CHAPTER 4

OPERATION AND CONTROL

4.1 BASIC OPERATING PARAMETERS

All generators are designed such that they have a “rating.” The rating of the machine is a series of parameters that describe the generator in engineering terms. These parameters tell about the available power output of the generator and its capability with regard to electrical, thermal and mechanical limits. With enough experience the trained person can also often infer other information about such things as the generator size and basic construction features.

Like any industrial apparatus large alternators are specified, designed, and constructed to meet a number of requirements. These requirements are predicated on the customer needs, as well as in mandatory industry standards and “best industry practice” guidelines. The requirements are given in the form of performance parameters, and dimensional standards.

The performance parameters of a large generator are defined in a number of standards. In the United States the leading standards defining the generator performance variables are ANSI C50.30/IEEE Std. 67 and ANSI/IEEE C50.13; see [1,2]. In other countries, these standards may also apply, in addition to ICE, CIGRE and local codes, like VDE in Germany and others. In the following items a definition and, when required, an explanation of all performance parameters is included.

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4.1.1 Machine Rating

A generator is usually described by giving it a rating. This rating is given at the generator's capability point of maximum continuous power output. The terms generally used to provide the rating are as follows:

Apparent power	MVA	Mega volt amperes
Real power	MW	Mega watts
Reactive power	MVARs	Mega volt amps reactance
Power factor	pf	A dimensionless quantity
Stator terminal voltage	V_t	Alternating voltage
Stator current	I_a	Alternating current amperes
Field voltage	V_f	Direct voltage
Field current	I_f	Direct current amperes
Frequency	Hz	Hertz
Speed	rpm	Revolutions per minute
Overspeed capability	rpm	
Hydrogen pressure	psi	Pounds per square inch
Hydrogen temperature	°C	

Stator winding insulation class
Stator winding temperature rise
Rotor winding insulation class
Rotor winding temperature rise
Short circuit ratio

Each of these parameters signifies a finite design quantity that describes a certain capability or limitation of the generator. In some cases they also provide operating limits that, if exceeded, will cause excess stress in the generator (mechanical, thermal, or electrical) on one or more of its components.

All large generators are designed with these parameters in mind and they are all reflected in the design standards for generators [2]. There are specific ranges for the above-mentioned parameters, and these are outlined in the design standards and discussed in documents regarding good operating practice of large generators [1].

The ratings of large generators have increased dramatically over the years as designers have learned to incorporate newer and better materials in their designs and to optimize the use of the materials. The rate of increase of generator ratings over the years has been a logarithmic increase (Fig. 4.1).

Gas-turbine generators are presently being built with ratings up to approximately 400 MVA. Steam-turbine generators are presently being built with ratings up to approximately 1600 MVA, but there are designs up over 2000 MVA. An example of a nameplate that may be found on a large generator is shown in Figure 4.2.

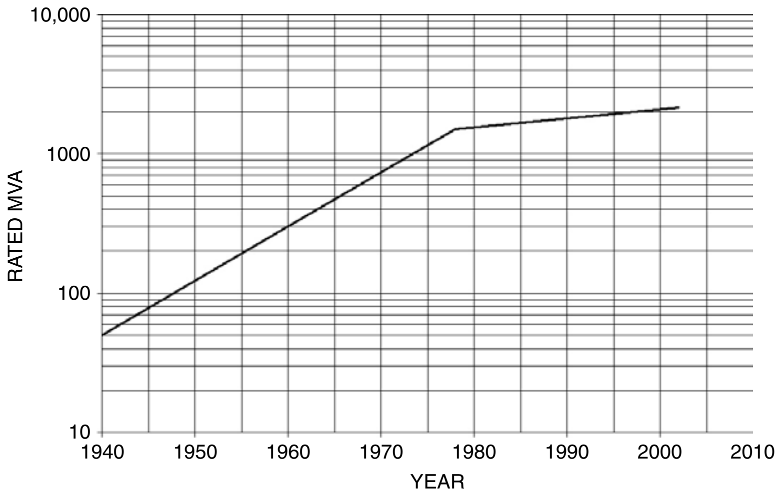


Fig. 4.1 Trend in MVA rating of large turbogenerators.

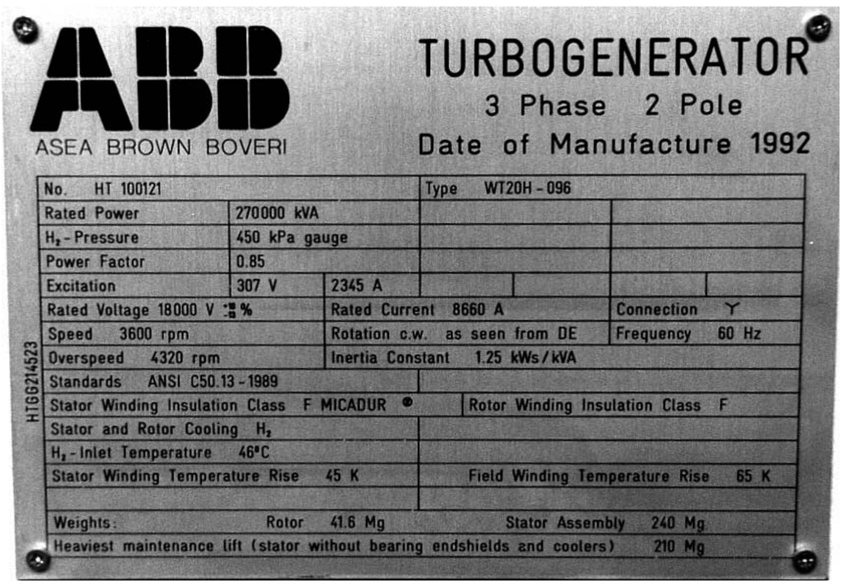


Fig. 4.2 Typical nameplate for a large turbogenerator.

4.1.2 Apparent Power

Apparent power refers to the rating of a turbine generator. In large generators it is almost always given in units of mega-volt-ampere (MVA), although it may be also be stated in kVA. Although machines are commonly talked about in terms of *real power* (almost always given in mega-watts [MW], though it may also be stated in kW), it is the *apparent power* that best describes the rating. This is so because the product of the voltage and the current (MVA) largely determines the physical size of a machine.

In a three-phase power system, the MVA is given by the following expression:

$$\text{MVA} = \sqrt{3}\ (\text{Generator's line current in kA}) \times (\text{Line voltage in kV})$$

Alternatively,

$$\text{MVA} = 3\ (\text{Generator's line current in kA}) \times (\text{Phase voltage in kV})$$

Also

$$\text{MVA} = \frac{\text{MW}}{\text{Power factor}}$$

Using the expressions above, one can find the maximum current that can be supplied by a generator at a given system voltage. This is important for sizing the conductors or busses that must carry the generator's energy into the system, as well as for setting protection relays. For a theoretical explanation about the origins of apparent power, see Section 1.3 in Chapter 1.

4.1.3 Power Factor

It was shown in Section 1.3 that the *power factor* is a measure of the angle between the current and the voltage in a particular branch or a circuit. In mathematical terms, the power factor is the cosine of that angle. Within the context of a generator connected to a system, the power factor describes the existing angle between the voltage at the terminals of the generator ($\mathbf{V_t}$), and the current flowing through those terminals ($\mathbf{I_1}$).

In the workings of generators, by definition, the angle between the current and the voltage is deemed *positive*, when the *current lags the voltage*, and vice versa, it is defined as negative, when the *current leads the voltage*. Therefore *power factor* is used to describe the generator as operating in the "lagging" or "leading" power factor range. A positive power factor indicates the unit is operating in the lagging region: it is generating VARs. A negative power factor, indicates the unit is operating in the leading region: it is absorbing VARs from the system. Additional names for describing if the unit is producing or consuming VARs, are "overexcited" or "inductive" for lagging power factor operation, and "underexcited" or "capacitive" for leading power factor operation. Unity power factor refers to a power factor of 1. It is common for generator operators to say the unit is "boosting" or "backing" VARs. Boosting in this context is synonymous with overexcited or inductive, and bucking means underexcited or capacitive.

These different terms for defining the same mode of operation can be confusing to the uninitiated. A simple way out is just to remember that if the generator is overexcited (i.e., if field current is increased), it will export more VARs into the system. On the other hand, if it is underexcited (i.e., if the field current is reduced), the generator will absorb VARs from the system in order to maintain the required airgap flux density.

Rated power factor is the operating point that maximizes both watts and VARs delivered, and it is a design variable. Increasing excitation from that point onward requires the unit to significantly reduce the active output (watts), in order to remain within the allowable operating region (more about that later). For most turbogenerators the rated power factor is in the range of 0.85 to 0.90 lagging (overexcited).

The power factor (actually reflecting the flow of reactive power) has a big influence on the power system in that it can change the system's voltage. The change in voltage in turn affects the ability of the system to carry the required levels of power, and consequently its stability. To illustrate this important concept, a very elementary example is offered. Figure 4.3 depicts a generator supplying a single radial circuit, with a load at the end of it.

Let us assume two cases: case 1 with a line impedance of $1 + j5$ ohms, and a load of 5 ohms; case 2 with the same line impedance, but the load now in addition to the 5 ohms resistance has a 5 ohms reactance (a reactance is denoted by preceding it's value with the letter j). Assume that the generator's voltage is maintained at 100 volts at both cases.

Case 1

The impedance of the line is $1 + j5\ \Omega$; the load is equal to $5\ \Omega$.

The magnitude of the current delivered by the generator is then

$$\mathbf{I} = \frac{100}{\sqrt{(6^2 + 5^2)}} = 12.8 \text{ amps}$$

The magnitude of the voltage at the load terminals is

$$\mathbf{V} = 12.8 \text{ A} \times 5\ \Omega = 64 \text{ volts}$$

And the power delivered to the load is

$$\mathbf{P} = 12.8^2 \text{ A} \times 5\ \Omega = 819 \text{ watts}$$

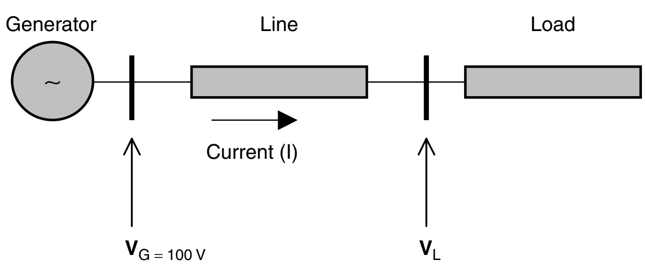


Fig. 4.3 Schematic representation of a generator feeding a load through a line.

Case 2

In this case the line impedance has not changed, but the load now has an additional inductive reactance of 5 ohms.

The magnitude of the current delivered by the generator is now

$$I = \frac{100}{\sqrt{(6^2 + 10^2)}} = 8.57 \text{ amps}$$

The magnitude of the voltage at the load terminals is

$$\mathbf{V} = 8.57 \text{ A} \times \sqrt{(5^2 + 5^2)}\ \Omega = 60.6 \text{ volts}$$

And the power delivered to the load is

$$\mathbf{P} = 8.57^2 \times 5\ \Omega = 367 \text{ watts}$$

As a result of the addition of a load reactance (the power factor of the load has been reduced from unity to PF = 0.71, the voltage at the load terminals dropped 5%, and the real power delivered to the load is reduced by more than 50%. This simple exercise illustrates the significant impact on a system of an addition of inductive reactance (i.e., in reducing the power factor). Increasing the excitation of the generator in the simple case of this example would increase the generator terminal voltage, driving the load voltage higher and somewhat compensating for the voltage drop introduced by the reduced power factor.

4.1.4 Real Power

The *rated power* (in MW) of the generator is the product of *rated apparent power* (in MVA) and *rated power factor*. The turbine determines the rated power of the turbogenerator, as a whole unit.

The rated power of the generator is often specified and designed to be somewhat higher than that of the turbine to take advantage of additional output that may become available, from the turbine, boiler, or reactor. This parameter is measured and monitored to keep track of the load point of the machine and allow the operator to control the operation of the generator.

The MW overload of the generator is a serious concern. MW overload means that the stator current's limit has probably been exceeded, and this will affect the condition of the stator winding. The stator terminal voltage may also have been exceeded during overload, depending on the main transformer tap settings, but it is more commonly associated with stator current's overload. Excessive terminal voltage will affect core heating.

Transient MW events from the system or internally in the machine will also show up as transients in the stator current and/or terminal voltage.

4.1.5 Terminal Voltage

The *rated or nominal voltage* of a three-phase generator is defined as the line-to-line terminal voltage at which the generator is designed to operate continuously. The rated voltage of large generators is normally in the range of 13,800 to 27,000 volts. Generators designed to IEEE standards and equivalent standards are able to operate at 5% above or below rated voltage at rated MVA, continuously.

When special requirements of a power system dictate the need for a wider terminal voltage range, then the manufacturer has to account for this in the generator design with a larger and more expensive machine. The cases where this type of variation is required depends on the location and requirements for interaction between the generator and the power system.

Monitoring of the generator terminal voltage is also critical and is done on a per phase basis. It is required to ensure that there is voltage balance at all times, to avoid negative sequence type heating effects, and it is most critical during synchronizing of the generator to the system. The terminal voltage of the generator must be matched in magnitude, phase, and frequency to that of the system voltage before closing the main generator breakers. This is to ensure smooth closure of the breakers and connection to the system, and to deter faulty synchronization.

4.1.6 Stator Current

Stator current capability in large generators depends largely on the type of machine in question. In the simplest machines (i.e., the indirectly air-cooled generator) the capability of the stator winding defines the rated stator current.

The capability of an indirectly hydrogen-cooled generator winding is significantly sensitive to the hydrogen pressure within the machine. Reduced capabilities are commonly stated for below rated pressures, down to 15 psig (103 kPa), and at slightly above atmospheric pressure. Modern generators may be found operating with hydrogen pressures up to 75 psig (518 kPa). A direct hydrogen-cooled stator winding is directly dependent on hydrogen pressure. Capabilities are commonly stated in increments of 15 psi (103 kPa) below rated hydrogen pressure.

The capability of a water-cooled stator winding is not normally sensitive to hydrogen pressure. However, hydrogen pressure does affect the cooling, and therefore the temperature, of many parts of the generator in which the losses are proportional to the stator current (leads, core, etc.). For this reason the generator capability is usually expressed in increments of 15 psi (103 kPa) below rated hydrogen pressure. In Figure 4.4 the dependency of the generator's rating on the pressure of the cooling hydrogen can be seen.

4.1.7 Field Voltage

Increasing the field voltage increases the field current in proportion to the rotor winding resistance. The field voltage is monitored but not usually used for alarms

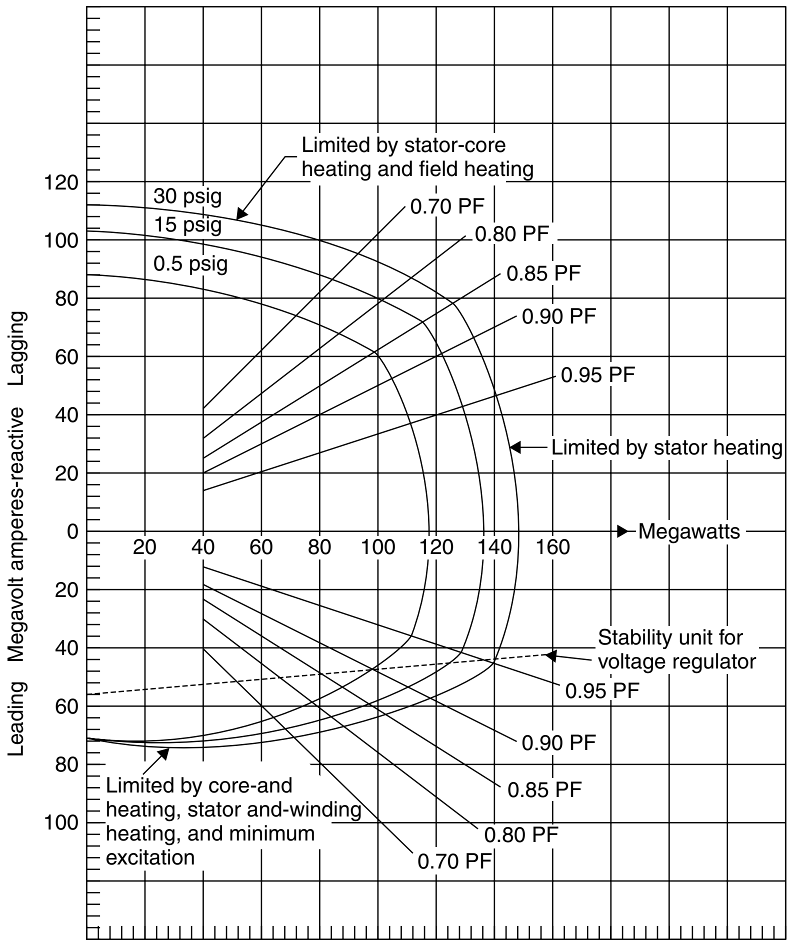


Fig. 4.4 Typical capability curves for a synchronous generator. (Copyright © 1987, Electric Power Research Institute. EPRI EL-5036, Power Plant Electrical Reference Series, Volumes 1–16, reprinted with permission)

or trips. It is used to calculate rotor winding resistance and subsequently the rotor winding average and hot spot temperature. Automatic voltage regulator problems can cause the field voltage to become too high, and this in turn causes the excitation to increase beyond design limits.

4.1.8 Field Current

The capability of the rotor winding is generally determined by the field current at the rated apparent power, the rated power factor, and the rated terminal voltage. All of the capability considerations described for indirectly and directly hydrogen-cooled stator windings apply to the rotor winding as well.

As was pointed out in Chapter 1, Section 1.7.3, and in Section 4.1.3 above, increasing the field current will

- Augment the MVARs exported to the system
- Increase armature (stator) current if the unit is already in the boost or overexcited region
- Tend to increase the differential of potential at the machine's terminals

4.1.9 Speed

Unlike an induction machine, the synchronous generator can only generate power at one speed, called the *synchronous speed* of that unit. That unique speed is related to the system's frequency and the number of poles of the machine, by the following equation:

$$\text{Synchronous speed (rpm)} = 120 \times \frac{\text{System frequency (Hz)}}{\text{Number of poles}}$$

Practically all large turbogenerators are of the two- or four-pole design. Therefore, almost without exception, the following apply:

60 Hz system	3600	rpm for two-pole generators
	1800	rpm for four-pole generators
50 Hz system	3000	rpm for two-pole generators
	1500	rpm for four-pole generators

4.1.10 Hydrogen Pressure

The *rated hydrogen pressure* is the required pressure of the hydrogen in the generator, when it is loaded to its nominal rating. It is commonly the maximum hydrogen pressure for which the generator is designed to operate. The range of rated hydrogen pressures for generators now being built is up to 75 psig (518 kPa). (The unit psig is pounds per square inch "gauge," relative to standard atmosphere.) For a discussion about the generator's capability dependence on the pressure of the hydrogen; see Section 4.1.6 above.

Regardless of the design hydrogen pressure for any given machine, the pressure is always maintained higher than the stator cooling water pressure, in water-cooled stator winding type machines. The reason for this is to allow hydrogen to leak into the stator cooling water, where it can be more easily dealt with by hydrogen detraining and removal systems that are almost always found with such machines. Therefore one of the sources of a drop in hydrogen pressure in the generator may be into the stator cooling water system, if a leak exists.

4.1.11 Hydrogen Temperature

Similar to pressure, the temperature of the hydrogen cooling gas is also maintained at a specific level for proper cooling of the internal generator components. The hydrogen gas picks up heat in the generator components as it flows over the various parts of the machine internals and transfers that heat to raw water circulating though hydrogen coolers in the generator. Therefore the gas entering the coolers is quite hotter than the gas leaving the coolers. These are generally referred to as hot and cold hydrogen gas temperatures.

Unlike the hydrogen pressure however, hydrogen temperature does not vary as widely and is governed by the generator design standards. Generally, the maximum allowable cold gas temperature is 46°C [2,8]. The hot gas temperature rise will vary depending on the generator cooling arrangement and the design of the hydrogen coolers. The cold gas operating set point is usually found between 30 to 40°C. A normal temperature difference between hot and cold hydrogen gas is around 15 to 25°C at the full load condition.

The hydrogen gas temperatures are usually maintained by an arrangement of four coolers, as being the most common. A balance between these is then maintained by adjusting the flow of raw water through the coolers, and locking the inlet valves in those positions. The balance is generally kept as close as possible and under 2°C on cold outlet gas temperature from the coolers. Further regulation in the generator on hydrogen temperature is then done on a bulk cooling water basis by an overall temperature control valve for flow or re-circulation, or both.

Temperature control of the hot and cold hydrogen gas is accomplished by installing thermocouples (TCs) or resistance temperature detectors (RTDs) in the gas path. These can then be monitored and set with alarm points to notify operators when limits are exceeded.

4.1.12 Short-Circuit Ratio

Short-circuit ratio (SCR) is defined as *the ratio of the field current required to produce rated terminal voltage on the open circuit condition, over the field current required to produce rated stator current on sustained three-phase short circuit, with the machine operating at rated speed*. During operation, to maintain constant voltage for a given change in load, the change in excitation varies inversely as the SCR. This means that a generator with a lower SCR requires a greater change in excitation, than a machine having a higher SCR, for the same load change.

The inherent stability of a generator in a power system is partly determined by its short-circuit ratio. It is a measure of the relative influence of the field winding versus the stator winding on the level of useful magnetic flux in the generator. The higher the short-circuit ratio, the less influence the changes in stator current have on the flux level and the more stable the machine tends to be. But the ratio will also be larger for the same apparent power rating and less efficient. However, machines with higher SCR are not necessary the ones showing higher stability in a particular setting. There are other important factors such as the speed of response of the voltage regulator and excitation systems, match between the turbine and generator time constants, control functions, and the combined inertia of turbine and generator.

The short-circuit ratio for turbine generators built in recent years has been in the approximate range of 0.4 to 0.6.

4.1.13 Volts per Hertz and Overfluxing Events

The term "volts per hertz" has been borrowed from the operation of transformers. In transformers the *fundamental voltage equation* is given by

$$V = 4.44 \bullet f \bullet \boldsymbol{B}_{\text{max}} \bullet \text{Area of core} \bullet \text{Number of turns}$$

where $\boldsymbol{B}_{\text{max}}$ is the vector magnitude of the flux density in the core of the transformer.

By rearranging the variables, the following expression is obtained:

$$\frac{V}{f[\text{V/Hz}]} = 4.44 \bullet \boldsymbol{B}_{\text{max}} \bullet \text{Area of core} \bullet \text{Number of turns}$$

Or alternatively,

$$\boldsymbol{B}_{\text{max}}[\text{tesla}] = \text{constant} \bullet \left(\frac{V}{f}\right)$$

Or, in another notation,

$$\boldsymbol{B}_{\text{max}} \propto \frac{\text{V}}{\text{Hz}}$$

The last equation indicates that the maximum flux density in the core of a transformer is proportional to the terminal voltage divided by the frequency of the supply voltage. This ratio is known as V/Hz.

A very similar set of equations can be written for the armature of an alternating-current machine. In this case the constant includes winding parameters such as winding *pitch* and *distribution factors*. However, the end result is the same: in the armature of an electrical alternate current machine, the maximum core flux density is proportional to the terminal voltage divided by the supply frequency (or V/Hz).

The importance of the short-circuit ratio resides in the fact that in machines, as well as in transformers, the operating point of the voltage is such that for the given rated frequency, the flux density is just below the knee of the saturation point.

Increasing the volts per turn in the machine (or transformer) raises the flux density above the knee of the saturation curve (see Fig. 4.5). Consequently large magnetization currents are produced, as well as large increases in the core loss due to the bigger hysteresis loop created (see Fig. 4.6). Both of these result in substantial increases in core and copper losses, and excessive temperature rises in both core and windings. If not controlled, this condition can lead to loss of

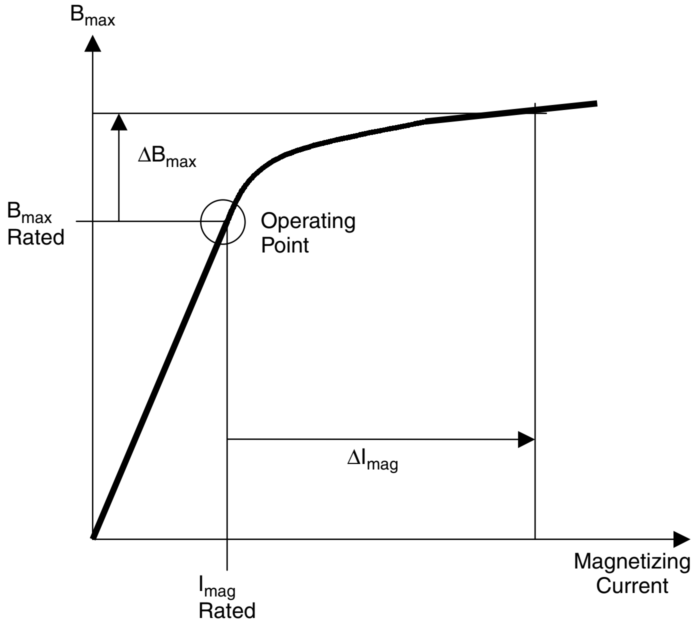


Fig. 4.5 Typical saturation curve for transformers and generators.

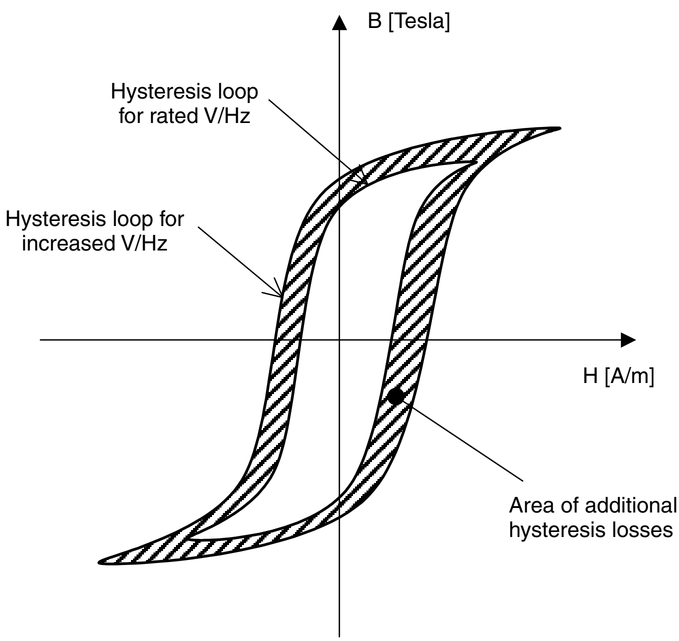


Fig. 4.6 Hysteresis losses under normal and abnormal conditions.

the core inter-laminar insulation, as well as loss of life of the winding insulation. In fact, if a unit becomes excessively overfluxed (i.e., the maximum V/Hz has been exceeded) for just a few seconds, complete failure of the core may result in short time, or after some time of operation.

The IEEE STD 67-1990 standard states that generators are normally designed to operate at rated outputs of up to 105% of rated voltage [1]. ANSI/IEEE C57 standards for transformers state the same percentage for rated loads and up to 110% of rated voltage at no load. In practice, the operator should make sure (by consulting vendor manuals and pertinent standards) that the machine remains below limits that may affect the integrity of both the generator and the unit transformer. For operation of synchronous machines at other than rated frequencies, refer to IEEE Std 67-1990 [1].

4.2 OPERATING MODES

4.2.1 Shutdown

Shutdown mode refers to the time when the generator is off line and not connected to the system. It also implies that the generator is at zero speed, with the main generator and field breakers open. Therefore there is no energy flowing to the generator or out from the generator.

4.2.2 Turning Gear

Turning gear is the mode of operation when the generator's rotor is turned at low speed. Tuning gear is generally used in two instances: (1) when the generator is to be put back on line and (2) when the generator comes off line from operation.

In the first instance the generator is usually started from rest with the turning gear, once high-pressure lifting oil has been put to the bearings, and then brought up to turning gear speed. The generator is then rolled off turning gear by firing the turbine, and brought up to rated speed. The main purpose is to reduce the required starting torque and allow the turbine a smooth start (for those units without a starter motor).

When coming off line, the generator is in the "hot" condition and requires a cooling down period, on a slow roll, prior to being allowed to sit in one position for any length of time. This is done to eliminate the possibility of a permanent bow being established in the rotor forging. The turning gear is used to accomplish this slow roll during the cool-down period.

Depending on the manufacturer, the turning gear speed may be anywhere from 3 to 50 rpm. The typical design consists of an induction motor (e.g., sized 10HP for a 155 MVA, 3600 rpm generator) linked by a gear-reduction system to the generator's shaft. Once the machine is accelerating by the force of the turbine, the gearbox de-links the motor from the generator. When performing a visual inspection of the inside of the machine, it is important to ascertain the turning

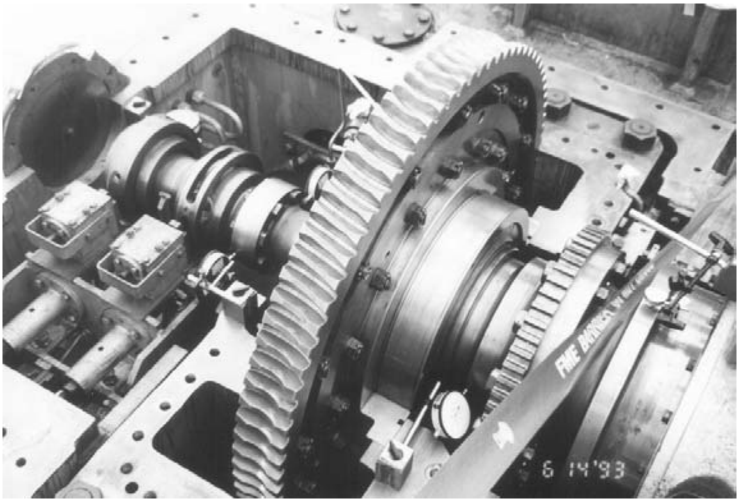


Fig. 4.7 1250 MVA, 4-pole, hydrogen-cooled generator. Shown is the shaft-mounted part of the generator's turning gear system. Not shown is the turning gear electric motor. The turning gear is being overhauled as part of the main outage undergoing by the unit.

gear mechanism will not be energized inadvertently (more about this in the section about inspections). See Figure 4.7 for a typical turning gear arrangement.

4.2.3 Run-up and Run-Down

Run-up refers to the period of speed increase from turning gear to rated speed by steam admission to the turbine, in the case of a steam-driven turbine, or by turbine firing, in the case of a combustion turbine. Alternatively, the unit may be accelerated by a "pony motor," or by a solid-state variable-speed drive, temporarily driving the generator as a motor. *Run-down* refers to the period of speed decrease when the generator is taken off line and allowed to coast down from rated speed to the speed at which it is placed on turning gear.

During both modes of operation the generator goes through its critical speeds. There are generally two critical speeds in large generator rotors. These are the natural resonance frequencies of the generator rotor mounted on its bearings. The rotor can become damaged if allowed to spin at these speeds for any length of time. Therefore, to avoid rotor damage, care is taken to run through these two frequency points fairly quickly.

4.2.4 Field Applied Off Line (Open Circuit)

The condition of the generator when the field is applied but the machine is not connected to the system is referred to as the *open-circuit* condition. At open circuit, if the generator is spinning at its rated speed, and the field's current magnitude equals the amperes field–no load (AFNL), the voltage at the generator's terminals will be the nominal voltage.

4.2.5 Synchronized and Loaded (On Line)

Once the generator is at rated speed and rated terminal voltage, the sinusoidal waveform of the generator output must be matched to the system waveform by frequency, voltage level, and phase shift. The frequency and voltage level are achieved in the open-circuit condition when the generator is brought to rated speed and the field current is raised to the AFNL value (see previous section). The phase shift (or vector shift) is accomplished automatically by a "synchronoscope," which adjusts the generator output voltage to be in phase with that of the system, or manually by the operator. Once the generator is synchronized to the system, the main generator breaker is closed and the generator is connected to the system. At this point, loading the turbine will increase the generator's MW output. Power factor and reactive power output are adjusted by changes to the rotor field current. More about synchronizing the generator to the system can be seen in Chapter 6. Table 4.1 contains a useful method to determine the generator operating mode, using indications of generator main (line) breaker status, field breaker status, rotor speed, and terminal voltage.

4.2.6 Start-up Operation

Following is a nonexhaustive list of activities that must be followed before attempting to starting a generator.

- Make sure all protection is enabled and operational. In some protective schemes a number of relays may have to have their trips curtailed during start-up. Make sure the OEM's operational instructions are followed to the letter.

TABLE 4.1 Generator Operating Modes

	Generator Breaker	Field Breaker	Rotor Speed (rpm)	Terminal Voltage
Shutdown	Open	Open	0	0
Turning gear	Open	Open	0 < rpm < 50	0
Run up/run down	Open	Open or closed/open	50 < rpm < RATED	0
Field applied open circuit	Open	Closed	Rated or lower	Rated or lower
Synchronized and loaded	Closed	Closed	Rated	Rated ±5%

Note: Turning gear speed is manufacturer dependent. Conditions in the table are typical for any industrial generator.

- Do not attempt to re-energize the machine without an investigation, after a protective relay has operated during a start-up.
- Follow OEM instructions regarding pre-warming.
- Follow OEM instructions regarding application of the field current and turbine speed.
- Establish clear procedures when energizing cross-compound machines.
- Watch maximum terminal voltage on open-breaker operation.
- Establish clear and safe synchronizing procedures and follow them carefully.

Pre-warming. Pre-warming of the turbine-generator unit is designed to maintain mechanical stresses within the turbine and the generator within acceptable levels. Sudden loading of a cold unit will stress certain components much more than the application of a gradual load. Pre-warming also has the effect of curtailing the thermal differentials within critical components of both turbine and generator. In some cases, were certain problems exist, it might be advisable to enhance the pre-warming operation. The operator should closely follow the OEM's instructions regarding pre-warming. For additional information, refer to the IEEE Std. 502 -1985, Section 9.5 on turbine rotor pre-warming [3].

4.2.7 On-line Operation

Following is a nonexhaustive list of activities that must be followed during the operation of a generator:

- The unit must remain within its capability curve at all times.
- Voltage regulators and power system stabilizers (when applicable) should be in operation at all times.
- All protection and monitoring devices must be in fully functional condition and always in operation.

Typical List of Generator Trips

Stator phase-to-phase fault
Stator ground fault
Generator motoring
Volts/Hz
Loss of excitation
Vibration (if unit not closely monitored by personnel)

Other protective functions/systems might also trip the unit, according to specific unit requirements and design.

Note: See Section 4.9 for an example of generator operating instructions provided by a generating company.

4.2.8 Shutdown Operation

Following is a nonexhaustive list of activities that must be followed during the shutdown of a generator.

- The turbine should be tripped *before* the generator.
- Make sure the generator does not *motor* the turbine.
- Attain electrical separation by following clearly established safe routines.
- Place the unit on turning gear as deemed necessary, to avoid bowing of the rotor shaft during cooling down periods.

4.3 MACHINE CURVES

4.3.1 Open-Circuit Saturation Characteristic

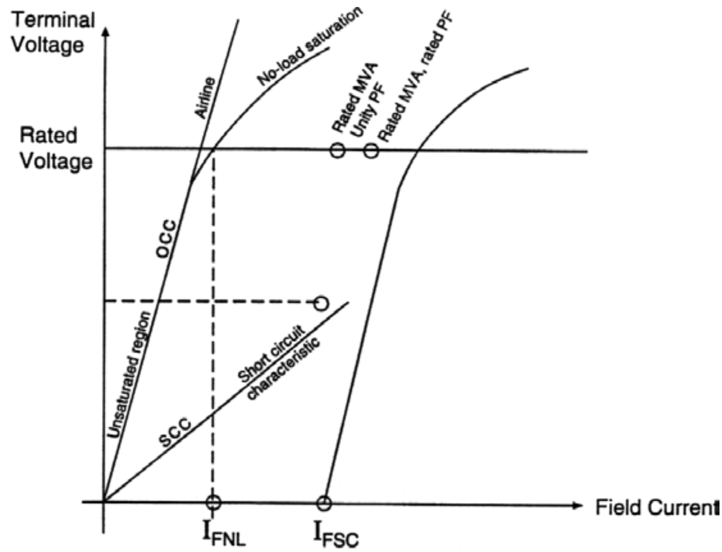
The *open-circuit saturation curve* for the generator provides the characteristic of the open-circuit stator terminal voltage as a function of field current, with the generator operating at rated speed.

At low voltage, and hence low levels of flux, the major reluctance (magnetic resistance) of the magnetic circuit is the airgap. In the linear portion of the open-circuit curve, terminal voltage and flux are proportional to the field current. This portion of the open-circuit saturation curve, which is linear, is called the "airgap line." At higher voltages, as the flux increases, the stator iron saturates, and additional field current is required to drive magnetic flux through the iron. This is due to the apparent higher reluctance of the magnetic circuit. Hence the upper part of the curve bends away from the airgap line in an exponential or logarithmic rate, dependent on the saturation effect in the stator. Without the presence of iron in the circuit, the airgap line would continue on linearly, meaning that the terminal voltage and machine flux would increase in linear proportion to the increase in field current. (Figure 4.8 shows the open-circuit saturation curve.)

4.3.2 Short-Circuit Saturation Characteristic

The *short-circuit saturation curve* is a plot of stator current (from zero up to rated stator current) as a function of field current, with the stator winding terminals short-circuited and the generator operating at rated speed. The short-circuit curve is usually plotted on the same graph along with the open-circuit curve. The short-circuit characteristic is for all practical purposes linear because in this short-circuit condition the flux levels in the generator are below the level of iron saturation.

The short-circuit curve is also called the "synchronous impedance curve" because it is the synchronous impedance of the generator that determines the level of the stator current for the machine. This can be readily seen by inspection of Figure 1.26, in Chapter 1). It can be seen in the figure that when $\mathbf{V_t} = 0$, the entire internal generated voltage ($\mathbf{E_m}$) is dissipated across the synchronous



IFNL = Field current required to produce open-circuit rated voltage

IFSC = Field current that produces rated armature current with short-circuited terminals

$$\text{Short-circuit ratio (SCR)} = \frac{I_{FNL}}{I_{FSC}}$$

In turbogenerators (most) SCR $\approx$ 0.5 - 0.6

Fig. 4.8 Open-circuit characteristics (OCC). Also shown short-circuit curves (SCC) and other points of interest as well as a graphic definition of the short-circuit ratio (SCR). The SCC relates almost exclusively to the "armature reaction" of the machine.

impedance ($\mathbf{Z_s}$). The synchronous impedance is highly dependent on the *armature reaction* of the machine ($\mathbf{X_a}$).

Both open- and short-circuit characteristics are shown in Figure 4.8. The figure also presents a number of typical acronyms that are commonly encountered when discussing machine characteristics.

4.3.3 Capability Curves

Capability curves are a plot of apparent power capability (MVA), at rated voltage, using active power (MW) and reactive power (MVAR) as the two principle axis. Circumferences drawn with their centers at the origin represent curves of constant stator current. A capability curve (see Fig. 4.4) separates the region of allowed operation, inside the curve, from the region of forbidden operation, outside the curve.

On an x-y graph where the x axis represents MW and the y axis represents MVAR, a circumference represents a constant MVA. If, as in the case of a machines capability curve, the voltage is kept constant (at rated value), then a circumference also represents a constant-current trajectory. On the same graph, any line starting at the intersection of the axis represents a particular power factor. Figure 4.9 illustrates the aforementioned. Different parts of the capability curve are limited by different machine components. There is a part limited by field winding capability, a part limited by stator winding capability (the circular part), and a part limited by core-end heating, as shown in Figure 4.4.

As the power factor is varied from fully overexcited, through unity to fully underexcited, first the field current, then the stator current, and then the stator core-ends are limiting. Accordingly curves that define a turbine-generator's capability have three segments that pictorially describe the effect of the capability of the three machine components.

Furthermore the capability curve represents the fact that the maximum temperature of the machine components during operation depends on the pressure of the hydrogen in hydrogen-cooled generators. This is shown as a set of curves, each for a given hydrogen pressure, up to the rated pressure. Similar set of

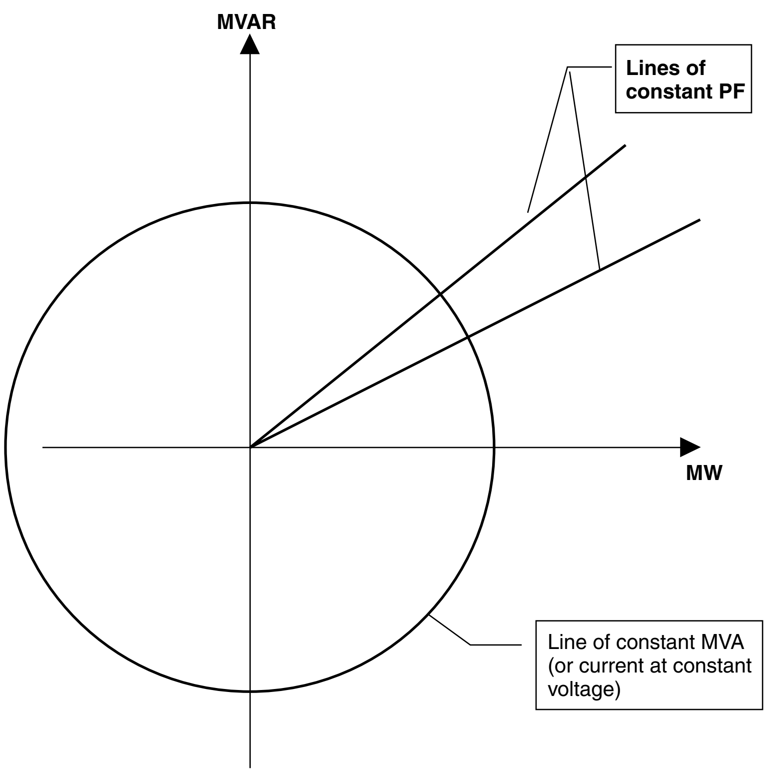


Fig. 4.9 Constant MVA, current, and power factor plotted on a MW-MVAR graph.

curves can be drawn for various water-inlet temperatures in directly or indirectly water-cooled machines. This topic is discussed in Section 4.1.6.

Construction of Approximate Reactive Capability Curve. As stressed often in this book, operators should always remain within the capability curves of the machine. Given the importance of this, it is rare where the capabilities of a generator are not available. However, for those rare occasions, one can construct an approximated capability curve for the lagging region by following the guide provided in ANSI/IEEE C50.30 -1972 or later, IEEE Std 67. For convenience sake, the method is shown in Figure 4.10.

Limits Imposed by the Turbine and the System. The turbine and the generator are designed to operate as a unit. As it was stated earlier in this book, the generator rating is almost always designed to be somewhat larger than the

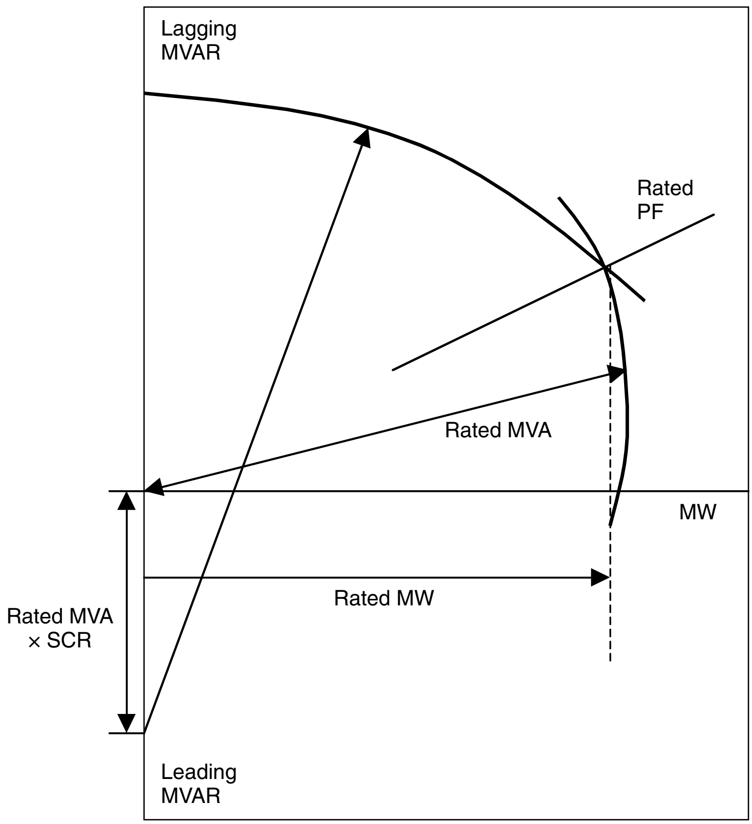


Fig. 4.10 Construction of approximate reactive capability curve, per ANSI/IEEE C50.30. The top curve is drawn after the intersection of the rated MVA circumference and the rated PF line. The leading (bottom) part of the curve is too dependent on the specific machine design to be drawn by any general algorithm.

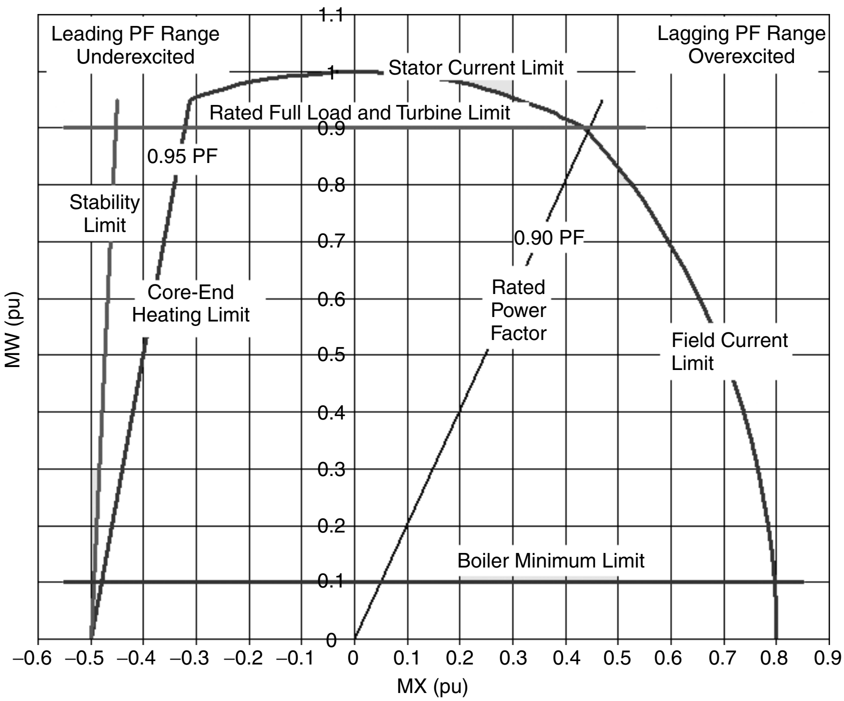


Fig. 4.11 Capability characteristics of a generator showing turbine and power system stability constraints. The curve is shown with the MW on the vertical axis. This is common in Canada, the United Kingdom, Australia, and a few other countries.

turbine. This fact is shown on the operators' screen as a line inside the maximum MW output of the unit at unity PF (see Fig. 4.11). In addition system stability issues may limit the number of MVAR the unit can import when operating in the leading PF region. This fact is shown as a line crossing the leading portion of the capability curve (see Fig. 4.11). Therefore, the "working" capability curve of the entire unit, represents a combination of generator, turbine and system constrains.

Pay attention to the fact the orientation of Figure 4.11 is different than that of Figure 4.4. In the United States and many other countries, it is common to show the MW axis on the horizontal. However, in Canada, the United Kingdom, Australia, and some other countries, it is common to present the capability curves with the MW on the vertical axis and the lagging MVAR on the right side of the horizontal axis. Figure 4.11 also presents all parameters in per unit (pu) of rated values.

Capability Curves Adjustments for Non-rated Terminal Voltage. As discussed in Section 4.15, most generators allow a $\pm$ 5% voltage deviation from nominal volts. Capability curves' behavior must be understood when attempting

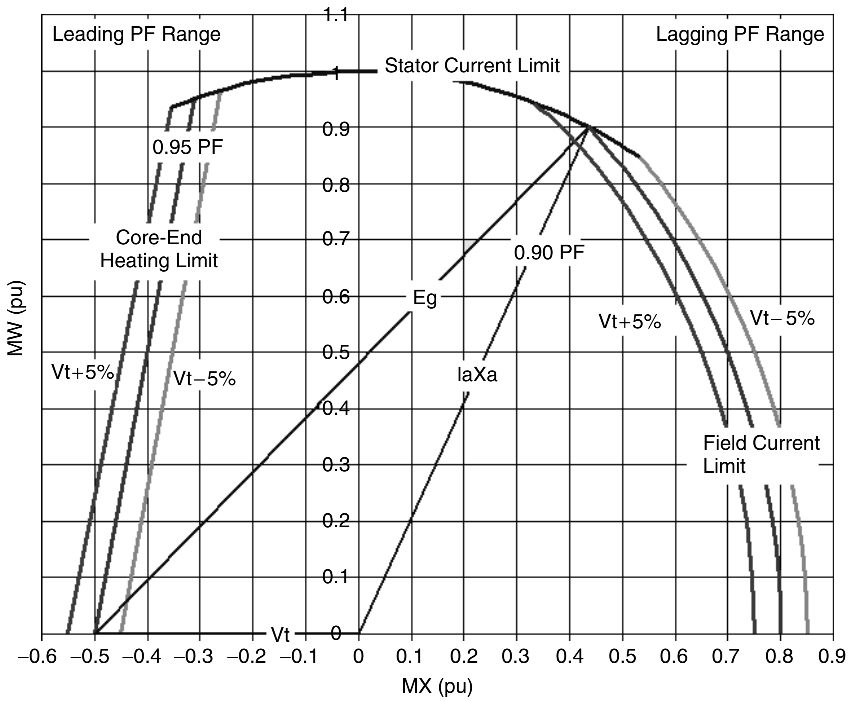


Fig. 4.12 Capability characteristics of a generator showing adjustments for operation over- and under-rated terminal volts (± 5% of rated).

to operate at maximum ratings under other than rated voltage. For instance, if operating at *minus*-5% voltage, the armature current should not be increased beyond its rated value. But the leading section of the capability curve shrinks by about the same 5%. The lagging (field-dominated) section expands by a similar amount. The opposite is true when operating at *plus*-5% voltage. See Figure 4.12.

4.3.4 V-Curves

V-Curves provide the apparent power (MVA) as a function of field current, plotted for various constant power factors, holding speed and stator voltage at the rated values. Horizontal lines represent constant stator current. The rating of the generator is the intersection of the line for rated apparent power (1.0 per unit) and the curve for rated power factor (usually 0.85 or 0.9 lagging). All constant-power-factor curves converge at a common point at zero apparent power. This is at the field current for rated voltage, open circuit.

Vertical and horizontal lines can also be shown for the field and stator winding capabilities at varying hydrogen pressures. The reduction in capability caused by stator core-end heating at low levels of excitation, below 0.95 power factor leading, can also be included, as it can be done for turbine and system-imposed limits. See Figure 4.13 for a typical V-curve.

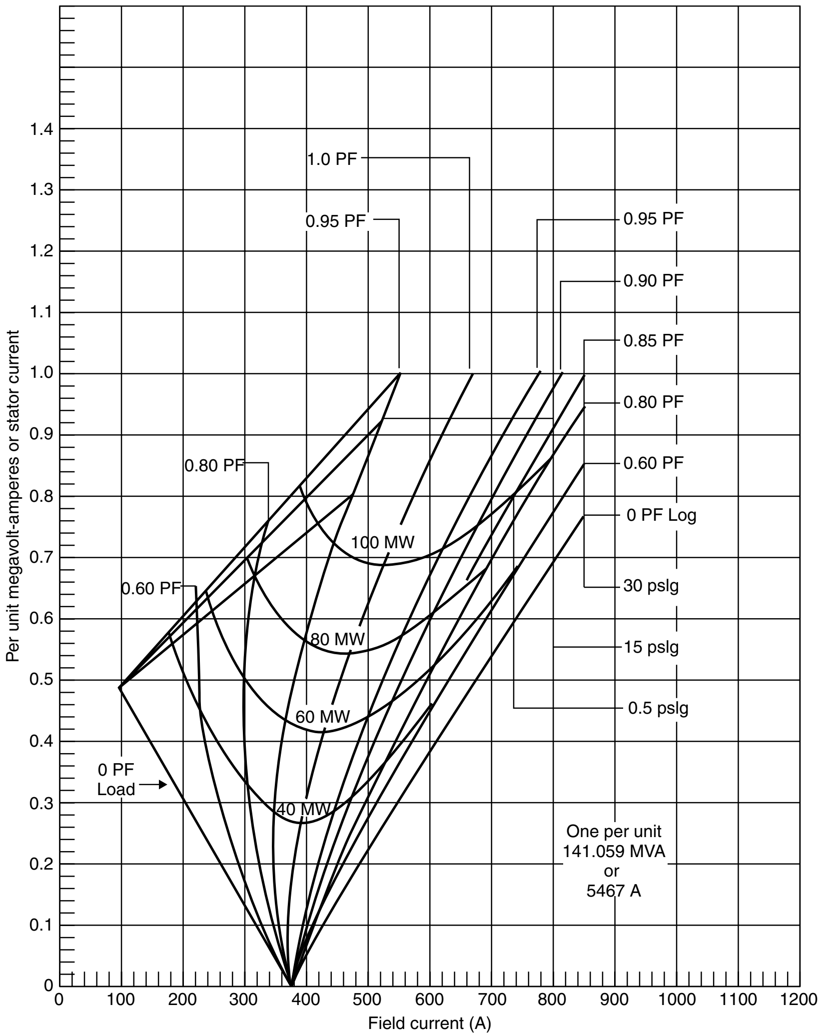


Fig. 4.13 Typical V-curves for generator operation. (Copyright © 1987. Electric Power Research Institute)

4.4 SPECIAL OPERATING CONDITIONS

4.4.1 Unexcited Operation ("Loss-of-Field" Condition)

Operation without field current is potentially dangerous and can occur under a number of circumstances. The following are the most common two:

1. *Loss of field during operation.* If for some reason the field current goes to zero while the generator is connected to the system, the machine starts acting as an induction generator. The rotor operates at a speed slightly

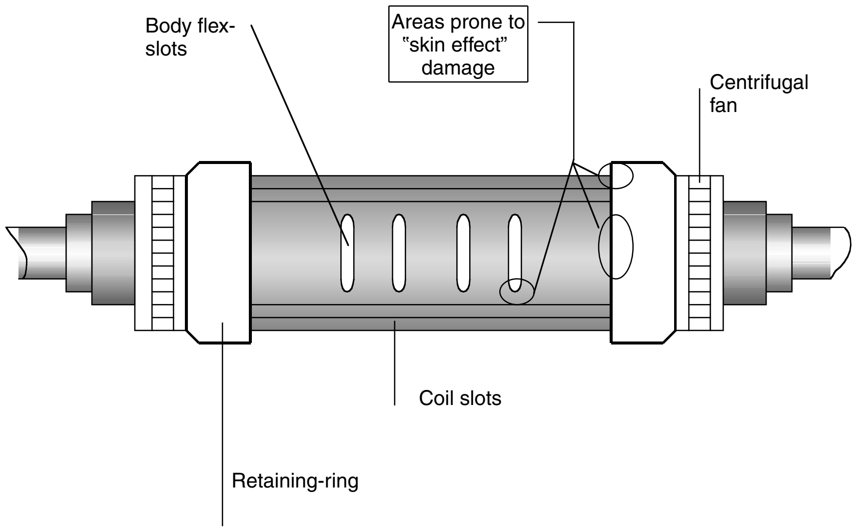


Fig. 4.14 Schematic representation of a turbogenerator's rotor and the areas most prone to be damaged by the "skin-currents" generated during inadvertent energization event.

higher than synchronous speed and slip-frequency currents are developed. These penetrate deep into the rotor body because they are of low frequency (this does not represent the skin effect discussed in case 2, below). Severe arcing between rotor components and heavy heating may result. The ends of the stator core also experience heating due to stray fluxes in the end region, more severely than for operation at underexcited power factor. Protection is commonly provided to prevent or minimize the duration of this mode of operation, by the so-called loss-of-field relay.

2. *Inadvertent energization*. If a generator is at rest and the main generator three-phase circuit breaker is accidentally closed connecting it to the power system, the magnetic flux rotating in the airgap (gasgap) of the machine at synchronous speed will induce large currents in the rotor. The rotor then will tend to start rotating as an induction motor. The very high currents induced in the rotor will tend to flow in its surface, in the forging, wedges and retaining rings. As the rotor accelerates the currents will penetrate deeper and deeper. The maximum of damage occurs while the speed is low and the large currents concentrate in a thin cross section around the surface of the rotor (due to the skin effect). The temperatures generated by the large currents, flowing in a relatively small cross section of the rotor, create very large temperature differentials and large mechanical stresses within the rotor. Areas most prone to damage are at the ends of the *circumferential flex slots*. Other areas are the wedges and in the body-mounted retaining rings, the area where the rings touch the forging and the end wedges (see Figs. 4.14 and 4.15)

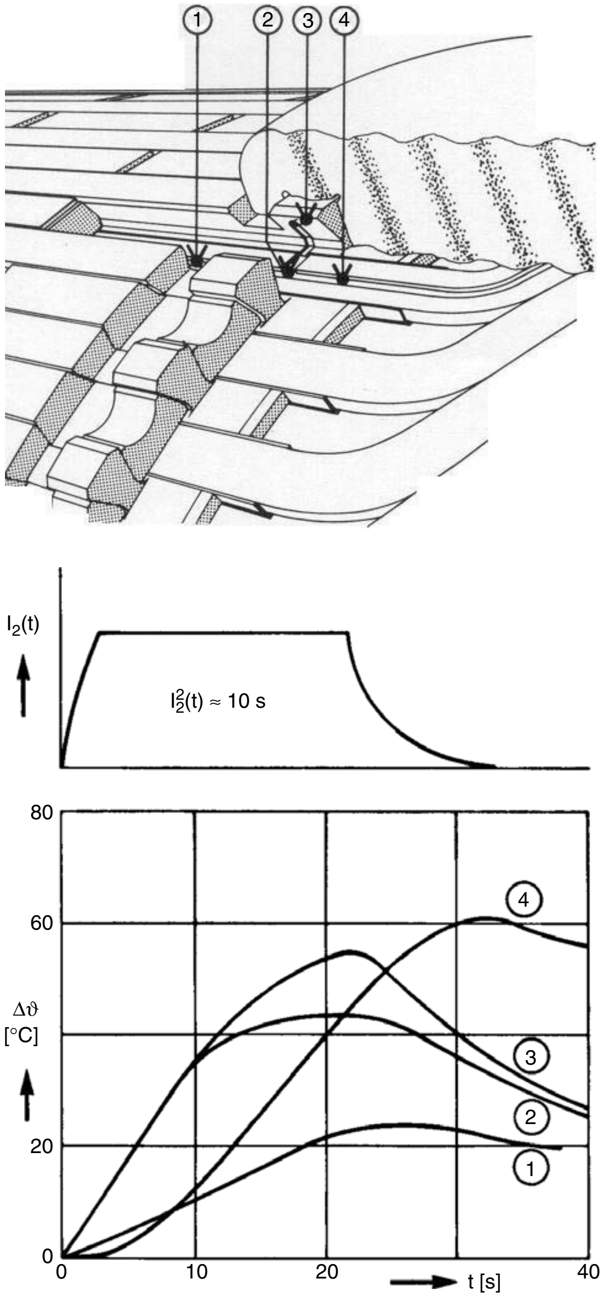


Fig. 4.15 Temperature rise measured at the end of the rotor body during short-term unbalanced load operation. (I_2 given in per unit) (Reproduced with permission from "Design and Performance of Large Steam Turbine Generators," 1974, ABB)

The initial stator current supplied from the power system will also be very high, but the most vulnerable part of the generator is the rotor. As the rotor speed rises, stresses increase at the same time that the temperatures of the stressed regions also increase due to circulating rotor body currents. Generators have been destroyed from this event, as extreme temperatures reduce the component material strengths. The internal rotor components are so weakened that they cannot handle the applied loads any longer. The result can be that the rotor wedges or retaining rings fail. Therefore protection is needed for the generator, even when it is out of service, to prevent or at least limit motoring from rest. Overheated ends of the circumferential flex slots can over time develop cracks in the forging, compromising its integrity.

Heating of the ends of the stator core is strongly affected by stray magnetic flux in the end region. This field is complex and is affected by the magnitudes and angular positions of the current in the stator and rotor windings.

4.4.2 Negative Sequence Currents

A three-phase balanced supply voltage applied to a symmetrical three-phase winding generates a constant-magnitude flux in the airgap of the machine, which rotates at synchronous speed around the circumference of the machine (see Fig. 1.23). In addition the slots and other asymmetries within the magnetic path of the flux create low-magnitude space harmonics (i.e., fluxes that rotate in both directions) of multiple frequencies of the fundamental supply frequency. In a synchronous machine under normal operation, the rotor rotates in the same direction and speed as the main (fundamental) flux.

When the supply voltage or currents are unbalanced, an additional flux of fundamental frequency appears in the airgap of the machine. However, this flux rotates in the opposite direction from the rotor. This flux induces in the rotor windings and body voltages and currents with twice the fundamental frequency. These are called *negative-sequence* currents (I_2). The negative sequence terminology derives from the vector analysis method of symmetrical components. This method allows an unbalanced three-phase system to be represented by *positive, negative*, and *zero sequences*. The larger the unbalance, the higher is the negative-sequence component.

There are several abnormal operating conditions that give rise to large currents flowing in the forging of the rotor, rotor wedges, teeth, end-rings, and field-windings of synchronous machines. These conditions include unbalanced armature current (producing negative-sequence currents), inadvertent energization of a machine at rest, and asynchronous motoring or generation (operation with loss of field), producing alternate stray rotor currents. As it was shown in the previous section, the resultant stray rotor currents tend to flow on the surface of the rotor, generating $(I_2)^2\ R$ losses with rapid overheating of critical rotor components. If not properly controlled, serious damage to the rotor will ensue. Of particular concern is damage to the end-rings and wedges of round rotors (see Figs. 4.14 and 4.15).

TABLE 4.2 Values of Permissible I_2 Current in a Generator

Type of Generator	Permissible I_2 as % of Rated Stator Current
Salient-pole	
With connected amortisseur winding	10
Without connected amortisseur winding	5
Cylindrical-rotor	
Indirectly cooled	10
Directly cooled up to 950 MVA	8
951–1200 MVA	6
1200–1500 MVA	5

All large synchronous machines have (should have) installed protective relays that remove the machine from operation under excessive negative sequence currents. To properly "set" the protective relays, the operator should obtain maximum allowable negative sequence I_2 values from the machine's manufacturer. The values shown in Table 4.2 are contained in ANSI/IEEE C50.13 -1989 [2] as values for continuous I_2 current to be withstood by a generator without injury, while exceeding neither rated MVA nor 105% of rated voltage.

When unbalanced fault currents occur in the vicinity of a generator, the I_2 values of Table 4.2 will probably be exceeded. In order to set the protection relays to remove the machine from the network before damage is incurred, but avoiding unnecessary relay operation, manufacturers have developed the so-called $(I_2)^2t$ values. These values represent the maximum time in seconds a machine can be subjected to a negative-sequence current. In the $(I_2)^2t$ expression, the current is given as per unit of rated stator current. These values should be obtained from the manufacturer. Table 4.3 shows typical values given in the standard [2].

Figure 4.16 depicts in graphic form the last two rows of Table 4.3, representing the negative sequence capability of generators with direct cooled stator windings.

4.4.3 Off-Frequency Currents

There are sources, in the generator and the power system, of currents at frequencies other than that of the power system. For example, current components at higher frequencies would be produced by transformer saturation and by incompletely filtered harmonic currents from rectifiers or inverters. Current

TABLE 4.3 Values of Permissible $(I_2)^2t$ in a Generator

Type of Machine	Permissible $(I_2)^2t$
Salient-pole generator	40
Salient-pole condenser	30
Cylindrical-rotor generator (the subjects of this book)	
Indirectly cooled	30
Directly cooled, 0–800 MVA	10
Directly cooled, 801–1600 MVA	10–(5/800)(MVA-800)

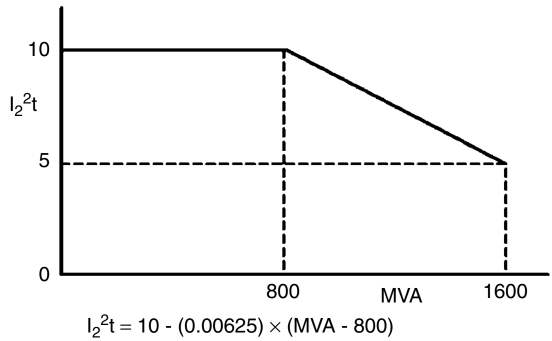


Fig. 4.16 Graphic representation of the negative-sequence capability of generators with directly cooled stator windings, according to ANSI/IEEE C50.13-1989.

components at frequencies lower than that of the power system have been produced by resonance between power-factor compensating series capacitors (used to increase the power handling capability of long ac transmission lines) and the inductance of generators and transformers. This is commonly known as subsynchronous resonance.

Off-frequency currents interact with the useful flux in the generator to produce pulsating torques felt by the combined turbine-generator shaft system. If the frequency of one component of the pulsating torque is identical to the torsional natural frequency of any mode of vibration of the complex shaft system, destructive vibration could result. The degree of damage depends on the mode shape and the level of the current damping present.

At the present state of the art, it is not possible to calculate the higher natural frequencies accurately. Hence designing to avoid higher stimulating frequencies may not be feasible. However, since the resonance peaks tend to be sharp (due to low damping), the likelihood of matching stimulus and response frequencies is low, but the consequences of a match may be severe.

The frequency of the torque due to subsynchronous resonance is variable, depending on the level of series capacitance compensation being used at the time. It is necessary to avoid those frequencies that would stimulate a rotor torsional natural frequency, or to block the current when at a potentially damaging frequency from reaching the generator. Subsynchronous resonance in a power system was first studied following the destruction in California of two new shafts belonging to generators rated several hundreds of megawatts. In that state there are long transmission lines compensated with series capacitors. The use of power system stabilizers, together with the voltage regulator, can suppress these types of harmonics.

4.4.4 Load Cycling and Repetitive Starts

It is well known in the power industry that load-cycling represents a long-term onerous mode of operation. Turbines and generators “like” to be in a steady-state condition, meaning where the temperatures in the machine are stable. Any situation in which load is changed significantly will result in relatively large changes in temperatures. It is the transition time between the steady states that embraces an amalgam of problems. For instance, when load is increased suddenly, the conductors will rise in temperature first, followed by the core and other components. As the temperature differentials increase momentarily, so do the mechanical stresses induced.

Another consequence of a change in temperature is related to the fact that the copper conductors expend and contract more than the iron core and frame. Sometimes this results in a “ratcheting” effect, by which the conductor or, more often its supporting system, is partially “stuck” and does not fully return to its original position. This problem shows up quite frequently in rotors, with resulting deformation of the field winding. Figure 4.17 clearly shows the results of such a ratcheting effect in a 90 MVA, hydrogen-cooled, 3600 rpm unit.

Figure 4.17 by no means depicts the only problem resulting from excessive load cycling. Other problems are loosening of stator wedges, looseness of the stator core, weakening of the stator end-winding support system, cracking of conductors, weakening of frame support systems, leakage of hydrogen through gasket degradation, accelerated deterioration of rotor and stator insulation, and so forth.

By far, the most onerous load-cycling is the complete start-and-stop operation. Numerous units nowadays start and stop every day. This type of operation stresses all those elements enumerated above to the extreme. Retaining-rings, in particular, spindle-mounted rings, are significantly stressed during start–stop operation due to the flexing they undergo when going from rest to full speed, and vice versa. Recognition of this accelerated deterioration of machines operated with many starts and/or load cycling demands that the inspection intervals be significantly shorter than for units operated under base-load conditions.

4.4.5 Overloading

In Section 4.3.3 it was stressed the need to remain within the capability curves of the machine at all times. Nonetheless, if a severe overload situation is reached, the

Fig. 4.17 Rotor field end-winding of a 90 MVA, 3600 rpm, hydrogen-cooled generator. The top turn of one coil has shifted during operation all the way across the gap separating it from the neighboring coil, resulting in a severe shorted-turns condition. This is the result of ratcheting during cycling and insufficient blocking.

need to schedule an inspection of the windings of the machine as soon as possible ought to be considered. Bear in mind the heating developed in a conductor is proportional to the square of the current. Thus a 10% overload condition will increase the heat generated in that conductor by about 20%. The temperature will change also in a similar fashion. However, the expected life of insulation is approximately halved for every 8 to 10°C increase in temperature (the Arrhenius law, after the Svante August Arrhenius, 1859–1927). Thus long-term operation at moderate overloads or short-time severe overloads, both can markedly reduce the expected life of a machine's insulation systems.

4.4.6 Extended Turning-Gear Operation

In Section 4.2.2 the benefit of turning gear operation was stated. However, turning-gear operation has inherent disadvantages. In particular, long periods of turning on gear may induce production of copper dusting in the rotor field conductors. The rotor field coils are rather heavy, and when radial clearances are present in the slot, slow rotation of the rotor results in the coils "falling" and "rising" in the slots (Fig. 4.18). This movement and the banging between turns (specifically in those designs with double copper conductors) will eventually lead to the presence of copper dusting. Copper dust has the potential to create shorted turns in the rotor field (Fig. 4.19).

How fast the rotor rotates, its dimensions, and the type of conductor, all are factors in determining if, and how much, copper dusting will result from extended

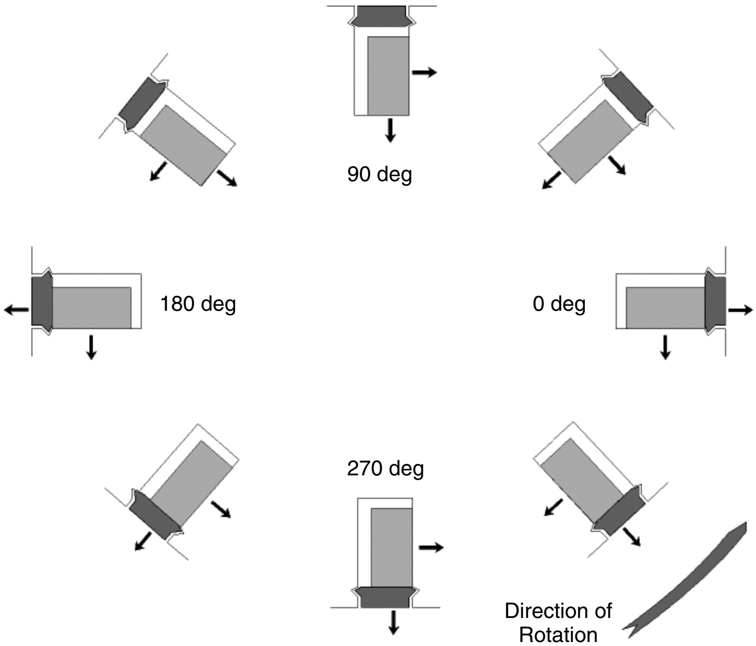


Fig. 4.18 Schematic representation of the movement of the coil in the slot a rotor when rotated at low speed (turning-gear operation). The continuous pounding of the heavy copper bar against the slot-sides generates over time copper dusting, in those coils where copper bars are in touch with each other.

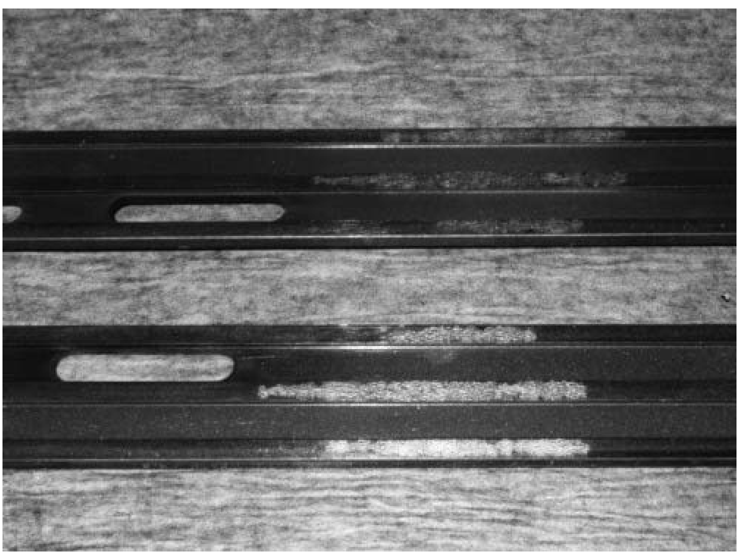


Fig. 4.19 Severe erosion on two halves of a conductor, due to continuous pounding and the generation of copper dust.

turning gear operations. It is therefore important the operator learns how his/her machine will be affected from this mode of operation.

4.4.7 Loss of Cooling

On occasion, a unit is inadvertently run without cooling medium (mainly water), for some period of time. It has happened more than once that someone walking on a turbine deck, and seeing external paint blistering and flaking away from a generator's casing, discovers that the unit was running without its water-cooling system in operation. This problem may result in serious overheating of the windings with, and perhaps irreversible, damage. After such an event the unit ought to be removed from service and opened for careful inspection of the windings.

What type of damage may occur under loss of cooling operation is largely predicated on the kind of insulation system. For example, thermoplastic systems (asphaltic) will deform under severe heating. Oozing of the asphalt may occur. These conditions can be very onerous. On the other hand, thermoelastic systems will be more resilient. Though a loss of expected life of the insulation might have occurred, the overall situation of the winding may be satisfactory for long-term operation.

There are a number of mechanical problems that may also result from high temperatures attained during a loss-of-cooling operation, such as severe misalignments and damage to the end-winding support systems.

4.4.8 Overfluxing

Overfluxing occurs when a generator is operated beyond its maximum continuously allowed V/Hz. In Section 4.1.13 above, an elaborate description of overfluxing has been included. There it was also indicated that overfluxing could destroy a large core in seconds.

Most common instances of severe overfluxing occur while the machine is being reved up prior to synchronization with the system. Under those conditions any misoperation of the excitation system, voltage regulator, or the voltage and current sensing systems may cause the excitation to go to "ceiling" and the terminal voltage go much higher than nominal. With the speed (thus frequency) rated or lower, the V/Hz so attained may cause the machine to be well beyond its heating withstand capability. Core melting is one of the probable results.

Once the machine is connected to the system, the probability of sudden damage due to overfluxing is very low. In any event, it is truly important that V/Hz protection is properly designed and set. Moreover it is important to design the voltage-sensing scheme for the excitation in such a way that loss of a single potential transformer winding will not result in a V/Hz situation. The ANSI/IEEE C37.106 has a good discussion of the subject and presents examples of how to design and set the protection schemes [4].

Figure 4.20 reproduces the V/Hz withstand curves of a number of manufacturers for purpose of illustration only. For your specific machine, consult the OEM when setting the protection.

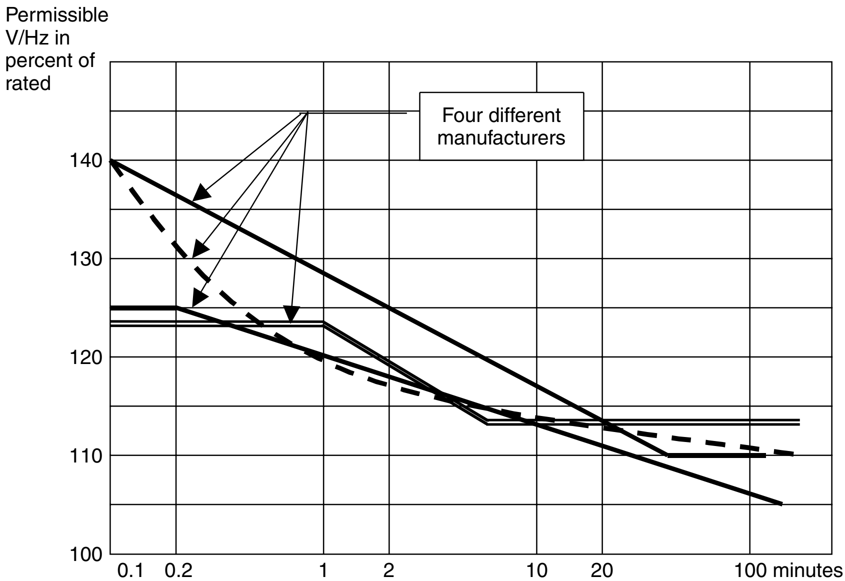


Fig. 4.20 *Permissible V/Hz curves* (or *withstand V/Hz characteristics*) of four manufacturers. The permissible area is *below* the curves.

4.4.9 Overspeed

A typical industry rule is that rotors of turbogenerators are designed to withstand a 120% spin test. Any significant overspeed can damage the rotor components to the extent that a new rotor or major parts (e.g., retaining-rings) is required. The protection against overspeed must be well designed and set, because a severe overspeed condition can be unforgiving. See Figure 4.21 for the unpalatable results of such an event.

4.4.10 Loss of Lubrication Oil

The result of a loss of lubrication oil during operation can be catastrophic. Such events are not unheard off, but only few result in severe loss of equipment. For this reason, lube-oil systems offer redundancy. In general, the backup is provided by a dc-motor operating a backup pump. Oftentimes shaft-mounted pumps provide critical lubrication for as long as the turbine rotates.

Failure of this system can be very costly in material and lost production. Whatever the system, it is very important that it is not forgotten when carrying out periodic inspections and operational testing of the unit's support systems.

4.4.11 Out-of-Step Synchronization and "Near" Short Circuits

Both out-of-step synchronization and short circuits occurring in or in the vicinity of the generator (in particular, between the generator's terminals and the main

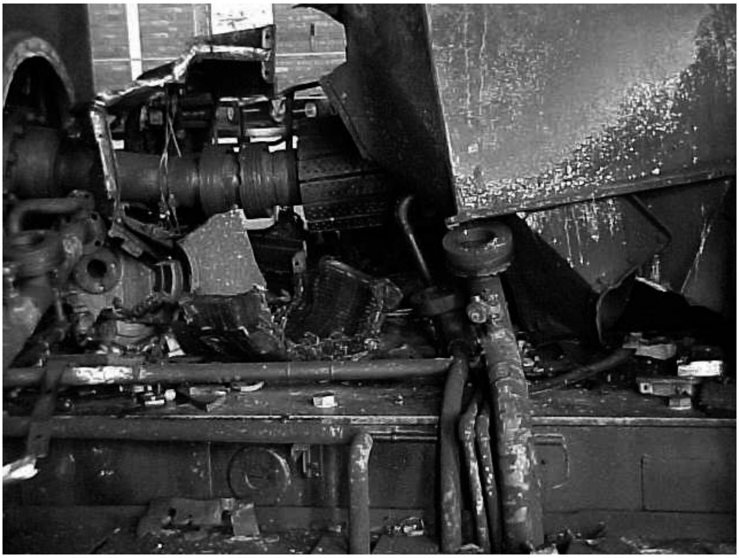


Fig. 4.21 Catastrophic failure of a turbine-generator unit due to overspeed (loss of governor control). This is a view into the generator (whatever is left of it).

step-up transformer) can result in severe damage to the unit: sheared coupling and frame supporting bolts; damaged stator coils, end-windings and end-winding supports; rotor end-winding deformation; shaft cracked or shared; bushings damage, and so forth.

The severity of the damage depends, for example, on generator rating, angle between system and generator voltage vectors at the moment of synchronization, and type of short circuit (phase-to-phase or three-phase). The presence of isolated phase busses (IPBs), makes a three-phase bolted short circuit on the terminals of any large generator an event with negligible probability of occurrence. Nonetheless, faults within the machine itself and on the main step-up transformer, or very close to the high-voltage side of it, can seriously damage the unit (both generator and turbine). Therefore, before a new attempt is made to synchronize the unit after a major out-of-step mishap, or in the aftermath of a strong and near short circuit, the unit should be opened at both ends for visual inspection. Alternatively, when easy access can be achieved for visual inspection such as removing coolers, opening of the end-shields might be avoided.

Out-of-step synchronization protection is provided by a couple of protective devices. See Chapter 6 on generator protection. For additional discussion on sudden short circuits, see Section 4.5.7 below.

4.4.12 Ingression of Cooling Water and Lubricating Oil

On occasion a water leak develops during operation. Also a large quantity of oil might be found to have leaked into the generator during operation or start-up.

Both of these situations present the possibility of short- and long-term deterioration and damage of many components, like some type of retaining-rings susceptible to water stress-corrosion cracking and winding and winding support system deterioration from excessive oil presence. Both issues will be discussed amply in the chapters covering monitoring and diagnostics, as well as stator and rotor inspection. Let us say here that these events require attention, and the severity of the situation determines how soon.

4.4.13 Under- and Overfrequency Operation (U/F and O/F)

The U/F and O/F operation indicates if the unit is operating slightly under or over the rated frequency of the system. Interestingly the turbine is, in general, more sensitive to this condition than the generator.

In the case of the generator, the main concern is that while running under frequency and at the highest allowable terminal volts, the machine may move beyond the permissible V/Hz region. This condition should be armed by the protective scheme so that the operator has an opportunity to correct it (lowering terminal voltage or removing the unit from operation.

However, as stated above, it is the turbine element that is more sensitive to U/F and O/F operation. The main areas of concern are the turbine blades moving into one of their natural frequencies, resulting in accelerated metal fatigue. It was once common knowledge that steam turbines are more sensitive than combustion turbines. This is not the case nowadays. To keep up with the ongoing drive to improve combustion turbine efficiencies, modern-day design practices for these units result in reduced margins, making them less tolerant of O/F and U/F operation, oftentimes less so than steam turbines. The protection of the turbine is done directly by protective devices on the turbine's panel sensing speed and load conditions (which are always set to the vendor's specifications) and indirectly by O/F and U/F protection monitoring of output voltage.

To prevent damage to the turbine, it is imperative that this protection be set up and maintained properly. Manufacturers provide curves for permissive regions of operation and the maximum accumulated time for the lifetime of the unit, and for periods of operation in the restricted zones. The maximum accumulated time over the unit's lifetime is, in general, given in minutes (usually within a few seconds to a few tens of minutes). Figure 4.22 gives an illustration. In all cases operators must refer to the equipment vendor for obtaining the correct information on their units.

4.5 BASIC OPERATION CONCEPTS

4.5.1 Steady-State Operation

A turbine generator can be seen as a nonlinear combination of magnetically coupled windings, airgap reluctance, and the electrically conductive mass of the rotor body (which acts as a distributed winding). Its electrical characteristics when it is

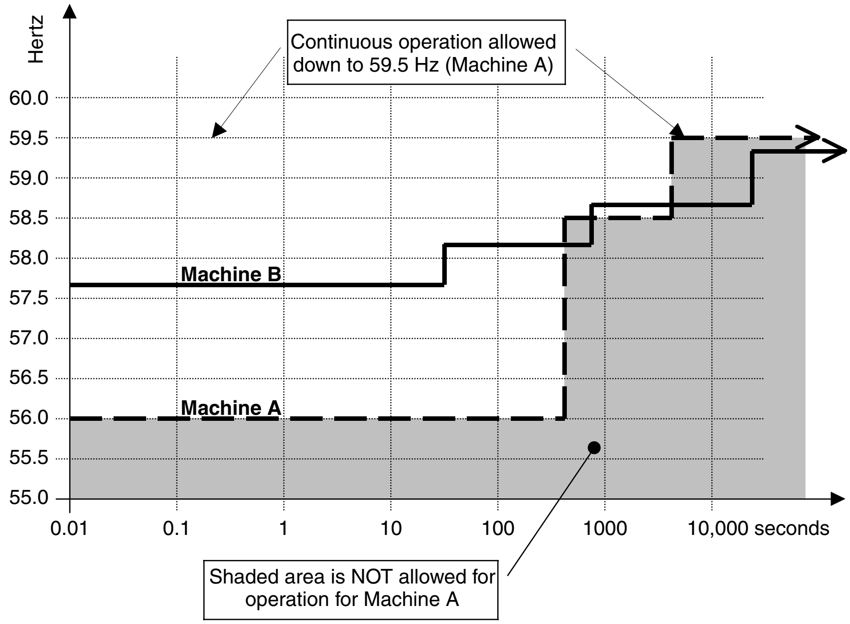


Fig. 4.22 Withstand underfrequency operation curves of machines A and B. For machine A, above the broken line operation is allowed below 59.5 Hz subject to the maximum total accumulated time over the life of the machine; below the broken line (the shaded area) operation is not allowed. Similar reasoning applies to Machine B. The graphs can be extended upward for higher rated frequencies (60 Hz in this case). The graphs so obtained for O/F operation are similar to those for the U/F region.

operating in a steady-state fashion are very different from those when conditions are changing. The turbogenerator has different characteristics under slow changes than it does under rapid changes. For many conditions a turbogenerator can be represented as a reactance in series with a voltage source. That reactance takes on different values for different operating conditions. In addition to the familiar concept of a reactance as it functions in an electric circuit, there are magnetic considerations that are useful in describing the operation of a synchronous machine. An inductance (which is multiplied by the angular frequency to obtain the reactance) can be defined as the flux linkages produced by one ampere of current. Thus the reactance is a measure of the ease with which current produces flux in the machine.

When the generator is operating in a steady load-carrying condition, it appears to the power system as a voltage source connected to the generator terminals through the generator's synchronous impedance (Fig. 1.26, Chapter 1). The generator resistance is negligible, and it is common to consider only the generator's reactance, in this case the synchronous reactance X_s.

During steady-state operation, a component of flux (φ_A in Fig. 4.23 or ϕ_S in Fig. 1.24) is produced by the stator current, and passes through the same

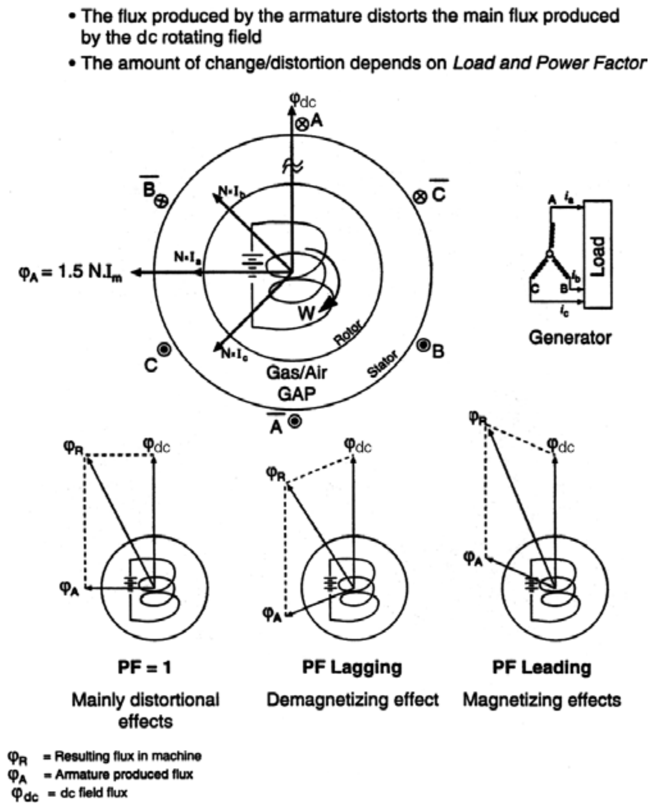


Fig. 4.23 Armature reaction. The top part of the figure shows how the resulting flux from the fluxes generated by a three-phase balanced winding (where three-phase balanced currents flow) is constant and of value equal to 1.5 the maximum value of the flux produced by each phase. This resultant flux rotates at synchronous speed. The bottom part of the figure shows how the stator-produced flux affects the rotor-produced flux for unity, leading and lagging power factors. This is the "armature reaction" effect.

magnetic circuit as that for the flux produced by the rotor field winding (φ_{DC} in Fig. 4.23 or ϕ_F in Fig. 1.24). This is an effective flux path, and a relatively high value of reactance may be expected, in the range of 1.5 to 2.1 per unit. The per unit synchronous reactance is approximately equal to the reciprocal of the short-circuit ratio.

The stator produced flux acts together with the rotor produced flux to create the total "useful" (meaning linking both windings) flux, called the resultant flux (φ_R in Fig. 4.23 or ϕ_R in Fig. 1.24). The way the stator-produced flux affects the rotor-produced flux is called the "armature reaction" of the machine. This can be clearly seen in Figure 4.23, where the bottom of the figure presents how the armature reaction affects the rotor-produced flux for three power factor conditions: unity, leading, and lagging.

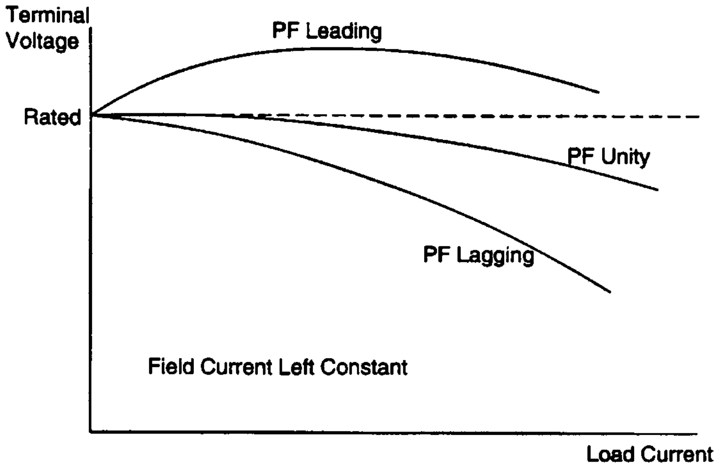


Fig. 4.24 How the armature reaction affects the output voltage of a generator for unity, leading, and lagging power factors.

The armature reaction of the generator affects the voltage regulation of the machine (i.e., how the terminal voltage changes as the load changes, all other things remaining the same; see Fig. 4.24). With lagging power factors, the armature reaction tends to accentuate the voltage drop in the machine, requiring additional dc current to be supplied by the exciter for compensation. How much armature reaction exists in a machine is the result of design compromises.

4.5.2 Equivalent Circuit and Vector Diagram

Section 1.7 in Chapter 1 introduced the reader to the most basic description of a synchronous machine operation. In this section the concept will be further developed, and the use of vector analysis will be illustrated with a few very basic examples.

Figure 4.25 presents the alternator's basic equivalent circuit that can be used by any individual to solve simple application problems. The *fundamental circuit equation* in Figure 4.25 relates machine variables to the connected system's current and voltage (at the generator's terminals). Figure 4.26 shows the vector representation of the *fundamental circuit equation* in the case of a synchronous machine acting as a generator. Figure 4.26 also shows the definition of regulation as it applies to an alternator.

4.5.3 Power Transfer Equation between Alternator and Connected System

The power transfer equation is one of the basic equations in electric power engineering. It states: "The power transmitted between two points in a ac circuit

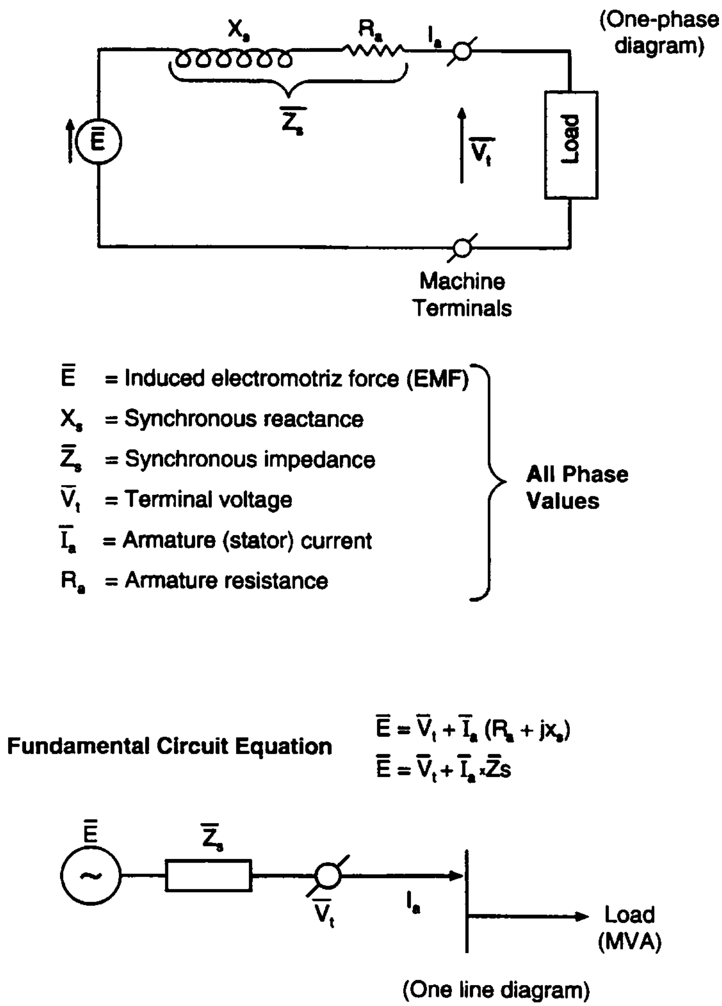


Fig. 4.25 Generator equivalent circuit. The equivalent circuit diagram of a synchronous machine developed in Figure 1.26 is reproduced here. Also shown is the one-line representation of the generator behind its synchronous impedance and the *fundamental circuit equation*.

is equal to the product of the magnitude of the voltages in each point, times the sine of the angle between the two voltages, divided by the reactance between the two points."

The maximum power that a circuit can deliver between two points is thus when the sine of the angle between the voltages equals 1, meaning the angle between the voltages equals 90°. Figure 4.27 illustrates the power transfer function as applies between two electric machines, and between an alternator and the electric power system.

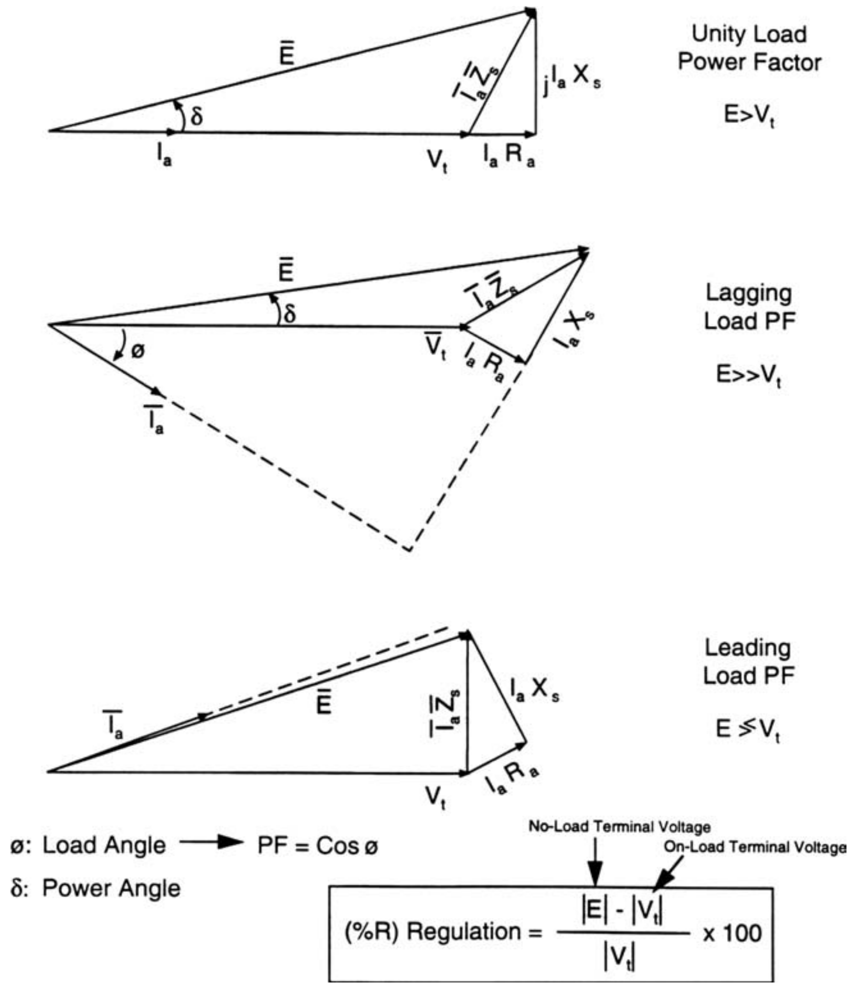


Fig. 4.26 Vector representation of the *fundamental circuit equation* in the case of a generator, for various power factor conditions. Also shown is the formula for the calculation of the *regulation*.

4.5.4 Working with the Fundamental Circuit Equation

The following two simple circuit problems with the generator connected to the system, illustrated how the fundamental circuit equation, the power transfer equation, the active power equation, and a little basic trigonometry can be used to obtaining solutions. Figure 4.28 captures those equations in a vector diagram.

Case 1: Change in Excitation. A generator is supplying power to the system. Now let us assume that the excitation is changed but the turbine's output is not changed. Additionally the system may be assumed to be much larger than that of

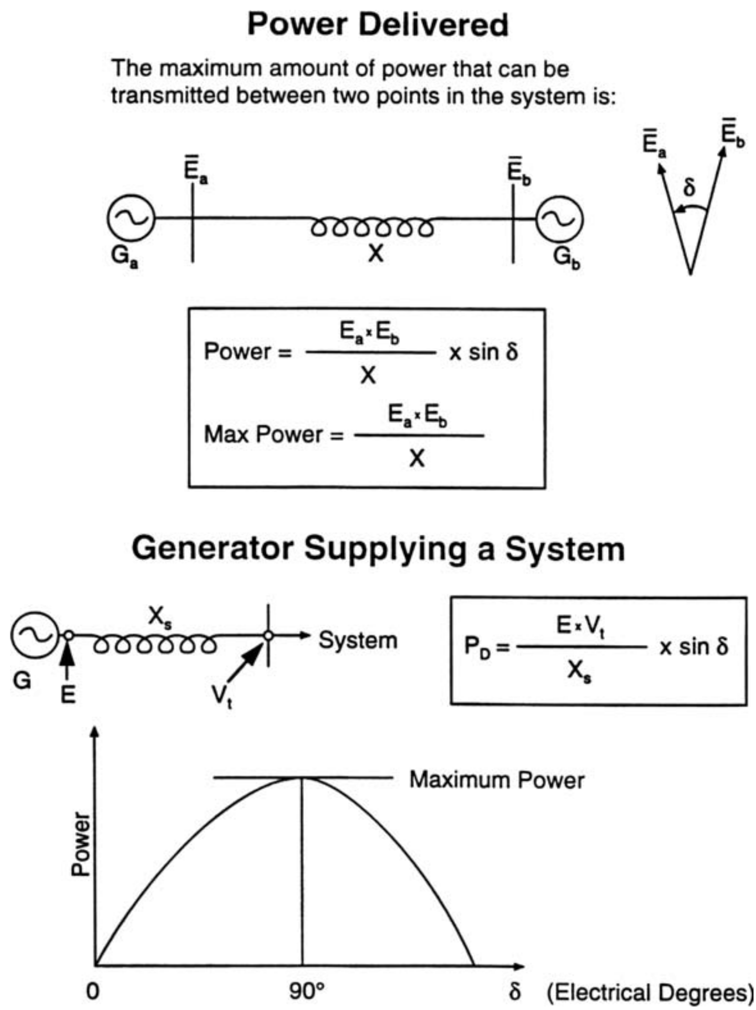


Fig. 4.27 Power transfer function applied to the power transferred between two electric machines, and between a generator and the power system.

the generator ("infinite" system) so that the frequency of the system (hence the generator's speed) and the voltage at the terminals do not change. Under these circumstances it is desired to estimate how the power factor PF and the armature current I_a change.

The solution of this simple problem can be found by inspection of the vector diagram in Figure 4.29. The voltage induced in the machine **(E)** multiplied by the terminal voltage ($\mathbf{V}_t$) and by the sine of the angle between them (δ) represent the power transferred from the machine to the terminals (power transfer equation):

$$\mathbf{E} \times \mathbf{V}_t \times \sin(\delta) = \text{Power delivered} = \text{Turbine's output (constant)}$$

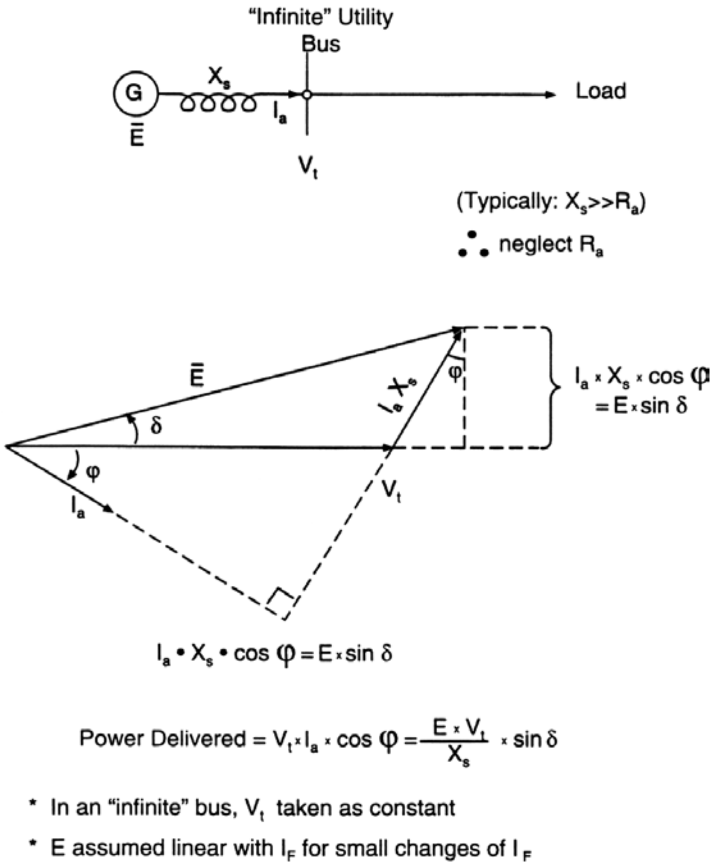


Fig. 4.28 Simple load change and excitation change calculation. The two basic equations can be combined to solve most steady-state problems of an electric machine connected to a power system (the power transfer and the active power equations).

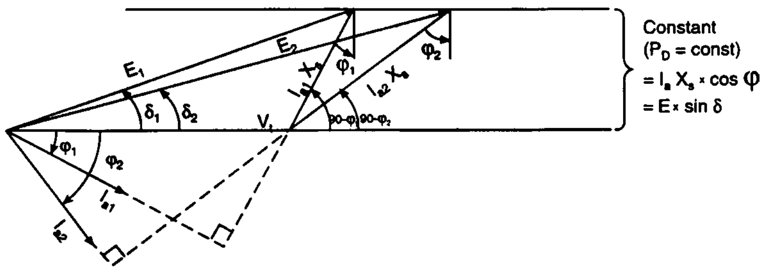
However, since as was stated above the terminal voltage does not change, we have

$$\mathbf{E} \times \sin(\delta) = \text{constant}$$

But $\mathbf{E} \times \sin(\delta)$ is the vertical projection of $\mathbf{E}$. Clearly, changing the field current changes $\mathbf{E}$. So, if $\mathbf{E} \times \sin(\delta)$ must remain constant, then δ must change in such a way that the vertical projection is still the same.

Finally, we know that the power delivered equals the product of the terminal voltage, times the current, times the power factor, $\cos(\varphi)$. By combining both equations and introducing a little trigonometry, the solution to the problem can be found.

Figure 4.30*a–b* presents a simple numerical example for case 1. (Recommended exercise: Repeat this simple example for your generator, using MVA, Let's assume I_F grows from I_{F1} to I_{F2} and turbine power output is not changed: How will the P.F. and armature current change?



1. $E_2 \cong E_1 \times \dfrac{I_{F2}}{I_{F1}}$

2. $E_1 \sin \delta_1 = E_2 \sin \delta_2 \longrightarrow \delta_2 = \sin^{-1}\left(\dfrac{E_1}{E_2} \sin \delta_1\right)$

3. $E_2 \cos \delta_2 = V_t + I_{a2} \times X_s \times \sin \varphi_2 \longrightarrow I_{a2} \times X_s \times \sin \varphi_2 = E_2 \times \cos \delta_2 - V_t$

4. $I_{a2} X_s \cos \varphi_2 = I_{a1} X_s \cos \varphi_1$

$$\therefore \quad \frac{I_{a2} \times X_s \times \sin \varphi_2}{I_{a2} \times X_s \times \cos \varphi_2} = \frac{E_2 \times \cos \varphi_2 - V_t}{I_{a1} \times X_s \times \cos \varphi_1} \longrightarrow$$

$$\longrightarrow \varphi_2 = \tan^{-1}\left(\frac{E_2 \times \cos \delta_2 - V_t}{I_{a1} \times X_s \times \cos \varphi_1}\right)$$

5. $I_{a2} = \dfrac{I_{a1} \times X_s \times \cos \varphi_1}{X_s \times \cos \varphi_2}$

Fig. 4.29 Change of excitation. The solution of a simple problem of a generator is connected to an "infinite" system, where only the excitation is increased from I_{F1} to I_{F2}. The changes in current and power factor are deduced.

volts, frequency, and field current as they apply to any given load point. After calculating the new PF and armature current, use the vendor's V-curves of your machine and calculate the new PF and current and compare with the calculated values.)

Case 2: Change in Power. In this instance the turbine's output is changed while feeding an "infinite" system. Thus the terminal voltage and frequency are kept constant by the system. The excitation field is also kept constant.

In this case the fact the excitation is kept constant means that **E** is constant. In Figure 4.31 is shown how from the power transfer equation applied to this case it is obvious that δ must change with the power **P**. This fact, and a little geometry, lead to a simple solution of the problem. Figure 4.32 provides a simple numerical example of finding the change in current and power factor of a generator feeding an “infinite” power system, when the excitation is kept constant and the turbine’s output is increased.

4.5.5 Parallel Operation of Generators

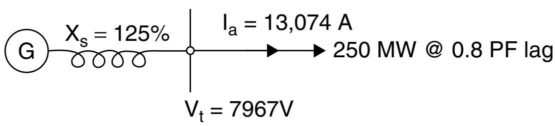
Most large generators are connected to a common switchyard bus via the main step-up transformer, while smaller machines, mainly below 100 MVA, may be found connected directly to a common bus, and from there to a step-up transformer.

When two or more generators have their terminals connected to the same bus, a number of issues may arise. The first is the existence of circulating currents. As in the case of transformers connected in parallel, generators in parallel are affected by circulating currents if voltages and impedance do not match. In the case of generators there is an additional degree of freedom than in transformers:

Example

A13.8 kV generator, rated 500 MVA, is delivering 250 MW @ 0.8 PF lagging if the excitation is increased by 10% what are the changes in PF and load amps? Assume infinite bus;steam inlet unchanged, and Xs = 125%

Solution



$$\text{(Phase value) } V_t = \frac{13{,}800}{\sqrt{3}} = 7967 \text{ volts}$$

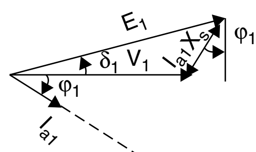
$$I_a = \frac{P}{\sqrt{3} \times V_{L-L} \times PF} = \frac{250 \times 10^6}{\sqrt{3} \times 13{,}800 \times 0.8} = 13{,}074 \text{ A}$$

$$X_{BASE} = \frac{KV^2{}_{RATED}}{MVA_{RATED}} = \frac{13.8^2}{500} = 0.38\ \Omega$$

$$X_s = 1.25 \times X_{BASE} = 1.25 \times 0.38 = 0.48\ \Omega$$

$$\varphi_1 = \cos^{-1} 0.8 = 37^\circ$$

$$PD = 3\,\frac{7967 \times E_1}{0.48} \times \sin \delta_1$$



$$\longrightarrow E_1 \sin \delta_1 = \frac{250 \times 10^6 \times 0.48}{3 \times 7967} = 5020$$

Fig. 4.30*a* Numerical example for the case shown in Figure 4.29.

$$E_1 \cos \delta_1 = V_t + I_{a1} \times X_s \times \sin \varphi_1$$

$$\frac{E_1 \times \sin \delta_1}{E_1 \times \cos \delta_1} = \tan \delta_1 = \frac{5{,}020}{7{,}967 + 13{,}074 \times 0.48 \times \sin 37^\circ} = 0.43$$

$$\therefore \tan^{-1}(0.43) = \delta_1 = 23^\circ$$

$$E_1 = \frac{5{,}020}{\sin 23^\circ} = 12{,}771 \text{ V}$$

$$\delta_2 = \sin^{-1}\left(\frac{E_1}{E_2} \sin \delta_1\right) = \sin^{-1}\left(\frac{E_1}{1.1\, E_1} \times \sin 23^\circ = 21^\circ\right)$$

$$\varphi_2 = \tan^{-1}\left(\frac{E_2 \times \cos \delta_2 - V_t}{I_{a1} \times X_s \times \cos\varphi_1}\right) = \tan^{-1}\left(\frac{1.1 \times 12{,}771 \times \cos 21^\circ - 7{,}967}{13{,}074 \times 0.48 \times \cos 37^\circ}\right) \cong 46^\circ$$

$$I_{a2} = \frac{I_{a1} \times X_s \times \cos\varphi_1}{X_s \times \cos\varphi_2} = \frac{13{,}074 \times 0.48 \times 0.8}{0.48 \times \cos 46^\circ} = 15{,}056 \text{ Amps}$$

Conclusions

By increasing field current by 10% →

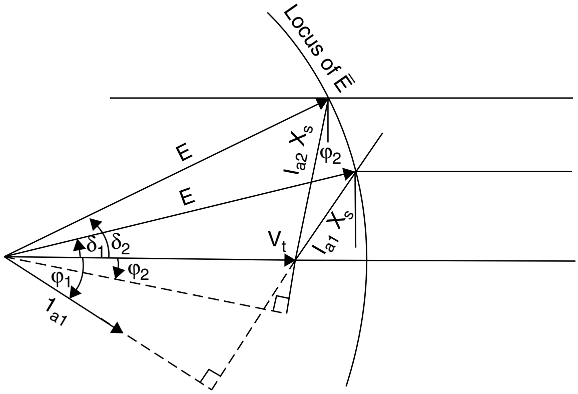
* **Power factor moved from 0.8 to 0.7 (LAG)**
* **Armature current increased from 13,074A to 15,056A (15% increase)**

Fig. 4.30*b* Continuation of numerical example for the case shown in Figure 4.29.

the angle of the voltage between both machines. Any mismatch will introduce significant circulating currents resulting in an exchange of VARs between the units. This results in unwanted losses and curtailment of available output from at least one of the units. Thus it is important that the operators control the units' parameters in such a way that circulating currents are kept to a minimum. Figure 4.33 shows how the circulating current is calculated.

Interestingly circulating currents between two or more generators tend to reduce the angle of the terminal voltages of the units. The explanation is beyond the scope of this book, but can be found in Chapter 10, ref. [5]. However, if there is a tendency to increase the angle—for instance, one turbine delivering more power than the other—then a "hunting" situation might be established between the units. These types of situations can be controlled by a fine-tuned AVR and operator input.

Let's assume the turbine's output is increased from PD1 to PD2
How will PF and armature current change?



1. $P_D = \underbrace{\dfrac{V_t \times E}{X_s}}_{\text{cnst}} \times \sin\delta \longrightarrow \sin\delta \propto P_D$

$\therefore \sin\delta_2 = \sin\delta_1 \times \dfrac{P_{D2}}{P_{D1}}$

2. $P_D = \sqrt{3}\cdot V_t\, I_a \cos\varphi \longrightarrow I_{a2} \times \cos\varphi_2 = \dfrac{P_{D2}}{P_{D1}}\, I_{a1}\cdot\cos\varphi_1$

3. From the figure: $E\cdot\cos\delta_2 = V_t + 1_{a2} \times X_s \times \sin\varphi_2 \longrightarrow I_{a2} \times \sin\varphi_2 = \dfrac{E\cos\delta_2 - V_t}{X_s}$

$2\oplus3 \longrightarrow \varphi_2 = \tan^{-1}\left(\dfrac{P_{D1}\,(E \times \cos\delta_2 - V_t)}{P_{D2} \times X_s \times I_{a1} \times \cos\varphi_1}\right)$

4. $I_{a2} = \dfrac{P_{D2}}{\sqrt{3}\,V_t\cos\varphi_2}$

Fig. 4.31 Change in power. The solution of a simple problem of a generator is connected to an "infinite" system, where only the power is changed and excitation kept constant. The changes in current and power factor are deduced.

4.5.6 Stability

One of the most fundamental concerns when operating industrial generators (and synchronous machines, in general), is that they may become "unstable," and eventually come "out-of-step" (also know as "slipping a pole or poles"). As explained in Chapter 1, the operation of a synchronous machine is predicated on the rotor and stator fluxes aligning themselves and rotating together at synchronous speed. When the machine is loaded as or generator, a *torque angle* appears between both fluxes. Similarly a power angle appears between the voltage induced in the machine **(E)** and the terminal voltage **(V_t)**. Recall from Section 4.5.3 that

Example

A 13.8 kV generator rated 500 MVA, is delivering 250 MW @ 0.8 PF lagging
If the output power is increased by 10%, what are the changes in PF and load amps?
Assume infinite bus; excitation unchanged and Xs = 125%

Solution

From Previous example we know: $V_t/\text{ph} = 7967\text{V}$; $I_{a1} = 13{,}074\text{A}$
$E = 12{,}771\text{V}$
$X_s = 0.48\ \Omega$

$$\varphi_2 = \tan^{-1}\left(\frac{P_{D1}\,(E\cos\delta_2 - V_t)}{P_{D2} \times X_s \times I_{a1} \times \cos\varphi_1}\right)$$

$$= \tan^{-1}\left(\frac{250\,(12{,}771 \times 0.9 - 7967)}{1.1 \times 250 \times 0.48 \times 13{,}074 \times 0.8}\right)$$

$$= \tan^{-1} 0.64 = 32.5^\circ$$

From $E\sin\varphi_1 = I_a X_s \cos\varphi_1$

$\longrightarrow \delta_1 = 23^\circ$

From $\sin\delta_2 = \sin\delta_1 \times \dfrac{P_{D2}}{P_{D1}}$

$\longrightarrow \delta_2 = \sin^{-1}(\sin 23^\circ \times 1.1) = 25.4^\circ$

$\cos\delta_2 = 0.9$

$$\cos\varphi_2 = \cos 32.5^\circ = .0.84$$

$$I_{a2} = \frac{P_{D2}}{\sqrt{3}\ V_t \cos\varphi_2} = \frac{250 \times 10^6 \times 1.1}{\sqrt{3} \times 13{,}800 \times 0.84} = 13{,}696\ \text{A}$$

- PF increased from 0.8 to 0.84
- Armature current increased from 13,074 to 13,696A (5%)

Fig. 4.32 Numerical example for the case shown in Figure 4.31.

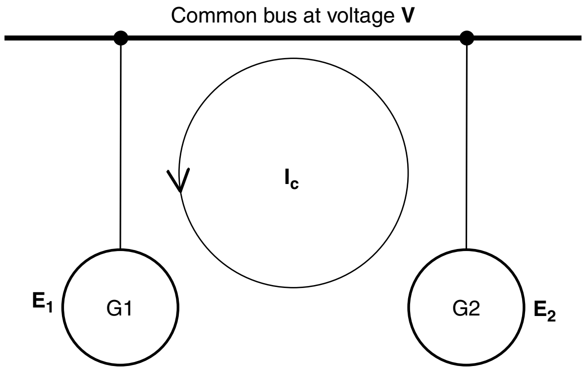
the power transfer equation determines the power flow in the machine, which is given by

$$\mathbf{P} = \mathbf{E} \times \mathbf{V}_t \times \sin(\delta)$$

Thus the maximum power the machine can deliver is,

$$\mathbf{P}_{max} = \mathbf{E} \times \mathbf{V}_t$$

This maximum power will occur when the internal generated voltage and the terminal voltage are 90° apart. However, if additional load is applied to the unit resulting in the voltages being pushed apart beyond 90°, the capability of delivering the required power (and torque) will not be satisfied, and the rotor



$$\mathbf{I_C} = (\mathbf{E_1} - \mathbf{E_2}) / (\mathbf{Z_1} + \mathbf{Z_2})$$

- In the figure, all bold letters represent vector variables.
- $\mathbf{E_1}$ and $\mathbf{E_2}$ represent the back-emf in each generator, i.e., the voltage generated in the armature, before the drop across the leakage reactance.
- $\mathbf{Z_1}$ and $\mathbf{Z_2}$ represent the synchronous impedance.
- $\mathbf{I_c}$ is the circulating current.

Conditions for Synchronization are:

1. Same phase sequence
2. Same voltage
3. Remaining within:
   - Maximum frequency slip
   - Maximum phase angle

Fig. 4.33 Calculation of circulating current between two generators connected directly to the same bus. Also shown are the conditions required for safe synchronization between a generator and the system.

will come out of synchronism. This phenomenon, called *out-of-step* or *slipping poles*, is extremely onerous. Generators can suffer extreme damage under this condition. Therefore it is the practice to operate a generator with its internal angle not reaching beyond 60 electrical degrees. Figure 4.34 presents a mechanical equivalent of slipping poles.

The maximum transfer of power limit applies to any branch or element of the circuit where a reactance separates two voltages. For a broader perspective of this issue, let us examine it first from a system's perspective.

Figure 4.35 depicts a simple transmission system comprising two lines connecting two busses. Both lines are transferring power $\mathbf{P}_0$ from bus A to bus B.

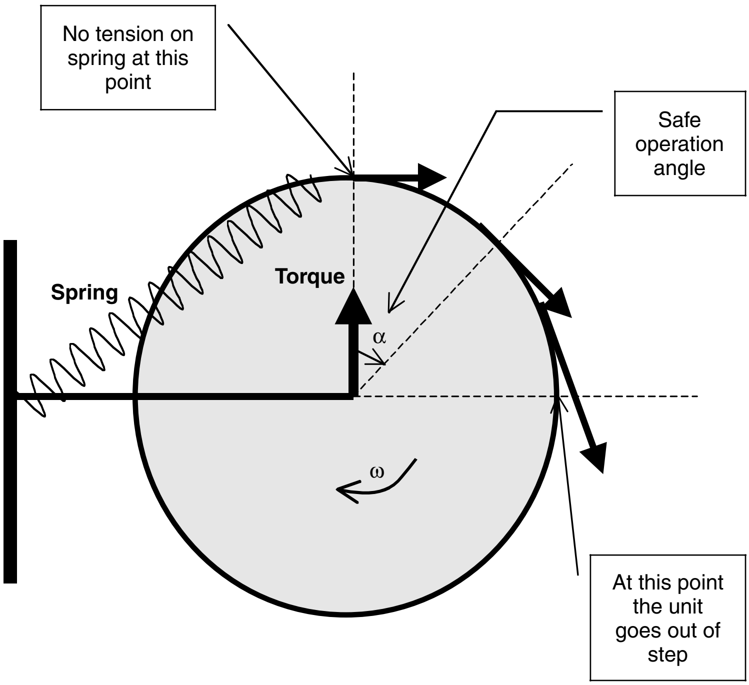


Fig. 4.34 Out-of-step mechanical conceptualization.

The top of Figure 4.35 shows that under that condition, the steady-state point $\mathbf{P}_0$ is well within the maximum power transfer capability of the two lines, meaning the lines can absorb a relatively large increase in transmitted power from A to B, without any stability concern. In mathematical terms, this is indicated by the angle $\delta_0 << 90^\circ$.

Now let us assume that line 2 breaker opens following a fault on it (see bottom of Fig. 4.35). The moment line 2 opens, the maximum capability to transfer power from A to B is given by the lower curve representing the capability of line 1. However, the power being transferred is still $\mathbf{P}_0$. The new equilibrium point (indicated by δ_1) comes very close to the maximum capability of the system. Thus a relatively small increase in load will throw the system in disarray. The system is now denoted as being *unstable* or *marginally stable*.

A similar treatment can be applied to the generator delivering power to a system. Figure 4.36 shows a generator feeding a power system. At normal operation the maximum capability of the system to transfer power is denoted by the higher curve in Figure 4.36*a*. Shown there is the operating internal angle δ_0, which is significantly lower than 90°. As the system experiences a fault on one of its lines the load $\mathbf{P}_2$ is removed, and the generator feeds only the remaining $\mathbf{P}_1$. Now the turbine does not (cannot) change its output instantaneously (the turbine keeps "pushing" watts into the system), so δ advances toward 90° as the system tries to find a new equilibrium. The excess power between what the turbine delivers

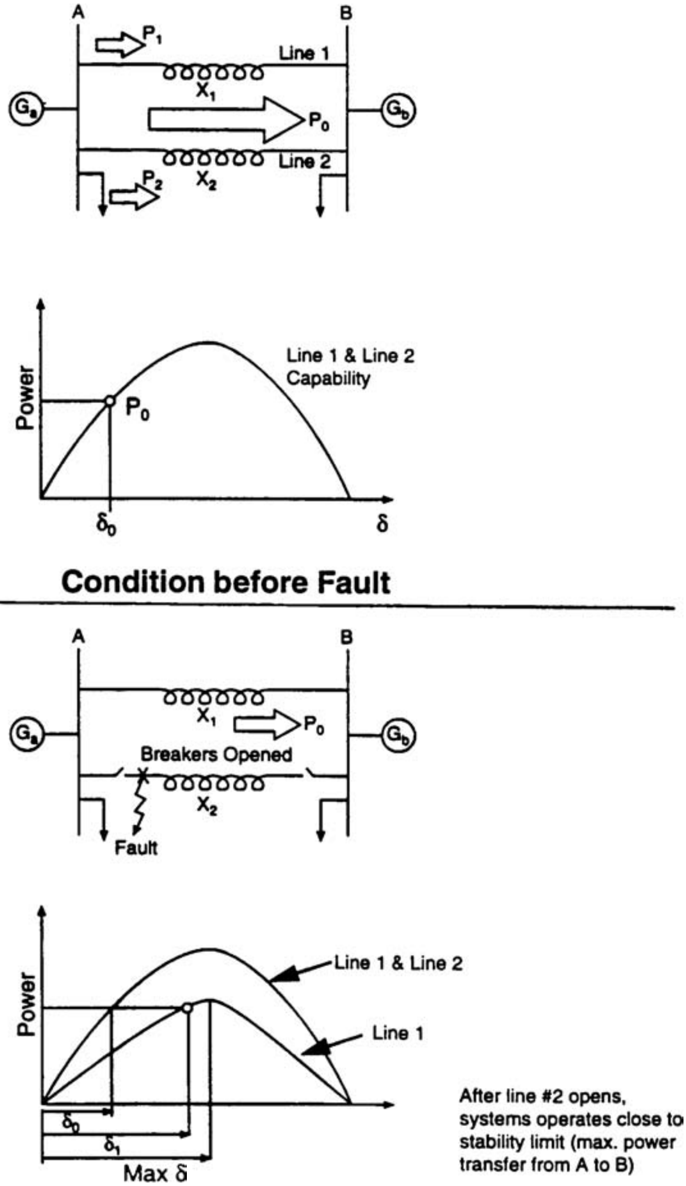


Fig. 4.35 Power system stability case with two lines and two busses, before and after the fault.

and the output of the generator goes into accelerating the unit's rotors and is converted into spinning energy. Depending on the power transfer capability of the remaining system and the ratio between $\mathbf{P}_1$ and $\mathbf{P}_2$, the generator may or may not remain stable. If it does not, it will slip a pole (see Fig. 4.34) or, if the protection is adequate, it will be removed from operation. In some cases the system may recover fully or partially (shown by the middle curve in Fig. 4.36*a*). In that case there is a greater chance that the generator will stay connected and stable. Mathematically, calculating the areas between the intersection of the power transfer curves and the output power can provide an estimation of the stability (Fig. 4.36*b* and *c*). These areas represent the additional spinning energy gone into the rotors during acceleration. This energy must return to the system once the generator is again stable (i.e., its speed is the system's synchronous speed). For a more in-depth study of stability issues, the reader is referred to a number of texts (e.g., [6]).

Transients and Subtransients. In the context of power system applications, a transient state occurs while a system is undergoing major changes. This may be due to, for instance, faults, switching on or off large loads, or loosing large chunks of generation. At the same time, internally, the generator is also undergoing significant changes. Under such unsteady conditions the changing flux produced by the changing stator current in the direct axis (parallel to the pole faces of the rotor) induces a voltage in the field winding, resulting in a field current that opposes the change in flux and hence the change in stator current. This makes it more difficult for the stator-produced magnetic flux to pass through the rotor poles than in the steady-state condition. Under the transient condition only the leakage flux paths of the stator and field windings are available, meaning fewer flux linkages per stator ampere. The result is that the generator looks like a reactance in the range of 0.15 to 0.35 per unit, which is much smaller than the synchronous reactance. This is called transient reactance, often denoted by X'_{d}.

The transient reactance is important to understanding transient stability, which, as stated above, is the ability of the power system to recover from a short circuit that has been interrupted, perhaps by circuit-breaker action. "Subtransient" is used to describe a rapidly changing condition that may last one to four cycles (0.016–0.07 s in a 60 Hz system). In this case the magneto-motriz force (mmf) of the stator winding changes so rapidly that it causes currents to arise in the rotor body as well as in the field winding, all of these opposing the change in stator current. This restricts the stator-produced flux to the stator leakage paths and to the very surface of the rotor. Therefore the generator appears as a smaller reactance, in the range of 0.10 to 0.25 per unit. This is called the subtransient reactance, often denoted by X''_{d}. The subtransient reactance is commonly used to calculate the maximum current following a nearby sudden short circuit.

Stator and Rotor Transient Capabilities. During sudden increases of rotor and/or stator currents the respective windings are subjected to additional losses. Given the short duration of these occurrences, the maximum temperature attained in the conductors is calculated by assuming no additional heat transfer from the conductor to the surrounding medium. Figure 4.37 shows the typical transient withstand capabilities of rotors and stators of turbogenerators, as given by the standards. From the plot of Figure 4.37, we obtain the data listed in Table 4.4.

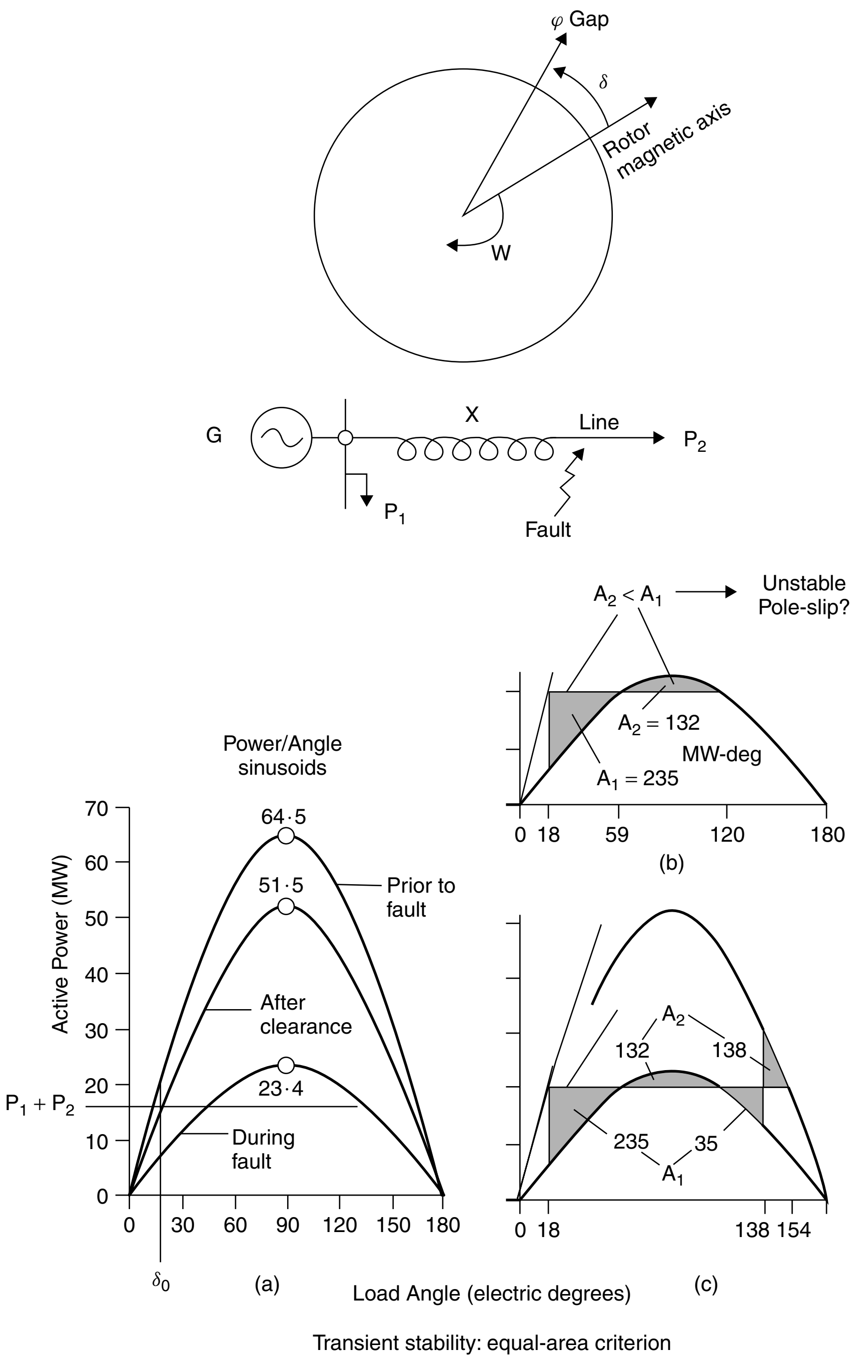


Fig. 4.36 Simple case of generator stability, from the generator perspective.

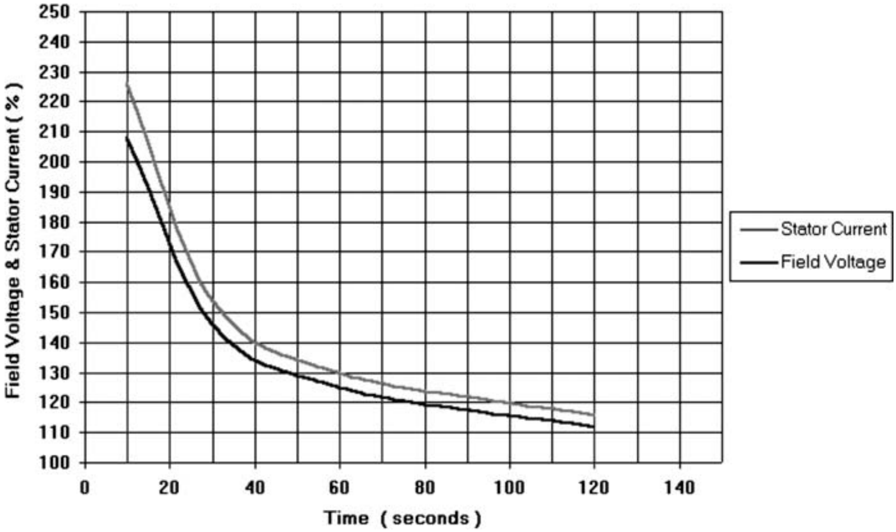


Fig. 4.37 Stator and rotor transient capability.

TABLE 4.4 Stator and Rotor Transient Capability

Permissible Transient Operation				
	Stator			
Time (s)	10	30	60	120
Stator current (%)	226	154	130	116
	Rotor			
Time (s)	10	30	60	120
Field voltage (%)	208	146	125	112

Source: After IEEE C50.13.

4.5.7 Sudden Short-Circuits

If a short circuit occurs suddenly in the power system near a turbine generator, a high-current transient ensues, which is of interest for several reasons. In the design of the turbine-driven generator, winding forces and torques experienced by the stator and torques on the rotor system must be adequately accommodated. Also external buses and circuit breakers that must carry and interrupt the current must be adequately specified.

For a sudden short circuit at the stator terminals, the exciter is assumed to be a source of constant voltage; it is not controlled by the voltage regulator. In addition the generator appears to react in a linear fashion in terms of electrical and magnetic circuits.

Each winding in the generator traps the flux, linking it at the instant of short circuit. The relationship is such that the flux linking such a winding does not change instantaneously. A large direct current suddenly appears in each phase of the stator winding in proportion to the flux linking it at the instant of short circuit, in order to sustain that flux. Since there is no source of direct current in the stator winding, it decays exponentially to zero in accordance to the stator time constant T_a (in 0.14–0.5 s). Large direct currents also arise in the field-winding and in the rotor iron circuit to sustain the flux trapped in them at the time of the short circuit. The field-current decays exponentially according to the transient time constant T_d' (in 0.4–1.6 s) to the steady value supplied by the exciter. The rotor iron current decays in accordance with the subtransient time constant, T_d'' (0.01–0.02 s) to zero, since there is no source for direct current in the rotor iron circuit.

Therefore both a decaying trapped flux in the stator and a decaying trapped flux rotating with the rotor are present. Because of relative motion, the stator flux produces a decaying alternating current of power-system frequency in all elements of the rotor, and the rotor flux produces a decaying alternating current of the same frequency in the stator winding.

At the instant of short circuit, the value of the dc component of current in each phase is equal and opposite to the instantaneous value of the ac component. This way there is no sudden change in current.

4.6 SYSTEM CONSIDERATIONS

Numerous industry standards have been developed, both nationally and internationally, that specify the required performance of a turbine generator. These standards define limiting temperatures at rating, required characteristics, and steady and transient conditions that must be successfully tolerated. Such standards are found in IEEE, ANSI, IEC, BS, VDE, and other industry publications.

With regard to the turbine generator, its primary requirement is to provide electric power continuously or for peak-load periods as needed, and to do so reliably and economically. A generator is also normally required to provide voltage support to the system by supplying the needed reactive power. The rated power factor assures that the generator will have adequate ability to carry out this function.

The rating normally defines the continuous duty required of the generator. A temperature class is assigned to the generator, which defines the thermal capability of the electrical insulation systems of the stator and field windings. Turbine generators are generally class B, F, or H, which implies a hot-spot capability of 130, 155, or 180°C, respectively, as prescribed in industry standards (which also specify limiting observable temperature rise over cold coolant temperatures for each class).

In sum, the general rises are as follows, but the precise values should be taken from reference [2]:

	CLASS B	CLASS F
Indirect air-cooled stator windings	85	110
Direct air-cooled stator windings	80	100
Indirect H_2-cooled stator windings	70–85	90–105
Direct H_2-cooled stator windings	70	90
Direct water-cooled armature windings	50	50
Indirect air-cooled rotor windings	85	105
Direct air-cooled rotor windings	60–80	75–95
Indirect H_2-cooled rotor windings	85	105
Direct H_2-cooled rotor windings	60–80	75–95
Direct water-cooled rotor windings	50	50

Note: The temperature rises given above are all relative to the input temperature of the cooling medium, which is 40°C.

The wave shape of the stator voltage must be very nearly sinusoidal to avoid certain environmental concerns such as telephone interference. To this end, it is common to specify a limiting *telephone influence factor* (TIF), which is calculated from the harmonic content of the voltage, using a weighting-factor curve that reflects the frequency response characteristics of telephone systems. A limiting deviation factor may also be specified. This is a measure of the maximum deviation that the stator voltage has relative to a sine wave.

A *voltage response ratio* is specified for the excitation system to be compatible with the stability needs of the power system. A turbine generator must also be able to operate successfully in a real power system where the ideal is not always achievable. Therefore other conditions that may be experienced by a turbine generator must be accounted for in the specification of its required capability, as discussed below.

4.6.1 Voltage and Frequency Variation

A generator must be able to deliver rated apparent power at terminal voltages deviating from the rated value by up to $\pm$ 5%, according to current international standards. These standards also specify the frequency range over which rated output can be delivered and which the manufacturer must provide.

4.6.2 Negative-Sequence Current

The three phases of a power system are not perfectly balanced in voltage and impedance. Accordingly a small amount of steady negative-sequence current is produced. The standards specify a maximum steady negative-sequence current that must be tolerated. This value, which varies among the various types and sizes of turbine generators, is based on an economic evaluation of system needs and generator rotor heating characteristics (see Section 4.4.2).

A disturbance may occur on one phase of the power system, which is then isolated by circuit breakers. The event may subject turbine generators in the vicinity to a large negative-sequence current for a brief period. Recognizing the economics of providing tolerance for the rotor heating that would result from such an event, the industry standards require that a turbine generator be capable of withstanding a prescribed value of $I_2{}^2t$, where $I_2{}^2$ is the square of the per unit value of the negative-sequence component of current, integrated over the period of exposure t in seconds.

4.6.3 Overcurrent

The stator and field-windings may withstand periods of overcurrent. For example, if the system voltage drops for a brief period, the excitation system may be called upon to apply ceiling voltage to the field winding. The field current will rise according to its time constant from the initial value, to a higher-than-rated value. The higher-than-normal current in both windings would result in a brief excursion to higher-than-normal temperatures. Accordingly industry standards require that a generator be capable of operating at specified levels of overcurrent in the stator and field-windings for a prescribed period of time (see Section 4.5.6).

4.6.4 Current Transients

Current transients may occur in a power system, for example, due to a sudden short circuit or due to switching where the voltages of the circuits to be connected are unequal in magnitude or phase angle. The high currents produce high electromagnetic forces in the stator winding in the end-regions and in the slots. They also result in transient torques felt by the rotor and the stator. To ensure that the turbine generator has the necessary ruggedness, U.S. industry standards require that it be capable of withstanding, without mechanical injury, a three-phase terminal sudden short circuit while at load and at 105% voltage.

4.6.5 Overspeed

A turbine generator is required to be able to withstand a brief overspeed test to 120% of rated speed to ensure that the rotor system is mechanically sound (see Section 6.9).

4.7 EXCITATION AND VOLTAGE REGULATION

4.7.1 The Exciter

The exciter supplies direct current to the field-winding of the generator, at whatever voltage is required to overcome the resistance of the winding. The rating of the exciter is specified as its output power, current, and voltage corresponding to the rating of the generator, recognizing the temperature limits of the generator's field-winding. The exciter rating generally has some margin over this requirement, as defined when the generator is designed.

The most common type of exciter used in early years was the commutator type dc generator. This is very rarely used for new generators today. Either one of the following systems usually supplies the newer turbine generators:

- A shaft-driven alternator with solid-state diode rectifiers
- A solid-state thyristor-based rectifier supplied by a transformer, deriving its power from the power system or from the generator' output
- A shaft-driven alternator with its output winding on the rotor, its output rectified by rotating solid-state rectifiers (commonly called a "brushless exciter")

The normal function of the exciter is to provide the proper level of direct current to the generator field-winding, as required for the apparent power being supplied to the system, the terminal voltage, and power factor of the generator load. In addition the exciter must also be able to produce a ceiling voltage (which is maximum exciter voltage) and to operate at that condition for a specified brief period, as required by the *voltage response ratio*, which is specified in excitation system's specification. The *voltage response ratio* is a measure of the change of exciter output voltage in 0.5 s when a change in this voltage is suddenly demanded.

When the exciter is a rotating machine driven by the generator shaft, it becomes part of the turbine-generator shaft system. It must be designed to accommodate axial motions due to thermal expansion of the turbine and generator rotors and vertical motions of the generator shaft due to bearing oil film and thermal expansion of the generator bearing support.

4.7.2 Excitation Control

Steady State. With the turbine's governor fixed, and the active power output of the generator therefore fixed, and with the configuration of the power system fixed, an increase in exciter output, that is, in generator field current, causes the stator voltage to try to rise. This changes the power factor and causes the reactive power delivered by the generator to increase. While the turbine governor responds to provide the power needed by the system, the exciter enables the generator to provide the needed reactive power and thus to help provide the needed voltage support in the system.

The control system includes a voltage regulator that causes the generator's field current to be at whatever level is required to maintain the stator terminal voltage at a selected value. The control system also can be instructed to hold the generator field current at a desired value, when voltage regulator is not needed. This is done by "manual control."

A lower limit is provided so that the field current is not reduced to the point where stator core-end heating becomes excessive (underexcited condition), or stability margins are compromised. An upper limit is provided so that the capability of the exciter and that of the generator field winding is not exceeded.

Volts-per-hertz protection is commonly provided to prevent the level of the magnetic flux in the generator and in the unit step-up transformer from exceeding safe levels. A volts-per-hertz control is occasionally specified to adjust generator excitation so as to avoid overfluxing.

Transient. The ability of the excitation system to change the generator field voltage rapidly may be important to system stability. Stability may be difficult to achieve when the system supplied has relatively high reactance for example, when a long transmission line separates a generator from its load. In such a situation providing an excitation system with a high voltage response ratio may help in the system's design. It can help reduce major expenses in additional transmission-line construction.

A relatively new concept made possible in part by the use of thyristor power rectifiers is the *high-initial-response* excitation system. In such a system the output voltage of the exciter changes almost instantly on command, enhancing system stability.

Another concept in excitation control function is the *power system stabilizer* (PPS). It operates to enhance stability in situations where one power system may swing at low frequency relative to another (i.e., subsynchronous resonance conditions).

4.8 PERFORMANCE CURVES

4.8.1 Losses Curves

Figure 4.38 shows the typical calculated loss curves for a 215 MW, hydrogen-cooled, 3600 rpm generator.

4.8.2 Efficiency Curve

Figure 4.39 shows typical calculated efficiency curves for a 215 MW, hydrogen-cooled, 3600 rpm generator.

4.9 SAMPLE OF GENERATOR OPERATING INSTRUCTIONS

Like for any other critical apparatus, generating stations develop *Operating Instructions* for their generators. Operating instructions must be tailored to the specific conditions of a given plant, equipment, and system requirements, but

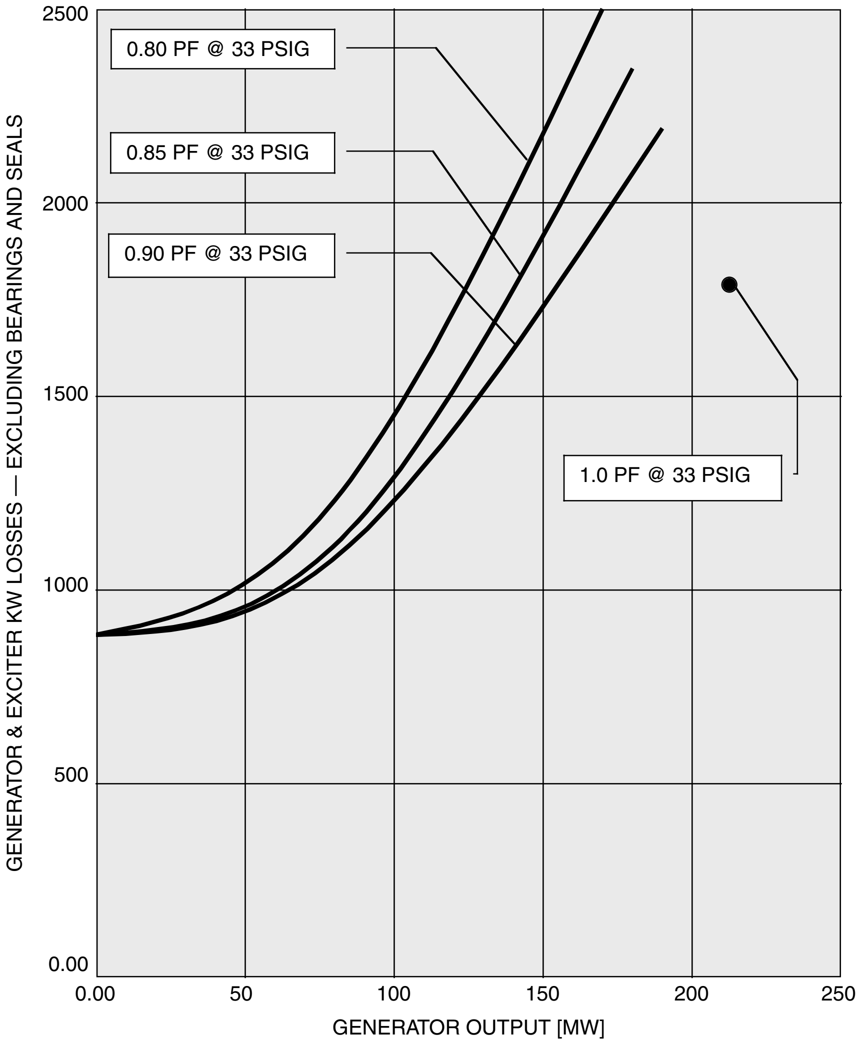


Fig. 4.38 Calculated losses curves for a 215 MW, 18 kV, 0.85 PF, 3600 rpm, hydrogen-cooled generator. Bearing and seal losses excluded from the graph, and are given as 286 kW.

they ought to capture the best industry practices, as developed over many years of experience.

Following is an example of a company's operating instructions. The reader should only look at these as an example of how such an operating instruction can be outlined. He or she must remember that each case may be different; therefore each operator must develop operating instructions that are specifically tailored to his/her plant and equipment.

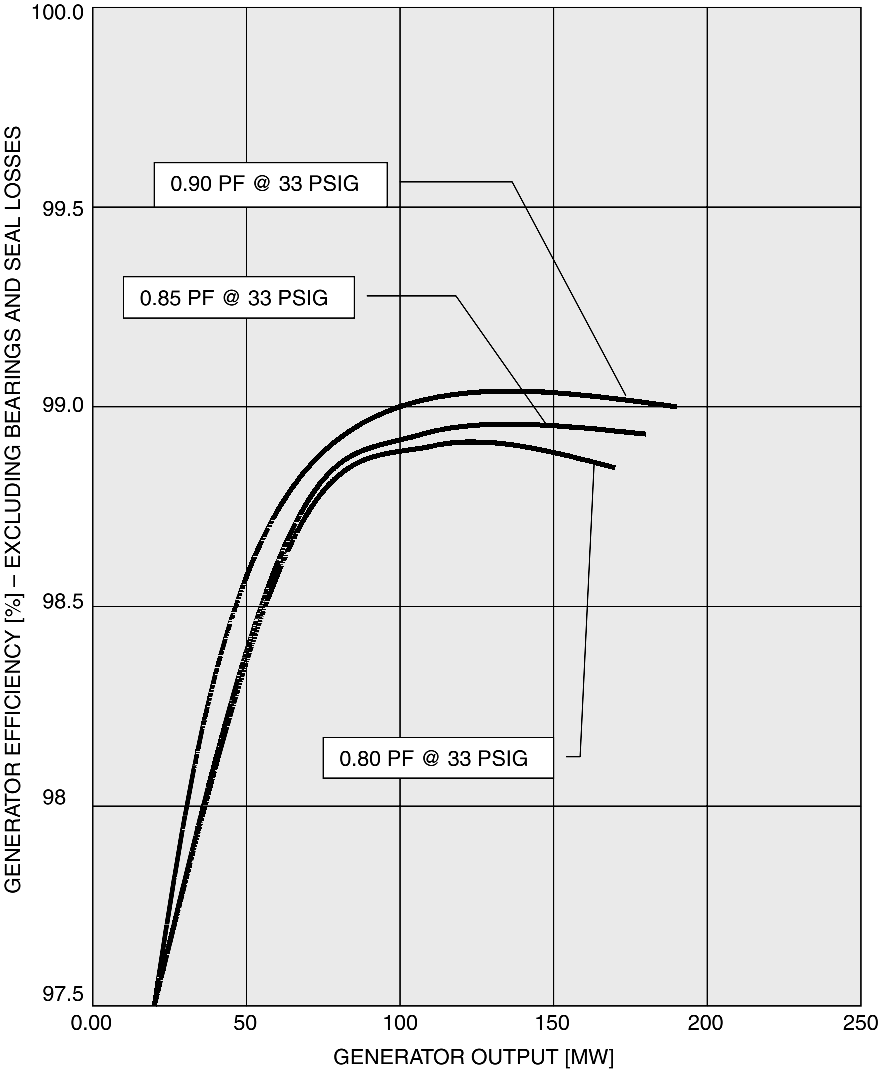


Fig. 4.39 Calculated efficiency curves for a 215 MW, 18 kV, 0.85 PF, 3600 rpm, hydrogen-cooled generator. Bearing and seal losses excluded from the graph, and are given as 286 kW.

MAIN GENERATOR OPERATING INSTRUCTION

I Purpose

The purpose of this order is to establish guidelines for the operation of main generators and the associated equipment during normal and emergency conditions.

II General

To ensure the continuing operational integrity of generators, generator temperatures, vibration and the various generator support systems must be closely monitored. Any abnormalities must be reported and investigated in a timely manner.

III Start-up Operation

At no time should excitation interlocks or relay protection be disabled or made nonautomatic for the purpose of establishing a generator field. Also a generator field should not be reestablished after operation of a generator protective relay until a thorough investigation has been completed.

On generators requiring field pre-warming, the manufacturer's instructions and established local procedures should be followed relative to maximum allowable field current.

A generator field should not be applied or maintained at turbine speeds above or below that recommended by manufacturer's instructions. On cross-compound units where a field is applied while on turning gear, extreme caution must be exercised. Should either or both shafts come to a stop, the field should immediately be removed to prevent overheating damage to the collector rings.

After the field breaker is closed, the generator field indications should be closely monitored. If a rapid abnormal increase occurs in field current and/or terminal voltage, immediately open the field breaker and inspect the related equipment for proper working condition before re-closing the breaker.

During off-line conditions, at no time is field current to be greater than 105% of that normally required to obtain rated generator terminal voltage at rated speed and no load.

When synchronizing the generator to the system, the synchroscope should be rotating less than one revolution every 30 seconds and should be 5 degrees or less from being in-phase when the switchyard circuit breaker is closed. Synchro-acceptors will typically not allow closing of the switchyard circuit breakers when the synchroscope is rotating faster than one revolution every 15 seconds. It is also critical that incoming and running voltages are matched as closely as possible when synchronizing the generator to the system; the allowable variation is plus or minus 10%.

IV Shutdown Operation

The unit should be removed from the line via the turbine emergency trip pushbutton. Closure of the turbine steam valves will initiate anti-motoring relay operation, opening the generator circuit breakers, field breakers, and auxiliary generator or transformer breakers.

If the limit switch circuitry fails to function properly, the unit may fail to clear itself electrically after closure of the steam valves. A generator will then drive the turbine in a motoring mode of operation. This condition will overheat the LP turbine blades (typical withstand time of 10 minutes) unless operator action is taken as follows to isolate the unit electrically:

A. Verify steam valves are closed (to prevent turbine overspeed when generator switchyard circuit breakers are opened).

B. If unit auxiliaries are not on the reserve transformer, open auxiliary generator or transformer circuit breakers (automatic transfer to reserve auxiliary transformer should occur).
C. Switch voltage regulators to manual operation and reduce field to no load.
D. Open generator switchyard circuit breakers.
E. Open generator field breakers.

The generator field should not be reestablished for the turbine coast-down until verification that the automatic voltage regulator is tripped and the field rheostat is at the no-load position. The exciter field breaker should be tripped open at a preset generator speed per the manufacturer's instructions.

During off-line conditions, at no time is field current to be greater than 105% of that normally required to obtain rated generator terminal voltage at rated speed and no load.

V System Separation

If, during system trouble, the unit is separated from the system, close attention to the field current/generator terminal voltage must be maintained, particularly when rated speed is not being continuously maintained. Reductions in speed can result in overexcitation (volts/Hz) as the voltage regulator attempts to maintain rated voltage.

VI On-line Operation

Generators should be operated within their capability curves, which limit loading and field current (as related to VAR output) at various levels of hydrogen pressure. Operation beyond these limits will result in generator overheating.

During normal operation the voltage regulator and, where applicable, power system stabilizer (PSS) should continuously be in service. To prevent a significant weakening of the generator field in the event the voltage regulator is lost, the field rheostat should be set at approximately 80% of generator field nameplate value ("nominal full load" or "blue light" setting).

If conditions require the unit be on manual voltage control, the unit will be operated off AGC and on turbine solid block or load limit. Unless directed otherwise by the ECC, the terminal voltage should always be maintained high enough to boost VARs, especially if the voltage regulator is out of service.

Loss-of-excitation protective relays are designed to separate a unit from the system in the event the generator field is lost. This serves to protect the generator from overheating. If the field is lost and the unit is not automatically tripped by relay protection, immediately trip the unit manually.

Normal "180 Hz third harmonic" residual voltage should be indicated on the generator stator ground voltmeter. The amount of this residual voltage will vary with load and should be read by pushing the 10% push-button. The absence of residual voltage indicates one of the following may exist:

A. The generator neutral potential circuit is not complete.
B. There is a ground near the neutral end of the generator stator windings.

To ensure this condition is detected as soon as possible, periodic monitoring of the residual voltage by operators at consistent intervals must be accomplished. Any abnormalities should be reported and investigated promptly.

VII Field Grounds

An internal generator field ground could be caused by high-temperature electrical arcing, insulation damage, or shorted turns and other severe damage in the generator field. Upon detection of a field ground, field temperature and generator bearing vibration levels must be closely monitored for changes. If a 25% change in the field temperature is observed (increase or decrease), or if there is a notable increase in generator bearing vibration levels, the unit should be removed from service immediately.

Each station should have detailed and up-to-date operating instructions that address locating and isolating field grounds for each individual unit type. Timely and thorough investigation should be performed to identify and isolate the source of the field ground. Considering the numerous peripheral components associated with the excitation system, it is very possible that the ground is outside the generator and can be corrected without removing the unit from service. The following should be accomplished:

A. Operators transfer from automatic to manual voltage control.
B. Operators pull fuses to isolate noncritical generator field related circuits.
C. Test technicians verify proper operation of the generator field ground relay.
D. Electricians inspect brush-rigging and all associated apparatus.
E. Test technicians lift wires as possible, to further isolate generator field related dc circuits.

If the ground cannot be isolated, the unit should be removed from service for further investigation.

VIII Power System Stabilizers (PSS)

This equipment is designed for aiding system stability by introducing a supplementary control signal into a continuous-acting voltage regulator. This has the effect of improved damping of power system swings. The power system stabilizer signal is a reflection of system speed deviation, as detected by a turbine shaft-driven tachometer or a frequency transducer at the generator voltage regulator potential transformer's (POT) secondaries.

To comply with system requirements and improve electrical system stability, the power system stabilizers should be maintained in service as much as possible. Some machines have overly sensitive power system stabilizers (PSS output is more active than desired) below approximately 25% load. On these units the PSS should be placed in service at approximately 25% load and removed from service below 25% load.

IX Voltage Regulators

Voltage regulator instability is evident when the regulator output meter and the unit varmeter swing between buck and boost. The swings may increase in magnitude. If this occurs, the voltage regulator must be removed from service. Disturbances elsewhere in the system are typically indicated by large initial voltage regulator output and unit varmeter swings, which then dampen out within a few seconds.

When transferring between manual voltage control and voltage regulator control, first verify the voltage regulator output is at zero "differential" or "nulled." Improperly removing the voltage regulator from service (i.e., field rheostat improperly set) could result in reduction of the generator field, bucking VARs, and a trip of the unit from loss of excitation relays.

When mobile spare exciters are in use for unit excitation they are not equipped with voltage regulators. Generator voltage control is strictly manual by use of the mobile exciter field rheostat or voltage adjuster.

If the exciter field should become demagnetized or reversed on amplidyne type voltage regulators, the amplidyne may be used to restore magnetism with correct polarity. The amplidyne should first be checked for proper polarity by tuning the amplidyne control switch to the test position and operating the voltage adjuster to obtain an amplidyne voltage of at least 100 volts boost. With the field breaker closed and the exciter at running speed, the amplidyne control switch should then be turned to the "on" position until the exciter volt meter begins to read upscale, indicating that magnetism with the correct polarity has been restored. Nonamplidyne equipped stations should have detailed operating instructions on how to restore loss of exciter magnetism for their particular excitation systems.

X Moisture Intrusion

Even small amounts of moisture inside generators can result in reduced dielectric capability, stress corrosion pitting of retaining-rings, or lead carbonate production and plating of the machine surfaces. The following recommendation should be adhered to, to maintain the generators in a dry condition:

A. The backup seal-oil supply from the bearing oil system is to be used only in emergency situations.
B. Hydrogen dryers must be maintained and serviced.
C. Desiccant is to be monitored and replaced or regenerated as needed.
D. Hydrogen cooler and inner cooled coil leaks are to be reported and repaired in a timely manner.
E. Moisture detectors routinely checked for proper calibration/operation.

Generators equipped with nonmagnetic 18Mn-5Cr retaining-rings, should be operated as dry as possible to reduce the possibility of stress corrosion pitting damage to the rings. Those units should be taken off line at the first indications of moisture intrusion (dew point higher than 30°F) and any required repairs completed before returning the unit to service.

XI Recommended Routines

To maintain the operating integrity of main generators, the following should be performed during routine inspection rounds:

A. Check hydrogen purity levels normal and adjust as needed.
B. Check seal-oil system operating properly/maintaining proper differential pressure.
C. Check hydrogen dryers in service/desiccant checked and regenerated as needed.
D. Check liquid level detectors for accumulations of water or oil. Report and monitor any abnormalities.
E. Check stator, field and gas path temperatures. Report and monitor any abnormalities.
F. Check generator residual ground voltage. Report and monitor any abnormalities.
G. Check collector ring areas for broken or arcing brushes.

XII Protective Relaying

Generator Differential Protection. Generator differential relays compare the secondary currents from current transformers (CTs) installed on the neutral end of the generator windings to current transformers installed on the output side of the generator or the output side of the generator circuit breaker. If an internal phase-to-phase or three-phase fault occurs between the neutral and output CTs, the current flows will not balance and the differential relay will instantaneously actuate to trip the unit off line. *The unit should not be re-energized following a generator differential trip until the cause of the relay operation can be determined and resolved by engineers or technicians.*

Generator Stator Ground. Generator stator ground schemes protect the generator, isolated-phase buses, generator bus circuit breaker (if included), arrestors and surge capacitors (if included), and the primary windings of potential, auxiliary, and main step-up transformers from breakdowns in the insulation system to ground. Typically the stator ground relays are set to operate in 1.0 second for a 100% ground-fault condition. Typically the relay senses voltage on the secondary side of the generator stator-grounding transformer, which is connected between the generator neutral and the station ground grid. Under normal operation the relay will see a few volts of the third harmonic (180 Hz for 60 Hz machines) due to the nonsymmetry of the stator core iron and zero volts at normal system frequencies (50 or 60 Hz). The stator ground relays are usually de-sensitized at 180 Hz and are normally set to operate for a 5% ground at system frequencies.

The unit should not be re-energized following a generator stator ground trip until the cause of the relay operation can be determined and resolved by station engineers or technicians.

Generator Bus Ground Detectors. Units equipped with generator circuit-breakers require a second ground detector scheme to protect the generator circuit-breaker, iso-phase buses on the transformer side of the circuit-breaker, and the primary windings of potential, auxiliary, and main step-up transformers, from ground-fault conditions when the generator circuit-breaker is open. This scheme normally uses a wye/broken-delta connection with a voltage relay installed on the secondary side to sense ground conditions. Under normal conditions when the unit is running, this scheme will detect a few volts of the third harmonic and zero volts at running frequency. However, the scheme can become unstable under certain conditions (neutral instability or three-phase ferro-resonance) causing a blown fuse(s) in the ground-detecting transformers. A blown fuse may cause the ground detector relay to actuate. Also coordination between the stator and bus ground detector schemes is difficult, and depending on the design, the station may not be able to quickly ascertain which side of the generator circuit-breaker has the ground condition.

Preferred designs alarm only for bus ground detector schemes or alarm when the generator circuit-breaker is closed, and trip with a short time delay when the generator circuit-breaker is open. This prevents the unit from tripping for blown fuse conditions and allows operators to quickly determine which side of the generator circuit-breaker has the ground condition. With these designs, the generator stator ground relay will trip the unit for a ground on either side of the generator circuit breaker when the unit is on line. If the ground is on the generator side of the circuit-breaker, the ground will clear after tripping. If not, the bus ground detector will sound an alarm or trip the unit main step-up transformer after generator tripping. For the alarm-only schemes, the bus section should be immediately de-energized by the operators through the appropriate switching to mitigate the possibility of the low-level ground fault current developing into a damaging high-current phase-to-phase or three-phase short circuit.

The unit and/or the transformer should not be re-energized following a generator bus ground trip until the cause of the relay operation can be determined and resolved by engineers or technicians.

Loss of Excitation. Synchronous generators are not designed to be operated without dc excitation. Unlike induction machines, the rotating fields are not capable of continuously handling the circulating currents that can flow in the rotor forging, wedges, amortisseur windings, and retaining rings during underexcited or loss of field operation. Consequently loss-of-excitation relays are normally included in the generator protection package to protect the rotor from damage during underexcited operation. Impedance type relays are usually applied to automatically trip the unit with a short time delay whenever the var flow into the machine is excessive. Limits in the automatic voltage regulator should be set to prevent loss-of-excitation relaying whenever the voltage regulator is in the automatic mode of operation.

The machine should not be re-synchronized to the system following a loss-of-excitation trip until an investigation has been completed to determine the cause of the relay operation. Given the complexity of modern excitation systems, unexplained events are not that uncommon. Engineers or technicians should inspect the physical excitation system, verify calibration of the loss of excitation relays, check the dc resistance of the field-windings, and review any available data acquisition monitoring that would verify the operating condition. The unit can then be started for test and proper operation of the excitation system can be ascertained by operations before synchronizing the unit to the system.

Overexcitation. Overexcitation (volts/Hz) relays are applied to protect the generator from excessive field current and overfluxing of the generator stator core iron. Typically generators are designed to handle a full load field with no load on the machine for 12 seconds before the stator iron laminations become overheated and damaged. The relays are often set to trip the unit in 45 seconds at 110% volts/Hz and 2.0 seconds at 118% volts/Hz. The term volts/Hz is used to cover operation below normal system frequencies (50 or 60 Hz) where generators and transformer can no longer withstand rated voltages. At normal system frequencies, the relays will operate in 45 seconds at 110% voltage and in 2.0 seconds at 118% voltage. Generators are continuously rated for operation at 105% voltage and transformers for continuous operation at 110% voltage. Consequently the generators are the weak link, and safe operation for generators will, in most cases, automatically protect unit transformers that are connected to generator buses.

The unit should not be re-synchronized to the system following a volts/Hz trip until an investigation has been completed to determine the cause of the relay operation. However, given the complexity of modern excitation systems, unexplained events are not that uncommon. Engineers or technicians should inspect the physical excitation system, verify calibration of the volts/Hz relays, and review any available data acquisition monitoring that would verify the operating condition. The unit can then be started for test and proper operation of the excitation system can be ascertained by operations before synchronizing the unit to the system.

Reverse Power. Reverse power or anti-motoring relays are often applied for both control purposes and for protective relaying. In the control mode, they are typically used to automatically remove units from service during planned shutdowns and to ensure that prime movers have no output before isolating units electrically to prevent overspeed conditions. In the protection mode, they are used to protect turbine blades from windage overheating and sometime to protect combustion turbine units from flameout conditions. The reverse power or anti-motoring protective relays should have enough time delay before tripping to allow for synchronizing excursions (typically around 6 seconds). *Motoring* is not damaging to generators as long as proper excitation is maintained. In steam turbines, the LP turbine blades will overheat from windage. Typically steam turbine blades can withstand motoring conditions for 10 minutes before damage.

Following a reverse power or anti-motoring protection trip, the operators should determine if the trip was caused by control instability by reviewing recorder or DCS trending of unit megawatt output. If control instability is evident, engineers or technicians should investigate and resolve the problem before re-synchronizing the unit. If control instability is not evident, engineers/technicians should check the calibration of the protective relays before returning the unit to service.

Negative Sequence Protection. Unbalanced phase current flow in generator stators cause double-frequency reverse rotation currents to circulate in the rotor body that can damage the rotor forging, wedges, amortisseur windings, and retaining rings. Cylindrical rotor generators designed according to ANSI standards are capable of continuously carrying 10% negative phase sequence current. This roughly corresponds to an operating condition where two phases are carrying rated current and the third phase has 70% of rated current. Depending on the design of the rotor (indirectly or directly cooled) generators with two phases at rated current, and no current in the third phase, can carry this unbalance for 90 to 270 seconds before damage occurs to the rotor components. Accordingly negative-phase sequence relays are necessary to protect generator rotors from damage during all possible operating conditions, including phase-to-phase and phase-to-ground faults on the transmission system.

Some negative-sequence overcurrent relays provide an alarm function with a pickup value set somewhere below the trip point. This alerts the unit operator to a negative-sequence condition prior to a trip. If the negative-sequence alarm is initiated, the operator should take the following action:

Notify the transmission dispatcher of the negative sequence condition and find out if there are any electrical problems on the transmission system. When a negative phase sequence alarm is activated, operators should also check the phase currents for balance. In addition to off-site causes for unbalance, open conductors, disconnect, or breaker poles at the site can cause the unbalance condition. If no abnormalities exist, notify dispatcher that load will be reduced on the generator until the alarm clears.

The generation should be taken off AGC, and load should be reduced until the alarm clears.

Engineers or technicians should verify calibration of the negative-phase sequence relay, and review any data acquisition monitoring devices (protective relay digital storage or DCS trends) to verify that the unit operated with a significant current unbalance.

If the alarm is coincident with any electrical switching in the switchyard or within the plant, the device should be opened, and if the alarm clears, the apparatus in question should be investigated for proper operation.

Following a negative phase sequence trip, the unit should not be returned to service until an investigation is completed. Engineers or technicians should prove the calibration of the negative-phase sequence relay, and review any data acquisition monitoring devices (protective relay digital storage or DCS trends) to verify that the unit operated with a significant current unbalance. It may have been caused by an electrical system fault that did not clear promptly because of faulty circuit-breakers or protective relays.

Under-Overfrequency Protection. Almost always, the O/U frequency protection of the unit is there to protect the turbine before it protects the generator. Turbines tend to be more sensitive to off-frequency operation that the generator. Therefore the U/O frequency protective devices are in general set to protect the turbine.

Operators should be aware of the frequency limitation for their particular turbines, and not operate them outside of the manufacturers recommended limits under any circumstances.

If a unit trip by the operation of a U/O frequency relay, the unit should not be returned to service, until, the system frequency stabilizes within acceptable limits, and the protection is found to be properly calibrated.

XIII Routine Operator Inspections

To maintain the operating integrity of generators, the following checks should be routinely performed by operations when making their daily inspection rounds:

- Check hydrogen purity levels (where applicable) and adjust gas flow to the purity monitor as required.
- Check that the seal oil system is operating properly. Verify that the proper pressure differential between the seal oil and hydrogen gas systems is maintained (where applicable).
- Check that the hydrogen dryers are in service (where applicable), operating properly, and the desiccant is in good condition.
- Check the liquid detectors for accumulation of water or oil.
- Verify proper water flow to hydrogen or stator coolers (where applicable).
- On generators equipped with water-cooled stator coils, verify proper flow, conductivity, and differential pressure between the water and the hydrogen gas systems.
- Check the stator, gas, and field temperatures.
- Check the bearing vibration levels.
- Check the generator stator ground scheme for proper residual or third harmonic voltages.
- Check the brush-rigging (where applicable) for broken, vibrating, and arcing brushes.
- When the rotor is stopped or on turning gear, the brush-rigging area should be checked periodically for hydrogen leakage (where applicable). Hydrogen gas can leak through the bore conductors and accumulate in the brush-rigging areas when the unit is off line.
- Check the shaft grounding brush(es) or braid(s), to verify physical integrity. In those units, where the grounding brushes/braids are not visually accessible, refer to the maintenance guideline (EMG-1) for periodic maintenance.
- Verify the field-winding ground-fault detection system is operational.
- Anomalies found during the routine inspections should be monitored and work orders prepared to resolve problems noted.

REFERENCES

1. IEEE Std 67-1990, or later, “IEEE Guide for Operation and Maintenance of Turbine Generators.”
2. IEEE/ANSI C50.13-1989, or later, “Requirements for Cylindrical-Rotor Synchronous Generators.”
3. IEEE Std 502-1985, “IEEE Guide for Protection, Interlocking, and Control of Fossil-Fueled Unit-Connected Steam Stations.”
4. ANSI/IEEE C37.106-1987, or later, “Protection for Power Generating Plants.”

5. M. G. Say, *Alternating Current Machines*. Pitman Publishing, 1978.
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7. IEEE Std 1-2000, "IEEE Recommended Practice—General Principles for Temperature Limits in Rating of Electrical Equipment and for the Evaluation of Insulation."