings is a serious problem. In general, when the temperature of the windings increases by 10°C above the rated value, the average lifetime of the machine is reduced by half. Since the increase in the temperature of the windings above the rated value drastically reduces the lifetime of the machine, a synchronous generator should not be overloaded unless it is absolutely necessary.

The service factor is the ratio of the actual maximum power of the machine to its nameplate rating. A 1.15 service factor of a generator indicates that it can operate indefinitely at 115 percent of the rated load without harm. The service factor of a motor or a generator provides a margin for error in case the rated loads were improperly estimated.

**REFERENCE**

Figure 32.1 illustrates a sectional view of a large generator. Hydrogen is used to cool most generators having a rating larger than 50 MW.

THE ROTOR

The rotor is made from a single steel forging. The steel is vacuum-degassed to minimize the possibility of hydrogen-initiated cracking. Reheating and quenching also hardens the forging. Stress-relieving heat treatment is done following rough machining. Ultrasonic examination is performed at various stages of the rotor. Figure 32.2 illustrates the winding slots in the rotor. Figure 32.3 illustrates a rotor cross section and the gas flow.

The generator counter torque increases to 4 to 5 times the full-load torque when a short circuit occurs at the generator terminals. The rotor and turbine-end coupling must be able to withstand this peak torque.

ROTOR WINDING

Each winding turn is assembled separately in half-turns or in more pieces. The joints are at the centers of the end turns or at the corners. They are brazed together after assembling each turn, to form a series-connected coil. The coils are made of high-conductivity copper with a small amount of silver to improve the creep properties. The gas exits through radially aligned slots.

Slot liners of molded glass fiber insulate the coils. These separators of glass fiber are used between each turn. They insulate against almost 10 V between adjacent turns (Fig. 32.4). The end rings and end discs are separated from the end windings by thick layers of insulation. Insulation blocks are placed in the spaces between the end windings to ensure the coils do not distort. The winding slots are cut in diametrically opposite pairs. They are equally pitched over two-thirds of the rotor periphery, leaving the pole faces without winding slots. This results in a difference between the stiffness in the two perpendicular axes. This difference leads to vibration at twice the speed. Equalizing slots are cut in the pole faces (Fig. 32.5) to prevent this problem from occurring. The slots are wider and shallower than the winding slots. They are filled with steel blocks to restore the magnetic properties. The blocks contain holes to allow the ventilating gas to flow.
FIGURE 32.1 Sectional view of a 660-MW generator.
FIGURE 32.2 Cutting winding slots in a rotor.

FIGURE 32.3 A section of a rotor.
FIGURE 32.4  Rotor slot.
The average winding temperature should not exceed 115°C. The hydrogen enters the rotor from both ends under the end windings and emerges radially from the wedges. Fig. 32.6 illustrates the fans used to drive the hydrogen through the stator.

Flexible leads made of thin copper strips are connected to the ends of the winding. These leads are placed in two shallow slots in the shaft. Wedges retain them. The leads are connected to radial copper studs, which are connected to D-shaped copper bars placed in the shaft bore. Hydrogen seals are provided on the radial studs. The D-leads are connected to the slip rings by radial connection bolts (Fig. 32.7).
ROTOR END RINGS

The end rings (Fig. 32.8) are used to restrain the rotor end windings from flying out under centrifugal forces. These rings have traditionally been made from nonmagnetic austenitic steel, typically 18 percent Mn, 4 percent Cr. A ring is machined from a single forging. It is shrunk-fit at the end of the rotor body. The material of the end rings was proven to be susceptible to stress-corrosion cracking. A protective finish is given to all the surfaces except the shrink-fit to ensure that hydrogen, water vapor, and so forth do not contact the metal. The rings should be removed during long maintenance outage (every 8 to 10 years) and inspected for detailed surface cracking using a fluorescent dye. Ultrasonic scanning is not sufficient due to the coarse grain structure. A recent development has proven that austenitic steel containing 18 percent Mn and 18 percent Cr is immune to stress-corrosion cracking. New machines use this alloy. It is also used for replacement rings. This eliminates the need for periodic inspection. It is important to mention that a fracture of an end ring can result in serious damage to the machine and at least a few months’ outage. It is highly recommended to replace the traditional material with the new material.
FIGURE 32.7 Rotor winding
The rings must be heated to 300°C to expand sufficiently for the shrink surface. Induction heating is preferred to direct heating to prevent possible damage to the rings. The end ring is insulated from the end winding with a molded-in glass-based liner or a loose cylinder sleeve. Hydrogen enters the rotor in the clearance between the end winding and the shaft. The outboard end of the ring is not permitted to contact the shaft to prevent the shaft flexure from promoting fatigue and fretting damage at the interfaces. A balancing ring is also included in the end disc for balancing the rotor.

**WEDGES AND DAMPERS**

Wedges are used to retain the winding slot contents. They are designed to withstand stresses from the windings while allowing the hydrogen to pass through holes. They must also be nonmagnetic to minimize the flux leakage around the circumference of the rotor. They are normally made of aluminum. One continuous wedge is used for each slot.

During system faults, or during unbalanced electrical loading, negative phase sequence currents and fluxes occur, leading to induced currents in the surface of the rotor. These currents will flow in the wedges, which act as a “damper winding” similar to the bars in the rotor of
an induction motor. The end rings act as shorting rings in the motor. Arcing and localized pitting may occur between the end rings and the wedges.

**SLIP RINGS, BRUSH GEAR, AND SHAFT GROUNDBING**

The D-leads in the bore are connected through radial copper connectors (which normally have backup hydrogen seals) and flexible connections to the slip rings (Fig. 32.9). The excitation current is around 5000 A DC for a 660-MW generator. The surface area of the slip rings must be large to run cool while transferring the current. Figure 32.10 illustrates the brush gear, including brushes and holders of a removable bracket. The holders can be replaced on-power. Constant-pressure springs are used to maintain brush pressure. A brush life should be at least 6 months. A separate compartment houses the brush gear. A shaft-mounted fan provides separate ventilation so that brush dust is not spread on other excitation components. Small amounts of hydrogen may pass through the connection seals. They may accumulate in the brush gear compartments during extended outages. The fan dilutes them safely during start-up before applying excitation current. The brush gear can be easily inspected through windows in the cover. Figure 32.11 illustrates brushless rotor connections.

A large generator produces normally an on-load voltage of between 10 and 50 V between its shaft ends due to magnetic dissymmetry. This voltage drives an axial current through the rotor body. The current returns through bearings and journals. It causes damage to their surfaces. Insulation barriers are installed to prevent such current from circulating. The insulation is installed at all locations where the shaft could contact earthed metal (e.g., bearings, seals, oil scrapers, oil pipes, and gear-driven pumps).

Some designs have two layers with a “floating” metallic component between them. The integrity of insulation is confirmed by a simple resistance measurement between the floating component and earth.

If the insulation remains clean and intact, a difference in voltage will exist between the shaft at the exciter end and ground. This provides another method to confirm the integrity of the insulation. The shaft voltage is monitored by a shaft-riding brush. An alarm is initiated when the shaft voltage drops below a predetermined value.

It is important to maintain the shaft at the turbine end of the generator at ground level. A pair of shaft-riding brushes ground the shaft through a resistor. Since carbon brushes develop a high-resistance glaze when operated for extended periods of time without current flow, a special circuit introduces a *wetting current* into and out of the shaft through the brushes. This circuit also detects loss of contact between the brush and the shaft.

**FANS**

Fans drive the hydrogen through the stator and the coolers. Two identical fans are mounted at each end of the shaft. Centrifugal or axial-type fans are used (Fig. 32.12).

**ROTOR THREADING AND ALIGNMENT**

The stator bore is about 25 cm larger than the rotor diameter. The rotor is inserted into the stator by supporting the inserted end of the rotor on a thick steel skid plate that slides into the stator, while the outboard end is supported by a crane.
FIGURE 32.9 Slip rings and connections.
Generator rotors rated at between 500 and 600 MW have two main critical speeds (natural resonance in bending). Simple two-plane balancing techniques are not adequate to obtain the high degree of balance that is required and to ensure low vibration levels during run-up and rundown. Therefore, balancing facilities are provided along the rotor in the form of taped holes in cylindrical surfaces. The manufacturer balances the rotor at operating...
speed. The winding is then heated and the rotor is operated at 20 percent overspeed. This allows the rotor to be subjected to stresses higher than the ones experienced in service. Trim balancing is then conducted, if required. There is a relationship between vibration amplitude and temperature in some rotors. For example, uneven ventilation can create a few degrees of difference in temperature between two adjacent poles. This effect can be partially offset by balancing to optimize the conditions at operating temperature (Fig. 32.13).

Uneven equalization of stiffness will cause vibration having a frequency of twice the operating speed. It is important to distinguish between the vibration caused by unbalance (occurring at \(1 \times\) operating speed) and equalization of stiffness. A large crack in the rotor will have a relatively larger effect on the double-frequency vibration component. Vibration signals during rundown are analyzed and compared with the ones obtained in previous run-downs. Oil whirl in bearings can cause vibration at half the speed. The amplitude and phase of vibration are recorded at the bearings of the generator and exciter using accelerometers mounted on the bearing supports and by proximity probes, which detect shaft movements.

**BEARINGS AND SEALS**

The generator bearings are spherically seated to facilitate alignment. They are pressure-lubricated, have jacking oil taps, and are insulated from the pedestals. Seals (Fig. 32.14) are
provided in the end shields to prevent hydrogen from escaping along the shaft. Most seals have a nonrotating white-metalled ring bearing against a collar on the shaft. Oil is fed to an annular groove in the ring. It flows radially inward across the face into a collection space and radially outward into an atmospheric air compartment. The seal ring must be maintained against the rotating collar. Therefore, it must be able to move axially to accommodate the thermal expansion of the shaft. Figure 32.15 illustrates a seal that resembles small journal bearings (radial seal). The oil is applied centrally. It flows axially inward to face the hydrogen pressure. It also flows axially outboard into an atmospheric compartment. The seal does not have to move axially, because the shaft can move freely inside it. This is a major advantage over the seal design illustrated in Fig. 32.14. Most generators use radial seals.
SIZE AND WEIGHT

The rotor of a 660-MW generator is up to 16.5 m long and weighs up to 75 tonnes (t). The rotor must never be supported on its end rings. The weight must be supported by the body surface. The rotor must also be protected from water contamination, while in transient or storage. A weatherproof container with an effective moisture absorbent must be used. If the rotor is left inside an open stator, dry air must be circulated.

TURBINE-GENERATOR COMPONENTS—THE STATOR

Stator Core

The core laminations are normally 0.35 or 0.5 mm thick. They are coated with thin layers of backed-on insulating varnish. Core flux tests are done on the complete core with a flux density of between 90 and 100 percent of the rated value. If there is contact between two adjacent plates, local hot spots will develop. The stator bore is scanned using an infrared camera to identify areas of higher-than-normal temperature during such a test. A bonding agent is used in some designs to ensure that individual plates, and particularly the teeth, do not vibrate independently. Packing material is used to correct any waviness in core buildup.
Some designs use grain-oriented sheets of steel. They have deliberately different magnetic properties in the two perpendicular axes (Fig. 32.16). The low-loss orientation is arranged for the flux in the circumferential direction. This allows higher flux density in the back of the core compared with nonoriented steel, for the same specific loss. The core plates of grain-oriented steel are specially annealed after punching.

**FIGURE 32.16** Flux in stator core.
The net axial length of magnetic steel that the flux can use is less than the measured stacked length by a factor of 0.9 to 0.95. This is known as the stacking factor. This is caused by the varnish layers and air spaces between the laminations due to uneven plate thickness and imperfect consolidation.

Hysteresis and eddy current losses in the core constitute a significant portion of the total losses. In some designs, the heat produced by these losses is removed by hydrogen circulating radially through the ducts and axially through holes (Fig. 32.17).

Thermocouples are installed in the hottest areas of the core. If a hot spot develops in service, it will not normally be detected by existing thermocouples. A flux test is the way to detect a hot spot. If accidental contacts occur at the tooth tips or damage the slot surfaces, circulating currents could occur. The magnitude of the current depends on the contact resistances between the back of the core plates and the core frame bars on which the plates are assembled. In most designs, all these bars (except for the one, which grounds the core) are insulated from the frame to reduce the possibility of circulating currents.

Core Frame

Figure 32.18 illustrates the core frame. The core end plate assembly is normally made from a thick disc of nonmagnetic steel. Conducting screens of copper or aluminum, about 10 mm thick, cover the outer surfaces of the core end plates (Fig. 32.19). They are called the end plate flux shield. The leakage flux creates circulating currents in these screens. These currents prevent the penetration of an unacceptable amount of flux into the core end plate or the ends of the core.

Stator Winding

In large two-pole generators, the winding of each phase is arranged in two identical parallel circuits, located diametrically opposite each other (Fig. 32.20). If the conductor is made of an assembly of separate strips, the leakage flux (the lines of induction that do not engage the rotor) density of each strip increases linearly with distance from the bottom strip (Fig. 32.21). This alternating leakage flux induces an alternating voltage along the lengths of the strips that varies with the square of the distance of the strip from the bottom of the slot. If a solid conductor were used, or if the strips were parallel to each other and connected together at the core ends, currents would circulate around the bar due to the unequal voltages. This will cause unacceptable eddy current losses and heating. This effect is minimized by dividing the conductor into lightly insulated strips. These strips are arranged in two or four stacks in the bar width. They are transposed along the length of the bar by the Roebel method (Fig. 32.22). Each strip occupies every position in the stack for an equal axial distance. This arrangement equalizes the eddy current voltages, and the eddy currents will not circulate between the strips. Demineralized water circulates in the rectangular section tubes to remove the heat from the strips (Fig. 32.23).

The conductors are made of hard-drawn copper having a high conductivity. Each strip has a thin coating of glass-fiber insulation. The insulation is wound along the length of the bar, consisting of a tape of mica powder loaded with a synthetic resin, with a glass-fiber backing. Electrical tests are performed to confirm the integrity of the insulation. A semiconducting material is used to treat the slot length of each bar to ensure that bar-to-slot electrical discharges do not occur. The surface discharge at the ends of the slots is limited by applying a high-resistance stress grading finish.

The bars experience large forces because they carry large currents and they are placed in a high-flux density. These forces are directed radially outward toward the bottom (closed
FIGURE 32.17 Stator ventilation.
FIGURE 32.18 Core frame.

FIGURE 32.19 Core end plate and screen.
end) of the slot. They alternate at 120 Hz. The closing wedges are not therefore needed to restrain these bars against these forces. However, the bars should not vibrate. The wedges are designed to exert a radial force by tapered packers or by a corrugated glass-spring member. Some designs have a sideway restraint by a corrugated glass-spring packer in the slot side. Insulation material consisting of packers, separators, and drive strips are also used in the slot (Fig. 32.23).

FIGURE 32.20  Arrangement of stator conductors.
The stator winding electrical loss consists of $I^2R$ heating ($R$ is measured using DC resistance of the winding phases at operating temperature) and "stray" losses, which include:

- AC resistance is larger than DC resistance (skin effect).
- Eddy currents (explained earlier).
- Currents induced in core end plates, screens, and end teeth.
- Harmonic currents induced in the rotor and end ring surfaces.
- Currents induced in the frame, casings, end shields, fan baffles, and so forth. Appropriate cooling methods are needed for these losses in order to avoid localized hot spots.

**FIGURE 32.21** Variations of eddy currents in stator conductors.

**FIGURE 32.22** Roebel transpositions.
FIGURE 32.23  Stator slot.
End Winding Support

Bands of conductors are arranged side by side in the end windings. They all carry the same currents (some in-phase with each other and some are not). Large electromagnetic forces are produced in the end windings during normal operation, and especially during fault conditions when large current peaks occur. The end turns must be strongly braced to withstand these peak forces and minimize the 120-Hz vibrations.

A large magnetic flux is produced in the end regions by the magnetomotive force (mmf) in the end windings of the stator and rotor. Metallic components cannot be used to fasten the end winding because of the following reasons:

- They would have Eddy currents induced in them. This will cause additional loss and possibly hot spots.
- Metallic components also vibrate and tend to become loose, or wear away their surrounding medium.

Therefore, nonmetallic components such as molded glass fiber are normally used. Large support brackets are bolted to the core end plate. They provide a support for a large glass-fiber conical support ring (Fig. 32.24). The vibration of the end windings must be limited because it can create fatigue cracking in the winding copper. This can have particularly serious consequences if it occurs in a water-carrying conductor because hydrogen will leak into the water system. Resonance near 120 Hz must be avoided because the core ovalizing and the winding exciting force occur at this frequency. Vibration increase in the end windings due to slackening of the support is monitored by accelerometers. The amplitude of vibration depends highly on the current. Any looseness developed after a period of operation is corrected by tightening the bolts, inserting or tightening wedges, and/or by pumping a thermosetting resin into rubber bags located between conductor bars.

Electrical Connections and Terminals

The high-end (line end) conductor bars and the low-voltage end (neutral end) of a phase band are electrically connected to tubular connectors. These connectors run circumferentially behind the end windings at the exciter end to the outgoing terminals. The connectors have internal water cooling. However, they must be insulated from the line voltage. Figure 32.25 illustrates a terminal bushing. It is a paper-insulated item, cooled internally from the stator winding water system. The insulation is capable of withstanding the hydrogen pressure in the casing without having any leakage.

Stator Winding Cooling Components

Demineralized water is used for cooling the stator windings. It must be pure enough to be electrically nonconducting. The water is degassed and treated continuously in an ion exchanger. The target values are as follows:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Target Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conductivity</td>
<td>100 μS/m</td>
</tr>
<tr>
<td>Dissolved oxygen</td>
<td>200 μg/L max (in some systems, &gt;2000 μg/L is acceptable)</td>
</tr>
<tr>
<td>Total copper</td>
<td>150 μg/L maximum</td>
</tr>
<tr>
<td>pH value</td>
<td>9 maximum</td>
</tr>
</tbody>
</table>
These levels have proven to have no aggressive attack on the winding copper after many years of service. Water enters one or more manifolds made of copper or stainless-steel pipes. The manifolds run circumferentially around the core end plate. Flexible polytetrafluoroethylene (PTFE) hoses connect the manifolds to all water inlet ports on the stator conductor joints. In a two-pass design, water flows through both bars in parallel. It is then transferred to the two connected bars at the other end. The water returns through similar hoses to the outlet manifold (Fig. 32.26).

The hydrogen is maintained at a higher pressure than the water. If a leak develops, hydrogen enters the water. The winding insulation would be damaged if the water were to enter the
hydrogen system. The water temperature increases by less than 30°C. The inlet temperature of the water is 40°C. There is a significant margin before boiling occurs at between 115 and 120°C (at the working pressure). The water temperature of each bar is monitored by thermocouples in the slots or in the water outlets. This allows detection of reduced water flow.

Hydrogen Cooling Components

Hydrogen is brought into the casing by an axially oriented distribution pipe at the top. Carbon dioxide is used to scavenge the hydrogen (air cannot be used for this function.
because an explosive mixture of hydrogen and oxygen will form when the volumetric concentration is between 4 and 76 percent). The carbon dioxide is admitted through a similar pipe at the bottom. The rotor fans drive hydrogen over the end windings and through the cores of the stator and rotor. During normal operation, the hydrogen temperature increases by about 25°C during the few seconds required to complete the circuit. Two or four coolers are mounted inside the casing. They consist of banks of finned or wire-wound tubes. The water flows into the tubes while hydrogen flows over them (Fig. 32.27).

The headers of the coolers are accessible. The tubes can be cleaned without degassing the casing. The supports of the tubes and the cooler frame are designed to avoid resonance near the principle exciting frequencies of 60 and 120 Hz. It is important to prevent moisture condensation on the stator end windings (electrical breakdown can occur). The dew point of the hydrogen emerging from the coolers is monitored by hygrometers. This dew point must be at least 20°C lower than the temperature of the cooled hydrogen emerging from the coolers. During normal operation, the stator winding temperature is above 40°C. Thus, if condensation occurred, it will be on the hydrogen coolers first. During start-up, the cooling water of the stator windings is cold. It is preheated electrically, or circulated for a period of time to increase the winding temperature before exciting the generator. This prevents the possibility of having condensation on the windings.

**Stator Casing**

The stator core and core frame are mounted inside the casing. The casing must withstand the load and fault torques. It must also provide a pressure-tight enclosure for the hydrogen.
Annular rings and axial members are mounted inside the casings to strengthen them and allow the hydrogen to flow (Figs. 32.28 and 32.29).

The end shields are made of thick circular steel plates. They are reinforced by ribs to withstand the casing pressure with minimal axial deflection. The stationary components of the shaft seal are housed in the end shields. The outboard bearing is also housed inside the end shields in some designs. The sealing of the end shield and casing joints must be leak-free against hydrogen pressure.
A hydrostatic pressure test is conducted on the whole casing. The casing must also be leak-tight when the hydrogen pressure drops from 4 to 0.035 bar in 24 h. Any leaks of oil or water are drained from the bottom of the casing to liquid-leakage detectors. These detectors initiate an alarm. A temperature sensor is installed at the carbon dioxide (CO₂) inlet. It initiates an alarm if the incoming CO₂ has not been heated sufficiently. Cool gas can create unacceptably high localized thermal stresses. Electrical heaters are mounted in the bottom half of the casing. They prevent condensation during outages.
The efficiency of a large generator is about 98.5 percent. In some designs, the losses are transferred to the boiler feedwater system.

**Hydrogen Cooling**

Hydrogen has four advantages over air for heat removal from the generator:

1. The density of hydrogen is one-fourteenth that of air. The windage losses (caused by churning the gas around the rotor) are much less with hydrogen.
2. The heat removal capability of hydrogen (at operating pressure) is about 10 times higher than that for air.
3. The degradation by oxidation processes cannot occur, because hydrogen is free from oxygen.
4. Hydrogen does not support fire, which can start by arcing.

The main disadvantage of hydrogen is that it forms an explosive mixture when it combines with air within a volumetric concentration in the range from 4 to 76 percent. Sophisticated sealing arrangements are required to ensure leak-tight casing.

**Hydrogen Cooling System**

It is essential to prevent air and hydrogen mixture inside the generator. Carbon dioxide is used as a buffer gas between air and hydrogen. The process is called *scavenging* or *gassing-up* and *degassing*. Carbon dioxide is normally stored as a liquid. It is expanded to a low pressure above atmospheric. It is also heated to prevent it from freezing due to the expansion process. CO$_2$ is fed into the bottom of the casing through a long perforated pipe. It displaces the air from the top via the hydrogen inlet distribution pipe to atmosphere outside the station. The proportion of CO$_2$ in the gas passing to atmosphere is being monitored by a gas analyzer. When the CO$_2$ concentration becomes sufficiently high, the flow of CO$_2$ is interrupted (Fig. 32.30).

High-purity hydrogen is fed to the casing from a central storage tank or electrolytic process. The hydrogen reaches the gas control panel at about 10 bar. Its pressure is reduced before it flows through the top admission pipe into the casing. Since hydrogen is much lighter than CO$_2$, it displaces the CO$_2$ from the bottom of the casings through the CO$_2$ pipe to the atmosphere. The reverse of this procedure is followed to remove hydrogen from the generator for long outages.

Separate procedures are used to scavenge tanks to prevent dangerous mixtures. The reverse of the listed procedure is done using CO$_2$ and dry compressed air to remove hydrogen from the generator. The hydrogen purity is normally high because air cannot enter a pressurized system.

A sample of casing hydrogen is circulated continuously through a Katharometer-type purity monitor (the sample is driven by the differential pressure developed across the rotor fans). The monitor initiates an alarm if the purity falls below 97 percent. Pure gases from the piped supplies are used to calibrate the purity monitor (and the gas analyzer).

Hydrogen is admitted by a pressure-sensitive valve when the casing pressure drops. A relief valve releases hydrogen to the atmosphere if the pressure becomes excessive. The hydrogen makeup is normally monitored.

Several thermocouples are used to monitor the hydrogen temperature. Hydrogen is flowing at 30 m$^3$/s typically (in a 500-MW generator). The heat absorbed by the hydrogen
is about 5 MW. The increase in temperature of the hydrogen is about 30°C. The cooled gas should not be at a temperature higher than 40°C. Thus, the hydrogen entering the coolers should not be hotter than 70°C.

The water pressure in the stator windings and hydrogen coolers is lower than the hydrogen pressure. Therefore, water cannot leak into the hydrogen system from the stator windings or hydrogen cooler. However, water can be released from the oil used for shaft sealing. The water concentration will increase if the oil is untreated turbine lubricating oil,
which has picked up water from the glands of the steam turbines. The moisture concentration in the hydrogen should be kept low to prevent condensation on the windings. The differential pressure across the rotor fans is used to send a hydrogen flow through a dryer. When the rotor is not turning, a motor-driven blower maintains a flow through the rotor (Fig. 32.31).

Hygrometers are used to monitor the humidity of the hydrogen. The maximum permissible dew point is more than 20°C below the cold gas temperature (measured at casing pressure).

In the event of a serious seal failure, hydrogen will escape rapidly. If it encounters an ignition source such as the shaft rubbing, it will burn intensely. In this case, the hydrogen in the casing should be vented to the atmosphere. CO₂ should be admitted into the casing.

**SHAFT SEALS AND SEAL OIL SYSTEM**

The seals are located in the end shields. They seal the hydrogen in the machine where the rotor shaft emerges from the casing and shields. The main type of seals are thrust and journal seal.
Thrust-Type Seal

Figure 32.14 illustrates a thrust-type seal. The seal ring acts like a thrust face acting on a shaft collar. Oil is supplied to a central circumferential groove in the white-metalled face of the seal ring. The oil pressure is higher than the casing hydrogen. Most of the oil flows outward due to centrifugal forces over the thrust face. It then drains into a well. A small oil flow moves inward against centrifugal forces. This flow is driven by the difference between the oil and the hydrogen into a drainage compartment, which is at hydrogen pressure. Entrained air and water can be released from this oil, resulting in contamination of the hydrogen. Therefore, it is important to minimize this oil flow.

The housing of the seal ring must be able to move axially about 30 mm to accommodate the thermal expansion of all the coupled rotors. The housing is designed to move inside a stationary member. It uses rubber sealing rings to contain the oil and exert axial pressure at the seal face.

Some seal designs have an additional chamber between the fixed and sliding components. It is fed with oil at varying pressures to control the overall pressure at the seal face. Other seal designs have additional pressure provided by springs.

Journal-Type Seal

This seal design is similar to a journal bearing floating on the shaft. This design allows the shaft to move axially through the seal. Thus, it does not need to accommodate the thermal expansion of the shaft. Again, oil is supplied to an annular groove in the white-metal ring. It flows in the clearances between the shaft and the bore of the seal. The flow is outward to a drain and inward to the space pressurized by hydrogen. The inward flow rate is much larger than the inward flow rate in the thrust-type seal because it is not inhibited by centrifugal forces. Thus, this flow is capable of contaminating the hydrogen significantly. The oil fed to the seals is subjected to vacuum treatment to reduce the contamination level of the hydrogen. The treatment involves the removal of air and water from the oil. Despite this disadvantage, the journal-type seal is considered better able to handle the axial movement of the shaft.

A more sophisticated design of the journal-type seal involves two separate oil supplies (Fig. 32.15). They are for the inward and outward flows. This design eliminates the need for vacuum treatment. The oil supplied is different from the turbine lubricating oil supply, which is the main source of entrained water.

Seal Oil System

In conventional design (Fig. 32.32), the shaft-driven lubricating oil pump supplies the oil for the main seal. The oil pressure is controlled by a diaphragm valve, which maintains a constant differential pressure above the hydrogen pressure at the seals. A water-cooled heat exchanger is used to cool the oil. The oil is sent through a fine filter to prevent metallic particles from reaching the tight clearances in the seal. When the unit is shut down, motor-driven pumps are used to supply the seals with oil. They are used as emergency backup. They are initiated by dropping the pressure of the seal oil. They are normally vertically submerged pumps mounted on top of the lubricating oil tank. A DC pump is also provided in case of emergencies (loss of AC power). This pump is expected to operate for a few hours only while the hydrogen is scavenged. There is a possibility that hydrogen enters the drain tank. Low-level alarms are normally installed. A blower is used to exhaust the gas above the oil in the tank to the atmosphere. The blower reduces the pressure in the bearing housings by creating a vacuum in the tank to reduce the egress of oil vapor at the bearings.
Figure 32.33 illustrates the demineralized water system used to remove the heat from the stator bars. The main criteria are as follows:

- Very low conductivity to prevent current flow and electrical flashover.
- High-integrity insulation is used to transfer water into the conductors.
FIGURE 32.33 Stator winding water cooling system.
Low water velocity to prevent erosion. Corrosion must also be prevented. Erosion or corrosion could result in a build-up of conducting material, leading to an electrical flashover.

The maximum water pressure must be lower than the hydrogen pressure. If a leakage occurs, the hydrogen enters the water circuit. If water is allowed to enter the hydrogen, the winding insulation could become damaged.

The maximum water temperature should be well below saturation (boiling occurs at 115°C at system pressure) to ensure adequate heat removal capability. The normal inlet and outlet temperatures are around 40 and 67°C, respectively.

A portion of the water is circulated through a demineraliser (Fig. 32.34). All the metals in contact with the water are nonferrous or stainless steel. If the metals had even a small amount of ferrous materials, magnetite will form. They will be held by electromagnetic forces. The water flows in flexible translucent hoses made of PTFE into and out of the conductors (Fig. 32.35). In the double-pass design, the water supply enters a circular manifold. The manifold is supported from the stator core end plate. The PTFE hoses are used to connect the manifold to the bars and between the top and bottom bars. The water flows in parallel channels in these bars. At the exciter end, the water is transferred through another PTFE hose to the outlet manifold. The inlet and outlet manifolds are located alongside each other. The terminal bushings and phase connections are cooled by a small flow. A higher pressure is required for the double-pass design compared with the single-pass design. However, only half the number of hoses is needed. This reduces the chance of leakage. In the single-pass arrangement, the manifolds are at opposite ends. The water flows through the bars in parallel.

The water temperature rises rapidly if the flow is reduced. The differential pressure across an orifice plate or the stator windings is used to detect a reduction in flow. In this case, the standby pump should be started immediately, or the unit should be tripped.

An initial test is done on the water circuit to confirm it has a very low leak rate. However, a small quantity of hydrogen still enters the water. It is detected in a settling tank installed on the outlet side of the generator. Most of the gas is largely detrained in a header tank. The gas is collected in a chamber that is equipped with timed release valves. An alarm is initiated if the release rate exceeds a predetermined level (Fig. 32.36).

Thermocouples are installed in each of the winding slots. They detect low-flow conditions. Modern machines have a thermocouple in each outlet hose. They provide a direct indication of low flow. As noted earlier, condensation should not occur on the windings. Some generators have an electric heating element. Other designs have an automatic cooler bypassing system. It prevents cold water from circulating in the windings during start-up and low-load conditions.

**OTHER COOLING SYSTEMS**

The hydrogen is cooled by passing it through a water-cooled heat exchanger mounted in the casing. The heat exchanger has nonferrous tubes. The heat exchangers have a double-pass water circulation to the inlet and outlet water connections at the same end. Demineralized water is used for these coolers.

Lake water is not used for these coolers due to the danger of corrosion. The hydrogen is maintained at a higher pressure than the cooling water in the heat exchanger. In the event of a leak, hydrogen will leak into the water (water ingress into the hydrogen can have serious consequences). In modern design, the water circuit has hydrogen detectors (Fig. 32.37). The hydrogen coolers have some redundancy. It is possible to operate with one hydrogen cooler isolated. The loss of cooling water is detected by increase in cooling temperature.
FIGURE 32.34 Demineralizer.
The rapid increase in hydrogen temperature will cause the unit to trip. The rotating exciters, and slip ring/brush gear or rotating rectifier chambers, have air-cooling systems. A closed-air circuit with a water-cooled heat exchanger is used for the rotating exciter. Open-air ventilation is normally used for the slip rings.

**EXCITATION**

**AC Excitation Systems**

Figure 32.38 illustrates a typical AC excitation scheme. It shows the shaft-mounted main and pilot exciters together with their brush gear. Permanent-magnet pilot exciters are used to minimize dependency on external power supplies. The pilot exciter provides the excitation power for the automatic voltage regulator (AVR) control equipment. A 660-MW plant has a salient-pole pilot exciter with ratings near 100 kW. The main and pilot exciters are cooled by air. Shaft-mounted fans are used to provide the cooling. The performance is monitored by measuring the temperature at the inlet and outlet of the cooling system.
Exciter Transient Performance

The ceiling requirements for exciters are considerably higher than rated full-load conditions. The transient performance of an exciter is given by

\[
\text{Exciter response ratio} = \frac{\text{average rate of increase in excitation open-circuit voltage (V/s)}}{\text{nominal excitation voltage}}
\]

In a typical exciter, the output voltage needs to be increased from 100 to 200 percent within 3.5 s. Figure 32.39 illustrates the average rate of increase of excitation open circuit voltage.
The Pilot Exciter

The permanent-magnet generator (PMG) pilot exciters used for 660-MW units are salient-pole design (Fig. 32.40). This design provides a constant voltage supply to the thyristor converter and AVR control circuits. A high-energy material like Alcomax is used for the permanent-magnet poles. The poles are bolted to a steel hub and held in place by pole shoes. A nonmagnetic steel is used for the bolts to prevent the formation of a magnetic

**FIGURE 32.37** Distilled water cooling system.

The Pilot Exciter

The permanent-magnet generator (PMG) pilot exciters used for 660-MW units are salient-pole design (Fig. 32.40). This design provides a constant voltage supply to the thyristor converter and AVR control circuits. A high-energy material like Alcomax is used for the permanent-magnet poles. The poles are bolted to a steel hub and held in place by pole shoes. A nonmagnetic steel is used for the bolts to prevent the formation of a magnetic
Section through main and pilot exciters.
shunt. The pole shoes are skewed in some designs to improve the waveform of the output voltage and reduce electrical noise. The stator windings are arranged in a two-layer design. The stator conductors are insulated with polyester enamel. The coil insulation is a class F epoxy glass material.

The Main Exciter

The main AC exciter normally has four or six poles (Fig. 32.41).

Exciter Performance Testing

The manufacturer of the exciters is required to perform these tests: open- and short-circuit, overspeed balancing, and high voltage.

Pilot Exciter Protection

The pilot exciter delivers its full current during field forcing. Modern AVRs have a time/current limiter. It allows the pilot exciter to deliver maximum current during a determined interval. The current is brought back to a normal value following this interval. The main exciter, like the pilot exciter, has a considerably higher margin than required. It has a 3.3-kV winding insulation despite having a working voltage of 500 V. The voltage ceiling of the main exciter is 1000 V. Its rated current is much lower than the maximum current.
FIGURE 32.40 Salient-pole permanent-magnet generator.

FIGURE 32.41 Main exciter.
Most modern gas turbines use brushless excitation systems. The rotating diodes are arranged as a three-phase bridge. The bridge arm consists of two diodes in series. If one of them fails (due to a short circuit), the second diode will continue to operate. Thus, the bridge continues to operate normally. If both diodes fail in the same arm, the fault is detected by a monitoring circuit, which trips the machine. Essential measurements, such as ground-fault indication, field current, and voltage, are taken by telemetry or instrument slip rings.

The Rotating Armature Main Exciter

Brushless machines require less maintenance than conventional ones. They also do not have sliding or rubbing electrical contacts that cause sparking and carbon dust. The main exciter is a three-phase rotating armature AC generator. The DC field is in the stator, and the AC winding is on the rotor. A typical rotating armature main exciter is illustrated in Fig. 32.42.

The exciter armature is made of low-loss steel laminations. The laminations are shrunk onto a shaft forged from annealed-carbon steel. Cooling air enters axial slots along the rotor body. The rotor conductors are made of braided strips in parallel. They are radially transposed to reduce eddy current losses.

The rotating rectifier of a 660-MW generator is illustrated in Fig. 32.43. It is mounted on the outboard of the main AC exciter. The three-phase AC power is supplied from the main exciter to the silicon diode rectifier by axial conductors taken along the surface of the shaft. A steel retaining ring contains the components of the rectifier against centrifugal forces. The retaining ring is shrunk on the outside of the hub.

THE VOLTAGE REGULATOR

Background

Early voltage regulators used mechanical components. They had a large deadband, long response time, and required regulator maintenance. Modern AVRs use integrated circuits or digital microprocessor techniques. Figure 32.44 illustrates a modern dual-channel arrangement.

System Description

The main function of the AVR is to maintain constant generator terminal voltage while the load conditions are changing. A dual-channel AVR with manual backup is normally used. The reliability of this design is high because the loss of one channel does not affect operational performance. The faulty channel can be repaired during operation.

The Regulator

The AVR is a closed-loop controller. It compares a signal proportional to the terminal voltage of the generator with a steady voltage reference. The difference (error) is used to control the exciter output.
When the load changes, the error increases. The channel A AVR applies a proportional-integral-derivative (PID) algorithm to the error and provides a corrective signal. This signal is amplified by the channel A converter. It is then sent to vary a field resistance. The excitation current will change, and the terminal voltage will change accordingly. It is critical to have a fast, stable response from the AVR. Special signal conditioning networks are introduced in the PID control to prevent instability. Accurate tuning (selection of PID coefficients) of the voltage response is achieved by having adjustable time constants.

The AVR receives the generator terminal voltage signal through its own interposing voltage transformer. The voltage signal is rectified and filtered before comparing it with the reference voltage.

**Auto Follow-Up Circuit**

In a dual-channel AVR, both channels can be active simultaneously. Each channel provides half the excitation requirements. An alternative design allows one channel to be active
while the other follows passively. If a channel trips, the other picks up the full excitation requirement in a “bumpless” manner. A follow-up circuit is used to achieve this function. It tracks the primary (or active) channel and drives the output of the standby channel to match the output of the primary channel.

**Manual Follow-Up**

This is a manual follow-up system similar to the auto follow-up system. When the AVR fails, the manual control takes over in a bumpless manner.
AVR Protection

The AVR plays a critical role in the overall protection scheme of the generator because it controls the suppression of the field after faults. The generator should also be protected against AVR component failure, which could jeopardize its operation. An overvoltage relay monitors the terminal voltage of the generator. If the voltage exceeds a safe level, the field current is reduced in minimum time. This relay is only active when the generator is not synchronized.

An overfluxing relay is also active only during unsynchronized operation. If the safe voltage-frequency ratio is exceeded, the generator transformer could be overfluxed. A special relay detects this condition and initiates an alarm. The AVR controls reduce excitation to a safe level. If this condition persists, the excitation is tripped. A component failure within the AVR results in over- or underexcitation. The active channel output is compared with the minimum and maximum field current. When a limit is exceeded for a few seconds, the channel is tripped.

The Digital AVR

The use of microprocessors in AVRs has many advantages. The reliability will increase due to the reduction of the number of components. Most of the control logic in solid-state AVRs is done by electromechanical relays. These relays will be replaced by a specified microprocessor software. The cost of microprocessor-based AVRs is lower than conventional solid-state AVRs. This is due to the replacement of the customized printed circuit boards by standard memory circuits. However, the main advantage of microprocessor-based AVRs is in the wide range of sophisticated control features. One type of controller, called the adaptive regulator, is capable of adjusting its structure to accommodate the changing plant conditions.
EXCITATION CONTROL

Modern excitation equipment includes a number of limiter circuits. These limiters operate like parallel controllers. Their signals replace the generator voltage, which is the controlled variable when the input signals exceed predefined limits.

Rotor Current Limiter

All exciters have the capability of supplying a field current significantly higher than the one required during normal operation. This field-forcing capability or margin is needed during a fault to increase the reactive power. However, the duration of the increase in current must be limited to prevent overheating of the rotor, which would lead to degradation of the insulation system. During a system fault, the AVR boosts excitation. This situation lasts normally milliseconds before the circuit breaker clears the fault. However, the backup protection is allowed to last up to 5 s (or more). After this delay, the rotor current limit circuit sends a signal that overrides the one from the AVR, causing a reduction in excitation current.

Overfluxing Limit

Modern AVRs have overfluxing limiter circuits in addition to the overfluxing protection circuit. The overfluxing limiter circuit is a closed-loop controller. It monitors the voltage-frequency ratio when the generator is not synchronized. When a predefined ratio is exceeded, the limiter reduces excitation.

THE POWER SYSTEM STABILIZER

When a generator is synchronized with the grid, it is magnetically coupled to hundreds of other generators. This coupling is not rigid like a mechanical coupling. It is a flexible coupling similar to a connection with rubber bands. During normal operation, the generator oscillates slightly with respect to the grid. These oscillations are similar to vibrations of a mass attached to a rigid surface by a spring. These electromechanical oscillations normally have a frequency of between 0.2 and 2.0 Hz. This frequency depends on the load and location of the generator with respect to other large generators. Each machine can have different modes of oscillations. The frequency of these oscillations can be 0.3 Hz or 1 to 2 Hz normally. Therefore, the electrical power that is produced by the generator is not matching the mechanical power produced by the turbine at every instant. However, the average mechanical power produced matches the electrical power that is generated by the unit.

In some cases, groups of generators at one end of a transmission line oscillate with respect to those at the other end. For example, in a four-unit generating plant, the four generators tend to be coherent. They tend to oscillate as a group. An oscillation of between 10 and 50 MW (above and below the 600-MW rating) is expected. These oscillations are called power system oscillations. They depend on the load. They must be prevented. Otherwise, they can severely limit the megawatt transfer across the transmission system. Following a system fault, an accelerating torque will be applied to the generator as a result of changes in the electrical transmission system. The generator must produce a breaking torque in this situation to counter the accelerating torque. The damper winding will produce a counter (breaking or damping) torque.
Note: The damper windings are bars normally made of copper or brass. They are inserted in the pole face slots and connected at the ends. They form closed circuits as in a squirrel-cage winding. During normal operation, the generator is operating at synchronous speed. The damper winding also moves at the same speed. Thus, it is inactive. During a transient, the generator speed changes. The damper winding is now moving at a different speed than the synchronous speed. The currents induced in the damper winding generate an opposing torque to the relative motion. This action helps return the rotor to its normal speed.

The losses (e.g., windage and bearing friction) are speed-dependent. They also produce a countertorque that will help to reduce the overspeed. (Windage losses increase with the cube of the speed. The journal bearing losses increase with the square of the speed. The axial thrust bearing loss increases with the speed.)

The power system stabilizer (PSS) is added when there is insufficient countertorque (damping). All units over 10 MW must be reviewed for need of PSS. Most of them require a PSS. The PSS measures the shaft speed and real power generated. It determines the difference between the mechanical power and the electrical power. It produces a signal based on this difference that changes the speed of the machine (it produces a component of generator torque in phase with the speed changes). The objective of the PSS is to keep the power leaving the machine constant. It changes the excitation current at the same frequency as the electro-mechanical oscillations. This action changes the generator voltage with respect to the voltage in the grid. Power will flow from the grid to the unit to provide the countertorque required when the speed of the shaft exceeds the synchronous speed. It is important to mention that an improperly tuned PSS can lead to disastrous consequences. This is due to the voltage variations that it creates during operation. If the voltage variations are incorrect, excessive torque changes can occur leading to significant damage.

In summary, the salient features about PSS are the following:

1. The PSS acts as a shock absorber to dampen the power swings.
2. The AVR cannot handle power swings, because it is monitoring the voltage only.
3. A fault on the line can excite a unit severely if the damping is poor.
4. The PSS monitors the change in power and change in speed.
5. During steady-state operation, the PSS will not interfere.
6. When a fault occurs, the voltage drops. The field current must be increased to push as much active power out to increase the synchronizing torque. However, this increase in synchronizing torque (active power out) lasts for a few seconds only due to these reasons: a. Active power flow between the generator and the load is proportional to:

   \[
   \frac{V_{\text{generator}} \times V_{\text{load}}}{(\text{Reactance between generator and load}) \times \sin \alpha}
   \]

   where, \(\alpha\) is the angle between the phasors of \(V_{\text{generator}}\) and \(V_{\text{load}}\), and the reactance includes the step-up transformer only.

   If excitation is increased, \(V_{\text{generator}}\) increases but \(\alpha\) changes within a few seconds so that the active power flow remains unchanged.

   b. The active power flow is determined by the turbine.

   It is also important to mention that the reactive power flow is proportional to:

   \[
   \frac{V_{\text{generator}} - V_{\text{load}}}{\text{Reactance between the generator and the load}}
   \]

   Any change in \(V_{\text{generator}}\) will result in significant change in the reactive power sent to the grid. Therefore, when the excitation changes, \(V_{\text{generator}}\) will change resulting in significant transfer of reactive power.
CHARACTERISTICS OF GENERATOR EXCITER
POWER SYSTEM (GEP)

The characteristics of a GEP are established by extensive system investigations. All plant operating modes must be examined to identify the conditions of marginal stability. In general, the periods of low system demand (at night) are the most critical. The generator operates at a leading power factor during these times. In pumped-storage plants (where the turbine is used to pump the water upstream during the night. This is done because the price of electricity is very low at night. The same water is allowed down through the turbine during the day because the price of electricity is higher) the situation is more critical. This is because of the large rotor angle (angle between the rotor flux and stator flux. This angle normally increases with the load when the generator operates) in comparison with the remaining machines on the system during the night. The generator is operating as a motor in this situation.

A number of simulations are done on the unit (including AVR and PSS). The PSS settings are adjusted for optimum performance of excitation under all critical operating conditions. These settings are then used during plant commissioning. This is done to reduce on-site testing, which can be expensive.

EXCITATION SYSTEM ANALYSIS

The generator excitation system has the primary responsibility for power system dynamic and transient stability. Dynamic stability refers to the performance of the system following small load changes. This can result in sustained oscillations around 0.5 Hz when large power is transferred over long distances. These oscillations must be rapidly attenuated. Otherwise, the transmission system will be severely limited. Transient stability refers to the ability of a generator or group of generators to maintain synchronous operation following system faults.

Following a fault, a boost of synchronous torque is required to maintain the generator in synchronism. (Note: The synchronous torque is the torque used to maintain the generator in synchronism. It is created by active power sent to the grid. This is done by increasing the field current.)

In this situation, the AVR bucks (resists, opposes) and/or boosts the field current to develop the additional synchronizing torque. Therefore, the AVR must be properly tuned to play an essential role in maintaining stable system operation under all operating conditions.

GENERATOR OPERATION

Running Up to Speed

Before running up to speed, air will have been scavenged from the generator casing. Hydrogen will fill the casing to almost-rated pressure. The hydrogen pressure increases with temperature. Rated pressure is achieved on steady load. The stator windings should remain warmer than the hydrogen to prevent condensation.

It is recommended to go through the first and second critical (around 900 and 2200 r/min) of the rotor quickly to avoid high vibrations (Fig. 32.13).

As the rated speed is approached, excitation is applied automatically by the voltage regulator (or manually) by closing the switches of the exciter and the main field. The
voltage-frequency control device prevents the voltage from exceeding the rated voltage-frequency. This is done to prevent overfluxing of the generator transformer. The rated voltage should be established at rated speed with the machine on open circuit.

**Open-Circuit Conditions and Synchronizing**

Generators are generally operated near their rated voltage. If the grid requires a different voltage, the transformer tap changers will accommodate this request. A voltage range of ±5 percent is normally specified. The open-circuit characteristic is normally determined by the manufacturer. Several measurements of rotor currents and stator voltage are taken and plotted (Fig. 32.45). The relationship is linear (the air gap line) up to about 75 percent rated voltage.

![Open-circuit characteristics](image)

**FIGURE 32.45** Open-circuit characteristics.

*Note:* The MMF is applied across the reluctance of the air gap and the reluctance of the core. The reluctance of the air gap dominates because it is much larger than the one of the core. When saturation is reached, the reluctance of the iron starts to change. This occurs at the knee of the curve (Fig. 32.45).

During a long outage, the open-circuit characteristic should be checked by measuring the parameters at a few points along the curve. Improper synchronization can have serious consequences. If the magnitude or angular position of the voltage phasors were significantly different when the circuit breaker is closed, large current would circulate from the system through the stator windings due to the voltage difference. This causes high forces in the windings.
If there is a significant difference in frequency, a large torque would be imposed on
the rotor due to the sudden pulling into synchronism. A backup device confirms adequate
synchronization conditions before allowing the circuit breaker to close.

The Application of a Load

If the generator voltage phasors (magnitude and angular position) match exactly, there will
be no current flow nor an electrical torque. An imbalance in phasors must be created in order
to generate a load. The steam turbine governing valves are opened gradually. The rotor
starts to accelerate due to the additional torque. It moves forward relative to its no-load
position while still remaining in synchronism with the grid. The difference in voltage phasor
created by this angular change generates current in the stator windings. An electrical torque
is generated, which balances the increased mechanical torque.

Capability Chart

Figure 32.46 illustrates the capability chart of a generator. It is an MW-MVAR diagram. A
constant megawatt limit is drawn at the rated power output of the turbine. The rated stator
current locus cuts the rated megawatt line at the rated megavoltampere and power factor
point. The rated rotor current imposes a limit on megawatt and lagging power factor. The
capability chart shows the limits of generated megawatt and MVAR.

Neutral Grounding

The neutral ends of the three stator winding phases are connected together outside the casing.
The star point is connected to ground through a neutral grounding device. It is designed to
limit the fault current upon a ground fault in the stator winding. The neutral grounding device consists of a single-phase transformer. Its primary is connected between the generator star point and ground. Its secondary is connected to a resistor. This arrangement is chosen because the apparent impedance of the resistor appears on the primary side as \( a^2Z \), where \( a = N_p/N_s \), and \( Z \) is the impedance of the resistor. This creates a very high impedance that limits the fault current to 15 A.

**Rotor Torque**

During electrical faults, the stator currents are many times larger than the rated value. The associated electromagnetic torques have similar magnitudes. The shaft and coupling must be designed to withstand stipulated fault conditions without failure. However, the coupling bolts exhibit distortion in some cases after a severe electrical fault.

**REFERENCE**

GENERATOR TESTING, INSPECTION, AND MAINTENANCE

GENERATOR OPERATIONAL CHECKS
(SURVEILLANCE AND MONITORING)

Regular monitoring of the following six parameters is required:

1. Temperature of stator windings
2. Core temperature
3. Temperature of slip rings
4. Vibration levels at the bearings
5. Brush gear inspection (monthly or bimonthly)

Remove the brush holder. Clean the carbon brushes by compressed air. Inspect the brushes for uneven wear (do not touch the brushes with bare hands). Replace worn brushes. Use a stroboscope to inspect the slip rings. Vary the frequency of the stroboscope to check for uneven wear of the slip rings. The temperature of the slip rings should be measured using an infrared detector. If the slip ring temperature is high, the brushes would overheat and wear quickly. Generator derating is required if the slip ring temperature is high.

6. On-line partial discharge activity

MAJOR OVERHAUL (EVERY 8 TO 10 YEARS)

The electrical and mechanical tests that are required are described in Appendixes A and B, respectively. In summary, the work includes the following:

1. Perform insulation resistance and polarization index tests.
2. Investigate causes of partial discharge.
3. Check the tightness of the stator wedges by tapping them with a hammer. The wedges must be tight to minimize the movement of the stator conductor bars during operation. Rewedging and adding packing may be required.
4. Perform EL-CID test to determine if there is any loosening in the core laminations or deterioration in the core insulation. Apply penetrating epoxy if insulation is degrading.
5. Perform casing pressure, and stator pressure and vacuum decay tests.
6. Refurbish rotor, including inspection of radial pin and end caps (including ultrasonic and dye penetrant testing), vacuum test, slip ring refurbishment, and checking for copper dusting.

Note: Copper dusting occurs due to fretting of the rotor copper windings as they move in the slots when the machine is on turning gear. This problem does not occur during normal operation because centrifugal forces push the windings against the wedges. Copper dusting can cause shorts in the machine.

7. Calibrate protection equipment.

**APPENDIX A: GENERATOR DIAGNOSTIC TESTING**

The following factors affect the insulation systems in generators:

- High temperature
- Environment
- Mechanical effects (e.g., thermal expansion and contraction, vibration, electromagnetic bar forces, and motor start-up forces in the end turns)
- Voltage stresses during operating and transient conditions

All of these factors contribute to loss of insulation integrity and reliability. These aging factors interact frequently to reinforce each other’s effects. For example, high-temperature operation could deteriorate the insulation of a stator winding, loosen the winding bracing system, increase vibration, and cause erosion. At some point, high-temperature operation could lead to delamination of the core and internal discharge. This accelerates the rate of electrical aging and could lead to a winding failure.

Nondestructive diagnostic tests are used to determine the condition of the insulation and the rate of electrical aging. The description of the recommended diagnostic tests for the insulation system of motors, along with the conditions they are designed to detect, will be presented later.

**Stator Insulation Tests**

An electrical test is best suited to determine the condition of electrical insulation. The tests on insulation systems in electrical equipment can be divided into two categories:

1. High-potential (hipot), or voltage-withstand, tests
2. Tests that measure some specific insulation property (e.g., resistance or dissipation factor)

Tests in the first category are performed at some elevated alternating current (AC) or direct current (DC) voltage to confirm that the equipment is not in imminent danger of failure if operated at its rated voltage. Various standards give the test voltages that are appropriate to various types and classes of equipment. They confirm that the insulation has not deteriorated below a predetermined level and that the equipment will most likely survive in service for a few more years. However, they do not give a clear indication about the condition of the insulation.

The second category of electrical tests indicates the moisture content, presence of dirt, development of flaws (voids), cracks and delamination, and other damage to the insulation. A third category of tests includes the use of electrical or ultrasonic probes that can determine
the specific location of damage in a stator winding. These tests require access to the air gap and energization of the winding from an external source. These tests are considered an aid to visual inspection.

**Direct Current Tests for Stator and Rotor Windings**

These tests are sensitive indicators to the presence of dirt, moisture, and cracks. They must be performed off-line with the winding isolated from ground, as shown in Fig. 33.1.

![Diagram of Direct Current Testing of a Generator Winding](image)

**FIGURE 33.1** Direct current testing of a generator winding.

Suitable safety precautions should be taken when performing all high-potential tests. When high-voltage DC tests are performed on water-cooled windings, the tubes or manifolds should be dried thoroughly to remove current leakage paths to the ground, and to avoid the possibility of damage by arcing between moist patches inside the insulating water tubes. For greater sensitivity, these tests can be performed on parts of the windings (phases) isolated from one another.

The charge will be retained in the insulation system for up to several hours after the application of high DC voltages. Hence, the windings should be kept grounded for several hours after a high-voltage DC test to protect personnel from a shock.

Tests using DC voltages have been preferred over the ones using AC voltages for routine evaluation of large machines for two reasons:

1. The high DC voltage applied to the insulation during a test is far less damaging than high AC voltages due to the absence of partial discharges.
2. The size and weight of the DC test equipment is far less than the AC test equipment needed to supply the reactive power of a large winding.

**Insulation Resistance and Polarization Index.** The polarization index (PI) and insulation resistance tests indicate the presence of cracks, contamination, and moisture in the
insulation. They are commonly performed on any motor and generator winding. They are suitable for stator and insulated rotor windings.

The insulation resistance is the ratio of the DC voltage applied between the winding and ground to the resultant current. When the DC voltage is applied, the following three current components flow:

1. The charging current into the capacitance of the windings.
2. A polarization or absorption current due to the various molecular mechanisms in the insulation.
3. A “leakage” current between the conductors and ground (the creepage path). This component is highly dependent on the dryness of the windings.

The first two components of the current decay with time. The third component is mainly determined by the presence of moisture or a ground fault. However, it is relatively constant. Moisture is usually absorbed in the insulation and/or condensed on the end winding surfaces. If the leakage current is larger than the first two current components, then the total charging current (or insulation resistance) will not vary significantly with time.

Therefore, the dryness and cleanliness of the insulation can be determined by measuring the insulation resistance after 1 min and after 10 min. The PI is the ratio of the 10-min to the 1-min reading.

Test Setup and Performance. Several suppliers, such as Biddle Instruments and Genrad, offer insulation resistance meters that can determine the insulation resistance accurately by providing test voltages of 500 to 5000 V direct current. For motors and generators rated 4 kV and higher, 1000 V is usually used for testing the windings of a rotor, and 5000 V is used for testing the stator windings.

To perform the test on a stator winding, the phase leads and the neutral lead (if accessible) must be isolated. The water must be drained from any water-cooled winding, and any hoses must be removed or dried thoroughly by establishing a vacuum (it is preferable to remove the hoses because vacuum-drying is usually impossible).

The test instrument is connected between the neutral lead or one of the phase leads and the machine frame (Fig. 33.1). To test a rotor winding, the instrument should be connected between a lead from a rotor winding and the rotor steel. During the test, the test leads should be lean and dry.

Interpretation. If there is a fault, or if the insulation is punctured, the resistance of the insulation will approach zero. The Institute of Electrical and Electronics Engineers (IEEE) standard recommends a resistance in excess of \( V_{LL} + 1 \) megohm (MΩ). If the winding is 13.8 kV, the minimum acceptable insulation resistance is 15 MΩ. This value must be considered the absolute minimum since modern machine insulation is in the order of 100 to 1000 MΩ. If the air around the machine had high humidity, the insulation resistance would be in the order 10 MΩ.

The insulation resistance depends highly on the temperature and humidity of the winding. To monitor the changes of insulation resistance over time, it is essential to perform the test under the same humidity and temperature conditions. The insulation resistance can be corrected for changes in winding temperature. If the corrected values of the insulation resistance are decreasing over time, then there is deterioration in the insulation.

It is more likely, however, that the changes in insulation resistance are caused by changes in humidity. If the windings were moist and dirty, the leakage component of the current (which is relatively constant), will predominate over the time-varying components. Hence, the total current will reach a steady value rapidly. Therefore, the PI is a direct measure of the dryness and cleanliness of the insulation. The PI is high (>2) for a clean and dry winding. However, it approaches unity for a wet and dirty winding.
The insulation resistance test is a very popular diagnostic test due to its simplicity and low cost. It should be done to confirm that the winding is not wet and dirty enough to cause a failure that could have been averted by a cleaning and drying-out procedure.

The resistance testing has a pass-fail criterion. It cannot be relied upon to predict the insulation condition, except when there is a fault in the insulation.

The high-potential tests, whether direct current or alternating current, are destructive testing. They are not generally recommended as maintenance-type tests. For stator windings rated 5 kV or higher, a partial discharge (pd) test, which in the past has been referred to as corona, should be done. The level of pd should be determined because it can erode the insulation and lead to insulation aging.

**Direct Current High-Potential Test.** A high-DC voltage withstand test is performed on a stator or rotor winding to ensure that the groundwall insulation can be stressed to normal operating voltage. The outcome of the test is simply pass or fail. Thus, it is not classified as a diagnostic test. The DC hipot test is done sometimes following maintenance on the winding, to confirm that the winding has not been damaged. It is important to consider the consequences of a hipot failure. Spare parts and outage time should be available before proceeding with this test.

The DC hipot test is based on the principle that weakened insulation will puncture if exposed to a high enough voltage. The test voltage is selected such that damaged insulation will fail during the test and good insulation will survive. Insulation that fails during a hipot test is expected to fail within a short period of time if placed in service. The distribution of electrical stresses within the insulation during a DC test is different from normal AC operation because the DC electric field is determined by resistances rather than capacitances. Figure 33.1 illustrates how the test is done. The winding is isolated and a high voltage connected between the winding and ground. If the stator windings are water-cooled, they must be drained and the system dried thoroughly to avoid electrical tracking of the coolant hoses. The hoses should be removed to ensure that they are not damaged by the test. The stator frame and all temperature sensors must be grounded. All accessories such as current and potential transformers must be disconnected or shorted. The suggested voltage test for a new winding is 1.7 times the root-mean-square (rms) ac voltage. A typical routine voltage used during maintenance is \( (2 \times V_{L-L}) \) kV direct current. However, the test voltages used by the manufacturer and during commissioning are significantly higher than the maintenance test voltage level. The rotor windings do not have a standard test voltage level.

If a hipot test is successful, it confirms that there are no serious cracks in the groundwall and the insulation system. The insulation will most likely withstand normal operating stresses until the next scheduled maintenance test.

**High-Voltage Step and Ramp Tests.** The variation of current (or insulation resistance) should be monitored as the DC hipot test is performed. If there is a weakness in the groundwall, a sudden nonlinear increase in current (or decrease in insulation resistance) will precede a breakdown as the voltage is increasing. An experienced operator can interrupt the test when the first indication of warning occurs. If the voltage achieved is considered sufficient, the machine can be returned to service until the repairs can be planned. Following identification of a suspect phase, the location of the weakness must be found. The variations of voltage with current obtained during the test can be used in future comparisons on the same winding if the same conditions exist.

The winding must be completely isolated (Fig. 33.1). A special ramp or conventional high-voltage DC test set is used for this test. The leakage current must be calculated at the end of each voltage step. The test operator must make a judgment based on the increase in leakage current before increasing the voltage further. The test voltage can alternatively be increased slowly with a recorder plotting the variations of leakage current against voltage [Fig. 33.2 (a, b)].
A weakness in the groundwall can be detected by a sudden increase in leakage current. If the condition of the groundwall is questionable, the machine can be returned to service if the achieved voltage is considered sufficient. Further investigations can be scheduled at a more convenient time.

**Alternating Current Tests for Stator Windings**

The DC tests are only capable of measuring the conductivity of the insulation system. The AC tests are usually more revealing of the insulation condition. However, they are more onerous than DC tests. The AC tests are also capable of being sensitive to the mechanical
condition of the system. For example, if delamination (air-filled layers) is present in the groundwall, the capacitance between the conductors and the core will decrease. However, if the winding is wet, the capacitance will increase.

**Partial Discharge Tests.** Partial discharges or pd’s (known in the past as corona), are spark charges that occur in voids within high-voltage insulation (>5 kV). They occur between the windings and core, or in the end winding region. These are “partial” discharges because there is some remaining insulation. The pd can erode the insulation and therefore contributes to its aging. However, a pd is a symptom of insulation aging caused by thermal or mechanical stresses. The measurement of a pd activity in a stator winding is an indication of the health of the insulation. Partial discharge tests provide the best means for assessing the condition of the insulation without a visual inspection. These tests should be done on stator windings in motors and generators rated higher than 5 kV.

**Off-Line Conventional Partial Discharge Test.** The conventional pd test involves energizing the winding to normal line-to-ground AC voltage with an external supply. A pd detector is used to measure the pd activity in the winding. The sparks caused by pd are fast-current pulses that travel through the stator windings. These pulses and the accompanying voltage pulses increase with the pd pulse. Figure 33.3 illustrates a high-voltage capacitor that can block the power frequency voltage and allow the high-frequency pulse signals to reach the pd detector. An oscilloscope is used to display the pulse signals after further filtering.

The pulse magnitudes are calibrated in picocoulombs (pC), even though the actual measurements are in millivolts (mV). The conventional test is done off-line. A separate voltage supply is used to energize the windings to normal voltage. The interference from high-frequency electrical noise in this test is a minimum.

**Test Setup and Performance.** The conventional test involves isolating the winding from the ground and energizing one phase of the winding by a 60-Hz power supply cable to rated line-to-ground voltage. This test is normally done on each phase separately while the remaining two are grounded. The phases are disconnected from one another at the neutral. Draining of the water-cooled winding is not required.

The test equipment includes a power separation filter (high-voltage) capacitor and a high-pass filter to block the power frequency and its harmonics—Fig. 33.3. The oscilloscope displays the pd pulses (Fig. 33.4). A pulse height analyzer is used to process the pulse data. It gives the pulse counts, pulse magnitudes, and comparisons between positive and negative pulses.
The AC voltage is raised gradually until pd pulses are observed on the oscilloscope. The voltage at which pd starts is called the discharge inception voltage (DIV). When the test voltage reaches the normal voltage, the magnitude of the pulses is read from the screen. The analysis of the pulse height is normally recorded. As the AC voltage is decreased, the voltage at which the pd pulses disappear is recorded. This is called the discharge extinction voltage (DEV). It is usually lower than the DIV. The actual test takes about 30 min, normally. However, the setup and disassembly can take up to a day.

**Interpretation.** There is no general agreement on the acceptable magnitudes of pd, DIV, and DEV. The inductive nature of the windings makes the calibration of the measured pd magnitudes (conversion from millivolts on the screen of the oscilloscope into picocoulombs) difficult. Thus, the measurement of the pulses may not provide an accurate value of the pd activity. These measurements cannot be calibrated from machine to machine or among the different types of commercial detectors.

The most useful method for interpreting the pd test results is by performing the test at regular intervals and monitoring for trends. The recommended interval for air-cooled machines is once or twice per year and every 2 years for hydrogen-cooled generators. As the condition of the insulation worsens, the magnitude of the pd will increase and those of the DIV and DEV will decrease. An increasing trend of pd activity indicates that the insulation is aging. Visual inspection of the winding condition may be required. Partial discharge results should only be compared if the same equipment and procedures are used during testing. This is due to the calibration problems mentioned earlier. Comparison of results can also be misleading if there are differences between the types of rating of the windings. Comparison of pd results are valid if the windings and test methods are identical.

A pd magnitude of less than 1000 pC indicates that the winding should not fail during the next few years. A visual inspection is recommended if the pd magnitude is more than 10,000 pC, especially if other identical machines have a pd less than 1000, and if the insulation is made of epoxy-mica. The DIV in modern epoxy or polyester windings should be greater than half the operating line-to-ground voltage. The test indicates that slot discharge is occurring if the DIV value is very low in epoxy-mica windings. However, older asphaltic and micafolium windings may not be in danger even if the magnitude of the discharge is high and the DIVs are low. This is in contrast with newer machines that have synthetic insulation, especially Mylar. Their condition deteriorates quickly in the presence of pd. However, older windings should be inspected if there is an increasing trend of pd activity.
There are many disadvantages for off-line conventional pd tests. Since the entire winding, including the neutral end, is fully energized, sites that are not normally analyzed can generate pulses. Large discharges can occur in sites that are not normally subjected to high voltages. This is misleading because the operator may believe that the winding is deteriorating.

**On-Line Conventional pd Test.** This test is similar to the off-line test except that an external power supply is not used to energize the winding. The generator is driven at normal speed by the turbine, and sufficient field excitation is applied. Therefore, the stator is at the normal operating voltage. The test can be performed with the generator synchronized to the grid or not. When the test is done on a motor, the winding is energized by the normal power supply. Extreme caution is required when the test is performed due to the considerable risk to personnel and the machine if the capacitor fails.

The test is more realistic than the off-line one because the voltage distribution in the windings is normal. Also, slot discharges that are caused from bar or coil movement are present.

The equipment used in the off-line test can be used in this test. The blocking capacitors are connected to the phase terminals during an outage. Dangerous events can occur if the capacitor fails during the test. An experienced operator can distinguish true pd from electrical interference from brushes, thyristor excitation systems, and background. If the generator is not synchronized, some generators can handle variations in the field current. In these cases, the DIV and DEV can be measured.

Some utilities leave the test equipment connected during normal operation. The pd activity can then be measured at low and full power. Deterioration in the condition of the insulation is detected by an increasing trend of pd. Since the test is done during normal operation, it gives the most accurate indication of the true condition of the insulation. External interference (from a power line carrier, radio station, etc.) can be severe during the test, especially in large generators. The interference can be misleading. The operator may believe that high pd activity is occurring while the winding is perfectly good.

**Dissipation Factor and Tip-up Tests.** The condition of the insulation system in a high-voltage winding can be evaluated by treating it as a dielectric in a capacitor. The capacitance and the dissipation factor (or power factor, or tan δ) of a winding can be measured during an outage. These measurements are normally made over a voltage range. Since pd’s are initiated when there are voids in the groundwall insulation, the change in dissipation factor with voltage is a measure of the initiation of additional internal losses in a winding.

Machine manufacturers use dissipation factor and tip-up (change in tan δ as the voltage is increased or Δ tan δ) as quality control tests for new stator bars and coils. A general weakness in the bulk insulation normally caused by incorrect composition or insulation that is not fully cured is indicated by an abnormally high dissipation factor. Excessive voids within the insulation will discharge at high voltage. They are indicated by a higher-than-normal increase in dissipation factor when the voltage is increased (tip-up).

The winding must be isolated into coils or coil groups to obtain a sensitive measurement during this test. This consumes a significant amount of time. Thus, this test is not widely used for testing motors and generators in utilities.

**Tip-up Test.** A half-day outage is normally required for a dissipation factor test. It can be performed on motors and generators of all sizes. A single measurement of dissipation factor on a complete winding has limited use. However, trends of measurements on coils or coil groups over years provide useful information. This test is most useful when done on low and high voltage. As the voltage is increased from a low to a high value, the dissipation factor will increase (i.e., tip-up). The pd activity within the insulation will increase with the voltage level. Dissipation factor is a measure of electrical losses in the insulation system. It

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*Note: Angle δ is defined as δ + θ = 90°, where θ is the phase angle between the current and the voltage.*
is a property of the insulation. It is desirable to have a low dissipation factor. However, a high dielectric loss does not confirm that the insulation is poor. A capacitance bridge is normally used to measure the dissipation factor. For example, the dissipation factor of a good epoxy-mica and asphaltic insulation is 0.5 and 3 percent, respectively.

The dissipation factor will not increase with the voltage in a perfect insulation. However, if air-filled voids are present in the insulation, pd will occur at a high-enough voltage. The electrical losses in the winding will increase due to energy consumption by heat and light generated by the discharges. The dissipation factor will increase with the voltage. As the pd activity increases, the tip-up will increase, and the condition of the winding will worsen. Therefore, the pd activity is measured indirectly by a tip-up test. A bridge is used to measure the dissipation factor. It effectively measures the ratio of the in-phase current in the sample to the capacitive (or quadrature) current. This ratio is determined over the total current in the sample. Thus, it represents the average loss over the entire winding being tested.

**Stator Turn Insulation Surge Test.** The surge tests are hipot tests used to check the integrity of the interturn, as well as the capability of the groundwall insulation, to withstand steep transients that are likely to be encountered in normal service. These surge tests are normally done on new windings in the factory to detect faults. A voltage is applied for a very short time to the turn insulation during the test, causing weak insulation to fail. Thus, the surge test is not a diagnostic test but a hipot test for the turn insulation. The impedances of two matching sections of the winding are compared by commercial surge testers. A voltage surge having around 0.2 μs risetime and adjustable magnitude is applied simultaneously to the two winding sections, $L_1$ and $L_2$ (Fig. 33.5). The shape of the surges is superimposed on an oscilloscope. A high-voltage transient is developed across the winding turns due to the short risetime. The two waveforms will be identical if both windings are free from faults (because the impedances are the same). Any discrepancy in the two waveforms may indicate a shorted turn in one of the windings. An experienced operator can identify the nature of the fault (Fig. 33.6) by comparing the magnitude and type of the discrepancy between the two waveforms.

![Simplified schematic for a turn insulation surge tester](image)

**FIGURE 33.5** Simplified schematic for a turn insulation surge tester. $L_1$ and $L_2$ are either coils or phases in a winding.

In some cases, the surge voltage is applied to an exciter coil, which is placed over the stator coil to be tested (direct connection of the surge tester to a stator coil is not required). This allows testing of coils in complete windings without disconnecting each coil from the other. The voltage is induced into the stator coil by transformer action when the surge is applied. This produces the turn-to-turn stress in the stator coil. However, interpretation of
the result is even more difficult. This induced surge test should be done carefully because high voltages may also be induced into coils other than the coil being tested. The test is normally performed by connecting the high-voltage output of the surge tester to two of the phases. The third phase is grounded to the surge tester. The voltage is applied and increased to specified limits, which should not exceed the groundwall DC hipot voltage. If the surge waveforms are identical, the turn insulation is presumed sound.

This test is based on comparing the shapes of surges applied with two winding sections. The two surge shapes may not be identical if the two winding sections being tested have slightly different impedances due to having different dimensions of coils. This will suggest a fault even when the insulation system is in good condition. It is also difficult to detect a turn fault in a coil tested in a circuit parallel with more than 10 coils because a shorted turn will have a minor change in the total impedance of the winding. As the number of coils being tested increases, it becomes more difficult to determine if a defective coil is present. This test does not indicate the relative condition of the turn insulation in different coils. It only indicates if shorts exist. It is a go/no-go proof test like the AC and DC hipot test for the stator groundwall insulation.

**Synchronous Machine Rotor Windings**

The presence of faults in rotor winding insulation can sometimes be indicated by a change in machine performance rather than by the operation of a protective relay. For example, if a coil develops a short circuit, a thermal bend may develop due to an asymmetric heat input into the rotor. This could lead to an increase in shaft vibration with increasing excitation current. This change can be used in some cases to determine if the interturn fault is significant. The location and severity of a fault cannot always be found easily when the rotor is removed. This is especially true in large turbine generator rotors whose concentric field windings are embedded in slots in the rotor body and covered by retaining rings at the ends. Many ground and interturn failures disappear at reduced speed or at a standstill. This makes their detection very difficult and emphasizes the need for an on-line detection technique. The
The following tests are used to determine if faults exist in the rotor winding, and/or they indicate their location. Solid-state devices used in exciters should be shorted out before conducting any test involving the induction or application of external voltages to the rotor winding.

**Open-Circuit Test for Shorted Turns.** An open-circuit test can be used to confirm if shorted turns in rotor field windings exist when there are indirect symptoms such as a change in vibration levels with excitation. The machine should be taken out of service for a short while but does not need to be disassembled.

Figure 33.7 illustrates the open-circuit characteristic of a synchronous machine. It relates the terminal voltage to field current while the machine is running at synchronous speed with its terminals disconnected from the grid. The open-circuit curve can be used to verify shorted turns if an open-circuit test characteristic with healthy turn insulation was done previously. A higher field current will be required to generate the same open-circuit voltage if there are shorted turns in a rotor field winding. If the difference between the two curves is more than 2 percent, the possibility of a turn insulation fault will be confirmed.

The difference in characteristics to indicate a shorted turn depends on the number of turns in the field winding and the number of shorted turns. For example, a single shorted turn cannot be detected by this test if the connected field winding has a large number of turns. This test is done while the machine is running at synchronous speed with its stator winding terminal open-circuited and the field winding is energized. Generators can easily be driven at synchronous speed because their drivers are designed to operate at synchronous speed. Motors may...
need to be driven by AC or DC drive at synchronous speed. If the test indicates the possibility of shorted turns, further confirmation should be obtained by performing additional tests. This test has the following two limitations:

1. It may not detect shorted turns, if the machine has a large number of turns and/or if there are parallel circuits in the field winding.
2. Differences in the open-circuit curve will also be created when the machine’s magnetic characteristics change (e.g., when the rotor wedges are replaced with a different material).

**Air Gap Search Coil for Detecting Shorted Turns.** Interturn faults in rotors are detected by an air gap search coil. Methods have been developed for on-line and off-line testing. This technique is especially useful for detecting faults present at operating speed, which disappear on shutdown. The coils and slots having shorted turns, as well as the number of turns shorted, can be identified by this method. Permanent flux probes have already been installed on some machines. Each rotor slot has local fields around it. This leakage flux is related to the current in the rotor. The magnetic field associated with a coil will be affected if the coil is shorted. The search coil records the high-frequency waveform (known as *slot ripple*) generated in the air gap. Each rotor slot generates a peak of the waveform in proportion to the leakage flux around it. If an interturn fault occurs, the peaks associated with the two slots containing the faulted coil will be reduced. The recorded data are analyzed to identify the faulted coil and the number of faults. Shorted turns also generate significant levels of even harmonics (multiples of the frequency), while a fault-free rotor generates only odd harmonics.

The search coil is normally mounted on a stator wedge. A gas-tight gland is required for the leads of the probe. Shorted rotor turns should not be a cause of grave concern if the rotor vibration is not excessive and the required excitation is maintained. A generator can operate adequately for a period of time under this condition. However, these shorted turns are normally caused by serious local degradation of the interturn insulation and possibly major distortion of the conductors. In some cases, where static exciters are used, arcing damage and local welding have been found.

It is difficult to interpret the on-load test results from the search coil due to the effects of saturations and magnetic anomalies in the rotor body. More complex and time-consuming detection techniques are required. However, modern on-line monitors have overcome these difficulties. They are designed for use with turbine generators equipped with an air gap search coil. The output from the search coil is continuously being processed. An alarm is initiated when a current-carrying shorted turn occurs in the rotor winding.

**Impedance Test with Rotor Installed.** Shorted turns in a field winding can also be detected by periodic measurement of rotor impedance using an AC power supply. These tests should ideally be performed while the machine is operating at synchronous speed because shorted turns may only exist when centrifugal forces are acting on the turn conductors. When the machine is shut down, there may not be any contact, or the fault resistance may be high. Shorted turns can be detected more accurately by impedance rather than resistance measurements. This is due to the induced backward current in a single shorted turn, which opposes the magnetomotive force (mmf) of the entire coil, resulting in a significant reduction in reactance. This technique is particularly effective in salient pole rotors, where one short-circuited turn eliminates the reactance of the complete pole. There is a sudden change in impedance when a turn is shorted during run-up or rundown (Fig. 33.8). A sudden change of more than 5 percent is needed to verify shorted turns.

The highest field current used for this test should be significantly lower than the normal current required for rated stator voltage at open circuit. The voltage applied should not exceed the rated no-load stator voltage. A normal winding will exhibit a reduction in
impedance up to 10 percent between standstill and operating conditions due to the effects of eddy currents on the rotor.

This test can only be performed if the field winding is accessible through collector rings because the low-voltage AC power should be applied while the machine is running. A 120-V, 1-ph, 60-Hz AC power is applied. The voltage, current, and shaft speed are measured. The power supply should be ungrounded because the rotor could get damaged if the field winding has a ground fault. The test includes the following five steps:

1. Perform an insulation resistance test on the field winding of the machine to be tested to check for ground faults. The impedance test should not be performed if a ground fault is found. The ground fault should be located using a different procedure.

2. Connect an instrumented and ungrounded power supply to the field winding (Fig. 33.9). The instruments used should be properly calibrated.

3. Take the reading from the local speed indicator to determine the relationship between impedance and speed.

4. Adjust the field winding voltage to give a maximum permissible current of 75 percent of the current required to achieve the rated open-circuit stator voltage.

5. Increase and decrease the speed of the machine while the stator windings are disconnected from the power supply. Measure the current, voltage, and speed, starting at 0 and increasing the speed at 100-r/min intervals until the rated speed is reached. Continuous measurements can also be recorded simultaneously on a multichannel strip chart recorder.

FIGURE 33.8 Detecting shorted rotor turns by impedance measurements.

FIGURE 33.9 Test setup for impedance measurement with rotor installed.
The values of the impedance \( Z = \frac{V}{I} \) should be plotted against the speed (Fig. 38.8). A sudden change in impedance of 5 percent or more or a gradual change of more than 10 percent will indicate a strong possibility of shorted turns in the winding. This test is not as sensitive as the previous two described earlier. It is also important to note that solidly shorted turns will not produce an abrupt change in impedance.

**Detecting the Location of Shorted Turns with Rotor Removed**

The exact location of a shorted turn should be found to minimize the disturbance to the winding when making repairs. One or a combination of the following four procedures should be used:

**1. Low-voltage AC test.** When the field winding of a synchronous machine rotor having shorted turns is connected to a low AC voltage (typically, 120 V), the tips of the teeth on either side of the slot(s) having the shorted turns will have significantly different flux induced in them. Figure 33.10 illustrates how the relative magnitudes of tooth fluxes can be measured. The teeth are bridged by a flux survey using a laminated-steel or air-core search coil, which is connected to a voltmeter and wattmeter. The voltage is measured by the voltmeter, and the direction of the induced flux is given by the wattmeter. The search coil is moved across all the teeth of the rotor and voltage and watts readings are taken. The search coil readings depend on its axial location along the rotor. Therefore, all the readings should be taken with the coil located at the same axial distance from the end of the rotor. Since the readings vary significantly near the end of the rotor, the coil should not be placed near the end of the rotor. It is important to note that core saturation may occur when a 60-Hz power supply is used. A higher frequency should be used if possible to reduce this problem.

The equipment that is used for the EL-CID test, described later, can be used to detect the shorted field winding turns. This test can be done without removing the end winding.
retaining rings if the rotor has steel wedges and no damper winding. If the rotor has a separate damper winding or aluminum-alloy slot wedges (shorted at the ends) used as a damper winding, they must be open-circuited at the ends before the test can be done. In this case, the retaining rings should be removed. Since many shorts are created by the action of centrifugal forces, they may not appear at standstill.

Figure 33.11 illustrates the flux distribution for a rotor with and without shorted turns. The sharp change in direction of the induced flux indicates the slot containing the shorted turns.

2. **Low-voltage DC test (voltage-drop test).** This method is used to locate the shorts based on a DC voltage drop between turns. The end rings should be removed to provide access to the turns. In some cases, the shorts should be induced by applying a radial force to the coils. This is normally done by tapping the wedges with a wooden block or clamping the coils at the corner.

   The test is done by applying a DC voltage to the field winding and measuring the drop in voltage across the turns. If a short occurs, the voltage drop across the turn would be lower than normal.

3. **Field winding ground fault detectors.** A large generator rotor operates at 500 V DC and 4000 A DC normally. If the insulation between the winding and the body is damaged or bridged by conducting materials, there will be a shift of the DC potential of the winding and exciter. The part of the winding where the fault occurred becomes the new zero-potential point. In most cases, this will not cause an immediate problem if there is no additional ground fault. A second ground fault in the rotor will be catastrophic.

   A rotor ground-fault detector is used to enunciate when a fault occurs. Some units are tripped automatically due to possible extensive damage to the rotor body by a DC arc across a separate copper connection. Ground-fault detectors have various configurations. The rotor winding is grounded in simple DC schemes on one end through a high ohmic resistance. However, these schemes become insensitive if the fault occurs close to this end. Ohm’s law determines the magnitude of leakage current from the rotor winding to the ground-fault relay. The shaft should also be grounded.

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**FIGURE 33.11** Flux distribution survey for two-pole turbine generator.
A sophisticated technique was developed to continue operation of a generator having a known ground fault (second ground-fault detector). It uses a microprocessor and measuring resistors to determine whether the power that is dissipated by the leakage current exceeds a value that would cause a failure if there are two or more ground faults from the winding. A search coil mounted in the air gap has been used to detect interturn faults and a second ground fault.

If a fault is identified, measurements of the slip ring–to–shaft voltages will give an indication of the location of the fault (is the fault at the middle or end of the winding). After disconnecting the ground-fault detector and while the generator is still on-line, the voltage readings between the brush holders and the shaft are taken. If one ground fault is present, the approximate location of the fault in percent of winding resistance is

\[
\frac{\text{Lower ring-to-shaft voltage}}{\text{Sum of two ring-to-shaft voltages}} \times 100\%
\]

During rundown of the unit (when it is unloaded and tripped), an insulation resistance tester is used to test the fault resistance. The brushes are raised or the field circuit breaker is opened to determine if the fault is in the generator rotor, external bus, or the exciter. The fault is also monitored as the speed drops. If the fault disappears, it will be impossible to find its location. The operator may decide to put the machine back in service. If the fault reappears when the unit is returned to service, the process should be repeated. If the fault is sustained, a low voltage is applied across the slip rings while the rotor is at standstill. It is usually provided from a 12-V car battery or from a 120-V AC variac. The voltage between the rotor body and each slip ring is measured. If the readings are full voltage with one and zero with the other, there is likely a low-resistance path at the slip rings. It could be caused by carbon dust or insulation failure. It may easily be corrected with a good cleanup. The rotor should be withdrawn if the fault is within the winding. When the rotor is removed, the low-voltage source is reapplied to the slip rings, and a voltmeter is installed between the rotor body and a long insulated wire. The insulation is removed off the last 5 mm of the wire, and it is used as a probe to contact the rotor winding metal through ventilation holes and under the retaining rings. This technique will identify the slot, bar, or ventilation hole having the closest voltage to the rotor body. The fault is usually located under the wedge near this location. The problem is rectified sometimes by cleaning the ventilation ducts. Otherwise, additional dismantling may be required.

If the ground fault is transient and needs to be found, a failure is forced with a moderate hipot test, and the same technique is used. The hipot test should be used as a last option.

4. Surge testing for rotor shorted turns and ground faults. This off-line method is used to detect rotor winding faults on stationary and rotating shafts. The location of the fault is identified. This method is very effective in finding ground faults and shorted turns. There is electrical symmetry in a healthy rotor winding. The travel time of an identical electrical pulse injected at both slip rings through the winding should be identical. The reflection of the pulse back to the slip rings would also be identical. If there is a short or ground fault, some of the pulse energy will be reflected back to the slip ring due to the drop in impedance at the fault. The reflections will change the input pulse waveform, depending on the distance to the fault. Therefore, a fault will generate different waveforms at each slip ring unless it is located exactly halfway in the winding.

The recurrent surge oscillography (RSO) is a technique based on the aforementioned principle. This test cannot be done on-line, because the winding should be isolated from the exciter. Two identical, fast-rising voltage pulses are injected simultaneously at the slip rings. The potential at each injection point is plotted versus time. Identical records should be obtained if there is no fault due to the symmetry in the winding. Differences between the traces are indicative of the winding fault. The fault is located from the time at which
irregularity occurred. Ground faults having a resistance of less than 500 Ω will be detected by the RSO method. These faults are also normally detected by the generator protection systems. The RSO technique is used to confirm ground faults. Interturn faults having a resistance of less than 10 Ω will also be detected by RSO. Faults that have a resistance of more than 10 Ω are more significant during operation and less severe off-load. These faults cannot be detected by RSO.

**Low-Core Flux Test (EL-CID)**

The conventional method for testing for imperfections in the core insulation of motors and generators has been the rated-flux test. This test requires high power levels of the excitation winding to induce rated flux in the core area behind the winding slots. The alternative low-flux test described in this section has been performed successfully across the world. Its main advantage is that it requires a much smaller power supply for the excitation winding. Only 3 to 4 percent of rated flux is induced in the core. In reality, the power supply can be obtained from a 120-V AC wall socket source. Also, the time required to perform this test is much shorter.

The *Electromagnetic Core Imperfection Detector* (EL-CID) identifies faulty core insulation. It is based on the fact that eddy currents will flow through failed or significantly aged core insulation, even if the flux is a few percent of the rated flux. A *Chattock coil* (or Maxwell’s worm) is used to obtain a voltage signal proportional to the eddy current flowing between the laminations. The solenoid coil is wound in a U shape.

Figure 33.12 illustrates how the coil is placed to bridge the two core teeth. The fault current $I_F$ is approximately proportional to the line integral of alternating magnetic field along its length $l$ (Ampere’s law). Thus, if the effects of the field in the core are ignored, the voltage output in the Chattock coil is proportional to the eddy current flowing in the area encompassed by the coil (the two teeth and the core behind them).

![Chattock coil mounting configuration and output voltage](image)

The excitation winding that generates the test flux in the core induces an additional voltage across the coil due to the circumferential magnetic field. A signal processor receives the output voltage from the Chattock coil. It eliminates the portion that is generated by the excitation winding and gives a voltage proportional to the eddy current (Fig. 33.13).
The output milliamperes of the signal-processing unit is proportional to the voltage in the Chattock coil generated by axial eddy currents. High milliampere readings are normally caused by faulty insulation in the core or interlamination shorts at the core surfaces. A reading higher than 100 mA indicates significant core plate shorting.

The Chattock coil is moved along the teeth of the core and the current readings are recorded. Areas where the readings exceed 100 mA should be marked with a nonconductive substance and examined for defects.

**APPENDIX B: MECHANICAL TESTS**

These tests will help to determine the integrity of the windings. Loose stator windings can cause mechanical and electrical damage to the groundwall insulation. Large machines are more susceptible due to the increased forces and slot discharges. Following are the tests that should be done during outages.

**Stator Winding Tightness Check**

The tightness of the stator wedges in the slot should be checked on a regular basis. The effective methods are wedge tapping and ultrasonic detection.

The stator wedge is struck by a blunt object. The tightness of the wedge in the slot will determine the type of sound ring. A tight wedge will give a dull sound, and a slack wedge a hollow sound. A ring between these extremes indicates that the wedge will become loose in the future.
A measuring instrument using ultrasonic technique can also be used to determine the tightness of the stator wedges. This portable equipment uses a vibrator, accelerometer, and force gauge to excite the wedge. It identifies the natural vibration resonance and assesses the tightness of the wedge assembly.

**Stator Winding Side Clearance Check**

This test is done to ensure a tight fit between conductor bars and the slot sides. A feeler gauge is inserted to determine the tightness.

**Core Lamination Tightness Check (Knife Test)**

This test involves inserting a standard winder’s knife blade (maximum thickness, 0.25 mm) between laminations at several locations in the core. If the blade penetrates more than 6 mm, then the core is soft. It should be retightened by packing.

**Visual Techniques**

If there is indication of insulation aging or a fault, the machine should be visually inspected. Flashlights and magnifying glasses are normally used. Small mirrors can be used for examining the inside edges of retaining rings. Boroscopes are used sometimes to gain access to stator core laminations or conductors. Magnetic strips are swept along the internal surfaces to pick up small magnetic fragments.

**Groundwall Insulation.** Early detection of deterioration of insulation can help in extending the life of the machine. Dusting or powdering of the insulation along the slot wedges or in the ventilation ducts may indicate damage to the insulation by mechanical abrasion. This powder should not be confused with the reddish powder that is caused by core problems, or copper dusting (which occurs due to fretting of the rotor winding when the machine is on turning gear). Another white or grey powder is caused by pd. This powder is only found in bars and coils near the line ends of the winding. This powder should be confused with the one caused by abrasion, which is found throughout the winding.

Other signs of mechanical distress are debris at the slot exit, stretch marks and cracks in surface paint in the slot area, or in the mechanical supports in the end winding area. Thermal aging is indicated normally by discoloration or undue darkening of the insulation surface. Electrical effects are normally indicated by carbonized tracking paths to grounded components. External pd, which normally occurs in line end coils, is confirmed by a grey or white powder. Chemical analysis of the dust will show a high percentage of salts.

**Rotor Winding.** Mirrors and boroscopes are used to perform rotor inspection without disassembly. In some cases, it may be necessary to disassemble the rotor partially by removing the retaining rings and some wedges.

**Turn Insulation.** The location of the turn faults in the rotor cannot usually be determined by visual means without some disassembly. Turn faults in the end windings become visible after removing the end caps. Those in the slot become visible by removing the wedges and lifting the turns. Faults caused by copper dusting can be verified by small copper particles in the slots and vent ducts.

**Slot Wedges and Bracing.** The movement of slot packing under wedges in gas-cooled rotors can be detected without disassembly. This problem can be identified by examining the gas exhaust holes in the wedges to see if packing has been moved to block the flow of cooling
gas out through them. The problem is also indicated by rotor thermal unbalance. The rotor should be disassembled if there is evidence of early signs of deterioration in slot wedges.

*Stator and Rotor Cores.* Severe overheating and melting would occur at the surfaces of laminated cores due to insulation faults. These can easily be detected by a visual examination. Faults that occur in the slot region are normally hidden by the winding and slot wedges. These are normally indicated by signs of burning in the vicinity of the insulation and wedges.