Rotating machinery protection

7.1 Introduction

The protection of rotating equipment involves the consideration of more possible failures or abnormal operating conditions than any other system element. Although the frequency of failure, particularly for generators and large motors, is relatively low, the consequences in cost and system performance are often very serious. Paradoxically, despite many failure modes that are possible, the application principles of the protection are relatively simple. There are none of the complications requiring a pilot scheme. Those failures involving short circuits are usually detected by some type of differential or overcurrent relay. Many failures are mechanical in nature and use mechanical devices such as limit, pressure or float switches, or depend upon the control circuits for removing the problem.\(^1\),\(^2\)

Some of the abnormal conditions that must be dealt with are the following.

1. Winding faults:
   - stator – phase and ground fault
2. Overload
3. Overspeed
4. Abnormal voltages and frequencies.

For generators we must consider the following.

5. Underexcitation
6. Motoring and startup.

For motors we are concerned with the following.

7. Stalling (locked rotor)
8. Single phase

There is, of course, some overlap in these areas, particularly in overloads versus faults, unbalanced currents and single phasing, etc. Thus, relays applied for one hazard may operate for others. Since the solution to a given failure or abnormality is not the same for all failures or abnormalities,
care must be taken that the proper solution is applied to correct a specific problem. In some instances tripping of the unit is required; in other cases reduction in load or removing some specific equipment is the proper action. This will be discussed in greater detail as we examine each type of failure.

Several of these abnormal conditions do not require automatic tripping of the machine, as they may be corrected in a properly attended station while the machine remains in service. Hence, some protective devices only actuate alarms. Other conditions, such as short circuits, require fast removal of the machine from service. The decision, whether to trip or alarm, varies greatly among utilities and, in fact, between power plants of a given utility or between units in a single plant. The conflict arises because there is a justifiable reluctance to add more automatic tripping equipment than is absolutely necessary. Additional equipment means more maintenance and a greater possibility of incorrect operation. In today’s systems, the loss of a generator may be more costly, in terms of overall system performance, than the delayed removal of a machine. On the other hand, failure to promptly clear a fault, or other abnormality, may cause extensive damage and result in a longer, more expensive outage. The decision is not obvious nor is it the same for all situations. It requires judgment and cooperation between the protection engineer and the appropriate operating and plant personnel.

7.2 Stator faults

7.2.1 Phase fault protection

For short circuits in a stator winding, it is standard practice to use differential protection on generators rated 1000 kVA or higher and on motors rated 1500 hp or larger or rated 5 kV and above. Rotating equipment provides a classic application of this form of protection since the equipment and all of the associated peripherals such as current transformers (CTs), breakers, etc. are usually in close proximity to each other, thereby minimizing the burden and possible error due to long cable runs. In addition, since there is only one voltage involved, the CT ratios and types can be the same, with matched characteristics. They should be dedicated circuits and should not be used with any other relays, meters, instruments or auxiliary transformers without a careful check on the effect on CT performance.

The CTs used for the generator differential are almost invariably located in the buses and leads immediately adjacent to the generator winding. This is done to limit the zone of protection so a fault in the generator is immediately identifiable for quick assessment of damage, repair and restoration of service. The buses themselves are usually included in their own differential or in some overall differential scheme.

In motor differential circuits, three CTs should be located within the switchgear in order to include the motor cables within the protection zone. The other three CTs are located in the neutral connection of the motor. Six leads must be brought out of the motor: three on the incoming cable side to connect to the switching device and three on the motor neutral to accommodate the CTs before the neutral connection is made (refer to Figure 7.15). Above 1500 hp this is standard manufacturing practice. Below 1500 hp the provision and connections for the CTs must be specified when the motor is purchased.\(^3\)

Figure 7.1 shows the basic differential connection using a simple overcurrent relay. This protection scheme is described in section 2.2, and shown in Figure 2.5. For an external fault, the relay sees \(I_1 - I_2\), which is zero or very small. For an internal fault, the relay will see \(I_1 + I_2\) which can be very large. This big difference between the current in the relay for an internal fault compared to an external fault makes the setting very easy, i.e. sufficiently above the external fault for security and enough below the internal fault for dependability. This precise distinction between the location of an internal and an external fault is what makes the differential circuit such an ideal protective principle.
Example 7.1

Consider the system shown in Figure 7.2 which represents a generator prior to being synchronized to the system. The generator is protected by an overcurrent relay, 87, connected in a differential circuit as shown. The maximum load is \( \frac{125\,000}{(\sqrt{3} \times 15.5)} = 4656.19 \) A. For this maximum load select a 5000:5 (1000:1) CT ratio. This results in a secondary current of 4.66 A at full load. Before the unit is synchronized, a three-phase fault at either F1 or F2 is \( \left( \frac{V_{pu}}{x''_d} \right) \times I_{f1} \) or \( (1.0/0.2) \times 4656.19 = 23280.95 \) primary amperes or 23.28 secondary amperes.

For the external fault at F2, 23.28 A flow through both CT secondary circuits and nothing flows in the overcurrent relay.

For the internal fault at F1, 23.28 A flow through only one CT secondary and the operating coil of 87.

*Although 51 is the ANSI recommended device function number for an overcurrent relay, this relay is connected as a differential relay and the designation 87 is more meaningful for this application.
This arrangement would be ideal if the CTs always reproduced the primary currents accurately. Actually, however, the CTs will not always give the same secondary current for the same primary current, even if the CTs are commercially identical. The difference in secondary current, even under steady-state load conditions, can be caused by the variations in manufacturing tolerances and in the difference in secondary loading, i.e. unequal lengths of leads to the relay, unequal burdens of meters and instruments that may be connected in one or both of the secondaries. What is more likely, however, is the ‘error’ current that can occur during short-circuit conditions. Not only is the current magnitude much greater, but there is the possibility of DC offset so that the transient response of the two CTs will not be the same. This difference in secondary current will flow in the relay. An overcurrent relay must then be set above the maximum error current that can flow during the external fault; yet it must be set significantly below the minimum fault current that can accompany a fault that is restricted due to winding or fault impedance.

The percentage differential relay solves this problem without sacrificing sensitivity. The schematic arrangement is shown in Figure 7.3. This scheme has already been introduced in section 2.2. Depending upon the specific design of the relay, the differential current required to operate this relay can be either a constant or a variable percentage of the current in the restraint windings. The constant percentage differential relay operates, as its name implies, on a constant percentage of the through or total restraint current. For instance, a relay with a 10% characteristic would require at least 2.0 A in the operating winding with 20 A through-current flowing in both restraint windings.

![Figure 7.3 Generator differential using percentage differential relay](image1)

![Figure 7.4 Percentage differential relay characteristics](image2)
A variable percentage relay requires more operating current at the higher through-currents, as shown in Figure 7.4. Regardless of the specific design, however, conceptually, the contact-closing torque (for an electromechanical relay) or tripping action (in a solid-state or digital relay) caused by the current in the operating coil is proportional to the difference between the secondary currents. In contrast, the contact-opening torque, or nontripping action, caused by the through-current in the restraint coils is proportional to the sum of the two currents, with the additional requirement that there must be current in both restraint windings.

For external faults, the restraining windings receive the total secondary current and function to desensitize the operating winding, particularly at high currents. The effect of the restraint windings is negligible on internal faults, since the operating winding has more ampere-turns and it receives the total secondary current while the net ampere-turns of the restraint winding are decreased by virtue of the opposite direction of current flow in the windings during an internal fault.

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**Example 7.2**

Figure 7.5 shows the difference in the operating characteristics of the generator differential when using an overcurrent relay as shown in Figure 7.1 or a constant percentage differential relay as shown in Figure 7.3. Also shown is a typical plot of the error current due to CT unbalance caused by different burdens or saturation. Both relays are set for the same pickup of 0.1 A. It is clear that a through-current greater than 4.5 A will exceed 0.1 A in the operating coil and will trip the overcurrent relay incorrectly, whereas the entire error current plot lies in the nonoperating region of the differential relay, and there would be no tendency for the percentage differential relay to operate.

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**Figure 7.5** Comparison between percentage differential and overcurrent relay performance

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**Example 7.3**

Consider the system and the associated positive sequence network shown in Figure 7.6 when the unit is synchronized to the system. The generator is protected by a percentage differential relay (87) set for a minimum pickup of 0.2 A. Full load current is $125000/(\sqrt{3} \times 15.5) = 4656.19$ A. Select a CT ratio of 5000:5 (1000:1). The per-unit reactances on a 100 000 kVA, 15.5 kV base are

$$x''_d = 0.2 \times (100/125) = 0.16 \text{ pu}$$
Generator parameters:
125 MVA
15.5 kV
$X^* = X_2 = 0.2 \text{ pu}$

Transformer parameters:
150 MVA
15.5/345 kV
$X_T = 15\%$

$x_t = 0.15 \times (100/150) = 0.1 \text{ pu}$

$x_{sys} = 0.025 \text{ pu}$

Figure 7.6 System and positive sequence network for Example 7.3

Three-phase faults at $F_1$ and $F_2$ are

$I_{1f} = 1.0/0.07 = 14.29$

$I_{base} = 100 000/(\sqrt{3} \times 15.5) = 3724.9 \text{ A}$

$I_f = 14.29 \times 3724.9 = 53228.82 \text{ A}$

$I_{gen} = 23346/1000 = 23.35 \text{ A, secondary}$

$I_{sys} = 29883/1000 = 29.89 \text{ A, secondary}$

For a fault at $F_2$, i.e. outside the generator differential zone, the generator contribution flows through both sets of CTs. If both sets of CTs reproduce the primary current accurately, there will be no current in the operating winding.

For a fault at $F_1$, i.e. within the differential zone of protection, the generator contribution flows through one set of CTs and the system contribution flows through the other set of CTs. Each restraint winding sees its associated current flowing in opposite directions (which decreases the net restraining torque) and the operating winding sees the sum of the two contributions, i.e. 53.24 A.

7.2.2 Ground fault protection

The method of grounding affects the amount of protection that is provided by a differential relay. When the generator is solidly grounded, as in Figure 7.7, there is sufficient phase current for a phase-to-ground fault to operate almost any differential relay. If the generator has a neutral impedance to limit ground current, as shown in Figure 7.8, there are relay application problems that must be considered for the differential relays that are connected in each phase. The higher the grounding impedance, the less the fault current magnitude and the more difficult it is for the differential relay to detect low-magnitude ground faults.

If a CT and a relay are connected between ground and the neutral point of the circuit, as shown in Figure 7.9, sensitive protection will be provided for a phase-to-ground fault since the neutral
relay (51N)\(^{\dagger}\) sees all of the ground current and can be set without regard for load current. As the grounding impedance increases, the fault current decreases and it becomes more difficult to set a current-type relay. The lower the relay pickup, the higher is its burden on the CT and the more difficult it is to distinguish between ground faults and normal third harmonic unbalance. This unbalanced current that flows in the neutral can be as much as 10–15\% of the rated current. Other spurious ground current may flow due to unbalances in the primary system. The total false ground

\(^{\dagger}\) Suffix ‘N’ is generally used in preference to ‘G’ for devices that are connected in the secondary of a current transformer whose primary winding is located in the neutral of a machine or power transformer. ‘N’ may also be used for devices connected in the residual circuit of the three secondary windings of the CTs connected in the primary as shown in Figure 7.12. However, if there are relays in both the neutral connection to ground and the residual circuit of the three phase CTs, it is common practice to differentiate between these two sets of relays by designating one ‘N’ and the other ‘G’. In the case of transmission line relaying, the suffix ‘G’ is used for those relays that operate on ground faults, regardless of the location of the CTs.
current flows through the neutral CT and relay. However, only the difference between the secondary currents will flow through the generator differential CTs. Since the spurious ground current is small, there should be no effect on the accuracy of the CTs.

If the machine is solidly (or low-impedance) grounded, and protected with a neutral CT and relay 51N as shown in Figure 7.9, an instantaneous overcurrent relay is applicable. In high-impedance grounding schemes, with the same protection, although the fault current is low and the potential damage is reduced, a time-delay overcurrent relay is preferred since it can be set lower than an instantaneous relay to accommodate the lower ground current and it would be set with sufficient time delay, e.g. 5–10 cycles, to override any false ground current that could be caused by switching or other system transients.

Example 7.4

Referring to the system diagram and the sequence networks shown in Figure 7.10, the phase current for the differential relay (87) and the neutral relay current (51N) for various values of grounding impedances are as follows.

(a) Solidly grounded: \( R_n = 0 \)

\[
I_1 = I_2 = I_0 = j1.0/(0.2 + 0.2 + 0.03) = 2.33 \text{ pu} \times 4656 = 10828.35 \text{ A}
\]

\( I_g = I_a = 3 \times I_0 = 32485 \text{ A primary. The secondary current in the generator differential relay will be } 32.5 \text{ A. The typical minimum pickup of this class of relay is } 0.2\text{–}0.4 \text{ A so } 32.5 \text{ A is sufficient to reliably operate on ground faults even with additional resistance or within the generator winding.} \)

(b) Moderately grounded: \( R_n = 1.0 \Omega \)

\[
1.0 \Omega = [(1) \times (125 000)]/[(1000) \times (15.5)^2] = 0.52 \text{ per unit}
\]

\[
I_1 = I_2 = I_0 = j1.0/[3(0.52) + j0.43] = 0.617\angle74.60^\circ \text{ per unit}
\]

Generator ratings:

125 MVA
15.5 kV
\( X_{d}^* = X_2 = 0.2 \text{ pu} \)
\( X_0 = 0.03 \)

\( 5000:5 \quad 5000:5 \)

\( 100:5 \quad 100:5 \)

\( R_n \quad R \quad 87 \quad GSU \quad V = 1.0 \)

\( R \quad 51N \)

(One phase shown) (Other phases similar)

Figure 7.10  System and sequence networks for Example 7.4
\[ I_g = I_a = 3 \times I_0 = 8618 \text{ A primary. The generator differential CT secondary will be 8.62 A, which is still adequate. However, if a neutral CT and relay were installed, the CT ratio could be as low as 100:5 which would result in a neutral relay current of 431 A.} \]

(c) High-impedance grounding: \( R_n = 10 \, \Omega \)pu

\[ 10 \, \Omega = 5.2 \, \text{pu} \]

\[ I_1 = I_2 = I_0 = j1.0/[3(5.2) + j0.43] = 0.06 \angle 1.5^\circ \]

\[ I_g = 3I_0 = 837 \, \text{A primary. The generator differential secondary current (0.84 A) is above pickup but does not allow for additional fault resistance. The neutral relay current (41.85 A) is sufficient to make a good relay setting.} \]

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Example 7.4 shows that, for a solidly grounded generator, there is enough relay current to operate the generator differential (32.5 A). As the impedance increases, the differential current falls to just above relay pickup (0.29 A). Any higher neutral impedance or fault resistance and the relay will not pick up. On the other hand, since the neutral CT does not have to consider load it can have any ratio that is determined by the available fault current. In this case, a ratio of 100:5 will result in a neutral relay current of 14.5 A, enough to operate a relay set at, say, 5.0 A.

If the machine is not grounded, then the first ground fault does not result in any current flow. This situation does not require immediate tripping since there is no fault current to cause any damage. However, a second ground fault will result in a phase-to-phase or turn-to-turn fault. This condition can result in heavy current or magnetic unbalance and does require immediate tripping. It is, therefore, essential to detect the first fault and start to take appropriate action. The usual ground fault detector is a potential transformer with the primary winding connected in a grounded wye configuration and the secondary winding connected in broken delta. This results in \( 3E_0 \) across the broken delta, as shown in Figure 7.11.

If the neutral is not accessible, or there is no neutral CT, an alternative protection scheme to the neutral relay is a residually connected relay, as shown in Figure 7.12. This is a relay that is

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**Figure 7.11** Broken-delta ground detector
connected in the residual of the CT secondary circuit so that it sees the vector sum of the secondary current of all three phases. This is particularly applicable in motor installations where each phase is energized at a different point of the voltage wave, resulting in different DC offsets and inrush currents. Because of these differences there is a difference in the CT secondary output, and this difference flows in the common residual circuit. Therefore, instantaneous relays cannot be used and a very-inverse or short-time induction relay, or its solid-state or digital equivalent, is required. The time delay prevents this type of relay from tripping falsely during startup. Typical pickup settings of the time-delay relay are one-fifth to one-third of the minimum fault current with some time delay. In power plants, to avoid incorrect trips due to vibration, the time delay is usually not set at the lowest setting although virtually any time delay will be longer than the starting current error.4

An alternative to the residually connected ground relay in motor applications is the toroidal CT, shown in Figure 7.13 and discussed in section 3.4. This CT encircles all three phase conductors and thereby allows all positive and negative sequence currents to be cancelled out so only zero sequence current appears in the relay. Care must be taken to keep all ground wires and cable shields
out of the toroid. If they conduct current during a ground fault, the net magnetic effect will be zero and no current will be seen by the relay. Because the secondary current is a true reflection of the total three-phase primary current, there is no CT error due to any unbalanced primary current. The CT ratio can be any standard value that will provide the relay current from the available ground current for adequate pickup. Since there will be no error current, the relay can be an instantaneous relay set at a low value. Typical relay calculations are shown in the following examples.

Example 7.5

Consider the 2000 hp motor installation shown in Figure 7.14. The CT ratio is selected to provide some margin above the trip setting so meters will not read off-scale. Normally, overcurrent relays are set at 125% of full load and the CT ratio should allow less than 5.0 A for this condition. If the motor is vital to the operation of the plant, advantage is taken of the motor service factor which is 115%. This results in a maximum load of $245 \times 1.15 = 282$ A and a relay pickup setting of $1.25 \times 282 = 352.5$ A. Select a CT ratio of 400:5 (80:1).

The time-delay overcurrent relay 51 sees 352.5/80 or 4.4 secondary amperes. To set the relay, the manufacturer’s instruction book and characteristic curves must be used. For our purposes, however, assume there is a 5.0 A tap and the characteristics of Figure 4.5 apply. The time delay must be set longer than the starting time of the motor. This assumes that the starting current lasts for the full starting time. This is not strictly true. The starting current starts to decrease at about 90% of the starting time. However, this is a conservative setting that is often used to cover any erratic motor behavior and to avoid false tripping during starting. The relay pickup during starting is $1609/(80 \times 5) = 4 \times \text{pu}$; the time delay must be at least 0.97 s which results in a time dial setting of 1.5. Two overcurrent relays are usually used, one in phase 1 and the other in phase 3, on the assumption that an overload is a balanced load condition. An ammeter (not shown) is usually connected in phase 2.
The instantaneous relay 50 must be set above the asymmetrical value of the locked rotor current, i.e. \(1.7 \times 1609 = 2735\) primary amperes or 34.19 secondary amperes. Set at 35 A. Check for pickup at minimum 4 kV bus fault; \(20000/(35 \times 80) = 7.14\) x pu. Three relays are used, one per phase, to provide redundancy for all phase faults.

The residual overcurrent relay 51G is set at one-third of the minimum ground fault. If the auxiliary system has a neutral resistor to limit the ground fault to 1200 A,\(^\dagger\) the residual CT current will be \(1200/80 = 15\) A. Set the relay at 5.0 A or less to ensure reliability without setting it at the lowest tap to avoid loss of security. Set the time dial at a low setting. There are no criteria for these settings except what is the usual practice at a given plant.

If the alternative scheme using a toroidal CT is used, the CT ratio can be 1200:5 (240:1) and an instantaneous relay set at 1.0 A. This will give 5 times pickup at the maximum ground fault current and provide sufficient margin above any false ground currents to prevent false tripping and still allow for reduced ground fault current due to fault resistance.

**Example 7.6**

Figure 7.15 shows a 7500 hp motor connected to the same auxiliary bus as the motor in Example 7.5. The time-delay overcurrent relays follow the same setting rules as for the 2000 hp motor.

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\(^\dagger\) See ground fault protection discussion and Figure 7.22.
The pickup of the two phase overcurrent relays 51 is equal to \(1.15 \times 1.25 \times 918\) or 1320 primary amperes.

Select a CT ratio of 1500:5 (300:1). The relay pickup tap is therefore \(1320/300 = 4.4\); use the 5.0 A tap. Pickup during starting is \(5512/(5 \times 300) = 3.7 \times \text{pu}\) and the time delay must exceed 3 s. From Figure 4.5, use #6 dial. The residual overcurrent relay 51G is set at one-third of the limited ground current \((1200/300 = 4)\) or 1.33 A. Use the 1.0 A tap and the same dial setting as in Example 7.5. If a toroidal CT is used, the setting rules used in Example 7.5 apply.

The setting of the instantaneous relays, however, introduces a problem. Using the criteria of Example 7.5 we should set the relays at \(1.7 \times 5512\) or 9370 A. Since the minimum 4 kV bus fault is 20 000 A we would only have \(2.1 \times \text{pu}\). This is not enough of a margin to ensure fast tripping. For a motor of this size we would use three differential relays (87). There is no setting required since the sensitivity of the differential relay is independent of the starting current.

If a generator is connected directly to a grounded transmission system, as shown in Figure 7.7, the generator ground relay may operate for ground faults on the system. It is therefore necessary for the generator ground relay to coordinate with any other relays that see the same fault. If the generator is connected to the system through a wye-delta transformer as shown in Figure 7.16, zero sequence current cannot flow in the generator bus beyond the delta connection of the stepup transformer. Faults on the wye side will, therefore, not operate ground relays on the delta side.

The most common configuration for large generators today uses the generator and its stepup transformer as a single unit, i.e. failure in the boiler, turbine, generator, stepup transformer or any of the associated auxiliary buses will result in tripping the entire unit-connected system. The generator is grounded through some resistance to limit the fault current, yet provide enough current or voltage to operate relays. A primary resistor or reactor can be used to limit the ground fault current but for economic reasons the most popular arrangement uses a distribution transformer and resistance combination, as shown in Figure 7.16. The primary voltage rating of the distribution transformer must be equal to or greater than the line-to-neutral voltage rating of the generator, usually with a secondary rating of 120, 240 or 480 V. The distribution transformer should have sufficient overvoltage capability so that it does not saturate at 105 % rated voltage. A secondary resistor is selected so that, for a single line-to-ground fault at the terminals of the generator, the power dissipated in the resistor is equal to the reactive power that is dissipated in the zero sequence capacitance of the generator windings, leads, surge arresters and transformer windings.

![Figure 7.16 Generator with transformer ground](image-url)
The secondary resistor is chosen to limit the primary fault current to 10–35 A. As we have seen, this is not enough to operate the generator differential relay. However, the voltage across the secondary resistor for a full line-to-ground fault, i.e. at the phase terminals of the generator, is equal to the full secondary voltage of the distribution transformer (120, 240 or 480 V) and is more than enough to operate a voltage relay.

The impedance reflected in the primary circuit is the secondary impedance times the square of the voltage ratio. For example, given a 26 kV generator (15 kV line-to-ground) and a 15 000 V/240 V distribution transformer with a 1 Ω secondary resistor, the resistance reflected in the primary will be $(15 000)^2/(240)^2$ times 1 Ω, or 3906 Ω. The resulting generator ground current is $15 000/3906$ or 3.8 A for a full line-to-ground fault.

Ground protection is provided by a voltage relay, 59GN, connected across the secondary resistor. The relay must discriminate between 60 Hz and third harmonic voltages and usually has a small (approximately 30 cycles) time delay. There is adequate security in this scheme since the voltage relay can easily be set between normal and abnormal operation. Dependability, however, should be improved since we are depending upon a single relay to protect against the most common fault. A backup to this scheme could be a CT in the secondary of the distribution transformer, as shown in Figure 7.16. The CT ratio is selected to give approximately the same relay current as that flowing in the generator neutral for a ground fault. In our example above, the secondary current is 3.8 A times 15 000/240, or 237.5 A. A 250:5 CT ratio would be adequate with the 51N relay set at 0.5 or 1.0 A and the same time delay as 59GN. Another backup scheme that is commonly used is to connect a potential transformer ground detector as shown in Figure 7.11 between the generator and the generator stepup (GSU).

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**Example 7.7**

Consider the system shown in Figure 7.17. The distributed generator capacitance to ground = 0.22 µF/phase; the distributed leads and transformer capacitance to ground = 0.10 µF/phase; and the surge arrester capacitance = 0.25 µF/phase. Therefore, the total capacitance = 0.57 µF/phase.

$$X_c = \frac{10^6}{2\pi f C} = \frac{10^6}{377 \times 0.57} = 4650 \ \Omega \text{ at } 60 \text{ Hz}$$

$$I_c = \frac{3V_{1-g}}{X_c} = \frac{3V_{1-g}}{\sqrt{3} \times X_c} = 5.77 \ \text{A}$$

Total capacitive kVA = $5.77 \times \frac{15.5 \text{ kV}}{\sqrt{3}} = 52 \text{ kVA}$.

To prevent ferroresonance, $I_{\text{neut}} > I_c$ and kW loss > kVA capac. Choose $I_{\text{neut}} = 10 \ \text{A}$.

$$R_{\text{neut}} = \frac{15 500}{\sqrt{3} \times 10} = 895\Omega \ \text{primary or } 895 \times \frac{(480)^2}{(1440)^2} = 1.0 \ \Omega \ \text{secondary}$$

$$I_{\text{sec}} = 10 \times \frac{14 400}{480} = 300 \ \text{A}$$

Resistor loss = $(300)^2 \times 1.0 = 90 \ \text{kW} > 52 \ \text{kVA}$

Assume third harmonic voltage is 3% of normal line-to-neutral voltage.

$$V_3 = 0.03 \times \frac{15 500}{\sqrt{3}} = 268 \ \text{V}$$
Reactance to third harmonic is $1/3X_c = 4650/3 = 1550$ $\Omega$ on a per-phase basis or $1550/3 = 517$ $\Omega$ on a three-phase basis.

$$Z_3 = R - jX_3 = 895 - j517 = 1035 \angle 30^\circ$$

$$I_3 = 268/1035 = 0.259 \text{ A}$$

$$V_{pri} = 0.259 \times 895 = 232 \text{ V}$$

$$V_{sec} = 232 \times 480/14400 = 7.74 \text{ V}$$

The relay should be set at about twice this value to ensure dependability. Assume the relay has a 16 V tap; that would be its setting. Since no coordination is required, set at lowest or next to the lowest time setting.

For ground faults at the phase terminal of the generator, the voltage across the relay and resistor is

$$\frac{15500 \times 480}{\sqrt{3} \times 14400} = 298 \text{ V}$$

$$298/16 = 18.6 \times \text{pickup}$$

Primary pickup voltage is 16 V times 14400/480 primary, which is the lowest voltage the relay will see. This results in an unprotected part of the winding equal to $480/(15500/\sqrt{3})$ or 5% of the total winding.

Since the entire winding is not protected, several alternative protective schemes have been developed which will protect 100% of the stator winding. They are covered extensively in the literature.5

Another method of providing high-impedance grounding to a unit-connected generator is the use of a reactor connected in the neutral of the generator and is referred to as ‘resonant grounding’ or a ‘Petersen coil’. The reactor is tuned to the total system capacitance so the only impedance in the circuit is the resistance of the conductors. As a result there is very little fault current for a line-to-ground fault.6,7
7.3 Rotor faults

The field circuits of modern motors and generators are operated ungrounded. Therefore, a single ground on the field of a synchronous machine produces no immediate damaging effect. However, the existence of a ground fault stresses other portions of the field winding, and the occurrence of a second ground will cause severe unbalance, rotor iron heating and vibration. Most operating companies alarm on the indication of the first ground fault and prepare to remove the unit in an orderly shutdown at the first opportunity.

Two commonly applied field ground detection schemes are as shown in Figure 7.18. The ground in the detecting circuit is permanently connected through the very high impedance of the relay and associated circuitry. If a ground should occur in the field winding or the buses and circuit breakers external to the rotor, the relay will pick up and actuate an alarm.

For a brushless-type machine, access is not normally available to a stationary part of the machine field circuit and no continuous monitoring is possible. However, pilot brushes can be provided that may be periodically lowered to the generator. If a voltage is read between ground and the brush, which is connected to one side of the generator field, then a ground exists. Alternatively, resistance measurements can be used to evaluate the integrity of the field winding.

The primary concern with rotors in squirrel-cage induction motor construction or insulated windings in wound-rotor induction or synchronous motor construction involves rotor heating. In almost all cases, this is the result of unbalanced operation or a stalled condition. Protection is therefore provided against these situations rather than attempt to detect the rotor heating directly.

7.4 Unbalanced currents

Unsymmetrical faults may produce more severe heating in machines than symmetrical faults or balanced three-phase operation. The negative sequence currents which flow during these unbalanced faults induce 120 Hz rotor currents which tend to flow on the surface of the rotor forging and in the nonmagnetic rotor wedges and retaining rings. The resulting $I^2R$ loss quickly raises the temperature. If the fault persists, the metal will melt, damaging the rotor structure.
Industry standards have been established which determine the permissible unbalance to which a generator is designed. The general form of the allowable negative sequence current is \( I_2^2 t = k \) (\( I_2 \) is the per-unit negative sequence current; \( t \) is the time in seconds). For directly cooled cylindrical rotors up to 800 MVA, the capability is 10. Above 800 MVA the capability is determined by the expression \([10 - (0.00625)(\text{MVA} - 800)]\). For example, a 1000 MVA generator would have an \( I_2^2 t = 8.75 \). No standards have been established for motors, although \( k = 40 \) is usually regarded as a conservative value.

A basic question concerns the cause of the system unbalance. For generators, such operation is very often the failure of the protection or equipment external to the machine. For large motors, the unbalance can be caused by the supply equipment, e.g., fused disconnects. Typical conditions that can give rise to the unbalanced generator currents are:

- accidental single-phasing of the generator due to open leads or buswork;
- unbalanced generator stepup transformers;
- unbalanced system fault conditions and a failure of the relays or breakers;
- planned single-phase tripping without rapid reclosing.

When such an unbalance occurs, it is not uncommon to apply negative sequence relays (46) on the generator to alarm first, alerting the operator to the abnormal situation and allowing corrective action to be taken before removing the machine from service. The relay itself consists of an inverse time-delay overcurrent relay operating from the output of a negative sequence filter. On a log–log scale, the time characteristic is a straight line of the form \( I_2^2 t = k \) and can be set to closely match the machine characteristic.

In the case of motors, such protection is generally reserved for the larger motors. On smaller motors, it is more common to use a phase balance relay. For example, in an electromechanical relay, two induction disc units are used: one disc responding to \( I_a + I_b \), the other to \( I_b + I_c \). When the currents become sufficiently unbalanced, torque is produced in one or both units to close their contacts and trip the appropriate breaker. Solid-state and digital relays can perform in a similar manner by incorporating the appropriate logic elements or algorithms in their design.

### 7.5 Overload

Protective practices are different for generators and motors. In the case of generators, overload protection, if applied at all, is used primarily to provide backup protection for bus or feeder faults rather than to protect the machine directly. The use of an overcurrent relay alone is difficult because the generator’s synchronous impedance limits the fault current of sustained faults to about the same or less than the maximum or rated load current. Typical three-phase 60 Hz generator synchronous impedance varies between 0.95 and 1.45 per unit. Using the unit in Example 7.1, this would result in a sustained fault current between 3211 and 4901 A; this is not enough to distinguish between a fault and full load of 4656 A. To overcome this problem, a voltage-controlled overcurrent relay or an impedance relay can be used. With this relay, the current setting can be less than the rated current of the generator, but the relay will not operate until the voltage is reduced by the fault. One hazard of all relays that rely on voltage is the inadvertent loss of voltage and consequent incorrect trip of the machine. This should be recognized and proper precautions taken through good design and adequate maintenance of the voltage supply.

Overload protection is always applied to motors to protect them against overheating. Fractional horsepower motors usually use thermal heating elements such as bimetallic strips purchased...
with the motor starter. Integral horsepower motors use time-delay overcurrent relays, as shown in Examples 7.5 and 7.6. However, heating curves are difficult to obtain and vary considerably with motor size and design. Further, these curves are an approximate average of an imprecise thermal zone, where varying degrees of damage or shortened insulation life may occur. It is difficult, then, for any relay design to approximate these variable curves adequately over the range from light, sustained overloads to severe locked-rotor overload.

Thermal overload relays offer good protection for light and medium (long-duration) overloads, but may not be good for heavy overloads (Figure 7.19(a)). A long-time induction overcurrent relay offers good protection for heavy overloads but overprotects for light and medium overloads (Figure 7.19(b)). A combination of two devices can provide better thermal protection, as in Figure 7.19(c), but the complication in settings, testing, etc. weighs heavily against it and such an application is rarely used. Today digital relays for motor protection are widely used to overcome the shortcomings of solid-state or electromechanical designs which use current as an indication of temperature or a thermal replica circuit that does not have the mass necessary to reproduce the thermal inertia of a motor. Digital relays take advantage of the ability to model the rotor and the stator mathematically and use algorithms that calculate the conductor temperature resulting from operating current, add the effect of ambient temperature, and calculate the heat transfer and the heat decay. They are therefore responsive to the effects of multiple starts, the major disadvantage of using only current as an indication of temperature. In addition, a digital device can record actual operating parameters such as ambient temperature, starting and running current and adjust the algorithms accordingly.8

The National Electric Code requires that an overload protective device be used in each phase of a motor ‘unless protected by other approved means’. This requirement is necessary because single-phasing (opening one supply lead) in the primary of a delta-wye transformer that supplies a motor will produce three-phase motor currents in a 2:1:1 relationship. If the two units of current appeared in the phase with no overload device, the motor would be unprotected.

A motor that is rotating dissipates more heat than a motor at standstill, since the cooling medium flows more efficiently. When full voltage is applied, a motor with a locked rotor is particularly vulnerable to damage because of the large amount of heat generated. Failure of a motor to accelerate when the stator windings are energized may be caused by many things. Mechanical failures of motor or bearings, low supply voltage or an open phase of a three-phase supply voltage are just a few of the abnormal conditions that can occur. If the motor fails to accelerate, stator currents may
Abnormal voltages and frequencies

Typically range from 3 to 7 or more times full load value depending on motor design and supply system impedance. In addition, the heat loss in the stator winding is 10 to 50 times normal when the winding is without the benefit of the ventilation normally produced by rotation of the rotor.

Over-temperature from a locked rotor cannot reliably be detected by sensing the line current magnitude. Since motors can stand high current for a short time during starting, some time delay must be incorporated in the current-sensing device or provision must be made to sense motor winding temperatures as well as line current magnitude. Digital relays are particularly suited to this type of logic combined with temperature sensing. Another possible protective scheme is to shunt out the current-sensing device during starting.

Some larger motors are designed to have a maximum allowable locked rotor current time less than the starting time of the drive. This is permissible since, during a normal start, much of the active power input during starting is utilized as shaft load, while on locked rotor all of the active power input is dissipated as heat. Therefore a time delay sufficient to allow the motor to start would have too much delay to protect against locked rotor.

Two approaches are possible to solve this dilemma.

1. Use a motor zero-speed switch which supervises an additional overload relay set for locked rotor protection.
2. Use a relay that incorporates temperature change and discriminates between the sudden increase during locked rotor and the gradual increase during load increases.

7.6 Overspeed

Overspeed protection for generators is usually provided on the prime mover. Older machines use a centrifugal device operating from the shaft. More modern designs employ very sophisticated electrohydraulic or electronic equipment to accomplish the same function. It must be recognized that, in practical situations, overspeed cannot occur unless the unit is disconnected from the system. When still connected to the system, the system frequency forces the unit to stay at synchronous speed. During overspeed the turbine presents a greater danger than the generator. Overspeed is not a problem with motors since the normal overcurrent relays will protect them.

7.7 Abnormal voltages and frequencies

In order to understand and appreciate the protection that should be provided against abnormal voltages and frequencies, the source of the abnormality must be examined.\textsuperscript{9}

7.7.1 Overvoltage

The voltage at the terminals of a generator is a function of the excitation and speed. Overvoltage may result in thermal damage to cores due to excessive high flux in the magnetic circuits. Excess flux saturates the core steel and flows into the adjacent structures causing high eddy current losses in the core and adjacent conductor material. Severe overexcitation can cause rapid damage and equipment failure.

Since flux is directly proportional to voltage and inversely proportional to frequency, the unit of measure for excitation is defined as per unit voltage divided by per unit frequency (V/Hz). Overvoltage exists whenever the per unit V/Hz exceeds the design limits. For example, the usual turbine generator design is for 105\% of rated V/Hz. Overvoltage exists at 105\% of rated voltage and per unit frequency or per unit voltage and 95\% frequency. Transformers are designed to withstand
110% of rated voltage at no load and 105% at rated load with 80% power factor. Overvoltage of a steam turbine–generator set is not usually a problem. The excitation and regulator circuits generally have inherent overvoltage limits and alarms. In a unit-connected generator–transformer set, the transformer may be more prone to failure from this condition, and a relay sensing volts as a function of frequency is usually used. This is discussed further in Chapter 8.

7.7.2 Undervoltage

Undervoltage presents a problem to the generator only as it affects the auxiliary system which will be discussed later. Low voltage prevents motors from reaching rated speed on starting or causes them to lose speed and draw heavy overloads. While the overload relays will eventually detect this condition, in many installations the low voltage may jeopardize production or affect electronic or digital controls, in which case the motor should be quickly disconnected. Protection from low line voltage is a standard feature of AC motor controllers. The contactor will drop out instantaneously when the voltage drops below the holding voltage of the contactor coil. If immediate loss of the motor is not acceptable, for example in a manufacturing plant, the contactor must have a DC (or AC rectified) coil and a time-delay undervoltage relay can then be used.

7.7.3 Overfrequency

Overfrequency is related to the speed of the unit and is protected by the overspeed device. It is possible to use an overfrequency relay as backup to mechanical devices. Again, if the unit is connected to a stable system, the generator cannot operate above the system frequency. However, if the system is dynamically unstable, with severe frequency excursions, overfrequency relays can alert the operator. In general, the governing devices will protect the unit from overspeed, but the system conditions must be addressed.

7.7.4 Underfrequency

While no standards have been established for abnormal frequency operation of generators, it is recognized that reduced frequency results in reduced ventilation; therefore, operation at reduced frequency should be at reduced kVA. Operating precautions should be taken to stay within the short-time thermal ratings of the generator rotor and stator. Underfrequency is a system condition that affects the turbine more than the generator. The turbine is more susceptible because of the mechanical resonant stresses which develop as a result of deviations from synchronous speed.

System load shedding is considered the primary turbine underfrequency protection and is examined in detail in sections 10.9, 11.3 and 11.4. Appropriate load shedding will cause the system frequency to return to normal before the turbine trouble-free limit is reached. The amount of load shed varies with coordinating regions and individual utilities but varies from 25 to 75% of system load. Since the load shed program can be relied upon only to the extent that the original design assumptions are correct, additional protection is required to prevent steam turbine damage. In order to have the unit available for restart, it is desirable to trip the turbine to prevent damage. This action in itself is considered as a last line of defense and is sure to cause an area blackout. It will, however, allow the unit to be ready to restore the system. Turbine manufacturers have published curves of frequency versus time which can be used as a guide for operators. The question is to trip or not to trip. The problem is loss of life and it is not clear that the best interests of the system are served by tripping the unit too quickly. From the protective relay point of view, a simple frequency relay can be used. However, the loss of life of the turbine blades is a cumulative deterioration every time the turbine passes through a low-frequency operating zone. Computer monitoring of the history of frequency can be applied.
7.8 Loss of excitation

When a synchronous generator loses excitation it operates as an induction generator running above synchronous speed with the system providing the necessary reactive support. Round-rotor generators are not suited for such operation because they do not have amortisseur (damper) windings and will quickly overheat from the induced currents in the rotor iron. The heating occurs in the end-iron region where the rotor bars leave one slot and enter another. Salient-pole generators, which are commonly used with hydro machines have such damper windings and do not have the problem. However, in addition to overheating, both salient-pole and round-rotor synchronous machines require a minimum level of excitation to remain stable throughout their load range. The typical generator capability curve, shown in Figure 7.20, shows the various limits associated with over- and underexcitation. The generator manufacturer supplies all of the temperature characteristics shown in Figure 7.20. The user must provide the steady-state stability limit.

There are several methods of detecting underexcitation. Small units can use power factor or reverse power relays. Manufacturers can provide current detectors in the excitation circuit. The most popular scheme, however, uses an impedance relay as the measuring element. This application is based on the behavior of the system impedance as seen from the generator terminals for various underexcited conditions. This behavior is explained in detail in section 10.4. Figure 7.21 shows how the impedance varies with loss of excitation for several system sizes. Despite the complexity of the phenomenon and the variation in conditions, the end result is surprisingly simple. Since the final impedance lies in the fourth quadrant of the $R–X$ diagram, any relay characteristic that will initiate an action in this quadrant is applicable. Various modifications are preferred by different relay manufacturers, but the concept is the same.\textsuperscript{14,15} Once again, the question of whether to trip or to alarm for this condition must be addressed. In almost every case, an alarm is provided early in the locus of the impedance swing so the operator can take the appropriate corrective action.

![Figure 7.20](image.png)  
*Figure 7.20* Generator capability curve
Whether this is followed by a trip after a time delay or further advance in the swing path is a utility’s decision.

### 7.9 Loss of synchronism

The primary difference in the protection requirements between induction motors and synchronous motors is the effect of the excitation system. Loss of synchronism of a synchronous motor is the result of low excitation exactly as with the synchronous generator. For large synchronous motors or condensers, out-of-step protection is applied to detect pullout by counting the power reversals that occur as the poles slip. Small synchronous motors with brush-type exciters are often protected by operation of an AC voltage relay connected in the field. No AC voltage is present when the motor is operating synchronously. This scheme is not applicable to motors having a brushless excitation system. For such a system a power factor relay is used.3

### 7.10 Power plant auxiliary system

#### 7.10.1 Auxiliary system design

The combination of motors, transformers and other electrically driven devices that form an auxiliary system for a power plant presents a protection problem that is, in effect, a microcosm of power system relaying and deserves special mention. In addition to the protection of each of the elements of the auxiliary system, there is the overall system which must be considered. The following comments are also applicable to an industrial complex where the auxiliary system is required to sustain the main production facilities. Our interest here does not involve the protection, per se, of the motors, transformers or other devices but the coordination of the protection of each of these devices from
the point of view of the normal and emergency operation of the entire plant. Faulted equipment must be removed from service as fast as possible. For many faults or abnormal events within the plant this may require that the generator be removed from the system, the excitation system tripped, the turbine valves closed and the boiler fires extinguished. However, it is necessary that vital services such as bearing oil pumps, instrument air compressors, exhaust and purging fans, etc. be maintained even though the unit has been tripped and is in the process of being shut down. In addition, the auxiliary system must be configured to allow the unit to return to service as soon as possible.

A portion of a typical auxiliary system of a unit-connected generator is shown in Figure 7.22. The 4 kV auxiliary bus is fed directly from the 20 kV generator leads or from the startup transformer and is the source for the major motors. As unit sizes increase, the auxiliary load increases proportionately, requiring higher rated transformers and higher rated, higher voltage motors. This has resulted in higher bus voltages, such as 6.9 kV and 13 kV. Phase fault currents also increased, requiring switchgear with higher interrupting capacity. In sizing the switchgear there are two contradictory factors that must be considered. The impedance of standard transformers increases as their ratings increase (Appendix C). Since the normal and short-circuit currents are also increasing, there is a greater voltage drop between the auxiliary bus and the motor. Normal design practice is to maintain at least 85% voltage at the motor terminals during motor starting. If the standard transformer impedance is specified to be at a lower value to reduce the voltage drop and maintain the 85% voltage criterion, the interrupting current will increase requiring larger rated switchgear. If the transformer impedance is raised to reduce the fault current, and hence the interrupting capacity requirement of the switchgear, the voltage drop will be too high. The art of designing the auxiliary system must take all of these factors into account. Transformers can be specified with special impedances at a greater cost. The auxiliary system can be designed with several bus sections thus reducing the transformer rating for each section. Current-limiting reactors can be used either as separate devices or incorporated in the switchgear.

In addition to the 4 kV (or higher) bus, a lower voltage auxiliary bus system is used to feed the dozens or hundreds of smaller motors, heating and lighting loads that are present in the plant. The nominal voltage rating of this lower voltage bus system can be 600 or 240 V. Note that this is the voltage class as defined by its insulation rating. The actual operating voltage can be any standard voltage such as 600, 550 or 220 V depending on the practice and preference of the user. The lower voltage buses are energized from the higher voltage bus as shown in Figure 7.22. Automatic throwover schemes between the several bus sections or between the GSU and startup transformer are used in the event of a 4 kV bus fault or failure of a 20 kV/4 kV or 4 kV/600 V transformer. In addition, manual throwover provides flexibility for maintenance without removing the generator from service. The circuit breakers used on the lower voltage buses are included in the metal-enclosed switchgear and are covered in ANSI standards C37.20-1 and C37.20-3. They may or may not be drawout type, do not have CTs and may be mounted in motor control centers. They may be air circuit breakers or molded case breakers with limited interrupting capacity. Protection is provided by series trip coils or thermal elements.3

7.10.2 Circuit breaker application

As discussed in section 1.5, there are many circuit breaker designs depending upon the particular application. Oil circuit breakers use the oil as both the insulating and the arc extinguishing medium. The energy in the arc causes the oil to expand, enlarging and cooling the arc. Air circuit breakers extinguish the arc by moving and stretching it into an insulating arcing chamber or arc chute. Vacuum circuit breakers extinguish the arc in a gap of less than 13 mm (0.5 in) because there are no constituents in the vacuum that can be ionized to support the arc. Sulfur hexafluoride (SF₆) circuit breakers extinguish the arc using one of two methods: the puffer design blows the arc out with a small amount of gas blasted in a restricted arc space; the rotating arc design uses the electromagnetic effect to rotate the arc through SF₆ that cools and extinguishes it. Buses rated above 2400 V use
metal-clad switchgear as defined in ANSI standard C37.20-2. The heart of the switchgear is the circuit breaker, and until the mid-1970s the use of air circuit breakers predominated. Nowadays, vacuum and SF₆ circuit breakers are more commonly used. These circuit breakers are drawout types allowing the breaker to be removed for maintenance. The switchgear compartment contains the CTs, auxiliary contacts and, usually, the relays and meters.

7.10.3 Phase fault protection

The phase overcurrent relays (51A and 51B) on the secondary of the unit auxiliary and startup transformers provide bus protection and backup relaying for individual motor protection and switchgear.

**Figure 7.22** Typical power plant auxiliary system
Figure 7.22 indicates the general arrangement of the buses and loads and shows the protection of the 2000 hp motor and the 7500 hp motor as discussed in Examples 7.5 and 7.6. Ideally, the backup overcurrent relays 51A and 51B should have pickup settings greater than the highest motor protection relay, and time delays longer than the longest starting time. These settings may be so high, or the times so long, that the protection is not acceptable and modifications or compromises are required as discussed below. If the relays are also the primary bus protective relays, the settings may be so high that there may not be enough bus fault current to provide sufficient margin to ensure pickup for the minimum bus fault. Even if coordination is theoretically possible, the required time delay may be too long to be acceptable. Some compromises are possible. Since the largest motors will probably have differential protection, the backup function could consider coordinating with the overcurrent relays of the smaller motors with an associated reduction in pickup. Assuming that the differential relays are always operative, coordination with the larger motors is not a problem since the differential protection is instantaneous. Coordination would be lost if the differential relays fail to clear a fault and the time-delay overcurrent relays must do it; this is usually an acceptable risk. A bus differential relay could be used to provide primary protection and the overcurrent relays provide backup protection for motor relay or switchgear failures. The time delay may then be acceptable. The pickup setting must still recognize the magnitude of starting current of the largest motor. If it cannot be set above this value, an interlock must be provided which will block the backup relay. Typically, an auxiliary switch on the motor circuit breaker is used to cut out the bus overload relay, and a voltage relay is used to unblock this protection should a fault occur.

Example 7.8

Consider the auxiliary system shown in Figure 7.22. The 2000 hp motor is protected and set as described in Example 7.5. The protection of the 7500 hp motor is described in Example 7.6. The total bus load is $13000/\sqrt{3} \times 4 = 1876$ A. Choose a 3000:5 (600:1) CT for both the main and reserve breakers. If the overcurrent relays, 51A and 51B, are used primarily for bus protection, they are set at $20000/3 = 6666$ primary amperes or 11 secondary amperes. Assume the relay has a 10 A tap so the actual pickup is 6000 primary amperes.

Check this setting against the starting current of the 2000 hp motor while the bus is fully loaded.

\[
2000 \text{ hp at 0.9 efficiency} = 1657 \text{ kVA}
\]

Total connected kVA less 1657 kVA = 11 343 kVA

Assume startup of this motor drops the bus voltage to 0.85 pu.

\[
I_{bus} = 11343/(\sqrt{3} \times 0.85 \times 4) = 1926 \text{ A}
\]

\[
I_{start} = 1926 \text{ A}
\]

\[
I_{rel} = 1926 + 1609 = 3535 \text{ A}
\]

This is below the 6000 A pickup of 51A and 51B so the setting is acceptable. Since the relays will not pick up during startup of the motor they can be set as fast as we want, e.g. the #1 dial.

Check the bus overcurrent setting against startup of the 7500 hp motor.

\[
7500 \text{ hp motor at 0.9 efficiency} = 6216 \text{ kVA}
\]

The total connected load less the motor is 13 000 kVA − 6216 kVA or 6784 kVA which is equal to 1153 A during motor startup.
Motor starting current is 5512 A. Therefore, total current through the bus overcurrent relay is 6665 A. This is above the 6000 A pickup of the relay and must be controlled by some interlock as discussed above.

7.10.4 Ground fault protection

The importance of ground fault protection cannot be overemphasized. Ground is considered to be involved in 75–85% of all faults. In addition, phase overcurrent may often reflect a temporary process overloading, while ground current is almost invariably an indication of a fault. Auxiliary systems may be either delta- or wye-connected. A delta system is normally operated ungrounded and is allowed to remain in service when the first ground indication appears. It is generally assumed that the first ground can be isolated and corrected before a second ground occurs. It is not uncommon for systems of 600 V and less to be delta-connected. Medium-voltage systems (601 V to 15 kV) are generally operated in wye, with a neutral resistor to limit the ground current to some definite value. The resistor has a time-related capability, e.g. 10 s, at the maximum ground current and it is a function of the ground protective system to remove all faults within this time constraint. In Figure 7.22, ground faults on the 4 kV system are limited by the 2.0 Ω neutral resistors in the auxiliary and startup transformers. The magnitude of the maximum fault current is the line-to-ground voltage divided by the 2.0 Ω resistor. The nominal voltage of the bus is 4 kV but its normal operating voltage is 4160 V. Therefore, the maximum ground current is 4160/(√3 × 2) or 1200 A. Coordination must, of course, begin at the load. If the motor ground overcurrent protection is provided by the toroidal CT shown in Figure 7.13 there is no coordination problem. These can have a ratio of 50:5 resulting in a relay current of 120 A. Set an instantaneous relay at 5.0 A. If a residual ground relay is used as shown in Figure 7.12, the maximum ground fault through the CTs on breakers A and B is 1200/600 = 2.0 A. Set the time-delay ground overcurrent relays at 0.5 A and 15–30 cycles. The motor relays trip the associated feeder breaker, 51A and 51B trip the 4 kV main breakers and the neutral relays 51N trip their associated primary breakers.

7.10.5 Bus transfer schemes

It is common practice to provide a bus transfer scheme to transfer the auxiliary bus to an alternative source in the event of the loss of the primary source. In power plants, the purpose of this alternative source is not to maintain normal operation but to provide a startup source, to act as a spare in the event an auxiliary transformer fails and to provide for orderly and safe shutdown. In industrial plants, the alternative source might have a different purpose, such as to provide flexibility in production or supply some facilities from the utility and others from a local generator. The transfer scheme must consider several factors. A manual, live transfer is performed by the operator while both the normal and startup sources are still energized. If the two sources can be out of synchronism, it will be necessary to include synchronizing equipment. A dead transfer refers to the condition where the auxiliary bus has been disconnected from the generator. The speed of the transfer can be fast or slow depending upon the switchgear and the requirements of the process. It is common to check the outgoing breaker, by monitoring a breaker auxiliary contact, to be sure the primary source is disconnected. There will always be an inrush current through the incoming source breaker and, in all probability, through the motor breakers, depending upon the residual voltage of the auxiliary bus at the instant of resynchronizing. Some schemes monitor this residual voltage and allow closing to the alternative source only after this voltage has been significantly reduced.
7.10.6 Generator breaker

Figure 7.22 shows a generator breaker as an alternative facility. This is common for generators that are connected to a common bus, such as in a hydro plant. With the advent of the unit system, however, this configuration has not been used as often. The unit system requires that the boiler, turbine, generator and GSU transformer be operated as a single entity and the loss of any one element requires that all of them be removed from service. The generator breaker is then unnecessary. In addition, as the unit sizes increased, the interrupting capability of a generator breaker became technically difficult. A 1300 MW generator can contribute as much as 100,000 A to a fault at the generator voltage level, e.g. on the bus feeding the auxiliary transformers. Not only is such a breaker extremely costly, it must be placed between the generator and the stepup transformer, which adds considerable length to the building. This introduces costs to every segment of the construction and installation. Nevertheless, the generator breaker has can be extremely useful. Its most important advantage is the fact that, for a fault on the generator or auxiliary buses, without a generator breaker to remove the generator contribution from the fault, the generator will continue to feed the fault until the generator field decays. This can take as much as 7–10 s. During this time the energy in the fault will result in extensive physical damage to all of the connected equipment and greatly increases the possibility of fire. With a generator breaker, the generator contribution is removed in 3–5 cycles; this is approximately the same time that the system contribution is removed by tripping the high-voltage breakers. A further advantage lies in the reduction in switching required when transferring the auxiliary bus. Referring to Figure 7.22, without a generator breaker, startup is accomplished by energizing the auxiliary buses through the 800 kV breaker F, the startup transformer and 4 kV breaker B. Synchronizing is done through 800 kV breaker E. In the event of a unit trip, the unit is removed from the system by opening breaker E and the auxiliary bus is transferred to the startup transformer by opening 4 kV breaker A and closing breaker B. Breaker F is operated normally closed. If the startup transformer is connected to some other system, then breaker B must be closed with synchronizing relays. If a generator breaker is provided, at startup the generator breaker is open and the auxiliary buses are fed through the GSU transformer and 4 kV breaker A. Synchronizing is done through the generator breaker. When removing the unit, only the generator breaker has to be opened; the auxiliary bus continues to be fed through the stepup transformer. There is no need for automatic or manual throwover schemes. In fact, there is no need for the startup transformer unless it is needed to provide an in-place spare for one of the auxiliary transformers. If the startup transformer is used it becomes a second source of startup or shutdown power; a source that can be used to satisfy reliability requirements associated with nuclear units.

7.11 Winding connections

So far, we have been concerned with the protection principles associated with generator and motor short circuits and overloads and the appropriate relays that should be applied. The specific implementation of these principles, particularly with differential relays, varies also with the particular winding connections involved. Most machines have star (wye) connections. So three relays that are connected to star-connected CTs as shown in Figure 7.23 provide both phase and ground protection. With delta-connected windings there is no connection to ground and the phase currents differ from the winding currents by $\sqrt{3}$ and a phase shift of 30°. Care must be taken to obtain correct current flow, as shown in Figure 7.24. Similarly, split-phase windings can be protected, as shown in Figure 7.25. If the neutral connection is made inside the machine and only the neutral lead is brought out, differential relays can only be provided for ground faults, as shown in Figure 7.26. It must be noted that turn-to-turn faults cannot be detected by a differential relay since there is no
Figure 7.23  Connection for star-connected generator

Figure 7.24  Connection for delta winding
difference in the currents at the ends of the winding. Such a fault would have to burn through to ground or to another phase before it would be detected.

7.12 Startup and motoring

The synchronous speed of a four-pole generator is 1800 rpm and 3600 rpm for a two-pole machine. A cross-compound turbine–generator unit consists of two shafts. Each shaft has its own steam turbine, generator and exciter. Either shaft could have a synchronous speed of 1800 or 3600 rpm. When the unit is ready to be synchronized to the system, the two shafts must be at their respective synchronous speeds. However, the units are rolled off turning gear by admitting steam into the high-pressure turbine. The steam flow goes from the steam generator through the high-pressure turbine, back to the steam generator and then to the low- or intermediate-pressure turbine. There is therefore a finite time before steam is admitted into the low- or intermediate-pressure turbine. If the speed of the two shafts were controlled only by the steam, the two shafts could never maintain the same speed ratio as they came up to synchronous speed. They therefore could not be synchronized to the system. To correct this problem, a cross-compound machine must have its
excitation applied to each generator while on turning gear (the turning gears are designed to have the same speed ratio as the respective synchronous speeds of each shaft). By applying field to the two machines, they act as a motor–generator set with the high-pressure turbine–generator driving the low-pressure turbine–generator at the proper speed ratio from turning gear up to synchronous speed. However, since both field and rotation are present, a voltage is generated during this startup period. A fault can therefore result in short-circuit current, even at low voltage and low frequency. Since the magnitude of the short-circuit current will be low, and, since most differential relays are relatively insensitive at frequencies below 60 Hz, it is common practice to add an instantaneous overcurrent relay in the differential circuit and an instantaneous overvoltage relay in the grounding circuit, as shown in Figure 7.27. Electromechanical relays, such as the plunger or clapper type, are insensitive to frequency.

These relays can be set as low as necessary, provided they are removed from service prior to synchronizing the unit to the system. One circuit to accomplish this is shown in Figure 7.28. The startup relays, 50S and 59GN, are connected to the breaker trip coil through time-delay dropout, auxiliary relay 81X, which takes both the operating coils and the tripping contacts out of service. The auxiliary relay is normally energized. When the system frequency goes above 55 Hz or the circuit breaker closes, the relay will drop out after a small time delay, usually 15 cycles. The time delay is necessary to give the startup relays a chance to operate in the event the generator is inadvertently energized. This is a situation that will be discussed below. Without the time delay, when the circuit breaker closes, there would be a race between the startup relays, 59GN and/or 50S, operating and auxiliary relay 81X removing them from service. If the differential relays are solid-state or digital, their response at low frequencies must be determined and the need for startup protection evaluated.
7.13 Inadvertent energization

A common, catastrophic mis-operation that has been reported many times involves the inadvertent closing of high-voltage breakers or switches while a unit is on turning gear or at some speed less than synchronous speed. When energized in this fashion, if field has been applied, the generator behaves as a synchronous motor or generator that has been badly synchronized. The result can destroy the shaft or other rotating element. There are several causes for this incorrect switching. Operating errors have increased dramatically as the complexity of stations and circuits increase. Stations are designed to have switching flexibility to allow a breaker or other switching device to be removed from service while still maintaining the generator in service. This has the opposite effect when the unit is offline. There are now several switching elements that can accidentally energize the generator. A flashover of breaker contacts is another possible cause, particularly when the unit is coming up to speed with field applied. As the unit rotates, the voltage increases and assumes a constantly rotating phasor not in synchronism with the system. The voltage difference, particularly when the generator and system phasors are 180° apart, can approach twice normal. If the pressure of the breaker insulating medium decreases, the breaker can flash over, connecting the unit to the system. The startup protection described in section 7.12 can usually act quickly enough to avoid or minimize the damage. Tandem machines, i.e. turbine–generators on one shaft, do not need startup protection since there is no need to apply field before the unit reaches synchronous speed. However, inadvertent energization is still a concern, since the machine will still behave as an induction motor when it is connected to the system before field is applied. The same protection provided for startup can be used in this case. Some utilities use dedicated protective circuits that are activated when the unit is taken out of service.

7.14 Torsional vibration

The potential for shaft damage can occur from a variety of electrical system events. In addition to short circuits or bad synchronizing, studies have indicated that subsynchronous resonance or automatic reclosing, particularly high-speed reclosing, can produce torque oscillations leading to fatigue and eventual damage. Subsynchronous resonance is a phenomenon associated with series capacitors and results from a resonant condition that is caused by the series capacitor and the
line inductance. This circuit oscillates at less than 60 Hz, resulting in extremely high voltages that are reflected back into the machine. There have been at least two well-documented incidents in the western USA and several in Europe that initiated investigations into this problem. Specific protection packages have been designed to detect the onset of the oscillations and to remove the series capacitor and reconfigure the primary system so it will not have a series-resonant condition at subsynchronous frequencies. The effect of high-speed reclosing is less certain and no events involving damage have been specifically reported at this time, although there are several monitoring studies in progress throughout the world. Nevertheless, criteria have been proposed, such as a 50% change in power flow following a switching event, that could serve as a warning to investigate further. The usual solution is to delay or remove high-speed reclosing or to prevent high-speed reclosing after a multiphase fault. This, of course, removes many of the advantages of high-speed reclosing and the total effect on the integrity of the system must be considered.

### 7.15 Sequential tripping

The purpose of sequential tripping a synchronous generator is to minimize the possibility of damaging the turbine as a result of an overspeed condition occurring following the opening of the generator breakers. With the breakers open, the unit is isolated from the system and the speed is determined by the steam through the turbine. If a valve fails to close completely after being given a trip signal, there is enough energy in the residual steam in the steam lines and parts of the boiler to drive the turbine to dangerous overspeeds. Sequential tripping is accomplished by tripping the prime mover before tripping the generator and field breakers. Reverse-power relays, pressure switches and/or valve limit switches are used to determine that the steam input has been removed and then to complete the trip sequence. Sequential tripping is essential because overspeeding the turbine is a more damaging operation condition than motoring. There are recorded instances where overspeed resulted in throwing turbine blades through the turbine casing, resulting in injury and death to personnel in the area and, of course, extensive and costly damage to the unit. Motoring, in which the system supplies the rotational energy with little or no steam input, will result in heating the last-stage turbine blades; a situation that can be controlled by attemperator sprays and which allows enough time for the operator to take corrective action.

Simultaneous tripping, i.e. tripping the boiler, closing all of the steam valves and opening the generator and field breakers at the same time, is required in the event of an electrical failure. Sequential tripping is the proper action in the event of a mechanical failure. When the unit is manually tripped it is commonly done sequentially.

### 7.16 Summary

In this chapter we have examined the problems that can occur with AC generators and motors and the protective devices that can be used to correct them. The most common electrical failure involves short circuits in the stator winding. For phase faults, differential protections with percentage differential relays are almost invariably used. For ground faults, the protection depends upon the method of grounding. We have examined high, medium and low impedance grounding methods and the associated protection schemes. High impedance grounding with the resistor on the secondary side of a transformer is the most common method for large unit-connected generators. Resonant grounding is also used, more in Europe than in the USA. Generator rotors are almost always ungrounded, so the only problem is to detect the ground and take some action before a second ground occurs. Two common ground detection methods are shown. The usual action is to alarm and allow the operator to decide if a trip is warranted.

Almost all integral horsepower motors are protected with time-delay overcurrent relays to avoid overheating due to overloads, low or unbalanced voltages or other abnormal operating conditions.
Instantaneous or differential relays are used to protect against phase faults. Ground relays depend upon the method of grounding and the application of phase or toroidal CTs. Time-delay overcurrent relays are used if the CTs are connected in the residual or neutral circuit, and instantaneous relays are used with toroidal CTs.

Unbalanced voltages and currents are usually caused by system problems, but the harmful effects are felt by the rotating elements on the system. Detecting abnormal voltages, current and frequency is not difficult. Volts/hertz, over- or undervoltage or negative sequence current are parameters that are easily relayed. The problem arises as to the appropriate action to take. Very often, immediate tripping is not required, although if the abnormality continues damage will result and the unit must be removed from the system. Abnormal frequency is another system condition that can harm a turbine–generator set. Low frequency will seriously stress the turbine blades and again, although the detection is simple, the remedy requires judgment.

The protection of power plant auxiliary motors has been studied, both from the point of view of the motor itself and as a system problem to ensure coordination. To examine the overall auxiliary system, we have introduced the various circuit breaker operating and interrupting mechanisms and bus transfer schemes. We have also examined a variety of operating or maintenance situations that can cause extensive damage to the turbine or the generator. Startup of the generator, motoring, inadvertent energization and torsional vibration are all potential hazards for which protection in the form of relays or logic circuits must be provided. The sequence of tripping the unit from the system is determined by the type of fault; an electrical fault, usually a short circuit in the generator or auxiliary bus, requires simultaneous tripping of the turbine and the generator and field breakers to remove the source of electrical energy and minimize damage. A mechanical failure, usually a boiler tube leak or turbine or pump problem, should initiate a sequential trip of the turbine, that is extinguish the fire and close the steam valves, followed by opening the generator and field breakers when there is no danger of overspeed.

Problems

7.1 Consider the power system shown in Figure 7.29 which represents a unit-connected generator prior to being synchronized to the system and protected with an overcurrent relay connected

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**Figure 7.29** One-line diagram for problem 7.1

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Generator parameters:
975 MVA
22 kV
\[ X''_d = X_2 = 0.21 \text{ pu} \]
as a differential relay. Determine the maximum load, select a CT ratio for the generator differential, calculate the relay operating currents for a three-phase fault at F1 and F2 and set the relay. Assume there is no CT error and the relay has the CO-11 time–current characteristics shown in Appendix D (section D.2).

7.2 Repeat problem 7.1 assuming that the line-side CT has an error of 1% of its secondary current. Set the overcurrent relay so it will not operate for an external fault.

7.3 Repeat problem 7.1 for a phase-to-phase fault at F1.

7.4 Figure 7.30 shows a percentage differential relay applied for the protection of a generator winding. The relay has a 0.1 A minimum pickup and a 10% slope. A high-resistance ground fault has occurred as shown near the grounded-neutral end of the generator winding while it is carrying load with the currents flowing at each end of the generator as shown. Assume that the CT ratios are as shown in the figure and they have no error. Will the relay operate to trip the generator under this condition? Would the relay operate if the generator were carrying no load with its breaker open? Draw the relay operating characteristic and the points that represent the operating and restraining currents in the relay for the two conditions.

7.5 Consider the system shown in Figure 7.31 with the generator, transformer and system parameters as shown. Calculate three-phase and phase-to-phase currents due to faults at F1 and F2 and determine the restraining and operating currents in the percentage differential relay for the four conditions.

![Figure 7.30](image)

*Figure 7.30 System for problem 7.4*

![Figure 7.31](image)

*Figure 7.31 System for problem 7.5*
7.6 For the system shown in Figure 7.32, draw the operating characteristics of an overcurrent and a percentage differential relay and show the tripping points for a fault at F₁ if \( R_N \) is, respectively, 0.5, 5 and 50 \( \Omega \).

![Figure 7.32 System for problem 7.6](image)

7.7 Draw the one-line diagram showing a 200 hp motor connected to a 4 kV bus. Assume the following bus and motor parameters:

- phase-to-phase bus fault = 15 000 A
- three-phase bus fault = 25 000 A
- maximum ground fault = 1500 A
- motor full-load current = 25 A
- motor locked rotor current = 150 A
- motor starting time = 1.5 s.

Select and set the phase and ground relays using the time–current characteristic of the three relays shown in Appendix D.

7.8 Repeat problem 7.7 for a 1500 hp, 6.9 kV motor with the same bus fault parameters and motor full-load current of 110 A, locked rotor current of 650 A and a starting time of 3 s.

7.9 For the distribution transformer, unit-connected generator shown in Figure 7.16 and the parameters given in Example 7.7, determine the value of the secondary resistor that will protect 85% of the winding. You may assume that a part winding voltage and leakage reactance is proportional to its length.

References


