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IEEE Guide for Protecting Power Transformers

IEEE Power Engineering Society

Sponsored by the
Power System Relaying Committee

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Approved 31 January 2008

IEEE-SA Standards Board

Abstract: This guide is intended to provide protection engineers and other readers with guidelines for protecting three-phase power transformers of more than 5 MVA rated capacity and operating at voltages exceeding 10 kV. In some cases, a user may apply the techniques described in this guide for protecting transformers of less than 5 MVA ratings or operating at voltages less than 10 kV. Information to assist protection engineers in applying properly relays and other devices to protect transformers used in transmission and distribution systems is provided in this guide. General philosophy, practical applications, and economic considerations involved in power transformer protection are discussed. Emphasis is placed on practical applications. Types of faults in transformers are described. Technical problems with the protection systems, including the behavior of current transformers during system faults, are discussed. Associated problems, such as fault clearing and reenergization, are discussed as well.
Keywords: analysis of dissolved gases in transformer oil, application of multifunction relays for transformer protection, differential protection, failures of transformers, overcurrent protection, protection of phase-shifting transformers, protection of transformers, volts-per-hertz protection

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Introduction

This introduction is not part of IEEE Std C37.91-2008, IEEE Guide for Protecting Power Transformers.

This document is a revision of IEEE Std C37.91™-2000, IEEE Guide for Protective Relay Applications to Power Transformers. This guide is intended to provide aid in the effective application of relays and other devices for the protection of power transformers.

In this revision, several areas have been improved. Most notably:

- Several clauses have been revised.
- Differential protection has been augmented to include the techniques used in numerical relays. Techniques now being used in numerical relays, such as harmonic restraint and harmonic blocking, wave shape recognition, low-current detection, and direct-current blocking methods, are included.
- An example of the relay blocking logic is included.
- New figures have been included to reflect the practice of connecting all current transformers (CTs) in wye configuration when numerical relays are used.
- The possibility of CT saturation when faults occur outside the protection zone of differential relays and the current does not flow through the differential zone is explained.
- Protection of transformers for faults in the grounded wye-connected windings has been expanded to include the use of restricted earth-fault relays.
- The practice of remote tripping of circuit breakers to protect transformers used to tap transmission and subtransmission lines is explained.
- The clause on gas analysis has been revised to bring it in line with the current practices. The use of rate of change of total dissolved combustible gases is incorporated.
- New annexes have been created. Annex B lists the transformer failure statistics collected by the Canadian Electrical Association. Annex C outlines the procedure for setting relays for protecting three transformers. The first transformer is a step-up transformer, the second transformer is a network autotransformer, and the third transformer is used for supplying energy to a distribution system. Annex D describes the need for monitoring current on the high-voltage and low-voltage windings, when automatic tap changing is used, for determining the hot-spot temperature of a transformer. Annex E outlines the methods that are used in differential relays for compensating for the phase shift in delta-wye transformers.

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1. Overview

This guide is intended to provide protection engineers and other readers with guidelines for protecting three-phase power transformers of more than 5 MVA rated capacity and operating at voltages exceeding 10 kV. In some cases, a user may apply the techniques described in this guide for protecting transformers of less than 5 MVA ratings or operating at voltages less than 10 kV.

1.1 Scope

The scope of this guide includes general philosophy, practical applications, and economic considerations involved in power transformer protection.

Emphasis is placed on practical applications. General philosophy and economic considerations in protecting transformers are reviewed. Types of faults in transformers are described. Technical problems with the protection systems, including the behavior of current transformers (CTs) during system faults, are discussed. Associated problems, such as fault clearing and reenergization, are discussed as well.

1.2 Purpose

The purpose of this guide is to provide protection engineers with information that helps them to properly apply relays and other devices to protect transformers used in transmission and distribution systems.

2. Normative references

The following referenced documents are indispensable for the application of this document (i.e., they must be understood and used, so each referenced document is cited in text and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

IEEE Std 32™-1972, IEEE Standard Requirements Terminology and Test Procedure for Neutral Grounding Devices.[1, 2]

IEEE Std C37.2™, IEEE Standard Electrical Power System Device Function Numbers and Contact Designations.

IEEE Std C37.100™, IEEE Standard Definitions for Power Switchgear.

IEEE Std C37.102™, IEEE Guide for AC Generator Protection.

IEEE Std C37.103™, IEEE Guide for Differential and Polarizing Relay Circuit Testing.

IEEE Std C37.108™, IEEE Guide for the Protection of Network Transformers.

IEEE Std C37.110™, IEEE Guide for Application of Current Transformers Used for Protective Relaying Purposes.

IEEE Std C37.112™, IEEE Standard Inverse-Time Characteristic Equations for Overcurrent Relays.

IEEE Std C37.113™, IEEE Guide for Protective Relay Applications to Transmission Lines.

IEEE Std C37.119™, IEEE Guide for Breaker Failure Protection of Power Circuit Breakers.

IEEE Std C57.12.00™, IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers.

IEEE Std C57.13.3™, IEEE Guide for Grounding of Instrument Transformer Secondary Circuits and Cases.

IEEE Std C57.91™-1995 (Reaff 2004), IEEE Guide for Loading Mineral-Oil-Immersed Transformers.

IEEE Std C57.104™-1991, IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers.[3]

IEEE Std C57.109™, IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration.

3. Definitions

For the purposes of this guide, the following terms and definitions apply. *The Authoritative Dictionary of IEEE Standards Terms* [B11][4] should be referenced for terms not defined in this clause. Definitions of several terms used in this guide are provided in IEEE Std C37.100.[5]

3.1 harmonic sharing: The principle of summing the magnitudes of the harmonic contents of the three operating currents in a differential application and checking if the ratio of the sum of the harmonic components and the fundamental frequency component of the operating current in each phase exceeds a prespecified threshold.

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[4] The numbers in brackets correspond to those of the bibliography in Annex F.
[5] Information on references can be found in Clause 2.

3.2 time-limited cross-blocking: A restraint in a differential relaying application based on blocking of tripping of all three phases when the operating current of any one phase has sufficient harmonic content for blocking during inrush. Adjacent phase blocking is removed after a predetermined time delay.

4. Device numbers

The device numbers used in this guide are listed in Table 1. Detailed definitions of these devices are given in IEEE Std C37.2, IEEE Standard Electrical Power System Device Function Numbers and Contact Designations.

Table 1—Device numbers and device identification

Device number	Identification
24	Volts-per-hertz (V/Hz) relay
26	Apparatus thermal device
46	Reverse-phase or phase-balance current relay (negative-sequence current relay)
49	Machine or transformer thermal relay
50	Instantaneous overcurrent relay
50N	Instantaneous neutral overcurrent relay
51	AC time overcurrent relay
51G	AC time ground overcurrent relay
51N	AC time neutral overcurrent relay
51NB	AC time neutral overcurrent backup relay
51NT	AC time neutral overcurrent torque-controlled relay
52	AC circuit breaker
59	Overvoltage relay
60	Voltage or current balance relay
63	Pressure switch
64	Ground detector relay
67	AC directional overcurrent relay
67G	AC directional ground overcurrent relay
86	Lockout relay
87	Differential protective relay
87G	Ground differential protective relay

5. Philosophy and economic considerations

Protective relays are applied to elements of a power system for several reasons. Some of the reasons are as follows:

a) To isolate the faulted equipment from the remainder of the system so that the system can continue to function properly

b) To limit damage to the faulted equipment

c) Minimize the possibility of fire

d) Minimize hazards to personnel

e) Minimize the risk of damage to adjacent high-voltage apparatus

In protecting some system elements, particularly high-voltage transmission lines, high speed is often critical for preserving the integrity of the system; limiting damage to equipment sometimes becomes a secondary benefit. With transformers, however, the high cost of repair or replacement, and the possibility of a violent failure or fire involving adjacent equipment, may make limiting the damage a major objective. Since sensitive, high-speed protection systems can reduce damage, and consequently reduce repair cost. The protection aspects of relays should be considered carefully when protecting transformers, particularly those of larger sizes.

Faults internal to the transformer quite often involve a few turns. While the currents in the shorted turns are large in magnitude, the changes of the currents at the terminals of the transformer are low compared to the rating of the transformer. This indicates a need for the protection systems that have high sensitivity and high speed.

There is no one standard way to protect all transformers, or even identical transformers that are applied differently. Most installations require individual engineering analysis to determine the best and most cost-effective scheme. Usually more than one scheme is technically feasible, and the alternatives offer varying degrees of sensitivity, speed, and selectivity. The selected plan should balance the best combination of these factors against the overall economics of the situation while minimizing

a) Cost of repairing damage
b) Cost of lost production
c) Adverse effects on the balance of the system
d) Spread of damage to adjacent equipment
e) Duration of unavailability of the damaged equipment

In protecting transformers, backup protection needs to be considered. The failure of a relay or breaker during a transformer fault may cause such extensive damage to the transformer that its repair may not remain a practical alternative. When a fault in the transformer protection zone is not cleared by the transformer protection system, remote line relays or other protective relays operate. Part of the evaluation of the type of protection applied to a transformer should include how the system integrity would be affected by such a contingency. In this determination, because rare but costly failures are involved, a diversity of opinion on the degree of protection required by transformers might be expected among those individuals familiar with power system protection engineering.

The major economic consideration ordinarily includes both the fault detection equipment and isolation devices. Circuit breakers often cannot be justified on the basis of transformer protection alone. At least as much weight should be given to the service requirements, the operating philosophy, and the system design philosophy. Evaluations of the risks involved and the cost effectiveness of the protection are necessary. Further discussion on this subject is provided by Elmore [B5], McNutt et al. [B19], Sterner [B36], and Warrington [B41].

6. Types of failures in transformers

The electrical windings and the magnetic core in a transformer are subject to a number of different forces during operation, for example

a) Expansion and contraction due to thermal cycling
b) Vibration
c) Local heating due to magnetic flux
d) Forces due to the flow of through-fault currents
e) Excessive heating due to overloading or inadequate cooling

These forces can cause deterioration and failure of the electrical insulation of the transformer windings. Statistics for the causes of transformer failures experienced in U.S. utilities are not readily available. The failure statistics collected by the Canadian Electrical Association are briefly reported in Annex B.

This guide primarily addresses the application of electrical relays to detect fault currents that result from an insulation failure. Clause 7 examines the current a relay can expect to see due to various types of winding insulation failures.

The detection systems that monitor other transformer parameters can be used to indicate an incipient electrical fault. Prompt response to these indicators may help avoid a serious fault. Some examples of actions taken to detect undesirable operating conditions are as follows:

1) Temperature monitors for winding or oil temperature are typically used to initiate an alarm requiring investigation by maintenance staffs. At this stage, the operators may start to reduce the load on the transformer to avoid reaching a condition where tripping the transformer would be required.
2) Gas detection relays can detect the evolution of gases within the transformer oil. Analysis of the gas composition indicates the mechanism that caused the formation of the gas, e.g., acetylene can be caused by electrical arcing; other gases are caused by partial discharge and thermal degradation of the cellulose insulation. The gas detection relays may be used to trip or to generate an alarm depending on the utility practice. Generally, gas analysis is performed on samples of the oil that are collected periodically. A continuous gas analyzer is available to allow online detection of insulation system degradation.
3) Sudden-pressure relays under oil respond to the pressure waves in the transformer oil caused by the evolution of gas associated with arcing.
4) Sudden-pressure relays in the gas space respond to sudden changes in the gas pressure due to evolving gases from an arc under oil.
5) Oil-level detectors sense the oil level in the tank and are used to generate an alarm indicating minor reductions in oil level and trip for severe reductions.
6) Online devices monitor bushings of the transformers, CTs installed in those bushings, and surge arresters installed on the transformers and generate an alarm indicating that repair is needed urgently so that major damage is avoided. Details of the modern techniques for monitoring these components are given by Coffeen et al. [B3].

These and other relays are discussed in greater detail in later clauses of this guide.

7. Relay currents

The following two characteristics of power transformers combine to complicate detection of internal faults with relays actuated with currents available at the terminals of a transformer:

a) The change in magnitude of current at the transformer terminals may be very small when a limited number of turns of a winding are shorted within the transformer.
b) When a transformer is energized, magnetizing inrush current that flows in one set of terminals may be equal to many times the transformer rating. These and other considerations require careful thought to obtain relay characteristics best suited to a particular application.

7.1 Minimum internal faults

The most difficult transformer winding fault for which to provide protection is the fault that initially involves one turn. A turn-to-turn fault results in a terminal current change of much less than rated full-load current. For example, as much as 10% of the winding may have to be shorted to cause full-load terminal current to flow. Therefore, a single turn-to-turn fault will result in an undetectable change of current at the transformer terminals.

7.2 Maximum internal faults

There is no limit to the maximum internal fault current that can flow, other than the system capability when the fault is on the source-side terminals of the transformer, or a fault external to the transformer but in the relay zone. The relay system should be capable of withstanding the secondary current of the CTs on a short-time basis. This may be a factor if the transformer is small relative to the system fault and the CT ratio is chosen to match the transformer rating.

7.3 Performance of current transformers

7.3.1 Internal faults

During an internal fault, or a fault external to the transformer but in the protected zone of the relay system, one or more CTs may saturate. Severe CT saturation can cause a harmonic restraint unit to pick up, thereby resulting in the failure of a transformer differential relay to operate or causing a delay in its operation. The effect depends on the relay's response to distorted currents. On a transient basis, second and third harmonics predominate initially when a CT saturates. Ultimately, the even harmonics disappear with the decay of the offset direct-current (dc) component of the short-circuit current. Whether or not the odd harmonics disappear depends on the steady-state saturation characteristic of the CT. The ratings of the CTs should be selected to avoid steady-state saturation.

7.3.2 External faults

Figure 1 shows three scenarios of external faults. The scenario in part (a) of Figure 1 shows a transformer that is connected to single bus arrangements on the source and load sides and an external fault at location F_1. In this scenario, the fault currents flow through the transformer. The scenario in part (b) of Figure 1 shows a transformer that is connected to a breaker-and-a-half bus arrangement on the source side and a single bus arrangement on the load side, and an external fault at location F_1. In this scenario, the fault currents flow through the transformer as well. (These fault-current flows are also referred to as through-currents.) These fault currents are limited by a series combination of the source impedance, Z_s, and the transformer impedance. The currents are not likely to cause the CTs to saturate if the CTs are selected after considering the levels of the fault currents and the relay burden (including the burden due to the leads connecting the CTs with the relay) as discussed in IEEE Std C37.110, IEEE Guide for Application of Current Transformers Used for Protective Relaying Purposes.

The scenario in part (c) of Figure 1 is the same as the scenario in part (b) of Figure 1 except that the fault is at location F_2. In this scenario, the fault current does not flow through the transformer but flows through the two CTs provided on the breaker-and-a-half bus that form part of the transformer protection scheme. The levels of primary currents in CTs would be substantially large because they are limited by the source impedance only. One or both CTs through which the fault current or currents flow may saturate. The unequal outputs of the CTs cause the difference currents to flow in the operating coils of the differential relay. (For more details, see the IEEE PSRC Report, "Transient Response of Current Transformers" [B12].) Time overcurrent relays, without restraint, can overcome this problem only by having their pickup and time dial settings made sufficiently high, to override this false differential current. Percentage differential relays offer the advantage of faster speed and security with reasonable sensitivity. Ideally, they should be applied with a restraint element in each CT circuit. Also, the burden of each CT secondary circuit must not be too high so that ratio errors recommended by the relay manufacturer are not exceeded.

Using the approach described in these scenarios, problems associated with CT performance can be reviewed for other scenarios.

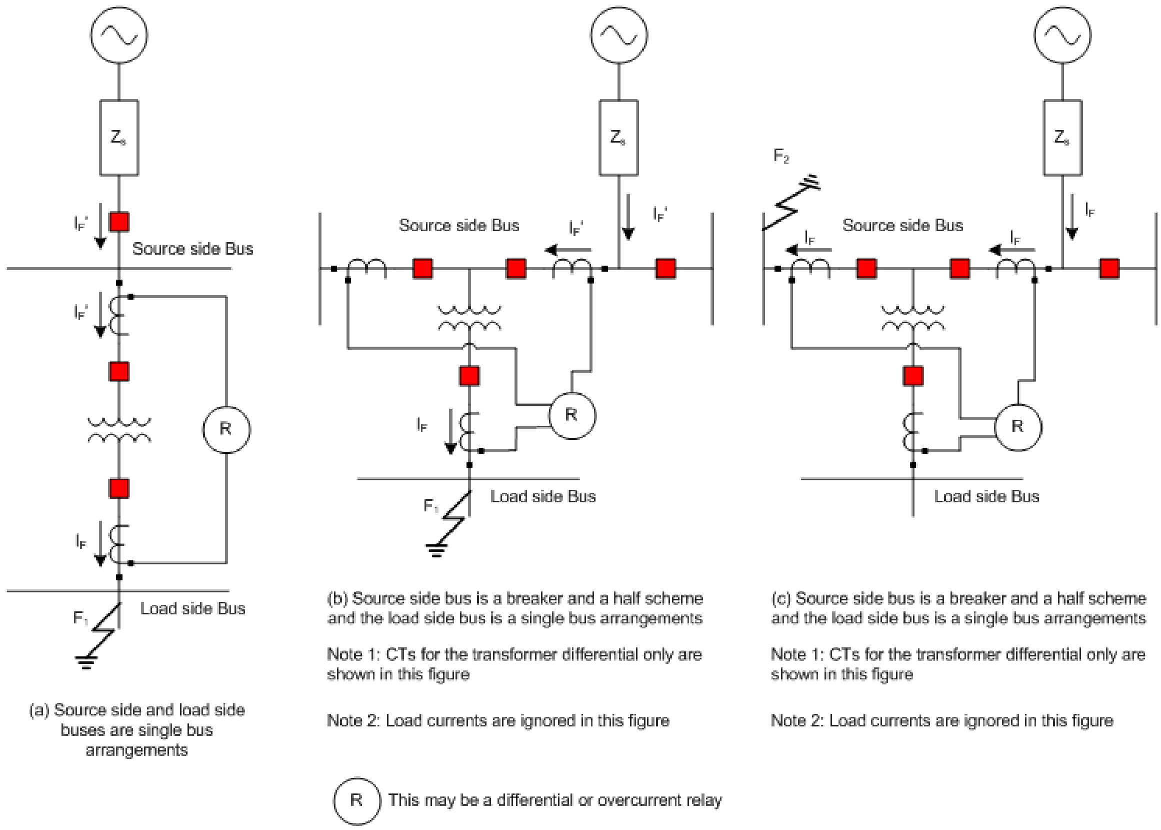


Figure 1—Three external fault scenarios

7.3.3 Current-transformer connections

The performance of a CT is a function of the burden connected to the secondary winding of the CT. The method of connecting the CTs and the impedances of the secondary circuit and the relay determine the total burden. Also, the physical and electrical locations of auxiliary CTs affect the burden. For more information on the effect of CT connections, see IEEE Std C37.110, IEEE Guide for Application of Current Transformers Used for Protective Relaying Purposes.

Before a decision is taken as to the manner in which the CTs should be connected, capabilities of the relay should be evaluated. Some differential relays can internally accommodate the phase shift of the transformer, allowing the engineer to choose CT connections that suit other devices connected to the same CTs. Many relays do not have this versatility, and, in those cases, the CTs must be connected to create the same phase shift as the transformer windings create.

For example, a transformer using both delta and wye connections create a 30° phase shift between the current entering and leaving the transformer. By connecting the CTs in delta on the wye side of the transformer and connecting the CTs in wye on the delta side of the transformer, the 30° phase shift can be matched between the transformer and the CT currents. Therefore, the relay does not see any phase shift between the input and output currents when current flows through the transformer.

CAUTION

The delta connection of the CTs should have the same configuration as the delta connection of the transformer winding. If the configurations of the delta connections are not identical, the phase angles of the currents contributed from the two windings will not match.

The grounded wye winding of a delta-wye transformer allows zero-sequence currents to flow in the wye winding when a ground fault occurs on the circuit connected to it. The zero-sequence currents in the grounded wye-connected winding circulate in the delta-connected winding and are not present at the terminals of the delta-connected winding. Some relays take care of this problem by removing the zero-sequence currents as part of the internal phase-shift accommodation. On the other hand, many other relays do not accommodate this function and must use the CT connections to filter out the ground current. The connections used in the example from the previous paragraph take care of this problem as well. The delta connection of the CTs on the wye side of the transformer trap the zero-sequence currents and prevent them from flowing in the secondary windings of the CTs. The result is that the differential relays do not see the mismatch due to the flow of zero-sequence currents.

7.4 Reasons for mismatch

There are nonfault-related currents or factors that may require compensation to prevent undesirable operation of differential relays. Subclauses 7.4.1, 7.4.2, and 7.4.3 include a discussion of some of those situations.

7.4.1 Unbalance caused by current-transformer ratios

Even if a transformer has a fixed ratio, it is frequently difficult to match CT ratios exactly on the two (or more) sides of a transformer. CT mismatches result in current flows in the operating circuits of differential relays. If a transformer has a load-tap changer (LTC), the possible mismatch is increased further. During a through-fault condition, the differential operating current due to mismatch can be very large.

7.4.2 Magnetizing inrush

This is a phenomenon that causes the violation of the basic principle of differential relaying. If the primary winding of a transformer is connected to a source and the secondary winding is connected to loads, magnetizing inrush currents flow from the source to the primary winding while no currents (or much smaller load currents) flow out of the transformer secondary windings. Current produced by magnetizing inrush can reach many times the transformer rating, and these currents appear in the differential relay. The inrush current duration can range from a few cycles to many seconds. Explanations of this phenomenon are given by Lin et al. [B17] and Rockefeller et al. [B27].

Although usually considered only in conjunction with the energizing of a transformer, magnetizing current inrush can be caused by any abrupt change of voltage at the transformer terminals. Such transients include the occurrence of a fault, the removal of a fault, the change of character of a fault (for example, the change from a single-phase-to-ground fault to a two-phase-to-ground fault), and out-of-phase synchronizing. Thus, a desensitizing scheme that is effective only when a transformer is being energized is not an adequate countermeasure.

There are several conditions that cause particularly severe magnetizing inrush phenomena. More details are given by Rockefeller et al. [B27]. One condition involves the energizing of a transformer at a station at which at least one other transformer is already energized (see Hayward [B9]). The inrush phenomenon involves transformers that are already energized as well as the transformer being energized (see Lin et al. [B17]). This inrush transient may be particularly long in duration. It is important to realize that the inrush into the transformer being energized occurs during the opposite half-cycle to that of the already energized transformer. Thus, the net inrush into all transformers may approximate a sine wave of the fundamental frequency, and, therefore, the harmonic restraint unit of a differential relay, if it is protecting both parallel-connected transformers, will not operate. However, the inrush is no more severe in this case than for a normal inrush. The problem is that there is inrush current from the previously energized transformer to the adjacent incoming transformer. The net inrush to both transformers contains little second harmonic. It is, therefore, desirable to provide a separate differential relay for each parallel-connected transformer.

The two important characteristics of magnetizing inrush current are as follows:

a) Magnetizing inrush currents contain substantial harmonics, particularly the second harmonic. These harmonics are not always present in high quantities in all the phases (see 8.2.3.1).

b) There is always a time during each cycle when the current magnitude is almost zero. This time is always greater than a quarter-cycle. A typical magnetizing inrush current waveform is shown in Figure 2.

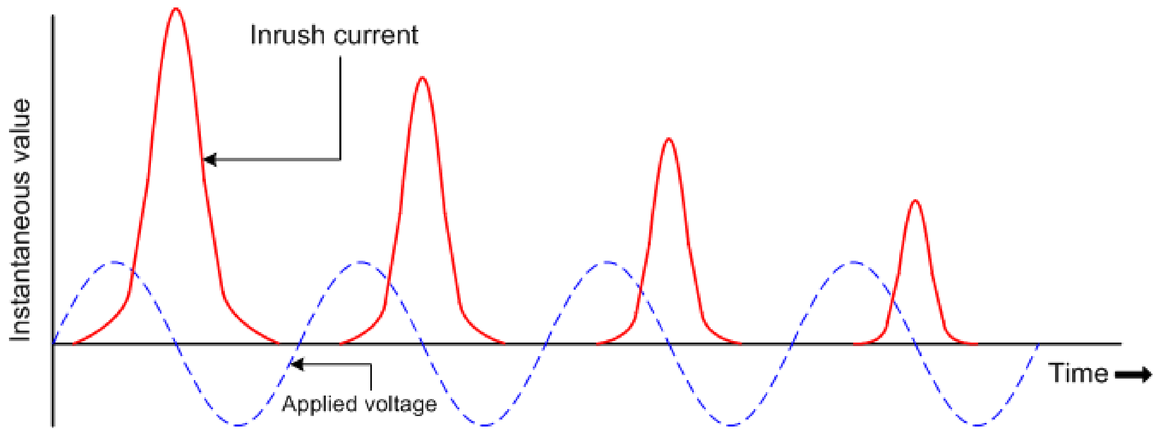


Figure 2 —Typical magnetizing inrush current waveform

The harmonic content of the inrush current depends on various factors, such as remanent flux in the core, switching angle, and load on the transformer. Harmonic analysis of the inrush current for such cases shows that the second-harmonic content of the inrush current is sensitive to all these conditions. The second-harmonic content reduces appreciably with increasing load at lagging power factor (see Lin et al. [B17]).

If three single-phase point-on-the-wave closing circuit breakers are used for switching on circuit breakers, controlling a transformer, substantial reduction in magnetizing inrush currents can be achieved. The approach used in such applications is to estimate the residual flux in the transformer core for each phase and close the circuit breaker of that phase at an instant the maximum flux in that core does not substantially increase from the normal maximum flux.

7.4.3 Magnetizing current during overexcitation

Sudden loss of load can subject a generator step-up transformer to substantial overvoltage. This can also occur during startup or shutdown of a generator if the generator is excited to nominal voltage while its speed is less than the specified normal value (an overexcitation condition). If saturation occurs, substantial exciting current will flow, which may overheat the core and damage the transformer. The waveform will be distorted; it will have harmonic content and zero-current periods. The waveform is distorted, but the behavior on the positive-going half-cycle is the same as on the negative-going half-cycle, and therefore no appreciable second harmonic is present. The extent of these effects depends on the generator connections and the transformer design and connections. The harmonic content of the relay current is also altered by delta connections of CTs. Fifth-harmonic blocking of tripping should be used to avoid tripping during overexcitation. A V/Hz relay is required if tripping is desired.

8. Electrical detection of faults

Fuses are commonly used to provide fault detection for transformers with minimum nameplate ratings of up to 5000 kVA, three-phase (Category I and Category II). Transformers 10 000 kVA and larger, three-phase, minimum nameplate (Category III and Category IV), are generally protected by a combination of protective devices as shown in Figure 3. Transformers that fall between these two ratings are either protected by fuses or relays; self-powered resettable fault interrupters can be used for transformers up to 50 000 kVA at 69 kV or up to 83 000 kVA at 138 kV. The choice of protection depends on the criticality of the load, the relative size of the transformer compared to the total system load, and potential safety concerns. System considerations, such as ability to coordinate fuses with upstream relays or with transformer damage curves, may determine what protection is used. Some other considerations include types of faults, personnel safety issues, speed of clearing, single phasing of load, and ferroresonance. More details of the definition of these categories are given in Annex A.

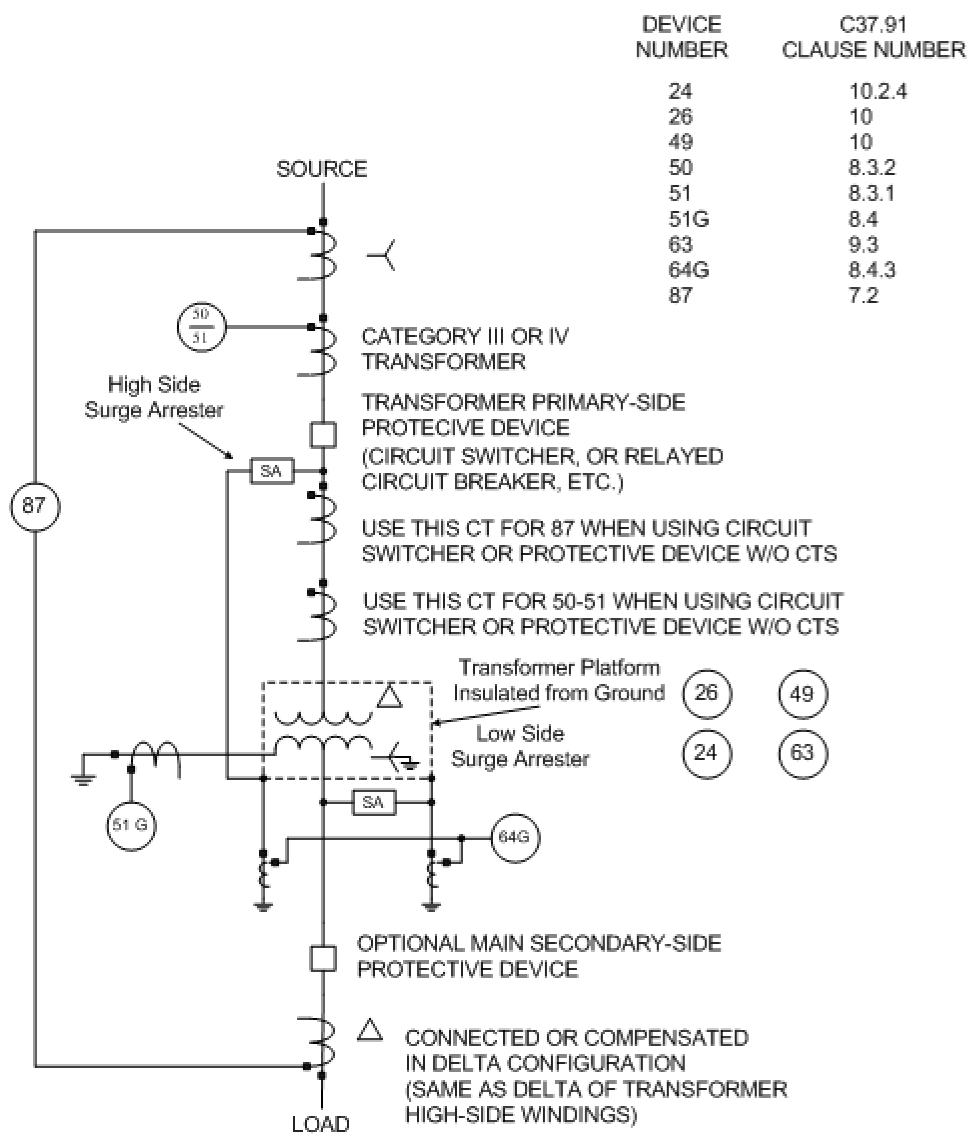


Figure 3 —Protection of a delta-wye transformer

8.1 Fuse protection and self-powered resettable fault interrupters

Fuses have the merits of being economical and require little maintenance. Battery supply and a relay building are not needed. Fuses can reliably protect some power transformers against damage from primary and secondary external faults. They, however, provide limited protection for internal faults. Generally, more sensitive means for protection from internal faults are provided for transformers of 10 MVA and higher ratings. Fuses have been used at higher transformer ratings depending on the availability of fuses that have the needed current ratings.

Self-powered resettable fault interrupters are applied similarly to fuses, but the interrupters generally have higher continuous current flow and fault-interrupting capabilities. They also have the capability of sensing neutral current and three-phase tripping capability. Like fuses, self-powered fault interrupters are economical and require little maintenance. A battery supply and relay building are not required because tripping power is derived from the CTs (usually, transformer bushing CTs) that provide current sensing. Fault interrupters are resettable after the occurrence of a fault. Transformers up to 50 MVA at 69 kV or up to 83 MVA at 138 kV can be protected with self-powered resettable fault interrupters.

Primary fuses for power transformers are not applied for overload protection; their main purpose is to protect during faults (see 8.6.1). It should be recognized that the operation of one fuse on a three-phase system will not necessarily deenergize the fault. If the fault is not deenergized, the resulting single-phase service may be detrimental to the connected polyphase motors and other loads. If required, special protection should be added for detecting and protecting from single-phasing conditions.

A typical transformer that exhibits this protection shortfall is a station transformer whose primary winding is connected in delta and the secondary winding is connected in wye configuration with neutral connected to ground. If a phase-to-phase-to-ground fault occurs on the secondary side between the transformer terminals and the low-side protective device, then the fault is cleared by the high-side fuses. The fuse with the highest current will operate first leaving the transformer energized through the remaining two fuses. At this point, the secondary fault is further limited by twice the transformer impedance and, depending on the fuse size, transformer impedance and system impedance, the remaining fuses may or may not operate. This condition could overload the transformer and may severely overload the neutral connection because the currents in the secondary windings are in phase and their sum flows in the neutral connection. Table 2 shows the magnitude of currents for a typical 69 kV/13.2 kV, 8.4 MVA power transformer before and after the first fuse clears. This transformer would normally be protected by a 100E fuse. Table 2 clearly shows that the current in the neutral connection remains essentially the same after the first fuse opens; this current will persist until the second fuse opens.

Table 2—Currents for a typical distribution station delta-wye power transformer

Phase B-C-ground fault on the low-voltage side before first fuse opens				Phase B-C-ground fault on the low-voltage side after first fuse opens			
High side		Low side		High side		Low side	
Phase	Current (A)	Phase	Current (A)	Phase	Current (A)	Phase	Current (A)
A	415	A	0	A	226	A	0
B	415	B	3764	B	226	B	2050
C	697	C	3764	C	0	C	2050
		Neutral	4100			Neutral	4100

The selection of the fuse and proper current rating should be based on the following factors:

a) Fuse fault-interrupting capability and available system fault current

b) Maximum anticipated peak load current, daily peak loads, emergency peak loads, maximum permissible transformer load current, and the applicable transformer through-fault-current duration curve (see Annex A)

c) Hot-load pickup (inrush current upon instantaneous reclosing of source-side circuit breaker) and cold-load pickup (inrush current and undiversified load current after an extended outage)

d) Available primary system fault current and transformer impedance

e) Coordination with source-side protection equipment

f) Coordination with low-side protection equipment

g) Maximum allowable fault time on the low-side bus conductors

h) Transformer connections and grounding impedance as they affect the primary current for various types of secondary faults

i) Sensitivity for high-impedance faults

j) Transformer magnetizing inrush

Current rating selection is facilitated by data published by fuse manufacturers. Such data includes time-current characteristic curves, ambient temperature, and preloading adjustment curves, plus daily and emergency peak-loading tables. Coordination examples are included in Annex A.

8.2 Differential protection

While fuse protection is a simple and minimal cost approach, many advantages are realized with differential protection (see Blackburn [B2], Elmore [B5], and Hayward [B9]). These advantages include the following:

a) Differential protection provides faster detection of faults that can reduce damage due to the flow of fault currents.

b) The location of the fault is determined more precisely depending on the "size" of the protection zone (i.e., transformer only, transformer + bus, transformer + bus + feeder breakers, etc.).

c) Accurate fault location allows the application of automation techniques, such as rapid isolation of faulted components, and restoring load.

d) The high-speed clearing of in-zone faults can significantly lower the arc flash incident energy levels and the associated clothing and personnel protective equipment needed for energized work.

Current differential relaying is the most commonly used practice for protecting transformers that are rated approximately 10 MVA (three-phase, self-cooled rating) or more (see IEEE PSRC Report, "Protection of Power Transformers" [B14]). Figure 4 shows a typical differential relay connection diagram for a single-phase transformer of ratio 1:1.

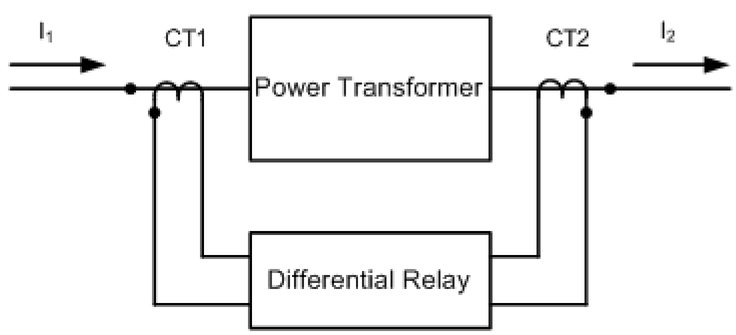


Figure 4 —Typical differential relay connection diagram for a single-phase transformer

If the ratios of CT1 and CT2 are 1:1, the operating current, I_o, which is the difference between the current entering one winding and the current leaving the other winding, can be expressed in Equation (1):

$$I_o = I_1 - I_2 \tag{1}$$

where

I_o is the operating current
I_1 is the current entering the transformer
I_2 is the current leaving the transformer

Relays of three general classes are used in current differential schemes. They are as follows:

a) Time overcurrent relays with or without an instantaneous trip unit
b) Percentage differential relays with restraint actuated by the currents going into and out of the protection zone
c) Percentage differential relay with restraint actuated by one or more harmonics in addition to the restraint actuated by the currents flowing into and out of the protection zone

Power transformers of 1:1 ratio are rarely used. The transformation ratio of the power transformer should be taken into account and CT connections and ratios must be such that the net current in the relay operating coil for any external fault is effectively zero, unless matching current taps are available in the relay. Various types of CT connections are used and some are shown in Figure 5 through Figure 9. Paralleling of two or more CTs for connection to a single restraint coil or element usually should be avoided for the most effective restraint action.

The arrangement shown in Figure 5, Figure 6, Figure 7, and Figure 8 are typical CT connections when electromechanical relays and some solid-state relays are used for differential protection. In these types of applications, when configurations such as delta-wye transformations are used, care must be taken while connecting the CTs. For example, in a typical delta-wye power transformer, the CTs would be connected as wye-delta. Another feature involves correction for CT ratios, which in the electromechanical world may require external auxiliary CTs. The secondary circuits of CTs should be grounded as explained and discussed in IEEE Std C57.13.3, IEEE Guide for Grounding of Instrument Transformer Secondary Circuits and Cases. As shown in Figure 5, Figure 6, Figure 7, and Figure 8, the secondary circuits and the circuits connected to them are grounded at a single physical location.

On the other hand, for microprocessor relays and some solid-state relays, all CTs are connected in wye as shown in Figure 9. The phase compensations are done by the software in the relay. The magnitude compensation in numerical relays is also done in the relay. Each set of CTs in this case is provided a separate ground. Because the inputs to the relay are from wye-connected CTs, the inputs can be used for protection functions, such as overcurrent and ground overcurrent protection.

Differential protection of transformers and its implementation in numerical relays is discussed in several books and published papers; some of these are Guzmán et al. [B7], [B8], Murty and Smolinski [B20], Murty et al. [B21], Phadke and Thorp [B22], [B23], Sachdev [B28], [B29], [B30], Sachdev and Nagpal [B31], Sachdev and Shah [B32], Sachdev et al. [B33], Sidhu et al. [B35], Thorp and Phadke [B38], and Ziegler [B42].

The issue of testing the differential circuits is not included in this guide. This is discussed in detail in IEEE Std C37.103, IEEE Guide for Differential and Polarizing Relay Circuit Testing.

If breaker-CTs are used for input to the transformer differential, bypassing the breaker will affect the inputs for the differential relays. Assuming that the differential relay is removed from service and there are other relay schemes protecting the transformer, care must be taken to insure that other breakers will trip in lieu of the bypassed breaker. If this alternative tripping is not available, the transformer breaker should not be bypassed.

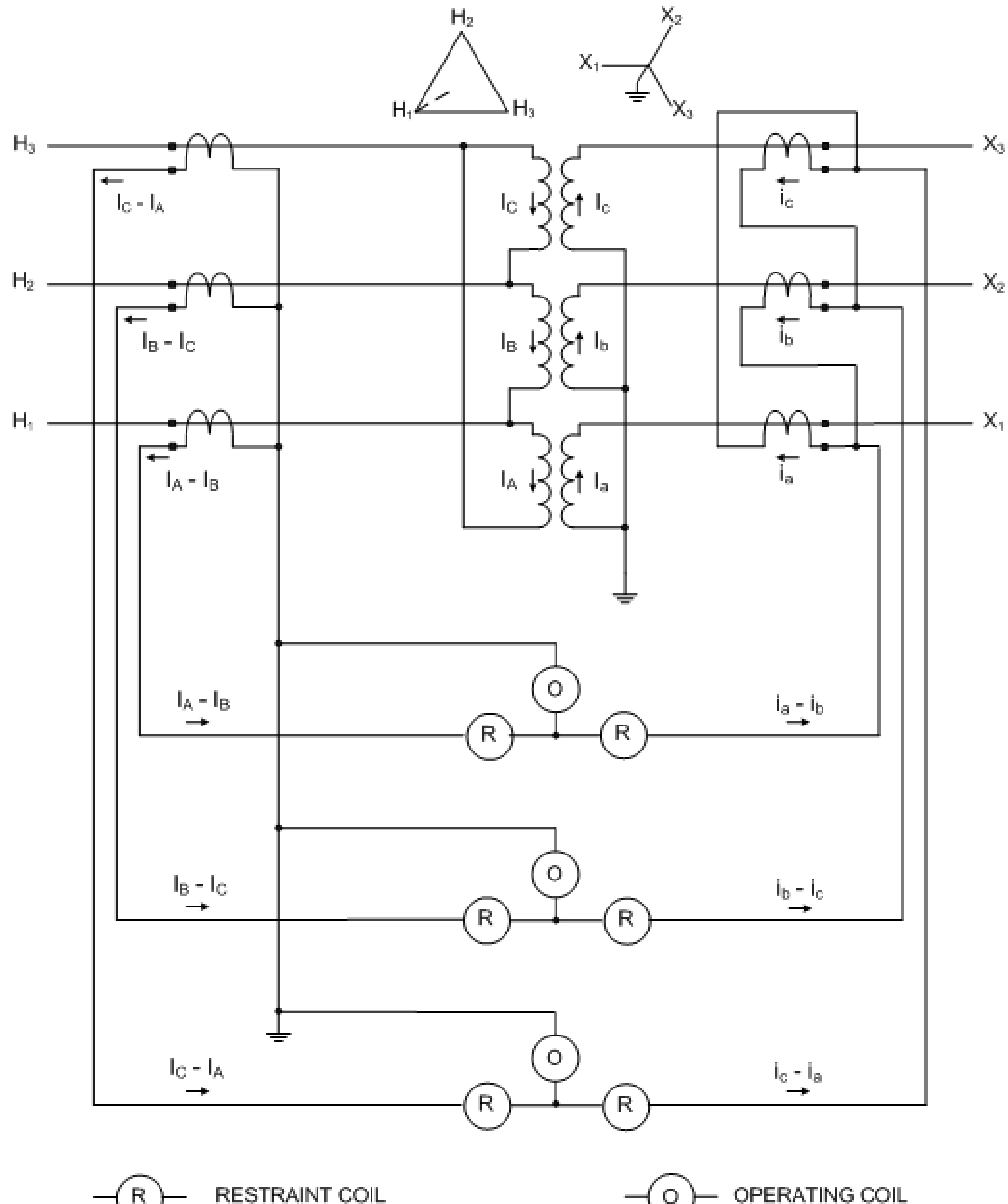


Figure 5—Typical schematic connections for percentage differential protection of a delta-wye transformer

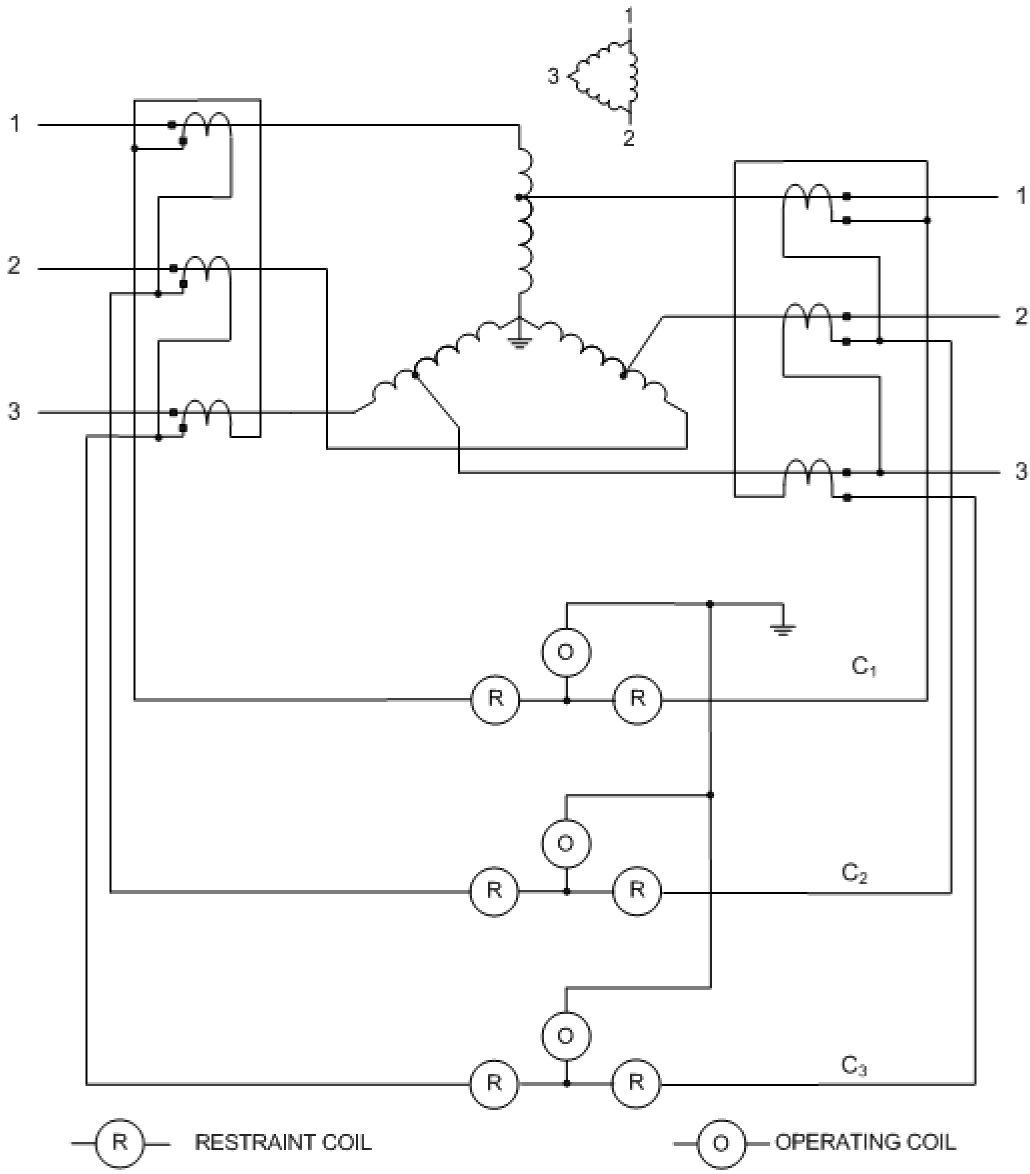


Figure 6 —Typical schematic connections for differential protection of a wye autotransformer with unloaded tertiary

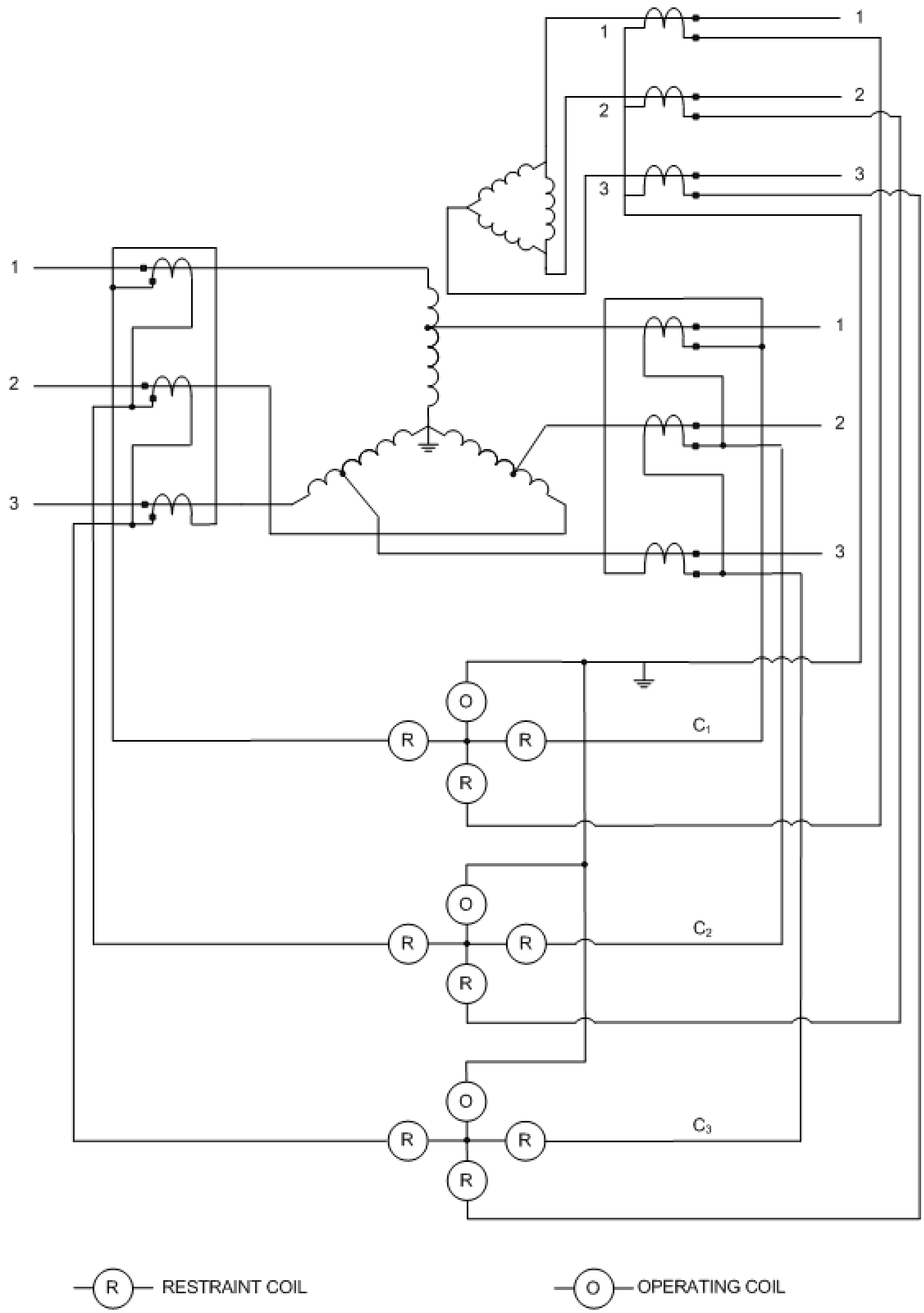


Figure 7—Typical schematic connections for differential protection of a wye autotransformer with loaded tertiary

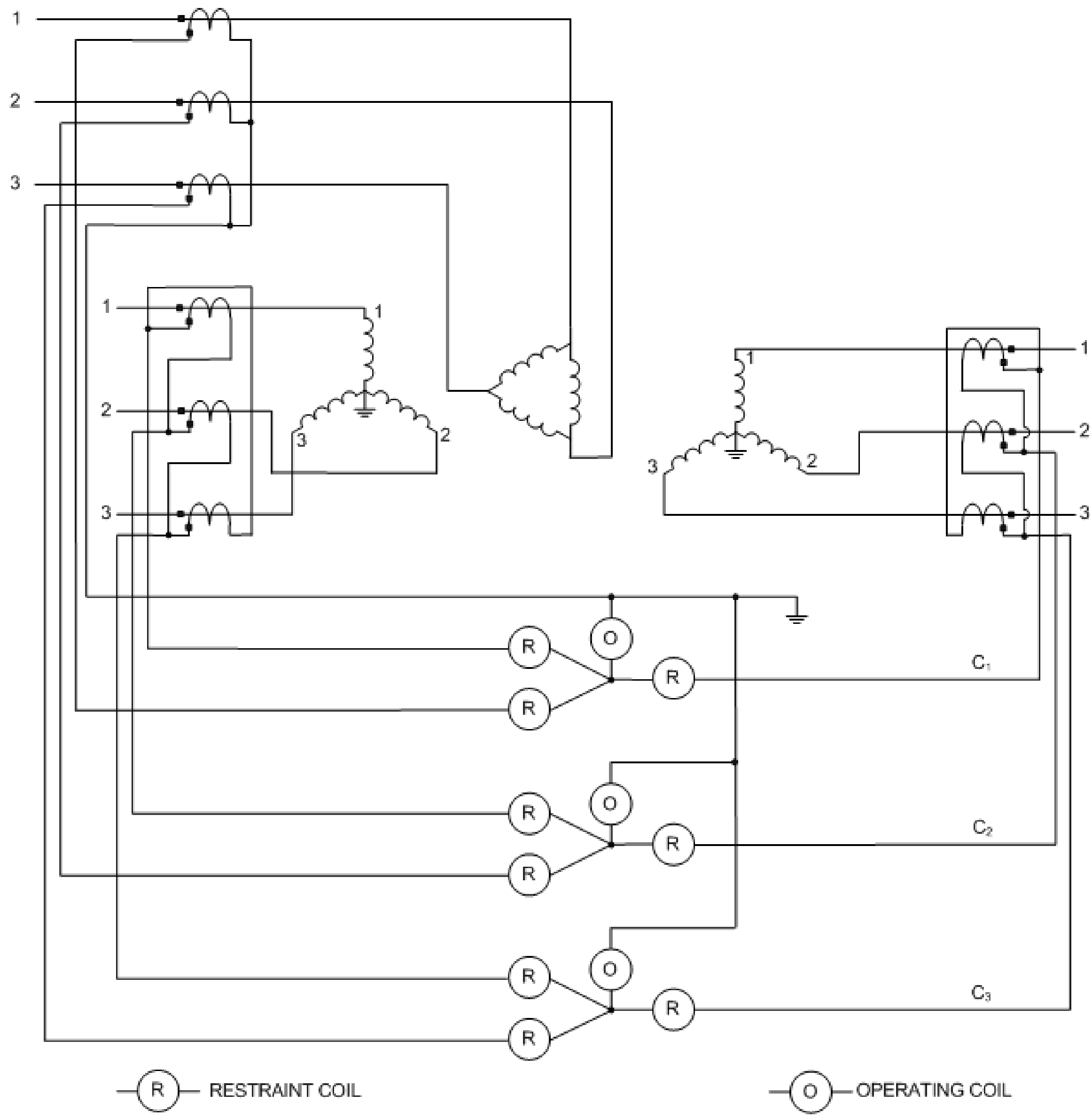


Figure 8 —Typical schematic connections for differential protection of a three-winding transformer

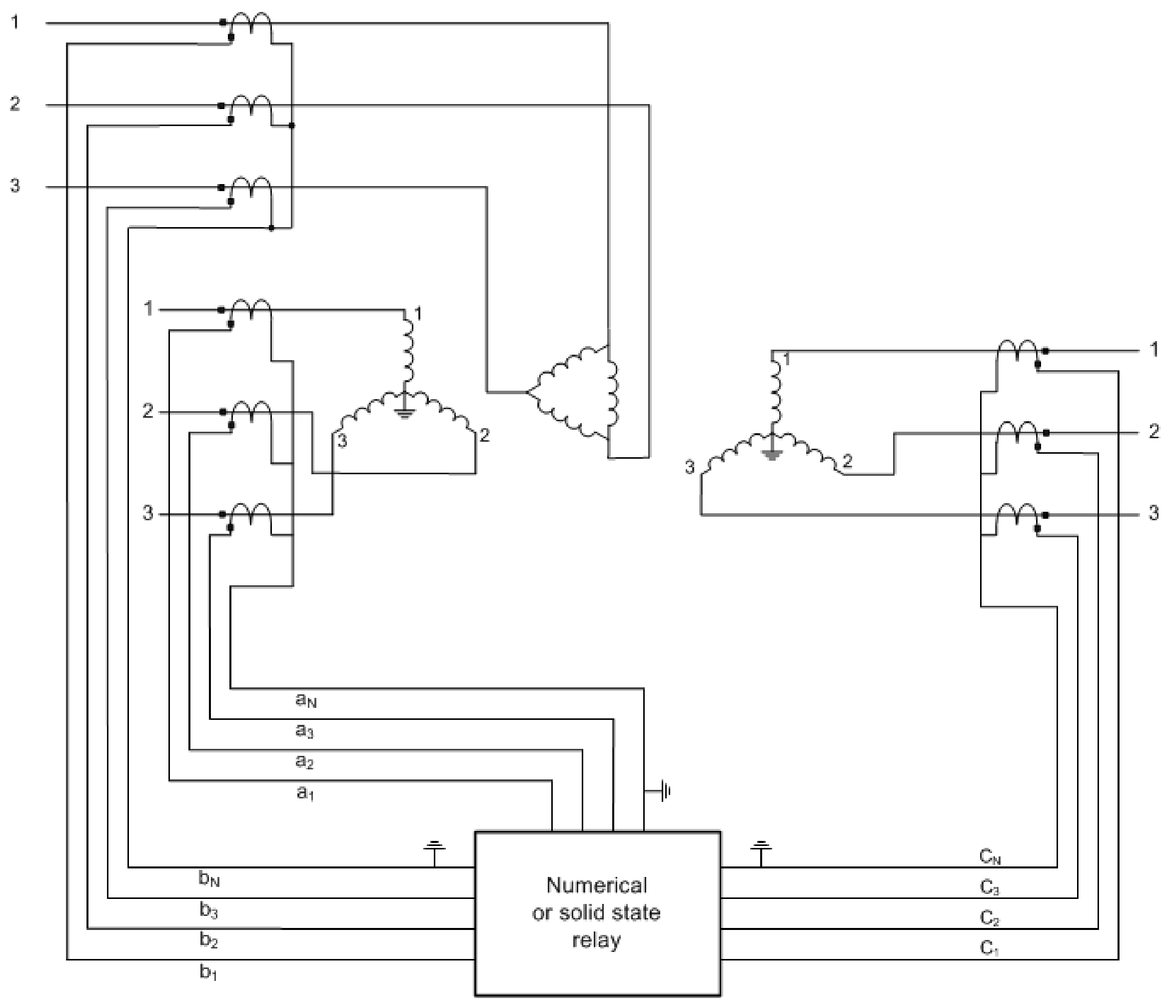


Figure 9 —Typical schematic connections for differential protection of a three-winding transformer using solid-state or numerical relays

8.2.1 Differential protection using time overcurrent relays

Overcurrent relays without restraint are seldom used due to their susceptibility to false operation from causes such as follows:

a) Saturation errors or mismatch errors of CTs

b) Magnetizing inrush current flow from the source end when energizing the transformer

To compensate for the saturation and mismatch errors, overcurrent relays should be set to operate above the anticipated inrush values. Time delay to override inrush is also necessary. Due to power transformer saturation, caution is advised against the use of this relay where exposure to geomagnetically induced currents (GICs) is possible.

8.2.2 Differential protection using percentage differential relays

To overcome the drawbacks of applying overcurrent relays for differential protection, manufacturers developed percentage differential relays. These relays offer sensitive differential protection at low currents and tolerate larger mismatches at high currents while still tripping for internal faults.

The basis of the percentage differential relay is that the difference current (as measured at the ends of the protected zones) is more than a predetermined percentage of the restraint current. The basic arrangement for percentage differential protection of a single-phase two-winding transformer is shown in Figure 4.

Different alternatives are used for obtaining the restraining current, I_R. Several combinations of the currents at the two terminals of the transformer shown in Figure 4 are used for restraining differential relays; some of these are expressed in Equation (2), Equation (3), and Equation (4):

$$I_R = k\left|I_1 + I_2\right| \tag{2}$$

$$I_R = k\left(\left|I_1\right| + \left|I_2\right|\right) \tag{3}$$

$$I_R = \max\left(\left|I_1\right|, \left|I_2\right|\right) \tag{4}$$

In these equations, k is a constant that is usually 1 or 0.5. Equation (3) and Equation (4) offer the advantage of being applicable to differential relays with more than two restraints.

The percentage difference can be fixed or variable, based on the relay's design. There is also a minimum differential current threshold before tripping without regard to the restraint current. Details of minimum pickup, restraint current, and characteristic slope vary among manufacturers. Slope may not be a straight line but may curve up depending on the design of the percentage restraint system. This curve allows even larger percentage mismatches during heavy through-currents. These options are shown in Figure 10.

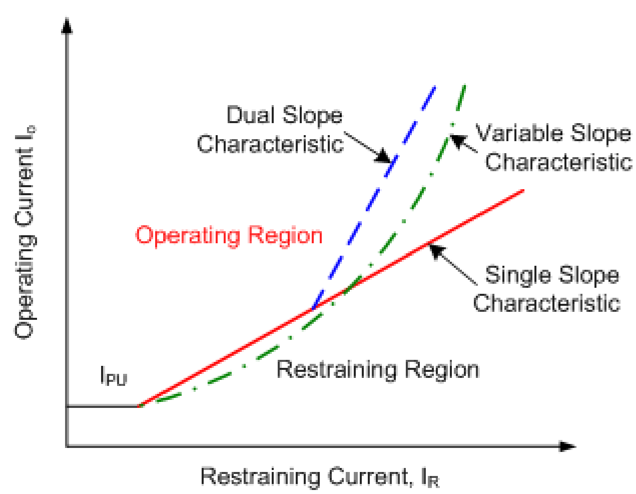


Figure 10—Typical options for the characteristics of percentage differential relays

High-voltage power transformers present several possibilities for current mismatch as seen by the differential relay. These mismatches, caused by different phenomena, can add to or offset each other, thus making the total mismatch difficult to predict. Therefore, the percentage differential relay must be tolerant of the worst-case addition of the mismatch errors.

First, the ratio of the high-voltage transformation inherently mandates different currents at the primary and secondary terminals. Depending on the transformer ratio, sometimes this difference is precisely compensated for by using offsetting ratio differences in the CT primary ratings. For example, a 138 kV/69 kV transformer could use 600:5 CTs on the 138 kV side and 1200:5 CTs on the 69 kV side.

For wye-delta transformer connections, the 30° phase shift is compensated by proper connection of the CT secondary windings when electromechanical relays are used, but the current ratio difference is affected by the multiplier for currents leaving the delta CT secondary connection. Alternatives used with electromechanical relays consist of using CTs with internal current taps to compensate for current input ratio differences and/or using special ratio auxiliary CTs. In solid-state and microprocessor relays, these differences are accounted for in the software/firmware of the relay. For more details, refer to Annex E of this guide.

Second, a large contribution to current mismatch is the application of LTCs for voltage regulation. A typical LTC range of ±10% voltage creates a ±10% variation in current. The differential must not operate for this substantial mismatch. In electromechanical relays, this was achieved by increasing the percentage slope, and this approach is also used in some numerical relays. However, in some modern microprocessor-based protection systems, the tap positions are monitored and the mismatches are taken care of in the software.

The third contributor to current mismatch is the difference in the performance of CTs applied to different voltage terminals of the transformer. At low currents, such as for load, the errors are very small and insignificant compared to the CT ratio and LTC errors. For heavy faults just outside the differential zone, CT saturation is a likely possibility. The difference in performance between the CTs on different transformer terminals appears as differential current in the relay. Some modern numerical relays can monitor the CTs for saturation and take remedial measures to remain secure from false differential current caused by CT saturation.

The fourth contributor to current mismatch during normal operation is the magnetizing inrush currents that flow when a transformer is energized, a parallel transformer is energized, or the system recovers from a fault outside the transformer protection zone. The magnetizing currents can be many times the rated current of the transformer.

The fifth and final reason for current mismatch is the overexcitation due to excessive voltage at the terminals of the transformer. When the voltage exceeds the rated value, the flux also exceeds the rated value. Typically, a 10% increase is tolerated because the transformer is operating in the linear range of the magnetizing characteristic of the core. When the voltage exceeds further, the transformer operates partly in the saturated region of the magnetic circuit. This results in large magnetizing currents for parts of each period of the voltage. Because this current is at one terminal of the transformer, it appears as differential current in the relay.

8.2.3 Differential protection using percentage differential relays with inrush and overexcitation restraint

The addition of some type of restraint that recognizes the characteristics of the inrush current allows the relay to be set with greater sensitivity.

8.2.3.1 Harmonic restraint

Harmonic restraint is used to avoid undesired tripping by the percentage differential relay due to the flow of magnetizing inrush currents when a transformer is energized. In addition, the use of harmonic restraint allows the use of more sensitive settings. Different methods are used in the relays for harmonic restraint. Typical methods are described in this subclause.

The general principle of operation, when harmonic restraint is used, can be expressed as shown in Equation (5):

$$|I_o| > s|I_R| + k_2|I_2| + k_3|I_3| + ... \quad (5)$$

where

I_o is the fundamental frequency component of the operating current

I_2, I_3, ... are the second-, third-, and higher harmonic components of the operating current

I_R is the unfiltered restraining current

k_2, k_3 are constants of proportionality

s is the slope of the percentage differential characteristics (nonvariable slope types)

The harmonic restraint is high when this approach is used and, therefore, it provides security for inrush conditions at the expense of operating speed for internal faults with CT saturation. In some relays, only the harmonic components of the operating current are used for restraining the relay. In other relays, the effect of the restraining current could become negligible. The operation of the differential relay can be expressed as shown in Equation (6):

$$|I_o| > k_1|I_1| + k_2|I_2| + ... \quad (6)$$

8.2.3.1.1 Second- and fifth-harmonic restraints

A three-phase differential relay with second- and fifth-harmonic restraint is reported by Einvall and Linders [B4]. This relay uses only the second-harmonic component of the operating current to identify inrush currents (originally proposed by Sharp and Glassburn [B34]), and it uses the fifth-harmonic component of the operating current to avoid incorrect operations during overexcitation of the transformer. The relay includes a maximum current detector that produces the percentage differential restraint current, so the restraint quantity is of the form shown in Equation (4). The relay forms an additional restraint by summing the second- and fifth-harmonic components of the operating current. The basic equation for the operation of one phase of the relay can be expressed as shown in Equation (7):

$$|I_o| > s|I_R| + k_2|I_2| + k_5|I_5| \quad (7)$$

In some relays, the harmonic restraint is proportional to the sum of the second- and fifth-harmonic components of the three phase-elements of the relay; its operation, therefore, can be expressed as shown in Equation (8):

$$|I_o| > s|I_R| + \sum_{n=1}^{3}\left(k_2|I_{2n}| + k_5|I_{5n}|\right) \quad (8)$$

Figure 11 shows the logic of a second- and fifth-harmonic restraint differential relay element defined by Equation (7) and a high set element for the fifth-harmonic component.

Note that in this harmonic restraint element, the operating current should overcome the combined effects of the restraining current, and the second and fifth harmonics of the operating current. As previously stated, the fifth-harmonic current is experienced when the transformer is overexcited due to excessive voltage applied to it. Excessive fifth-harmonic current can damage the transformer, and therefore many relays include a high-current setting for I_5; the fifth-harmonic restraint is removed if the I_5 exceeds the setting.

Common harmonic restraint or blocking increases the security of the differential relay, but it is likely to delay the relay operation for internal faults combined with inrush currents in the nonfaulted phases.

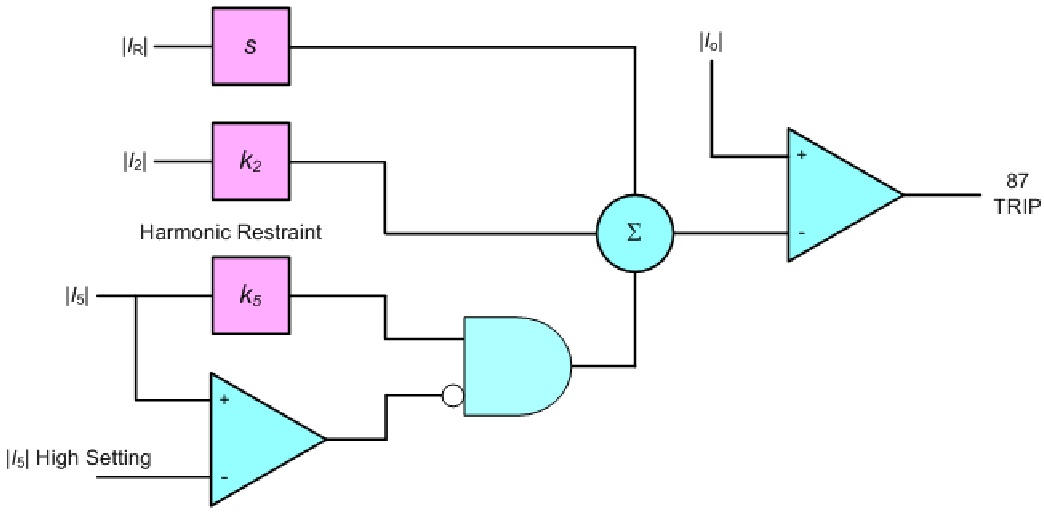


Figure 11 —Second- and fifth-harmonic restraint logic of a differential element

8.2.3.1.2 Even-harmonic restraint

The use of even harmonics (second and fourth) in a restraint scheme is another method that ensures security during inrush currents that may have very low second-harmonic current. The equation that represents this differential function is shown in Equation (9):

$$|I_o| > s|I_R| + k_2|I_2| + k_4|I_4| \tag{9}$$

In contrast to the odd harmonics, which are generated by CT saturation caused by excessive alternating current (ac), even harmonics are a better indicator of magnetizing inrush. Even harmonics resulting from dc saturation of a CT are transient in nature. The use of even harmonics (and not only the second harmonic) usually provides better discrimination between inrush and internal fault currents.

8.2.3.2 Harmonic blocking

Harmonic blocking can also be used to avoid undesired tripping by the percentage differential relay due to the flow of magnetizing inrush currents when a transformer is energized. Typical methods are described in this subclause.

8.2.3.2.1 Second-harmonic blocking

In one design (see Sharp and Glassburn [B34] for more details), the relay consists of a differential unit and a harmonic unit. The operating current defined in Equation (1) is used in the differential unit. The current is rectified and applied to the operating coil of a polarized relay unit. The current applied to the restraint unit has the form of Equation (4). The polarized relay unit performs an amplitude comparison of the operating and the restraining currents and implements the percentage differential characteristic using Equation (10):

$$|I_o| > m|I_R| \tag{10}$$

The harmonic unit compares an operating signal formed by the fundamental component, plus the third- and higher-order harmonics of the operating current, with a restraint signal that is proportional to the second harmonic of the operating current. The operation of the harmonic blocking unit can be expressed by Equation (11):

$$|I_o| + k_3|I_3| + k_4|I_4| \ldots > k_2|I_2| \tag{11}$$

8.2.3.2.2 Second- and fifth-harmonic blocking

Typically, numerical transformer differential relays use second- and fifth-harmonic blocking logic. The differential relay generates a trip if the condition defined by Equation (10) is satisfied and the blocking conditions defined in Equation (12) and Equation (13) are satisfied:

$$|I_o| > k_2 |I_2| \tag{12}$$

$$|I_o| > k_5 |I_5| \tag{13}$$

It is important to appreciate that, in this case, the operating current is independently compared with the restraint current and the second- and fifth-harmonic components of the operating current.

It is a common practice to use the fifth harmonic of the operating current to avoid the operation of the differential relay when the protected transformer experiences overexcitation. One solution may be to use a harmonic blocking scheme in which the fifth harmonic is independently compared with the operating current. In this scheme, a given relay setting, in terms of percentage of the fifth harmonic, always represents the same overexcitation condition. In a fifth-harmonic restraint scheme, a given setting may represent different overexcitation conditions, depending on the other harmonics that may be present.

8.2.3.2.3 Harmonic sharing

Harmonic sharing is a modification of the harmonic blocking technique; in this technique, the harmonic content of all three phases is summed before checking if the ratio of the fundamental frequency and harmonic components of the operating current is more than a prespecified threshold. This approach adds security in applications in which harmonic content on one or two phases is not sufficient to block the operation of the relay.

8.2.3.3 Wave shape recognition methods

Wave shape recognition techniques represent another alternative for discriminating internal faults from inrush conditions. However, these techniques fail to identify transformer overexcitation conditions as effectively as the presence of fifth harmonic does. Identification of the separation of differential current peaks represents a major group of wave shape recognition methods. Rockefeller [B26] proposed blocking relay operation if successive peaks of the differential current fail to occur at about 7.5 ms ~ 10 ms on a 60 Hz system.

8.2.3.3.1 Low-current detection method

A well-known principle recognizes the length of the time intervals during which the differential current is nearly zero (see Rockefeller et al. [B27]). Figure 12 depicts the basic concept behind this low-current detection method.

The differential current is compared with positive and negative thresholds of equal magnitudes. This comparison helps to determine the duration of the intervals during which the value of the current is less than the value of the threshold. The time intervals are then electronically compared with a threshold value equal to one-quarter cycle. For inrush currents shown in part (a) of Figure 12, the low-current intervals, t_A, are greater than one-quarter cycle, and the relay is blocked. For internal faults shown in part (b) of Figure 12, the low-current intervals, t_B, are less than one-quarter cycle, and the relay operates.

It is possible that the low-current intervals of a magnetizing inrush current may not be greater than one-quarter cycles in a specific case. If this happens, the low-current detection technique fails and remedial measures are needed to identify the situation as magnetizing inrush.

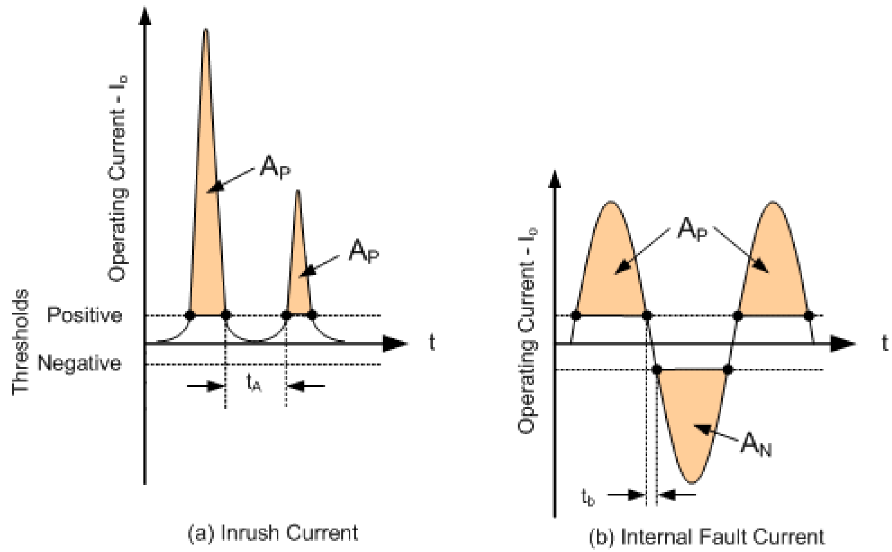


Figure 12 —Differential relay blocking based on recognizing the duration of low-current intervals

8.2.3.3.2 DC blocking method

This waveform recognition method depends on the dc signal information apart from the harmonic content of the differential current. The dc component of inrush current typically has a greater time constant than that for internal faults. The presence of dc offset in the inrush current is an additional indicator that can be used to guarantee relay security during magnetizing inrush. This wave shape recognition method is relatively easy to apply in a digital relay because extraction of the dc component is a low-pass filtering process.

In the dc blocking method, the relay splits the differential current into its positive and negative half-cycles and calculates the one-cycle sums for both half-cycles. The one-cycle sum of the positive half-cycle is proportional to the area A_P shown in Figure 13, and the one-cycle sum of the negative half-cycle is proportional to the area A_N. The positive, S_P, and negative, S_N, one-cycle sums of the differential current are formed. Then the minimum and the maximum of the absolute values of the two one-cycle sums are determined, and the dc ratio, D_R, is calculated by dividing the smaller one-cycle sum value by the larger one-cycle sum value. When D_R is less than a threshold value, say 0.1, the relay issues a blocking signal. Figure 13 shows a logic diagram of the dc blocking method for a relay element.

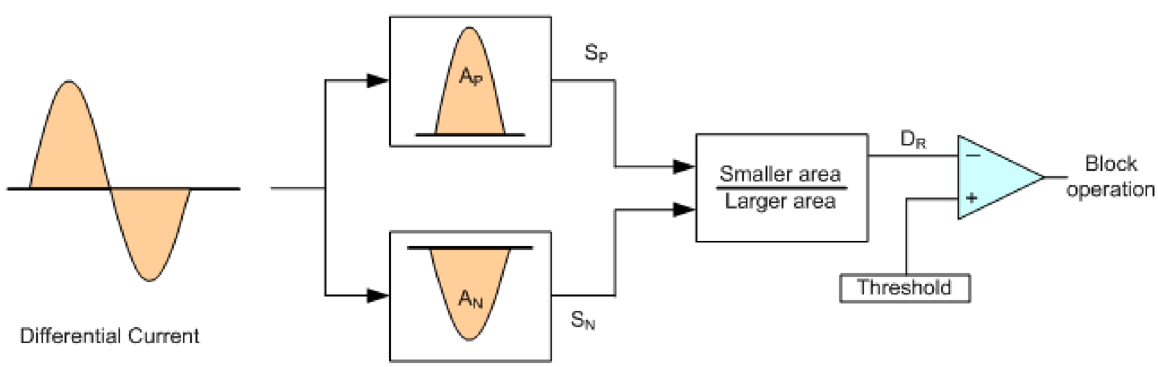


Figure 13 —Logic diagram for dc blocking

8.2.3.4 Relay blocking logic

The security of harmonic restraint relays can be improved by using a time-limited, cross-blocking signal, which consists of restraining the whole unit when current in one phase is found to have sufficient harmonic content instead of requiring sufficient harmonics in all three phases. This may be desirable for transformers that have insufficient harmonics on some phases to block during inrush. However, common blocking has the downside of the possibility of delaying a trip when energizing a faulted transformer if the healthy phases sense inrush. The effect of cross-blocking can be limited to inrush by using a time limitation since harmonic blocking can also cause trip delays on internal faults with CT saturation.

Three-phase differential relays, which use independent harmonic restraint in each phase, take protective action when any of the three phase-elements operate. The three-phase differential relays, which use harmonic blocking, use two different approaches. One approach consists of using harmonic blocking in each phase-element of the relay; in these designs, the relay takes protective action when any of the phase-elements operate. The second approach is to block the operation of the three-phase relay if blocking function operates for any of the phase-elements.

Modern numerical transformer differential relays provide the user with choices to apply even-harmonic restraint or even-harmonic blocking to the fifth-harmonic and dc blocking functions. The logic, used for selecting these choices in one of the relays, is shown in Figure 14. If the even-harmonic restraint is not in use, switch S1 closes to add even-harmonic blocking to the fifth-harmonic and dc blocking functions. In this case, the differential elements operate in a blocking-only mode. Enabling or disabling of each blocking function is achieved by using switches S2, S3, S4, and S5. The output of the differential element blocking logic asserts when any one of the enabled logic inputs asserts.

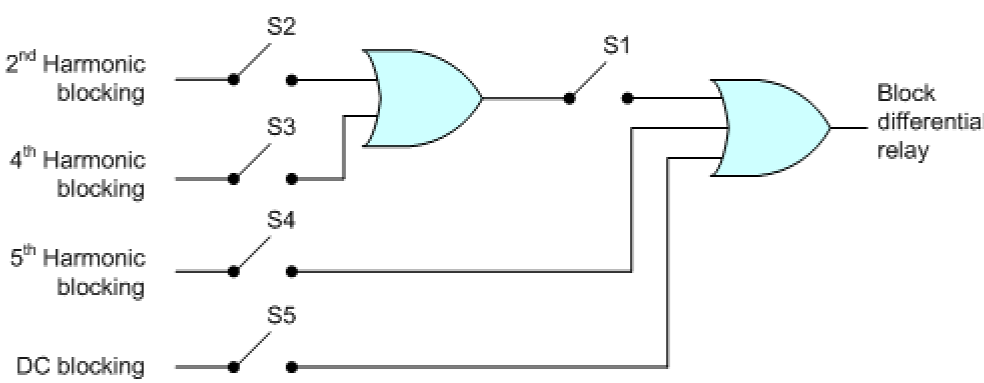


Figure 14—Example of blocking logic for a numerical differential relay

The purpose of these designs is to provide a relay that properly restrains regardless of the amount of inrush but permits relatively high-speed operation if an internal fault occurs with or without simultaneous magnetizing inrush. Another design objective is not to have excessive restraint due to harmonic distortions of the CT secondary currents. The distortions might have occurred due to CT saturation during severe internal or external faults. To provide protection during CT saturation, modern differential harmonic restraint relays also include unrestrained instantaneous overcurrent relays that are set above the maximum expected magnetizing inrush currents but below that current that might result in CT ac saturation. The usual factory setting is eight to ten times the tap value. Refer to IEEE Std C37.110, IEEE Guide for Application of Current Transformers Used for Protective Relaying Purposes, for considerations regarding ac and dc saturation of CTs.

A consideration in the use of harmonic restraint relays is the performance during transformer overexcitation. Whether or not a differential relay will operate on exciting current due to overexcitation depends on the magnitude of exciting current, the harmonic content of the current (predominately odd harmonics), the shape of the waveform, and the restraint characteristic of the relay. A relay that restrains on odd harmonics (in addition to the second harmonic present during initial inrush) is less likely to operate under such conditions. On the other hand, transformers connected to rectifiers or variable-speed drive systems, whose currents contain relatively high levels of odd harmonics, would be better protected by the harmonic restraint relays using only the second harmonic. Relay application engineers should check the publications listed in Annex F for assistance in defining specific transformer protection objectives and preferred type of harmonic restraint relay characteristic.

Harmonic restraint differential relays often can be justified by considering the following points:

a) Fewer false trips due to inrush
b) Faster operating time (0.01 s to 0.05 s versus 0.1 s to 0.2 s for the percentage restraint type)
c) Lower pickup (10% to 50% of transformer rating versus 40% to 100% for the percentage restraint type)

Occasional false trips by harmonic restraint differential relays have been observed when transformers with directly connected transmission lines were energized. Analysis of magnetizing inrush current waveforms for this configuration showed noticeable reduction in harmonic content when compared with energizing the transformer isolated from the line. The same point-on-wave closing signal was used for comparison. It was concluded that insufficient inrush harmonic content for this configuration was the cause of false trips.

8.2.4 Unit generator transformer sets

On cross-compound generators, the fields may be applied while the generators are on turning gear, or at speeds of 15% to 35% of synchronous speed, depending on the design and users' preferences. Application of the fields to such machines normally excites the generator step-up and unit station service transformers and the generator so that protection is required for the entire unit. The filter circuit of some harmonic restraint relays may block relay operation if a fault occurs before the machine is up to synchronous speed. Since relay designs vary, the relay performance at reduced frequency should be checked. V/Hz relaying may be required to protect the transformer from damage due to overexcitation (see 10.2.4 for further details).

8.2.5 Generator station service

Where a startup or station service transformer is connected to the high-voltage bus, high-speed fault clearing is usually required for stability reasons, even though the transformer is relatively small. The low CT ratio required for satisfactory sensitivity may result in severe CT saturation for high-side faults. If the burden is high, the high peak voltages could result in insulation breakdown and, thus, failure of the differential relay to operate. An additional CT with a high ratio, supplying an overcurrent relay, with an instantaneous unit, would then be required to back up the differential. If high sensitivity is not required, the differential relay may be omitted.

When a unit auxiliary transformer is connected at a point between the generator and step-up transformer, a CT connection should be provided for the overall differential scheme. A connection from the overall differential to the low-side CTs of the unit auxiliary transformer avoids the saturation problem that may occur with high-side CTs. This saturation problem could prevent the operation of the unit auxiliary transformer differential relays. The overall differential thus connected provides protection for the unit auxiliary transformer, generator, and step-up transformer. It should be noted, however, that the relay sensitivity for the unit auxiliary transformer faults may be low due to the high CT ratios. If additional sensitivity is desired, time and instantaneous overcurrent relays are utilized on the high side of the auxiliary transformer.

8.2.6 Multiple-winding transformer differential protection

Differential relays for three or more winding transformers are available in the percentage differential and harmonic restraint relay types. Multiple-winding transformers frequently have different capacity ratings for the individual windings. For example, a three-winding transformer may have a high-side rating of 90 MVA with the other two windings each rated at 50 MVA. The sum of the ratings of the small windings can be greater than the rating of the main (input) winding. Care should be taken in selecting CT ratios and selecting differential relay current balancing taps in electromechanical relays and ratio matching settings in numerical relays. These should be based on the through-flow of current equivalent to the largest winding rating regardless of the rating of the other winding considered. Proper restraint tap selection may be accomplished if through-load current involving only two windings is studied at a time.

8.2.7 Parallel transformers

A major disadvantage of using one differential relay to protect two transformers operating in parallel is the reduction in sensitivity. The CT ratios are selected on the basis of total kilovolt-ampere (kVA), and hence, the sensitivity for each transformer is less than one-half of what it would be if individual protection was provided. When a transformer is energized in parallel with an already energized transformer (see 7.4.2), the harmonic restraint unit on a differential relay protecting both transformers may not restrain. Thus, an undesired trip may occur. Therefore, each transformer should be protected by separate sets of differential relays.

8.2.8 Effect of overexcitation on differential relays

Overexcitation of a transformer could cause unnecessary operation of transformer differential relays. This situation may occur in generating plants when a unit-connected generator is separated (tripped) while exporting vars. The resulting sudden voltage rise impressed on the unit transformer windings from the loss of var load can cause a higher than nominal V/Hz condition, which causes overexcitation of the transformer. This could also occur in transmission systems when a large reactive load connected to a transformer is tripped while the primary winding remains energized.

When the primary winding of a transformer is overexcited and driven into saturation, more apparent power (voltamperes) appears to be flowing into the primary of the transformer than is flowing out of the secondary. A differential relay, with its inputs supplied by properly selected CTs to accommodate for ratio and phase shift, will perceive this as a current difference between the primary and secondary windings and, therefore, will operate. This would be an undesirable operation because there is no internal fault; the current imbalance is created from the overexcitation condition.

Three methods have been applied to prevent false transformer differential operations when overexcitation occurs. The methods would be in addition to the second harmonic or gap detection principle used for inrush detection and restraint (described in 8.2.3.1). These methods are as follows:

- Use a V/Hz relay to block the tripping of the differential relay, or to desensitize the differential relay when V/Hz reaches a certain level.
- Overexcitation manifests itself with the production of odd harmonics. As the third harmonic (and other triplens) may be effectively cancelled in delta transformer windings, the level of fifth harmonic is often used as a restraining quantity in the differential relay.
- Use of a modified differential scheme that extracts and uses the third-harmonic exciting current from the transformer delta winding to restrain the differential relay.

Instead of blocking the differential relay during an overexcitation condition (identified by the presence of the fifth-harmonic component of the differential current), the pickup setting of the differential current can be adaptively increased to prevent operation of the relay during overexcitation while disconnecting the transformer from the system if severe overexcitation occurs. The logic for this application is shown in Figure 11.

8.2.9 Differential protection of autotransformers using high-impedance relays

Some utilities provide protection for large, high-voltage and extra-high-voltage autotransformers by using voltage-operated, bus-type high-impedance differential relays. Typical connections of this protective system for autotransformers, with the neutral point of the wye winding solidly grounded, are shown in Figure 15. This arrangement provides protection for all types of phase faults and ground faults but not turn-to-turn faults. In this application, three sets of three-phase CTs are required—one set on the high-voltage side, another set on the low-voltage side, and the third set in the neutral ends of the winding. All CTs should have the same turns ratio and should be reasonably matched in accuracy class. A single high-impedance relay connected in a ground differential scheme is also applicable for autotransformer protection.

This protection is immune to the effects of magnetizing inrush current because inrush current is cancelled by the neutral CTs. Also, there is no imbalance current in the relay circuit due to the load-tap-changing equipment. Thus a high-impedance differential relay can be applied without any harmonic restraint, load bias, or time delay.

Autotransformers are often provided with a delta-tertiary winding. It should be noted that with this type of scheme no protection is afforded for faults occurring in the delta-connected tertiary winding. Where the terminals for this winding are not brought out to supply load, one corner of the delta can be connected between the end of one phase of the main winding and its neutral CT. This connection is shown in Figure 15. In such an arrangement, the tertiary winding is included in the differential protection zone and the relay would sense ground faults in the tertiary winding provided they are not close to the grounded terminal. This scheme does not provide protection for phase faults or turn-to-turn faults in the tertiary winding.

Where the tertiary winding is used to supply load, the delta winding corner connection cannot be used. Hence, separate protection is required. The tertiary winding overcurrent protection is described in 8.3.2.

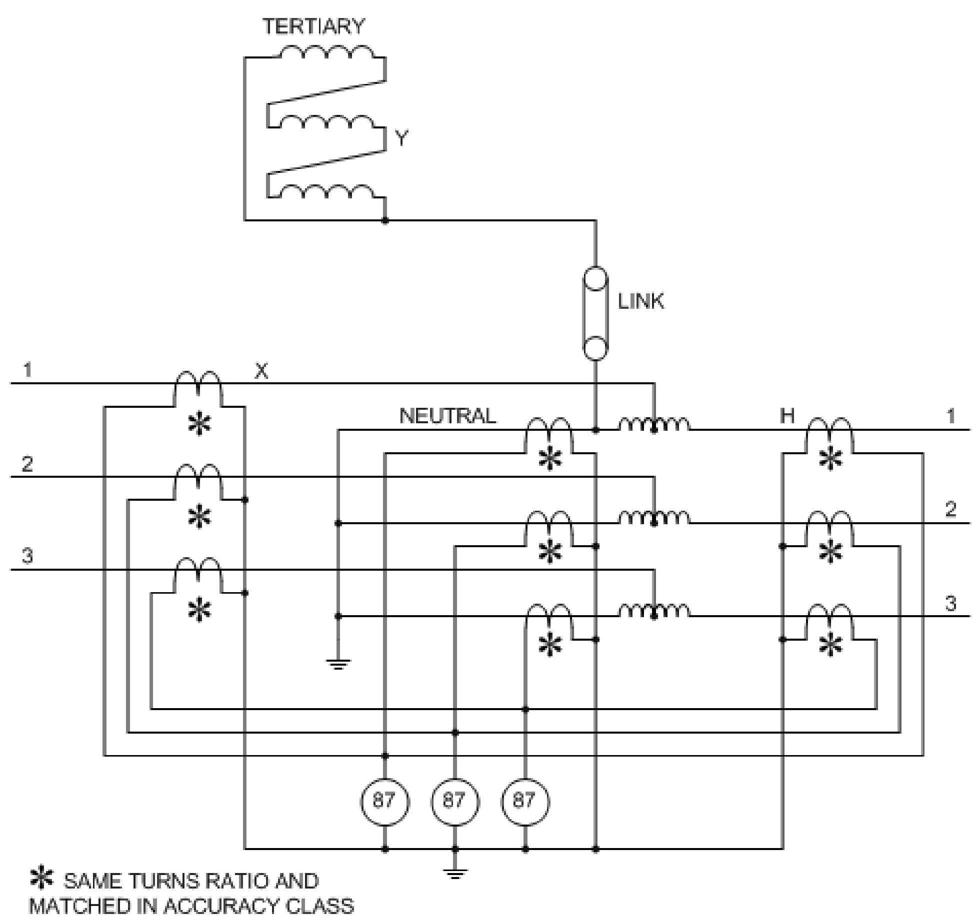


Figure 15—Typical schematic connection for high-impedance differential protection of a wye autotransformer with unloaded tertiary

8.2.10 Current-transformer requirements

The CT ratios and relay matching taps should be selected to minimize the unbalance current at the center of any applicable tap changer range. These should also be selected to avoid CT saturation during a maximum symmetrical through-fault (see IEEE Std C37.110, IEEE Guide for Application of Current Transformers Used for Protective Relaying Purposes). If saturation is likely to occur, burdens and capabilities of CTs should be matched so that all sets of CTs begin to saturate at about the same fault level. CT capability is increased and cable burden reduced by using the highest CT ratio compatible with relay taps. Cable burdens may be further reduced by using larger conductor or two conductors per phase. The risk of CT saturation may also be reduced by specifying higher "C-" ratings for the CTs at the time of purchase for initial installation or for retrofitting.

8.3 Overcurrent relay protection

8.3.1 Phase instantaneous overcurrent

Fast clearing of severe internal faults may be obtained through the use of instantaneous overcurrent relays. When these relays are used, they should be set to pick up at a value higher than the maximum asymmetrical through-fault current. This is usually the fault current through the transformer for a low-side three-phase short circuit. Instantaneous units that are subject to transient overreach are set for pickup in the range of 125% to 200% (a 175% setting is often used) of the calculated maximum low-side three-phase symmetrical fault current. This setting generally provides sufficient margin to avoid false tripping while providing protection for severe internal faults. For instantaneous units with negligible transient overreach, a lesser margin can be used. The settings in either case should also be above the transformer inrush current to prevent nuisance tripping. In some cases, instantaneous trip relays cannot be used because the necessary settings are greater than the available fault currents. In these cases, a harmonic restraint instantaneous relay may be considered for providing the desired protection.

If overcurrent protection (relays or fuses) is applied only to the high-voltage (delta) side of a delta-wye grounded transformer, the protection should be coordinated with the protection devices provided on the wye side. However, providing sensitive fault protection for the delta side of the transformer that coordinate with the low-side protection devices may not be possible. For low-voltage (wye-side) phase-to-phase faults, the high-side line current will be 115% of the low-voltage per-unit (p.u.) fault current. For low-voltage (wye-side) phase-to-ground faults, the high-side line current will be only 58% of the low-voltage p.u. fault current (see Figure 16, Figure A.6, Figure A.7, and Figure A.8). When the wye is grounded through a resistor, the high-side fault current may be less than the maximum transformer load current. Similar concerns are applicable when the wye is grounded through a reactor.

8.3.2 Tertiary-winding overcurrent

The tertiary winding of an autotransformer, or three-winding transformer, is usually of much smaller kVA rating than the main windings. Therefore, fuses or overcurrent relays set to protect the main windings offer almost no protection to these tertiary windings. During external ground faults on the high-voltage or low-voltage side of the transformer, the tertiary windings may carry very heavy currents. Hence, in the event of failure of the primary protection for external ground faults, separate tertiary overcurrent protection may be desirable.

The method selected for protecting the tertiary winding generally depends on whether or not the tertiary is used to carry load. If the tertiary does not carry load, protection can be provided by a single overcurrent relay connected to a CT in series with one winding of the delta-connected winding. This relay will sense system grounds and also phase faults in the tertiary or in its leads.

If the tertiary winding is used to carry load, partial protection can be provided by a single overcurrent relay supplied by three CTs, one in each winding of the delta and connected in parallel to the relay. This connection provides only zero-sequence overload protection and does not protect for positive- and negative-sequence overload currents. In this case, the relay will operate for system ground faults but will not operate for phase faults in the tertiary or its leads. Where deemed necessary, separate relays, such as differential type, should be provided for protecting against phase-to-phase faults in the tertiary windings or its leads.

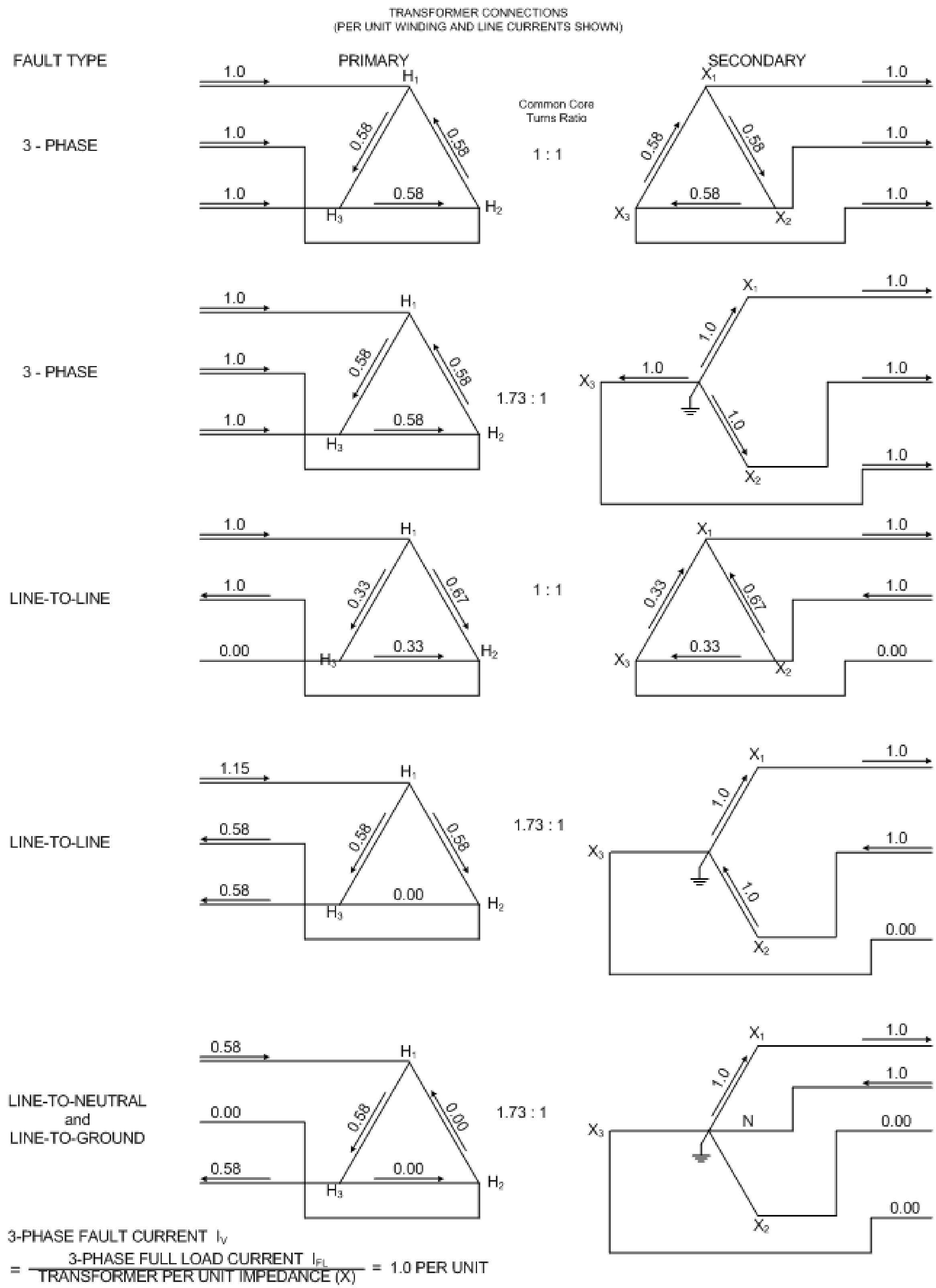


Figure 16 —Line and transformer winding currents for delta-delta and delta-wye transformers

The setting of the overcurrent relays, which are provided for protecting the tertiary windings, can normally be based on considerations similar to those in 8.3.1. However, three CTs (one in each phase) can be connected in parallel to provide zero-sequence currents to an overcurrent relay; this relay can be set below the rating of the tertiary winding. However, this relay should still be set to coordinate with other relays on the system.

When tertiary windings are connected by cables, the overcurrent protection provided for the tertiary winding should account for the thermal withstand capability of the cables. Alarming and tripping as a result of prolonged unbalance condition or LTC malfunction should prevent damage to cables.

8.4 Ground-fault protection

Sensitive detection of ground faults can be obtained by differential relays or by overcurrent relays specifically applied for that purpose. Several schemes are practical, depending on transformer connections, availability of CTs, zero-sequence current source, and system design and operating practices.

8.4.1 Faults in delta-connected transformer windings

A residual relay, device 51N, shown in Figure 17 and Figure 18, detects ground faults within the delta winding of the transformer and in the phase conductors between the CTs and the winding, when an external source of zero-sequence current is available. Instantaneous overcurrent relays may be used, but sensitive settings are likely to result in incorrect operations from dissimilar CT saturation and magnetizing inrush. This can be avoided by using a short-time overcurrent relay with a sensitive setting. The scheme is particularly valuable in plants or systems where the transformers are remote from the circuit breakers. By using CTs at the circuit breaker, sensitive detection is obtained for cable, bus, delta winding, and bushing faults. A single window CT supplying an instantaneous relay (as commonly used in motor protection) is secure, but is limited to low and medium voltages where all three conductors can be fitted through the CT window.

8.4.2 Faults in grounded wye-connected transformer windings

To successfully detect faults in grounded wye-connected transformer windings, the relay system should discriminate between faults internal and external to the protected zone. The ground differential relay, device 87G in Figure 17, typically an overcurrent relay or the directional ground relay, device 67G, connected as in Figure 18, is satisfactory. Both relay schemes will operate correctly for any internal ground faults with the circuit breaker in the circuit to the grounded wye winding open or closed. They will operate correctly with an external zero-sequence current source, and they will not operate for external ground faults. The auxiliary CT is necessary if the phase and neutral CTs are of different ratio if the relay is of the electromagnetic or solid-state type. If a numerical relay is used, the auxiliary CT is not needed because the ratio mismatch is taken care of during the computations in the relay. Both schemes are particularly applicable where the ground-fault current is limited and phase differential relays may not respond. The operating current in device 67G is zero for an external fault with CT ratios matched. Therefore, it is advisable to select the auxiliary CT ratio to give definite nontrip bias to device 67G for an external ground fault (auxiliary CT secondary current slightly greater than the transformer neutral CT secondary current).

Unequal CT currents can produce residual error current during external phase faults. No transformer neutral current is produced and sensitive relays could operate unnecessarily. Some modern relays allow relay operation only if the current in the transformer neutral exceeds a threshold.

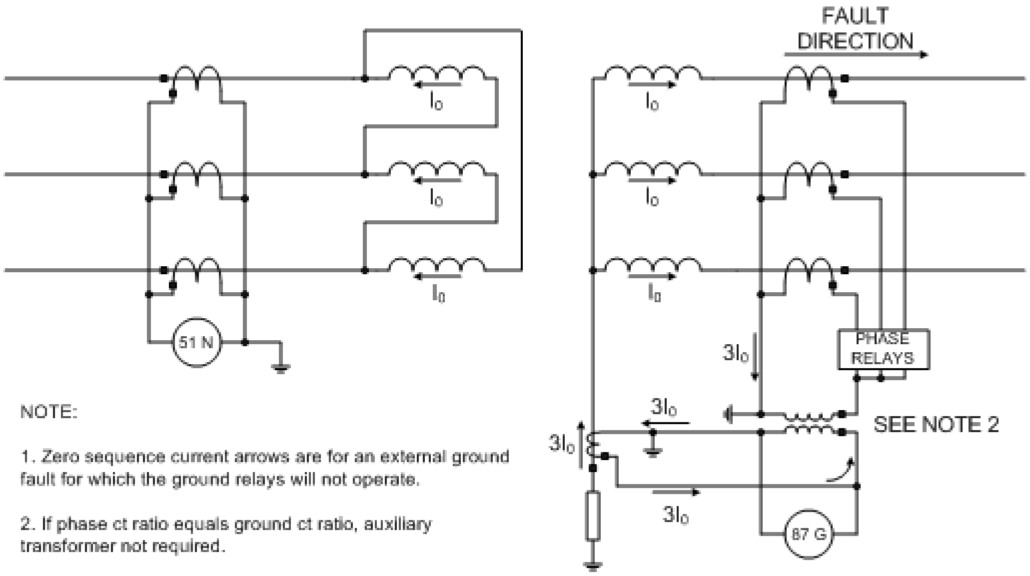


Figure 17—Complete ground-fault protection of a delta-wye transformer using a residual overcurrent and differentially connected ground relay

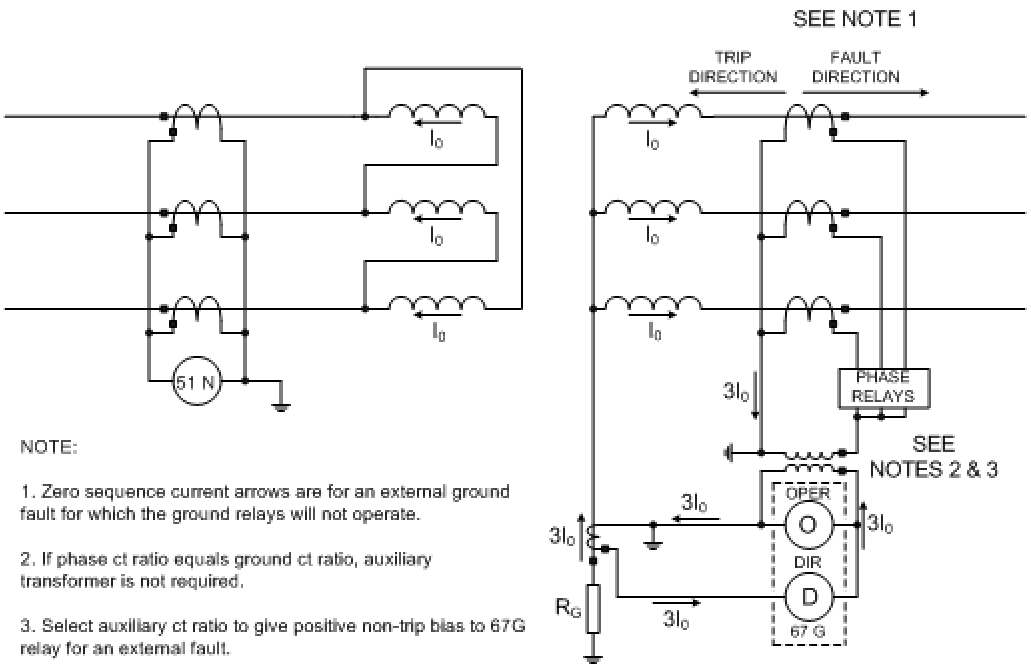


Figure 18—Complete ground-fault protection of a delta-wye transformer using a residual overcurrent and directional relay

Another approach is to use either a biased, restricted earth-fault system or a high-impedance restricted earth-fault relay. One form of restricted earth-fault relay uses the following combinations of currents for operating and restraining the relay, as expressed in Equation (14) and Equation (15):

$$I_{\mathrm{OP}} = \left| k_1 \sum \left[I_A + I_B + I_C \right] + k_2 I_N \right| \tag{14}$$

$$I_{\mathrm{RES}} = \left| k_1 \sum \left[I_A + I_B + I_C \right] \right| \tag{15}$$

The relays that use this approach could operate due to unequal CT saturation. A variation of this approach is implemented in numerical relays; they use the operating current defined by Equation (14) and the restraining current defined by Equation (16):

$$I_{\mathrm{RES}} = \frac{1}{2}\left[k_1 \max\left(|I_A|, |I_B|, |I_C| \right) + k_2 I_N \right] \tag{16}$$

One of the differential characteristics used in such designs is shown in Figure 19.

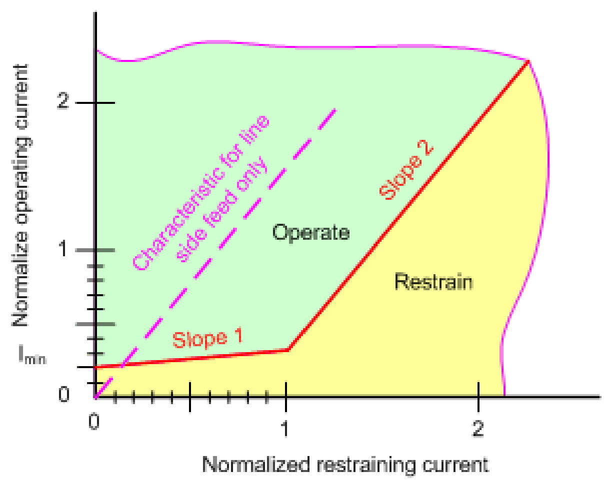


Figure 19—Operating characteristic of a restricted earth-fault relay

High-impedance restricted earth-fault protection can be used for protecting transformer windings just like it is used for bus-bar protection. The arrangement is shown in Figure 20.

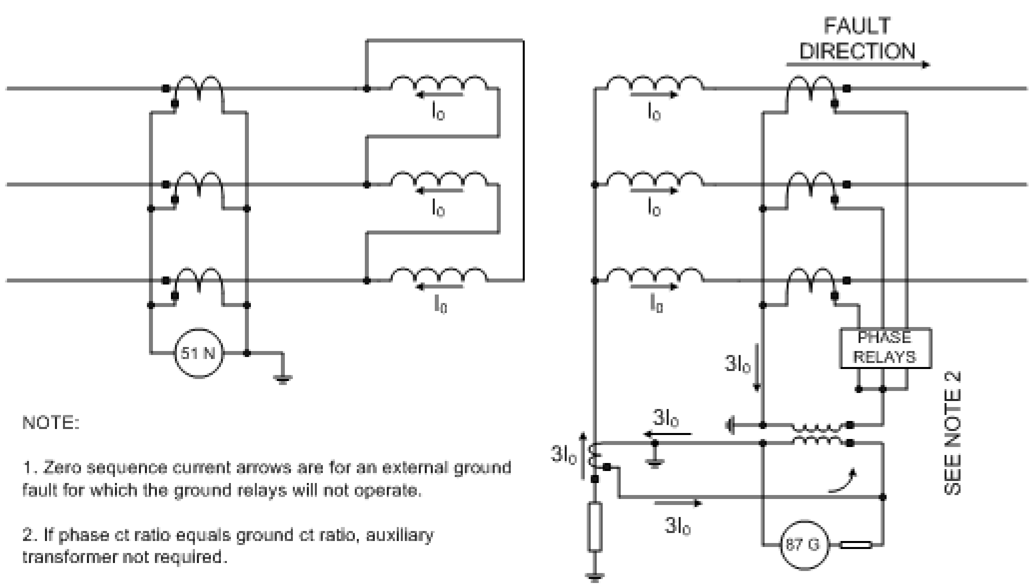


Figure 20—Restricted earth-fault protection using a high-impedance relay

8.4.3 Case ground

On a grounded neutral system, it is possible to isolate the transformer case from ground except for a single point. A window type of CT and overcurrent relay at this grounding point would detect any internal ground fault, primary arrestor failure, or bushing flashover. Although effective, several problems are encountered. The system should be tested periodically to determine that no accidental grounds have been added. Incorrect operations can result from accidental grounds from power tools and transformer auxiliary equipment, or the improper application of grounding both ends of cable shields in this case. Careful coordination between auxiliary equipment circuit breaker or fuse curves, arrester characteristics, and a time overcurrent trip relay can minimize this danger. A window type of CT rather than a bus-type or wound CT should be used to further minimize ground resistance and surge voltages across the CT.

This type of isolated transformer case from the ground is also referred to as “frame-earth protection,” “frame-leakage protection,” and “tank-earth protection” (see Warrington [B41]). This type of scheme is also shown in IEEE Std C37.108, IEEE Guide for the Protection of Network Transformers.

In practice, this type of scheme can yield very favorable results, but as previously indicated, isolation between the transformer tank and ground is required prior to installing a known ground. Once the isolation has been tested to be adequate, then the grounding conductor(s), CT(s), and overcurrent relay can be applied.

Construction techniques for mounting power transformers may include resting on metal rails that are bolted into reinforced concrete foundations. The resistivity or leakage resistance of concrete can be in the 10 Ω to 100 Ω range, which is affected by many factors. These factors include the mix ratio and components themselves, water concentrations, placement of the rebar within the foundation, etc., as many variables affect the resistivity.

One method to make a rough leakage measurement would be to have the transformer isolated from all known grounds, and then to measure the resistance from the tank ground pad to the substation ground mat. Typically, known grounds have been attached to the ground mat and are waiting to be bolted to the transformer ground pads. The resistance of the grounding cables should be very low. Assuming a typical length of around 3 m (10 ft) or so, from the ground mat to the attachment point on the transformer ground pad, would result in a typical dc resistance of less than 0.01 Ω, or for a properly connected resistance on the order of 0.1 Ω or less. In this example, having a shunt concrete leakage of 10 Ω or more would be adequate. Ten ohms is also indicated by Warrington [B41] and implied in IEEE Std C37.108, IEEE Guide for the Protection of Network Transformers.

Another factor to consider is the quality of the CTs used, secondary lead length and relay burden characteristics, versus the available fault current and the effects of CT saturation. Using a high “C-” class rating would be one alternative. Another alternative would be to expand the single point connection, described in the first paragraph of this subclause, to two connections provided on diagonally opposed corners of the transformer tank ground pads with each grounding conductor passing through its own window-type CT, and the secondary windings of the CTs connected in parallel. This method divides the primary fault current into two paths and provides redundant paths for the fault current. This assumes a well-designed ground mat system in the substation; otherwise, circulating currents will be present in the ground connections through the tank of the transformer.

Further, by moving the high- and low-side arrestors to the transformer, the lead lengths to the transformer bushings and ground path are reduced; this provides better protection for the transformer.

An arrestor failure can be detected by the overcurrent relay and aids in the isolation of faulted equipment for maintaining the supply of energy to the customers.

8.4.4 Impedance grounded system

Transformer differential relays may not be sensitive enough to operate on ground faults where the transformer bank or system is grounded through an impedance. In these cases, it may be necessary to apply a sensitive time overcurrent relay in the transformer impedance grounded neutral or a time overvoltage relay connected across the neutral impedance. These relays should be coordinated with feeder and line protection relays that they may overlap. It is possible to provide high-speed protection and to avoid the need for coordination by using sensitive relays, which are connected to trip only for ground faults in the protected zone. Figure 21 is a method used when there is no other possible ground source. An overcurrent relay connected to a neutral CT is torque-controlled by the blocking contacts of a plunger-type instantaneous relay in the neutral of the main breaker CTs. Since the transformer differential relays may not operate for such ground faults within the differential zone, these ground-fault relays must trip the source-side circuit breakers.

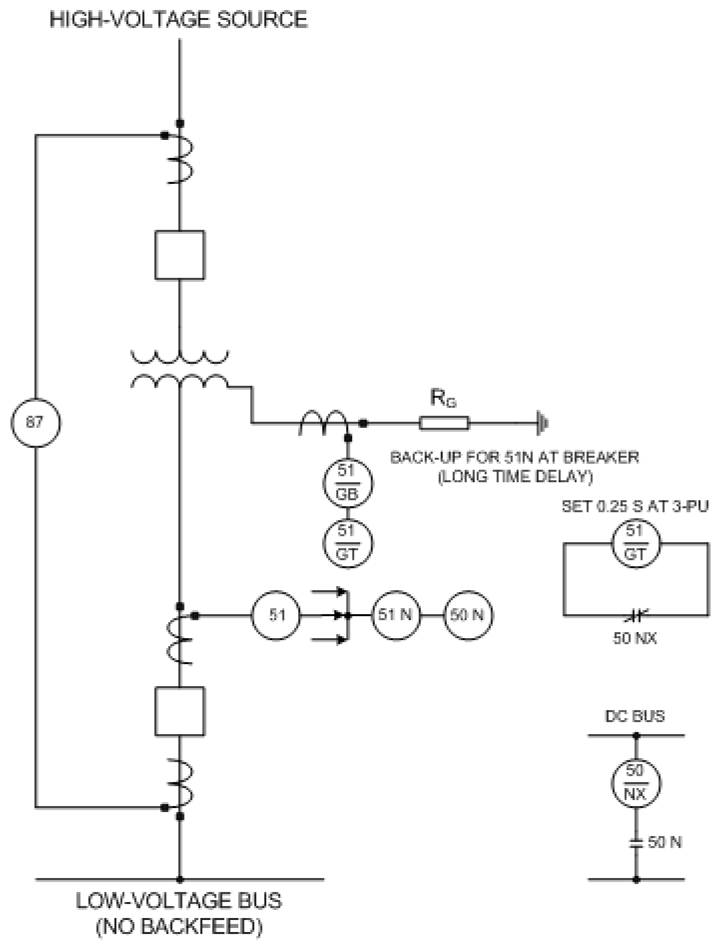


Figure 21 —Sensitive high-speed ground-fault protection with impedance grounding (alternate to Figure 17)

8.4.5 Ground relays used for sensitive ground-fault protection

The primary advantage of ground relays over phase relays is their sensitivity. In systems where the ground-fault current is purposely limited, their use may be vital. Ground relays can normally be applied with sensitivities of 10% or less of full-load current. This compares very favorably with differential relays, whose pickup current may be from 20% to 60% of full-load current under the most advantageous conditions. It is common practice in the United Kingdom and other countries influenced by the United Kingdom to protect all power transformers with the restricted earth relay. The term "restricted earth" is an expression referring to a sensitive ground relay system that is designed to detect ground faults within a well-defined protective zone (similar to Figure 17).

8.5 Fault detection for special-purpose transformers

8.5.1 Four-winding transformers

Four-winding transformers are used in high-voltage direct-current (HVDC) converter and inverter stations; they are also used for supplying power to variable frequency drives for very large synchronous motors typically used in gas and oil pipeline operations. The primary winding is configured as a grounded wye with a dual-winding secondary configured as a wye and delta, which are used to feed the rectifier/inverter at 12 pulse. A tertiary winding is used to connect filter banks necessary for harmonic suppression resulting from rectification and inversion. Transformers are usually rated from 35 MVA to 150 MVA; the rating depends on the system requirements. The larger transformers are found in HVDC applications. A typical configuration is shown in Figure 22. The CT connections are shown for connecting to an electromechanical differential relay. If a numerical relay is used, all CTs would be connected in wye as shown in Figure 9; the neutrals of all CTs would be grounded at the first point of entry in the control room as detailed in IEEE Std C57.13.3, IEEE Guide for Grounding of Instrument Transformer Secondary Circuits and Cases. Protection of these transformers is similar to multiple-winding transformers. The protection procedures described for two- and three-winding transformers are also applicable to these transformers.

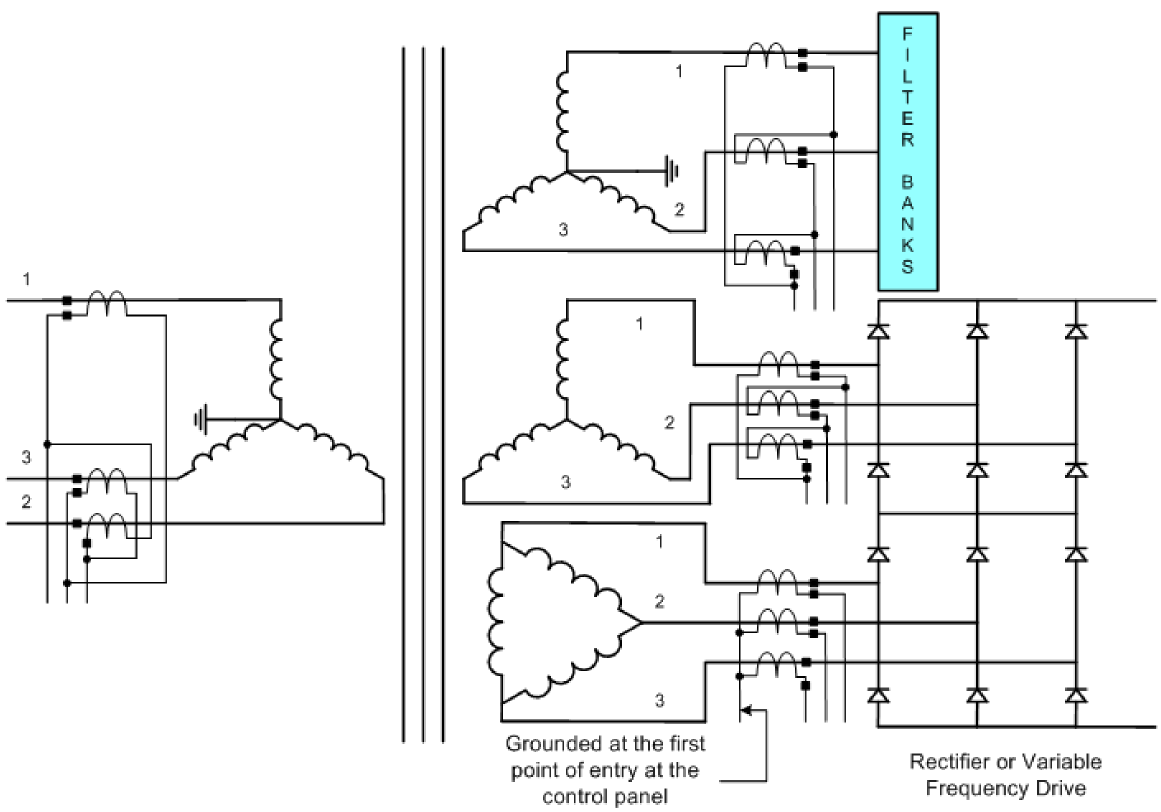


Figure 22—Four-winding transformer for application in HVDC and variable frequency drives

8.5.2 Regulating transformers

The exciting winding of a regulating transformer presents a special protection problem, since ordinary power transformer differentials are not sensitive enough to sense faults in this high-impedance winding. Regulating transformers can be either the most common in-phase type employing only voltage regulation, or the phase-shifting type that provides regulation of phase angle, or both magnitude and phase. For application of regulating transformer, the reader should refer to IEEE Std C57.135™, IEEE Guide for the Application, Specification, and Testing of Phase-Shifting Transformers [B16].

Sudden-pressure or fault-pressure relays will offer good protection for all three types. However, electrical protection may differ substantially between the in-phase type and the others. The tap changer mechanism compartment may be protected with gas or oil sudden-pressure relays. Pressure variations during normal tap changing arc interruption have not been found to cause false operation of the sudden-pressure relays. The use of vacuum interrupter switches in the tap changing mechanism eliminates any pressure variations in the tap changing compartment.

Transformer manufacturers usually provide special protection and monitoring schemes of their own design on regulating transformers. The scheme may stop the tap changing sequence or initiate a trip for a switch or mechanism malfunction.

8.5.2.1 In-phase type

Although overall differential relaying is usually provided for in-phase regulators, special-purpose relays are also available to protect the exciting winding more sensitively. On each phase, this type of relay compares the exciting winding current (obtained from a CT in the high-voltage lead or neutral end of the exciting winding) with one of the phase currents as shown in Figure 23.

The relay has one operating coil or element and one restraint coil or element and is generally set to operate for a current imbalance of 15% greater than the imbalance due to maximum regulation. It should be noted that the exciting winding of a ±10% regulator has a full-load current rating only 10% of the rating of the series winding; CT ratios should be chosen with this in mind. The use of delta-connected CTs is a necessary precaution to prevent tripping for external ground faults (if the neutral of the exciting winding is grounded). Because of the location of the CT in the exciting winding, the proper CT should be specified when ordering the transformer.

8.5.2.2 Phase-shifting or combined phase-shifting and in-phase regulating transformers

For these types of transformers, neither type of protection shown in Figure 23 is suitable. For example, for a quadrature phase-shifting transformer, the exciting winding shown in Figure 23 might not introduce a voltage in the same phase; it could, however, introduce a voltage in each of the other two phases. Conversely, the series winding shown in Figure 23 would be two series windings deriving their voltages from the exciting winding of the other two phases. The effects of these factors are as follows:

a) With respect to the normal percentage differential relay shown in Figure 23, an external fault on either one of the other two phases, or both, can produce current predominantly on only one side of the differential relay. This relay operates as though there was an internal fault if the fault current is above pickup.

b) With respect to the exciting winding protection of Figure 23, an external fault on either one of the other two phases, or both, can cause the exciting (operating) current to be substantially equal to the line (restraining) current. The relay, connected as shown, would operate.

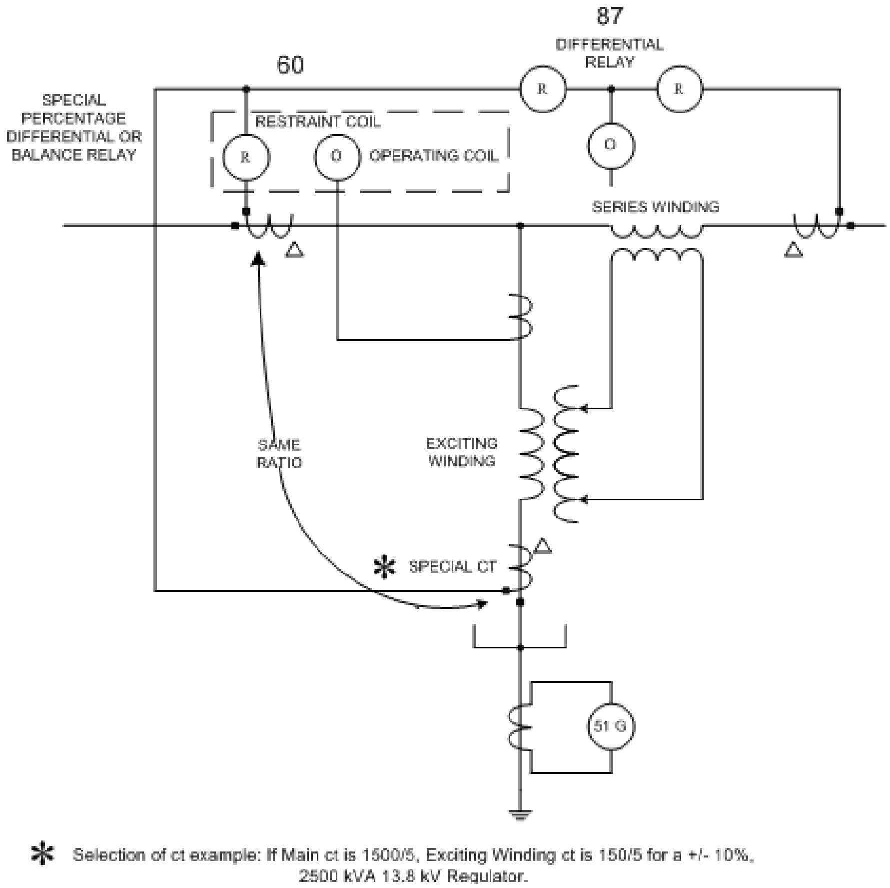


Figure 23—Protection for in-phase regulating transformers

The relay protection of the phase-shifting transformer presents problems not common to a normal transformer. The primary winding, the series transformer, and the shunt transformer should all be considered in determining a viable relay protection scheme. Because of the large number of possible varieties of phase-shifting transformers, specific electrical protection of those types of transformers is considered to be beyond the scope of this guide. It is pertinent, however, to point out that electrical protection will probably require CTs inside of the transformer rather than the usual bushing CTs (see Figure 24). Consequently, the protection should be decided upon early enough so that CTs can be specified before the transformer design is started. For protection of this type of transformer, the sudden-pressure or fault-pressure relay should be considered to be the first line of protection.

Protection of phase-shifting transformers is not discussed in detail in this guide. Detailed information on protecting phase-shifting transformers is provided in Tziouvaras and Jimenez [B39], Ibrahim and Stacom [B10], Plumptre [B24], and Thomson et al. [B37].

8.5.3 Combined power and regulating transformers

A power transformer, such as a wye-delta transformer, may also have regulating features, either in phase, out of phase (such as quadrature), or both. Such transformers are called tap-changing-under-load, or load-tap-changing, transformers.

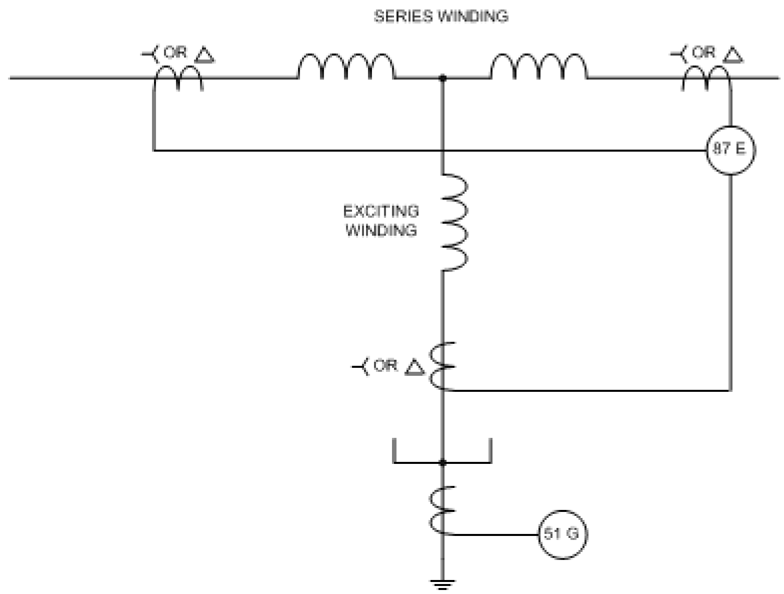


Figure 24—Protection for phase-shifting transformers

The protection of such a transformer of the in-phase variety has been previously covered in this guide. However, the electrical protection of the out-of-phase variety is even more difficult than the protection of the phase-shifting regulating transformer because the power transformer has no exciting winding as such since excitation is obtained from loaded windings. Comments with respect to phase-shifting regulating transformers apply equally well to this type of transformer (see 8.5.2.2). In any case, the sudden-pressure or fault-pressure relay should be considered the first line of protection.

8.5.4 Grounding transformers

A grounding transformer can be either a zig-zag or a wye-delta connected transformer. The electrical protection scheme is simple and consists of overcurrent relays connected to delta-connected CTs as shown in Figure 25 and Figure 26. In many situations, a zig-zag grounding transformer is protected by a differential relay and a backup ground overcurrent relay as shown in Figure 27.

If the grounding transformer is of the zig-zag variety, internal faults, such as turn-to-turn faults, may be limited by the magnetizing impedance of an unfaulted phase. Consequently, a sudden-pressure or fault-pressure relay should be considered to be the first line of protection.

Grounding transformers are seldom switched by themselves. However, when they are switched, they are subject to magnetizing inrush current as with any other type of transformer. Overcurrent relays with harmonic restraint may be used to prevent inadvertent tripping upon energizing.

A phase-to-ground fault should not be allowed to persist on a grounding transformer that is provided with low or no neutral impedance that permits a fault-current magnitude greater than the continuous current rating. Therefore, the selection of a CT ratio associated with the grounding transformer is more dependent on the pickup of the ground relay than the rating of the grounding transformer. However, if a fault is allowed to persist, then the CT ratio must be selected with the continuous current in mind. A grounding transformer has a continuous rating based on a set fraction of its thermal current rating according to IEEE Std 32-1972, IEEE Standard Requirements Terminology and Test Procedure for Neutral Grounding Devices.

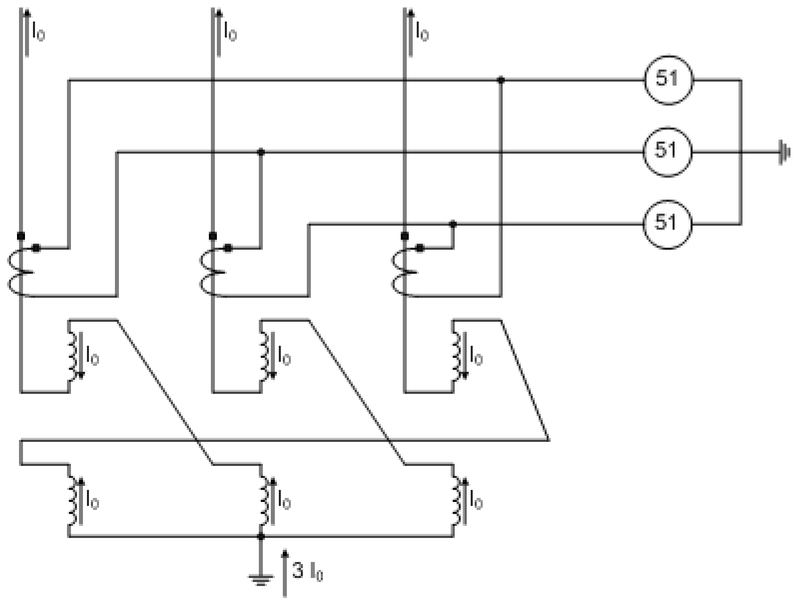


Figure 25—Protection of zig-zag grounding transformer

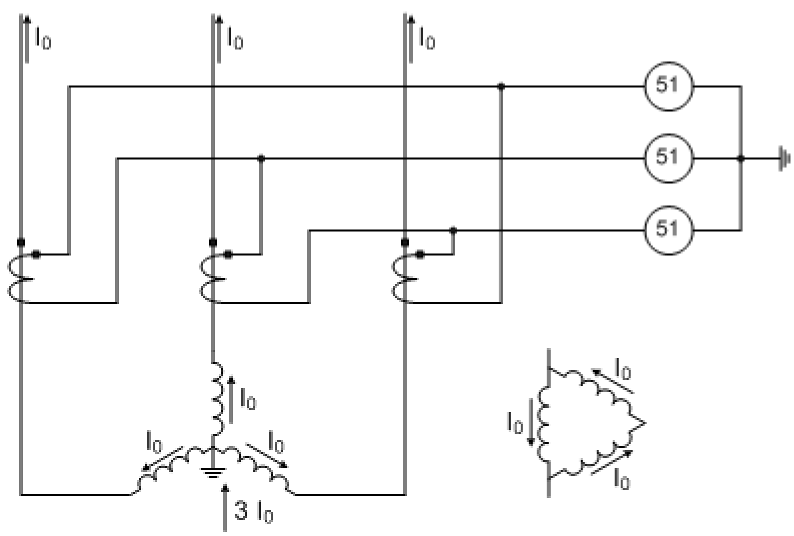


Figure 26—Protection of wye-delta transformer

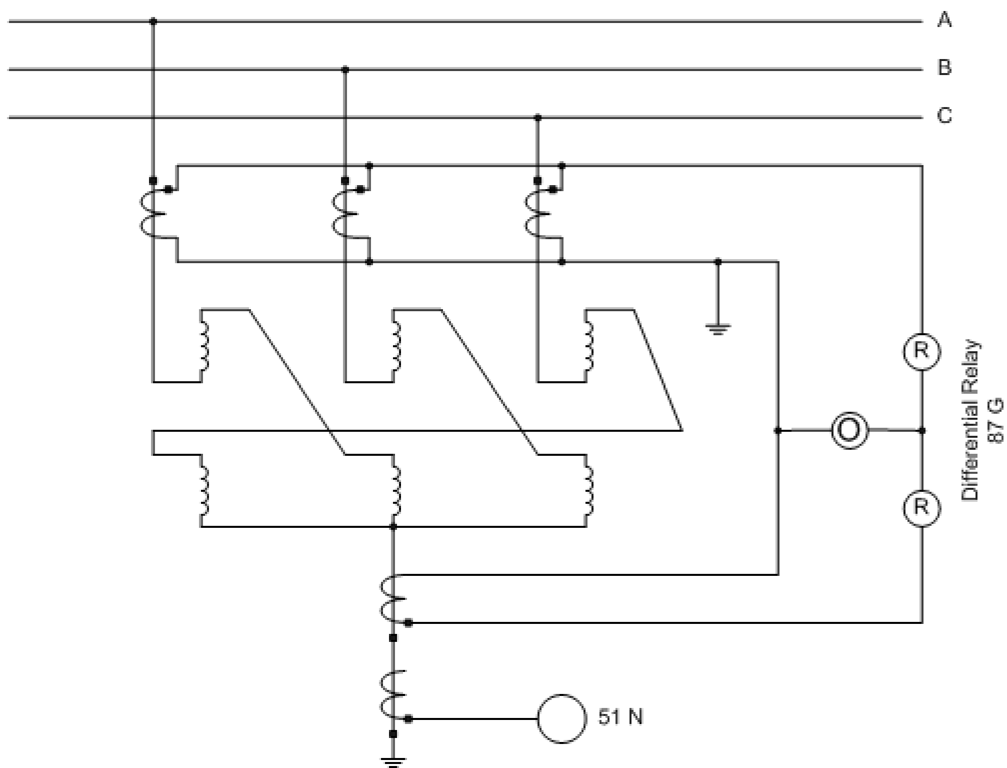


Figure 27 —Protection of a zig-zag grounding transformer with differential relay and a backup ground relay

If the continuous current rating of a grounding transformer is not available, it can be determined as follows:

a) Obtain the zero-sequence impedance (ohms, or percent, or p.u. on some base) from the transformer manufacturer.

b) Determine a kVA rating that will have approximately the same zero-sequence impedance relative to the grounded neutral side by assuming a mean value of the standard range of impedances.

c) Having determined the fictitious kVA rating, choose the CT ratio based on full-load current for that kVA rating.

8.6 Backup and external fault protection

Protection of a transformer against damage due to the failure to clear an external fault should always be carefully considered.

This damage usually manifests itself as internal, thermal, or mechanical damage caused by fault current flowing through the transformer. The curves in Annex A show through-fault-current duration curves to limit damage to the transformer. Through-faults that can cause damage to the transformer include restricted faults or those some distance away from the station. The fault current, in terms of the transformer rating, tends to be low (approximately 0.5 to 5.0 times transformer rating) and the bus voltage tends to remain at relatively high values. The fault current will be superimposed on load current, compounding the thermal load on the transformer.

Several factors will influence the decision as to how much and what kind of backup is required for the transformer under consideration. Significant factors are the operating experience with regard to clearing remote faults, the cost effectiveness to provide this coverage considering the size and location of the transformer, and the general protection philosophies used by the utility.

Backup protection for the transformer can be divided into several categories, as described in 8.6.1 through 8.6.5.

8.6.1 Overcurrent relays

When overcurrent relays are used for transformer backup, their sensitivity is limited because they should be set above maximum load current. Separate ground relays may be applied with the phase relays to provide better sensitivity for some ground faults. Usual considerations for setting overcurrent relays are described in 8.3.

When overcurrent relays are applied to the high-voltage side of transformers with three or more windings, they should have pickup values that will permit the transformer to carry its rated load plus margin for overload. Locating phase overcurrent relays on the low-voltage side of each winding allows a gain in sensitivity since only the full-load rating of an individual winding need be considered.

When two or more transformers are operated in parallel to share a common load, the overcurrent relay settings should consider the short-time overloads on one transformer upon loss of the other transformer. Relays on individual transformers may require pickup levels greater than twice the forced cooled rating of the transformer to avoid tripping. Higher pickup levels result in a loss of backup protection sensitivity. To improve the sensitivity of backup protection, the CTs on each transformer source to a bus may be paralleled so that one set of overcurrent relays receive the total current of the sources associated with the individual bus. Switching out a transformer, therefore, does not affect the relay sensitivity. However, all sources should be tripped when the overcurrent relays operate. This is usually referred to as a bus overload or partial differential scheme.

For sensitive ground protection, each transformer neutral may be grounded through a CT with a lower ratio than that used for the phase overcurrent relay. With due consideration for imbalanced phase-to-ground load and time coordination, it may be possible to approach the sensitivity of the feeder ground relays. See 8.3 and 8.4 for a comprehensive discussion of overcurrent and ground protection, respectively.

8.6.2 Negative-sequence relays

Since these relays do not respond to balanced load or three-phase faults, negative-sequence overcurrent relays may provide the desired overcurrent protection. This is particularly applicable to delta-wye grounded transformers where only 58% of the secondary p.u. phase-to-ground fault current appears in any one primary phase conductor. Backup protection can be particularly difficult when the wye is impedance grounded. A negative-sequence relay can be connected in the primary supply to the transformer and set as sensitively as required to protect for secondary phase-to-ground or phase-to-phase faults. This relay will also provide better protection than phase overcurrent relays for internal transformer faults. The relay should be set to coordinate with the low-side phase and ground relays for phase-to-ground and phase-to-phase faults. The relay must also be set higher than the negative-sequence current due to unbalanced loads.

8.6.3 Fuses

Applications of fuses to the high-voltage or source windings of transformers present the same types of sensitivity problems discussed in 8.3. In addition, fuses are single-phase devices and operate individually. See 8.1 for discussion of the application of fuses.

8.6.4 Breaker failure

Protection for the failure of a feeder breaker to clear a fault may be provided by addition of a timer started by the operation of feeder overcurrent relays in a breaker failure scheme. The principal advantage of this arrangement is that the backup sensitivity is equal to that of the feeder protection. The additional complication of this protection increases the risk of inadvertent loss of the station load due to relay malfunction or testing errors. Breaker failure protection associated with a transformer requires a scheme that may have to recognize small fault currents. "Breaker 'a' auxiliary switch contacts (open)" may have to be used in combination with fault-current detectors. A transformer connected to a line without a line-side breaker requires transfer trip or a ground switch to cause the remote breaker to trip. If the remote breaker fails to trip, the transformer fault probably will not be cleared. For more details on breaker failure protection, refer to IEEE Std C37.119, IEEE Guide for Breaker Failure Protection of Power Circuit Breakers.

8.6.5 Dual-input relays

System voltages are lower during fault conditions than during load conditions with comparable current. This results from the fault current being highly reactive, which causes larger voltage drops across the system. This fact is utilized in several different dual-input relays.

8.6.5.1 Voltage-controlled overcurrent relay

In this relay, the overcurrent unit is set based on the minimum fault-current condition independent of any load-current requirements. This relay is then torque-supervised by an undervoltage relay. The undervoltage unit is set to operate below the normal minimum system load voltage, but above the maximum expected fault voltage. Thus, sensitive phase fault protection is provided with no hazard of tripping due to load current. Low-side potential should be used to allow the undervoltage unit to drop out for low-side faults. The potential supply should be monitored. There may be an application problem with this relay if the system voltage during a limited fault is not reduced substantially.

8.6.5.2 Voltage-restraint overcurrent relay

In this relay, the overcurrent unit operating value is a function of the applied voltage. The relay is set so that maximum load current will not cause operation with the minimum expected system operating voltage. During fault conditions, the reduced voltage causes less restraint and the relay will operate at a lower current, which varies with the voltage magnitude. There may be an application problem with this relay if the system voltage during a limited fault is not reduced substantially.

8.6.5.3 Impedance relay controlling an overcurrent relay

This scheme is less dependent on the exact change in the level of system voltage than either of the two methods in 8.6.5.1 and 8.6.5.2. In this method, the impedance from the relay location to the most distant fault needing backup protection is set on the distance relay, with suitable margin. The overcurrent relay is then set at a current less than the minimum expected fault current. A mho-type distance relay characteristic or a specially shaped load encroachment element can be used for this purpose.

8.6.5.4 Overcurrent directional relay

This relay responds to the product of the magnitude of a voltage, current magnitude, and cosine of the angle between the current and the reference voltage. If the voltage that normally lags the unity power factor current by 90°, the relay responds only to the reactive component of the current. It will not respond to the real component of any load current and hence has good loadability. The relay can be set for the minimum expected fault current with suitable margin.

8.7 Temperature relays

Transformer damage from remote low-current faults that are not properly cleared may be similar to that from sustained overload causing thermal damage. The most direct solution to the backup problem is the use of thermal relays as discussed in Clause 10.

8.8 Miscellaneous relays

In certain applications, advantages can be taken of relays not directly associated with the transformer. In the case of a unit-connected generator, backup may be provided by protective relays essentially designed for generator backup. These include the voltage-controlled overcurrent relay, a distance relay for remote faults (usually applied with a fixed time delay rather than inverse time delay), the generator negative-sequence overcurrent relay and the generator overexcitation relay.

9. Mechanical detection of faults

Some transformer faults go undetected when the schemes described in Clause 8 are used. A turn-to-turn fault can cause considerable current to flow in the shorted turn, while current in the remaining winding remains relatively unchanged. Since there is little or no change in the current monitored by the CTs, there is no differential current for the relays to operate. Eventually, the turn-to-turn fault will evolve into a ground fault giving the protective relays the necessary change in current to operate.

There are two methods of detecting transformer faults other than by electric measurements. These methods are as follows:

a) Accumulation of gases due to slow decomposition of the transformer insulation or oil. These relays can detect heating due to high-resistance joints or due to high eddy currents between laminations.

b) Increases in tank oil or gas pressures caused by internal transformer faults.

9.1 Gas accumulator relay

This type of relay, commonly known as the Buchholz relay, is applicable only to transformers equipped with conservator tanks and with no gas space inside the transformer tank. The relay is placed in the pipe from the main tank to the conservator tank and is designed to trap any gas that may rise through the oil. It will operate for small faults by accumulating the gas over a period of time or for large faults that force the oil through the relay at a high velocity. This device is able to detect a small volume of gas produced by low-energy arcs, overheating, and insulation decomposition. The accumulator portion of the relay is frequently used for alarming only; it may detect gas that is not the result of a fault, but that can be evolved by gassing of the oil during sudden reduction of pressure. This relay may detect heating due to increased power transfer, increased ambient temperature, full or partial failure of the cooling system, high-resistance joints, high eddy current between laminations, low- and high-energy arcing, or accelerated aging due to overloading.

9.2 Gas detector relay

The gas detector relay can be used only on conservator transformers, either conventional or sealed. The relay will often detect gas evolution from minor arcing before extensive damage occurs to the windings or core. This relay may detect emission of gases due to overall heating, high-resistance joints, high eddy current between laminations, low- and high-energy arcing, or accelerated aging due to overloading.

Essentially, the gas detector relay is a magnetic-type liquid-level gage with a float operating in an oil-filled chamber. The relay is mounted on the transformer cover with a pipe connection from the highest point of the cover to the float chamber. A second pipe connection from the float chamber is carried to an eye-level location on the tank wall. This connection is used for removing gas samples for analysis. The relay is equipped with a dial graduated in cubic centimeters and a snap action switch set to function to give an alarm when a specific amount of gas has been collected.

9.3 Pressure relays

When high current passes through a shorted turn, a great deal of heat is generated. This heat, along with the accompanying arcing, breaks down the oil into combustible gases. Gas generation increases pressure within the tank. A sudden increase in gas pressure can be detected by a sudden-pressure relay either located in the gas space or under the oil. The sudden-pressure relay usually operates before other relays sensing electrical quantities thus limiting damage to the transformer.

One drawback to using a sudden-pressure relay is its tendency to operate on high-current through-faults. The sudden high current experienced from a close-in through-fault causes windings of the transformer to move. This movement causes a pressure wave that is transmitted through the oil and detected by the sudden-pressure relay. If the pressure is large enough, the sudden-pressure relay operates. Various methods to prevent undesired operation have been developed. The most common method takes advantage of the fact that a close-in through-fault creates a high current in the transformer. An instantaneous overcurrent relay supervises the sudden-pressure relay. Any high-current condition detected by the instantaneous overcurrent relay blocks the sudden-pressure relay. This method limits the sudden-pressure relay to low-current incipient fault detection. Another method, used less often, is to place sudden-pressure relays on opposite corners of the transformer tank. Any pressure wave due to through-faults will not be detected by both sudden-pressure relays. The contacts of the sudden-pressure relays are connected in series so both must operate before tripping.

Experience with sudden-pressure relays varies. Due to the previously mentioned drawback, some users choose to use sudden-pressure relays for alarm only. Others are reevaluating their use altogether, since most times the high-speed differential relay and the sudden-pressure relay both operate for faults. Still, the sudden-pressure relay is a viable protection alternative for turn-to-turn fault detection in some applications, particularly grounding transformers and transformers with complicated circuits like phase-shifting transformers, which make applying differential protection difficult.

9.3.1 Sudden-oil-pressure relay

The sudden-oil-pressure relay is applicable to all oil-immersed transformers and is mounted on the transformer tank wall below the minimum liquid level. Transformer oil fills the lower chamber of the relay housing, within which a spring-backed bellows is located. The bellows is completely filled with silicone oil, and additional silicone oil in the upper chamber is connected to that in the bellows by way of two small equalizer holes.

A piston rests on the silicone oil in the bellows and extends up into the upper chamber, separated from a switch by an air gap. Should an internal fault develop, the rapid rise in oil pressure or pressure pulse is transmitted to the silicone oil by way of the transformer oil and the bellows. This then acts against the piston, which closes the air gap and operates the switch.

In the event of small rises in oil pressure, for example, due to changes in loading or ambient, the increased pressure is also transmitted to the silicone oil. However, instead of operating the piston, this pressure is gradually relieved by oil that escapes from the bellows into the upper chamber by way of the equalizer holes. The bellows then contracts slightly. The pressure bias on the relay is thus relieved by this differential feature. Relay sensitivity and response to a fault is thus independent of transformer operating pressure.

This relay has proven sufficiently free from false operations to be connected for tripping in most applications. It is important that the relay be mounted in strict accordance with the manufacturer's specifications. Further, a scheme similar to Figure 28 or Figure 29, which provides a shunt path around the 63X auxiliary relay coil or element, is preferred to prevent its operation due to disturbances in the electrical control circuit.

9.3.2 Sudden-gas/oil-pressure relay

A more recent design of the relays shown in Figure 28 and Figure 29 utilizes two chambers, two control bellows, and a single sensing bellow. All three bellows have a common interconnecting silicone-oil passage with an orifice and ambient-temperature-compensating assembly inserted at the entrance to one of the two control bellows.

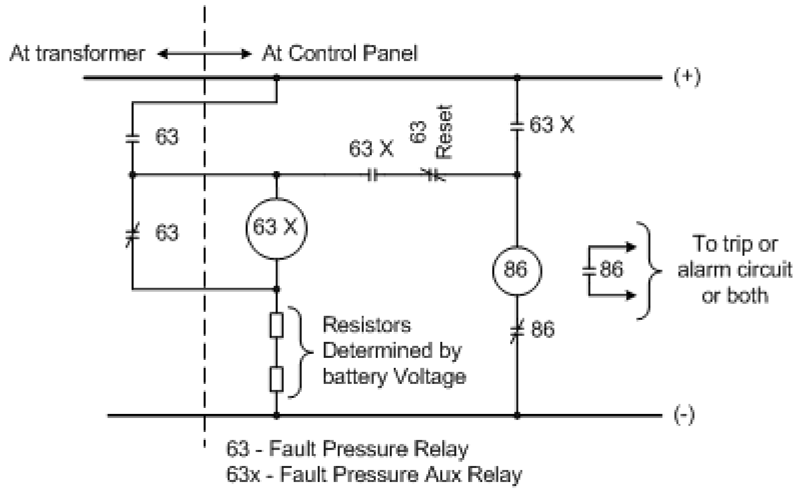


Figure 28 —Fault-pressure relay scheme; auxiliary relay at control panel

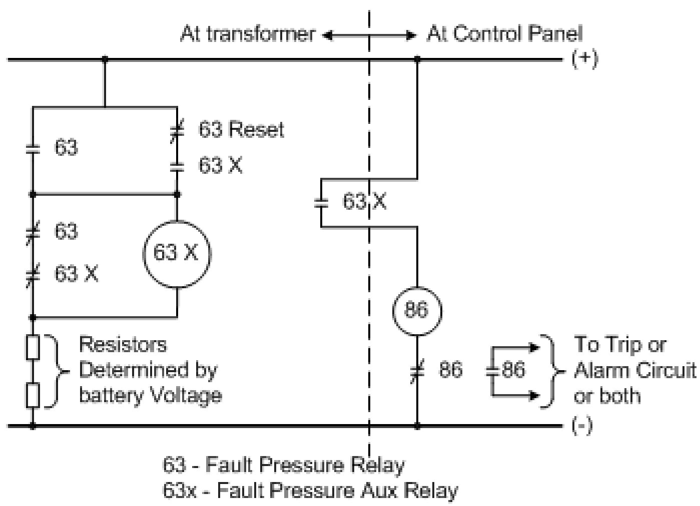


Figure 29 —Fault-pressure relay scheme; auxiliary relay at transformer with manual reset

An increase in transformer pressure causes a contraction of the sensing bellow thus forcing a portion of its silicone oil into the two control bellows and expanding them. An orifice limits the flow of oil into one control bellows to a fixed rate, while there is essentially no restriction to flow into the second control bellows. The two control bellows expand at a uniform rate for gradual rate of rise in pressure, but during high rates of transformer pressure rise, the orifice causes a slower rate of expansion in one bellows relative to the other. The dissimilar expansion rate between the two control bellows will cause a mechanical linkage to actuate the snap action switch, which initiates the proper tripping.

9.3.3 Sudden-gas-pressure relay

The sudden-gas-pressure relay is applicable to all gas-cushioned, oil-immersed transformers and is mounted in the region of the gas space. It consists of a pressure-actuated switch, housed in a hermetically sealed case and isolated from the transformer gas space except for a pressure-equalizing orifice.

The relay operates on the difference between the pressure in the gas space of the transformer and the pressure inside the relay. An equalizing orifice tends to equalize these two pressures for slow changes in pressure due to loading and ambient temperature change. However, a more rapid rise in pressure in the gas space of the transformer due to a fault results in operation of the relay. High-energy arcs result in the evolution of a large quantity of gas, which operates the relay in a short time. The operating time is longer for low-energy arcs.

This relay has proven to be sufficiently free from false operations and is, therefore, connected for tripping in most applications. It is important that the relay be mounted in strict accordance with the manufacturer's specifications. Further, a scheme similar to Figure 28 or Figure 29, providing a shunt path around the auxiliary relay coil or element, is preferred to minimize the effects of control circuit electrical disturbances.

9.3.4 Static pressure relay

The static pressure relay can be used on all types of oil-immersed transformers. They are mounted on the tank wall under oil and respond to the static or total pressure. These relays, for the most part, have been superseded by the sudden-pressure relay, but many are in service on older transformers. However, due to their susceptibility to operate for temperature changes or external faults, the majority of the static pressure relays that are in service are connected for alarm only.

10. Thermal detection of abnormalities

10.1 Thermal relays for winding temperature

10.1.1 Causes of transformer overheating

Transformers may overheat due to the following reasons:

a) High ambient temperatures

b) Failure of cooling system

c) External fault not cleared promptly

d) Overload

e) Abnormal system conditions such as low frequency, high voltage, nonsinusoidal load current, or phase-voltage unbalance

10.1.2 Undesirable results of overheating

a) Overheating shortens the life of the transformer insulation in proportion to the duration of the high temperature and in proportion to the degree of the high temperature.

b) Severe overtemperature may result in an immediate insulation failure.

c) Severe overtemperature may result in the transformer coolant heated above its flash temperature, with a resultant fire.

d) Overheating can generate gases that could result in an electrical failure.

10.1.3 Hot-spot location

The location of the hottest spot within a transformer is sometimes predicted from the design parameters. It is customary to measure or to simulate this hot-spot temperature and to base control action accordingly. The desired control action will depend on the users' philosophy, the amount of transformer life the user is willing to lose for the sake of maintaining service, and the priorities the user places on other aspects of the problem. Transformer top-oil temperature may be used with or without hot-spot temperature to establish the desired control action.

A common method of simulating the hot-spot temperature is with a thermal relay responsive to both top-oil temperature and to the direct heating effect of load current. In these relays, the thermostatic element is immersed in the transformer top oil. An electric heating element is supplied with a current proportional to the winding current, so that the responsive element tracks the temperature that the hot spot of the winding attains during operation. If this tracking is exact, the relay would operate at the same time as the winding reaches the set temperature. Since insulation deterioration is also a function of the duration of the high temperature, additional means are generally used to delay tripping action for some period of time. One common method is to design the relay with a time constant longer than that of the winding. Thus, the relay does not operate until some time after the set temperature has been attained by the winding. There are no standards established for this measuring technique, nor is information generally available for one to make an accurate calculation of the complete performance of such a relay. These relays can have from one to three contacts that close at successively higher temperature. With three contacts, the lowest level is commonly used to start fans or pumps for forced cooling, and the second level to initiate an alarm. The third step may be used for an additional alarm or to trip load breakers or to deenergize the transformer.

Loss of oil flow requires special attention in transformers without a self-cooled rating. Heat exchangers in these transformers will dissipate only insignificant amounts of heat without operable cooling systems. The hot-spot relay is calibrated to replicate true hot-spot temperature with forced oil circulation in the windings, and will indicate a temperature many degrees cooler than the actual hot spot if oil flow is restricted. In such cases, detection of loss of oil flow may be used to drop load and deenergize the transformer. There are also some techniques that allow the measurement of actual winding temperature.

Another type of temperature relay is the replica relay. This relay measures the phase current in the transformer and applies this current to heater units inside the relay. Characteristics of these heaters approximate the thermal capability of the protected transformer. In the application of a replica-type relay, it is desirable to know the time constants of the iron, the coolant, and the winding. In addition, the relay should be installed in an ambient temperature approximately the same as the transformer and not be ambient compensated.

10.1.4 Modern refinements

In recent years, attention has been focused on the use of the differential equations from heat transfer theory to mathematically model (and hence calculate) continuously varying top-oil temperature and hot-spot temperature as functions of the continuously measured load current and ambient temperature. At this time, the IEEE-approved equations from IEEE Std C57.91-1995, IEEE Guide for Loading Mineral-Oil-Immersed Transformers, are under scrutiny. These equations, along with related insulation-loss-of-life equations also under consideration, allow some interesting possibilities, some of which are commercially available at this time. The following practices are sometimes used:

a) Adaptive overcurrent: In this scheme, the pickup current for inverse-time overcurrent protection is automatically raised when the ambient temperature is low, and lowered when the ambient temperature is high. This is an alternative to the practice in some utilities of raising the pickup setting by, say, 25% in the winter, especially in severe climate-swing locations.

b) Predicted severe hot-spot temperature or severe loss of insulation-life: Equations, reported in Annex D or similar equations developed for this purpose, may be used to predict either of these conditions well before they occur, usually on the basis that load current and ambient temperature remain unchanged for that period into the future. The prediction may go for, say, 30 min into the future. The calculation is done every few minutes, so that if the loading or ambient should change, the prediction will update automatically. The time to overtemperature or time to excessive loss of life may be continuously displayed, or simply an alarm triggered. A refinement of this is to automatically activate full cooling, that is, to base it on the predicted hot-spot temperature rather than the actual hot-spot temperature.

c) Cooling failure detection: If hot-spot temperature can be calculated accurately enough, and also measured—either by fiber-optic sensors or the traditional "winding temperature indicator" (WTI) method—then a significantly higher measured value would indicate that the cooling system is in some way faulty, and an alarm could be generated. One difficulty is that sun, wind, and rain also have an effect, but they are not normally taken into account. Another difficulty is that the cooling model for calculations changes for a multistage-cooled transformer as it switches from one stage to the next. Normally, the parameters for changes to the model under partial cooling conditions are not known. There is a well-established mathematical procedure for finding the parameters under "cooling OK" conditions.

10.2 Other means of thermal protection

10.2.1 Top-oil temperature

Many transformers are equipped with a thermometer or resistance temperature detectors (RTDs) immersed in the top oil. If the thermometer is equipped with contacts that close at selected temperatures, these contacts can be used to start cooling fans or pumps, or to sound an alarm. If the temperature indicated by an RTD exceeds a set value, the cooling fans or pumps can be started. Since the top-oil temperature may be considerably lower than the hot-spot temperature of the winding, especially shortly after a sudden load increase, the top-oil thermometer is not suitable for effective protection of the winding against overloads. However, tripping on top-oil temperature may be satisfactory when the policy toward transformer loss of life permits. This has the added advantage of directly monitoring the oil temperature to ensure that it does not reach the flash temperature.

10.2.2 Fuses or overcurrent relays

Other forms of transformer protection such as fuses or overcurrent relays provide little or no thermal protection to the transformer due to the need for them to allow for short-time overloads. Application of these devices is discussed in 8.1 and 8.3.

10.2.3 Thermal relays for tank temperature

When wye-connected, three-legged core-type transformers without delta windings are applied unbalanced voltages, the magnitude of the flux in the three cores is not equal. This results in the zero-sequence component of the flux to link with the core and the transformer tank. Effectively, the tank acts as a high-impedance delta-tertiary winding (generally known as a phantom tertiary). Under severe conditions, damaging heat can be produced. A thermal relay mounted to sense tank temperature can detect this condition. Because this condition usually occurs due to an open phase, which does not cause other protection to operate, the device should trip the transformer. The device can be a dial-type temperature indicator with a switch, a direct acting thermostat, or a set of RTDs placed at different locations on the tank. Settings of 105 °C to 125 °C will be the temperatures reached under normal operating conditions, and will correspond to temperatures reached in 1 min to 4 min under maximum heating conditions (one phase of supply open and grounded). See 8.3 for overcurrent relay application.

10.2.4 Overexcitation protection

Overexcitation of a transformer can occur whenever the ratio of the p.u. voltage to p.u. frequency (V/Hz) at the secondary terminals of a transformer exceeds its rating of 1.05 p.u. on transformer base at full load, 0.8 power factor, or 1.1 p.u. at no load. The generator connected to that transformer would have a limit of 1.05 p.u. on the generator base. When an overexcitation condition occurs, saturation of the laminated steel cores of the generator and transformer can occur. Stray magnetic fields increase in magnitude, particularly at the ends of the cores. Nonlaminated components at the ends of the cores, which were not designed to carry these higher levels of flux, begin to heat up due to the higher losses induced in them. This can cause severe localized overheating in the transformer and generator and eventual breakdown in the core assembly or winding insulation. The permissible short-time overexcitation capability of a specific transformer or generator should be obtained from the manufacturer. Figure 30 shows V/Hz limiting curves provided by three different transformer manufacturers.

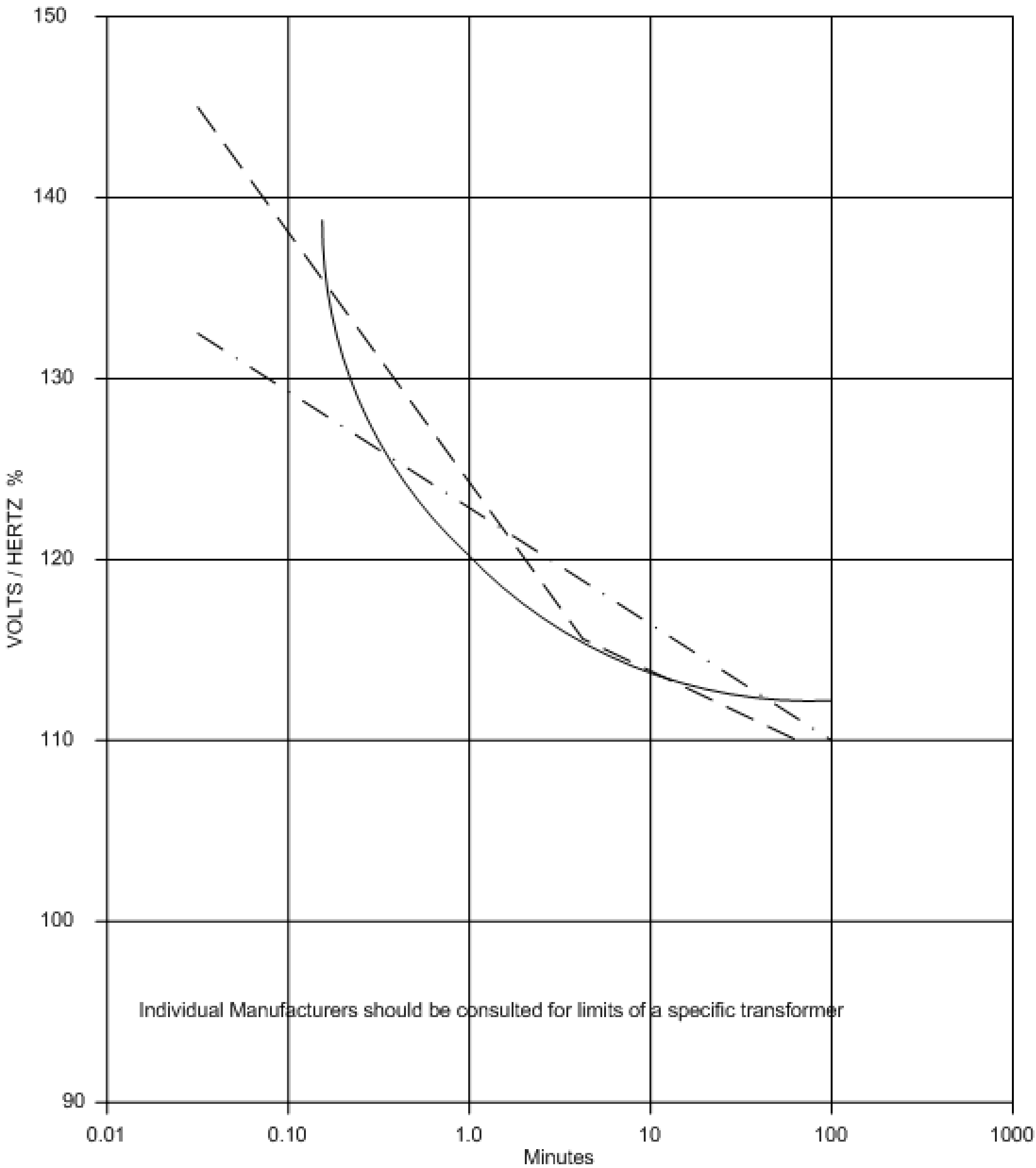


Figure 30 —Overexcitation limits of three transformers of different manufacturers

Overexcitation is of major concern on directly connected generator unit transformers. One of the primary causes of excessive V/Hz on generators and unit transformers is operation of the unit under regulator control at reduced frequencies during generator startup and shutdown. Another cause of excessive V/Hz is inadvertent manual overexcitation during generator startup and shutdown. Overexcitation can also occur during complete load rejection that leaves transmission lines connected to a generating station. Under this condition, the V/Hz may exceed 1.25 p.u. With the excitation control in service, the overexcitation will generally be reduced to safe limits in a few seconds. With the excitation control out of service, the overexcitation may be sustained and damage can occur to the generator and/or transformers. Failures in the excitation system or loss of signal voltage [i.e., blown voltage transformer (VT) fuse] to the excitation control can also cause overexcitation.

Prolonged high system overvoltages combined with low frequency during major disturbances could cause overexcitation and failure of transmission and distribution transformers (for more discussion, see Tziouvaras [B40]. V/Hz protection may, therefore, be considered for major transmission and distribution transformers.

Occasionally, a transformer remote from a generation station will be exposed to overflux conditions that may not be protected by an overvoltage relay or by protecting the associated generation station with V/Hz protection. A typical case would be a transformer on the end of a long line connected to a generating plant. During a load rejection in which this transformer is connected to the generator, the transformer may have a significantly higher V/Hz than that at the generator facility due to the Ferranti effect. In this case, or similar cases, V/Hz protection should be applied to the remote transformer.

Overexcitation protection for the transformer is generally provided by the generator overexcitation protection, which uses the VTs connected to the generator terminals. So, the curves that define generator and transformer V/Hz limits must be coordinated to properly protect both pieces of equipment. Generally, the transformer V/Hz curve is put on a generator voltage basis.

Therefore, a 13.2 kV/115 kV transformer being used as a step-up transformer for a 13.8 kV generator will reach its continuous no-load V/Hz limit of 110% at a generator voltage of 105.2% of the generator rated voltage.

Generator manufacturers recommend an overexcitation protection system as part of the generator excitation systems. These systems will limit the V/Hz (V/Hz limiter) to a safe value in the automatic control mode. To provide protection when the unit is under manual control, the V/Hz limiter may send a relay alarm signal during overexcitation condition and, if the condition persists, decrease the generator excitation or trip the generator and field breakers, or both. The generator manufacturer should be requested to provide recommendations for overexcitation protection.

It should be noted that if the generator can be operated with leading power factor, the high-side voltage of the transformer may have a higher p.u. V/Hz than the generator V/Hz. This aspect may need to be considered in proper V/Hz protection of the transformer.

It is a common practice to apply separate V/Hz protection in addition to the protection built in the excitation control system. Several forms of protection are available including definite time, preprogrammed inverse time curves, and user-programmable inverse time curves. A detailed discussion on various forms of V/Hz relays can be found in 4.5.4 of IEEE Std C37.102-2006, IEEE Guide for AC Generator Protection. When the transformer rated voltage is equal to the generator rated voltage, the same V/Hz relay that is protecting the generator may be set to protect the transformer. In some cases, however, the rated transformer voltage is lower than the rated generator voltage and protection may not be provided. It may, therefore, be desirable to provide supplementary protection for the transformer. Since the V/Hz capabilities of transformers may differ appreciably, it is not possible to provide definitive protection recommendations that would cover all units.

11. Fault clearing

A faulted transformer can be separated from its power source by devices such as circuit breakers, power-operated disconnects, circuit switchers, fuses, or by remote tripping of fault-interrupting devices. In addition to separating the transformer from its power source, due consideration should be given to tripping oil pumps and fans to reduce their possible adverse effects in sustaining or spreading a transformer oil fire and to halt circulation of contaminants in the oil resulting from the arc. Determination of the type of fault-clearing devices to be used should involve considerations such as the following:

a) Installation and maintenance cost

b) Fault-clearing time relative to fire hazard and repair or replacement costs of the transformer

c) System stability and reliability

d) System operating limitations

e) Device interrupting capability

11.1 Relay tripping circuits

Usually a transformer protective relay operation requires a careful inspection for the cause of tripping before any attempt is made to reenergize the transformer. Usually two or more breakers or switching devices may have to be tripped. Therefore, tripping is usually done by a lockout relay that multiplies the number of tripping contacts and blocks the closing circuits until the lockout relay is manually reset. When using modern relays with multiple tripping contacts, it is possible to direct-trip each circuit breaker from the relay and also trip the lockout relay for the blocking function. This improves speed and reliability and eliminates the need for multiple lockout relays for redundancy as described in the following paragraph.

For a large transformer having several protective relays, two lockout relays and dc power supplies are often used. If both lockout relays trip the same breakers, the differential relays may operate one lockout relay and the sudden-pressure relay and overcurrent relays, including instantaneous units, may operate the second lockout relay for the greatest redundancy. If the two lockout relays perform different or duplicate tripping functions, then a different assignment of protective relays to each lockout relay may be desired. If a breaker is tripped by a modern relay, an additional contact may be used to initiate breaker failure relaying. If the breaker is tripped by a lockout relay, a high-speed self-reset relay connected in parallel with the lockout relay could initiate breaker failure relaying.

Relays should be connected to trip fault-interrupting devices that will clear faults in the zone that the relay is intended to protect. For example, the relays 87G in Figure 17, 67G in Figure 18, and 51GB and 51GT in Figure 21 must trip the high-side (source) circuit breaker in order to clear a ground fault on the low-voltage side of the transformer.

11.2 Circuit breakers

Circuit breakers directly actuated by a protective relay system are usually provided where it is desirable to isolate a faulted transformer with minimum effect on other segments of the power system. They offer the fastest fault-clearing time and highest interrupting capability.

Many of the diagrams in this guide show only relay connections and not circuit breaker location. Wherever possible, the circuit breaker should be included in the relay zone of protection so that a fault in the breaker or leads to the transformer and its bushings is detected.

11.3 Tripping of remote circuit breakers

In some situations, it may be difficult to justify the cost of local circuit breakers. For example, a transmission line may be tapped for supplying power to customers as shown in Figure 31. The following two types of actions are taken when a fault occurs in the transformer:

a) Some faults in the transformer would be seen by the line protection relays and would result in the relays tripping the line circuit breakers resulting in isolating the faulted transformer. Action can then be taken to open the motor-operated disconnect (MOD) and then reclose the line.

b) Less severe faults will not be seen by the line protection relays. Because there is no local circuit breaker, remote circuit breakers must be tripped to save the transformer from severe damage. The options available for this purpose are discussed in 11.3.2 and 11.3.3.

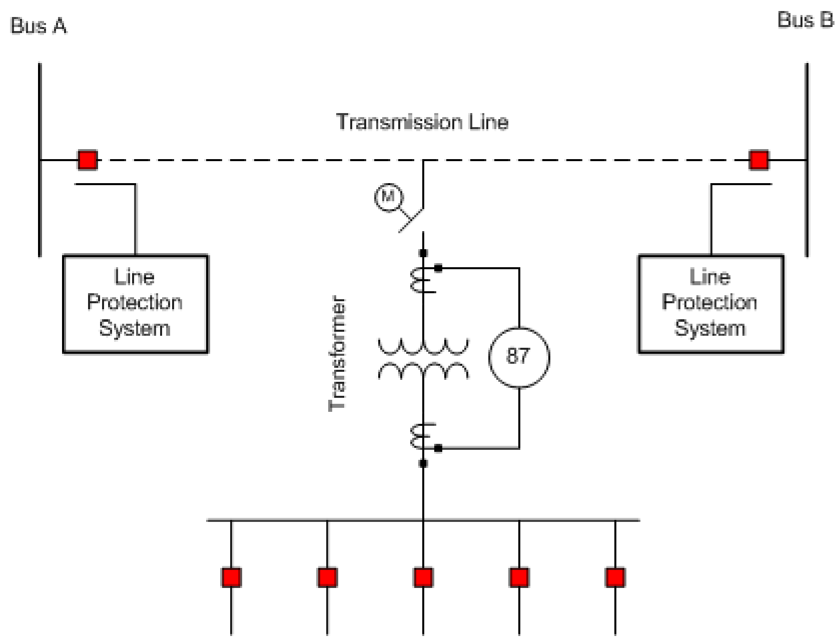


Figure 31—Transmission line tapped for a transformer supplying load

11.3.1 Transfer trip schemes

The transformer protection relays, such as the differential relay shown in Figure 31, would detect a fault in the transformer and send a transfer trip signal to the remote circuit breakers that control the line. After the line circuit breakers have opened, the MOD is opened and line is reenergized.

Six types of communication channels are in general use for transferring trip signals to remote circuit breakers: pilot wire, power-line carrier, fiber optic, leased telephone line, microwave, and radio. The signal may be a simple application of voltage or audio tones on a pair of wires or may utilize frequency-shift-type audio tones or frequency-shift carrier. Frequency-shift equipment employs a guard frequency for channel monitoring and added security against trips by spurious signals. Transformer protective relays will actuate the shift to trip frequency. These schemes have the advantage of speed and the capability to block reclosing of the remote circuit breakers until the faulted transformer is isolated from the system. For more details on communication channels, see IEEE Std C37.113, IEEE Guide for Protective Relay Applications to Transmission Lines.

CAUTION

If the transfer trip scheme fails to work as intended, the transmission line will not be disconnected from the system. Fault currents will continue to flow in the transformer until the line circuit breakers are tripped by the line protection relays. This may happen after the transformer has suffered major damage.

11.3.2 Automatic opening of a motor-operated disconnect

When remote tripping is used, an MOD is usually connected on the source side of the transformer (as shown in Figure 31) to isolate it from the system. The MOD is arranged to open automatically after the transfer trip is sent to the line terminals and a specified time has elapsed to ensure that the line circuit breakers have opened. After the opening of the MOD is completed, the transfer trip is canceled so that the line circuit breakers can be reclosed.

CAUTION

There is a danger that the MOD contact could start to open before the line circuit breakers have isolated the line. This would cause serious damage to the MOD or even destroy it.

In the event of the failure of the line circuit breaker to open (because of any component of the protection and control system not functioning as intended), the MOD will be destroyed. This is a less damaging alternative than allowing the fault currents to flow in the transformer until it is severely damaged.

11.3.3 Fault-initiating switch (high-speed ground switch)

Remote tripping of circuit breakers can be accomplished by applying a fault (usually solid single-phase-to-ground) to the source line so that the remote line relays will detect it and trip the remote circuit breakers. A disadvantage of this scheme is the additional time involved while the ground switch is closing and the remote relays in turn detect the fault. Another consideration is that the ground switch phase and the faulted phase on the transformer may be different, thus imposing a multiphase fault on the system. Also, the switch represents a significant maintenance and testing concern.

The impact of adding a high-speed ground switch on system stability should be assessed. If the protection system provided at the remote terminal is equipped with high-speed reclosing facility, high-speed reclosing should be disabled. Fault-initiating switches are usually used on systems operating at voltages less than 100 kV.

11.4 Circuit switcher

Modern circuit switchers have interrupting capacity comparable to circuit breakers and are applied similarly in fault protection schemes. Circuit switchers do not offer multiple-shot reclosing capability, a feature generally not used in transformer protective schemes (see Clause 12). Older model circuit switchers are mechanical switching devices with a limited fault-interrupting rating.

A circuit switcher can have a disconnect as an integral part of the switcher or can have no disconnect. Many utilities use the disconnect-less version and connect a motor-operated isolating disconnect (MOD) in series with the switcher. The circuit-switcher–MOD combination is provided on the source side of the transformer for isolating the transformer when the current due to a fault in the transformer is less than the rating of the circuit switcher. After the circuit switcher opens, the MOD is opened to isolate the circuit switcher from the line.

It should be possible to coordinate remote line relays to avoid remote tripping for the lower magnitude faults. High-magnitude source-side faults on the transformer exceeding the interrupting rating of the circuit switcher should be detected by remote line relays and cleared by the remote breakers before the contacts of the slower operating circuit switcher open. The circuit switcher may be blocked from tripping using an instantaneous overcurrent relay or it may be allowed to operate, relying on operating time coordination with the remote circuit breakers, depending on user preference.

CAUTION

If the option of opening the circuit switcher after a time delay (for allowing the remote circuit breakers to disconnect the line) is used, inability of the remote circuit breakers to disconnect the line in the expected time due to its maloperation could result in severe damage to the circuit switcher.

11.5 Fuses

When applicable, power fuses are used due to their low installation cost and simplicity. See 8.1.

11.6 Self-powered resettable fault interrupters

Self-powered resettable fault interrupters have low-trip energy requirements, which they derive from the sensing CTs through their integral control scheme. Usually, the transformer bushing CTs are used for sensing and tripping energy. A battery supply and relay building are not required. Application is similar to power fuses in their simplicity and relatively low cost of installation, but the self-powered resettable fault interrupters offer the additional advantages of three-phase tripping capability, higher continuous current capability, and higher interrupting capacity. Interrupting capacity is comparable to modern circuit switchers or circuit breakers. A series disconnect switch is used to isolate the interrupters from the source during the reset process and for closing the circuit after the fault interrupters are reset. See 8.1 and 8.3.1.

12. Reenergizing practice

There is no universal practice with respect to reenergizing a transformer that has been disconnected from the system by relay action that may have been caused by a transformer fault. Because no one intentionally energizes an internally faulted transformer, the differences in practice seem to be based on the lack of knowledge of where the fault is or if there is a fault.

Consider a transformer differential arrangement that includes external leads. A fault within the differential zone may not be an internal fault. If the transformer has a pressure relay, this may give indication of an internal fault. If not, one has to rely on the presence or lack of evidence indicating an external fault. In the absence of this definite information that a fault was external, most operating companies will not reenergize the power transformer without checking it completely.

Now consider a form of transformer protection that includes just the transformer. This may be a differential relay (operating from transformer bushing CTs) or a pressure relay. The one reason to reenergize a transformer so protected is the lack of confidence in the relays. While a few may reenergize a transformer so protected, it may be argued that such a practice does not appear to be warranted when numerical relays are used. Current waveforms are reconstructed from the values of the samples received by the relay. If the level of the currents is more than is normally expected, a review of the waveforms can lead to a decision if the fault is in the transformer or is outside the transformer.

The use and location of the transformer will affect the decision whether or not to reenergize. One is less likely to reenergize a generator step-up transformer or a large system tie transformer than a small substation transformer. The presence of a spare transformer would lessen the necessity to reenergize right away. A history of failures of a certain type transformer may affect the decision by operating companies to reenergize that type of transformer.

If a user’s practice is not to reenergize after a protective relay has disconnected the transformer from the system, a real and continuing problem is how to proceed after such a relay operation; that is, if no fault is evident upon visual inspection, what should be done to determine whether or not an actual fault exists. Several tests are available to check a transformer prior to reenergization. Turns ratio, resistance of the insulation, power factor of insulation, and low-voltage impulse tests are available.

It is a common practice to analyze the dissolved and emitted gases, where the facilities are available, before a transformer is tripped by its protection system. The practice is becoming increasingly popular and is found to be quite reliable when the tests are properly performed (IEEE PSRC Report, “Protection of Power Transformers” [B14] and Pugh and Wagner [B25]).

Normally, power transformers are not reenergized by automatic reclosing schemes except where the transformer may be connected to a line or bus that may be reenergized following a relay trip by the line or bus protective relays. The transformer protective relays usually operate a lockout relay that trips the local interrupting devices (power circuit breaker, circuit switcher, or disconnect switch) and prevents the devices from closing. Where a local interrupting device is not present, transfer trip may be used to operate a remote interrupting device. The transfer trip may also be used to lock out the remote interrupting device, thus preventing reenergizing the transformer. If an automatic grounding switch is used on the high side of a transformer and high-speed reclosing is used on the line, the transformer will probably be reenergized before a high-side MOD can open. However, if delayed reclosing is used on the line, the MOD will have time to open and the transformer will not be reenergized. Usually, high-speed reclosing would not be used on lines with automatic grounding switches.

If a transformer tapped on a line is fused on the high side, there is no way to prevent its reenergization if the line relays detect the fault and trip, unless all three fuses blow.

In recent years, operating companies seem to have an increasing reluctance to reenergize transformers following a protective relay operation where the transformer might be subjected to a second fault. This reluctance is partly due to recent transformer failure rates and partly due to increased cost and time to repair internal failures. Also, operating companies may be gaining more confidence in protective relays, particularly pressure relays.

Differential-zone protection devices can determine whether the fault is in the transformer zone or externally in the bus and breaker zone. When external faults are identified, operating companies may choose to automatically reenergize the transformer based upon fault history (temporary faults versus permanent faults) and experience, or to pick up the load from the adjacent transformer when available. Various control checks must be verified in the protection and control scheme in order to process successfully any automatic reclosing.

13. Gas analysis

Dissolved-gas analysis (DGA) is an analytical tool for determining the operating condition of insulating fluid-immersed transformers. This analysis is not an exact science but rather an approximation based on prior transformer operating history and field experience. The degradation of liquid and solid insulating materials due to thermal or electrical disturbances cause gas formation in the insulating fluid. The type and quantity of a gas detected can be used to determine if a fault exists inside of a transformer as well as the extent or severity of the problem. For an in-depth discussion, refer to IEEE Std C57.104-1991, IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers.

Analysis of the type and concentration of the gases can indicate the type of fault and magnitude of the problem. The gases involved are called key gases and consist of hydrogen, acetylene, methane, ethylene, ethane, carbon monoxide, and carbon dioxide. Based on laboratory studies and empirical evidence, predominant patterns of gases are likely to be as given in Table 3.

The gases listed in Table 3 are typically grouped together, except for carbon dioxide, and are identified as total dissolved combustible gas (TDCG). IEEE Std C57.104-1991, IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers, provides recommended levels for determining what course of action should be taken depending on the values of the key gases and the TDCG.

Gas analysis on transformers should be made periodically by manual or automatic methods. Fixed continuous monitoring instruments are available, which monitor specific gases or the total combustible dissolved gases in the oil. The instruments can be set to alarm when gas levels exceed a setpoint, or for critical transformers trip the unit offline. Monitoring should begin when a new transformer is placed in service and at regular intervals to gain baseline data. The interval between tests may be varied according to the size, importance and loading of the transformer, and its exposure to faults. Analysis should be performed following protective relay or sudden-pressure relay operations before reenergizing the transformer.

Table 3—Predominant gases emitted for different conditions

Condition	Predominant gases in typical order by decreasing concentration (the concentrations of gases may vary with the level of the energy in the arc)
Partial discharge	Hydrogen, methane, ethane, when more severe small amount of acetylene may be present
Overheating of oil	Methane, ethane, ethylene, depends on temperature that predominates. If very high temperature overheating of oil occurs acetylene might be present in trace to significant amounts.
Arcing	Hydrogen, acetylene; ethylene and methane, can be in similar concentration as acetylene
Overheating cellulosic materials (paper, pressboard, wood)	Carbon monoxide and carbon dioxide

One approach is to monitor the level of TDCG in the gas space in sealed transformers and sound an alarm when the level exceeds a predetermined level. Another approach, which is used in cases where the sample of the gas and/or oil can be taken, consists of analyzing the samples in a laboratory and determining the amount of different gases. Two approaches are proposed in IEEE Std C57.104-1991, IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers, for the basis on which action may be taken to either keep the transformer in service or take it out of service.

13.1 Level of TDCG and rate of change of TDCG approach

An important criterion is to consider the amount of TDCG and the rate of change of TDCG per day in successive tests taken at regular intervals. Based on the observations, different courses of action are recommended. The following five procedures are defined in IEEE Std C57.104-1991, IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers.

a) Procedure A considers that the level of TDCG is checked at one-week intervals and the rate of change per day is calculated. In case the rate remains the same or decreases, TDCG should be checked at one-month intervals. If the TDCG continues to remain unchanged or decreases, the tests may be conducted on a bimonthly basis. If no TDCG is detected, the interval between tests may be increased to four to six months.

b) Procedure B considers that the level of TDCG is checked at three-day intervals and the rate of change per day is calculated. In case the rate remains the same or decreases, TDCG may be checked at one-month intervals.

c) Procedure C consists of checking the level and rate of change of TDCG every day. If these levels exceed specified thresholds, the transformer should be checked for audible partial discharge and overloading. In case the levels of TDCG and its rate of change reduce, testing may revert to Procedure B and then to Procedure A.

d) Procedure D consists of taking a gas sample for analysis.

e) Procedure E consists of taking an oil sample for analysis.

The use of these procedures and the levels of TDCG and its rate of change recommended in IEEE Std C57.104-1991, IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers, are listed in Table 4.

Table 4—Actions based on levels of TDCG and its rate of change

TDCG rate increase (percent per day)	TDCG level present			
	≤ 0.49	0.5 to 2.0	2.1 to 5.0	> 5.0
Less than 0.01	Procedure A	Procedure B	Caution Procedures C, D, and E	Extreme caution Plan outage Procedures C, D, and E
0.01 to 0.03	Procedure B	Caution Procedure C	Extreme caution Plan outage Procedures C, D, and E	Reduce load Plan outage
More than 0.03	Caution Procedures C, D, and E	Extreme caution Procedures C, D, and E	Extreme caution Reduce load Plan outage Procedures C, D, and E	Extreme caution Hazardous to continuous operation

13.2 Ratio of gases approach

Another approach to evaluate possible fault types is by taking ratios of the previously mentioned key combustible fault gases. Depending on the level of each key gas and the ratio of specific combinations of key fault gases, the type of fault can be determined. The ratios are designated as Doernenburg and Rogers ratios. (Refer to IEEE Std C57.104-1991, IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers, for further information.) Doernenburg ratios and Rogers ratios are defined in Table 6.

Table 5—Categories associated with operating conditions

Condition 1	TDCG levels are normal indicate the transformer is operating properly. Any individual combustible gas exceeding specified levels should prompt additional investigation.
Condition 2	TDCG levels within this range indicate greater than normal combustible gas level. Exercise caution, analyze monthly.
Condition 3	TDCG levels within this range indicate a high level of decomposition. Exercise caution, analyze weekly, consider planned outage, notify manufacturer.
Condition 4	TDCG levels within this range indicate excessive decomposition. Continued operation could result in transformer failure. Analyze daily, consider removal from service, notify manufacturer.

Table 6—Definitions of Doernenburg ratios and Rogers ratios

Doernenburg ratio	Definition	Rogers ratio	Definition
DR-1	CH_4/H_2	RR-1	CH_4/H_2
DR-2	C_2H_2/C_2H_4	RR-2	C_2H_2/C_2H_4
DR-3	C_2H_2/CH_4	RR-3	C_2H_4/ C_2H_6
DR-4	C_2H_6/C_2H_2		

CAUTION

IEEE Std C57.104-1991, IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers, is being revised. Information given in this clause is likely to be superseded in the revised guide. Before using the information in this clause, refer to the revised guide if it has been published.

14. Special protective schemes

Many transformer protection problems can be solved by means of special CT connections. The applications presented are in industry use but are not readily found in the published literature.

14.1 Overall unit generator differential

14.1.1 Configuration

This consists of a unit generator and a transformer with the winding of the generator in wye, high-impedance grounded through a transformer with secondary resistor. The unit transformer low-side winding is in delta with the high-side winding in a solidly grounded wye.

14.1.2 Problem

Overall unit differential relay operation on sudden unloading of a machine is to be avoided. False tripping and indicating of unit trouble can cause operating confusion and delay restoration.

A sudden unit unloading during a fault may be caused by the clearing of a system fault and, hence, the machine may be at ceiling of the excitation system if the fault has persisted for a second or more. The unit transformer may be excited with voltages exceeding 130% of normal. Because of transformer iron saturation with overexcitation, the exciting current can exceed 25% of the unit current rating. Hence, for relays without overexcitation restraint capability, normal differential relay connections could result in relay operation under these conditions.

14.1.3 Solution

As the transformer magnetizing current has appreciable harmonic content during overvoltage conditions, this current is used for additional restraint. Thus, the normal differential CT connections are altered as shown in Figure 32. (This discussion assumes that electromechanical relays are used. If numerical relays are used, all CTs are wye connected, but the connections shown in Figure 32 are emulated in the relay software.) The additional restraint is provided by CTs inside the delta winding of the transformer; these CTs have the same ratio as the ratio of the CT provided on the generator. The paralleling of the CTs provided on the delta winding of the transformer eliminates normal load current. Only zero-sequence current, third harmonic, and odd multiples of the third harmonic are supplied to the primaries of the three auxiliary CTs connected in series. The output of the auxiliary CTs is connected in wye and the output of each auxiliary CT is supplies to a differential relay restraint element.

Normally, a differential relay with three restraint elements is used for the overall unit. The three restraint elements are supplied current from CTs installed at the generator, transformer high side, and station service transformers. To provide separate relay restraint from the CTs inside the delta winding of the transformers, CTs provided on the station service transformer are connected in parallel with the generator CTs.

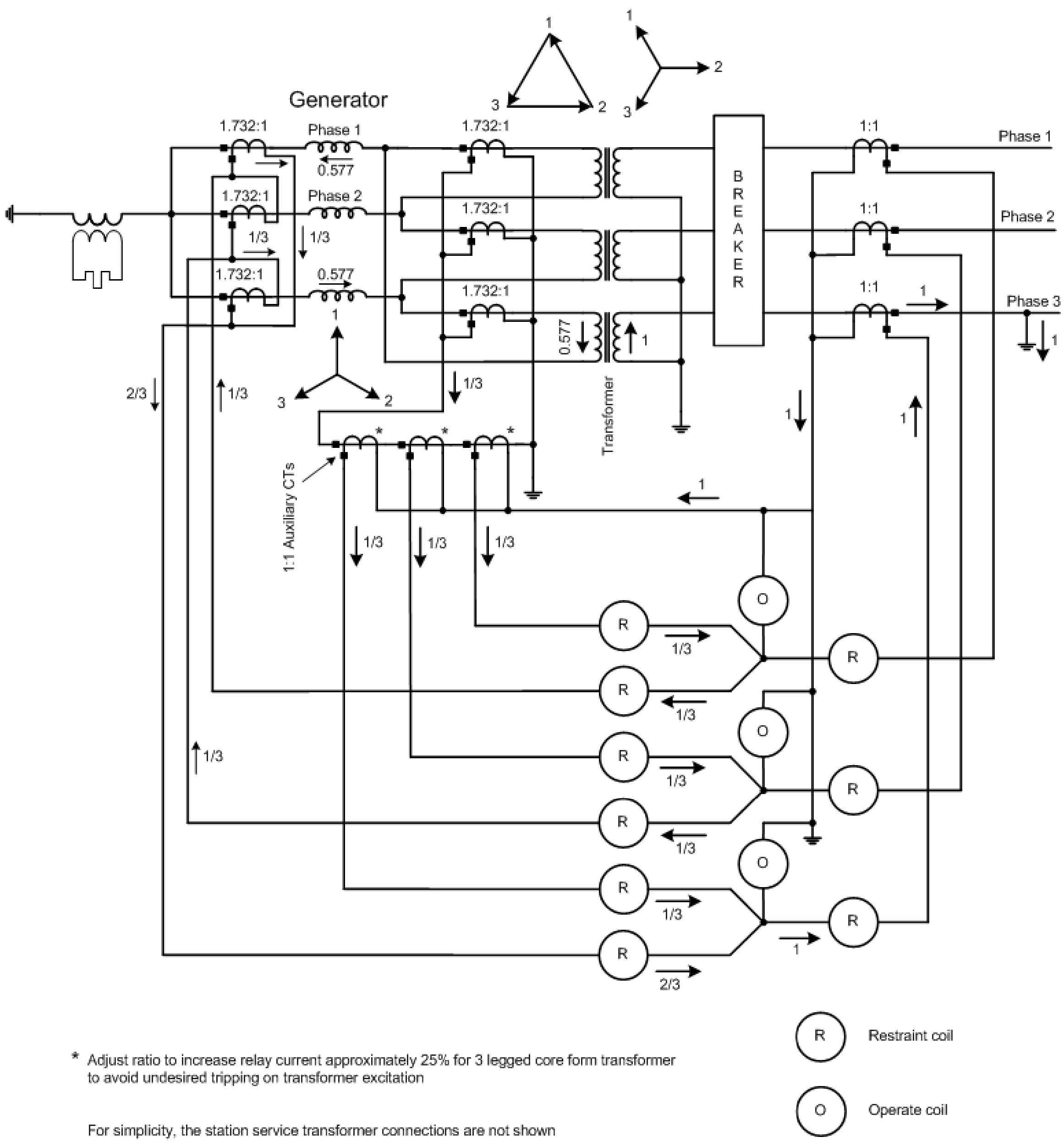


Figure 32—Special differential relay connections for overall protection of unit generator

Normally, the CTs on the delta-connected winding side are connected in wye and the CTs on the grounded wye-connected winding are connected in delta. The delta-connected CTs act as zero-sequence filters. Because zero-sequence current is inserted by the low-side connections, it should be introduced from the high-side connections as well. This is done by connecting the high-side CTs in wye. Then, for proper phasing relationship, the low-side CTs are connected in delta. Considering only the generator CTs are connected in delta and the transformer high-side CTs are connected in wye, an analysis reveals that this connection is proper for load and external phase faults but not for external ground faults. The CTs provided inside the transformer delta winding provide the balance for external ground faults.

Thus, on overexcitation of an unloaded transformer, additional harmonic restraining current is provided to prevent incorrect operation of the relays. The CT connections to the harmonic restraining differential relays are usually tested to 135% of normal voltage. The transformer of 150 MVA, 17/132 kV rating could have exciting current of 25 A at normal voltage. With 135% of normal voltage applied, the exciting current could be 600 A or as high as 1200 A. The saturation characteristic of each transformer determines the magnitude of exciting current at ceiling generator voltages. Several installations have performed correctly following the clearing of high-voltage bus faults.

Figure 32 also shows the proper balance for an external ground fault. The main transformer is given as 1:1 overall voltage ratio and the CT ratios are shown for this condition. The fault current is assumed as one p.u. Phasors for the CT connections are also shown in Figure 32.

CAUTION

This modification must be used with caution since transformers have been severely damaged by high temperatures from excessive magnetizing current. When this scheme is used, overexcitation relaying should be considered.

14.2 Unit transformer of three-legged core form type

If the core of the unit transformer is constructed with three legs, the zero-sequence current contribution of the transformer case is not accounted for by the connections shown in Figure 32. In such a situation, the case may contribute as much as 20% to 25% of the zero-sequence current. Thus, the previously described differential connections require modification. While exact solutions are possible with additional auxiliary CTs, these are not discussed. A simple empirical solution is to adjust the ratio of the CTs provided on the delta winding of the transformer so that the current to the relay is increased by 25%. The ratio of the auxiliary CTs can be determined more accurately from the zero-sequence impedance test data of the transformer obtained from the manufacturer of the transformer.

14.3 Grounding transformer inside the main transformer differential zone

14.3.1 Configuration

To establish a grounded system, a grounding transformer is frequently installed on the low-side leads of the supply transformer and is thereby included in the transformer differential zone.

14.3.2 Problem

Zero-sequence current supplied by the grounding transformer may cause differential relay operation during an external ground fault.

14.3.3 Solution

Since external ground faults cause zero-sequence current to flow in the CT secondary circuits, a zero-sequence filter is provided as shown in Figure 33 when electromagnetic and solid-state relays are used. This filter is composed of three auxiliary CTs. One possible approach is to connect the primary windings of the auxiliary CTs wye and the secondary in delta. The ratio of the auxiliary CTs is not critical, but a 5/5 A ratio is suggested. When a numerical relay is used, auxiliary CTs are not needed because the filtering is done by calculating the zero-sequence current and subtracting it from the phase currents.

The alternate filter connection is also shown in Figure 33. This requires 1:3 ratio auxiliary CTs. The primary windings of the auxiliary CTs are connected in wye and the secondary windings are connected in series. Thus, the secondary windings of the auxiliary CTs carry three times the current in the primary windings.

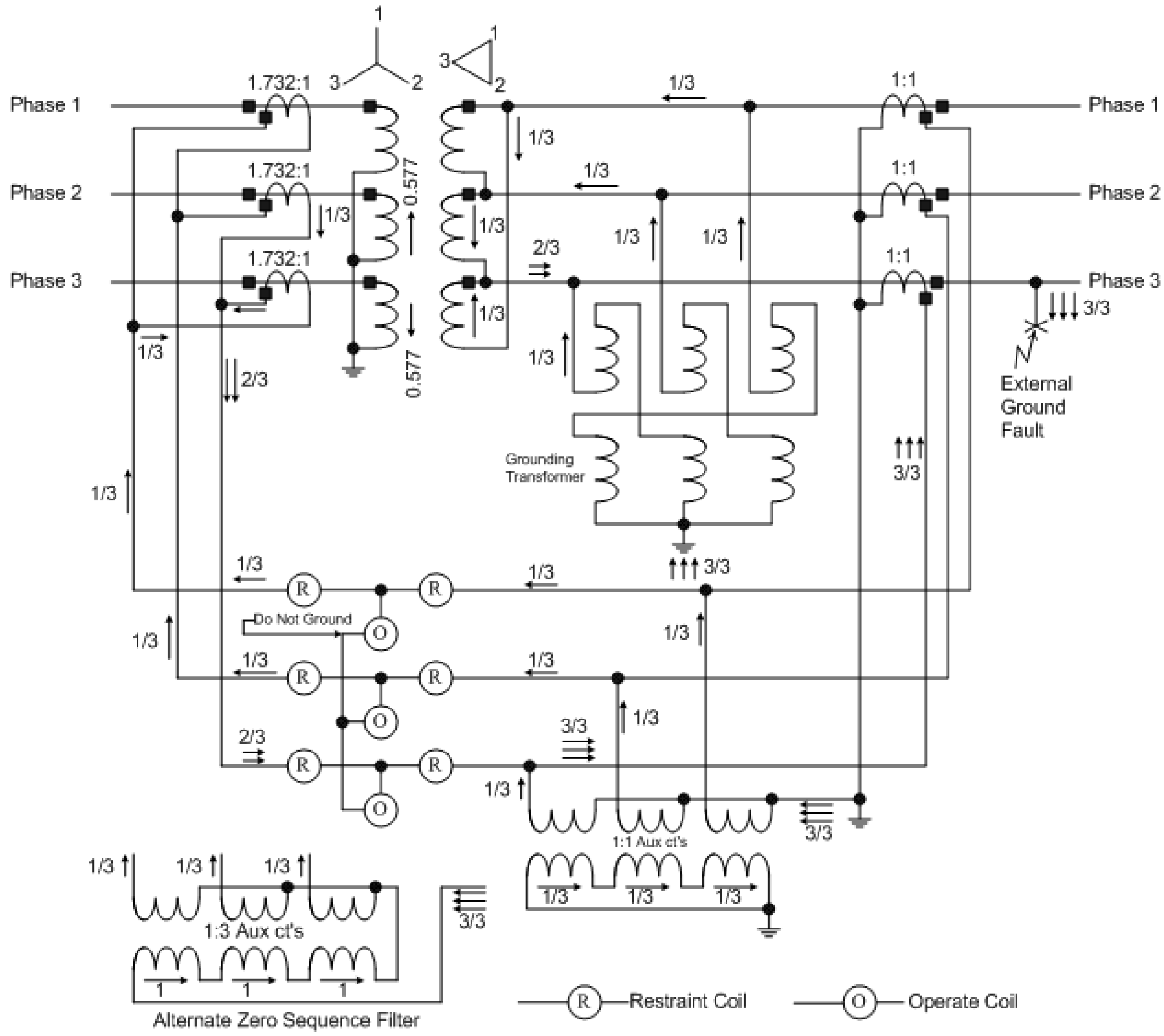


Figure 33—Grounding transformer in differential zone (external fault condition shown)

Both of these connections present relatively high magnetizing impedance to all but zero-sequence currents. However, modern differential relays are of even lower burden than the usual auxiliary CTs. Thus, the common point of the relay connections should not be connected to the common point of the wye-connected transformers (a connection that is necessary without a zero-sequence filter). Only the filter neutral should be connected to the CT common point.

The primary current and CT secondary current for an external ground fault are also shown in Figure 33. It is assumed that the overall transformation ratio is 1:1 and the fault current is one p.u. The zero-sequence filter used in this arrangement prevents relay imbalance.

14.4 Unbalanced voltage protection for wye-connected, three-legged, core-type transformers

14.4.1 Configuration

Three-phase, three-legged, core-type wye-wye connected transformer or autotransformer is considered in this case.

14.4.2 Problem

When unbalanced voltages are experienced by a wye-connected core-type transformer, the flux in each core is not of the same magnitude. The zero-sequence component of the flux finds a path from the core to the transformer tank and back. This induces currents in the transformer tank. Excessive heat can be produced by sustained flow of these circulating currents in the tank.

14.4.3 Solution

An overcurrent relay is energized by CTs connected to duplicate the effective tertiary current in this case. For a two-winding transformer, the required zero-sequence current is obtained by connecting the CTs provided on the high- and low-side grounding connections as shown in part (a) of Figure 34. An alternate method is shown in part (b) of Figure 34 wherein the sum of the residuals of wye-connected CTs provided on the high and low sides of the transformer is used. Part (c) of Figure 34 shows the connections for an autotransformer using the residual of wye-connected CTs and a neutral CT.

14.4.4 Relay setting

The proper equivalent tertiary impedance of the case should be used to determine the zero-sequence current for various faults. From this, the required relay sensitivity is established. A long time dial setting for overcurrent relay operation will provide thermal protection and coordination with other relaying for external faults.

An application may use an inverse relay whose pickup is set at 30% of transformer rating and the time is set at 1.7 s at 300% of the current setting. The pickup depends on the effective contribution of the equivalent tertiary of the case. The transformer manufacturer should be consulted.

14.4.5 Alternative solution

An alternative approach for currents flowing in the transformer case is given in 10.2.3.

14.5 Differential protection of single-phase transformers connected in three-phase banks

When single-phase transformers are connected in three-phase banks, care should be taken to ensure that a differential relay will operate for all internal transformer faults, particularly when the transformer has a delta-connected winding. If CTs for the delta tertiary are located in a breaker, the differential may be connected as it normally is for a three-phase transformer. But if the CTs should be located in the transformer, some special connections should be considered.

Complete protection for internal faults requires CTs on both bushings of a winding if that winding is in a three-phase delta connection. Without CTs on both bushings, an internal bushing flashover can go undetected by a differential relay if the connected system is grounded.

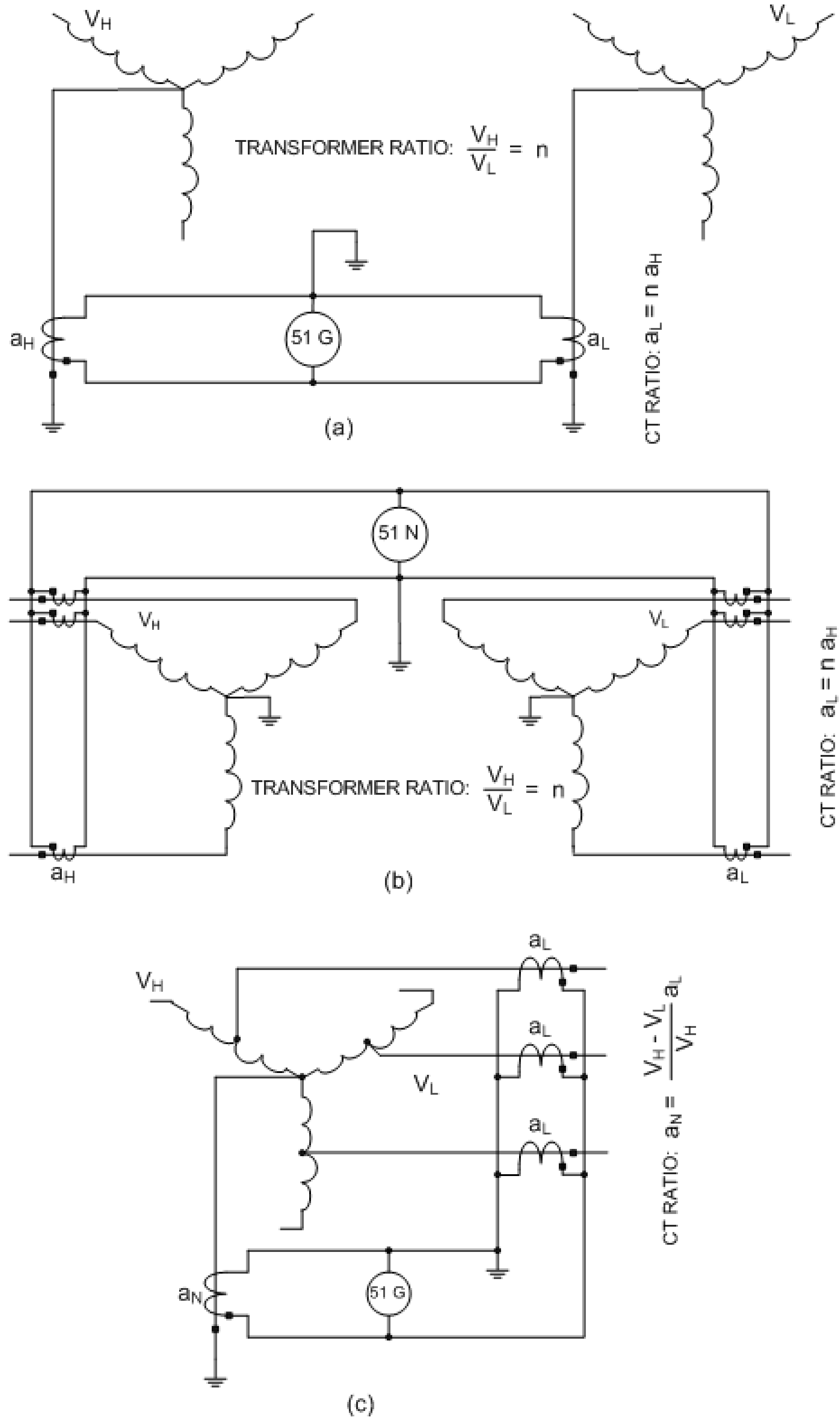


Figure 34—Protection of wye-wye connected core-type transformers with no delta for unbalanced voltage condition

14.6 Differential protection of a bank of three single-phase autotransformers with delta tertiary

Figure 35 and Figure 36 show two differential relay connections that provide complete winding protection for the delta winding on a bank of single-phase autotransformers equipped with one delta-tertiary winding in each transformer. Note that the CT ratios and taps used should take into account that the CTs in the delta winding supply the relay with two times winding current.

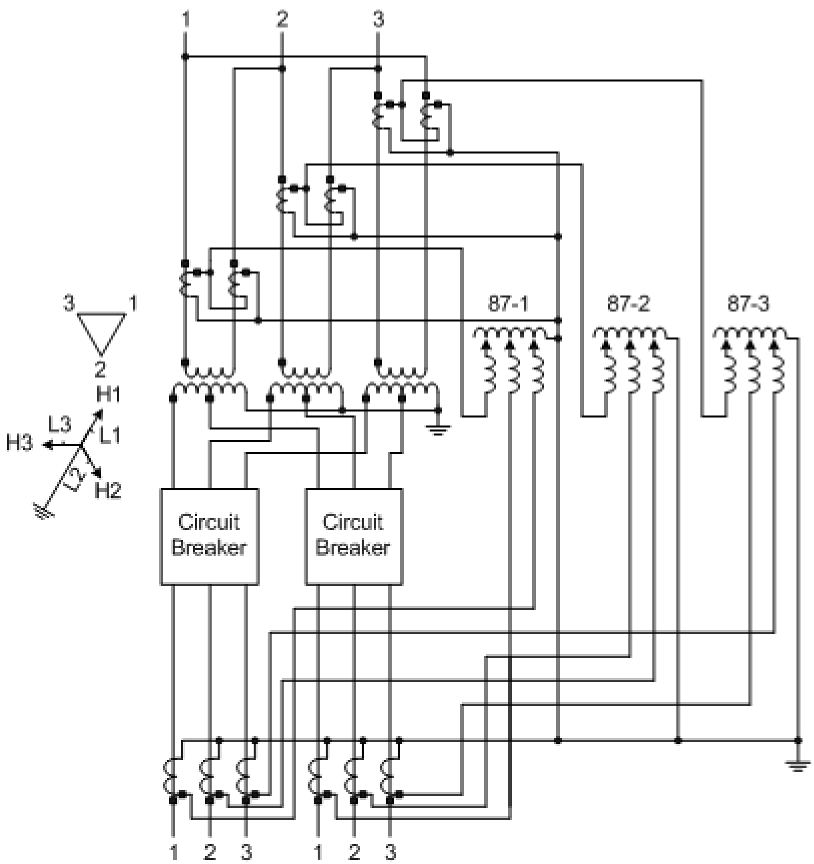


Figure 35—Differential protection of a bank of three single-phase autotransformers with a delta tertiary with two CTs on each phase of tertiary

There are advantages for both connections. The connection shown in Figure 35 provides greater relay sensitivity because of the method of connecting the CTs in the delta-connected tertiary windings. Additionally, third-harmonic currents flowing in the delta-connected windings flow in the differential relay restraint circuit. The connection shown in Figure 36 permits more than one relay to detect an internal fault. Also, note that the high-side CTs shown in Figure 35 should not be used without the CTs in the tertiary windings. If the high- and low-side CTs are connected in wye, the differential could operate for an external ground fault if the CTs are not provided on the tertiary windings to balance the currents.

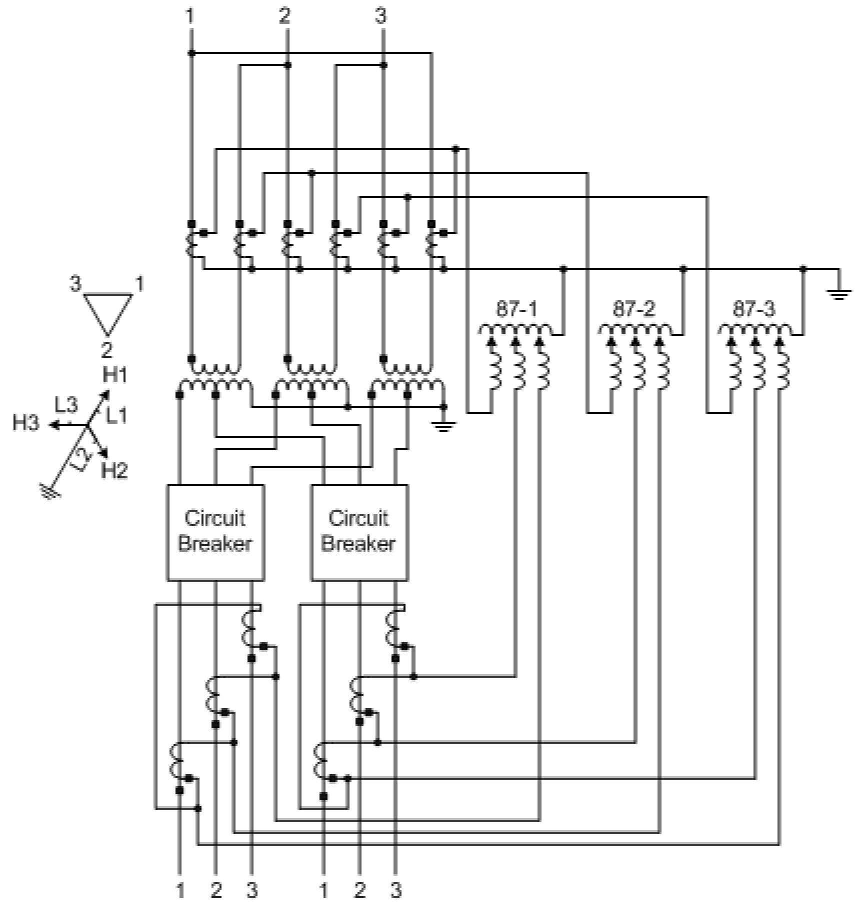


Figure 36—Alternate differential protection of a bank of three single-phase autotransformers with a delta tertiary

14.7 Differential protection of single-phase transformers in a three-phase bank with a spare transformer

With the increase in usage of single-phase transformers in three-phase banks with spare transformers, the question frequently arises of how to best include the spare in a transformer differential scheme. Differential relay connections are dependent to some extent on transformer connections, location of CTs, and whether or not the spare power transformer will be energized all the time.

If the differential zone extends to circuit breakers on both sides of a transformer, then changing the CT secondary circuits is not required to place the spare transformer in service. However, if the spare transformer is to remain energized all the time, consideration should be given on how to protect the spare when not in use. When the transformer bank differential is used to protect the spare transformer, the result is not always as sensitive to protection of the spare as of the transformers in service.

If bushing CTs are used on both sides of the transformer bank, a separate relay for the spare could be used to facilitate rapidly placing the spare transformer in service. This is true whether or not it will remain energized. It will provide an energized spare with adequate protection. To connect a differential relay for three-phase and single-phase transformers, see 14.5.

The most difficult situation to handle is that where CTs on one side of transformer bank are located in a circuit breaker and the other in the transformer. Unfortunately, this is a common occurrence. In this case, CT secondary circuits have to be switched or rewired to place the spare power transformer in service.

With any of the previously mentioned combinations of transformer connections, it is possible to switch or rewire the CT secondary circuits. However, switching CT secondary circuits is not recommended as a good practice without a thorough analysis of the switching device and the risks of an open CT connection during the switching, or the result of a defective switching contact.

15. Other considerations

There are several conditions that may occur on a power system that have the potential to adversely affect power transformer performance. These conditions are generally not considered during protection design but, in fact, have the capability to subject a transformer to atypical operating conditions, specifically excessive nonfundamental frequency currents (dc and quasi-dc).

The imposition of dc into a power transformer can occur from several sources including geomagnetic storms, cathodic protection systems, and dc-operated traction systems. If sufficient dc is present in the winding(s) of a power transformer, the core will saturate. The amount of dc required to saturate the core will vary with design but could be as low as 0.3 A in a winding or 0.9 A in the neutral of a three-phase transformer. Magnetizing current of a transformer in saturation will consist of a series of unidirectional current pulses that are a measure of the average value of applied dc. Documented cases show that transformer dc neutral currents due to geomagnetic storms have been in excess of 100 A and the dc measured in the neutral of a generator step-up transformer at a gas turbine plant due to cathodic protection has been as high as 37 A.

The effects of dc saturation on a power transformer are increased harmonic current flow in the transformer and power system, increased heating, increased sound level, increased var consumption, and mechanical vibration of the transformer. If the saturation is severe enough, there is potential for damage to the transformer due to additional heating of the windings, leads, structural components, and insulation deterioration due to the increased vibration. The flow of harmonic currents in the system may cause additional heating of rotors in nearby generators and motors, which could damage these devices or cause operation of negative-sequence protections. Saturation of the transformer core also causes an increase in var consumption by the transformer. This effect can have implications in terms of both operating conditions for possible voltage collapse and financial impact where vars are being traded as a commodity.

Solar activity can cause a circulating “electrojet” current to occur in the earth’s upper atmosphere. This circulating current then creates a varying magnetic field and subsequent electric field in the surface of the earth. Potential differences on the earth’s surface are conveniently shunted by transmission lines connected to earth via grounded transformer banks. During a geomagnetic storm, dc can enter or leave a transformer neutral and cause harmonics to be generated by the transformer. More details are given in the IEEE PSRC Report, “The Effects of Solar Magnetic Disturbances on Protective Relaying” [B13].

The presence of dc in transformer neutrals generated by GICs has caused dramatic effects on the power system in the recent past including a large-scale blackout and physical damage to transformers. If the level of the harmonics generated by the GIC is sufficiently high, it is conceivable that a transformer differential protection may become inactive due to harmonic restraint. The implication of this is that the differential protection may not operate during periods of high geomagnetic activity.

Due to increased awareness of the presence of dc in the power transformer and suspicion of failures being initiated by the presence of these currents, it may be a valuable exercise to monitor and alarm for excessive levels. Transformers supplying static loads, such as adjustable speed drives and inverter loads, can also be subjected to high-harmonic currents. These harmonic currents can limit the safe loading of a transformer to a level that is significantly less than the transformer rating. Under these conditions, the transformer should be derated as suggested in IEEE Std C57.110™, IEEE Recommended Practice for Establishing Transformer Capability When Supplying Nonsinusoidal Load Currents [B15], or as recommended by the manufacturer.

Annex A

(informative)

Application of the transformer through-fault-current duration guide to the protection of power transformers

Overcurrent protective devices, such as relays and fuses, have well-defined operating characteristics that relate fault-current magnitudes to operating time. It is desirable that the characteristic curves for these devices be coordinated with comparable curves, applicable to transformers (see IEEE Std C57.109, IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration), which reflects their through-fault withstand capability. Such curves for Category I, II, III, and IV transformers (as described in IEEE Std C57.12.00, IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers) are presented in IEEE Std C57.109, IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration, and are reproduced in this annex as through-fault protection current duration curves. These curves apply to transformers designed according to IEEE Std C57.12.00-2000, IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers. Based on the historical evolution of short-circuit withstand requirements, these curves should be applicable to transformers built later than early 1970s. However, as a precaution, it is recommended that the manufacturer be consulted for confirmation of this, especially for transformers built during the early 1970s. For transformers built prior to the 1970s, the manufacturer should be consulted for short-circuit withstand capabilities. It should also be noted that the coordination curves show currents that are in a specific winding of a transformer. The overcurrent protection for that winding may be applied on a leg of the transformer that may see a different magnitude of current. For example, line current may differ from winding current depending on the connections of the windings of the transformer and the type of fault experienced. The operating characteristic of the protecting device should be adjusted so that the detecting device will operate at or less than the suggested levels of current in each transformer winding. Also, additional margin should be allowed if automatic circuit reclosing is employed without allowing the transformer to cool to normal operating temperature between reclosing shots; for example, the total combined fault-current duration of all shots of a reclosing sequence should not exceed the fault-current duration of a single fault as shown in the curves.

It is widely recognized that damage to transformers from through-faults is the result of thermal and mechanical effects. The mechanical effects have gained increased recognition as a major concern of transformer failures. Though the temperature rise associated with high-magnitude through-faults is typically quite acceptable, the mechanical effects are intolerable if such faults are permitted to occur with any regularity because of the cumulative nature of some of the mechanical effects, particularly insulation compression, insulation wear, and friction-induced displacement. The damage that occurs as a result of these cumulative effects is a function of the magnitude and duration of through-faults as well as the total number of such faults.

The through-fault protection curves, presented in this annex, take into consideration that the transformer damage is cumulative, and the number of through-faults to which a transformer can be exposed is inherently different for different transformer applications. For example, transformers with secondary-side conductors enclosed in conduit or isolated in some other fashion, such as those typically found in industrial, commercial, and institutional power systems, experience an extremely low incidence of through-faults. In contrast, transformers with overhead lines connected to the secondary windings, such as those found in utility distribution substations, have a relatively high incidence of through-faults, and the use of reclosers or automatic reclosing circuit breakers may subject the transformer to repeated current surges from the fault. For a transformer in these two different applications, a different through-fault protection curve should apply; the protection curve would depend on the type of the application. For applications in which faults occur infrequently, the through-fault protection curve should reflect primarily the thermal damage considerations because cumulative mechanical damage effects of through-faults will not be a problem. For applications in which faults occur frequently, the through-fault protection curve should reflect the fact that the transformer will be subjected to thermal and cumulative mechanical damage effects of through-faults.

In using the through-fault protection curves to select the time-current characteristics of protective devices, a protection engineer should take into account not only the inherent level of through-fault incidence but also the location of each protective device and its role in providing transformer protection. The secondary-side feeder protective equipment is the first line of defense against through-faults experienced by power transformers and its time-current characteristics should be selected by reference to the frequent-fault-incidence protection curve. More specifically, the time-current characteristics of feeder protective devices should be below and to the left of the appropriate frequent-fault-incidence protection curve. Main secondary-side protective devices (if applicable) and primary-side protective devices typically operate to protect for through-faults only in the rare event of a fault between the transformer and the feeder protective devices, or in the equally rare event that a feeder protective device fails to operate or operates too slowly due to an incorrect (higher) rating or setting. The time-current characteristics of these devices should be selected by reference to the infrequent-fault-incidence protection curve. In addition, these time-current characteristics should be selected to achieve the desired coordination among the various protective devices.

In contrast, transformers with protected secondary conductors (for example, cable, bus duct, or switchgear) experience an extremely low incidence of through-faults. Hence, the feeder protective devices may be selected by reference to the infrequent-fault-incidence protection curve. The main secondary-side protective device (if applicable) and the primary-side protective device should also be selected by reference to the infrequent-fault-incidence protection curve. Again, these time-current characteristics should also be selected to achieve the desired coordination among the various protective devices.

For Category I transformers (5 kVA to 500 kVA single-phase, 15 kVA to 500 kVA three-phase), a single through-fault protection curve applies. See Figure A.1. This curve may be used for selecting protective device time-current characteristics for all applications regardless of the anticipated level of fault incidence.

For Category II transformers (501 kVA to 1667 kVA single-phase, 501 kVA to 5000 kVA three-phase), two through-fault protection curves apply as is shown in Figure A.2.

a) The left-hand curve reflects both thermal and mechanical damage considerations and may be used for selecting time-current characteristics of feeder protective device for frequent-fault-incidence applications (for example, faults occurring more than 10 times during the service life of the transformer.) There are different curves for different transformer impedances. The curves are derived considering that the fault currents are from 50% to 100% of the maximum possible fault current and reflect $I^2t = K$; K is 2 s for the worst-case mechanical duty.

b) The right-hand curve reflects primarily thermal damage considerations and may be used for selecting feeder protective device time-current characteristics for infrequent-fault-incidence applications. This curve may also be used for selecting the main secondary-side protective device (if applicable) and a primary-side protective device time-current characteristic for all applications regardless of the anticipated level of fault incidence.

For Category III transformers (1668 kVA to 10 000 kVA single-phase, 5001 kVA to 30 000 kVA three-phase), two through-fault protection curves apply. See Figure A.3.

1) The left-hand curve reflects both thermal and mechanical damage considerations and may be used for selecting feeder protective device time-current characteristics for frequent-fault-incidence applications (for example, faults occurring more than 5 times during the service life of the transformer.) There are different curves for different transformer impedances. The curves are derived considering that the fault currents are from 50% to 100% of the maximum possible fault current and reflect $I^2t = K$; K is 2 s for the worst-case mechanical duty.

2) The right-hand curve reflects primarily thermal damage considerations and may be used for selecting feeder protective device time-current characteristics for infrequent-fault-incidence applications. This curve may also be used for selecting main secondary-side protective device (if applicable) and primary-side protective device time-current characteristics for all applications regardless of the anticipated level of fault incidence.

For Category IV transformers (above 10 000 kVA single-phase, and above 30 000 kVA three-phase), a single through-fault protection curve applies as is shown in Figure A.4. This curve reflects both thermal and mechanical damage considerations and is to be used for selecting protective device time-current characteristics for all applications regardless of the anticipated level of fault incidence. There are different curves for different transformer impedances. The curves are derived considering that the fault currents are from 50% to 100% of the maximum possible fault current and reflect $I^2t = K$; K is 2 s for the worst-case mechanical duty.

The delineation of infrequent- versus frequent-fault-incidence applications for Category II and III transformers can be related to the zone or location of the fault as is shown in Figure A.5. For convenience, the through-fault protection curves for Category I, II, III, and IV transformers are summarized in Table A.1.

Fuse or overcurrent relay coordination with the through-fault protection curves, or both, are shown in Figure A.6, Figure A.7, and Figure A.8.

A coordination issue when delta-wye transformers are to be protected is worth considering here. (The primary winding is connected in delta and the secondary winding is connected in wye.) Assume that the transformation ratio is 1:1. On the secondary side, the current in each phase winding is the same as the current in the outgoing line. When a three-phase fault occurs, the line currents on the primary side are 1.73 times the currents in the primary winding.

When a single-phase-to-ground fault occurs on the secondary side of the transformer, the line currents on the primary side are 0.577 times the line current on the primary side. The operating characteristic of the primary-side fuse or relay should be shifted to the right on the coordination plots.

When a two-phase fault occurs on the secondary side of the transformer, the current in the faulted phases is 86.6% of the three-phase fault current on the secondary side. On the primary side, current will be 100% of the three-phase fault current in one phase and 50% of the three-phase fault current in the other two phases. The applicable primary-side curves should be shifted to the left on the phase-to-phase fault coordination plots.

An example of the application of the new thermal/mechanical limit curves to a three-winding autotransformer (wye-wye-delta) with overcurrent relays on the 30 MVA tertiary follows using Table A.2 nameplate data.

The coordination steps are as follows:

i) Select the category from the minimum nameplate rating of the principal winding (75 000 kVA is Category IV).

ii) Select the impedance to use so as to plot the Category IV curves (Z for 132/13.2 kV = 7.94% at 30 000 kVA).

iii) Calculate “constant” $K = \left[\begin{array}{c} I^2t = \left(\dfrac{100}{7.94}\right)^2 \times 2 \\ = 317.24 \end{array}\right]$ at 2 s.

iv) Times normal base current at 2 s >> 12.59.

v) The 50% point is $\left[\dfrac{317.24}{(12.59 \div 2)^2}\right] >> 8\text{ s}$.

The coordination of the overcurrent relays for this example is shown in Figure A.9.

Table A.1—Summary of through-fault protection curves; minimum nameplate (kVA) of principal winding

Category	Single phase (kVA)	Three phase (kVA)	Through-fault protection curve[a]
I	5 to 500	15 to 500	Figure A.1
II	501 to 1 667	501 to 5 000	Figure A.2
III	1 668 to 10 000	5 001 to 30 000	Figure A.3
IV	≥ 10 000	≥ 30 000	Figure A.4

[a] The times normal base current scale in Figure A.1, Figure A.2, Figure A.3, and Figure A.4 relates to minimum nameplate kVA. Low values of 3.5 or less times normal base current may result from overloads rather than faults, and for such cases, loading guides may indicate allowable time durations different from those given in Figure A.1, Figure A.2, Figure A.3, and Figure A.4. (For more details, see IEEE Std C57.91-1995, IEEE Guide for Loading Mineral-Oil-Immersed Transformers.)

Table A.2—An application example of the thermal mechanical limit curves for a three-winding transformer

60 Hz, Class ONAN/ONAF/OFAF, three-phase voltage rating: 132 000 GR wye/76 200 to 66 000 GR wye/38 100 to 13 200			
H winding (MVA)	**X winding (MVA)**	**Y winding (MVA)**	**Type of cooling**
75 (output)	60	30	Continuous 55 ºC rise, self-cooled
100 (output)	80	40	Continuous 55 ºC rise, forced-air
125 (output)	100	50	Continuous 55 ºC rise, forced-oil and forced-air
140 (output)	112	56	Continuous 65 ºC rise, forced-oil and forced-air

— Impedance volts 5.00% 132 000 GR wye to 66 000GR wye V at 60 MVA

— Impedance volts 7.94% 132 000 GR wye to 13 200 V at 30 MVA

— Impedance volts 11.43% 66 000 GR wye to 13 200 V at 30 MVA

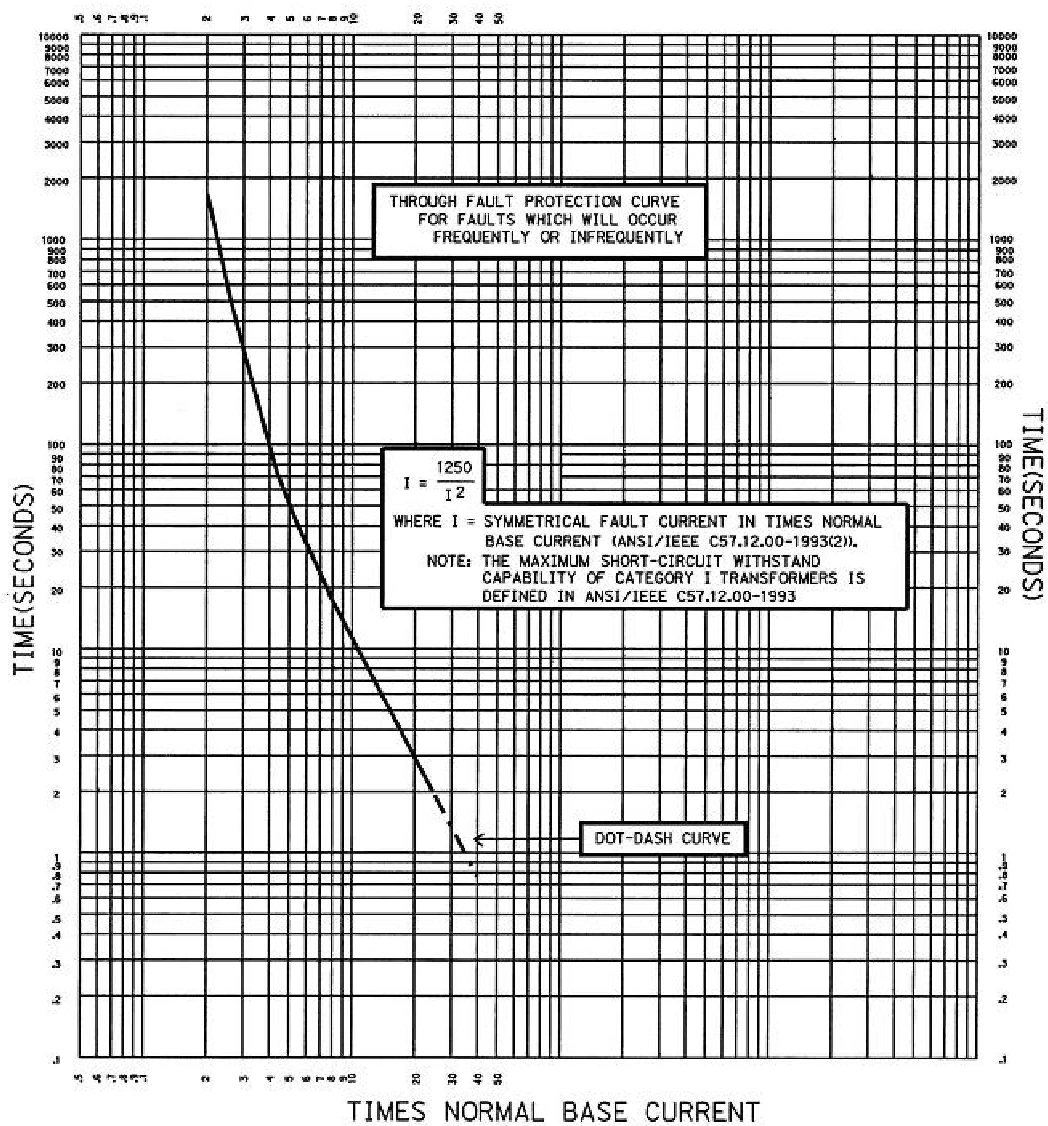


Figure A.1—Category I transformers: 5 kVA to 500 kVA single-phase; 15 kVA to 500 kVA three-phase

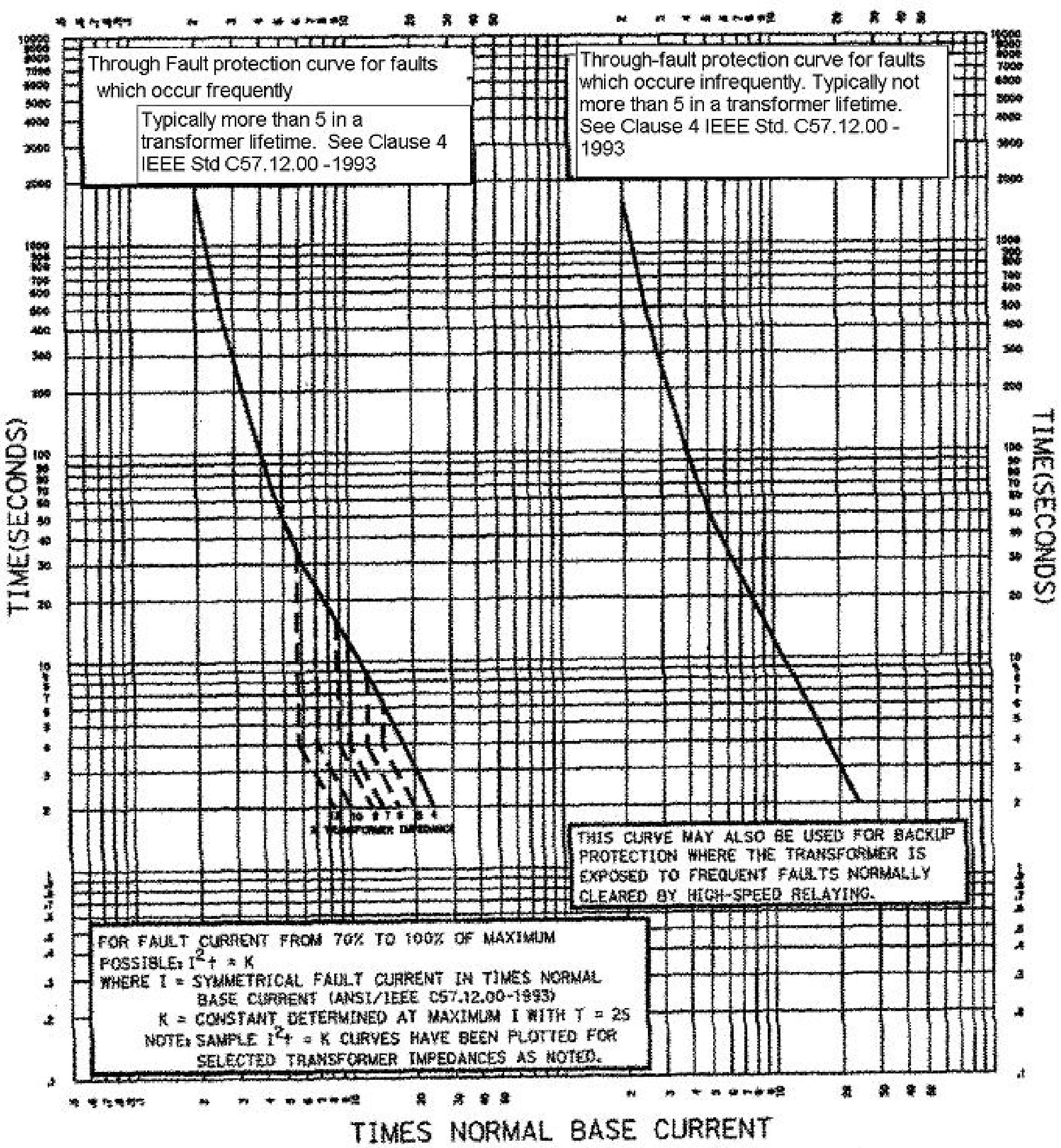


Figure A.2—Category II transformers: 501 kVA to 1667 kVA single-phase; 501 kVA to 5000 kVA three-phase

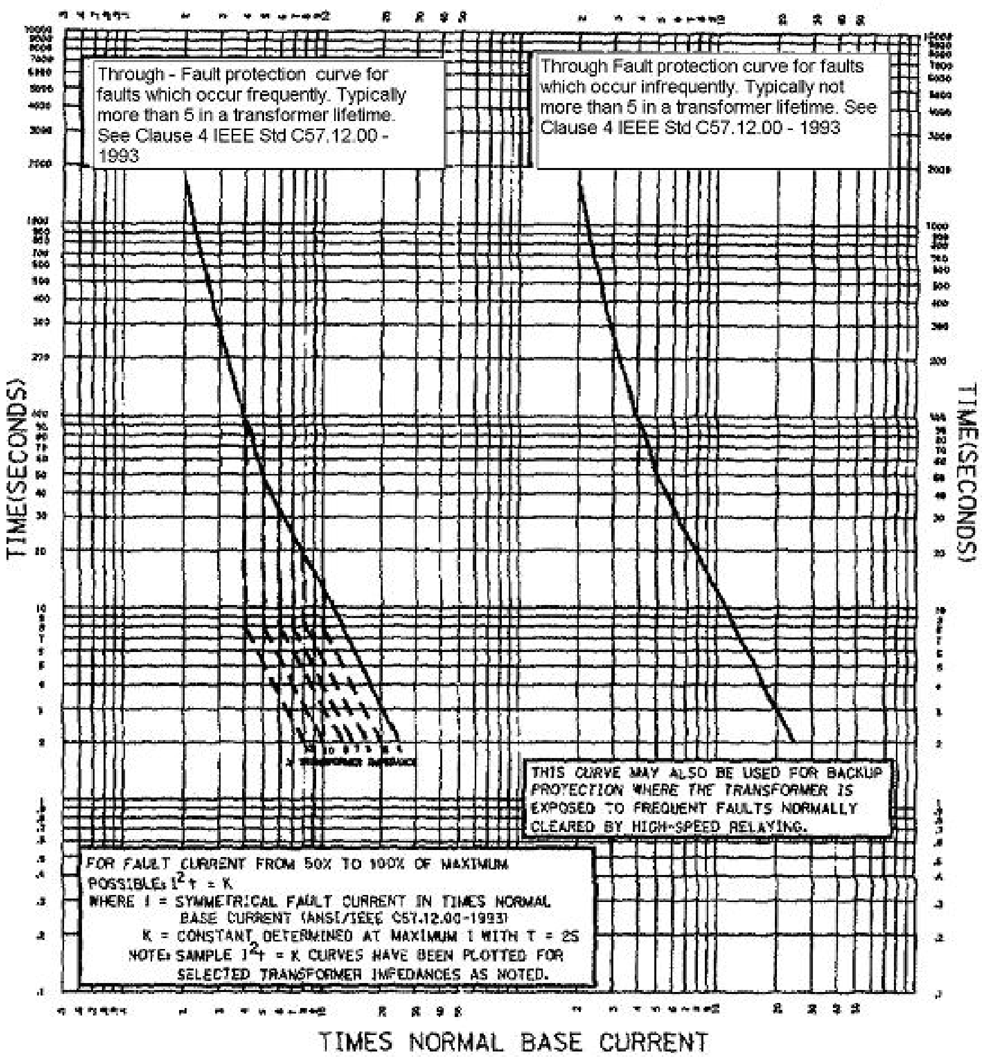


Figure A.3—Category III transformers: 1668 kVA to 10 000 kVA single-phase; 5001 kVA to 30 000 kVA three-phase

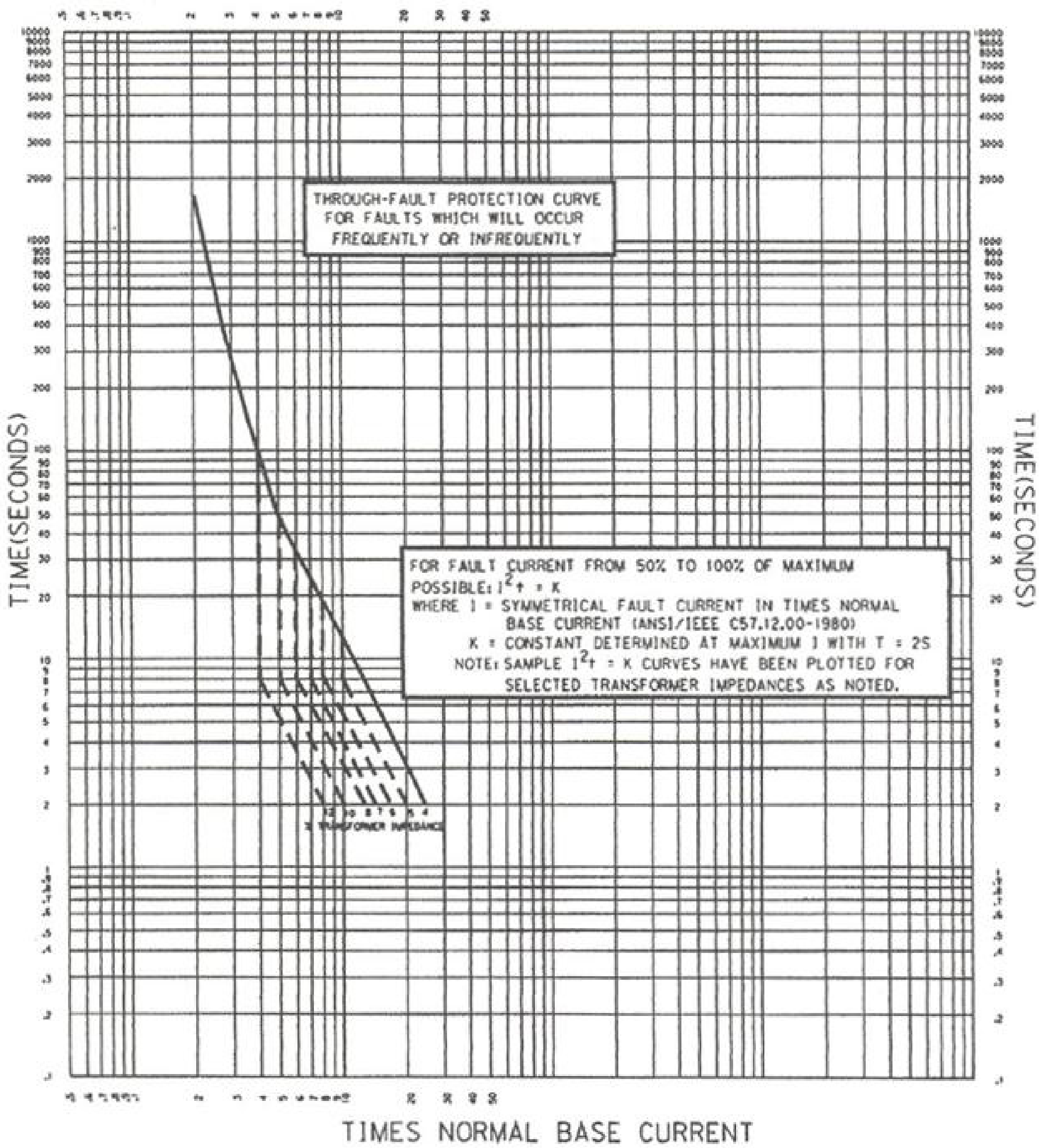


**Figure A.4—Category IV transformers:
above 10 000 kVA single-phase;
above 30 000 kVA three-phase**

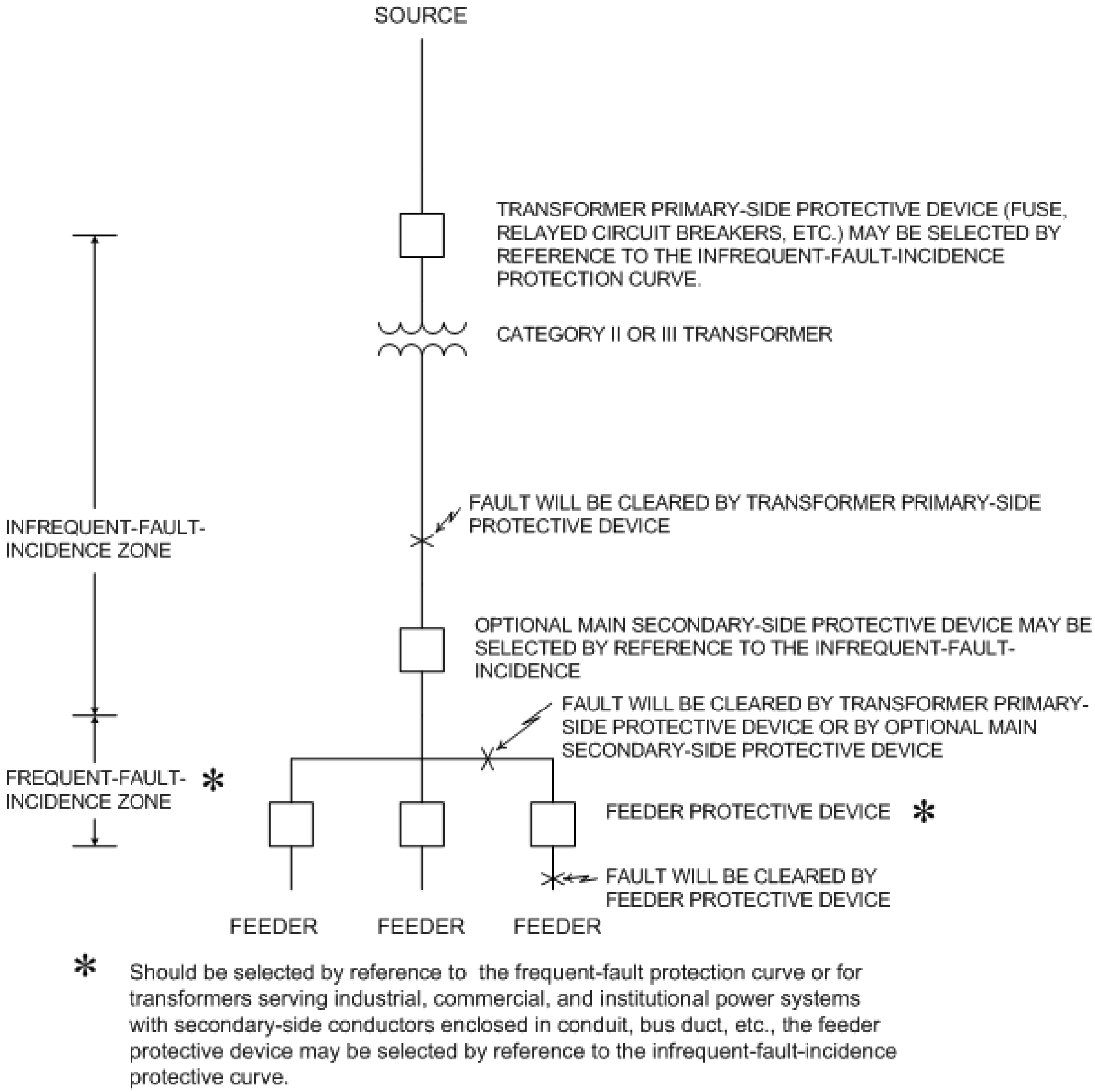


Figure A.5—Infrequent- and frequent-fault-incidence zones for Category II and Category III transformers

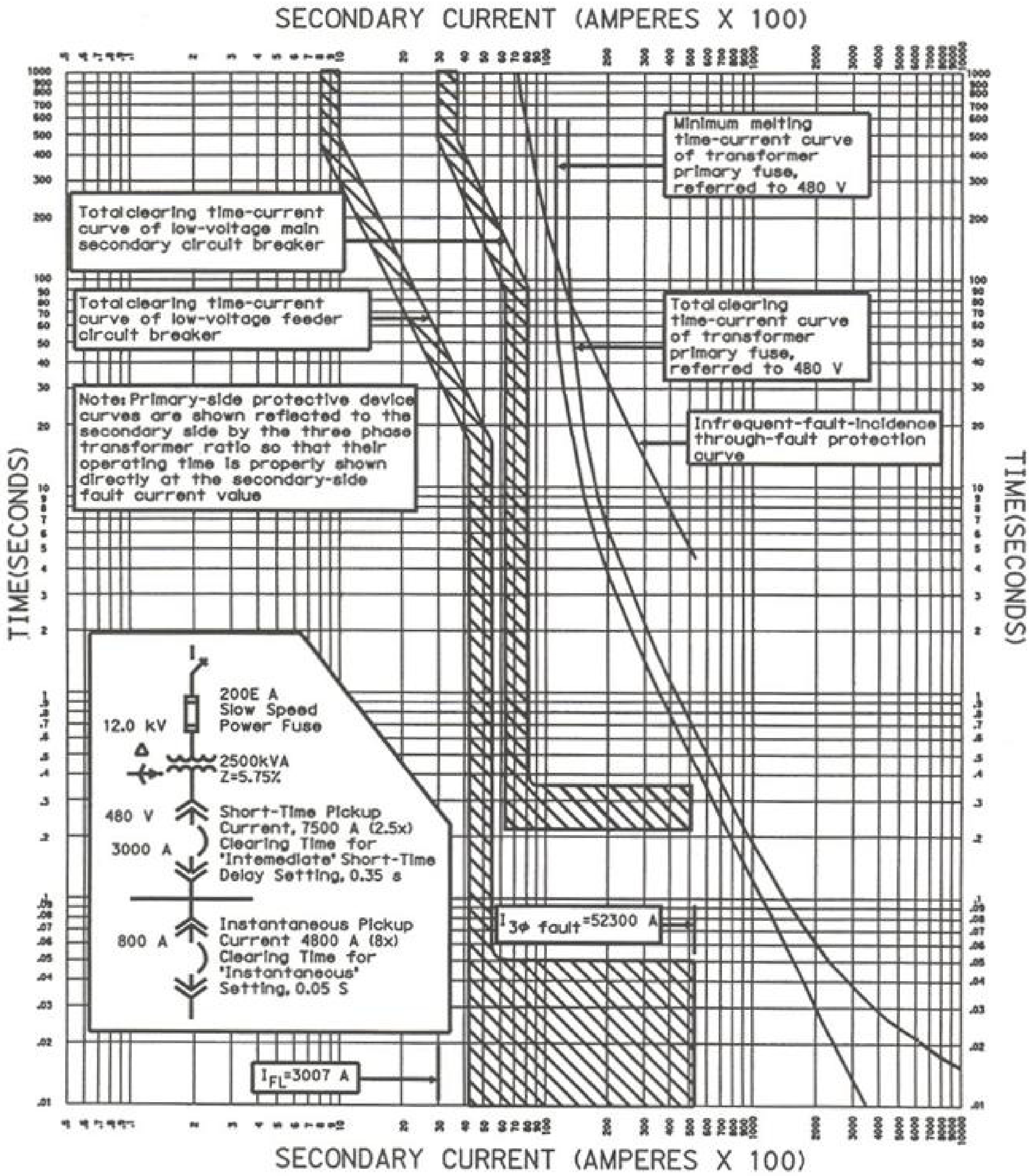


Figure A.6—Protection of Category II transformer serving protected secondary-side conductors (e.g., cables, ducts, or switchgear) for a three-phase secondary-side fault

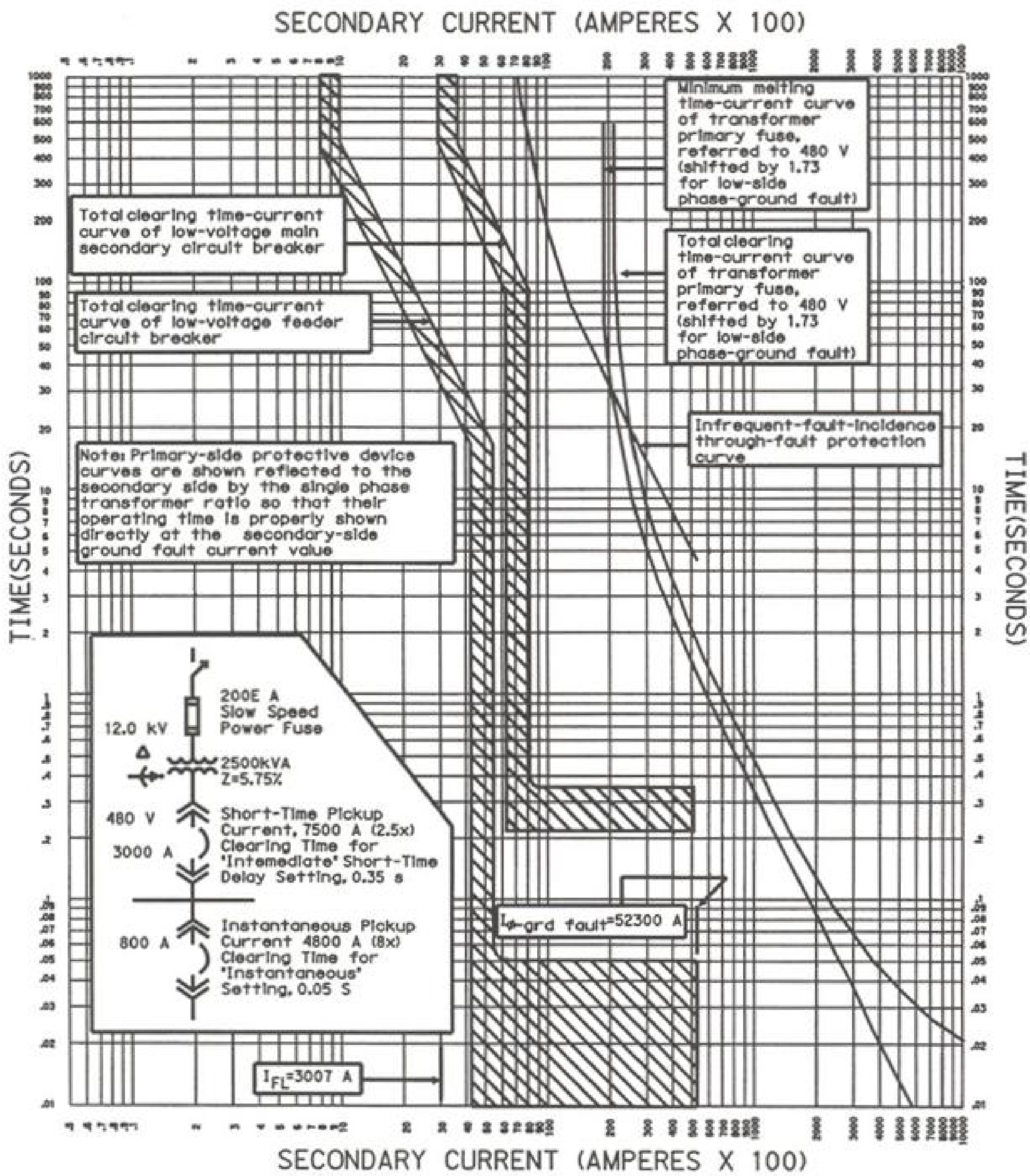


Figure A.7—Protection of a Category II transformer serving protected secondary-side conductors (e.g., cable, bus duct, or switchgear) for phase-to-ground secondary-side fault

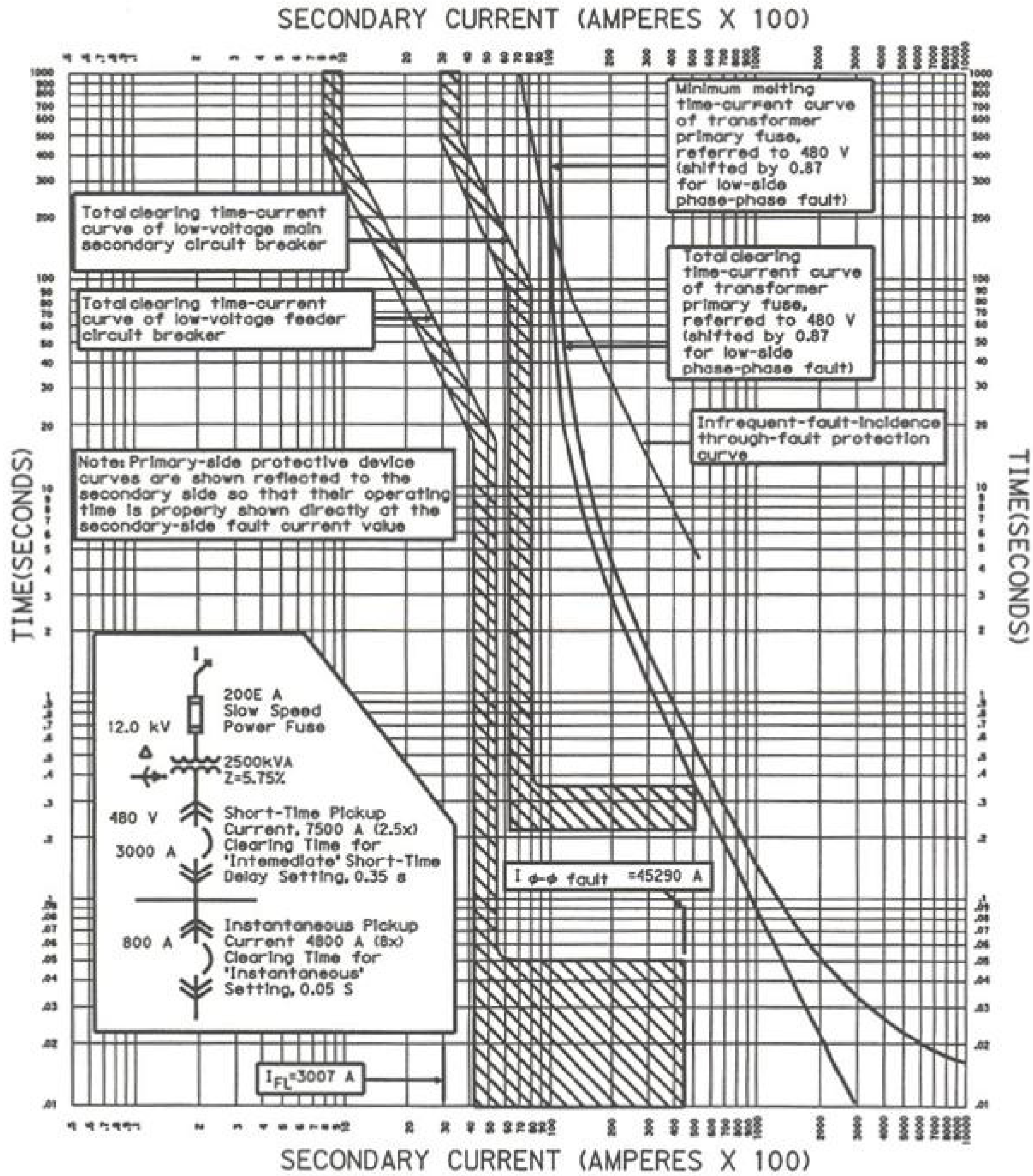


Figure A.8—Protection of a Category II transformer serving protecting secondary-side conductors (e.g., cable, bus duct, or switchgear) for phase-to-phase secondary-side fault

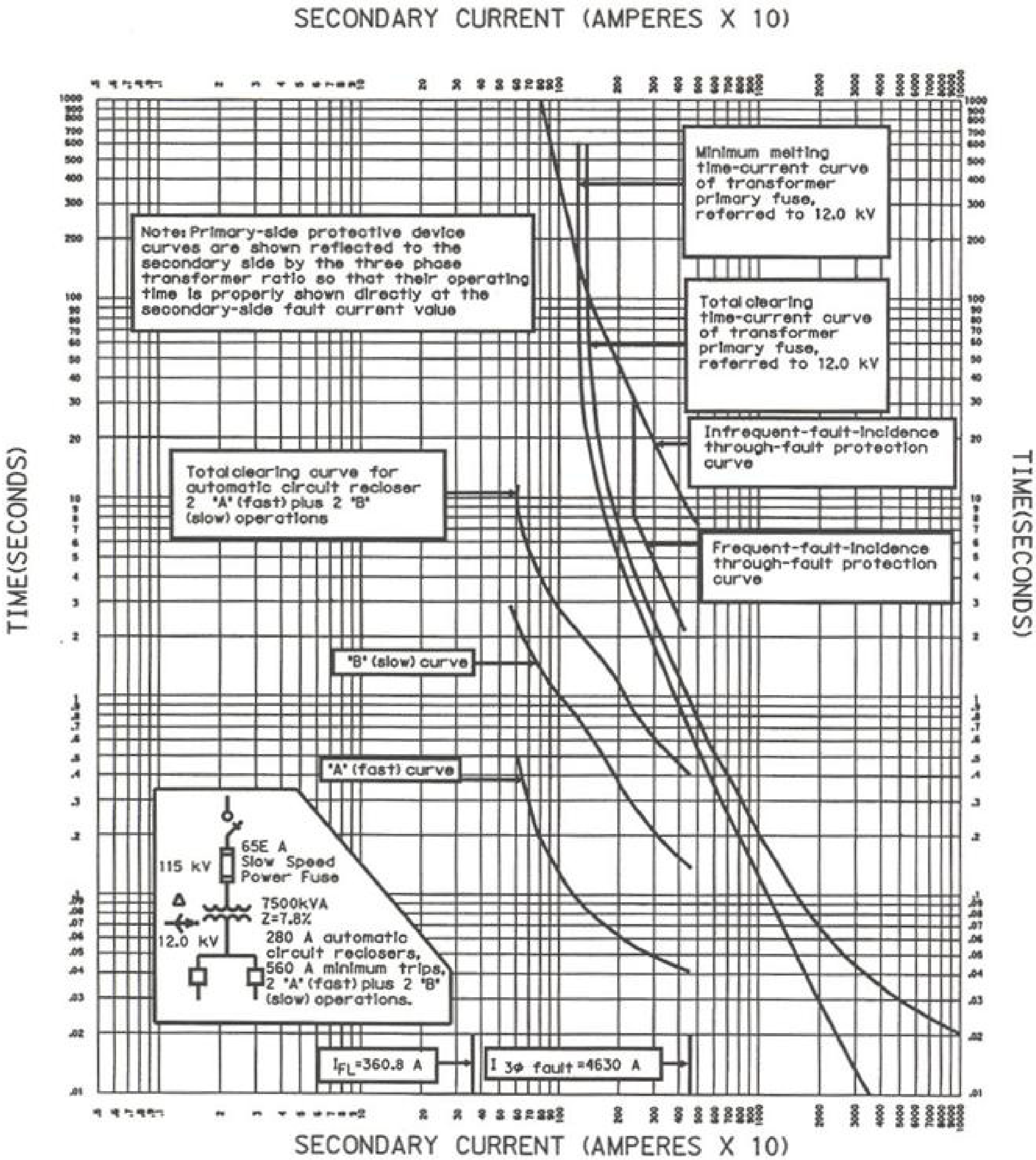


Figure A.9—Protection of a Category III transformer serving secondary-side overhead lines, for three-phase secondary-side fault

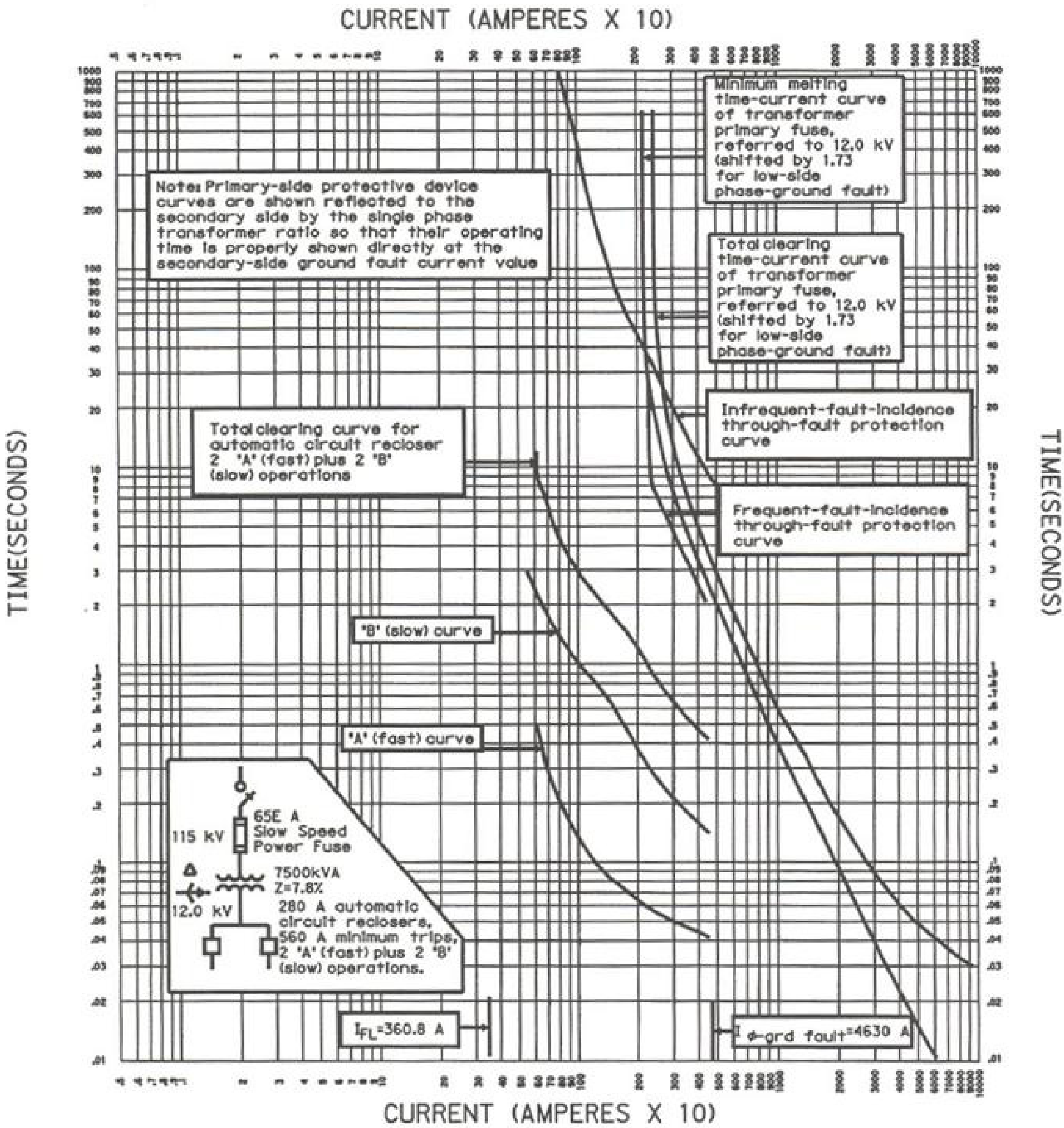


Figure A.10—Protection of Category III transformer serving secondary-side overhead lines, for phase-to-ground secondary-side fault

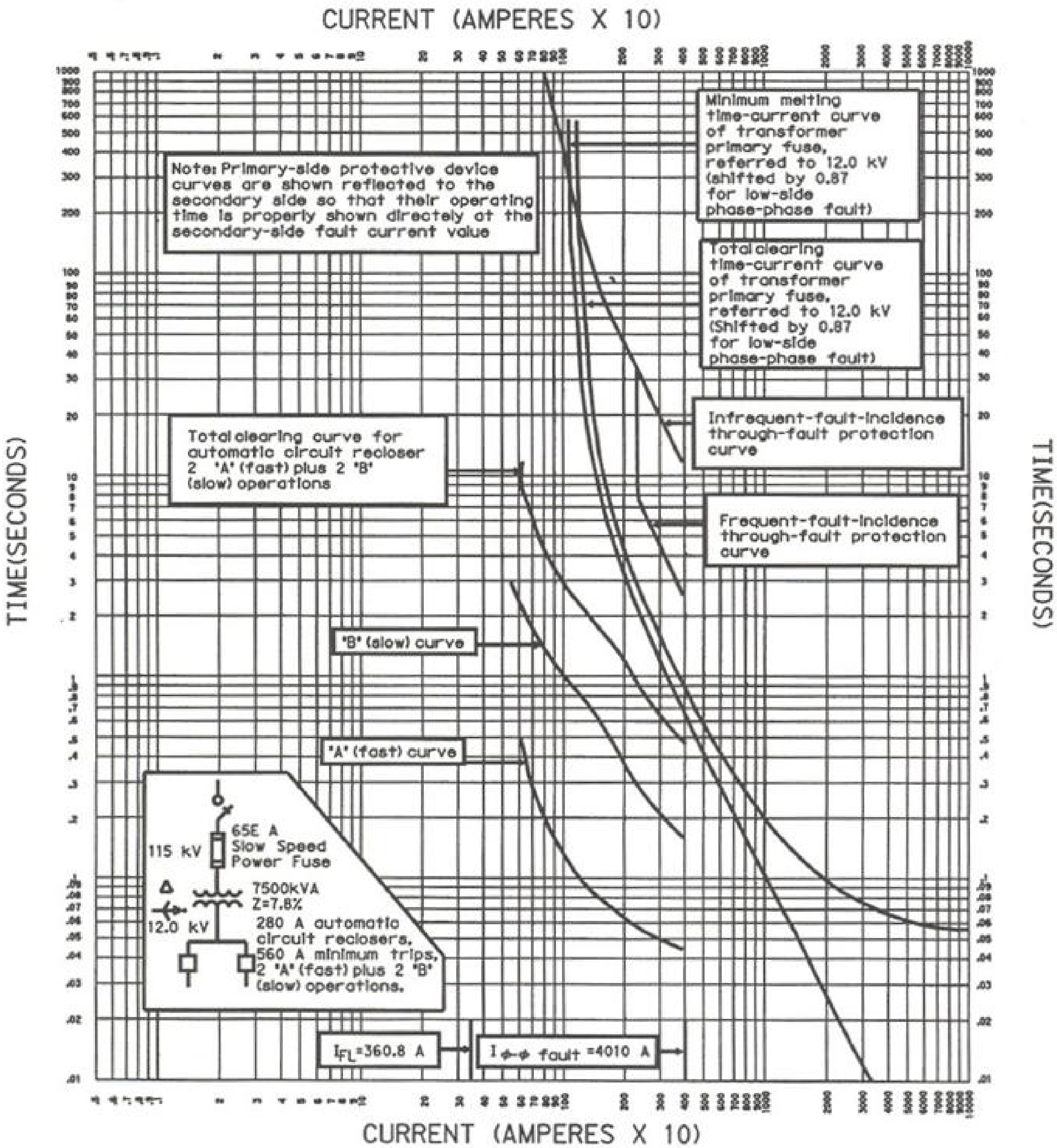


Figure A.11—Protection of a Category III transformer serving secondary-side overhead lines, for phase-to-phase secondary-side fault

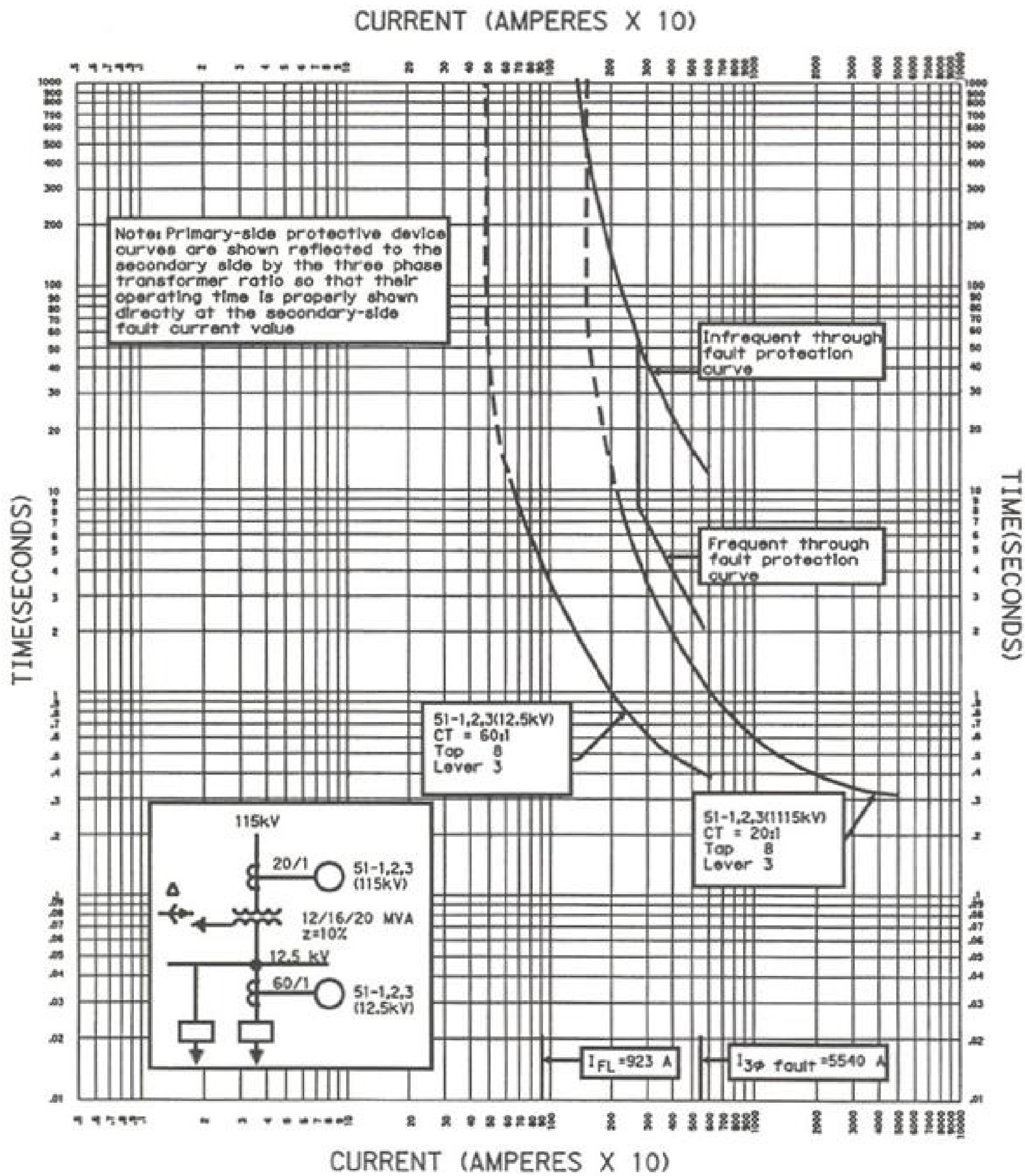


Figure A.12—Protection of Category III transformer three-phase secondary fault

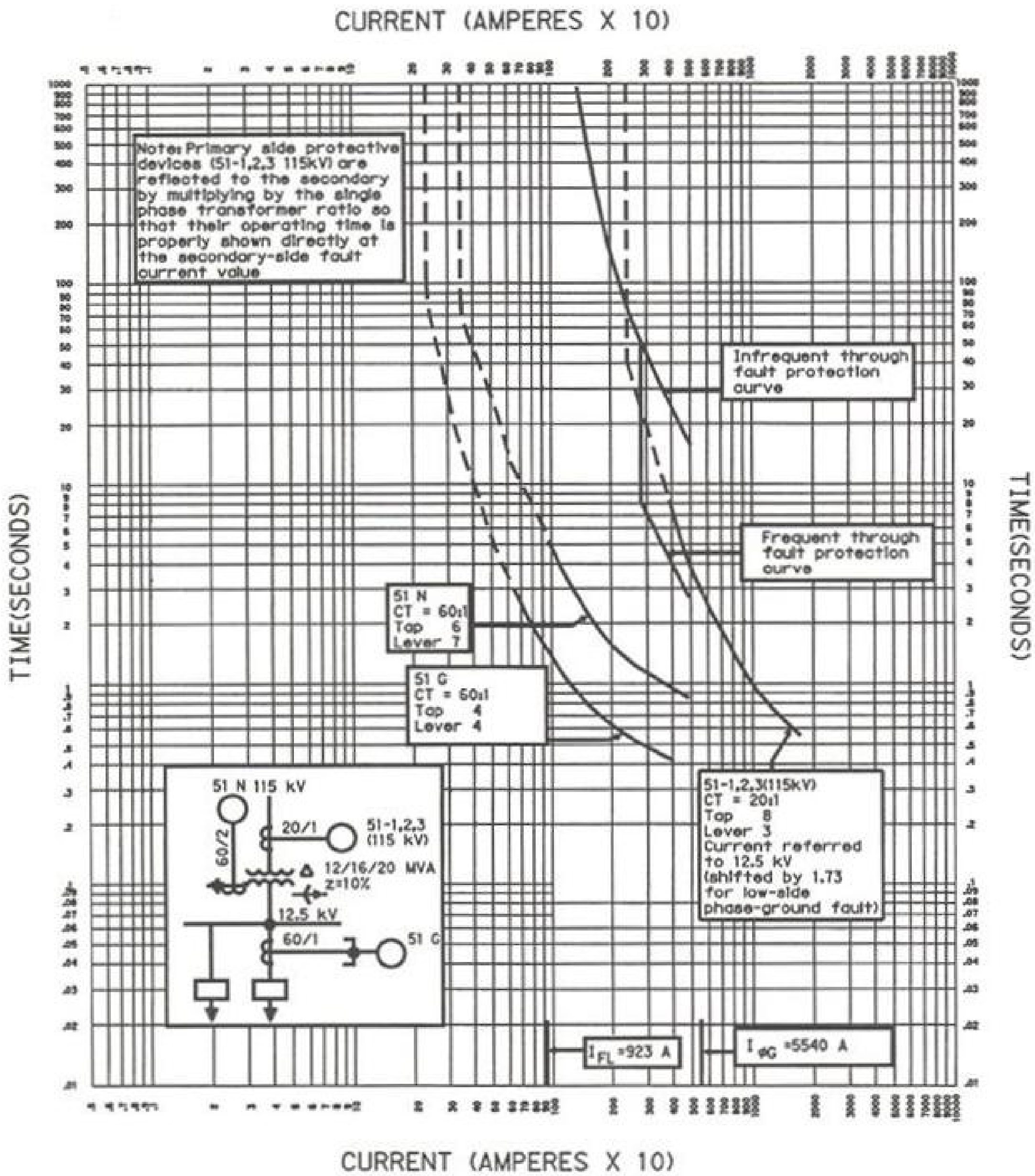


Figure A.13—Protection of Category III transformer phase-ground secondary fault

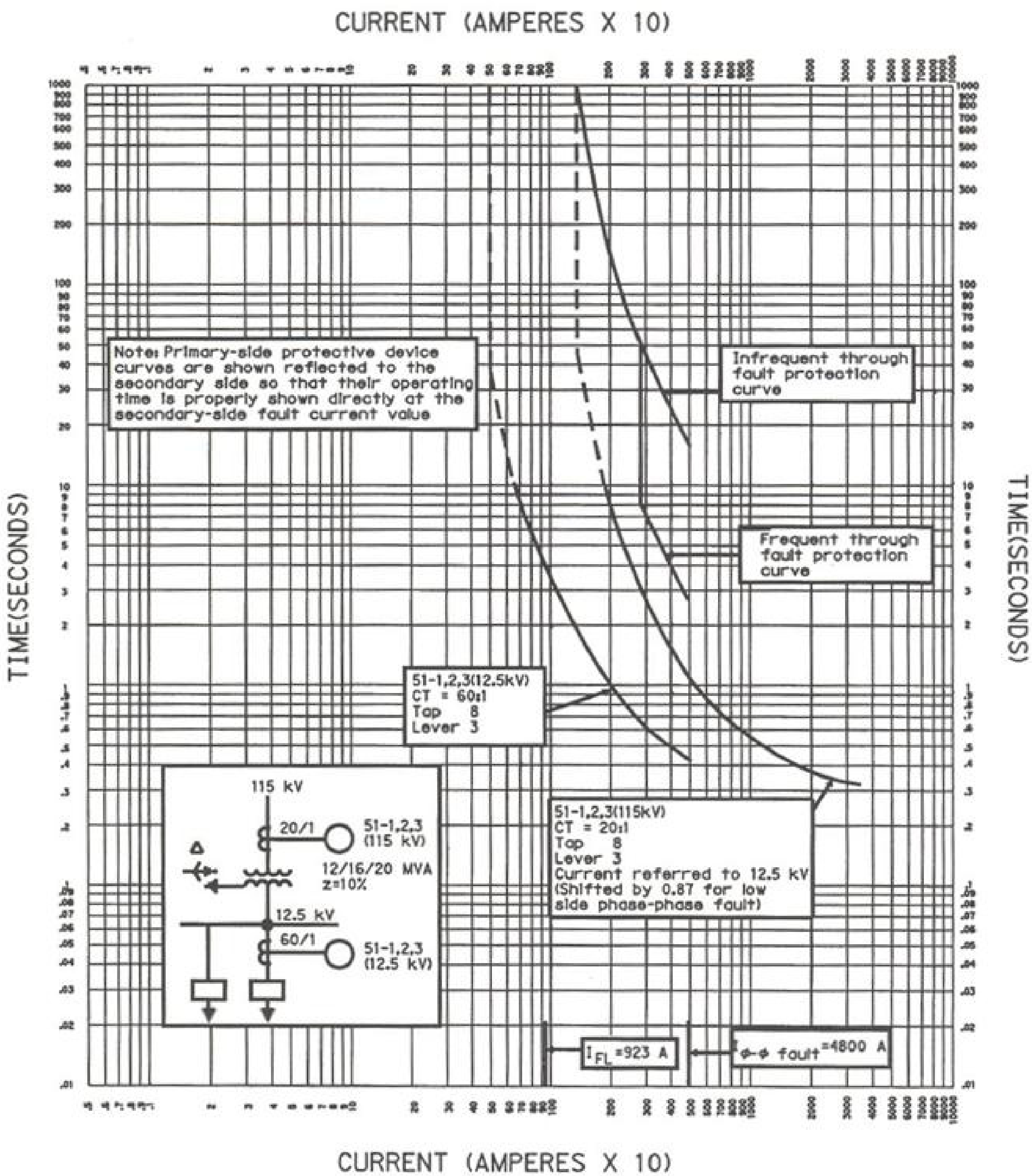


Figure A.14—Protection of Category III transformer phase-phase secondary fault

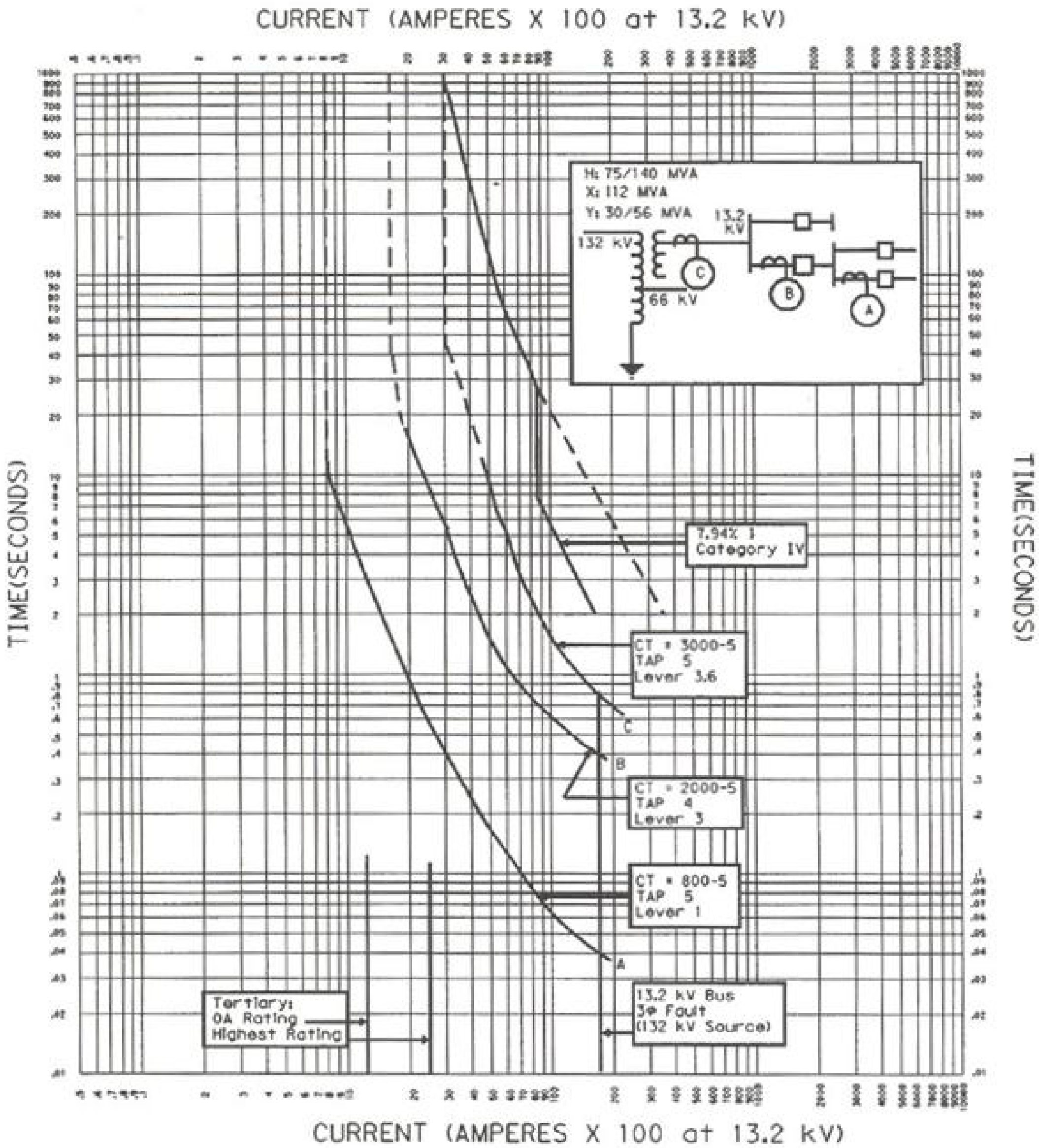


Figure A.15—Coordination of tertiary overcurrent relays for large autotransformer

Annex B

(informative)

Transformer failure statistics

The statistics of failures of equipment and lines are collected by the Canadian Electricity Association, Montreal, Canada, from Canadian electric power utilities and are published in the "Forced Outage Performance of Transmission Equipment" reports [B6]. The reports included forced outages of transmission equipment and components associated with transmission systems installed in Canada and operating at voltages equal to and more than 60 kV. Specifically included in the reports are outage data in the following categories:

a) Transmission-line analysis by subcomponent for line-related sustained forced outages
b) Transmission-line analysis by subcomponent for line-related transient forced outages
c) Transmission-line analysis by subcomponent for terminal-related forced outages
d) Transmission-line analysis by primary cause for line-related sustained forced outages
e) Transmission-line analysis by primary cause for line-related transient forced outages
f) Transmission-line analysis by primary cause for terminal-related forced outages
g) Transformer bank analysis by voltage classification and subcomponent
h) Circuit-breaker analysis by voltage classification and subcomponent
i) Cable analysis by subcomponent for cable-related forced outages
j) Cable analysis by subcomponent for terminal-related forced outages
k) Synchronous compensator analysis by voltage classification and subcomponent
l) Static compensator analysis by voltage classification and subcomponent
m) Shunt reactor bank analysis by voltage classification and subcomponent
n) Shunt capacitor bank analysis by voltage classification and subcomponent
o) Series capacitor bank analysis by voltage classification and subcomponent

The forced outages experienced from January 1, 1988, to December 31, 2002, are published in "Forced Outage Performance of Transmission Equipment for the Period January 1, 1998 to December 31, 2002" [B6]. The overall statistics of failures of transformers reported in this report are reproduced in Table B.1 through Table B.7. The information in each column of these tables is defined as follows:

Column 1: Component years (a)—The summation of the product of the number of units of a major component and the period duration in years, for the major component under consideration.

Column 2: Subcomponent—The constituent components of a major component and includes those external elements that are associated with it.

Column 3: Number of outages—The number of major-component-related forced outages that involved the indicated subcomponent or primary cause.

Column 4: Frequency per year—The number of outages divided by terminal years or component years.

Column 5: Total time (h)—The sum of the forced unavailable times (in hours) of major-component-related forced outages involving the indicated subcomponent or primary cause. Forced unavailable time is the elapsed time required to completely restore a major component to service.

Column 6: Mean duration (h)—The total time divided by the number of outages.

Column 7: Median duration (h)—The time at which 50% of the forced unavailable times are greater than this value and 50% are less.

Column 8: Mean op. pos. (h)—The mean time that the operating position was out of service. This time differs from mean duration for those forced outages that resulted in the major component being removed from service and replaced with another.

Table B.1—Transformer bank analysis by subcomponents for operating voltages from 60 kV to 109 kV

Component years (a)	Subcomponent	No. of outages	Frequency per year	Total time (h)	Mean duration (h)	Median duration (h)	Mean op. pos. (h)
3019.5	Bushings including CTs	14	0.0046	9 580	684.3	101.56	684.3
	Windings	13	0.0043	16 387	1260.5	265.47	1260.5
	On-load tap changer	81	0.0268	30 865	381.1	69.23	381.1
	Core	4	0.0013	2 531	632.7	537.27	632.7
	Leads	2	0.0007	232	115.8	115.8	115.8
	Cooling equipment	6	0.0020	240	40.0	42.17	40.0
	Auxiliary equipment	6	0.0020	377	62.8	25.61	62.8
	Other	42	0.0139	22 687	540.2	45.02	540.2
	All integral components	168	0.0556	82 898	493.4	68.78	493.4
	Control and protection equipment	80	0.0265	9 966	124.6	3.29	124.6
	Surge arrester	7	0.0023	358	51.1	20.83	51.1
	Bus	13	0.0043	1 387	106.7	2.53	106.7
	Disconnect	49	0.0162	11 987	244.6	25.57	244.6
	Circuit switcher	0					
	CT (free standing)	1	0.0003	1	1.1	1.13	1.1
	Potential devices	6	0.0020	1 979	329.8	129.45	329.8
	Motor-operated ground switch	7	0.0023	538	76.8	40.22	76.8
	Other	21	0.0070	4 926	234.6	4.00	234.6
	Unknown	17	0.0056	532	31.3	9.48	31.3
	All terminal equipment	201	0.0666	31 675	157.6	9.13	157.6

Table B.2—Transformer bank analysis by subcomponents for operating voltages from 110 kV to 149 kV

Component years (a)	Subcomponent	No. of outages	Frequency per year	Total time (h)	Mean duration (h)	Median duration (h)	Mean op. pos. (h)
9302	Bushings including CTs	93	0.0100	22 144	238.1	14.58	226.3
	Windings	31	0.0033	24 876	802.5	10.35	130.1
	On-load tap changer	187	0.0201	51 806	277.0	26.78	274.5
	Core	15	0.0016	493	32.9	1.27	32.9
	Leads	2	0.0002	17	8.6	8.56	8.6
	Cooling equipment	28	0.0030	1 590	56.8	17.61	56.8
	Auxiliary equipment	24	0.0026	6 166	256.9	18.76	256.9
	Other	162	0.0174	37 455	231.2	24.80	231.2
	All integral components	542	0.0583	144 547	266.7	22.82	225.3
	Control and protection equipment	323	0.0347	23 407	72.5	1.78	72.5
	Surge arrester	31	0.0033	3 104	100.1	14.33	100.1
	Bus	61	0.0066	14 132	231.7	1.18	231.7
	Disconnect	157	0.0169	28 664	182.6	24.00	182.6
	Circuit switcher	3	0.0003	71	23.6	4.85	23.6
	CT (free standing)	11	0.0012	1 585	144.1	4.23	144.1
	Potential devices	27	0.0029	6 971	258.2	73.95	258.2
	Motor-operated ground switch	31	0.0033	7 661	247.1	22.58	247.1
	Other	64	0.0069	1 977	30.9	2.94	30.9
	Unknown	220	0.0237	34 341	156.1	14.03	156.1
	All terminal equipment	928	0.0998	121 911	131.4	6.66	131.4

Table B.3—Transformer bank analysis by subcomponents for operating voltages from 150 kV to 199 kV

Component years (a)	Subcomponent	No. of outages	Frequency per year	Total time (h)	Mean duration (h)	Median duration (h)	Mean op. pos. (h)
594	Bushings including CTs	18	0.0303	11 143	619.1	4.88	619.1
	Windings	2	0.0034	6 678	3 339.2	3 339.24	3 339.2
	On-load tap changer	28	0.0471	16 109	575.3	57.76	575.3
	Core	0					
	Leads	0					
	Cooling equipment	6	0.0101	2 151	358.5	239.53	358.5
	Auxiliary equipment	18	0.0303	955	53.0	12.00	53.0
	Other	16	0.0269	12 493	780.8	248.86	780.8
	All integral components	88	0.1481	49 529	562.8	32.00	562.8
	Control and protection equipment	19	0.0320	6 439	338.9	23.90	338.9
	Surge arrester	7	0.0118	973	139.0	37.10	139.0
	Bus	4	0.0067	3	0.6	0.62	0.6
	Disconnect	26	0.0438	27 024	1 039.4	127.53	1 039.4
	Circuit switcher	0					
	CT (free standing)	1	0.0017	4 626	4 625.6	4 625.63	4 625.6
	Potential devices	8	0.0135	3 350	418.7	122.70	418.7
	Motor-operated ground switch	3	0.0051	688	229.3	104.43	229.3
	Other	1	0.0017	1	0.7	0.68	0.7
	Unknown	9	0.0152	628	69.8	0.70	69.8
	All terminal equipment	78	0.1313	43 730	560.6	28.04	560.6

Table B.4—Transformer bank analysis by subcomponents for operating voltages from 200 kV to 299 kV

Component years (a)	Subcomponent	No. of outages	Frequency per year	Total time (h)	Mean duration (h)	Median duration (h)	Mean op. pos. (h)
5940.0	Bushings including CTs	32	0.0054	6 283	196.3	13.83	196.3
	Windings	19	0.0032	23 225	1222.4	68.97	891.0
	On-load tap changer	90	0.0152	25 148	279.4	12.81	279.4
	Core	5	0.0008	557	111.5	30.18	111.5
	Leads	5	0.0008	140	28.0	2.58	28.0
	Cooling equipment	34	0.0057	2 187	64.3	3.64	64.3
	Auxiliary equipment	35	0.0059	9 024	257.8	9.25	257.8
	Other	90	0.0152	21 719	241.3	29.14	241.3
	All integral components	310	0.0522	88 284	284.8	16.92	264.5
	Control and protection equipment	207	0.0348	8 280	40.0	2.70	40.0
	Surge arrester	27	0.0045	1 491	55.2	23.55	55.2
	Bus	15	0.0025	282	18.8	6.13	18.8
	Disconnect	59	0.0099	14 469	245.2	31.40	245.2
	Circuit switcher	1	0.0002	3	3.2	3.23	3.2
	CT (free standing)	3	0.0005	401	133.8	68.17	133.8
	Potential devices	9	0.0015	106	11.8	8.52	11.8
	Motor-operated ground switch	6	0.0010	1 059	176.4	9.03	176.4
	Other	41	0.0069	1 224	29.9	3.45	29.9
	Unknown	120	0.0202	5 990	49.9	18.23	49.9
	All terminal equipment	488	0.0822	33 305	68.2	9.03	68.2

Table B.5—Transformer bank analysis by subcomponents for operating voltages from 300 kV to 399 kV

Component years (a)	Subcomponent	No. of outages	Frequency per year	Total time (h)	Mean duration (h)	Median duration (h)	Mean op. pos. (h)
1771.0	Bushings including CTs	10	0.0056	2 296	229.6	6.98	229.6
	Windings	13	0.0073	397	30.5	9.42	30.5
	On-load tap changer	42	0.0237	3 079	73.3	7.50	73.3
	Core	1	0.0006	11 399	11 399.4	11 399.42	11 399.4
	Leads	0					
	Cooling equipment	10	0.0056	1 027	102.7	9.32	102.7
	Auxiliary equipment	11	0.0062	143	13.0	16.67	13.0
	Other	46	0.0260	2 998	65.2	19.39	65.2
	All integral components	133	0.0751	21 340	160.4	13.67	160.4
	Control and protection equipment	28	0.0158	2 134	76.2	3.82	76.2
	Surge arrester	8	0.0045	443	55.3	15.80	55.3
	Bus	1	0.0006	480	480.2	480.15	480.2
	Disconnect	16	0.0090	5 300	331.3	74.21	331.3
	Circuit switcher	0					
	CT (free standing)	1	0.0006	7	6.6	6.63	6.6
	Potential devices	0					
	Motor-operated ground switch	0					
	Other	7	0.0040	290	41.5	13.65	41.5
	Unknown	14	0.0079	4 369	312.1	24.14	312.1
	All terminal equipment	75	0.0423	13 023	173.6	6.98	173.6

Table B.6—Transformer bank analysis by subcomponents for operating voltages from 500 kV to 599 kV

Component years (a)	Subcomponent	No. of outages	Frequency per year	Total time (h)	Mean duration (h)	Median duration (h)	Mean op. pos. (h)
1044.0	Bushings including CTs	4	0.0038	4 792	1198.1	97.77	1198.1
	Windings	1	0.0010	1 007	1007.1	1007.05	1007.1
	On-load tap changer	3	0.0029	32	10.7	4.27	10.7
	Core	0					
	Leads	0					
	Cooling equipment	5	0.0048	555	111.1	5.30	111.1
	Auxiliary equipment	2	0.0019	7	3.6	3.60	3.6
	Other	6	0.0057	7 552	1258.7	48.95	1258.7
	All integral components	21	0.0201	13 946	664.1	30.20	664.1
	Control and protection equipment	14	0.0134	179	12.8	2.17	12.8
	Surge arrester	3	0.0029	269	89.6	45.10	89.6
	Bus	2	0.0019	57	28.5	28.50	28.5
	Disconnect	6	0.0057	387	64.5	21.05	64.5
	Circuit switcher	0					
	CT (free standing)	0					
	Potential devices	3	0.0029	142	47.3	52.45	47.3
	Motor-operated ground switch	0					
	Other	5	0.0048	51	10.3	1.17	10.3
	Unknown	1	0.0010	31	30.6	30.55	30.6
	All terminal equipment	34	0.0326	1 116	32.8	6.59	32.8

Table B.7—Transformer bank analysis by subcomponents for operating voltages from 600 kV to 799 kV

Component years (a)	Subcomponent	No. of outages	Frequency per year	Total time (h)	Mean duration (h)	Median duration (h)	Mean op. pos. (h)
2539.0	Bushings including CTs	6	0.0024	3 801	633.5	115.76	633.5
	Windings	6	0.0024	920	153.3	20.45	153.3
	On-load tap changer	11	0.0043	888	80.7	65.08	80.7
	Core	2	0.0008	252	125.9	125.86	125.9
	Leads	0					
	Cooling equipment	11	0.0043	736	66.9	32.00	66.9
	Auxiliary equipment	11	0.0043	746	67.9	30.52	67.9
	Other	25	0.0098	14 788	591.5	16.37	591.5
	All integral components	72	0.0284	22 131	307.4	25.02	307.4
	Control and protection equipment	37	0.0146	932	25.2	4.52	25.2
	Surge arrester	6	0.0024	1 626	271.0	71.48	271.0
	Bus	2	0.0008	165	82.4	82.38	82.4
	Disconnect	17	0.0067	1 647	96.9	13.18	96.9
	Circuit switcher	0					
	CT (free standing)	0					
	Potential devices	0					
	Motor-operated ground switch	2	0.0008	712	355.8	355.82	355.8
	Other	3	0.0012	39	13.0	8.47	13.0
	Unknown	6	0.0024	133	22.1	3.65	22.1
	All terminal equipment	73	0.0288	5 253	72.0	8.48	72.0

The summary of the statistics of outages of transformer banks from January 1, 1998, to December 31, 2002, is given in Table B.8, Table B.9, and Table B.10.

Table B.8—Transformer bank statistics for forced outages involving integral subcomponents

Voltage classification	Component years (a)	Number of outages	Total time (h)	Frequency per year	Mean duration
Up to 109 kV	3019.5	168	82 898	0.0556	493.4
110 kV to 149 kV	9302.0	542	144 547	0.0583	266.7
150 kV to 199 kV	594.0	88	49 529	0.1481	562.8
200 kV to 299 kV	5940.0	310	88 284	0.0522	284.8
300 kV to 399 kV	1771.0	133	21 340	0.0751	160.4
500 kV to 599 kV	1044.0	21	13 946	0.0201	664.1
600 kV to 799 kV	2539.0	72	22 131	0.0284	307.4

Table B.9—Transformer bank statistics for forced outages involving terminal equipment

Voltage classification	Component years (a)	Number of outages	Total time (h)	Frequency per year	Mean duration
Up to 109 kV	3019.5	201	31 675	0.0666	157.6
110 kV to 149 kV	9302.0	928	121 911	0.0998	131.4
150 kV to 199 kV	594.0	78	43 730	0.1313	560.6
200 kV to 299 kV	5940.0	488	33 305	0.0822	68.2
300 kV to 399 kV	1771.0	75	13 023	0.0423	173.6
500 kV to 599 kV	1044.0	34	1 116	0.0326	32.8
600 kV to 799 kV	2539.0	73	5 253	0.0288	72.0

Table B.10—Transformer bank statistics for forced outages involving integral subcomponents and terminal equipment

Voltage classification	Component years (a)	Number of outages	Total time (h)	Frequency per year	Mean duration
Up to 109 kV	3019.5	369	114 573	0.1222	310.50
110 kV to 149 kV	9302.0	1470	266 458	0.1580	181.26
150 kV to 199 kV	594.0	166	93 259	0.2795	561.80
200 kV to 299 kV	5940.0	798	121 589	0.1343	152.37
300 kV to 399 kV	1771.0	208	34 363	0.1174	165.21
500 kV to 599 kV	1044.0	55	15 062	0.0527	273.85
600 kV to 799 kV	2539.0	145	27 384	0.0571	188.86

Annex C

(informative)

Examples of setting transformer protection relays

General information on setting relays for protecting transformers is provided in this annex for use by protection engineers and technologists. Three setting cases are discussed. The first case deals with setting differential relays for step-up transformers installed at generating stations. Issues that are relevant when electromechanical relays are used are first discussed, and issues that are relevant when numerical relays are then presented. The second case deals with the setting of a numerical relay and an electromechanical relay for protecting a network transformer. Finally, the third case demonstrates the setting procedure for a combination of electromechanical and numerical relays for protecting a power transformer. All figures are drawn assuming that the relays used are of the electromechanical type. In the case of numerical relays, all CTs are connected in wye configuration and the phase shift and ratio match are done in the relay as shown in Figure 9 and discussed in 8.2.

C.1 Electromechanical relays for protecting a step-up transformer

This information provided in this clause is for setting protection relays for a generator step-up transformer. Both selection of CTs and setting of relays are discussed. The scenario is assumed to be as follows:

- A 110 MVA generator rated at 13.8 kV is connected to a 230 kV network by a 13.8 kV/230 kV step-up transformer.
- The low-voltage (13.8 kV) winding of the step-up transformer is connected in delta configuration and the high-voltage (230 kV) winding is wye connected with the neutral grounded.
- Voltage regulation is provided by taps on the transformer high-voltage winding from 205 kV to 255 kV by an LTC.
- The transformer is protected by a differential relay. Backup protection of the transformer is provided by a Buchholz relay.
- In the first part of the example, it is assumed that an electromechanical relay provides protection to the transformer.
- In the second part of the example, it is assumed that a numerical relay provides protection to the transformer.

The first issue considered in this example is the selection of CTs that provide information on the currents in the low- and high-voltage circuits to the relay.

C.1.1 CT ratio selection for electromechanical relays

C.1.1.1 Phase-shift correction

Phase-shift correction, as shown in Figure C.1, is typically achieved by connecting the CTs provided on the low-voltage (delta-connected winding) side in wye and the CTs provided on the high-voltage (wye-connected winding) side in delta.

C.1.1.2 CT selections for high-voltage and low-voltage sides

The CT selection procedure consists of establishing their ratios considering the manner in which they are connected together and then to the relay. Figure C.1 shows the usual manner in which CTs are connected to electromechanical differential relays.

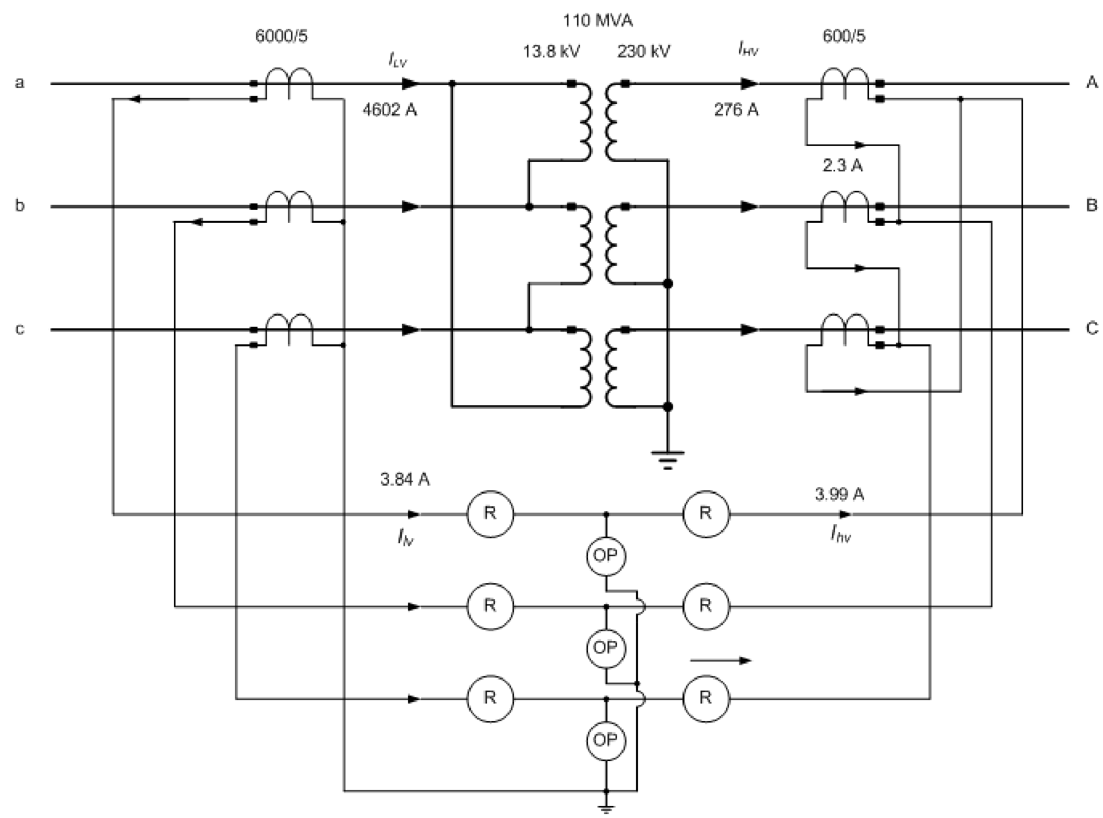


Figure C.1—CT connections with the electromechanical differential relay

a) The rated currents of the transformer high-voltage side, I_{HV} and the rated current of the transformer on the low-voltage side, I_{LV} are as follows:

$$I_{\mathrm{HV}} = 110\left(\mathrm{MVA}\right) \times 1000 \div \left[230\left(\mathrm{kV}\right) \times \sqrt{3}\,\right] = 276\,\mathrm{A}$$

$$I_{\mathrm{LV}} = 110\left(\mathrm{MVA}\right) \times 1000 \div \left[13.8\left(\mathrm{kV}\right) \times \sqrt{3}\,\right] = 4602\,\mathrm{A}$$

b) It usually works better if the CTs provided on the low-voltage side of the power transformer (delta-connected winding of the transformer) are first selected because the CTs are connected in wye configuration.

Many utilities select the rating of the CT primary current close to the 125% of the rated current of the transformer. For this example, select 125% of the rated current of the transformer that works out to 4602 × 1.25 = 5753 A.

This is not a standard rating for CT primary windings. It is therefore appropriate to select the next practical rating for the low-voltage CTs that is 6000/5 A.

The current, I_{lv}, out of the secondary windings of the CTs provided on the low-voltage side when the transformer is carrying its rated current is $4602 \times 5 \div 6000 = 3.84$ A. This current flows into the relay from the low-voltage side of the transformer.

c) The next step is to select the CT ratio for the high-voltage side. Ideally, the current, I_{hv}, from the CTs provided on the high-voltage side of the transformer should be the same as the current provided by the CTs selected for the low-voltage side of the transformer.

   1) Ideal $I_{hv} = I_{lv} = 3.84$ A.

   2) The CTs on the high side are connected in delta configuration. Ideal current in the leads connecting these CTs with the relay should be 3.84 A. To have this current in the connections out of the delta-connected CTs, the current in each CT should be $3.84 \div \sqrt{3} = 2.21$ A.

   3) The rated current of the transformer on the high-voltage side is 276 A. Because the nominal secondary rating of the CTs is 5 A, the ideal primary rating of CTs (provided on the high-voltage side of the transformer) should be $(276 \div 2.21) \times 5 = 625$ A.

   4) Select 600/5 A CT ratio for high-voltage side (625/5 A is not a standard CT rating).

d) Because the ratings of the selected CTs are not equal to the ideal ratings, current mismatch resulting from the selected CTs should be checked. Current provided by the high-side CTs when the transformer is supplying load equal to the rating of the transformer will be $(276 \times 5 \div 600) \times \sqrt{3} = 3.98$ A.

e) Therefore, the percentage error due to CT mismatch is $[(3.98 - 3.84) \div 3.84] \times 100 = 3.65\%$.

C.1.1.3 Minimum pickup setting

Minimum pickup value cannot be set in most electromechanical relays. This issue is discussed in C.1.2.3.

C.1.1.4 Percentage slope

Some electromechanical relays provide the option of choosing a percentage slope and others do not. This issue is also discussed in C.1.2.4.

C.1.2 CT ratio selection procedure for numerical relays

The procedure for selecting the ratios of CTs is slightly different and is discussed in C.1.2.2. The phase-shift correction is first discussed in C.1.2.1.

C.1.2.1 Phase-shift correction

As discussed in 8.2 and shown in Figure 9, the CTs on both sides of the delta-wye and wye-delta transformers are connected in wye configuration. The phase-shift compensation is done in the relay internally. The users, however, are required to manually enter the phase relationship information between the high-voltage and low-voltage windings for proper phase-shift relationship. The method for determining the phase relationship in the delta-wye transformer considered in this example is as follows:

a) The currents in the primary and secondary windings of the transformer are in phase with each other.

b) The phase-a current, I_a, on the delta side is a phasor difference of I_A and I_C as shown in Figure C.2.

c) I_A lead I_a by 30°; similarly, I_B lead I_b by 30° and I_C lead I_c by 30° as shown in Figure C.2.

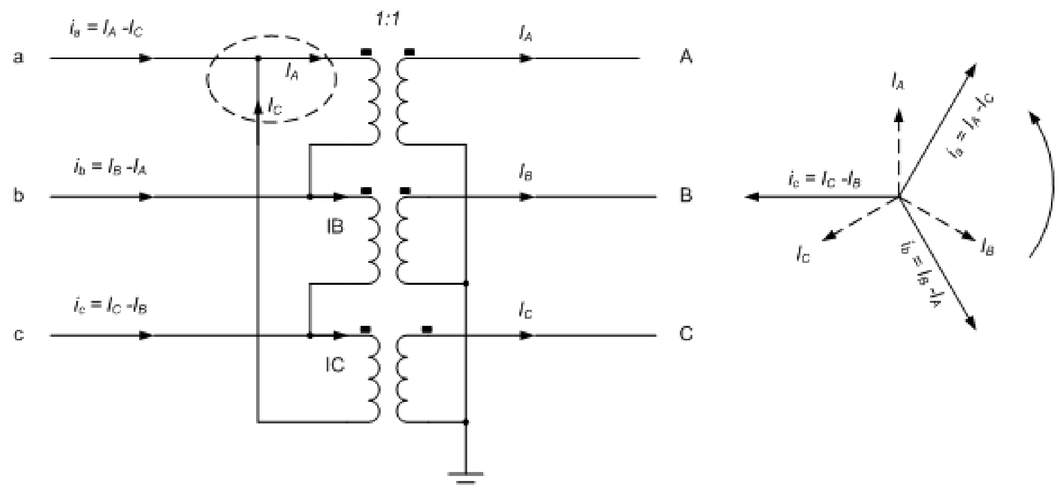


Figure C.2—Phase relationship when current in phase A leads current in phase a by 30°

C.1.2.2 Selecting ratios for current transformers on the high-voltage and low-voltage sides

CTs provided on the low-voltage side (delta-connected windings) as well as CTs provided on the high-voltage side (wye-connected windings) of the transformer are connected in wye configuration. As discussed in item b) of C.1.1.2, CTs of ratio 6000/5 A are selected for the low voltage of the transformer.

Because the CTs on the high-voltage side of the transformer are also wye connected, the rating of the primary windings of these CTs could be (276 × 125 ÷ 100) = 345 A.. This is not a standard rating; therefore, select the next higher standard rating of 400 A. Hence, select 400/5 A CTs for use on the high-voltage side of the transformer.

C.1.2.3 Minimum pickup setting

The minimum pickup of the relay should be set at a level greater than the sum of the steady-state exciting current of the transformer under normal load conditions and the measurement error that is likely to occur at low load levels. If a level of 20% of nominal rating of the CT is selected for this purpose, the minimum pickup current would be (5 × 20 ÷ 100) = 1 A.

C.1.2.4 Percentage slopes setting

Assume that the relay protecting the transformer has a provision for using two slopes—one for lower levels of operating currents and the other for higher levels of operating currents. Also, assume that the restraining current is defined as 0.5 ($I_1 + I_2$).

a) For determining slope 1, the following factors are usually considered for determining the maximum unbalance:

   1) The first factor is the current due to CT mismatch. In this example, it has already been calculated as [(3.98 − 3.84) ÷ 3.84] × 100; 4%.

   2) The second factor that should be considered is the errors due to the accuracy of the CTs and the accuracy of the auxiliary CTs, if they are used. A typical value used for this purpose is 5%.

3) The third factor that should be considered is the error because the transformer may be operating at off-nominal taps for voltage regulation. Considering that the minimum voltage at which the transformer could be operating is 205 kV, the regulation, R, is $[(205 - 230) \div 230] = -0.109$. Alternatively, the transformer could be operating at 255 kV tap. The voltage regulation in this case is also $[(255 - 230) \div 230] = 0.109$. The maximum differential current due to the operation of the transformer at off-nominal tap, could be 11%.

4) Total error that could be experienced at full-load operation of the transformer is the sum of the errors calculated in factor 1), factor 2), and factor 3). This works out to $4 + 5 + 11 \approx 20\%$. When a numerical relay is used, the CT ratio mismatch is taken care of in the relay algorithm. The 4% CT mismatch error should not be included in calculating the total error.

5) Set slope 1 at 30%; this leaves sufficient margin above the calculated value of 20%.

b) Slope 2 is effective in the infinite region beyond the knee point of the operating characteristic of the transformer. This slope becomes important when through-faults occur and the restraint is quite high and a CT saturates as well. A 70% setting for this slope is reasonable. A utility may develop its own approach for calculating the required slope under these conditions. An approach used by a utility is described in C.4.

c) The restraint current at which slope 2 takes over from slope 1 is typically three p.u.

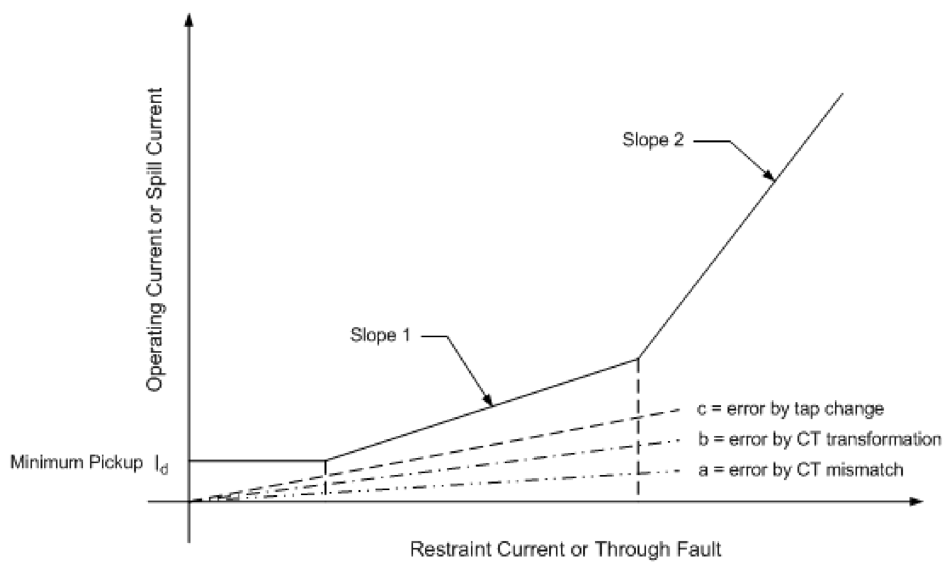


Figure C.3—Percentage differential slopes and differential currents due to various errors for the differential relay

C.2 Setting relays for a network autotransformer

The information provided in this clause is for setting numerical transformer protection relays for a network transformer. Consider the following scenario of a network substation:

— The voltage ratings of two networks are 345 kV and 118 kV.

— A 345/118 kV autotransformer with 34.5 kV delta-connected tertiary winding is provided to connect the two networks.

— The transformer is protected by an electromechanical differential relay. Backup protection is provided by a sudden-pressure relay.

— The relay has discrete taps ranging from 2.9 to 8.7 and these taps can be used to match currents from the windings during normal load.

— Total current into the relay during an internal fault should not exceed 220 A for one second.

— The substation is upgraded and a new autotransformer of 675 MVA replaces the original transformer. The self-cooled rating of this transformer is 400 MVA.

— The transformer has wye-connected primary and secondary windings and a delta-connected tertiary winding that is connected to a 50 MVAr reactor. The phase angle of delta winding with reference to the 345 kV winding is −30°.

— The original electromechanical differential relay is used to protect the new transformer.

— The original CTs continue to provide currents to the electromechanical differential relay.

— A numerical transformer differential relay is added for redundant protection. Backup protection is provided by a Buchholz relay that replaced the sudden-pressure relay provided on the older transformer.

— A new set of CTs are added to the substation for providing input to the numerical differential relay.

— Three CTs are buried in the tertiary winding (one in each phase of the delta winding). The secondary windings of these CTs are connected in parallel and the resulting output is provided to a backup overcurrent relay.

— Two lockout relays are provided; one relay is tripped by the electromechanical differential relay and the overcurrent relay, and the other lockout relay is tripped by the numerical relay and the Buchholz relay.

C.2.1 Transformer data

The data of the transformer being considered in this example is given in Table C.1. A single line diagram, showing the transformer, CTs, and relays, is given in Figure C.4.

Table C.1—Data of the 675 MVA transformer

	Winding 1	Winding 2	Winding 3
Voltage rating (kV)	345	118	34.5
Connection	Grounded wye	Grounded wye	Delta
Base (ONAN) rating (MVA)	400	400	80
Maximum rating (MVA)	675	675	80
Tap changer	No load; ±5% of 345 kV	None	None
Transformer current at base MVA (A)	669	1957	1339
Transformer current at maximum rated MVA (A)	1130	3303	1339
Primary protection	Microprocessor-based multifunction relay		
Secondary protection	Electromechanical relay (87) with CT ratio adjusting taps		

C.2.2 Electromechanical differential relay setting (87TS)

The ratios of CTs used for the electromechanical differential relay, the connections of the CTs, currents provided by the CTs, and the relay currents are listed in Table C.2.

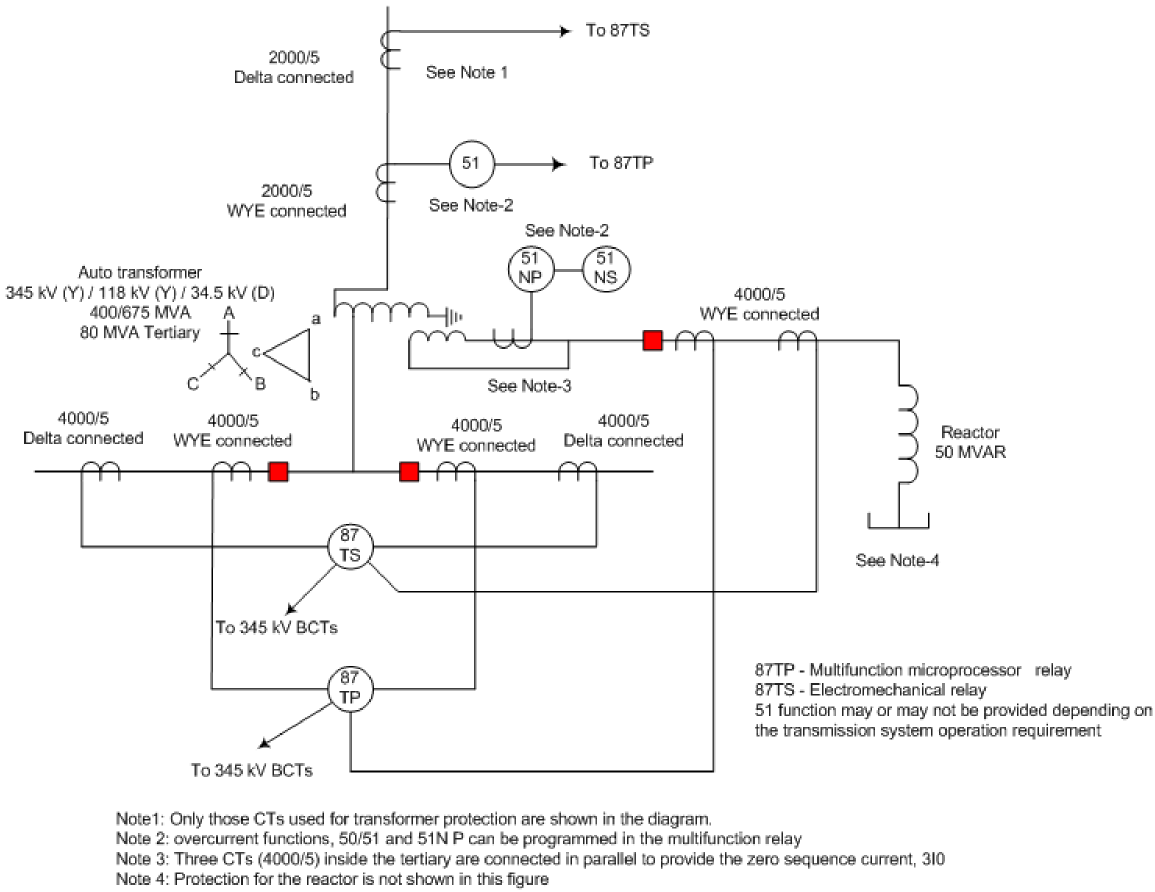


Figure C.4—Protection system for a 675 MVA, 345/118 kV autotransformer with delta-connected tertiary winding

Table C.2—CT and relay data for electromechanical differential relay

	Winding 1	Winding 2	Winding 3
CT ratio	2000/5	4000/5	4000/5
CT connection	Delta	Delta	Wye
CT secondary current at 400 MVA (A)	1.67	2.45	8.36 [a]
CT secondary current at 675 MVA (A)	2.82	4.13	14.11 [a]
Relay current at 400 MVA (A)	2.89	4.24	8.36 [a]
Relay current at 675 MVA (A)	4.89	7.15	14.11 [a] [1.67 A at 80 MVA]

[a] Though the tertiary winding is rated for 80 MVA, relay currents are calculated at MVA rating of the higher rated windings, to check for relay stability for external faults.

C.2.2.1 Criteria for CT ratio selection and relay tap setting

It is a practice in many utilities to ensure that the following ratings are not exceeded:

a) CT secondary current at maximum transformer MVA (675 MVA in this example) does not exceed the thermal rating of the CT secondary winding.

b) The relay current at maximum transformer MVA should not exceed the continuous thermal rating of the relay.

The following is also desirable:

— The CT ratios are selected such that the relay currents under maximum internal fault conditions do not exceed the relay short-time thermal ratings to prevent damage.

— The relay taps are chosen such that the error due to mismatch is below 5%.

CAUTION

If a transformer is loaded beyond the nameplate rating due to an emergency, the CT or relay, or both, are likely to be damaged if their thermal ratings are exceeded.

The relay current at self-cooled rating of 400 MVA of this transformer should not exceed the tap value. This is to prevent the operation of the unrestrained high-set unit (typically eight times the tap value) due to inrush current.

The ratios of currents from CTs (as a fraction of the current from winding 1), selected tap settings, and ratios of tap settings (as a fraction of the tap on winding 1) are listed in Table C.3. The percentage errors and total mismatch are also listed in this table.

Table C.3—Current ratios, relay taps, tap ratios, and mismatch errors

	Winding 1	Winding 2	Winding 3
Selected relay tap	2.9	4.2	8.7
Current ratio	1	1.46	2.89
Tap ratio	1	1.45	3.0
Percentage error		$\frac{(1.46-1.45)}{1.45}\times 100 = 0.7\ \%$	$\left\lvert\frac{(2.89-3.0)}{3.0}\right\rvert\times 100 = 4\ \%$
Mismatch error	Less than 5%		

C.2.2.2 Minimum pickup

In many electromechanical relays, the user cannot set the minimum pickup current of the relay. It is a fixed percentage of the tap setting and it varies with the manufacturer. Typical values are 30% and 35%.

C.2.2.3 Harmonic blocking/restraint setting

This is not a user-defined setting. The percentage varies with the manufacturer—the value of one manufacturer's relay is 20% whereas the value of another manufacturer's relay is 15%.

C.2.2.4 High-set-unit current setting

The setting is typically eight times the tap value, and it is not a user-defined setting.

C.2.2.5 Other settings

Mismatch due to no-load taps is 5% and the maximum ratio error mismatch is 4%. The total mismatch error is, therefore, approximately 9%.

The available slope settings are 15%, 25%, and 40%. The slope setting of 25% could be selected.

C.2.2.6 Verification of the thermal rating of the relay coils

Consider that the fault currents at this location are as listed in Table C.4. Currents for faults on the 34.5 kV side are less than the currents for faults on the 118 kV side.

Table C.4—Currents for faults in the transformer zone

Fault		Fault currents (A) from		Currents (A) to electromechanical relay from		
Type	Location	345 kV side	118 kV side	345 kV side	118 kV side	Total
Three phase	345 kV	26 500	5 500	115	12	127
Three phasee	118 kV	5 530	34 169	24	74	98

Total current in the electromechanical relay is less than 220 A, which is the maximum allowed in this case.

Relay currents due to single-phase-to-ground and other shunt faults should also be checked to verify that the currents in the relay will not exceed the rating of the relay. In this example, it is assumed that relay currents during other types of shunt faults are less than those listed in Table C.4.

C.2.2.7 CT burden verification

The burden on the CTs should be checked, as described in IEEE Std C37.110, IEEE Guide for Application of Current Transformers Used for Protective Relaying Purposes, to ascertain that the CTs do not saturate for faults in the transformer zone and in the networks to which it is connected.

C.2.2.8 Transformer overload capability

Continuous current rating of the relay coils vary with the manufacturer. One manufacturer specifies the continuous rating as two times the tap setting, whereas another manufacturer has a minimum rating of 8 A with a maximum varying with the tap setting. Consider that the relay used in this case is for the first type.

The tap setting on the 345 kV side is 2.9. This is $(2.89 \div 4.89) \times 100 = 59\%$ of current at 675 MVA.

The tap setting on the 118 kV side is 4.2. This is $(4.24 \div 7.15) \times 100 = 59\%$ of current at 675 MVA.

The tap setting on the 34.5 kV side is 8.7. This is 167% of current at 80 MVA.

The transformer can be overloaded up to 118% (2×59) of 675 MVA rating on 345 kV and 118 kV windings without exceeding the thermal limit of the relay. If the transformer needs to be loaded beyond 118% of its rating, CTs of higher ratio should be used and then auxiliary CTs should be used to match the working of the differential relay. This would allow higher tap settings to be used on the 345 kV and 118 kV sides.

If the second type of relay is used, the 2.9 tap setting has 8 A continuous rating and 4.2 A tap has a rating of 13 A. The transformer could be loaded up to 160% without exceeding the continuous rating of the relay inputs.

C.2.3 Microprocessor relay settings, 87TP

All CTs that are connected to the relay are connected in wye configuration.

Most of the modern relays need the settings whose procedures are described in the following parts of C.2.3: To make this document nonvendor-specific, all settings available with each vendor are not covered. Refer to the manufacturer's manuals for additional settings.

As previously mentioned in this clause, the phase angle of the delta winding with reference to the 345 kV winding is −30°. This setting may not be needed for some numerical relays. The ratios of CTs, CT connections, and tap settings are listed in Table C.5.

Table C.5—Ratios of CTs, connections of CTs, and tap settings of numerical relay

	Winding 1	Winding 2	Winding 3
CT ratio (A)	2000/5	4000/5	4000/5
CT connection	wye	wye	wye
Tap setting	2.82	4.11	14.11

Most of the relays can automatically calculate the TAP setting based on the values entered for the rated voltage and rated MVA. TAP setting is the secondary current at the rated MVA, usually the top-rated MVA.

Some relays require an internal compensation setting whereas others automatically determine the setting based on the winding configuration and the phase relationship of the winding with respect to winding 1 (the 345 kV connections in this example). However, the compensation setting that eliminates zero-sequence current should be chosen for grounded wye windings to avoid misoperation for single line-to-ground faults external to the transformer.

C.2.3.1 Minimum pickup

The minimum pickup is user-selectable. A setting of 0.2 times the nominal current ($0.2 \times 5 = 1$ A in this case) may be selected.

C.2.3.2 Slope of the relay characteristic

The slope is user-selectable. Slope 1 of 25% and slope 2 of 50% may be selected for this application. The switchover from slope 1 to slope 2 is also user-selectable. Switchover at three times the tap setting may be selected for this application.

C.2.3.3 Harmonic blocking

Harmonic blocking is also user-selectable. A setting of 15% may be selected. Transformer and relay manufacturers' advice is usually invaluable in this respect.

C.2.4 High-set overcurrent protection

A setting of eight times the tap value may be used. If the transformer is connected to a weak system, a lower setting may be used.

C.2.5 Ground overcurrent settings

All CTs inside the tertiary are connected in parallel configuration to provide $3I_0$ current. The pickup of the 51N relay should be set higher than the zero-sequence current expected due to the unbalance load currents. A typical setting of 1 A may be used. The time-current characteristics can be selected depending on the user's standards. It may be set as the moderately inverse curve defined in IEEE Std C37.112, IEEE Standard Inverse-Time Characteristic Equations for Overcurrent Relays.

The time dial is set to coordinate with other relays on the 345 kV and 118 kV systems. In this example, the time dial may be set to provide an operating time of at least 45 cycles for maximum current contribution for a single line-to-ground fault either on the 345 kV or 118 kV systems.

C.2.6 Instantaneous and inverse-time overcurrent relay settings

When instantaneous overcurrent function is used, it is set at 200% of the maximum contribution of the fault current on the low-voltage faults. This pickup value can vary. Refer to 8.3.

The pickup of the time overcurrent element, if used, is set above the maximum allowable load beyond the transformer top rating. In this example, it is set to 200% of the top rating. The time dial is coordinated with other relays on the 345 kV and 118 kV systems. A moderately inverse characteristic is selected for this application.

NOTE—The minimum pickup setting on the time overcurrent may be stipulated by utility, regional, or national guidelines.[6]

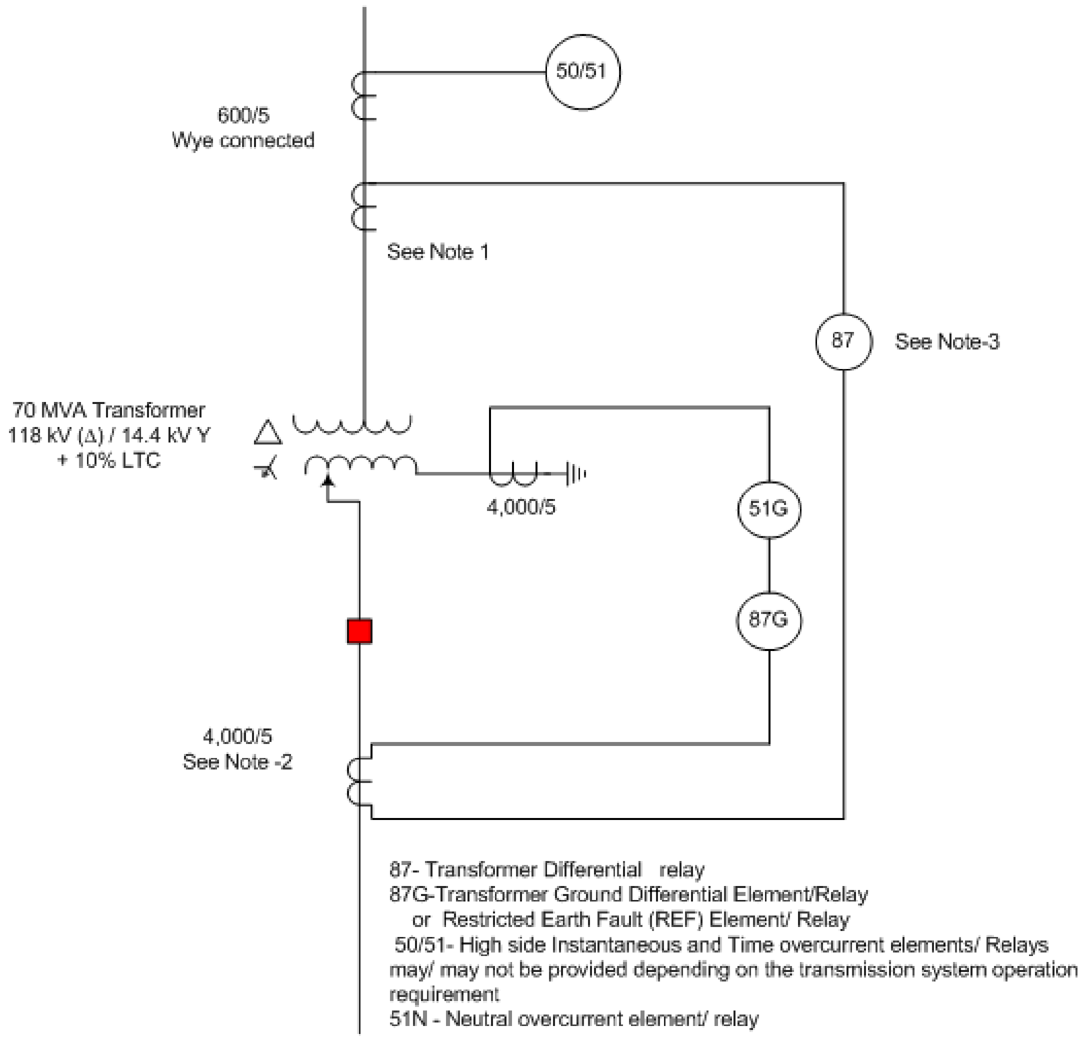
C.3 Relay settings for a transformer supplying energy to distribution systems

The information provided in this clause is for setting relays for protecting a power transformer that supplies energy to distribution systems. Consider the following scenario of a network substation shown in Figure C.5:

— A 70 MVA transformer steps down 118 kV to 14.4 kV for distribution of energy to customers.
— The primary winding of the transformer is connected in delta configuration.
— The secondary winding of the transformer is connected in wye configuration with neutral connected solidly to ground.
— A differential relay with harmonic restraint/harmonic blocking (87) is provided to protect the transformer.
— An instantaneous overcurrent/inverse time delay overcurrent relay (50/51) is provided for backup protection.
— A restricted earth-fault protection relay (87G) is provided for sensitive ground-fault protection on the wye winding of the transformer.
— An inverse-time overcurrent relay (51N) is provided for protection from earth fault.
— Two relays are used for providing 50/51 and 51N functions.
— A multifunction numerical relay is used for other protection functions.
— Two lockout relays are used; the first one is tripped by the differential relay and the second is tripped by the gas detection relay (sudden pressure/Buchholz) and overcurrent relays.

Another possible alternative to this protection configuration is to use two multifunction relays and activate all functions in each relay; this would provide full redundancy. The actual decision in this respect depends on the practice of the utility that evolves from its past experience.

[6] Notes in text, tables, and figures of a standard are given for information only and do not contain requirements needed to implement this standard.



Note-1: Only those CTs used for transformer protection are shown in the diagram.

Note 2: If the differential relay doesn't have the phase shift compensation setting, this CT should be connected in Delta and separate set of CTs or aux. CTs are required for 87G connection.

Note 3: All protection functions can be programmed in a single multifunction Relay. However, if additional CTs are available, for redundancy, 50/51 and 87 are generally connected to separate CTs or a second multifunction relay is installed.

Figure C.5—Protection of a 70 MVA transformer

C.3.1 Transformer data

The transformer data used for setting relays is listed in Table C.6.

Table C.6—Power transformer data

	Winding 1	Winding 2
Voltage rating (kV)	118	14.4
Winding connection	delta	wye-grounded
Phase shift	0	−30°
Capacity (MVA)	70	70
No-load-tap changer	−5% to +7.5% in 2.5% steps	
LTC		+10% in 32 steps
LTC setpoint	Set to regulate the low-side voltage to 14.0 kV	
CT ratio	600/5	4,000/5
Accuracy class	C400	C800
Thermal rating factor	1.5	1.5
CT connection	wye	wye (See NOTE)

NOTE—If the relay does not have internal compensation for transformer phase shift, this CT must be connected in delta. For this example, it is connected in wye and it is assumed that compensation setting is available in the relay.

C.3.1.1 Transformer and relay currents

Full-load currents and relay currents are listed in Table C.7.

Table C.7—Load, relay currents, and other relay settings

	High-voltage side	Low-voltage side
Full-load current at 70 MVA	342 A at 118 kV tap	2886 A at 14 kV LTC setpoint
Relay current at 70 MVA	2.85 A	3.61 A
Tap	2.85	3.61 (See NOTE 1)
Internal compensation (See NOTE 2)	Setting A (See NOTE 3)	Setting B 30° lag

NOTE 1—Most relays can automatically calculate the tap setting based on the rated voltage and MVA.

NOTE 2—Some relays require this setting whereas others automatically determine the setting based on the winding configuration and the phase relationship of the winding with respect to winding 1. In all cases, the compensation setting that eliminates zero-sequence current should be chosen for the grounded wye winding.

NOTE 3—Setting specifics depend on the type of the relay.

C.3.2 Differential relay setting

C.3.2.1 Minimum pickup setting

The maximum unbalance due to no-load-taps setting is 7.5% and the maximum unbalance due to LTC is 10%. The total error due to mismatch is therefore 17.5%. The minimum pickup setting should be greater than this value; a setting of 20% (0.2 times the tap setting) may be selected.

C.3.2.2 Slope of the relay characteristic

The slope is user-selectable. Slope 1 of 25% and slope 2 of 50% may be selected for this application. The switchover from slope 1 to slope 2 is also user-selectable. Switchover at three times the tap setting may be selected for this application.

NOTE—Most modern relays have a second slope setting. The switchover setting varies with the manufacturer.

C.3.2.3 Harmonic blocking

Harmonic blocking is also user-selectable. A setting of 15% may be selected. The manufacturer's advice is usually invaluable in this respect.

C.3.2.4 High-set overcurrent protection

A setting of eight times the tap value may be used. This setting should be higher than the maximum expected inrush current. If the transformer is connected to a weak system, a lower setting may be used.

C.3.3 Instantaneous overcurrent function settings

The instantaneous overcurrent relay setting should be 200% of the maximum fault contribution for a 14 kV bus fault. In this application, the fault current for a low-side fault is 1554 A. The setting of the instantaneous overcurrent function works out to be the following:

$$\frac{(2\times1554)}{\text{CT ratio}}=\frac{3108}{120}$$
$$=25.9\text{ A}$$

The overcurrent function (50) may be set at 26 A.

C.3.4 Inverse-time overcurrent function setting

The pickup is set above the maximum allowable load beyond the transformer top rating when time overcurrent function is used. In this example, it is set to 200% of the rating. The pickup, therefore, is [(2 × 342)/120] = 5.7 A. Time dial setting is coordinated with other relays on 14 kV and 118 kV systems. Moderately inverse characteristic is selected for this application. Relay characteristic curve selected at this location is the moderately inverse type defined in IEEE Std C37.112, IEEE Standard Inverse-Time Characteristic Equations for Overcurrent Relays. The time dial setting is selected to coordinate with low-side overcurrent relays protecting the 14 kV bus.

NOTE—The overcurrent curve should be below the mechanical damage curve of the transformer as described in Annex A of this guide.

C.3.5 Neutral overcurrent protection function

The pickup of neutral overcurrent protection function (51N) is set the same as bus ground overcurrent relay on the 14 kV side. Time dial is set to coordinate with bus overcurrent relays. Moderately inverse curve, defined in IEEE Std C37.112, IEEE Standard Inverse-Time Characteristic Equations for Overcurrent Relays, is selected.

C.3.6 Restricted earth-fault function

The transformer differential protection (87) with minimum pickup of 20% to 30% of rated current is not sensitive to detect ground fault that are close to the grounded neutral of the wye winding. Restricted earth-fault protection is provided for this purpose and is usually set at 10% of the transformer rating with inverse time-current characteristic. There is no coordination issue with other system relays because this relay operates only for ground faults on the wye winding of the transformer. Very low time dial and a very inverse time characteristic, defined in IEEE Std C37.112, IEEE Standard Inverse-Time Characteristic Equations for Overcurrent Relays, can be used for this application.

C.4 Calculating slope for use in a transformer differential relay

Figure C.1 shows the characteristic of a typical percentage-bias differential restraint relay. The x-axis and y-axis show restraint and differential currents used by the relay. In almost all relays, differential current is the vector difference of all input currents. However, there are variations as to how the restraint current is calculated; some of the options used are as follows:

— Half of the sum of the magnitude of all restraint or input currents

— Sum of magnitudes instead of half of the sum of all input currents

— Average of the magnitudes of all input currents

— Half of the vector sum of all input currents

The characteristic shown in Figure C.1 has restraint current calculated as half of the sum of the magnitudes of all input currents. Also, differential and restraint currents are calculated using p.u. or normalized values of all input currents. Typically, tap values, which are CT secondary currents when the transformer is operating at maximum rating at nominal voltage, are used as a basis for per-unitizing.

A proper application of percentage-bias characteristic decreases protection sensitivity as the differential currents increase with increased load currents or fault currents due to external faults so that the relay does not misoperate. Sources of these erroneous differential currents include transformer magnetizing current, operation at off-nominal taps, mismatch in ratio or characteristics of CTs, unmetered loads on tertiary windings, and relay measurement errors.

The characteristic, as shown, has three distinct restraint regions: minimum pickup, first slope, and second slope. The minimum restraint setting prevents misoperation when the transformer is lightly loaded and the through-currents are of low values. Considering that the transformer is operating at maximum offset tap, the differential current due to CT ratio mismatch would be 0.1 p.u.. If the magnetizing current is assumed to be 0.03 p.u., the total expected differential current would be 0.13 p.u. However, the CT and relay measurement errors at light loads can be higher than the nominal errors. Higher settings for the minimum pickup are often used; these can be as high as 0.3 p.u. on forced rating, which is approximately 0.5 p.u. on natural rating.

The second slope prevents misoperation when heavy external faults and mismatch increases significantly due to CT saturation. Based on experience, 60% to 70% for the second slope is used as a rule of thumb and breakpoint between the first and second slopes is set at 3.0 p.u.

Instead of using this rule of thumb, it is possible to simulate the performance of a differential characteristic when a CT saturates. The procedure starts with simulating an external fault and preparing a data file of the fault currents at the high-voltage level. Models of unsaturated and saturated CTs can then be used to calculate the data that would be provided to the differential relay algorithm that calculates the phasors of the operate currents and restraint currents. Plots of the restraint-operate currents can then be prepared. One such plot from a simulation is shown in Figure C.6. This plot shows that the margin between the calculated restraint-operate currents combination during CT saturation and the second slope is small. The gradient of the second slope needs to be increased to ensure adequate security margin.

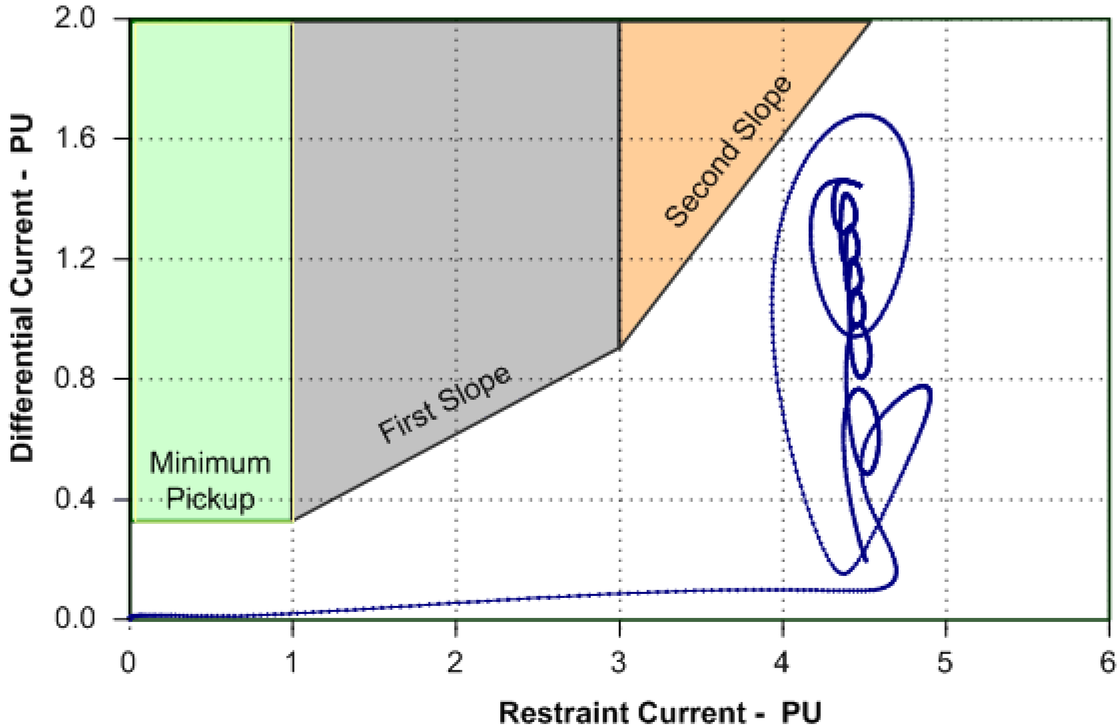


Figure C.6—Percentage-bias characteristic with simulated restraint and differential currents superimposed

Annex D

(informative)

Thermal overload protection

D.1 General theory

The insulating material surrounding the phase-current conductors in transformers ages rapidly if the temperature exceeds the value used during the design process. All electrical conductors have finite resistance at operating temperatures, and the active power losses, I^2R, cause the temperature to increase; the losses are proportional to the square of the current. The thermal energy is removed from the conductors by conduction; the removal is proportional to the temperature difference between the conductor and the surrounding material. The temperature increase of the conductor, when nominal current is applied, can be defined as a function of time by the so-called thermal time constant, T, as shown in Figure D.1. The temperature rises to 63% of the final value in a time equal to T and reaches 98% of the final value in time $4T$. If the current is reduced to 71% of the nominal value, the temperature decreases and settles at about half of the final value ($0.71^2 = 0.50$) because the increase in temperature is proportional to the square of the current. If a current equal to 1.26 times the rated value is applied, the temperature rise to the maximum value in time T (1.262 × 0.63 = 1) and the final temperature would be 1.6 (= 1.26^2) times the rated value.

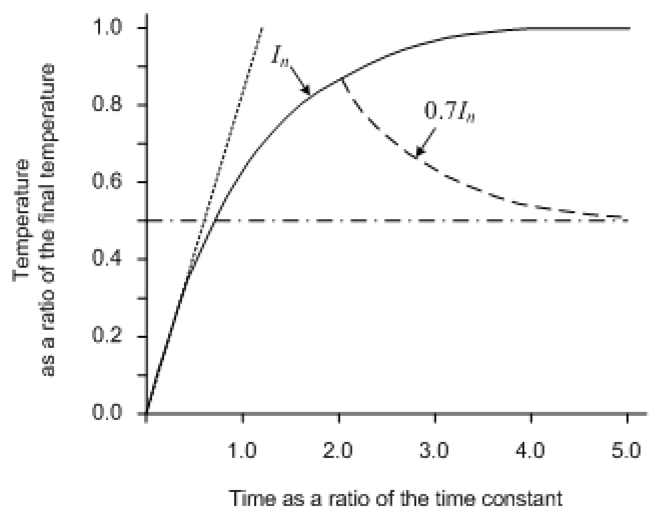


Figure D.1—Temperature rise as a function of time

Power transformers and cables are often required to permit short-time overloads, usually up to 1.5 times the rated current. The short-circuit overcurrent relays used for phase-fault protection are normally set at an operating value that is far too high to provide any thermal protection.

Temperature and overload of oil-filled transformers are monitored with indicating thermostats that have become standard accessories. The oil thermometer, which measures the top-oil temperature, cannot be relied upon to detect short-time overloads beyond permissible limits. Large transformers often have a so-called "winding thermometer." In this arrangement, the oil temperature augmented with a heater element fed from the load current is used. This device provides good monitoring of the temperature of the winding if properly calibrated and maintained during service.

D.2 Winding temperature monitoring on transformer with on-load-tap changer

OLTCs are provided to regulate the voltage delivered downstream on the network. Depending on the tap position of the OLTC transformers, the base currents may be different on the high-voltage and low-voltage windings. Usually the rated current is established for both windings at the mid-tap position, and this leads to reduced rated power on some taps. When such transformers operate under overload conditions during system contingencies, the OLTC typically moves from the normal operating position to the end of the tapping range to compensate for the voltage drop in the system. Depending on the design of the transformer, the winding hottest spot may well move from the high-voltage winding to the low-voltage winding or vice-versa. Most transformers are provided with a single WTI, which does not allow independent monitoring of the temperature of all windings.

Accurate temperature monitoring on both windings is needed to take full advantage of the loading capabilities of the transformer during emergency conditions. Limitations of the WTI should be accounted for when transformers are expected to be overloaded. For more details, see Aubin et al. [B1].

D.3 Limitations of traditional winding temperature indicator

Power transformers are usually provided with a WTI. This device comprises a temperature-sensing bulb inserted in a well in the top layer of the insulating oil. Surrounding the bulb is a heater element to which a sample of the load current is applied as shown in Figure D.2. The current flow in the heater element causes the temperature bulb to read the oil temperature plus a temperature rise from the heater, which is calibrated to be the same as the winding hottest temperature rise above top-oil temperature. The fluid in the bulb expands through a capillary tube connected to a dial gage equipped with switches that can be set at any temperature within the operating range. This arrangement provides accuracy of 3 °C to 5 °C if the transformer designer succeeded in properly evaluating the winding hottest-spot temperature. This device can be used for “transformer temperature high” alarm. These systems are sufficiently rugged to be used for protection purpose if the recommended maintenance is carried out at regular intervals. WTIs offered by several manufacturers provide dependable winding temperature indication at a cost-effective price.

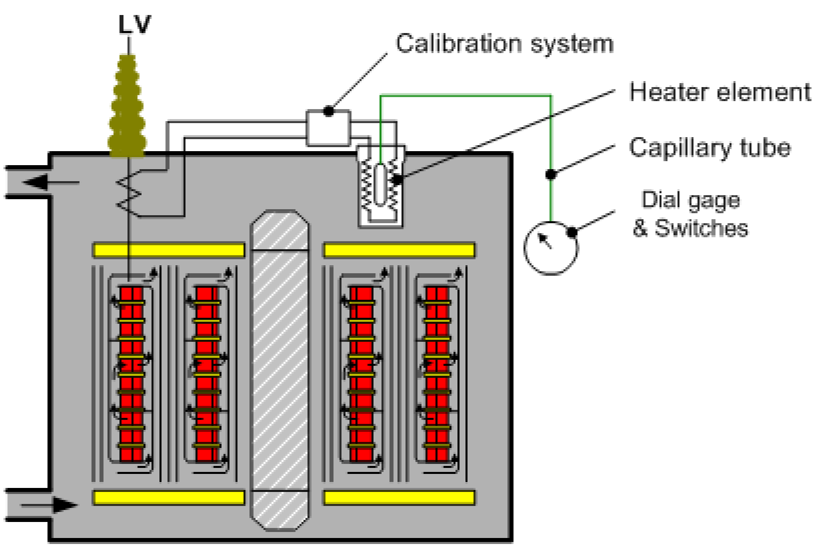


Figure D.2—Thermomechanical winding-temperature-type indicator

A single WTI is sufficient for a transformer without tap changer because the calibration circuit allows for the simulation of the hottest winding temperature even if the current is measured on a different winding. However, the situation is different on a transformer with a tap changer because the ratio of primary and secondary currents varies as the tap position changes. In such cases, the WTI cannot be used to monitor the temperature on the primary side if the CT providing the load-current measurement is on the secondary winding. Common practice requires the winding hot-spot temperature indicator to be fed by a CT on the low-voltage winding. This provides good control over the temperature of the low-voltage winding regardless of the transformer load. For the high-voltage winding, the situation is not so clear.

D.3.1 An example

Consider a 42 MVA, wye/delta-connected, 120/26.4 kV transformer with a tap changer of ± 8 steps at the neutral end of the high-voltage winding. Each step changes the rated voltage on the primary by 2.25 kV or 1.875% of the rated voltage. The tap changer is intended to regulate the voltage on the secondary side (26.4 kV) of the transformer. Therefore, the voltage and current variations are listed in and are shown in Figure D.3.

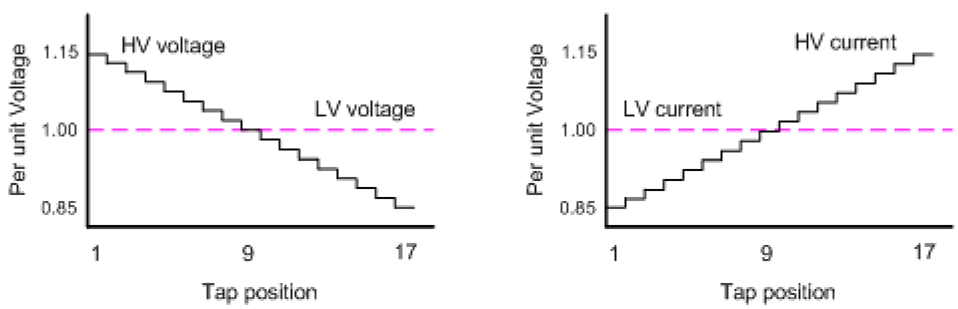


Figure D.3—Voltage and current characteristics for a transformer with full-load capacity on all taps

The current in the high-voltage winding is less than the value at 1.0 tap position when the tap setting is between 1 and 9. Therefore, this winding will be cooler than the rated value. If the tap position is between 9 and 17, the high-voltage winding will be carrying more current than the current at tap 1.0, and therefore the temperature of the winding will be higher than the rated temperature at tap 1.0. Unfortunately, the WTI will not reveal this situation. When the transformer in designed to deliver full MVA on any tap, the high-voltage winding has to be enlarged by a value close to the tapping range so that it would have the capability of carrying the extra current on tap 17.

In most cases, the maximum losses due to load currents are to be found on tap position 17; therefore, this is the tap position that will be used to carry out the temperature rise test. Since the winding temperature rise is known in position 17 and the WTI is fed by a CT on the secondary winding, the winding temperature simulation, on any tap position, will be realistic for the low-voltage winding and conservative for the high-voltage winding.

In practice, transformers with OLTCs are commonly designed with a reduced capacity for some parts of the tap range. This is a well-recognized practice in the industry. The voltage and current variations for a transformer, similar to the one described previously but with reduced capacity on some taps, are given in Table D.2 and are illustrated in Figure D.4. The full capacity is available from tap 1 to tap 9, but from tap 9 to tap 17 there is a progressive reduction of the delivered power due to limitation current capacity of the primary winding.

Table D.1—Voltage and current variations for three-phase transformer with full-load capacity on all taps

120/26.4 kV, 25/33/42 MVA; Full MVA rating on all taps Wye-Delta transformer with OLTC on the primary HV side (±15% regulation)										
Primary side					Secondary side				Operational limits	
Tap	V_{prim} kV	I_{prim} A	S_{prim} MVA	Winding	V_{sec} kV	I_{sec} A	S_{sec} MVA	Winding	I_{sec} A	Delivered power at 26.4 kV (MVA)
1	138.00	176	42.00	↑ COLDER				Const. Temp.	919	42.00
2	135.75	179	42.00						919	42.00
3	133.5	182	42.00						919	42.00
4	131.25	185	42.00						919	42.00
5	129.00	188	42.00						919	42.00
6	126.75	191	42.00						919	42.00
7	124.5	195	42.00						919	42.00
8	122.25	198	42.00						919	42.00
9	**122.25**	**202**	**42.00**		**26.4**	**920**	**42.07**		919	42.00
10	117.75	206	42.00	HOTTER ↓				Const. Temp.	919	42.00
11	115.50	210	42.00						919	42.00
12	113.25	214	42.00						919	42.00
13	111.00	218	42.00						919	42.00
14	108.75	223	42.00						919	42.00
15	106.50	228	42.00						919	42.00
16	104.25	233	42.00						919	42.00
17	102.00	238	42.00						919	42.00

Table D.2—Voltage and current variations for three-phase transformer with reduced-load capacity on some taps

285/26.4 kV, 84/112/160 MVA with reduced MVA ratings on some taps Wye-Delta transformer with OLTC on the primary HV side (±15% regulation)										
Primary side					Secondary side				Operational limits	
Tap	V_{prim} kV	I_{prim} A	S_{prim} MVA	Winding	V_{sec} kV	I_{sec} A	S_{sec} MVA	Winding	I_{sec} A	Delivered power at 26.4 kV (MVA)
1	327.75	247	140.22		26.4	3062	140.01		3066	140.22
2	322.40	251	140.16		26.4	3062	140.01	H	3065	140.16
3	317.05	255	140.03	C	26.4	3062	140.01	O	3062	140.03
4	311.70	259	139.83	O	26.4	3062	140.01	T	3058	139.83
5	306.40	264	140.10	L	26.4	3062	140.01	T	3064	140.1
6	301.05	268	139.74	D	26.4	3062	140.01	E	3056	139.74
7	295.70	273	139.82	E	26.4	3062	140.01	R	3058	139.82
8	290.35	278	139.81	R	26.4	3062	140.01		3057	139.81
9	**285**	**284**	**140.19**		**26.4**	**3062**	**140.01**		3066	140.19
10	279.65	**284**	137.56		26.4	3008	137.56	C	3008	137.56
11	274.30	**284**	134.93	H	26.4	2951	134.93	O	2951	134.93
12	268.95	**284**	132.30	O	26.4	2893	132.30	L	2893	132.30
13	263.60	**284**	129.67	T	26.4	2836	129.67	D	2836	129.67
14	258.30	**284**	127.06	T	26.4	2779	127.06	E	2779	127.06
15	252.95	**284**	124.43	E	26.4	2721	124.43	R	2721	124.43
16	247.60	**284**	121.80	R	26.4	2664	121.80		2664	121.80
17	242.25	**284**	119.16		26.4	2606	119.16		2606	119.16

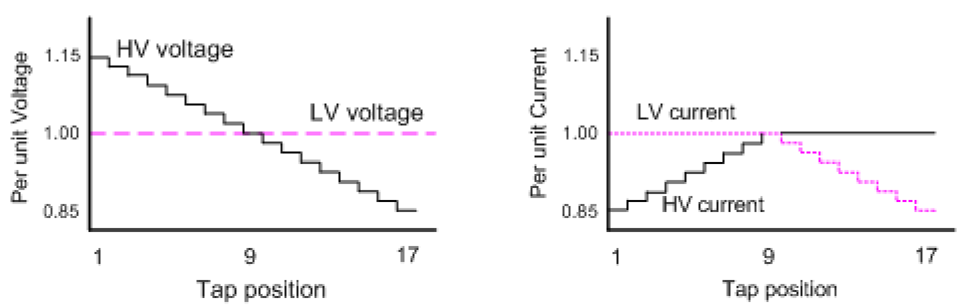
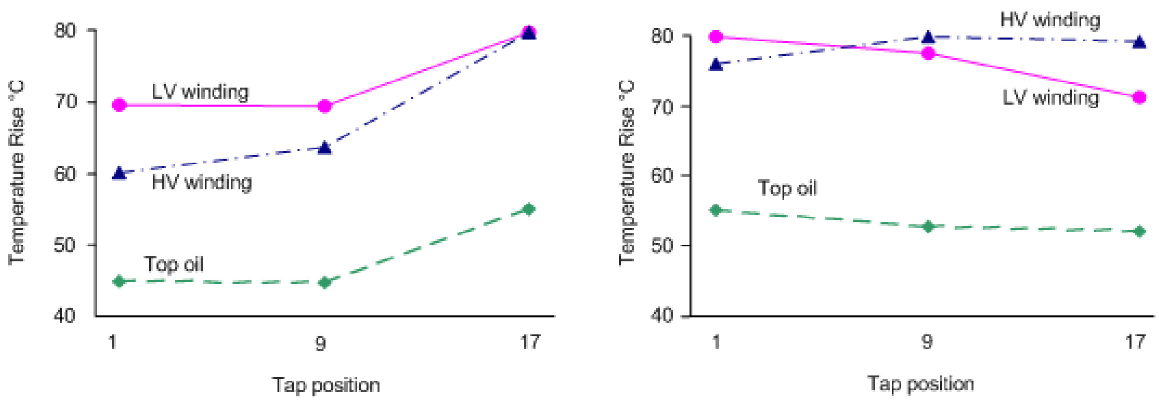


Figure D.4—Voltage and current characteristics for a transformer with reduced-load capacity on some taps

For transformers with full capacity on all taps, the position showing maximum losses due to load currents is tap 17. For transformers with reduced capacity on some taps, the highest losses are on tap 1 and this is the connection that should be used for the temperature rise monitoring. This situation makes it more difficult to monitor with confidence the high-voltage winding hot-spot temperature from a measurement of the secondary winding current. Although test results normally show a lower temperature rise for high-voltage windings, it is clear that between tap positions 9 and 17, the primary winding will reach its temperature limit long before the secondary winding. The difference between the temperature patterns for the two types of transformer is illustrated in Figure D.5. It is assumed that both transformers show a winding temperature rise to the limit of 80 °C, top-oil temperature rise to 55 °C, and an additional 25 °C temperature rise due to winding currents.



a) Full capacity on any taps

b) Reduced capacity on some taps

Figure D.5—Winding temperature pattern for the two different types of transformers

It can be seen that for a full-capacity transformer tested on tap 17, the low-voltage winding is always the limiting factor. But for transformers with reduced capacity and tested on tap 1, the highest temperature may shift from one winding to another depending on the tap position.

Monitoring only the low-voltage winding temperature can be deemed acceptable for loads up to nameplate rating, but this situation becomes unacceptable when overloading is considered because during overload conditions, the temperature difference may exceed 20 °C depending on the position of the tap changer.

D.4 Protection

Thermal protection of transformers is primarily provided by the WTI. Overcurrent protection could provide partial backup protection depending on the relay setting, but this practice should not be relied upon. If the setting of overcurrent protection is raised to allow for overload conditions, the WTI should be considered as the main thermal protection for the transformer windings, and monitoring only one winding of the power transformer may not be adequate. Consequently, one option would be to add a WTI on the second winding so that both windings would be protected independently regardless of the tap changer position. If not already available, this would require the installation of an additional CT on one of the high-voltage bushings to monitor the high-voltage current. But, it is generally not practical to add a CT on existing bushings. Therefore, this option is applicable only on new units where the additional CT can be provided at a reasonable price.

D.5 Digital relays for transformer thermal winding protection

One application is the use of a digital protection device that calculates independently the temperature on the primary, secondary, and tertiary windings using the measured top-oil temperature and currents in all the windings as inputs. This is illustrated in Figure D.6.

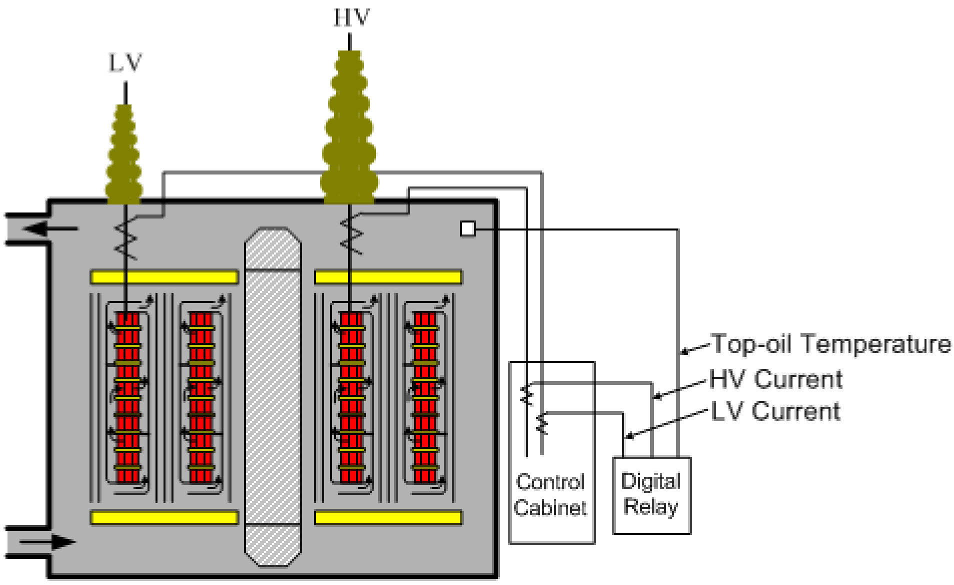


Figure D.6—A typical protection against hottest-spot temperature of a transformer

In many relays, the winding temperature is calculated as recommended in the IEEE Std C57.91-1995, IEEE Guide for Loading Mineral-Oil-Immersed Transformers. For the high-voltage winding hottest spot, the ultimate value of the temperature rise above top oil is given by the Equation (D.1):

$$\Delta\Theta_{\mathrm{HVu}} = \Delta\Theta_{\mathrm{HVR}}\left[\frac{I_{\mathrm{HV}}}{I_{\mathrm{HVR}}}\right]^{2m} \tag{D.1}$$

where

- Θ_{HVu} is the ultimate high-voltage winding hot-spot temperature rise above top oil
- Θ_{HVR} is the rated high-voltage winding hot-spot temperature rise above top oil
- I_{HV} is the load current in the high-voltage winding
- I_{HVR} is the rated value of load current in the high-voltage winding
- m varies from 0.8 to 1.0

The response of the winding to a sudden load increase is not instantaneous. Considering the winding time constant τ, the actual winding hot-spot temperature rise above top oil at time t is given by Equation (D.2):

$$\Delta\Theta_{\mathrm{HVt}} = \left[\Delta\Theta_{\mathrm{HVu}} - \Delta\Theta_{\mathrm{HVi}}\right]\left[1-e^{-\frac{\Delta t}{\tau}}\right] + \Delta\Theta_{\mathrm{HVi}} \tag{D.2}$$

where

Θ_{HVt} is the high-voltage winding hot-spot temperature rise above top oil at time t

Θ_{HVi} is the high-voltage winding hot-spot temperature rise above top oil at time $t - \Delta t$

Δt is the time increment used in the calculation

τ is the winding time constant

A similar set of equations are used for calculating the winding temperature rise above top oil for low-voltage windings and tertiary windings. These temperature rises are then added to the measured top-oil temperature. This approach has been found to be sufficiently accurate for reliable monitoring of the winding temperatures and protection of the transformer from insulation aging.

D.6 Methods for calculating winding temperature

Winding temperature measurement for substation power transformers has traditionally been the desired method to control the cooling systems. Typically, the devices that measure winding temperature are used on transformers larger than 7.5 MVA but can be used on smaller transformers as well.

D.6.1 Simulating or calculating hot-spot temperature

The reason for using the simulated or calculated winding temperature for controlling the cooling of oil-filled power transformers is that it responds faster to a step response in load current than the devices that measure the top-oil temperature. The details of the reason for this difference is given in IEEE Std C57.91-1995, IEEE Guide for Loading Mineral-Oil-Immersed Transformers. The equations for performing these calculations are also given in IEEE Std C57.91-1995, IEEE Guide for Loading Mineral-Oil-Immersed Transformers. Those equations illustrate that the winding temperature is derived by multiplying the ratio of load current to rated load raised to an exponent and then multiplied by a derived hot-spot gradient over top oil at rated load. Typically, the exponent is in the range of 1.6 to 2.

As the load on the transformer approaches the rated load, the ratio of load to rated load approaches unity. At unity, the simulated or calculated winding temperature is the top-oil temperature plus the hot-spot gradient. As the load current increases beyond the rated load, the ratio quickly increases due to the fact that the ratio is an exponential relationship. Because of this relationship, the load step response of winding temperature is faster than that of oil temperature, which is dependent on the volume of oil in the tank.

Since the 1980s, electronic systems have been developed that calculate the winding temperature using the thermal models used to simulate winding temperature. The devices rely on the computational power of the microprocessor. The equations used are typically based on the models described in IEEE Std C57.91-1995, IEEE Guide for Loading Mineral-Oil-Immersed Transformers. The major advantage of the calculated winding temperature is that it is faster than simulated winding temperature because it does not rely on a physical heating element to raise the probe temperature above the top-oil temperature. In addition, calculated winding temperature has been found to be more accurate and less subject to drift over time.

D.6.2 Measuring temperature with embedded resistance temperature detector sensors

RTDs, also called remote thermal devices, are sensors that are widely used in industrial applications for monitoring temperature. These sensors are typically made from platinum, copper, or nickel and are built as wire-wound or thin film devices. They have found widespread use in industry due to their accuracy, stability, reproducibility, and linear temperature dependency. RTDs made from platinum are generally used for monitoring application in transformers due to the inert characteristic of platinum.

Unlike thermocouples, which produce a voltage when heated, RTD sensors are resistance-based devices that are connected to a remote voltage source. A change in resistance, due to a change of temperature of the surrounding, is measured by the monitoring circuit using two, three, or four lead-wire connections. RTDs can be directly connected to commercially available devices including some relays or intelligent electronic devices (IEDs). A four-wire connection provides the most accurate temperature reading because the resistances of the leads to the sensor are balanced in a bridge network. Three-wire configurations are very popular in industrial applications and provide good accuracy if the resistances of all the leads are equal.

RTDs used for transformer temperature monitoring should consider calibration and maintenance aspects of the device as well as immunity to noise on the low-voltage leads that connect the output of the RTDs to the IED and the voltage source. Some RTDs are capable of using a fiber-optic link from the transformer to the IED in order to minimize the effects of noise on the leads.

RTDs have an advantage over the traditional temperature monitoring devices in that the measured quantity can be used as a direct input into the protection equipment. However, the response times of the thermal process and, consequently, the RTDs are not fast enough for high-speed relaying applications.

D.7 Testing thermal relays

The manufacturers' recommendations should be followed in testing and calibrating these devices. One method with one design is to remove the relay from the transformer and immerse the temperature sensitive element in a controlled-temperature oil bath. The heating element that provides the load-current effect is an integral part of the well in which the relay sensing element is mounted, and provision is made to circulate current from a test source through this heater to check the operation of this element. These relays consist of dial-type temperature indicators with shaft-operated switches. The design should ensure that the high temperature contact, which is used for tripping, cannot be operated by reverse rotation under very low temperature conditions.

Calibration procedures should ensure that the relay contacts and the temperature dial indication are within specified limits. The thermal time constant of the system is not usually adjustable in the field. It can be confirmed by plotting the indicated temperature versus time duration of a constant load current. The time constant is the time it takes for the reading to reach 63.2% of the total change of temperature readings. This should relate to the 5 min to 15 min time constant of the transformer winding, rather than to the 1 h to 2 h time constant of the oil. The calibration cannot be considered complete without confirming the ratio of the CT used to provide current to the relay heating element. These CTs are generally made to saturate at high fault current, so as to avoid heater damage and to ensure that the thermal relay does not operate before planned protective relay action occurs. Should severe overloads also cause CT saturation, the thermal relay will not respond in the desired manner.

Annex E

(informative)

Phase shift and zero-sequence compensation in differential relays

The phase angles of the primary and secondary line currents at the terminals of wye-delta and delta-wye transformers do not match; there is a phase shift that depends on the connections of the wye and delta windings. Also, the zero-sequence currents circulate in the delta windings and therefore do not appear in the line currents. Transformer differential protection applications in such cases require compensation for the phase shift and the lack of zero-sequence currents in the lines connected to the delta windings. Traditionally, this compensation has been achieved by judicious connection of the CTs. The basic premise is to mirror the connections of the windings of the protected transformer with the connections of the CTs.

E.1 Example

To illustrate the concept, consider the example shown in Figure 5 of this guide (also shown as Figure E.1). The protected transformer has a delta-connected winding on the high-voltage side and wye-connected winding on the low-voltage side. The positive-sequence currents in the lines connected to the high-voltage winding (delta winding) lead the currents in the lines connected to the low-voltage winding (wye winding) by an angle of 30°. This connection is usually referred to as a “delta A minus B” (DAB). The IEC standard refers this as Dy1 (1 refers to the number of 30° by which the positive-sequence currents in the lines connected to the low-voltage winding lag the positive-sequence currents in the lines connected to the high-voltage winding).

While the positive-sequence currents in the lines connected to the low-voltage winding have a 30° phase lag with respect to the currents in the lines connected to the high-voltage winding, the negative-sequence currents in the lines connected to the low-voltage winding have a 30° phase lead with respect to the currents in the lines connected to the high-voltage winding. The zero-sequence currents in the three phases, if flowing on the low-voltage side, are in phase with each other and the currents induced in the high-voltage winding due to the flow of the zero-sequence currents in the low-voltage winding circulate in the delta winding. The zero-sequence currents in the lines connected to the wye winding (because of ground faults) are, therefore, not reflected in the lines connected to the high-voltage windings.

When electromechanical relays are used, the CTs provided in the lines connected to the delta winding are connected in wye and the CTs provided in the lines connected to the wye winding are connected in delta using the ($I_a - I_b$, $I_b - I_c$, and $I_c - I_a$) connection. The result is that the currents in the differential protection circuits always match the currents in the protected transformer. There is no differential current for load currents and external fault currents flowing through the transformer.

Most modern static analog and numerical relays have the ability to internally combine the phase currents such that compensation is accomplished without using special CT connections. The relay is provided with secondary values of the phase currents by connecting all of the CTs in wye. The relay internally combines these currents to achieve the desired compensation. In a static analog relay, jumpers or some other means are used to combine the currents in the appropriate configuration. In a numerical relay, the desired combination of currents is achieved mathematically.

The compensation of phase shift and nonreflection of the zero-sequence currents to the lines connected to the delta winding is needed in numerical relays. A simple multiplication of the calculated phasors of the currents of the low-voltage side by $1 \angle 30°$ is not sufficient because this compensates for the shift of positive-sequence components only. All numerical relays, therefore, emulate the traditional approach for combining the currents.

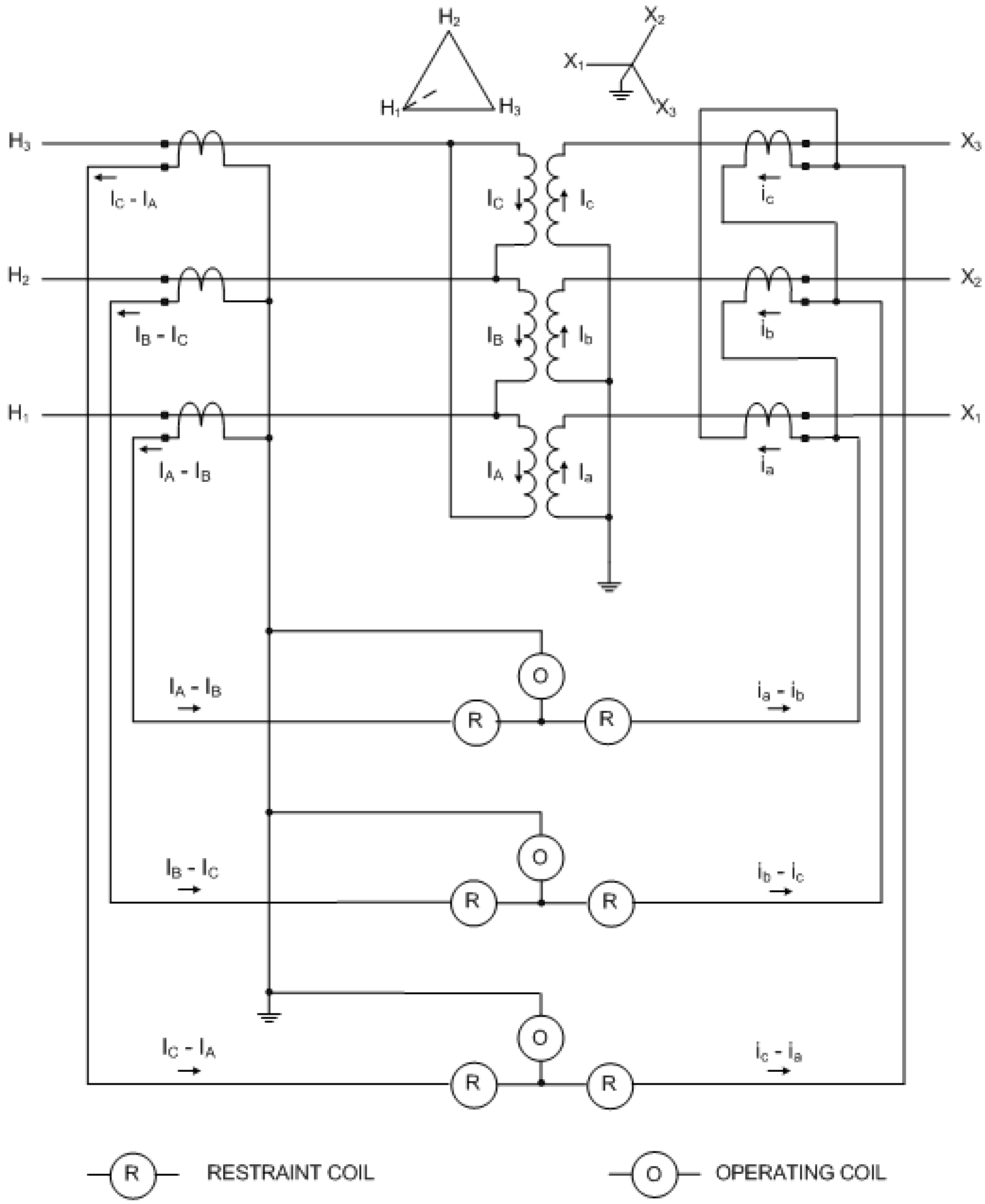


Figure E.1—Typical schematic diagram for a percentage differential relay for a delta/wye transformer

E.2 Reasons for using internal compensation

The ability to connect CTs in wye is desirable for the following reasons:

— With wye-connected CTs, the current that the phase and negative-sequence overcurrent relays see is the same as that seen by other system relays making it easier to coordinate them.

— Residual overcurrent protection can be used with wye-connected CTs.

— Using wye-connected CTs is convenient when relays perform multiple functions.

— Each set of CTs can be connected independently to ground if they are wye connected.

— Delta-connected CTs see three times the lead burden for a three-phase fault while wye-connected CTs see only one times the lead burden for the same fault. This makes CT saturation less likely when the CTs are wye connected.

However, keeping the delta-connected CTs (on the wye winding) can be more economical for upgrade or retrofit applications because the design, layout, and rewiring can be quite expensive. If it is decided to keep the existing wiring where CTs on the wye winding are connected in delta, the other functions available on numerical relays, such as 50/51, will see the delta currents and may not coordinate properly with the downstream protection systems. In such cases, the numerical relays utilize phase currents by calculating them from the delta currents and the ground current so that protection functions (50/51) work properly.

E.3 Differential current compensation connections

A protection system designer can choose one out of a number of options for achieving the desired current compensation for differential protection of transformers. The options include the applications in which delta-wye transformers, like the one considered in E.2, are to be protected. Two other issues are important. One is the protection of delta-delta connected transformers and the other is trapping the zero-sequence currents. With the use of auxiliary CTs, there are two additional possibilities—double-delta compensation and zero-sequence trap. Wye connection of CT secondary circuits is shown in part (a) of Figure E.2, the double-delta connection is shown in part (b) of Figure E.2, and the delta connection of the CT circuit is shown in part (c) of Figure E.2. The matrix representations of these connections are also shown in these figures (these matrices are those shown in row 0 and row 1 of Table E.1).

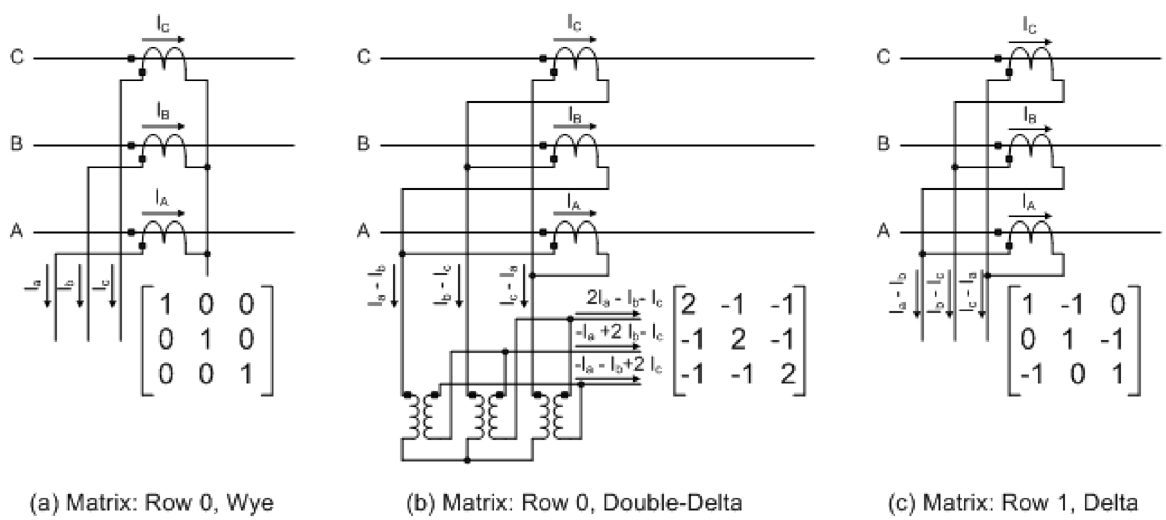


Figure E.2—Wye, double-delta, and delta connections of CTs and mathematical representations of those connections

Table E.1 shows compensation arrangements for phase shifts that cover all possible 30° increments around the clock. The table is arranged with five columns. The first column lists the row number and the second column indicates the number of degrees of phase shift that the compensation matrix will cancel out. For example, if the phase shift across the transformer is 30° lagging for an ABC phase-sequence system, a matrix in row 1 would be required to shift the current back to 0°. The third, fourth, and fifth columns show the specific matrix of the three possible types of compensation matrixes: wye, delta, or double-delta.

The most often used transformer connections are listed in rows 1, 2, 5, 7, and 11.

Table E.1—Compensating differential currents for numerical relays

Row	Degrees shift that would be cancelled		Wye	Delta	Double-Delta
0	ABC, 0*30° cw[a]	0°	$1\begin{bmatrix}1 & 0 & 0\\0 & 1 & 0\\0 & 0 & 1\end{bmatrix}$ Wye		$\frac{1}{3}\begin{bmatrix}2 & -1 & -1\\-1 & 2 & -1\\-1 & -1 & 2\end{bmatrix}$
	ACB, 0*30° ccw[b]	0°			
1	ABC, 1*30° cw	30°		$\frac{1}{\sqrt{3}}\begin{bmatrix}1 & -1 & 0\\0 & 1 & -1\\-1 & 0 & 1\end{bmatrix}$ Delta A-B (DAB)	
	ACB, 1*30° ccw	330°			
2	ABC, 2*30° cw	60°	$1\begin{bmatrix}0 & 0 & -1\\-1 & 0 & 0\\0 & -1 & 0\end{bmatrix}$		$\frac{1}{3}\begin{bmatrix}1 & -2 & 1\\1 & 1 & -2\\-2 & 1 & 1\end{bmatrix}$
	ACB, 2*30° ccw	300°			
3	ABC, 3*30° cw	90°		$\frac{1}{\sqrt{3}}\begin{bmatrix}0 & -1 & 1\\1 & 0 & -1\\-1 & 1 & 0\end{bmatrix}$	
	ACB, 3*30° ccw	270°			
4	ABC, 4*30° cw	120°	$1\begin{bmatrix}0 & 1 & 0\\0 & 0 & 1\\1 & 0 & 0\end{bmatrix}$		$\frac{1}{3}\begin{bmatrix}-1 & -1 & 2\\2 & -1 & -1\\-1 & 2 & -1\end{bmatrix}$
	ACB, 4*30° ccw	240°			
5	ABC, 5*30° cw	150°		$\frac{1}{\sqrt{3}}\begin{bmatrix}-1 & 0 & 1\\1 & -1 & 0\\0 & 1 & -1\end{bmatrix}$	
	ACB, 5*30° ccw	210°			
6	ABC, 6*30° cw	180°	$1\begin{bmatrix}-1 & 0 & 0\\0 & -1 & 0\\0 & 0 & -1\end{bmatrix}$		$\frac{1}{3}\begin{bmatrix}-2 & 1 & 1\\1 & -2 & 1\\1 & 1 & -2\end{bmatrix}$
	ACB, 6*30° ccw	180°			

[a] cw = clockwise

[b] ccw = counter clockwise

Table E.1—Compensating differential currents for numerical relays *(continued)*

Row	Degrees shift that would be cancelled		Wye	Delta	Double-Delta
7	ABC, 7*30° cw	210°		$\frac{1}{\sqrt{3}}\begin{bmatrix}-1 & 1 & 0\\ 0 & -1 & 1\\ 1 & 0 & -1\end{bmatrix}$	
	ACB, 7*30° ccw	150°			
8	ABC, 8*30° cw	240°	$1\begin{bmatrix}0 & 0 & 1\\ 1 & 0 & 0\\ 0 & 1 & 0\end{bmatrix}$		$\frac{1}{3}\begin{bmatrix}-1 & 2 & -1\\ -1 & -1 & 2\\ 2 & -1 & -1\end{bmatrix}$
	ACB, 8*30° ccw	120°			
9	ABC, 9*30° cw	270°		$\frac{1}{\sqrt{3}}\begin{bmatrix}0 & 1 & -1\\ -1 & 0 & 1\\ 1 & -1 & 0\end{bmatrix}$	
	ACB, 9*30° ccw	90°			
10	ABC, 10*30° cw	300°	$1\begin{bmatrix}0 & -1 & 0\\ 0 & 0 & -1\\ -1 & 0 & 0\end{bmatrix}$		$\frac{1}{3}\begin{bmatrix}1 & 1 & -2\\ -2 & 1 & 1\\ 1 & -2 & 1\end{bmatrix}$
	ACB, 10*30° ccw	60°			
11	ABC, 11*30° cw	330°		$\frac{1}{\sqrt{3}}\begin{bmatrix}1 & 0 & -1\\ -1 & 1 & 0\\ 0 & -1 & 1\end{bmatrix}$	
	ABC, 11*30° ccw	30°			

[a] cw = clockwise
[b] ccw = counter clockwise

The matrix representation is a convenient way to describe each configuration. These compensation matrixes would be inserted into Equation (E.1):

$$\begin{bmatrix} I'_A \\ I'_B \\ I'_C \end{bmatrix} = \begin{bmatrix} \text{Matrix} \\ \text{from} \\ \text{Table} \end{bmatrix} \begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix} \tag{E.1}$$

where

I_A is the phase-A current provided to the relay by the wye-connected CTs

I_B is the phase-B current provided to the relay by the wye-connected CTs

I_C is the phase-C current provided to the relay by the wye-connected CTs

I'_A is the phase-A current in the differential circuit after phase shift and zero-sequence compensation

I'_B is the phase-B current in the differential circuit after phase shift and zero-sequence compensation

I'_C is the phase-C current in the differential circuit after phase shift and zero-sequence compensation

The Matrix from Table in Equation (E.1) represents the possible compensation listed in Table E.1.

The following clarifications should be kept in mind when looking at the information contained in Table E.1.

E.3.1 Internal compensation settings

Internal compensation settings are device specific. Table E.1 shows possible ways of combining three phase-currents in a specific device. In this case, there are two possibilities for each even numbered row of the table. A device typically uses only one or the other but not both.

The method for selecting the current compensation to be used on each restraint input varies from device to device. Usually, the required settings are some variation of the following two methods:

— The user describes the connections of the transformer to be protected and the connections of the CTs. The device selects the correct compensation to be used on each restraint input.

— The user directly selects the compensation or the phase shift required for each restraint input.

The relay manufacturers typically provide only a subset of these possible solutions. For example, many relays only accommodate wye, delta A-B, or delta A-C compensations because phase shifts beyond ±30° or ±60° are unusual.

E.3.2 Magnitude compensation

In addition to phase shift and zero-sequence compensation, magnitude compensation is also provided in transformer differential relays. This compensation is for accommodating the CT ratio error and error due to operation at off-nominal taps.

The multiplier in front of each matrix represents the scaling adjustment required to bring the currents after compensation back to one p.u.

— In a wye matrix, there is no change in the apparent magnitude; so the multiplier is 1.

— In a delta matrix, the compensated currents are $\sqrt{3}$ times higher than the phase currents; therefore, a multiplying factor of $1/\sqrt{3}$ is used to bring the currents back to one p.u.

— In a double-delta matrix, the compensated currents are three times higher than the phase currents; therefore, a multiplying factor of 1/3 is used to bring the currents back to one p.u.

In traditional systems, this factor is included in the tap adjustment setting calculations. In most numerical relays, this factor is included in the compensation routine so it is not required to be included in the tap adjust setting calculation. The user should consult the specific relay manufacturer's documentation to determine if the internal current compensation includes this scaling adjustment factor or if this needs to be included in the tap adjustment setting calculation.

E.3.3 Zero-sequence compensation

The compensation matrices in the wye column of Table E.1 do not provide zero-sequence compensation. The following four approaches address this issue:

a) Accommodating for zero-sequence currents. The user must make sure that the wye compensation is only used on delta-connected windings where zero-sequence compensation is not required.

b) Removing zero-sequence currents from all three-phase inputs. This approach removes all concern about zero-sequence current compensation. However, this approach may reduce sensitivity to ground faults by one-third.

c) Removing zero sequence from an input with wye compensation. This has the advantage of allowing for situations where there is a zero-sequence source inside the zone of protection but only when needed.

d) Using "double-delta" compensation that results in no phase shift instead of wye compensation. This provides a delta for removing the zero-sequence currents but no phase shift like the wye compensation does. An example of this would be the compensation shown in the double-delta column of row 0 in Table E.1.

Options c) and d) are mathematically equivalent.

Consider method c) to remove zero-sequence currents from the phase currents. The result is shown in Equation (E.2):

$$\begin{bmatrix} I_A^{'} \\ I_B^{'} \\ I_C^{'} \end{bmatrix} = \begin{bmatrix} I_A - I_0 \\ I_B - I_0 \\ I_C - I_0 \end{bmatrix} \tag{E.2}$$

Also, $I_0 = (1/3)\ (I_A + I_B + I_C)$; substituting this in Equation (E.2) provides Equation (E.3):

$$\begin{aligned} \begin{bmatrix} I_A^{'} \\ I_B^{'} \\ I_C^{'} \end{bmatrix} &= \begin{bmatrix} I_A - \tfrac{1}{3}(I_A + I_B + I_C) \\ I_B - \tfrac{1}{3}(I_A + I_B + I_C) \\ I_C - \tfrac{1}{3}(I_A + I_B + I_C) \end{bmatrix} \\ &= \frac{1}{3}\begin{bmatrix} 2I_A - I_B - I_C \\ -I_A + 2I_B - I_C \\ -I_A - I_B + 2I_C \end{bmatrix} \end{aligned} \tag{E.3}$$

Consider method d) to remove zero-sequence currents from the phase currents (row 0 − double-delta connection). The result is shown in Equation (E.4):

$$\begin{aligned} \begin{bmatrix} I_A^{'} \\ I_B^{'} \\ I_C^{'} \end{bmatrix} &= \frac{1}{3}\begin{bmatrix} +2 & -1 & -1 \\ -1 & +2 & -1 \\ -1 & -1 & +2 \end{bmatrix}\begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix} \\ &= \frac{1}{3}\begin{bmatrix} 2I_A - I_B - I_C \\ -I_A + 2I_B - I_C \\ -I_A - I_B + 2I_C \end{bmatrix} \end{aligned} \tag{E.4}$$

E.4 Examples

An example is included in this clause to illustrate the concepts of compensation and zero-sequence removal. Consider the system shown in Figure E.3. This system consists of a wye/delta transformer with a grounding transformer, which is inside the protection zone of the transformer, connected on the delta side. This application requires compensation for the phase shift, as well as compensation for the ground source on the delta side of the transformer. Sequence component and phase current flows are shown for an external single line-to-ground fault on the low side. The current flows are matched using two different approaches. The current magnitude changes from the various transformations are assumed to be taken care of and, therefore, are not considered in this example.

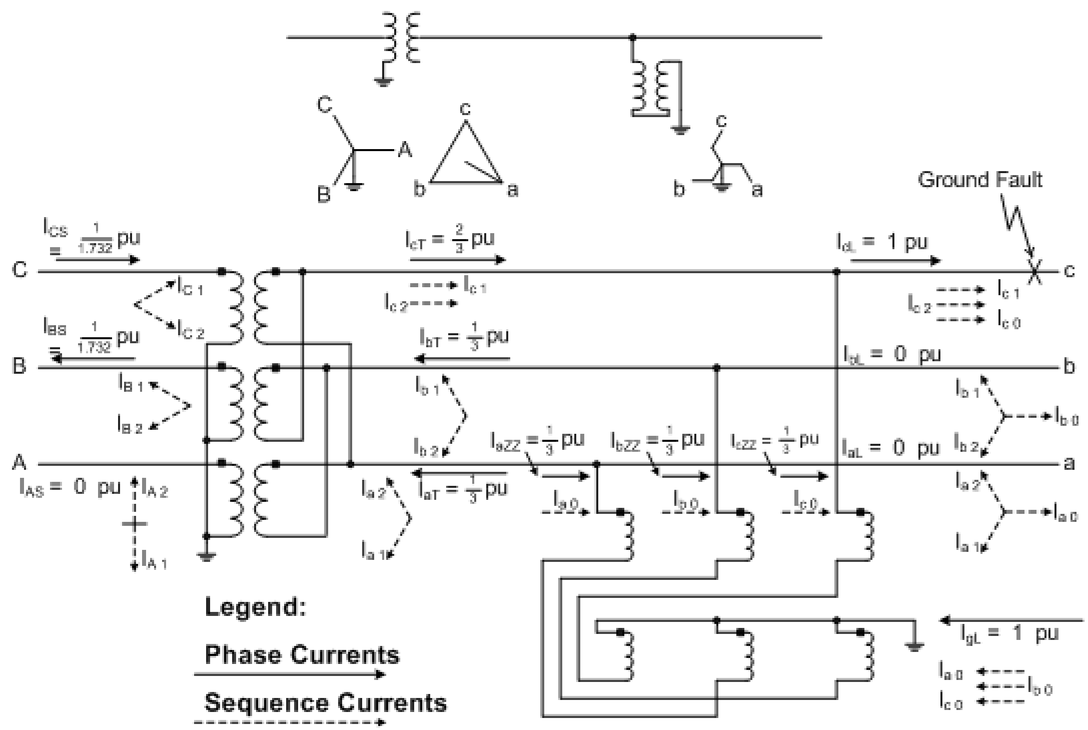


Figure E.3—Wye-delta transformer with ground bank in the transformer protection zone and an external ground fault on the low side

Figure E.4 shows one possible approach that uses special CT connection for compensating the differential currents for phase shift between the high-side and low-side currents as well as for the zero-sequence currents by using special CT connections. This approach uses delta connections for the CTs on the high side and wye connections for the CTs on the low side along with zero-sequence current removal. The internal compensation listed in Table E.1 that would be equivalent to the CT connections shown in Figure E.3 would be as follows:

- — High-side CT connections are as in Table E.1, row 11, delta (delta A-C).
- — Low-side CT connections are as in Table E.1, row 0, wye with zero-sequence removal ($I_A - 1I_0$, $I_B - 1I_0$, $I_C - 1I_0$).

Figure E.5 shows another possible approach to differential current compensation that addresses both phase shift and zero-sequence trap implemented using special CT connections. This approach uses delta compensation on the high side and double-delta compensation on the low side. The internal compensation from Table E.1 that would be equivalent to the CT connections shown in Figure E.5 as follows:

— High-side compensation would be row 11, delta (delta A-C).

— Low-side compensation would be row 0, double-delta (delta 2A-B-C). Note that the way the low-side currents, as marked in this figure, include the delta conversion in the power transformer in addition to the delta in the phase CTs and delta in the auxiliary CTs. So, the coefficients in the current equation on the right-hand side of the differential element do not match those in Table E.1.

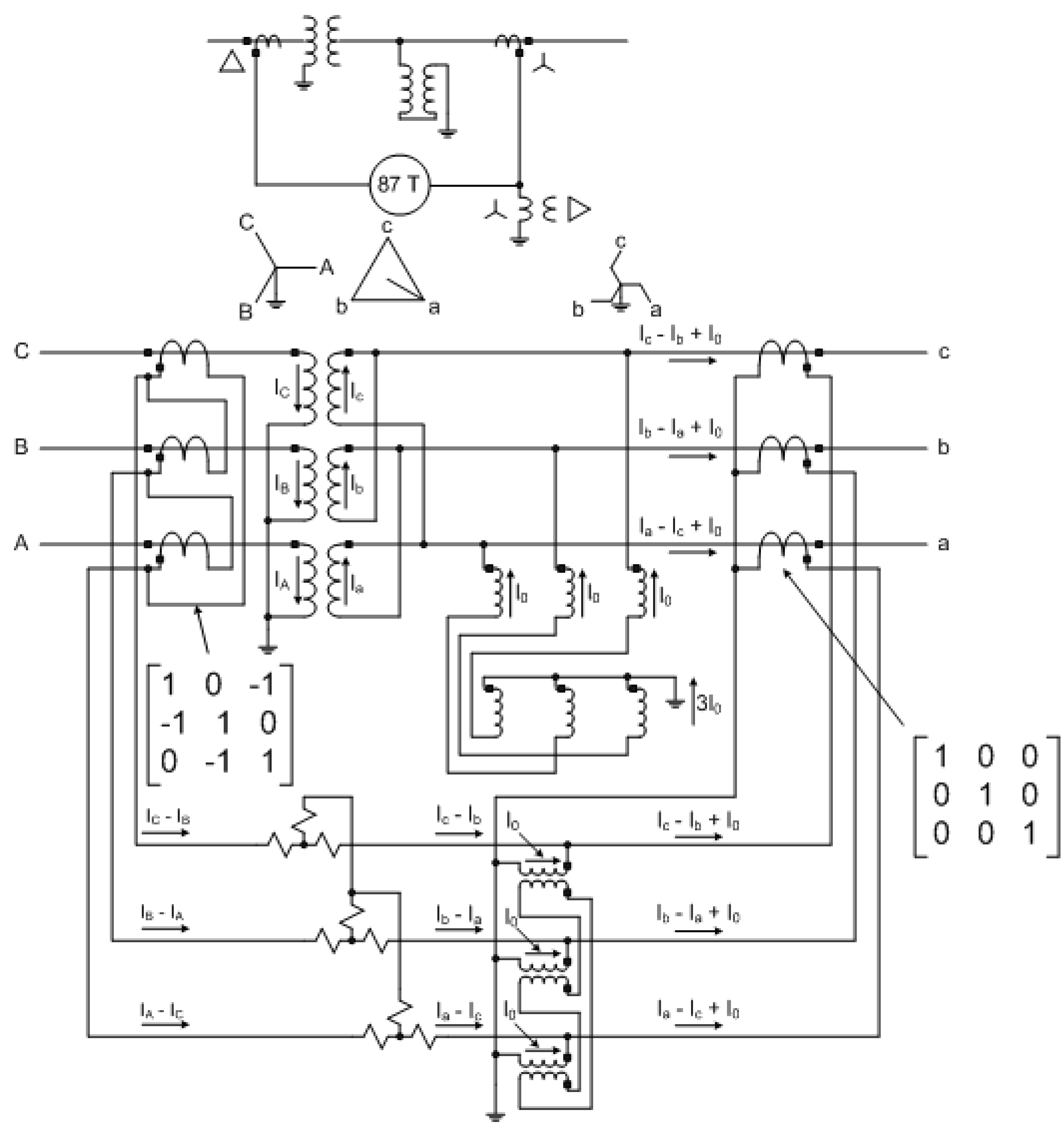


Figure E.4—Differential current compensation using zero-sequence trap

It is important to note that, when using auxiliary CTs to combine the currents in a traditional application, the double-delta approach illustrated in Figure E.5 is not recommended. The recommended approach is covered in 14.3 of this guide. The reason is that, in a double-delta, the currents that go to the differential relay elements are required to be transformed by the auxiliary CTs. This introduces the possibility of problems due to saturation of the auxiliary CTs. In the approach recommended in 14.3, and illustrated in Figure E.4, the auxiliary CTs only provide a low-impedance path to shunt the zero-sequence currents and prevent them from flowing in the differential elements. The currents flowing to the differential elements are not transformed by the auxiliary CTs in this case so they cannot introduce saturation problems. This particular caution, of course, does not apply to double-delta compensation using numerical techniques.

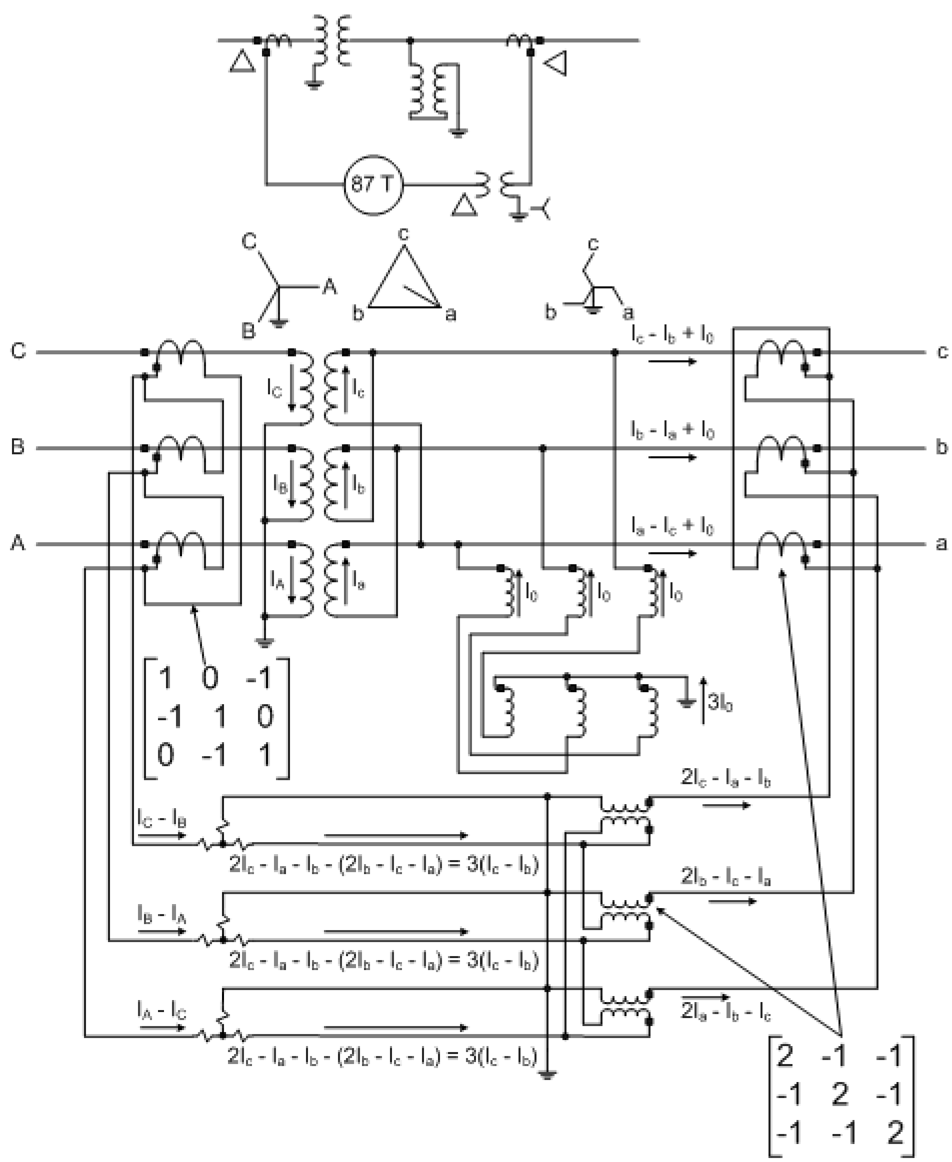


Figure E.5—Differential current compensation using double-delta CTs

Annex F

(informative)

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Annex G

(informative)

Additional sources of information

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