TRANSFORMER PROTECTION

A large number of transformers are typically installed in any given power system. This represents a large investment for both utility and industrial power systems. These devices provide the necessary voltage conversions to transport power through the system. Faults within a transformer can cause a tremendous amount of damage in a very short time. In some cases, the unit can be returned to the manufacturer for repair. In other cases, the transformer may be damaged beyond repair. Protection is applied to the transformer to detect faults within or adjacent to a transformer and remove it from service fast enough to limit the amount of damage sustained.

The type and extent of protection applied on transformers is a compromise between such factors as the sensitivity, speed of operation, security, and cost of implementation. The more important and expensive the transformer is to the power system, the greater the amount of protection that is typically applied. If a transformer can be replaced relatively easily and at a minimum cost, less protection can be used. However, for larger, more costly transformers or transformers that are part of a critical process, additional protection may be warranted to minimize the damage and resulting downtime required to replace a badly damaged transformer.

The location of the transformer also dictates the type and amount of protection required. For transformers in industrial facilities or independent power producers that parallel the utility power system, additional protection is required for the interconnection and for backup protection against faults on either side of the parallel connection.

The following text discusses the most commonly used protective methods for transformers. Factors affecting protective methods are described at length, including operating characteristics of the transformer itself and characteristics of the power system.

FACTORS AFFECTING PROTECTION

There are several factors that affect the design of a transformer protection scheme. These include (1) the magnetizing inrush characteristics of the transformer; (2) the transformer's winding connections; (3) the overexcitation characteristic of the transformer's windings; (4) the addition of tapped windings, such as de-energized taps on the transformer's primary or load-tap-changers on the transformer's secondary; and (5) the through-fault capability of the transformer. Each of these factors must be considered when protecting a transformer because they have varying effects based on the type of protection applied. A more detailed discussion of each follows.

Magnetizing Inrush Current

Magnetizing inrush is a transient current that results from the sudden change in exciting voltage across a transformer's windings. This can occur at initial energization, upon reenergization after clearing a fault, or during the inrush period of a parallel-connected transformer. Because inrush current has varied effects on the devices protecting the transformer, the causes and characteristics of this current should be carefully considered in applying such protection.

Magnetizing inrush current, in part, depends on the transformer rating and the available fault current. Because of the voltage drop across the source impedance during the inrush period, the inrush current is less when the transformer is supplied from a weak source compared with a strong source.

The inrush at transformer energization is primarily a function of the residual magnetism remaining in the transformer core and the magnitude of the instantaneous voltage when the transformer is energized. The core of the transformer displays properties typical of magnetic materials. For example,

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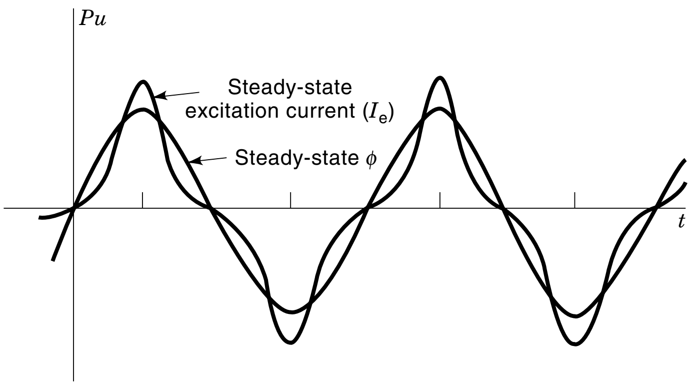


Figure 1. Typical transformer steady-state flux and excitation current waveforms resulting from an applied voltage.

when the applied voltage is reduced to zero, the magnetic flux within the transformer's core does not fully dissipate. Normally some amount of residual flux is trapped in the core material. Figure 1 shows the relationship between the excitation current I_e and the steady-state flux ϕ in the transformer core. The steady-state flux waveform is similar in shape to that of the applied voltage. The beginning polarity and magnitude of the remnant flux depend on the point when the transformer is deenergized.

When the transformer is reenergized, the magnitude of the core flux will change from the remnant flux point, as shown in Fig. 2(a). The excitation current resulting from the core flux begins at zero and increases proportionally to the increase in core flux. If reenergization occurs at a point in the voltage waveform that produces substantially increased flux levels, the transformer core can possibly be driven into saturation, as shown in Fig. 2(a). On the other hand, if the transformer is reenergized when the polarity of the voltage and flux are the same, but decreasing in magnitude, the magnetizing inrush current can be significantly lower, as shown in Fig. 2(b).

Because these two parameters are unknown and uncontrollable, there is no way of knowing the magnitude of the inrush current during any particular energization. The magnetizing inrush current can reach peaks as high as twelve times (or greater) the rated transformer peak current. However, with the increasing use of improved core steel in power transformers, magnetizing inrush current can be as low as 8% of the fundamental current.

Magnetizing inrush current can be classified as either initial, recovery, or sympathetic. Initial inrush occurs similar to

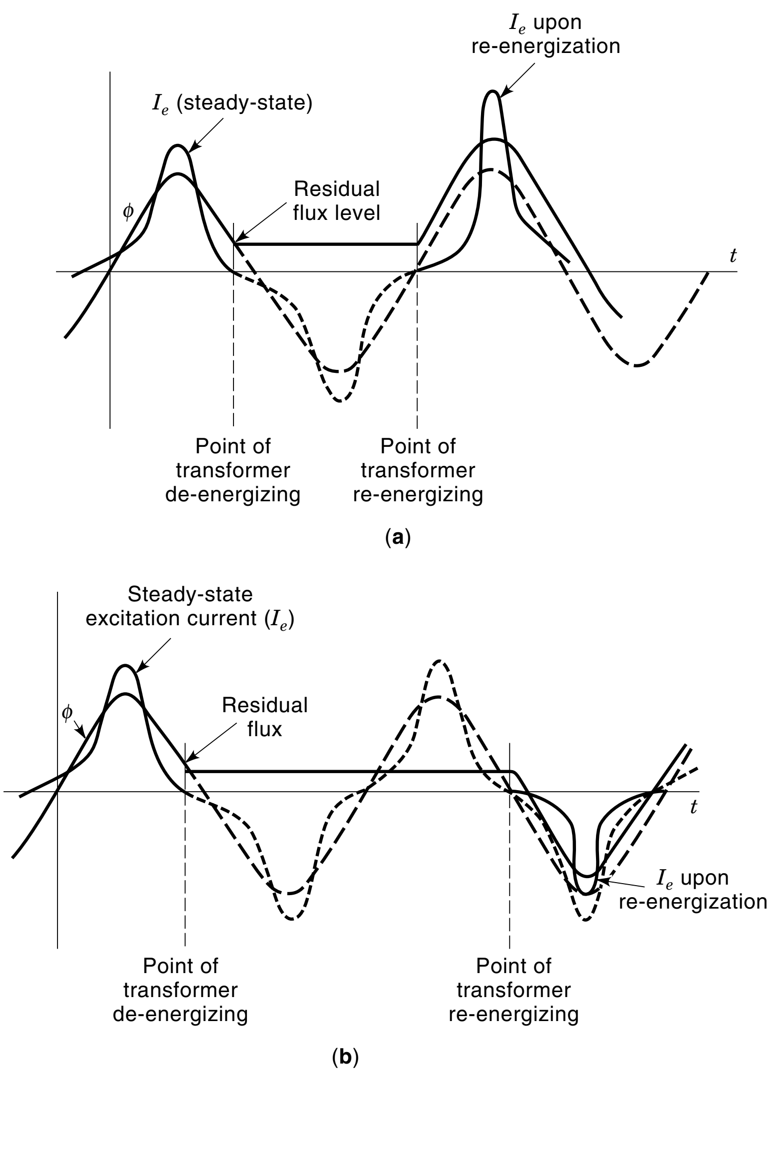


Figure 2. Magnetizing inrush current resulting from transformer re-energization. (a) Same polarity with increasing applied voltage. (b) Same polarity with decreasing applied voltage.

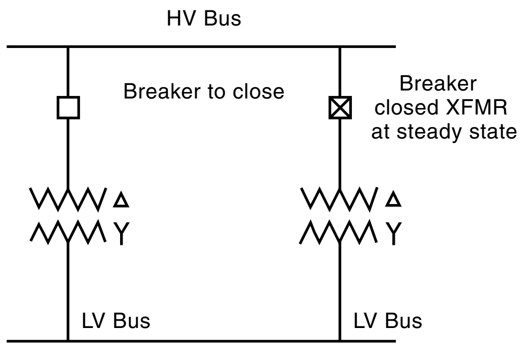


Figure 3. Transformer connections resulting in sympathetic inrush currents.

that described previously. Initial inrush typically occurs when a transformer is energized for the first time or after being deenergized for a time. In addition, there are no connected loads and no other transformers are being operated in parallel. Under these conditions, the inrush characteristics are similar to those described before. If these conditions are not met, then the inrush will display different characteristics.

When a transformer carrying a load experiences a momentary loss of source voltage, followed by reenergization (e.g., following automatic breaker reclosing), the magnetizing inrush current is composed of two components: (1) inrush due to the transformer itself, and (2) load recovery inrush due to the sudden increase in voltage from its depressed level during the fault. As mentioned before, a voltage transient from the recovering voltage causes a flux increase within the transformer's core, resulting in an increased exciting current. Coupled with the load current rise at the same time is a notable inrush current after the fault is cleared.

Sympathetic inrush current occurs in one transformer as a result of energizing an adjacent transformer, as shown in Fig. 3. The severity of the sympathetic inrush is a function of the level of the voltage drop across the source resistance resulting from the primary magnetizing inrush current.

One predominant factor of any type of inrush described above is the harmonic content of the current waveform. Table 1 shows typical harmonic contents for transformer magnetizing inrush currents due to an internal fault with no current transformer (ct) saturation (1).

As previously stated, magnetizing inrush can reach significantly large magnitudes. Table 1 also shows that this inrush current includes a large percentage of second, third, and fifth harmonic currents. Without proper attention, these inrush currents and their harmonic content can lead to nuisance operation of the protective devices applied to the transformer. However, it will be shown later that these same harmonics can be utilized to the advantage of the transformer protection scheme.

Table 1. Transformer Harmonic Content Under Fault and Energizing Conditions

Component	Internal Fault, %	Magnetizing Inrush, %
Peak	145%	244%
DC	38%	58%
Fundamental	100%	100%
Second harmonic	9%	63%
Third harmonic	4%	22%
Fourth harmonic	7%	5%
Fifth harmonic	4%	32%
Sixth harmonic	6%	4%
Seventh harmonic	2%	3%

Winding Connections

Power transformers can have any one of several winding configurations, as shown in Table 2. The characteristics of these configurations vary and must be considered when applying protective devices.

For example, referring to Table 2, a delta/grounded-wye transformer exhibits a 30° phase shift. If the transformer is manufactured according to ANSI/IEEE Standard C57.12.70, the high-voltage side phase-to-ground voltage leads the low-voltage side phase-to-ground voltage by 30°. This is true of both the voltage and current phasors. This presumes that the phase rotation is A-B-C and the phases are connected to terminals H_1, H_2, and H_3, respectively. If the phase rotation or connections are reversed, the phase shift mentioned is no longer true.

The winding connections and resulting phase shift vary depending on the system phase sequence, ABC or ACB, and the location of the delta winding with respect to the system. As shown in Figures 4 and 5, the connections differ depending on whether the delta winding is connected to the high voltage or the low voltage. However, in either case, given an ANSI Standard connection, the high-voltage winding always leads the low-voltage winding by 30°.

In addition, the phase shift across a delta–wye transformer requires special attention to the current transformer connection when applying differential protection. To match the currents in current transformer secondary circuits, it is necessary to provide connections that account for the necessary phase shift and the resulting phase currents. This subject is addressed in more depth in a later section on differential protection.

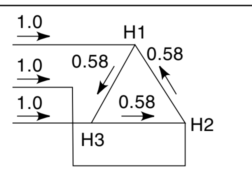
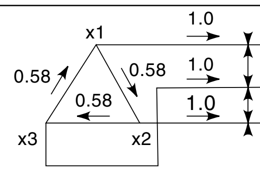
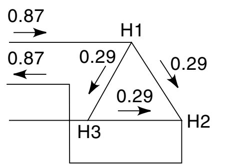
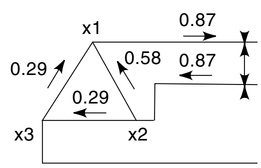
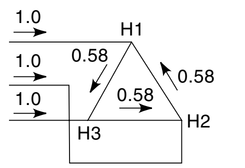
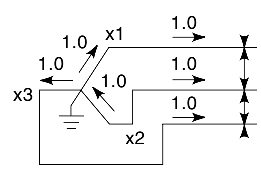
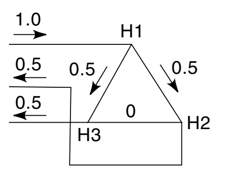
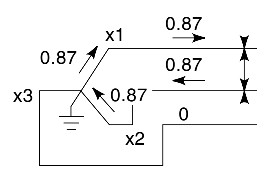
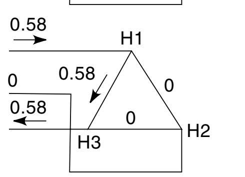
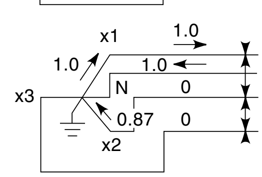
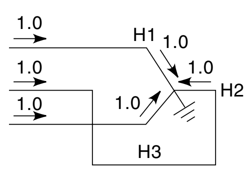
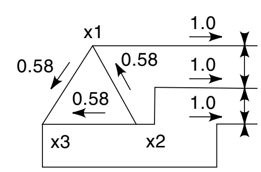
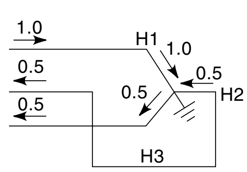
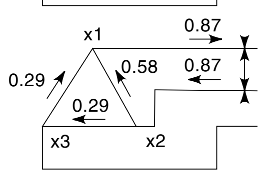
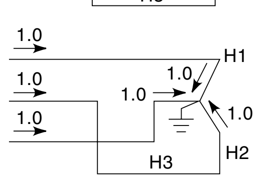
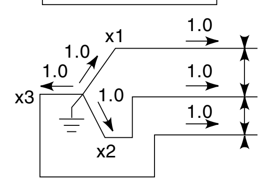
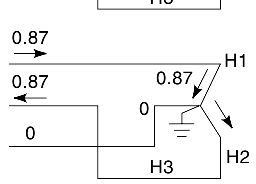
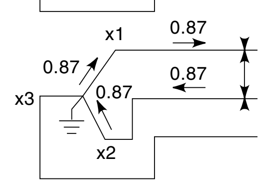
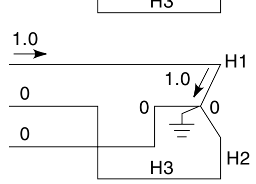
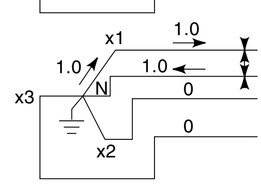
Winding Taps

Most transformers are equipped with either a high-voltage or low-voltage tap changer. In some cases, both are present. The purpose of these devices is to adjust the nominal voltage ratio from one winding to the other to maintain a sufficient load voltage based on the load requirements.

The low-voltage tap changer, or *load-tap-changer* (LTC), is operated under load, therefore, some type of impedance is necessary to maintain the circuit continuity while changing between taps (i.e., the switch must be make-before-break to avoid loss of power to the load). This is accomplished with resistance bridging, reactance bridging, or vacuum type switching devices. Generally, load-tap-changers have a voltage adjustment range of ±10% of rated voltage in 32 equal steps, or $\frac{5}{8}$% for each step.

The high-voltage tap changer is normally restricted to use only when the transformer is deenergized. This tap changer is known as a *no-load* (NLTC) or *deenergized* tap changer (DETC). Deenergized tap changers typically have a switching range of ±5% of rated voltage in four $2\frac{1}{2}$% steps. Because

Table 2. Typical Transformer Winding Connections with Line Currents (in per Unit) for Secondary Faults

Fault Type	High-Voltage Winding	Low-Voltage Winding
Three phase		
Line-to-line		
Three phase		
Line to line		
Line to neutral		
Three phase		
Line to line		
Three phase		
Line to line		
Line to neutral		

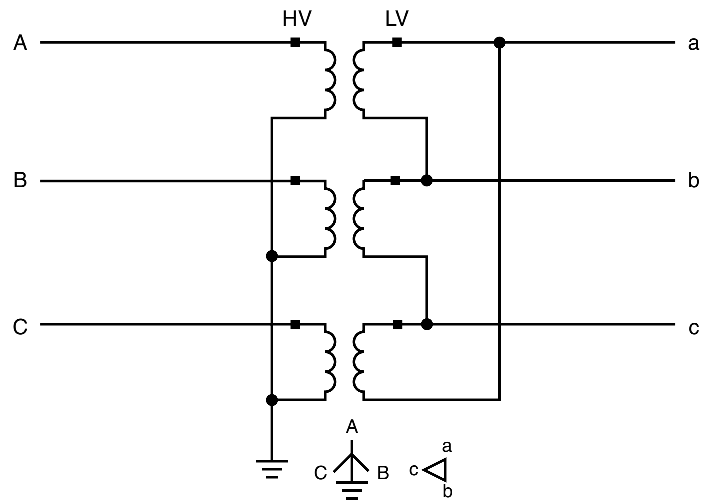


Figure 4. Differential relay connection for high-voltage wye winding.

these taps are switched while the transformer is de-energized, there is no need for any type of bridging between the contacts.

Because these tap changers actually modify the winding ratio of the transformer, care should be taken to ensure that any protection employed is not adversely affected by the normal operation of changing tap positions. Thus, actual rather than typical winding ratios should be considered for protection setting calculations.

Through-Fault Capability Limits

A transformer through-fault is defined as a fault that occurs on the secondary of the transformer, resulting in the flow of high magnitude currents through the windings. These fault currents can be at magnitudes that damage the transformer windings, reducing the effective life of the unit. ANSI/IEEE C57.12 establishes through-fault capability limits for distribution and power transformers. These limits are represented

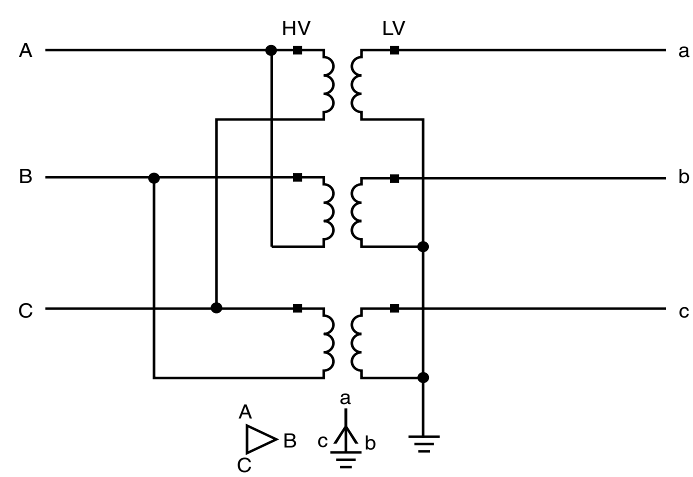


Figure 5. Differential relay connection for high-voltage delta winding.

Table 3. KVA Transformer Ratings

Category	Single-Phase	Three-Phase
I	5–500	15–500
II	501–1667	501–5000
III	1668–10,000	5001–30,000
IV	Above 10,000	Above 30,000

by time-current curves and are divided into four categories (Table 3):

These curves are derived on the basis of three-phase secondary faults for transformers of various impedance levels and for the frequency with which faults occur—frequently or infrequently. Because the damage that results from through-faults is cumulative over the life of the transformer, units subject to frequent fault occurrences have their capability curves restricted to lower values.

The protection applied to a distribution or power transformer must address these capability curves. Overcurrent devices should detect and clear damaging fault currents before reaching the levels established by the capability curves. Consideration should also be given to the transformer's winding connection to ensure that adequate minimum and maximum protection levels are achieved for various types of faults, as shown in Table 2.

PROTECTION METHODS

There are several methods of applying protection to power transformers. Each differ in complexity, sensitivity, and selectivity. The objective of any protective scheme is to provide fast fault clearing while minimizing equipment damage, system disturbance, and service outage time. The faster a fault, either internal or external, is detected and cleared from the system, the lower the possibility of catastrophic damage to the transformer.

In addition to faults, transformers should be protected against damaging overload conditions. Extended transformer overloading leads to increased temperature in the windings and other components. If allowed to go beyond the maximum designed temperature limit, deterioration of the insulation system occurs, reducing the transformer's useful life. If the insulation is weakened sufficiently, a moderate overvoltage may cause a breakdown of the insulation and lead to a turn-to-turn or phase-to-ground fault within the transformer. Therefore, transformers should be monitored for overloads beyond their design capability. IEEE Standard C57.12.91 and C57.12.92 provide guidance for anticipated loss of transformer life verses overload level and duration.

The type and amount of protection used is dictated by the specific application. Smaller transformers (up to about 3750 kVA and 2.4 kV) normally have adequate protection with primary fuses and secondary ground overcurrent relays. A greater degree of protection is normally recommended for transformers of larger sizes (5000 kVA and greater), primarily because of the greater expense of these transformers or availability of a replacement spare unit and the desire to provide increased sensitivity and selectivity. Increased sensitivity aids in quickly detecting and clearing transformer faults. The greater selectivity helps during inspection in locating the precise area where the fault occurred. And of course, it is always recommended that a transformer be inspected after it has sustained an internal fault and before it is placed back into service.

A discussion of various types of transformer protection is given below. Methods included are fuses, harmonic restrained percentage differential, phase and ground overcurrent, overexcitation, and other ancillary protection.

FUSE PROTECTION

Fuses have been used for many years as the primary protection for transformers of various sizes. Within industrial facilities, fuses are generally applied to transformers up to about 3750 kVA as primary protection from short-circuits. The application of fuses at utilities vary considerable, but some provide power fuses for transformers up to about 10 MVA. Most utilities however, use circuit breakers or circuit switchers with relays for transformers above about 5000 kVA. In most applications, system conditions determine whether or not to use fuses for transformer primary protection. Fuses are not commonly used above 69 kV because of fuse availability and transformer costs.

The application of fuses for transformer protection requires considerable knowledge of the system characteristics and the performance of the fuse itself. Fuses must be sized to provide adequate protection, yet ensure that misoperation does not occur during normal operation. Smaller fuse sizes may be necessary to detect and quickly clear certain types of faults to limit transformer damage. However, the characteristics of the smaller fuse size must be coordinated with other factors to minimize nuisance operations. For instance, it is not commonly possible to clear low magnitude faults under the transformer through-fault capability curve, especially for ground faults on the secondaries of delta–wye transformers.

Other factors considered when selecting fuses for primary transformer protection include

- system voltage
- fuse ampere rating selection factors including maximum available fault current (fault interrupting rating); load current including normal, peak, emergency, and cold load pickup; and magnetizing inrush current
- type of secondary loads
- coordination with other overcurrent devices

System Voltage

Fuses used to provide primary protection for three-phase transformers should have a maximum design voltage rating that equals or exceeds the maximum phase-to-phase system operating voltage. However, for single-phase transformers, the maximum voltage rating need only equal or exceed the system phase-to-neutral voltage. Although, it is sometimes economically desirable to use phase-to-neutral rated current-limiting fuses to protect three-phase power transformers, the following conditions should be considered to ensure proper operation:

- Transformer connection is grounded-wye/grounded-wye, grounded-wye/delta, or wye/delta.

- Phase-to-phase or three-phase ungrounded faults are unlikely.
- Fault current is high enough to operate two fuses simultaneously in less than 0.2 s.
- The load is predominately ungrounded.
- A secondary breaker is used to interrupt overloads.

Fault Current Interrupting Capability

The fuse should be selected so that its short-circuit interrupting rating is equal to or greater than the maximum fault current available. Anticipated changes in system growth should also be considered to reduce the possibility of outgrowing the fuse capability.

Fuse Ampere Rating Selection

The continuous current loading capability of the transformer primary fuse should accommodate all loading conditions, including normal daily loading, cold load pickup, periodic peak loads, and any emergency peak loads. The fuse should provide for these current levels and the loading duration without operating. Therefore, sufficient margin should be allowed in the rating selection. The drawback to selecting a larger fuse rating is that the protection level afforded the transformer is lowered. This should be evaluated closely to ensure that adequate transformer protection is provided. Typically fuses are chosen that have full load current ratings 1.5 to 2.5 times the transformer full load current.

The operating characteristic of the fuse should also be capable of withstanding any magnetizing inrush currents that are expected, without operating or damaging its fusible elements. Typical inrush currents include initial, recovery, and sympathetic inrush currents, as described above. The magnitude and duration of the inrush current vary with transformer size, however, a conservative estimate generally used is a current magnitude 12 times the transformer primary full-load rated current for 0.1 s.

Fuses should also protect the transformer against damaging secondary overload currents while maintaining coordination with other overcurrent devices. Current-limiting fuses are designed to provide high-speed fault clearing where the threat of damage from extremely high fault current levels is present. These fuses usually provide inadequate protection for transformer overloads and coordination with other fuse types is difficult. Effort should be taken to select a fuse size that provides primary protection, while maximizing the protection against secondary overloads.

Type of Secondary Loads

Care should be exercised when applying fuses to protect transformers that carry three-phase secondary loads, such as induction motors. Fuses open only one phase in response to single-phase overcurrent conditions. For single line-to-ground faults on the transformer primary circuit, unbalanced voltages will be applied to the terminals of the secondary loads.

For single-phase loads, this poses no problems. However, for three-phase loads, these unbalanced voltages will produce negative sequence currents in the secondary circuit, as shown in Fig. 6. These negative sequence currents will result in thermal damage if not removed quickly.

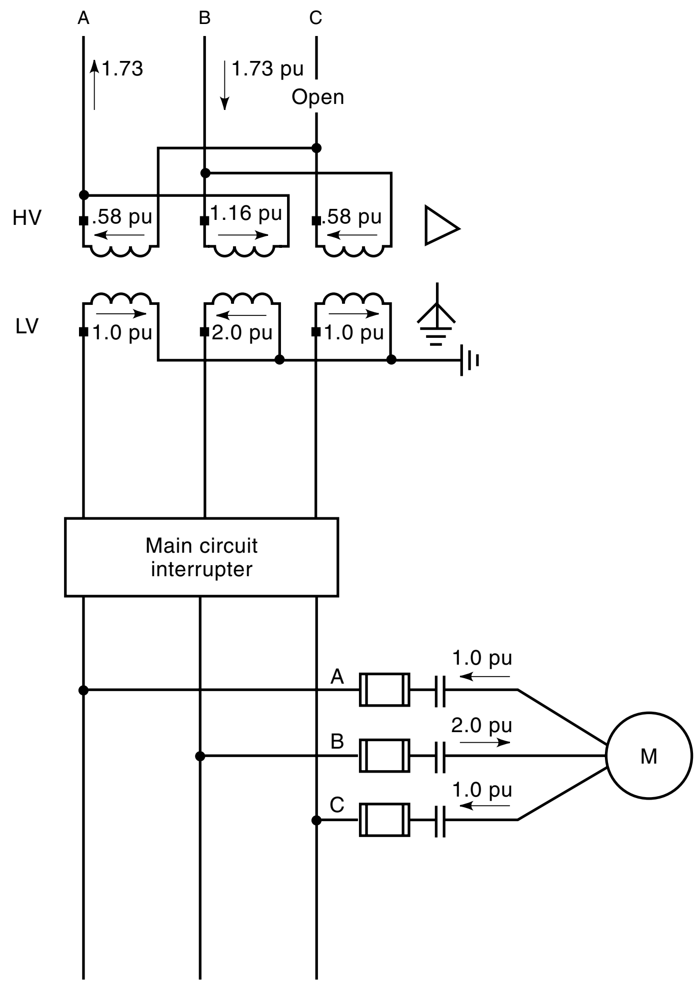


Figure 6. Transformer secondary currents with open primary phase supplied to a three-phase induction motor.

Negative sequence overcurrent protection may be applied to the secondary of the transformer for this type of condition. However, consideration should be given during the selection of the protective devices to ensure adequate protection of the transformer and its secondary loads.

Coordination with Other Devices

When applying fuses for primary transformer protection, it is necessary to coordinate the operating characteristics with other overcurrent protective devices on both the primary and secondary. Coordination with other devices ensures that only the faulted portion of the power system is taken out of service for a given fault. Without coordination, large portions of the system would be interrupted, making it difficult to locate the origin of the problem. For line-to-ground faults, fuses on the delta side of a delta–wye transformer may see current that is significantly less than the current on the wye side of the transformer. This will have notable effects on the transformer fuse coordination with downstream devices. See Table 2 for typical effects of transformer winding connections.

OVERCURRENT PROTECTION

Overcurrent relays are used as primary protection for smaller transformers and as backup protection for transformers with differential protection. Overcurrent relays are applied for both phase and ground fault protection. Overcurrent relays on the transformer primary typically include instantaneous and time-overcurrent functions. However, the instantaneous relay is normally set not to trip for secondary faults. Overcurrent relays on the transformer secondary circuit are normally limited to time-overcurrent functions because of the requirement to coordinate with devices downstream of the transformer. The primary protective devices must also coordinate with the magnetizing inrush characteristics of the transformer to limit nuisance tripping.

Because overcurrent relays operate on the magnitude of the current flowing in the circuit, these devices are susceptible to all factors that produce high currents, including magnetizing inrush and overloads. As a result, the pickup setting of the instantaneous and time-overcurrent relays must be set above these levels to alleviate nuisance operations.

For example, a transformer with a rated primary load current of 125 A could have an initial magnetizing inrush current of as much as 1500 (125 A $\times$ 12) amperes. Although this current decays relatively quickly, the time-overcurrent relay must be set with a sufficient pickup and time dial to prevent operation. As shown in Fig. 7, the time-current characteristic of the overcurrent relay should be above and to the right of the transformer magnetizing inrush point. The magnetizing inrush point is defined as the magnitude of the inrush current at 0.1 s. If the curve falls below the inrush point, the overcurrent relay could operate during transformer energizing.

The operating characteristic of the overcurrent relays must also coordinate with other time-dependent protective devices upstream and downstream of the protected transformer. The application of instantaneous overcurrent relays is frequently limited to use on the high-voltage winding of the transformer.

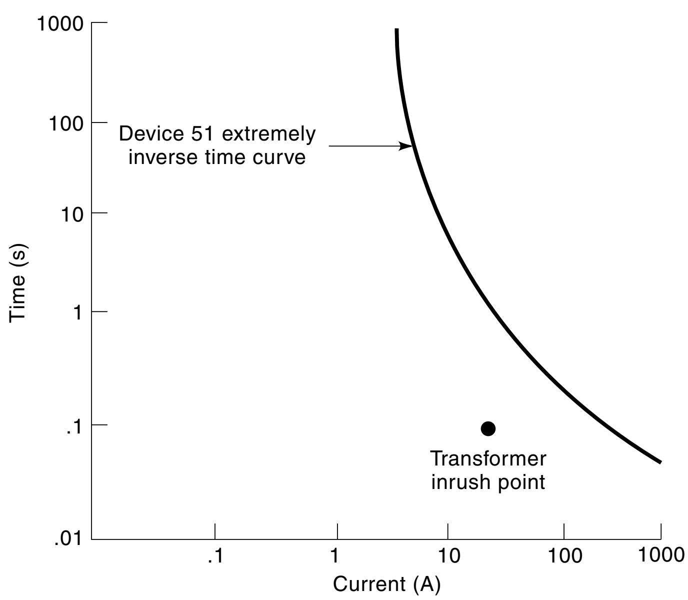


Figure 7. Example of time-overcurrent relay coordination with magnetizing inrush point.

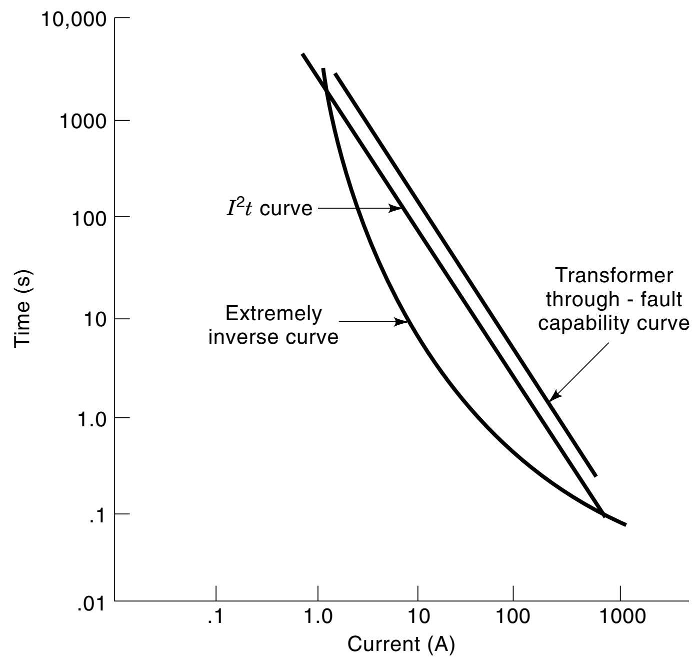


Figure 8. A comparison of extremely inverse and I^2t time curves for transformer through-fault protection.

Because of the quick operating time of instantaneous overcurrent relays, coordination with downstream time–overcurrent devices is difficult. If applied on the transformer secondary circuit, instantaneous overcurrent relays would require a time delay to allow downstream time-dependent devices (e.g. fuses and relays) to function first for faults on feeders or branch circuits, except where the nearest protective devices have fault duties below the instantaneous setting. However, applied to the high-voltage winding, the pickup can be set sufficiently high to alleviate any loss of coordination with downstream devices. Some microprocessor-based protection systems communicate blocking signals to other like systems, making application of instantaneous protections on the transformer secondary winding feasible.

In either case, the pickup of the relay should conform to the requirements of the ANSI/NFPA 70-1996 (National Electrical Code). The NEC establishes upper limits for protecting transformers in industrial or power systems. These are maximum limits and should not be considered the preferred settings. Generally, transformer secondary protective devices set for approximately 125% to 150% of the maximum rated load current, provide excellent overload and fault protection.

The slope of the time-current characteristic should match the through-fault withstand capability curve of the transformer as closely as possible. This provides the required protection and does not limit operation of the transformer. Most modern numerical relays include a variety of time-current curves, including standard inverse and I^2t time curves. The I^2t time curve matches exactly the slope of the through-fault withstand curve and provides the best protection. The extremely inverse curve would be the next preferred selection and adequately protects the transformer against damage. A comparison of these two characteristic curves is shown in Fig. 8.

Overcurrent relays provide excellent protection for applications whose fault current is high. However, because overcurrent relays must be set sufficiently high to allow for normal operating conditions, as described before, they provide only limited protection for winding faults or ground faults on transformers with impedance grounding. In these cases, the fault current can be well below the sensitivity setting for overcurrent relays. Thus, additional means of protection should be employed.

DIFFERENTIAL PROTECTION

Differential protection is often used as primary protection on transformers rated 5000 kVA and above. This type of protection provides fast, secure operation for faults within its zone of protection. However, differential relays do not generally detect turn-to-turn faults within the transformer's windings.

Theory of Operation

Differential relays establish a zone of protection, bounded by current transformers on either side of the protected equipment. The differential relay compares the currents flowing into and out of the protected zone based on the replicated signals in the current transformer secondary circuits. If the currents on either side of the protected equipment are not equal in phase angle and magnitude, the relay provides a contact output for tripping. A further examination of the differential principle follows.

Figures 9(a) and 9(b) show a simplified schematic representing the differential principle applied to one phase. The protected equipment in this case could be a generator, bus, or power transformer. The current transformers are located on both sides of the equipment, and each has a ratio of 600 : 5 A.

Under normal conditions, Figure 9(a), the load current of 360 A flows into the left side and out of the right side of the protected equipment. With 360 A flowing into the polarity side of the left-side current transformer primary winding, a current of 3.0 A is produced which flows out of the polarity side of the secondary winding. Similarly, the 360 A flowing into the nonpolarity side of the right-side current transformer primary winding, produces a current of 3.0 A which flows out of the nonpolarity side of the secondary winding. From this, it can be seen that the secondary current flowing into and out of points "A" and "B" are equal and the current simply circulates through the secondary windings of the current transformers. There is no current flowing through the operating circuit, and the relay does not provide a trip output.

Figure 9(b) shows the same circuit with a fault located outside of the protected zone. As can be seen, the effect on the differential relay is the same as previously for normal operation. Because the fault is outside the differential zone, the flow of current through the protected equipment is not affected. The magnitude could change depending on the system conditions. However, this magnitude change will similarly affect the current transformers on both sides of the protected equipment, resulting in no operation of the differential relay.

In Figure 9(c), the fault is located within the protected zone. Now the current flow to the fault from the left side of the protected equipment has increased to 1920 primary amperes, whereas the current on the right side has not changed. Because of the higher fault current on the left side, the secondary current contribution from that side increases to 16 A. The secondary current contribution from the right side is only 3.0 A. This differential current of 13.0 A flows through the operate circuit of the relay resulting in a trip output.

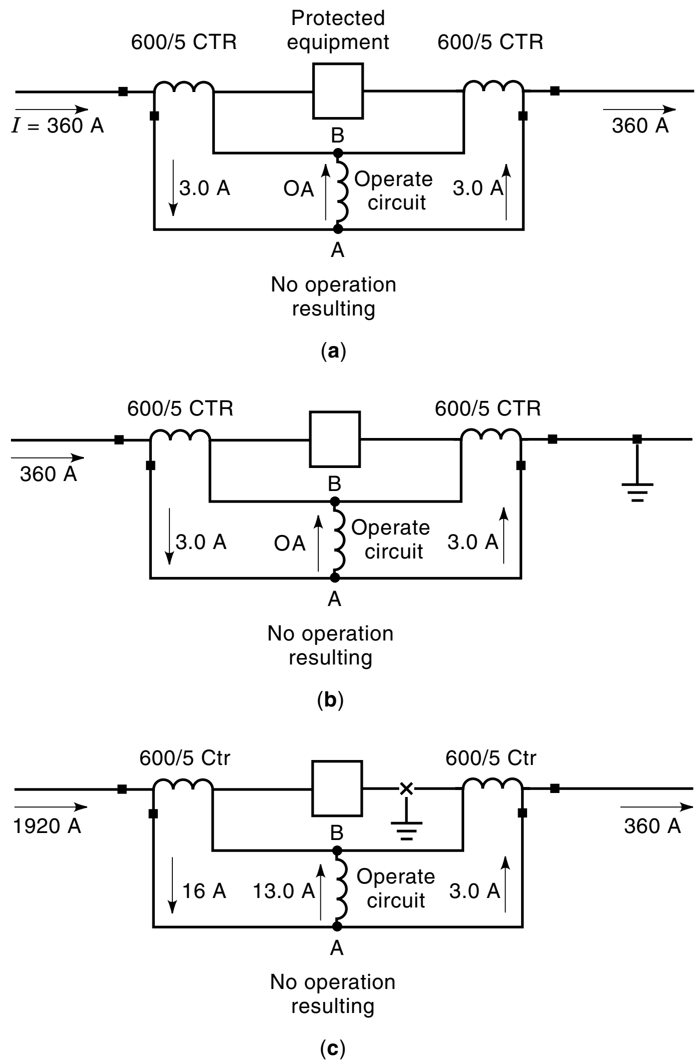


Figure 9. Differential operating principle. (a) Normal operating condition. (b) External fault condition. (c) Internal fault condition.

This example has assumed ideal conditions with 100% accuracy of the current transformers and no current or phase angle variations on either side of the protected equipment. Applied in its strictest definition, any differential current would produce an operation of the relay. When the differential principle is applied to transformers, these and several of the factors discussed previously must be taken into consideration.

Differential Applications

Inherently, the currents on either side of a power transformer differ because of the voltage change across the windings. Therefore, it is necessary to match or balance the currents into the differential relay. This is normally accomplished by using taps on the relay. All differential relays include internal current transformers with various tap settings for adjusting the current inputs to closely match within the relay. For most differential relays, matching the relay nominal current inputs to within 5% to maximize the relay's sensitivity and alleviate any false operations is suggested.

Depending on the relay design, it may be necessary to include auxiliary current transformers in the secondary circuit to achieve the desired current level. This is usually the case with electromechanical type relays which have fewer tap settings. Static design relays normally have taps adjustable in 0.1 A increments across the complete tap range. This allows keeping the mismatch to a minimum without the need for auxiliary current transformers.

Differential relays for transformer applications are of the following two types: *overcurrent differential* or *percentage differential.* Both of these are discussed here.

Overcurrent Differential Protection

Overcurrent differential relays operate on the basis of a fixed difference current. This type of differential protection is the least expensive. However, it is also the most affected by extraneous system characteristics. Overcurrent differential protection is achieved by placing high-speed instantaneous overcurrent relays within the differential circuit. Referring to Fig. 9, an overcurrent relay would be connected between points "A" and "B."

The pickup setting placed on the relay should be set high enough to allow for transient system conditions, such as magnetizing inrush, tap changer action, and imbalances due to current transformer errors. Of course, the higher the set point on the relay, the greater the loss of sensitivity. In some cases, the setting could be so high that many low-grade faults are not detected. Therefore, overcurrent relays for transformer differential protection are normally not recommended.

Percentage Differential Protection

There are several types of percentage differential relays available depending on the particular application. These include

fixed percentage
variable percentage
variable percentage with harmonic restraint

Variable percentage relays with harmonic restraint are normally used for protecting power transformers. The greater selectivity afforded by the variable percentage characteristic makes this function desirable. The harmonic restraint function is needed to eliminate false operations during magnetizing inrush.

In actual practice, there is a difference in the secondary currents because of the current transformer performance error current. If not corrected, this could result in false operation of the differential relay. To restrain operation for through faults and allow for normal imbalances, a restraining winding is placed in each current input circuit of the relay, as shown in Fig. 10.

The restraining windings are the basis behind the percentage differential relay. The percentage differential principle considers the ratio of the operating current to the restraint current. When the operating current exceeds the percentage set point of the restraint current, the relay provides a trip

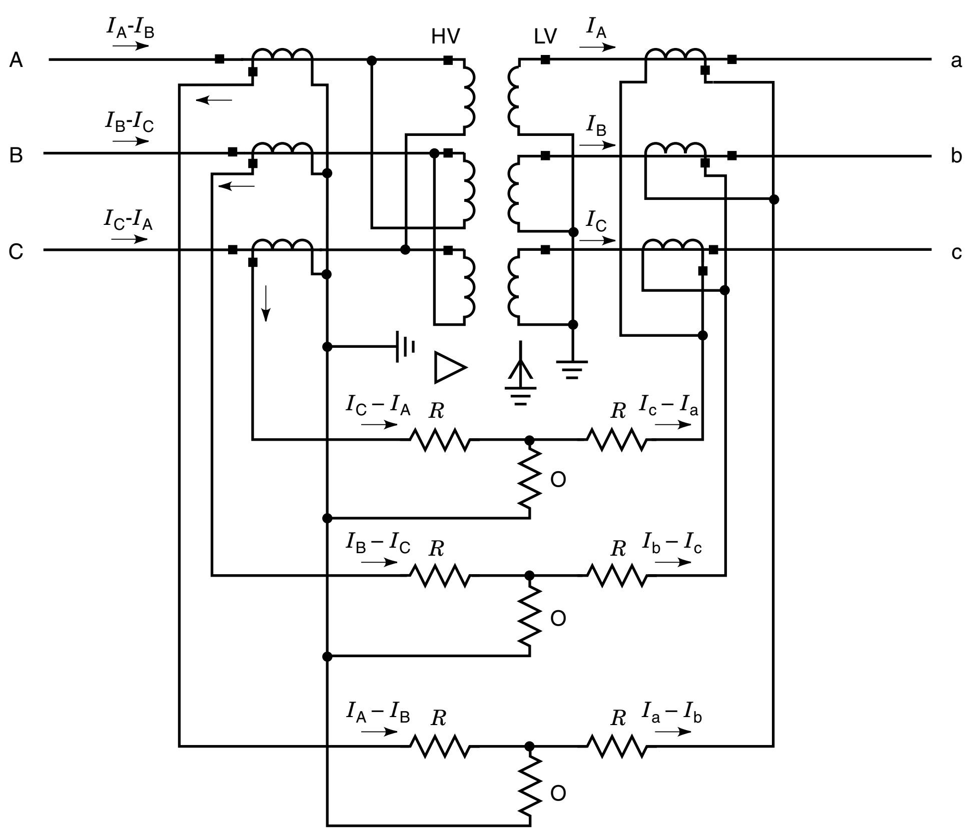


Figure 10. Differential circuit with restraining windings for delta–wye grounded transformer.

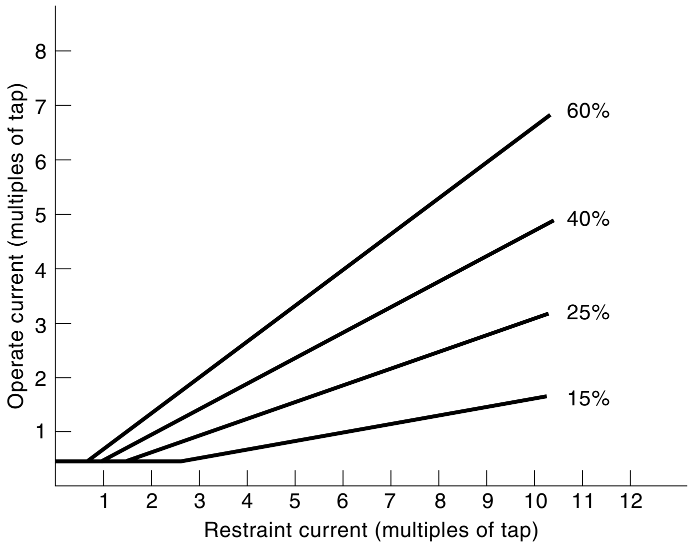


Figure 11. Typical percentage differential operating characteristic.

output. This principle provides an operating characteristic similar to that shown in Fig. 11.

The operating current is plotted on the vertical axis and the restraint current is plotted on the horizontal axis. The value used for the restraint current varies among relay manufacturers. Some use the average of the restraint currents, and others use the maximum restraint current. Using the maximum restraint current provides greater security but forfeits some sensitivity over that of the average restraint method.

Consider the example shown in Fig. 10. Assume that the settings on the relay are for a tap of 2.0 and 4.6 for the high-voltage and low-voltage inputs of the power transformer, respectively. The percentage slope is set to 25%. Then, using the maximum restraint method, the 10 A secondary current on the high-voltage side is selected. From the characteristic curve shown in Fig. 11, extend a line from 10 A on the restraint current axis up to the slope characteristic of 25%. From this point, cross over to the operate current axis. This intersection indicates the amount of operating current (in multiples of tap setting) required to produce an output. In this example, the relay would require 2.5 A of current through the operate circuit for operation, given a restraint current of 10 A, or 0.25×10 A.

This same method can be used for any multiple of restraint or operating current or any percentage slope setting. Slope settings and characteristics vary among manufacturers. However, the basic premise behind all percentage characteristics is similar.

The harmonic restraint capability functions to inhibit operation of the relay during periods of magnetizing inrush currents. As indicated in the second section, harmonic currents produced during energization can develop magnitudes that will create enough difference current to operate the relay. By using a filter to measure the harmonic content of the current signal, operation of the relay can be inhibited if the harmonic current is above a certain level.

Relay manufacturers utilize the harmonic content of the magnetizing inrush current to inhibit the relay's operation during transformer energization. The specific harmonic current(s) that the relay utilize differ among relay designs. Some inhibit on a percentage range of second harmonic current only, whereas others include a percentage range for all harmonics up to some finite multiple (i.e., seventh harmonic). Each of these methods has advantages and disadvantages. However, both have been used for years to provide adequate protection against misoperation under energizing conditions.

As mentioned in the second section, delta-wye connected transformers produce a 30° phase shift from the high-voltage winding to the low-voltage winding. This phase shift must be accounted for in applying the differential relay. There are currently two methods which allow for this phase shift: (1) connect the current transformers so that the secondary currents provide the appropriate phase-shift correction, or (2) provide the required correction within the settings of the differential relay.

Figure 10 shows the method of using current transformer connections for phase-shift correction. Connecting the cts of the delta side of the transformer provide secondary currents that match the phase shift of the primary line currents. To match these on the transformer wye side, its current transformers should be connected in delta. The delta connection will provide a phase shift from the wye line currents in the primary and match the phase shift of the secondary currents from the transformer's delta side. Care should be taken to ensure that the phase shift is made in the correct direction so that the secondary currents in each phase are exactly 180° displaced from one another.

GROUND DIFFERENTIAL PROTECTION

Ground differential protection may be applied on transformers where the ground fault current is limited by impedance grounding. This type of differential protection utilizes the residual connection of the phase ct's and a ct in the neutral ground connection of the transformer, as shown in Fig. 12.

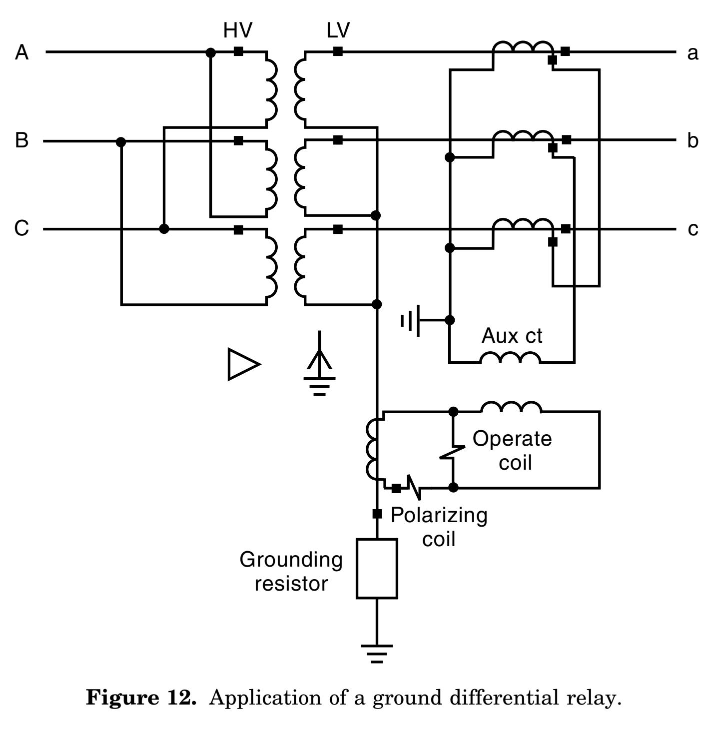


Figure 12. Application of a ground differential relay.

The ground differential scheme protects for ground faults only on the wye-connected winding of the power transformer. Because secondary ground faults are blocked from the delta primary, this scheme does not protect the delta-connected windings. However, ground differential protection does provide a high degree of sensitivity for low magnitude ground faults on the transformer secondary, thereby, minimizing equipment damage while enhancing system stability. Because this scheme is based on the differential principle, there is no need to coordinate operate time with other devices. Therefore, ground differential protection provides selective, sensitive, high-speed ground fault detection and tripping.

Ground differential protection may be accomplished by using a single-phase, nondirectional overcurrent relay, a product type relay, or a current polarized directional ground overcurrent relay.

The ground differential scheme protects equipment located between the phase cts and the neutral cts. For the example shown in Fig. 12, this includes the secondary main circuit breaker. The auxiliary current transformer (ACT) is required to match the secondary currents from the phase ct residual connection to the neutral ct.

Figure 13 shows the application of a nondirectional overcurrent relay. For a line-to-ground fault external to the differential zone, the secondary neutral currents are of equal magnitude and direction and simply circulate in the ct's secondary, with no resultant current through the relay. Should the fault be within the protected zone, there is an imbalance of secondary currents, and the difference current flows through the relay, causing operation. Because of the reliance on the direction of current flow, it is critical that the polarities of all cts be connected properly.

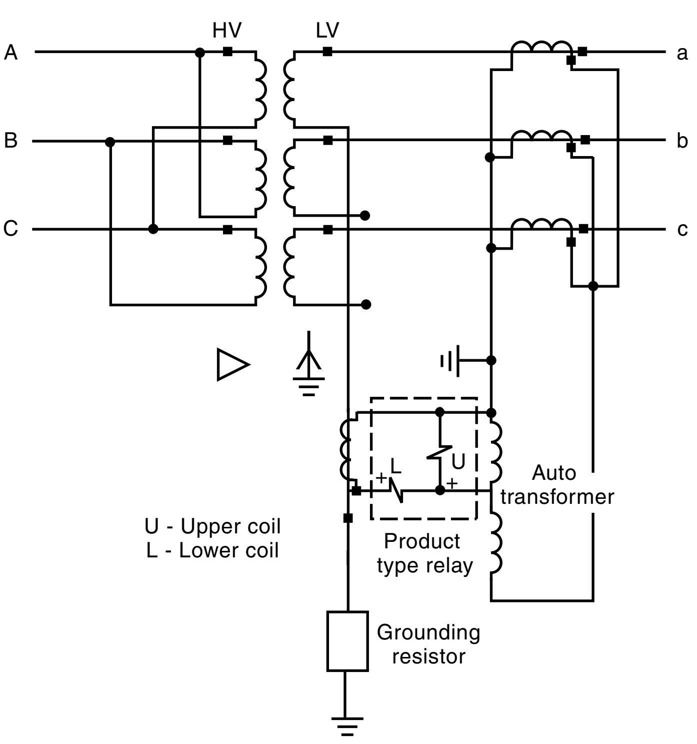


Figure 13. Ground differential scheme using a product type relay and current matching autotransformer.

The major disadvantage of using a nondirectional overcurrent relay is its inability to set the pickup and trip time to clear low-grade faults quickly, while remaining secure for phase faults or magnetizing inrush. During phase faults, the current can be as much as 100 times the maximum current flowing during a ground fault. Therefore, small differences in the performance of the cts produce a false residual difference current that can cause operation of the ground differential relay. Thus, sufficient time delay must be used to ride through these types of faults, giving time for the phase fault protection to operate.

Allowances for magnetizing inrush currents must also be made. As described previously, the magnetizing inrush appears as an internal fault to the differential circuit. Therefore, the overcurrent relay must include sufficient delay to prevent operation during this time.

The use of a product type relay alleviates some of the disadvantages of the overcurrent relay. The product type relay is an electromechanical design that utilizes an upper and a lower coil on the same shaft. The pickup sensitivity of the relay is a function of the current in the lower coil and the current in the upper coil times the cosine of the phase angle between them. The current transformers in this scheme, shown in Fig. 13, must be connected so that the current flows into the polarity marks of both coils simultaneously for an internal fault. When the currents flow into the polarity marks, they are in phase with $\cos 0° = 1$ and produce a maximum operating torque on the relay.

During an external fault, the phase angle between the currents is 180° with a cosine of -1. This produces a maximum torque in the coils that oppose each other, inhibiting operation of the relay.

The directional overcurrent relay that has inverse time characteristic can be used similarly to the product type relay, where the nondirectional operate circuit is connected in series with the current polarizing circuit. The scheme can use either an autotransformer (Fig. 13) or an auxiliary current transformer (ACT), as shown in Fig. 14.

The nondirectional overcurrent function operates on the magnitude of fault current. The directional polarizing circuit provides a torque control to inhibit operation of the relay for faults outside the differential zone. The directional circuit must be connected with the proper polarity for this scheme to work correctly.

Analysis shows that this scheme provides accurate and fast operation for secondary ground faults, even with no current contribution from the system. It can operate adequately with wide differences in currents or ct performance; thus, providing excellent ground fault protection for the transformer secondary circuit.

OVEREXCITATION PROTECTION

Transformer overexcitation occurs when the voltage applied to the primary windings exceeds the rated voltage for extended periods of time. Power transformers are operated at voltages near the knee of their excitation curve. Because this is the point at which the core has maximum permeability, small increases in voltage result in significant increases in the excitation current. For voltages higher than about 110% of rated, the excitation current reaches a damaging level very

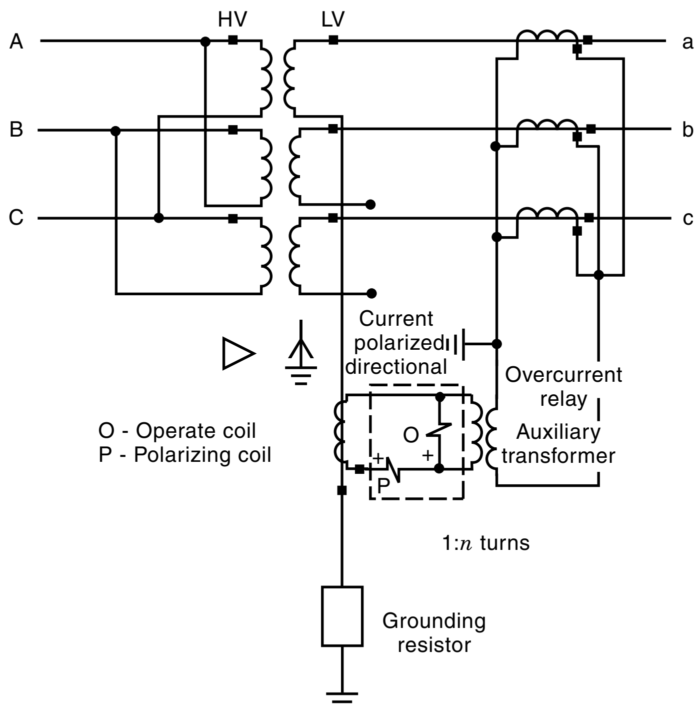


Figure 14. Ground differential scheme using a directional overcurrent relay and auxiliary current transformers.

quickly. If left undetected, thermal damage of the insulation occurs, leading to reduced transformer life, or worst case, resulting in a turn-to-turn short-circuit or phase-to-ground fault.

Overexcitation protection is seldom placed directly on transformers unless the transformer is connected as a unit step-up for a generator. Then the protection is applied on the generator in the form of a volts/hertz relay. The ratio of the voltage and frequency on a generator should remain constant. The volts/hertz relay monitors this ratio and trips for deviations outside the set point. This also protects the unit-connected transformer against damaging overvoltage conditions.

Protection against overexcitation on smaller transformers is rarely used because of the location relative to the generation source. However, it may be necessary to apply overexcitation protection to transformers located in a transmission system remote from a cogenerator operating on a distribution system. Most overexcitation conditions originate near the source of generation but may also occur on long transmission lines. Because protection is normally provided at these locations, it becomes unnecessary to duplicate this protection at the remote transformer locations.

ANCILLARY PROTECTION

Ancillary protection varies with the type of preservation system for the transformer core and windings. Preservation systems based on dry or liquid methods are available. Dry type transformers offer open ventilated, filtered ventilated, totally enclosed nonventilated, or sealed-air or gas-filled designs. Liquid preservation systems offer designs using sealed tank, positive pressure inert gas, gas-oil seal, or conservator tank. Most protection methods available are primarily limited to monitoring the gas or oil used in the preservation system. In addition, strategically located resistance temperature detectors (RTDs) are used to measure the heat within different areas of the transformer, monitoring the transformer hot spots.

Protection devices for liquid preservation systems include the following:

Liquid Level Gauge. If the insulating liquid drops too low, overheating or an internal flashover could result. The liquid level gauge monitors the liquid level and provides contacts to alarm or trip.

Pressure-Vacuum Gauge. provides a comparison of the internal gas pressure and the external ambient temperature for sealed tank oil preservation systems. Large variations in pressure can indicate abnormal conditions and should be detected before tank rupture or deformation occurs.

Pressure-Vacuum Bleeder Valve. provides an automatic relief for gradual changes in pressures that exceed predetermined limits.

Pressure Relief Device. provides an automatic relief for both gradual and extreme sudden changes in pressures that exceed predetermined limits. This unit typically provides remote alarming and automatic resetting.

Gas Accumulator or Detector Relay. is used on conservator type tanks to trap any gases that rise through the oil toward the conservator tank. It is usually monitored as alarm only because any type of gassing can cause the relay to operate.

Sudden Pressure Relay. is used to trip the transformer from the system upon a sudden change in internal tank pressure. This sudden change in pressure indicates internal winding or ground faults, requiring immediate isolation. Sudden pressure protection is considered by some as primary protection.

Oil Temperature Indicator. measures the temperature of the insulating oil at the top of the transformer tank. As the temperature of the insulating liquid increases, it becomes lighter and travels toward the top of the tank. This provides a measure of the winding temperature as related to transformer loading. Multiple contacts are normally provided for automatic stage switching of forced-air cooling equipment. A contact is also used for alarming if the preset temperature level is exceeded.

Other types of ancillary mechanical protection devices are available depending on the manufacturer of the transformer. It is recommended that each application be examined and the appropriate devices applied to provide the desired level of transformer protection.

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Omicrom Electronics Corporation

TRANSFORMERS. See Current transformers; Instrument transformers; Potential transformers; Superconducting transformers.