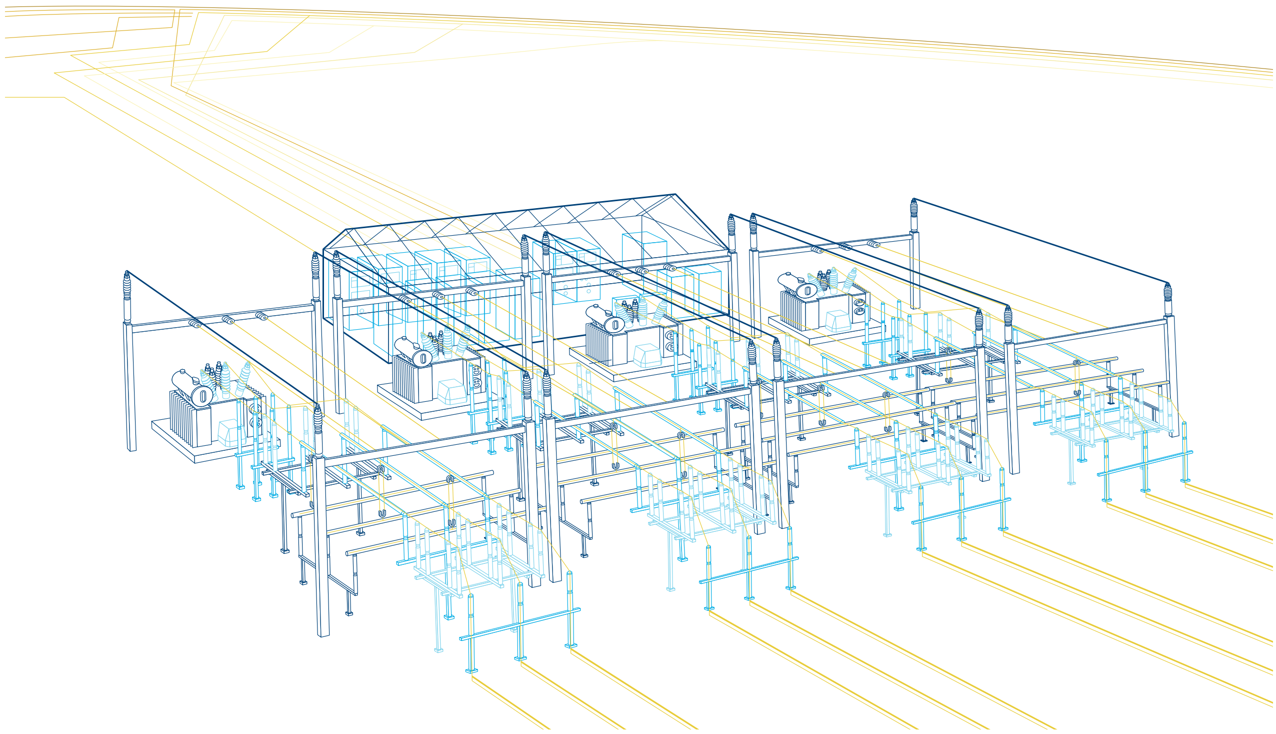
Distribution Automation Handbook

Section 8.12 Generator Protection



Contents

8.12 Protection of Synchronous Generators

Most power systems tolerate the disconnection of one generating unit, one power transformer, one power line or one busbar section without running into serious problems. A fault on adjacent power system component may cause the generator protection system to operate non-selectively.

8.12.1 Introduction

A generator has more failure modes than any other component in the power system. It is very important that the protection system detect all faults that may hurt humans and damage equipment. The generator protection system must detect the faults rapidly.

8.12.1.1 General Demands

The general demands on the protection system are based on some risk analysis, experience and tradition. Commonly, it is required that earth faults, short circuits and other severe faults must be detected by two independent protections. The fault must be cleared even if one switching device fails to operate. The generator protection system must also provide adequate backup protection for adjacent components.

8.12.2 Synchronous Machines

A synchronous machine is not a simple device. The armature, or stator, winding is arranged in three symmetrical phase belts in slots in the stator surface. The magnetic field intensity can be controlled via the DC-current in the rotor, or field, winding. A synchronous machine can operate as a generator or as a motor.

8.12.2.1 Power Station Configuration

Varying power station configurations obstruct the use of a uniform and standardized generator protection system. The most important factor is the varying power station configuration. Besides the varying power station configuration, following factors influence the design of the generator protection system:

- generator circuit-breaker or not
- earthing of the generator neutral
- location of the voltage transformers
- location of the current transformers

8.12.3 Earthing of Generators

There are even more methods for earthing of generators than for earthing of networks. In power stations, there are many combinations of generators, transformers, busbars and outgoing power lines. References [8.12.11] and [8.12.14] provide information on the earthing of generators. Even if there are many possibilities, the main focus here is on the resistance earthing, which is the dominating system. A neutral point resistor controls the potential of the generator windings. The introduction of a neutral-point resistor will result in a small earth-fault current. We can neglect the risk for severe generator damages if the earth-fault current is less than 15 A.

The neutral-point resistor can also be connected on the secondary side of a distribution transformer. The rated voltage of the neutral-point transformer must not be less than the rated phase-to-neutral voltage of the generator. To reduce the inrush current to the neutral-point transformer, it should have a rated voltage equal to the rated phase-to-phase voltage of the generator.

8.12.4 Faults and Abnormalities

The protection of synchronous generators involves the consideration of more possible faults and abnormal conditions than the protection of any other power system component. We have to consider (1) stator faults, (2) rotor faults, (3) abnormal operating conditions and (4) faults in the connected power grid.

8.12.4.1 Stator Faults

Damage to the stator winding itself or to its insulation may cause stator short circuits or stator earth faults.

Ageing, overvoltage, overcurrent or loss of cooling may cause stator short circuits. External short circuits, improper synchronization and loss of synchronism may cause large currents. These currents cause high forces that may displace the stator winding and cause an internal short circuit.

An external short circuit is accompanied by very large fault currents. The electromechanical forces increase considerably when the size of the generator increases. The size of the electromechanical forces may amount to more than 100 N/cm at sudden short circuits. Generally, the utilities require that synchronous generators shall withstand, without damage, all types of short circuit on the generator terminals.

Short circuits clear of earth are less common faults. They may occur on the end portion of the stator coils. They may also occur in the slots if there are two coils in the same slot. In the latter case, the fault will involve earth in a very short time.

Thermal power units commissioned during the last 30 years often have phase-segregated generator bus-work. This reduces considerably the risk for two- and three-phase short circuits close to the generator terminals.

Pohl has investigated how the earth-fault current damages the sheets of a synchronous machine. In [8.12.6], he describes the result of tests with three different insulating materials between the stator sheets, two different values of the earth-fault current and four values of the fault clearance times.

8.12.4.2 Rotor Faults

The field circuit of a synchronous generator consists of the rotor winding proper and associated circuits. These may include the slip rings and brushes, the field circuit-breaker, the armature of a rotating exciter or the rectifier and the secondary winding of the magnetization transformer in a static exciter. This circuit is an isolated DC-circuit and it is not necessary to earth it. The field circuit of modern generators is often operated unearthed. Earth faults, interturn faults and open circuits may occur in the field circuit. Over-excitation or unbalanced loading may overheat the rotor.

8.12.4.3 Abnormal Operating Conditions

Here are several situations when abnormal operating conditions can result in damages of the generating unit. Some of the generator protection functions shall detect such abnormal conditions and initiate trip of the generator before internal faults occur. Examples of abnormal conditions are: (1) abnormal voltage, (2) abnormal frequency, (3) loss of synchronism and (4) unbalanced loading.

8.12.5 Differential Protection

A rotating machine provides a classical application of differential protection. The generator differential protection gives a fast and absolutely selective detection of generator stator short circuits. Usually, all equipment, the CTs and the circuit-breakers are near each other. This minimizes the possible error due to long cable runs. In addition, there is only one voltage level involved. This means that the CT ratio and types can be the same.

It is very important that the differential protection does not operate in case of external short circuits. There is a risk that the generator differential protection misoperates if a CT saturates. Close to power stations, the time constant of the DC-component of the short circuit current may be very long and in the order of 100 to 150 ms. External short circuits with a fully developed DC-component puts severe demands on CT and differential protection.

There may be more than one differential protection in a power station. In such cases, one differential protection is associated with the generator and one with the generator step-up transformer. The sensitivity of the generator step-up transformer differential may be about 20% of the rated current of the transformer. This differential protection must not trip when the step-up transformer is energized and a high inrush current flows from the network to the transformer. The overall differential protection provides backup protection. The sensitivity of the overall differential protection is equal to the sensitivity of the transformer differential protection. The overall differential protection may operate non-selectively if its tripping signal is not delayed.

8.12.6 Underimpedance Protection

The line protections shall detect all shunt faults on the transmission network and trip the associated line circuit-breakers. The backup protection system must operate when a line protection fails to operate or when a circuit-breaker fails to interrupt the fault current. Often the generator underimpedance protection is one part of this backup protection system. Sometimes there is no overall differential protection and another type of backup protection is needed when the main protection fails to operate.

8.12.7 Overcurrent Protection

Many synchronous generators have rotating exciters. The old generators often have simple overcurrent protections. The task of this overcurrent protection is to provide backup protection for internal short circuits and external shunt faults. Generally, the setting is $1.5 \times I_n$ where I_n is the rated current of the generator. The time delay is set to assure selectivity to other protections.

The introduction of static exciters made it necessary to replace the overcurrent protections by under-impedance protections or voltage-restrained overcurrent protection.

Persisting overcurrent in the interval $[1.0 \times I_n, 1.4 \times I_n]$, where I_n is the rated current of the generator, are not detected by overcurrent protections or by underimpedance protections. Such overload must be detected by dedicated thermal overload protections or by overtemperature sensors. Modern overload protections may have an adjustable time constant that can be adjusted to the thermal properties of the generator.

8.12.8 Stator Earth-fault Protection

There are many methods for the detection of earth faults in generators. The choice of method depends on the layout of the power plant. There are units with the generator and the step-up transformer connected as a unit. The generator may or may not have a generator circuit-breaker. Two or more generators may share a common step-up transformer. One may connect several generators to a common generator busbar. In such cases, the number of step-up transformers may be one or more. The method for the detection of earth faults depends also on the system earthing.

8.12.8.1 Earthing of Generating Units

Most generators have high-impedance (high-resistance) earthed neutral. One method is to use a high-voltage resistor and connect it directly to the neutral point of the generator. It is also possible to use a low-voltage resistor and connect it on the secondary side of a single-phase distribution transformer. The neutral point of the generator is connected to the primary side of the distribution transformer. The main task of the neutral-point resistor is to limit the overvoltage on the windings and buswork of the generating units. Overvoltages on the high-voltage side of the step-up transformer may cause such an overvoltage. The stray capacitances between the high-voltage winding and the low-voltage winding of the step-up transformer determine the magnitude of the overvoltage on the generator winding and associated buswork. It is often necessary to install surge capacitors on the low-voltage side of the step-up transformer if there is a generator breaker. The highest overvoltage on the buswork occurs when the generator breaker is open.

There is a rule of thumb for the selection of the neutral-point equipment. The effective resistance R_N [Ω] seen from the neutral point of the generator should be equal to the capacitance to earth as in equation (8.12.1). All capacitances are zero-sequence capacitances (capacitances to earth with all phase conductors connected to each other).

$$R_N = \frac{1}{3 \cdot \omega \cdot (C_w + C_b + C_a + C_t)} \qquad \textbf{(8.12.1)}$$

Here

C_w Is the capacitance of the generator winding [F/phase]

C_b	Is the capacitance of the buswork [F/phase]
C_t	Is the capacitance of the step-up transformer [F/phase]

High earth-fault currents may damage the iron core if the fault clearance time is long. The risk for damage is small if the earth-fault current is lower than 15 A when there is an earth fault on one generator phase terminal.

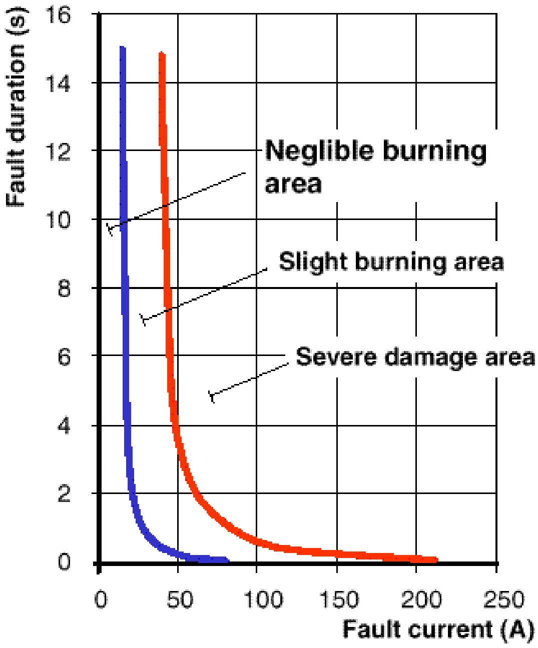


Figure 8.12.1: Consequences of a stator earth fault

8.12.8.2 The Earth-fault Protection System

The task of the earth-fault protection is to detect earth faults on the winding of the generator, on the associated buswork, on the primary winding of the auxiliary transformer and on the primary winding of the step-up transformer. A single phase-to-earth fault will cause an increase of the voltage on the other phases and the neutral point. The voltage rise depends on the fault location and fault resistance. The healthy phases will assume full phase-to-phase voltage if an earth fault without fault resistance hits the line terminal of one winding of the generator. Simultaneously, the neutral point will assume full phase-to-neutral voltage. The voltage rise will decrease when the fault resistance increases. The voltage rise will be negligible if the earth fault occurs on the phase winding close to the neutral point.

To detect an earth fault on the windings of a generating unit, a neutral point overvoltage relay, a neutral point overcurrent relay, a zero-sequence overvoltage relay or a residual differential protection can be used. These protection schemes are simple and have served well during many years. However, at best these simple schemes protect only 95% of the stator winding. They leave 5% at the neutral end unprotected.

Under unfavorable conditions, the blind zone may extend to 20% from the neutral. There are several methods to detect an earth fault close to the neutral point. Figure 8.12.2 illustrates some fundamental properties of some types of earth-fault protections. The intention is to illustrate general methods and define some classes of earth-fault protections.

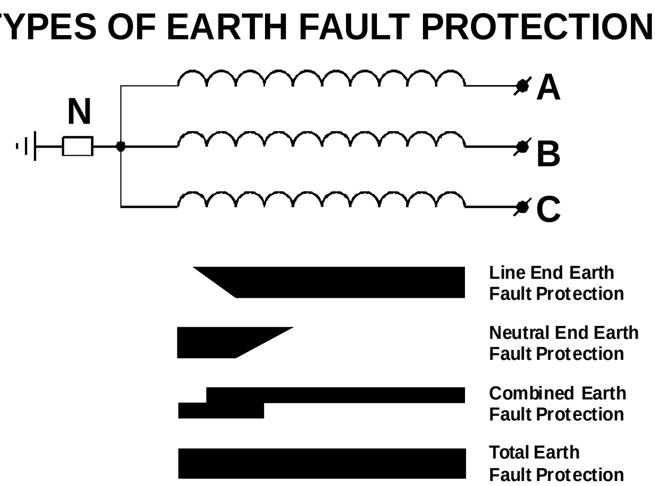


Figure 8.12.2: Types of earth-fault protections

The line end earth-fault protection can detect earth faults on almost entire winding but has unfortunately a blind zone close to the neutral point. The size of the blind zone may be 5-20%. The main task of the neutral end earth-fault protection is to detect an earth fault close to the neutral point. Such protections may cover 20-40% of the winding.

8.12.8.3 Line End Earth-fault Protection

Neutral-point overvoltage protections, neutral-point overcurrent protections, zero-sequence overvoltage protection and residual differential protections are line end earth-fault protections.

8.12.8.3.1 Unit Generator-Transformer Configuration

The neutral point overvoltage protection is a common earth-fault protection for unit-connected generators. Figure 8.12.3 shows such a protection.

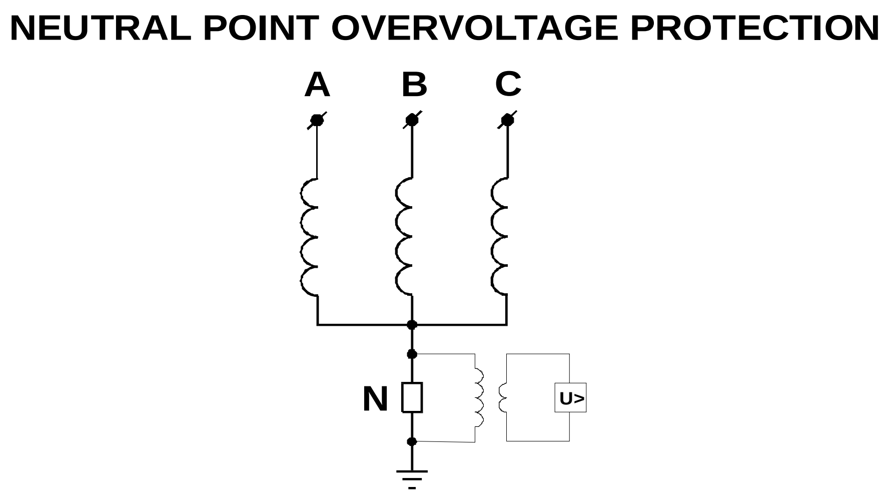


Figure 8.12.3: Neutral-point overvoltage protection

A single-phase voltage transformer connected to the generator neutral energizes the neutral-point overvoltage protection. Such protection detects earth faults on the generator windings, on the buswork and on the primary winding of the auxiliary transformer. It can also detect earth faults on the primary winding of the step-up transformer both in units without a generator breaker and while the generator breaker is closed. The blind spot near the neutral may be as small as 5%.

A zero-sequence overvoltage protection can also detect faults on the generator system. Figure 8.12.4 shows such zero-sequence overvoltage protection.

Three single-phase voltage transformers energize the zero-sequence overvoltage protection. The primary winding of each voltage transformer is connected to a phase conductor. A secondary winding on each voltage transformer forms a broken delta that energizes the overvoltage relay.

Each voltage transformer has an amplitude error and a phase error. This means that the secondary zero-sequence voltage may not represent the primary zero-sequence voltage exactly. To avoid unwanted operation, the zero-sequence overvoltage setting must be higher that the neutral-point overvoltage setting.

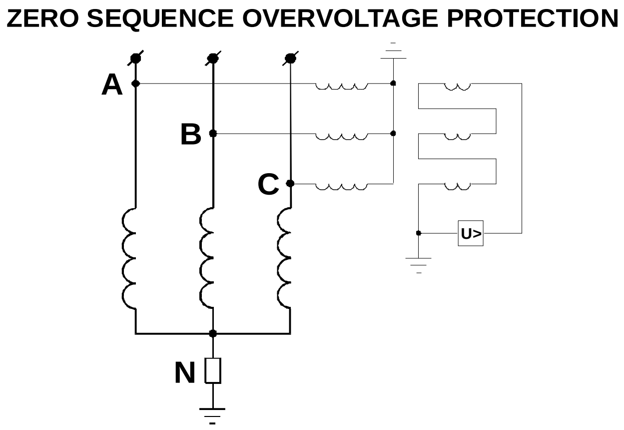


Figure 8.12.4: Zero-sequence overvoltage protection

The earth-fault protections described above cannot detect earth faults on the primary winding of the step-up transformer while the generator breaker is open. To detect such faults, a zero-sequence overvoltage protection can be used. It is connected to the primary winding of the step-up transformer. The sensitivity is about 80%, and the delay is equal to 0.8 second.

8.12.8.3.2 Several Generators Connected to a Common Busbar

In a power plant with several generators connected to a common busbar, the busbar can have one or more transformer bays. Usually, the busbar has no feeder bays. In such plants, it is a common practice that the generators have an unearthed neutral. Often there is a requirement to limit the overvoltage on the busbar while only one generator is in service. This case determines the maximum size of the resistor connected to the neutral point of the generator. When all generators with such resistors are in service, the total earth-fault current may become too high.

Some busbars may have a bay for an earthing transformer with a neutral point resistor. In such cases, the system has a high-impedance earthed neutral. Some plants may have only a step-up transformer with a Y- or Z-connected winding connected to the busbar. This neutral point can be used to connect a neutral point resistor. It is not necessary to install neutral-point resistors at each generator if there is an earthing transformer with a neutral-point resistor of if the step-up transformer has a neutral-point resistor. It is also possible to avoid using neutral-point disconnecters otherwise necessary to limit the earth-fault current.

Neutral-point overvoltage protections, neutral-point overcurrent protections and zero-sequence overvoltage protections cannot select the faulty generator if several generators are connected to one common busbar.

Figure 8.12.5 shows a residual differential protection that can select the faulty generator when several generators are connected to the busbar.

Only a three-phase current transformer is needed if the neutral point of the generator is unearthed. Unavoidable amplitude errors, high CT-ratio and phase errors limit the sensitivity of the earth-fault protection. On external short circuits, the fault current from the generator may be very high and may contain a substantial DC-component. The fault currents may cause a false secondary zero-sequence current. There is a risk that this false current will cause unwanted operation of the earth-fault protection. To avoid such unwanted operations, the short circuit protection may block the earth-fault protection on external short circuits. The closing of the generator breaker may cause transient residual currents. These currents may limit the sensitivity of the residual differential protection.

We assume that each generator has a neutral point resistor. To obtain selective clearance of earth faults, it is necessary to use a residual differential protection. Figure 8.12.5 shows such a protection that is energized from three-phase current transformers and one neutral-point current transformer.

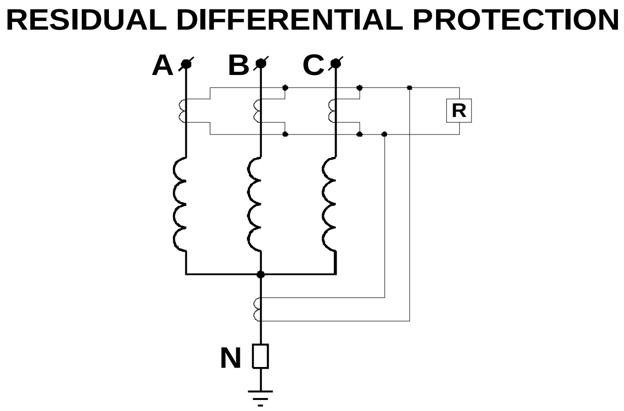


Figure 8.12.5: Residual differential protection

8.12.8.4 Neutral-end Earth-fault Protection

An overvoltage (or overcurrent) generator earth-fault protection is a straightforward, secure and dependable earth-fault protection. However, it suffers from two disadvantages, [8.12.3] and [8.12.8]. First, it will not detect earth faults near the generator neutral. Second, it is not self-monitoring. That is, an open circuit anywhere in the relay, the primary or secondary of the voltage transformer (the current transformer) or an open neutral-point resistor may not be detected before a fault occurs.

The induced EMF in a synchronous generator contains harmonics. It is possible to use the third harmonic to detect earth faults close to the neutral point and in the neutral point equipment. The third harmonic voltages, having zero-sequence characteristic, cause a third harmonic current that flows through the neutral-point resistor.

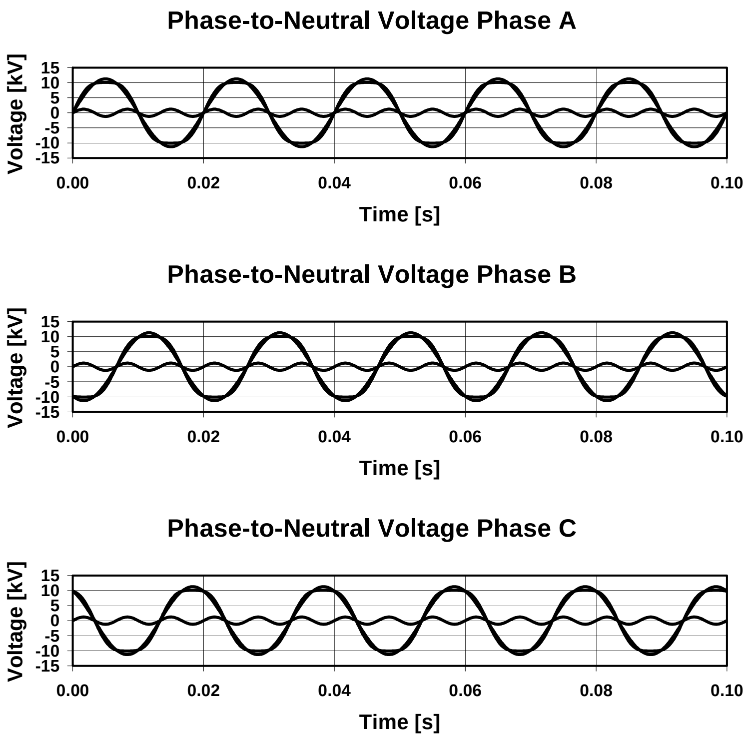


Figure 8.12.6: Fundamental and third harmonic voltage

An earth fault close to the neutral point will shunt the neutral-point resistor and the third harmonic voltage across the neutral-point resistor. The fault can be detected as a low neutral-point third harmonic voltage or as a changed relation between the neutral point and generator terminal third voltage level.

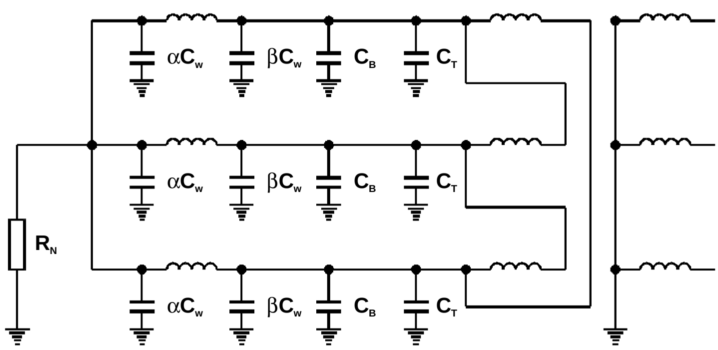


Figure 8.12.7: Distribution of capacitances

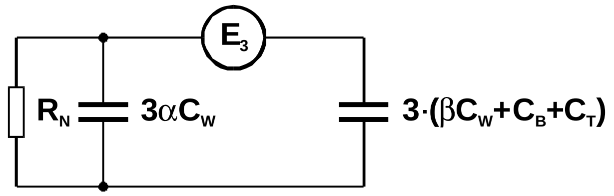


Figure 8.12.8: Equivalent circuit for third harmonic

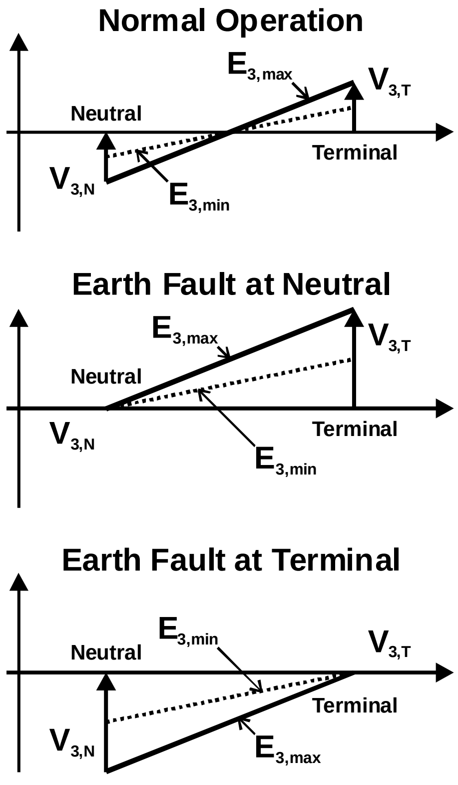


Figure 8.12.9: Third harmonic neutral-end earth-fault protection

8.12.9 Field Earth-fault Protection

The field circuit comprises the field winding of the generator and the associated circuits of the exciter. Faults in the field circuit can be classified as open circuits, earth faults and short circuits.

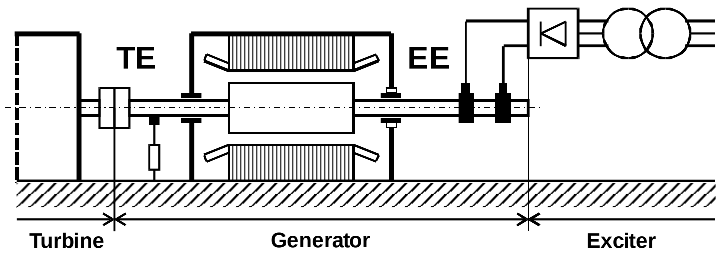


Figure 8.12.10: Earthing of a turbo generator

8.12.9.1 Open Circuits

Open circuits in the field circuit may occur on any type of generator. Experience has shown that they are more likely to occur on hydro-generators, especially those with low rated rotational speed [8.12.16]. An open field circuit may cause burning at the fault location. Besides local damages, an open field circuit causes a complete loss of excitation.

8.12.9.2 Earth Faults

The field winding is always insulated from the metallic parts of the rotor. A fault in the insulation of the field circuit will result in a conducting path from the field winding to earth. This means that the fault has caused a field earth fault.

The field circuit of a synchronous generator is normally unearthed. Therefore, a single earth fault on the field winding will cause only a very small fault current. Furthermore, it will not affect the operation of a generating unit in any way. Utilities have operated generators in this condition for considerable periods. However, the existence of a single earth fault increases the electric stress at other points in the field circuit. This means that the risk for a second earth fault at another point on the field winding has increased considerably. A second earth fault will cause a field short circuit with associated consequences described below.

8.12.9.3 Short Circuits

Danger arises if a second earth fault occurs at another point on the field winding. The second earth fault will cause a short circuit in the field winding. An overcurrent relay in the field circuit cannot detect a short circuit if only a few turns are involved or if one pole of a slow-speed hydro-generator is short-circuited. Furthermore, it is highly desirable for the field circuit not to be opened during external power system faults.

Such faults may cause high currents to flow in the field circuit. Therefore, field overcurrent protections are uncommon [8.12.16].

The normal field current of a large generator is considerable. The fault current caused by the short circuit may very rapidly cause serious damage at the fault locations.

8.12.9.4 Earth-fault Detectors for Units with Brushes

Earth-fault detection in the field circuit often involves AC or DC auxiliary supply. The AC-scheme comprises an auxiliary supply transformer. Its secondary winding is connected between earth and one side of the field circuit through an interposed capacitor and a relay coil [8.12.15]. The field circuit is subjected to an alternating potential that has practically the same level throughout. Therefore, an earth fault anywhere in the field circuit will cause an AC-current that is detected by the relay. The capacitor limits the current and blocks the normal field voltage. It also prevents the discharge of a large DC-current through the auxiliary transformer.

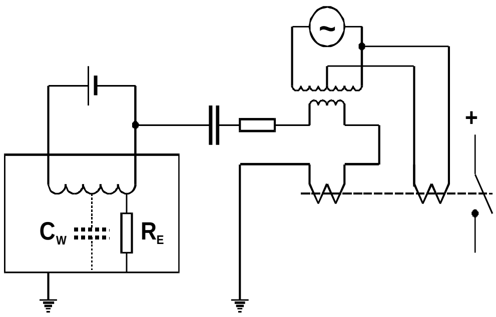


Figure 8.12.11: Rotor earth-fault protection

The capacitive currents associated with AC-injection can be avoided by injecting a DC-voltage through a resistor [8.12.15]. The injected DC-voltage is arranged to bias the positive side of the field circuit to a negative voltage to earth. The negative side of the field circuit is at an even greater negative voltage to earth. This means that an earth fault at any point on the field winding will cause current to flow through the power unit and the DC-type relay. The current is limited by including a high resistance in the circuit, and a sensitive relay is used to detect the current.

8.12.9.5 Earth-fault Detectors for Units without Brushes

The introduction of brushless exciters has increased the difficulties to detect earth faults on the field winding [8.12.9].

Generators with brushless exciters are supplied with means to drop pilot brushes on slip rings to measure the insulation level of the field winding on a periodic basis [8.12.1].

8.12.10 Underexcitation Protection

The production of reactive power from a synchronous machine can be increased by increasing the excitation current (the rotor current). The machine acts like a shunt capacitor. A synchronous machine can consume reactive power if the excitation current is low enough. In this state, the machine acts like a shunt reactor.

The acceptable limit for overexcitation (reactive production) depends on the prevailing active power generation (consumption). The acceptable limit for underexcitation (reactive consumption) may or may not depend on the active generation (consumption).

8.12.10.1 Underexcitation of Synchronous Machines

There are limits for the underexcitation of a synchronous machine. A reduction of the excitation current weakens the coupling between the rotor and the external power system. The machine may lose the synchronism and starts to operate like an induction machine. Then, the reactive consumption will increase. Even if the machine does not lose synchronism, it may not be acceptable to operate in this state for a long time. The underexcitation increases the generation of heat in the end region of the synchronous machine. The local heating may damage the insulation of the stator winding and even the iron core.

8.12.10.2 Loss of Excitation

A fault in the Automatic Voltage Regulator (AVR) or in the excitation system may cause a total loss of excitation. A short circuit on the slip rings will reduce the excitation voltage down to zero. This will cause a gradual reduction of the excitation current and eventually a loss of excitation. An open circuit in the field circuit will also cause a total loss of excitation. When the field breaker is open, a high voltage is induced in field winding and there is a risk for damages to the discharge resistor.

8.12.10.3 Underexcitation Protection

Undercurrent relays connected in the field circuit have been used [8.12.5] for underexcitation protection. Mason [8.12.5] and Sarma [8.12.7] both claim that the most reliable underexcitation protection is either an MHO-relay or a directional impedance relay with its characteristic in the negative reactance area.

Many generators use a directional overcurrent relay for underexcitation protection. The underexcitation relay shall trip the generator breaker and start the breaker failure protection. Underexcitation cannot occur while the terminal voltage is low if the excitation system operates correctly. Therefore, the underexcitation protection should use an undervoltage criterion. Underexcitation will not cause a low terminal voltage if the generator is connected to a strong network or if there are several generating units in the power plant. In such a case, the stator current of the faulty generator will increase. Therefore, the underexcitation protection should use an overcurrent relay. Two criteria must be fulfilled before the underexcitation equipment may trip the generator. The first criterion is the directional overcurrent relay has operated. The second criterion is that either the undervoltage relay has operated or the (non-directional) overcurrent protection has operated. It must however be mentioned that the undervoltage/overcurrent criteria cannot be used for generators having a very high synchronous reactance, thus limiting the voltage drop and stator current at loss of excitation.

8.12.11 Overvoltage Protection

Some events can cause a high voltage on the generator both with the generator synchronized to the network and before synchronization. The overvoltage can cause stress on insulation material and overexcitation of transformer and generator.

The overvoltage protection system should, according to Sarma [8.12.7], have two steps if the generator does not have an AVR. In thermal power plants, the first step should pick up if the voltage exceeds 125%. For hydropower plants, the corresponding figure is 140%. The first step should trip without delay. The second step should pick up if the voltage is higher than 110% and should have a dependent time characteristic.

Most generators have two sets of voltage transformers. One set comprises three single-phase transformers and it energizes the protection equipment and the AVR. The second set may comprise only two single-phase voltage transformers. This set energizes the overvoltage protection system. It is necessary to use two sets of voltage transformers because otherwise the overvoltage protection system and the AVR do not have independent input sources. Usually, a phase-to-phase voltage energizes the overvoltage protection system to avoid unwanted operation at single phase-to-earth faults.

8.12.12 Reverse Power Protection

Sometimes the mechanical power from a prime mover may decrease so much that it does not cover bearing losses and ventilation losses. Then the synchronous generator becomes a synchronous motor and starts to take electric power from the rest of the power system. This operating state, where individual synchronous machines operate as motors, implies no risk for the machine itself.

Often the motoring condition may imply that the turbine is in a very dangerous state. The task of the reverse power protection is to protect the turbine and not to protect the generator itself. Generally, AC-current and voltage energize the reverse power protection system and it trips the generator breaker. Therefore, the reverse power protection is included in the generator protection.

Steam turbines overheat easily if the steam flow becomes too low or if the steam ceases to flow through the turbine. Therefore, turbo-generators should have reverse power protection. Several contingencies may cause reverse power. One is a break of the main steam pipe. A second is damage to one or more blades in the steam turbine. The third is an inadvertent closing of the main stop valves. In the last case, it is highly desirable to have a reliable reverse power protection. It may prevent damage to an otherwise undamaged plant.

During the routine shutdown of many thermal power units, the reverse power protection gives the tripping impulse to the generator breaker (the unit breaker). By doing so, the disconnection of the unit is prevented before the mechanical power has become zero. Earlier disconnection would cause an acceleration of the turbine generator at all routine shutdowns. This should have caused overspeed and high centrifugal stresses.

When the steam ceases to flow through a turbine, the cooling of the turbine blades will disappear. The critical time to overheating of a steam turbine varies, according to Mason [8.12.5], from about 0.5 to 30 minutes, depending on the type of turbine. A high-pressure turbine with small and thin blades will overheat more easily than a low-pressure turbine with long and heavy blades. The conditions vary from turbine to turbine, and it is necessary to ask the turbine manufacturer in each case. It is also prudent to measure the reverse power during the commissioning of new units.

A hydro turbine that rotates in water with closed wicket gates will draw electric power from the rest of the power system. This power will be about 10% of the rated power. If there is only air in the hydro turbine, the power demand will fall to about 3%. It is prudent to measure these values during the commissioning.

Diesel engines should, according to Mason [8.12.5], have reverse power protection. The generator will take about 15% of its rated power or more from the system. According to GEC [8.12.15], a stiff engine may require perhaps 25% of the rated power to motor it. An engine that is well run in might need no more than 5%. According to Sarma [8.12.7], diesel engine units usually require reverse power protection with a setting of 15% to 25%. It is necessary to obtain information from the engine manufacturer and to measure the reverse power during commissioning.

A reverse power relay and a timer can provide adequate reverse power protection. The reverse power relay can be a directional undercurrent relay that measures the current that flows from the generator to the network (an underpower relay). It may also be a directional overcurrent relay that measures a current that flows from the network to the generator (an overpower relay). There are few sensitive current relays that can also withstand the normal load current continuously. The relay must also temporarily withstand the fault current that may flow through the relay. The setting range of the timer should be from a few seconds to some minutes.

Figure 8.12.12 illustrates the properties of reverse power protection with an underpower relay and with an overpower relay. The underpower relay gives higher margin and provides better dependability. On the other hand, the risk for unwanted operation immediately after synchronization may be higher. The underpower relay should be set to trip if the active power from the generator is less than about 2%. The overpower relay should be set to trip if the power flow from the network to the generator is higher than 1%.

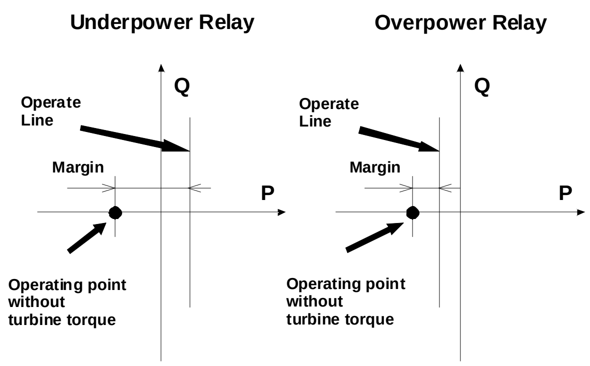


Figure 8.12.12: Characteristics of the reverse power protection

The demands on the reverse power protection are increasing. An AIEE report [8.12.16] says that the reverse power relays may only give an alarm immediately when power flows from the network to the generator. The reverse power relay should trip if the power reversal persists long enough to cause damage to the turbine from overheating. A delay of at least one minute will be permissible between the times when the power reversal starts and tripping should occur.

8.12.13 Unbalance Protection

Single-phase loads, series faults and unsymmetrical faults may cause continuous and temporary unbalance loading of a synchronous machine. If the unbalanced loading is too high and persists too long, the rotor of the machine overheats and becomes damaged. Equation (8.12.2) gives the stator phase currents of a three-phase generator that carries balanced load.

$$\begin{aligned} I_a &= I \cdot \sin(2\pi f - \frac{0\pi}{3}) \\ I_b &= I \cdot \sin(2\pi f - \frac{2\pi}{3}) \\ I_c &= I \cdot \sin(2\pi f - \frac{4\pi}{3}) \end{aligned} \qquad \textbf{(8.12.2)}$$

Equation (8.12.3) gives the phase-to-earth stator voltages of a three-phase generator that carries balanced load.

$$\begin{aligned} V_a &= V \cdot \sin(2\pi f - \frac{0\pi}{3} + \varphi) \\ V_b &= V \cdot \sin(2\pi f - \frac{2\pi}{3} + \varphi) \\ V_c &= V \cdot \sin(2\pi f - \frac{4\pi}{3} + \varphi) \end{aligned} \qquad \textbf{(8.12.3)}$$

8.12.13.1 Unbalanced Loading

The generator carries an unbalanced load if equations (8.12.2) and (8.12.3) do not hold true. A well-defined description of unbalance is the relative amount of negative-sequence current I_2/I_n that the generator carries. Equation (8.12.4) defines the negative sequence current I_2.

$$I_2 = \frac{I_a + a^2 \cdot I_b + a \cdot I_c}{3} \qquad \textbf{(8.12.4)}$$

Here I_n is the rated stator current of the machine. The relative negative-sequence current is therefore well defined and it can be measured.

8.12.13.1.1 Causes of Unbalanced Loading

Unbalanced loading may produce more severe heating than balanced three-phase operation. Series faults close to the generator will cause negative sequence currents. Unsymmetrical faults may produce more severe heating in three-phase synchronous machines than symmetrical faults. Typical conditions and incidents that can cause unbalanced loading are:

- Single-phase loads close to the power plant
- Untransposed transmission circuits
- Unbalanced step-up transformers
- Series faults in the transmission network
- Series faults on the secondary side of the step-up transformer
- Series faults on the primary side of the step-up transformer
- Pole discrepancy in the generator breaker
- Unbalanced shunt faults close to the power plant
- Unbalanced shunt faults on the generator buswork

8.12.13.1.2 Consequences for the Generators

The rotor of a synchronous machine overheats quite rapidly if the generator carries negative-sequence currents. The negative-sequence current generates a stator-MMF that rotates with the same speed as the rotor but in the opposite direction. Seen from the rotor, this MMF has a frequency $2f_n$, where f_n is the power frequency (50 or 60 Hz). The MMF induces voltages with a frequency $2f_n$ in the rotor and its windings.

These voltages cause currents to flow in the rotor and associated windings. Due to the skin effect, these currents flow close to the surface of metallic objects in the rotor. The penetration depth in magnetic steel is less than one millimeter at 50 Hz. These currents will quickly heat: the rotor body, the slot wedges, the retaining ring and the damper winding if there is one. These components are normally already under great stress in large turbo-generators. If the negative-sequence current persists, the metal will melt and damage the rotor structure.

The amount of negative-sequence current that the machine can tolerate depends on the design of the generator.

8.12.13.1.3 Turbo-Generators

Generators without damper winding do not have well-defined paths for the induced double frequency currents. The electromagnetic and thermal utilization increases steadily. This is especially true for the rotors in turbo-generators. This means that the turbo-generators are very sensitive for unbalanced loading.

8.12.13.1.4 Hydro-Generators

Salient pole generators with damper windings (hydro-generators) have well-defined paths for the induced double frequency currents. The currents flow mainly in the damper windings. Generally, hydro-generators have strong damper windings and they can withstand higher negative-sequence currents than the turbo-generators can. There are very few hydro-generators without damper windings.

8.12.13.2 Continuous I_2-capability

Because unbalanced loading may continue for long periods, each machine is assigned a continuous negative-sequence current capability (continuous I_2-capability). Usually it is expressed in percent of the rated stator current. Table 8.12.1 shows a typical continuous negative-sequence current capability for generators with different forms of cooling.

Most countries support [8.12.2] the American suggestion concerning the continuous I_2-capability. Table 8.12.2 presents the suggested capability. The machine manufacturers can provide accurate values.

Table 8.12.1: Negative-sequence current capability

Type of machine	**Cooling and cooling medium**	$(I_2)_{\max}$	K
		%	s
Turbo generator	Direct hydrogen 30 lb/in^2	10	7
Turbo generator	Conventional hydrogen 30 lb/in^2	15	12
Turbo generator	Conventional hydrogen 15 lb/in^2	15	15
Turbo generator	Conventional hydrogen 0.5 lb/in^2	15	20
Salient pole machine	Conventional air	40	60

Table 8.12.2: Suggested continuous I_2-capability

Cooling Method	S_n	$(I_2)_{\max}$
	MVA	%
Indirectly cooled		10
Directly cooled	<960	8
Directly cooled	961-1200	6
Directly cooled	>1200	5

Figure 8.12.13 shows the requirements on the negative-sequence current withstanding capability in graphical form.

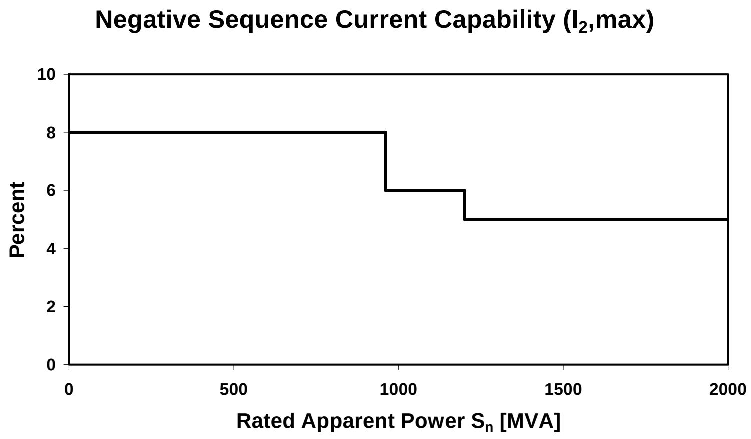


Figure 8.12.13: Negative-sequence current withstand capability

8.12.13.3 Temporary I_2-capability

The synchronous machine may carry large negative-sequence currents during fault conditions. Because normal fault clearance times are short, the machine loses only little heat while the fault currents are flowing. In addition, the heating caused by these currents may cause damage and therefore the input energy must be limited. This means that a temporary negative-sequence current capability (temporary I_2-capability) has to be defined. The length of time T [s] that a machine can operate with negative-sequence current without danger of being damaged can be expressed in the form.

$$\int_0^T i(t)_2^2\,dt = K \qquad \textbf{(8.12.5)}$$

Here

$i_2^2(t)$ is the negative-sequence current [p.u.] as a function of time

K is a constant

Equation (8.12.6) gives period T [s] that the generator can withstand a constant negative-sequence current I_2 [A].

$$T = \left(\frac{I_n}{I_2}\right)^2 \qquad \textbf{(8.12.6)}$$

Here

I_n is the rated current of the generator [A]

K is a constant that is typical for the type of generator [s]

The constant K tells how many seconds the machine can withstand a negative-sequence current equal to the rated current of the generator. The constant K depends on the size of the generator and the method of cooling. For most generators, the value is from 5 to 30 s, but for some hydro-generators it may be as high as 60 s.

There are industry standards that determine the permissible unbalance for which a generator is designed [8.12.4]. Equation (8.12.7) defines the requirements for turbo-generators with $S_n \leq 800$ MVA.

$$K \geq 10 \qquad \textbf{(8.12.7)}$$

Equation (8.12.8) defines the requirements for $S_n > 800$ MVA.

$$K \geq 10 - 0.00625 \times (800 - S_n) = \frac{800 - S_n}{160} \qquad \textbf{(8.12.8)}$$

Figure 8.12.14 shows these requirements in a graphical form. A 500 MVA generator should have $K = 10$ s and a 1 600 MVA generator should have $K = 5$ s. Figure 8.12.15 shows data on the negative-sequence current capability. The ability of large generators to stand negative-sequence current is progressively decreasing because their specific rating is still increasing, although their size has almost reached the limit of the present material.

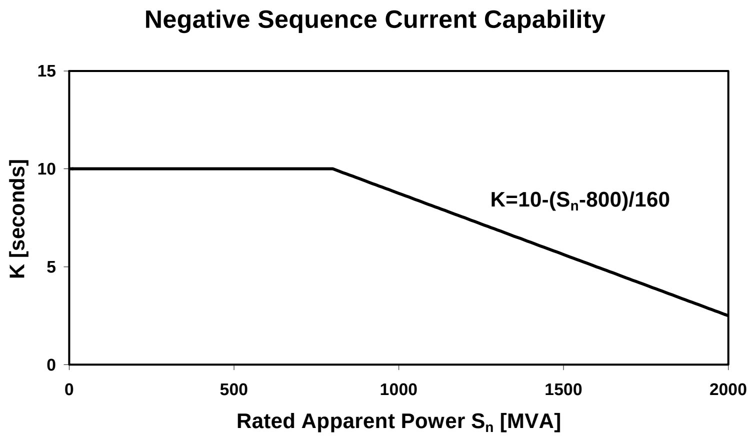


Figure 8.12.14: Continuous and short time unbalanced current capability of generators

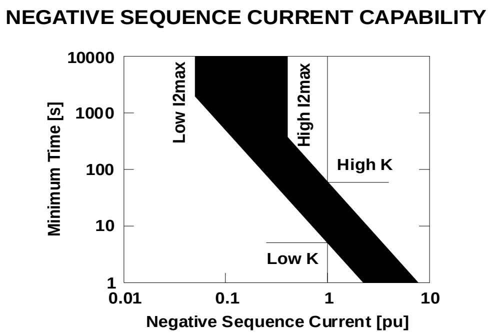


Figure 8.12.15: Maximum time for a given negative-sequence current

8.12.13.4 Unbalance Protection

Generally, the unbalanced protection consists of a dependent time overcurrent relay. A negative-sequence filter energizes the overcurrent relay. On a log-log scale, the time characteristic is a straight line and can be set to match the machine characteristic.

8.12.14 Out-of-Step Protection

Severe stress may result when a generator loses the synchronism without having lost the excitation. Pole slipping is associated with high current pulses and violent oscillations of the air gap torque in the generator.

8.12.14.1 Asynchronous Operation

There are incidents that may cause a sustained loss of synchronism or transient loss of synchronism. Generally, loss of synchronism is an abnormal mode of operation for synchronous machines.

If the field circuit-breaker receives an opening impulse when a synchronous generator is connected to a strong power system, the breaker will disconnect the exciter from the field winding. The inductance of the field winding will cause a gradual decrease of the field current. It will fall as the discharge resistor absorbs the energy stored in the field winding. Eventually, the loss of excitation will cause a sustained loss of synchronism.

After this, the synchronous machine will operate as an induction machine and it will run above the synchronous speed. It will continue to generate power, and the setting of the turbine governor will determine the amount of power generated. The slip frequency current will flow in several paths in the rotor. The field winding may form such a path. Another path is the damper winding of a salient pole machine. The current will also flow in slot wedges and the solid rotor body.

When the machine operates as an induction generator, the external power network will provide the necessary excitation. This means that the machine will absorb much reactive power. The reactive current may approach or even exceed the rated current of the machine.

Synchronism can, according to GEC [8.12.15], be regained if the load is sufficiently reduced, but if this does not occur within a few seconds, it is necessary to isolate the generator and then re-synchronize.

Out-of-step conditions can also occur as a consequence of a short circuit in the power system where the fault clearance time is so long that synchronism cannot be maintained. This can be the consequence of a backup protection function.

Out-of-step conditions can also occur if there are undamped oscillations between different groups of generators in the power system.

The out-of-step protection is often based on impedance measurement. In normal operation, the apparent impedance, seen by the impedance protection with forward direction to the grid, will be on the right-hand side (R > 0). In case of pole slip, the apparent impedance will move to the left-hand side of the R-X-diagram in Figure 8.12.16.

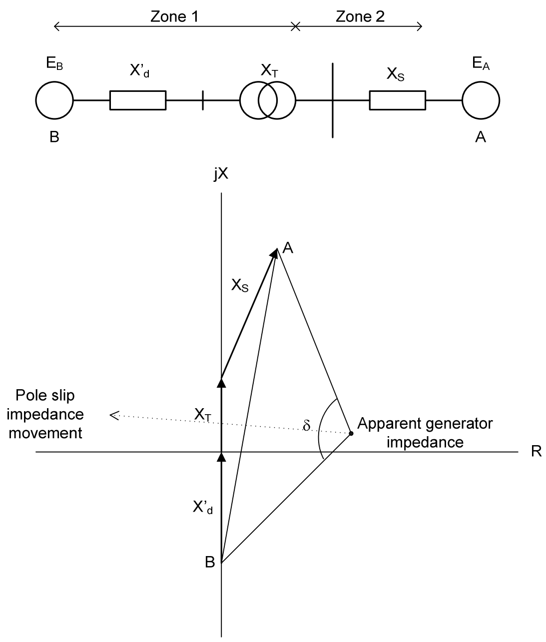


Figure 8.12.16: Apparent impedance at pole slip in the R-X diagram

8.12.15 Abnormal Frequency Protection

Abnormal frequency is related to abnormal speed of the generating units. A single failure in the power plants will usually not cause abnormal speed deviations if the power system is large and stable. However, if the system is a small and isolated with large generating units, the loss of one unit may cause a big power deficit. Then, the system frequency begins to fall and may reach so low values that it becomes necessary to disconnect other units. Faults in the network may occasionally split a large power system into small electrical islands. They may have a big power surplus or a big power deficit. Here, there is a risk for abnormal frequencies. There are cases on record where a subsystem established a balance at 50% of normal system frequency and 50% of normal network voltage.

8.12.15.1 Aims of the Abnormal Frequency Protection

The frequency control system shall provide the first line of defense against abnormal frequency. A load-shedding system provides the second line of defense. Then, the abnormal frequency protection provides the last defense line. One task is to prevent the operation of customer loads at abnormal frequencies. Another task of the abnormal frequency protection is to prevent damage to power plant equipment.

Some utilities use an underfrequency relay to trip generating units to houseload when a widespread blackout has occurred. The idea is to have the generating units in a hot standby state and ready for synchronization. When the network operator has a voltage restored the transmission system, a new generation will become available with a minimum time delay. Such actions aim at reducing the customer interruption times instead of preventing loss of voltage.

There are two major considerations associated with operating power plants at abnormal system frequency:

- Protection of equipment from damage
- Prevention of cascading trips that lead to a complete blackout

8.12.15.2 Effects of Abnormal Frequency

There are no standards for abnormal frequency operation of synchronous generators. Reduced frequency results in reduced ventilation. Therefore, operation at the reduced frequency should be at a reduced apparent power. The underfrequency limitations on the generator, however, are usually less restrictive than the limitations on steam turbines. Overfrequency is usually the result of a sudden load reduction. Therefore, overfrequency is associated with light load or no-load operation of the generator. Operation within the allowable overfrequency limits of the turbine will not produce generator overheating as long as operation is within the rated apparent power and 105% of the rated voltage. Abnormal frequency presents hazards to other parts of the plant such as:

- Steam turbine vibrations and increased stresses on blades
- Reduced capacity of auxiliary equipment
- High temperatures caused by increased excitation current
- Overexcitation of transformers

8.12.15.3 Coordination with Load Shedding

The aim of the frequency-controlled load shedding is to reestablish a balance between available generation and load by disconnecting the load when the system frequency drops below certain levels. The amount of load shedding varies from country to country and from region to region. Typical values range from 20% to 60% of system load. The generator underfrequency protection must not interfere with the load-shedding system (selectivity).

8.12.15.4 Realization of Abnormal Frequency Protection

All prime movers should have overspeed protection. The overspeed device may be a mechanical centrifugal device or an overfrequency relay.

The setting of the overspeed device may be 108% to 115% for turbo-generators and 140% to 160% for hydro turbines.

The overspeed protection may be a part of the prime mover, speed-governing system or generator protection. The overspeed element should operate the main stop valve to shut down the prime mover. It should also trip the generator circuit-breaker and the auxiliary breaker where the auxiliary power comes from the generator buswork. By doing so, it is possible to prevent overfrequency operation of customer loads and power plant auxiliaries.

The overspeed element should usually operate at 3% to 5% above the full-load rejection speed. The under-frequency protections often have two steps. One frequency relay trips the unit breaker without delay if the system frequency falls below 95%. Another frequency relay trips the unit if the frequency does not recover.

8.12.16 Inadvertent Energizing Protection

Operating errors, breaker head flashovers, control circuit malfunctions or a combination of these have resulted in inadvertent or accidental energizing of off-line generators [8.12.12]. Many large generators have been severely damaged, sometimes beyond repair [8.12.13].

8.12.16.1 Inadvertent Energizing

Operating errors: The use of more complex breaker patterns has resulted in more frequent operating errors. Even with extensive interlocks between unit breakers and disconnecters, there has been an increase in the number of documented cases in which off-line units have been inadvertently energized through the high-voltage switch.

Breaker head flashover: The extreme dielectric stress in breakers and the small contact gap spacing associated with their high-speed interrupting requirement can lead to contact flashover. The risk of a flashover is higher just before synchronization or just after the unit is removed from service.

8.12.16.2 Generator Response to Inadvertent Energizing

Three-phase energizing: When a generator is accidentally energized with a three-phase system voltage while at low speed, it behaves like an induction motor. If the generator is connected to a strong network, the stator current will be about 3 to 4 times the rated current.

Single-phase energizing: Single-phase energizing of a generator from the high-voltage system while at low speed subjects the generator to a significant unbalance current. There will be no significant accelerating torque if the voltage applied to the generator is single-phase. Breaker head flashover is the most frequent cause of single-phase inadvertent energizing.

8.12.16.3 Damage Caused by Inadvertent Energizing

Turbo-generator damage: The initial effect of inadvertent energizing of a generator from standstill is rapid heating in iron parts near the rotor surface. Slot wedges have little clamping load at standstill, resulting in arcing between them and the rotor iron. The arc heating begins to melt the metals.

Steam turbine damage: During an inadvertent energizing incident, the generator acts as an induction motor to drive the turbine. The generator starts to accelerate the turbine and the exciter. As it comes up to speed, the unit passes through its natural torsional frequencies. Vibration, blade distortion and rubbing may cause turbine damage if the energizing source is not removed soon enough. The blades in the steam turbine may become overheated if the turbine continues to rotate at high speed without any steam flow. Bearing failure due to insufficient lubrication can occur.

Hydro unit damage: Heating of the damper windings and the rotor material, combined with the lack of proper ventilation, will cause damage quickly.

8.12.16.4 Systems to Detect Inadvertent Energizing

Dedicated protection systems are recommended to detect inadvertent energizing. Unlike conventional protection systems that provide protection when equipment is in service, these schemes provide protection when equipment is out of service. The most widely used dedicated protection systems are:

Frequency-supervised overcurrent relays: This system uses a frequency relay to supervise the trip output of sensitively set instantaneous overcurrent relays. The overcurrent relays are automatically armed by the frequency relay as the unit is taken offline and they remain armed while the unit is shut down.

Voltage-supervised overcurrent relays: This system utilizes undervoltage relays to supervise the trip output of high-speed instantaneous overcurrent relays. The overcurrent relays are automatically armed by separate undervoltage relays when the unit's field is de-energized and they remain armed while the unit is shut down.

Auxiliary contact-enabled overcurrent relays: This system uses a combination of auxiliary contacts on breakers and switches to enable and disable high-speed instantaneous phase overcurrent relays.

Distance relays: This scheme uses a distance relay located in the high-voltage switchyard that is set to look into the machine. The relay should be set to detect the sum of the generator step-up transformer and machine transient reactance with an appropriate margin.

Directional overcurrent relays: This scheme uses three directional phase overcurrent relays with very inverse time characteristics. Voltage sensing is from the generator such that the overcurrent relays will pick up on a current into the generator.

8.12.16.5 Schemes to Detect Breaker Head Flashover

Some of the dedicated schemes for inadvertent energizing can detect breaker head flashover. However, the following schemes are widely used to detect breaker head flashover in the generator breaker or in the unit breaker.

Modified breaker failure scheme: An instantaneous overcurrent relay is connected in the neutral of the step-up transformer. The relay is set to respond to a breaker pole flashover. A breaker auxiliary contact, which is closed when the breaker is open, provides an additional start to the breaker-failure scheme. When the breaker is open and one pole of the breaker flashes over (or two poles flash over), the resulting transformer neutral current is detected by the overcurrent relay and the breaker failure scheme issues a tripping impulse.

Breaker pole disagreement: A current relay augments the conventional breaker pole disagreement scheme. This relay senses whether any phase is below a certain low threshold level (indicating an open breaker pole) while the other phase current is above a substantially higher threshold level (indicating a closed or flashed over pole). Operation of the disagreement circuitry initiates breaker failure tripping.

8.12.17 Breaker Failure Protection

It is prudent to require that frequent faults with serious consequences shall be cleared even if one relay or one switching device fails to operate when required.

It is sufficient to note that the probability of a failure to open is low but greater than zero. Few protection engineers are prepared to recommend their companies to neglect the risk of breaker failure.

Sometimes it is possible to rely on remote backup protection. By introducing breaker failure protection for the generator breaker and the unit breaker, it is possible to reduce the time for backup fault clearance. Often it is less expensive to install a local backup protection and breaker failure protection than to reinforce the power system for longer fault clearance times.

It is a common practice to use breaker failure protection with three or four overcurrent relays and a timer. The breaker failure protection checks if all phase currents, and sometimes also the residual current, fall to zero within a certain time after the operation of protection system. Usually the timer is set to operate after 150 to 200 milliseconds. If all currents are detected to have dropped out, the circuit-breaker has interrupted the current and no further action is necessary. If this is not true, the breaker failure protection trips the adjacent circuit-breakers.

References

[8.12.1] Blackburn, J.L.: "Protective Relaying, Principles and Applications", Marcel Dekker, New York, 1987.

[8.12.2] Glebov, I.A., Danilevich, J.B. & Mamikoniants, L.G.: "Abnormal Operation Conditions of Large Synchronous Generators and their Influence on Design and Performance in a Power System", Report 11-07, CIGRE-Session, Paris, 1976.

[8.12.3] Griffin, C.H. & Pope, J. W: "Generator Ground Fault Protection Using Overcurrent, Overvoltage, and Undervoltage Relays", IEEE Trans. on Power Apparatus and Systems, vol. PAS-101, no. 12, pp. 4490-4501, December 1982.

[8.12.4] Horowitz, S.H. & Phadke, A.G.: "Power System Relaying", Research Studies Press and John Wiley & Sons, Taunton and New York, 1992.

[8.12.5] Mason, C.R.: "A New Loss-of-Excitation Relay for Synchronous Generators", AIEE Trans., vol. 68, pt. II, pp. 1240-1245, 1949.

[8.12.6] Pohl, R.: "Eisenverbrennung durch Lichtbögen niedriger Stromstärke", AEG Mitteilungen, vol. 20, no. 1, pp. 36-41, January 1930.

[8.12.7] Sarma, M.S.: "Synchronous Machines (Their Theory, Stability, and Excitation Systems)", Gordon and Breach, New York, 1979.

[8.12.8] Schlake, R.L., Buckley, G.W. & McPherson, G.: "Performance of Third Harmonic Ground Fault Protection Schemes for Generator Stator Windings", IEEE Trans. on Power Apparatus and Systems, vol. PAS-100, no. 7, pp. 3195-3202, July 1981.

[8.12.9] Ungrad, H., Winkler, W. & Wisniewski, A.: "Schutztechnik in Elektroenergisystemen. Grundlagen, Stand der Technik, Neuentwicklungen", Springer-Verlag, Berlin, 1991.

[8.12.10] Wright, A. & Christopoulos, C.: "Electrical Power System Protection", Chapman & Hall, London, 1993.

[8.12.11] "Electrical Transmission and Distribution Reference Book", 4th ed., Westinghouse Electric Corporation, East Pittsburgh, 1959.

[8.12.12] "Impact of HV and EHV Transmission on Generator Protection", IEEE Committee Report, IEEE Trans. on Power Delivery, vol. 8, no. 3, pp. 962-974, July 1993.

[8.12.13] "Inadvertent Energizing Protection of Synchronous Generators", IEEE Committee Report, IEEE Trans. on Power Delivery, vol. 4, no. 2, pp. 965-977, April 1989.

[8.12.14] "Power System Protection", vol. 3, 2nd ed. Edited by The Electricity Council, Peter Peregrinus Ltd., Stevenage, 1981.

[8.12.15] "Protective Relays Application Guide", Second Edition, GEC Measurement, 1975, 5th printing, October 1983.

[8.12.16] "Relay Protection of A-C Generators", AIEE Committee Report, AIEE Trans., vol. 70, pt. I, pp. 275-282, 1951.

Document revision history

Document revision/date	History
A / 07 October 2010	First revision

Disclaimer and Copyrights

Trademarks

This page is intentionally left blank.

Contact information

ABB Oy, Distribution Automation
P.O.Box 699
Visiting address: Muottitie 2A
FI-65101 Vaasa, FINLAND
Phone: +358 10 22 11
Fax: +358 10 22 41094

www.abb.com/substationautomation