

IEEE Guide for Protective Relay Applications to Power Transformers

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Abstract: The protection of power transformers is covered; various electrical protection schemes are explored; and guidelines are given for the application of these schemes to transformers. Alternative detection methods including mechanical, thermal, and gas analysis are discussed.

Keywords: power, protection, relaying, transformer

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Introduction

(This introduction is not part of IEEE Std C37.91-2000, *IEEE Guide for Protective Relay Applications to Power Transformers*.)

This is a revision of IEEE Std C37.91-1985, *IEEE Guide for Protective Relay Applications to Power Transformers*. This guide will 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 figures were corrected.
- Subclauses 5.5.2 and 6.2.3 on current inrush were rewritten to include a new form of inrush restraint.
- Current transformer connections were updated in 5.4 to be in line with IEEE Std C37.110-1996, *IEEE Guide for Application of Current Transformers Used for Protective Relaying Purposes*.
- Geomagnetic influence on transformers and protective relays is discussed in Clause 13.
- Clause 11, Gas analysis, was revised to reflect current philosophy and practice.

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This standard is dedicated to the memory of Graham Clough, who passed away during the final stages of preparation of this document. He will be remembered for his contributions to this document and his service to the relay industry.

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IEEE Guide for Protective Relay Applications to Power Transformers

1. Overview

1.1 Scope

This guide covers practical applications, general philosophy, and economic considerations of power transformer protection.

1.2 Purpose

The purpose of this guide is to aid in the effective application of relays and other devices for the protection of power transformers. Emphasis is placed on practical applications. The general philosophy and economics of transformer protection are reviewed. The types of faults experienced are described, and technical problems with such protection, including current transformer (CT) behavior during fault conditions, are discussed. Various types of electrical, mechanical, and thermal protective devices are also described and associated problems such as fault clearing and reenergizing are discussed.

2. References

This guide shall be used in conjunction with the following publications. When the following standards are superseded by an approved revision, the revision will apply.

IEEE Std 32-1972 (Reaff 1997), IEEE Standard Requirements, Terminology, and Test Procedures for Neutral Grounding Devices.¹

IEEE Std C37.2-1996, IEEE Standard Electrical Power System Device Function Numbers and Contact Designations.

IEEE Std C37.110-1996 IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes.

¹IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (<http://standards.ieee.org/>).

IEEE Std C57.12.00-2000, IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers.

IEEE Std C57.91-1995, IEEE Guide for Loading Mineral-Oil-Immersed Transformers.

IEEE Std C57.92-1981 (Reaff 1991), IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers Up to and Including 100 MVA with 55 °C or 65 °C Average Winding Rise.²

IEEE Std C57.109-1993, IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration.

3.Philosophy and economic considerations

Protective relaying is applied to components of a power system for the following reasons:

- a) Separate the faulted equipment from the remainder of the system so that the system can continue to function
- b) 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 components, particularly high-voltage transmission lines, the limiting of damage becomes a by-product of the system protection function of the relay. However, since the cost of repairing faulty transformers may be great and since high-speed, highly sensitive protective devices can reduce damage and therefore repair cost, relays should be considered for protecting transformers also, particularly in the larger sizes.

Faults internal to a transformer quite often involve a magnitude of fault current that is low relative to the transformer base rating. This indicates a need for high sensitivity and high speed to ensure good protection.

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 plan selected should balance the best combination of these factors against the overall economics of the situation while holding to a minimum

- a) Cost of repairing damage
- b) Cost of lost production
- c) Adverse effects on the balance of the system
- d) The spread of damage to adjacent equipment
- e) The period 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 would not be practical. When the fault is not cleared by the transformer protection, remote line relays or other protective relays may operate. Part of the evaluation of the type of protection applied to a transformer should include how the system integrity may be affected by such a failure. In this determination, since rare but costly failures are involved, a diversity of opinion on the degree of protection required by transformers might be expected among those familiar with power system relay engineering. The major economic consideration is

²This standard has been revised and redesignated to IEEE Std C57.91-1995.

not ordinarily the fault detection equipment but the 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 system design philosophy as to the protection of the transformer. Evaluations of the risks involved and the cost-effectiveness of the protection are necessary to avoid going to extremes. Such considerations involve the art rather than the science of protective relaying. See [B22], [B24], [B29], and [B59]³.

4.Types of transformer failures

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) Impact forces due to through-fault current
- e) Excessive heating due to overloading or inadequate cooling

These forces can cause deterioration and failure of the winding electrical insulation. Table 1 summarizes failure statistics for a broad range of transformer failure causes reported by a group of U.S. utilities over a period of years.

Table 1—Failure statistics for three time periods

	1955–1965		1975–1982		1983–1988	
	Number	Percent of total	Number	Percent of total	Number	Percent of total
Winding failures	134	51	615	55	144	37
Tap changer failures	49	19	231	21	85	22
Bushing failures	41	15	114	10	42	11
Terminal board failures	19	7	71	6	13	3
Core failures	7	3	24	2	4	1
Miscellaneous failures	12	5	72	6	101	26
Total	262	100	1127	100	389	100

This guide deals primarily with the application of electrical relays to detect the fault current that results from an insulation failure. Clause 5 examines the current a relay can expect to see as a result of 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. For example

- a) Temperature monitors for winding or oil temperature are typically used to initiate an alarm requiring investigation by maintenance staff.

³The numbers in brackets correspond to the references listed in Annex B of this guide.

- b) 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 corona and thermal degradation of the cellulose insulation. The gas detection relays may be used to trip or alarm depending on utility practice. Generally, gas analysis is performed on samples of the oil, which are collected periodically. Alternatively, a continuous gas analyzer is available to allow on-line detection of insulation system degradation.
- c) Sudden-pressure relays respond to the pressure waves in the transformer oil caused by the gas evolution associated with arcing.
- d) Oil level detectors sense the oil level in the tank and are used to alarm for minor reductions in oil level and trip for severe reductions.

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

5. Relay current

Two characteristics of power transformers combine to complicate detection of internal faults with current-operated relays

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

5.1 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 will result in a terminal current 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 amount of current.

5.2 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 a terminal fault 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 CT on a short-time basis. This may be a factor if the transformer is small relative to the system fault and if the CT ratio is chosen to match the transformer rating.

5.3 Through-faults

Fault current through a transformer is limited by the transformer and source impedance. While current through a transformer thus limited by its impedance can still cause incorrect relay operations or even transformer failure, CT saturation is less likely to occur than with unlimited currents.

The above favorable aspect may disappear if the transformer protective zone includes a bus area with two or more breakers on the same side of the transformer through which external fault current can flow with no

relationship to the transformer rating. An example is a transformer connected to a section of a ring bus with the transformer protection including the ring bus section.

5.4 Performance of CTs

5.4.1 Internal faults

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

5.4.2 External faults

Transformers can be connected to buses in such ways that either the CTs used for the differential will be in series with the transformer windings or they will be in breakers that are part of the bus, such as a ring bus or breaker-and-a-half scheme. For the CTs with primaries in series with the transformer winding, the CT primary current for through-faults will be limited by the transformer impedance. When the CTs are part of the bus scheme, as mentioned above for ring buses or breaker-and-a-half schemes, the CT primary current is not limited by the transformer impedance. In fact, high primary currents may be experienced. In either case, any deficiency of CT output caused by saturation of one CT that is not matched by a similar deficiency of another CT will cause a difference current to appear in the operating circuit of a differential relay. See IEEE Committee Report [B8]. 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 to avoid a ratio error exceeding that recommended by the relay manufacturer (see IEEE Std C37.110-1996).

5.4.3 CT connections

CT performance is a function of the secondary burden. The method of connecting the CTs and the relay burden will determine the total effective burden. Also, the physical and electrical locations of auxiliary CTs can similarly affect the effective burden. For more information on the effect of CT connections, see IEEE Std C37.110-1996

First, the relay's capabilities must be evaluated. Some *differential* relays can internally accommodate the phase shift of the transformer, allowing the engineer to choose CT connections at the transformer that suit other schemes connected to the same CTs. Many relays do not have this versatility, and therefore, the CTs must be connected to create the same phase shift as the primary transformer windings.

For example, a transformer using both Δ and Y connections creates a 30° phase shift between the respective terminals of the transformer. By connecting the CTs in Δ on the Y side of the transformer and the CTs in Y on the Δ 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 at its input terminals.

Second, Δ -Y transformers are a source of ground fault current. The zero sequence current on the grounded Y side is not reflected in the terminals on the Δ side. Some relays can ignore this contribution as part of the above internal phase shift accommodation. Again, many other relays can not accommodate this function and

must use the CTs to filter out the apparent ground current contribution. As for the above example, the Δ CT connection on the Y side of the transformer traps the zero sequence current from the CT secondaries and prevents the differential relay from seeing the mismatch current.

5.5 Reasons for mismatch current

There are non-fault-related currents or factors that may require compensation to prevent undesirable relay operation. The following subclauses include a discussion of some of those situations.

5.5.1 Unbalance caused by CT 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 mismatch causes current flow in the operating circuit of the differential relay. If the transformer has a load tap changer, the possible mismatch is increased further. During a through-fault condition, the differential operating current due to mismatch can approach the current rating of the transformer.

5.5.2 Magnetizing current inrush

This is a phenomenon that causes the violation of the basic principle of differential relaying since the magnetizing branch of the transformer can have a very low impedance without a transformer fault. 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 up to many seconds. See [B23] and [B17] for an explanation of this mechanism.

Although usually considered only in conjunction with the energizing of a transformer, magnetizing current inrush can be caused by any abrupt change of magnetizing voltage. 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 operative only when energizing a transformer may not be adequate.

There are several conditions that cause particularly severe magnetizing inrush phenomena [B23]. One involves the energizing of a transformer at a station at which at least one other transformer is already energized [B48]. The inrush phenomenon [B17] will involve transformers that are already energized as well as the transformer being energized. 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 fundamental frequency, and therefore not operate the harmonic restraint unit of a differential relay if it is protecting both parallel transformers. Another inrush phenomenon involves the energizing of a transformer by means of an air switch. Arcing of the switch can result in successive half-cycles of arc of the same polarity. Thus if the first half-cycle results in substantial residual magnetism in a transformer core, succeeding half-cycles can cause a cumulative increase in residual magnetism, each time resulting in a more severe inrush.

Two important characteristics of magnetizing inrush current are

- a) It contains substantial harmonics, particularly the second harmonic. These harmonics are not always present in high quantities in all three phases (see 6.2.3.1).
- b) That there is always a time during each cycle where the current magnitude is almost zero. This time is always greater than a quarter cycle. See Figure 1 for a plot of typical inrush current [B22].

The harmonic content of the inrush current depends on various factors such as remnant flux in the core, switching angle, and load on the transformer. Harmonic analysis of the inrush current during the events in

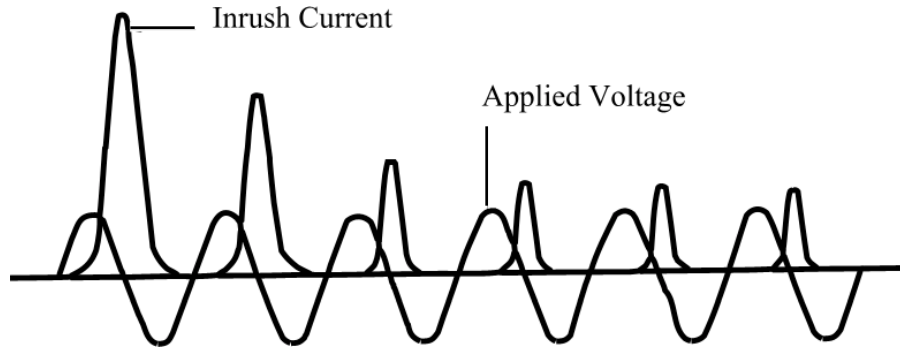


Figure 1—Typical magnetizing inrush current wave

Figure 1 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 conditions [B19].

5.5.3 Magnetizing current during overexcitation

Sudden loss of load can subject the generator step-up transformer to substantial overvoltage. This can also occur during start-up or shutdown of the generator if nominal voltage is maintained while the speed is below normal (an overexcitation condition). If saturation occurs, substantial exciting current will flow, which may overheat the core and damage the transformer severely. The waveform will be distorted and again the wave will have harmonic content and current zero periods. The extent of these effects will depend on the generator connections and the transformer design and connections. Relay current harmonic content will also be altered by Δ CT connections.

5.5.4 Phase-shifting transformers

A phase-shifting transformer, as its name implies, has a purposely introduced angular voltage difference, usually adjustable in steps, between the primary and secondary voltages. If the angular difference is fixed at 30° , as it is with the familiar Y- Δ transformer, CT connections for proper differential relaying are easy to obtain. However, if the phase angle shift is variable or some fixed angle other than 30° , then specific knowledge of the transformer design is necessary to develop a custom differential scheme for that transformer. Because of the variety of designs for phase-shifting transformers, the manufacturers of the transformer and of the protection scheme should be consulted for the best type and placement of CTs.

6. Electrical detection of faults

Fuses are commonly used to provide fault detection for transformers with minimum nameplate ratings up to 5000 kVA, three phase (Categories I and II). Transformers of 10 000 kVA and larger, three phase, minimum nameplate (Categories III and IV) are generally protected by a combination of protective devices, as shown in Figure 2. Transformers that fall between these two ratings are protected by either fuses or relays. 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 coordinating fuses with upstream relays or with transformer damage curves, may determine what protection is used. Some other considerations include types of faults, personal safety issues, speed of clearing, single phasing of load, and ferroresonance. See Annex A for further definition of these categories.

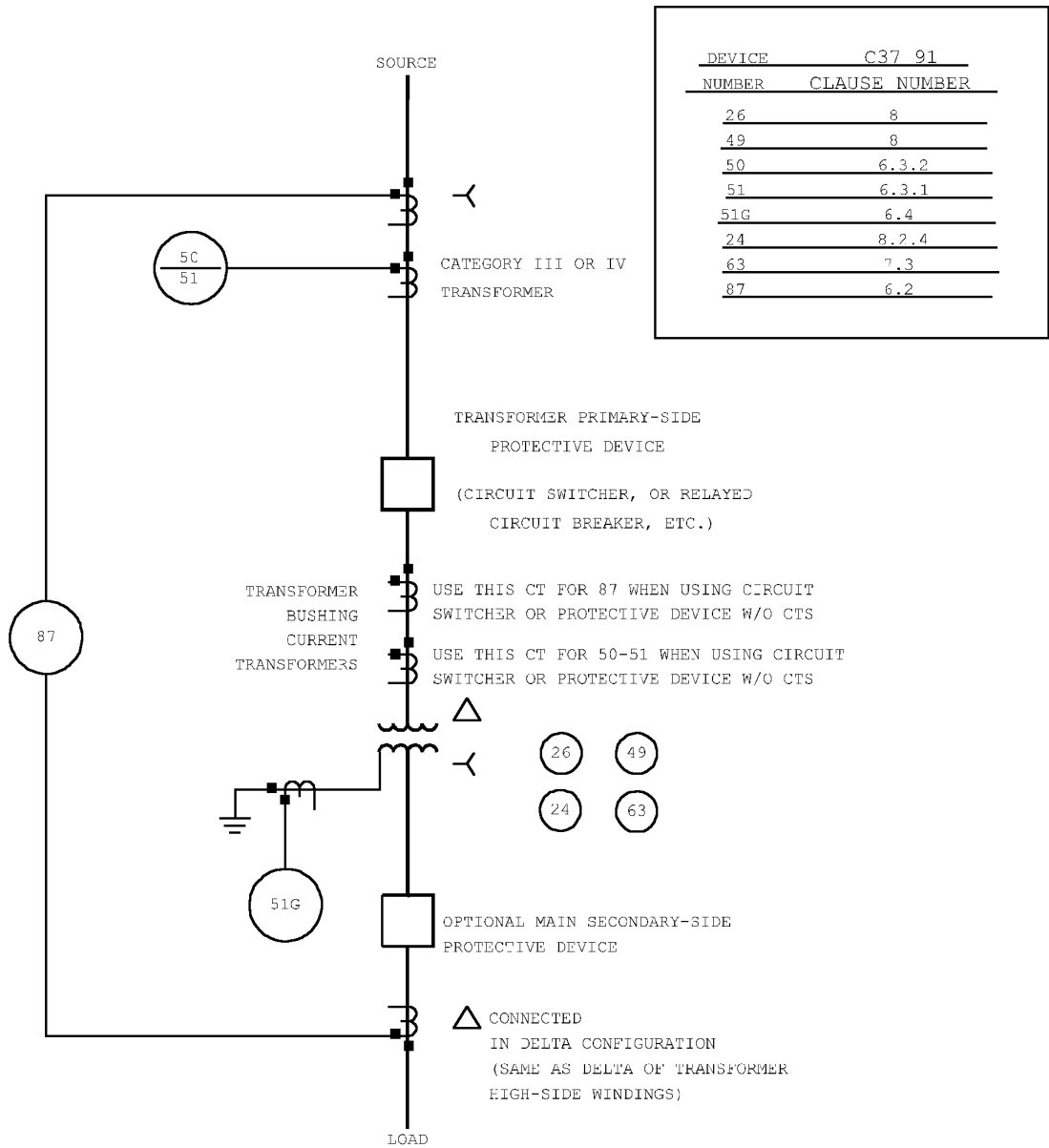


Figure 2—Protection for a Δ-Y transformer

6.1 Fuse protection

Fuses have the merits of being economical and requiring 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 will provide limited protection for internal faults. Generally, more sensitive means for protection from internal faults is provided for transformers of 10 MVA and higher. Fuses have been used at higher transformer ratings, depending on the currently available fuse ampere ratings. Primary fuses for power transformers are not applied for overload protection, their main purpose being fault protection (see 6.6.1). It should be recognized that the blowing 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 single-phase conditions.

A typical transformer that exhibits this protection shortfall is a Δ primary, grounded T secondary distribution station transformer that is protected with fuses on the primary side. 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 must be 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 but severely overloads the neutral connection because the currents in the secondary windings are in phase and sum algebraically in the neutral connection. Table 2 shows the magnitude of currents for a typical 69–13.2 kV, 8.4 MVA distribution transformer before and after the first fuse clears. This transformer would normally be protected by a 100E fuse. The table clearly shows that the current in the neutral connection remains essentially the same after the first fuse opens and will persist until the second fuse opens.

Table 2—Currents for a typical distribution transformer

Phase B-C-ground fault before first fuse opens		Phase B-C-ground fault after first fuse opens	
High-side phase current (A)	Low-side phase current (A)	High-side phase current (A)	Low-side phase current (A)
ØA 415	ØA 0	ØA 226	ØA 0
ØB 415	ØB 3764	ØB 226	ØB 2050
ØC 697	ØC 3764	ØC 0	ØC 2050
—	Neut. 4100	—	Neut. 4100

NOTE—Ø = Phase

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

- Fuse fault-interrupting capability and available system fault current
- 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)
- Hot load pickup (inrush current on instantaneous reclosing of source-side circuit breaker) and cold load pickup (inrush current and undiversified load current after an extended outage)
- Available primary system fault current and transformer impedance
- Coordination with source-side protection equipment
- Coordination with low-side protection equipment
- Maximum allowable fault time on the low-side bus conductors
- Transformer connections and grounding impedance as they affect the primary current for various types of secondary faults
- Sensitivity for high-impedance faults
- Transformer magnetizing inrush

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

6.2 Differential protection

Current differential relaying is the most commonly used type of protection for transformers of approximately 10 MVA three-phase (self-cooled rating) and above (IEEE Committee Report [B49]). The term refers to the connection of CTs so that the net operating current to the relay is the difference between input and output currents to the zone of protection. Relays of three general classes are used with this current differential. They are

- a) Time overcurrent relay, which may include an instantaneous trip unit having a high-current setting
- b) Percentage differential with restraint actuated by the input and output currents
- c) Percentage differential relay, with restraint actuated by one or more harmonics in addition to the restraint actuated by the input and output currents

CT connections and ratios must be such that the net current in the relay operating coil or element for any type or location of external fault is effectively zero, unless relay current matching taps are available. Various types of CT connections are shown in Figure 3, Figure 4, and Figure 5. 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.

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 ensure 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.

6.2.1 Differential protection using time overcurrent relays

Overcurrent relays without restraint are seldom used because of their susceptibility to false operation from causes such as

- a) Saturation errors or mismatch errors of CTs
- b) Magnetizing inrush current when the transformer is energized

To compensate for the saturation/mismatch errors, the overcurrent relays must be set to operate above anticipated values. Time delay to override inrush is necessary to compensate for the magnetizing inrush current. Because of the possibility of power transformer saturation, caution is advised against the use of this relay where exposure to geomagnetic induced currents (GICs) is possible.

6.2.2 Differential protection using percentage differential relays

To overcome the drawbacks of applying simple overcurrent relays to 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 the difference current (as measured at the ends of the protected zones), which must exceed a predetermined percentage of the through current before tripping can occur. The through-current is referred to as the restraint current. The percentage difference can be fixed or

variable, depending on the relay's design. There is also a minimum differential current threshold before tripping, without regard to the restraint current.

The basic arrangement for percentage differential protection of a two-winding transformer is shown in Figure 3.

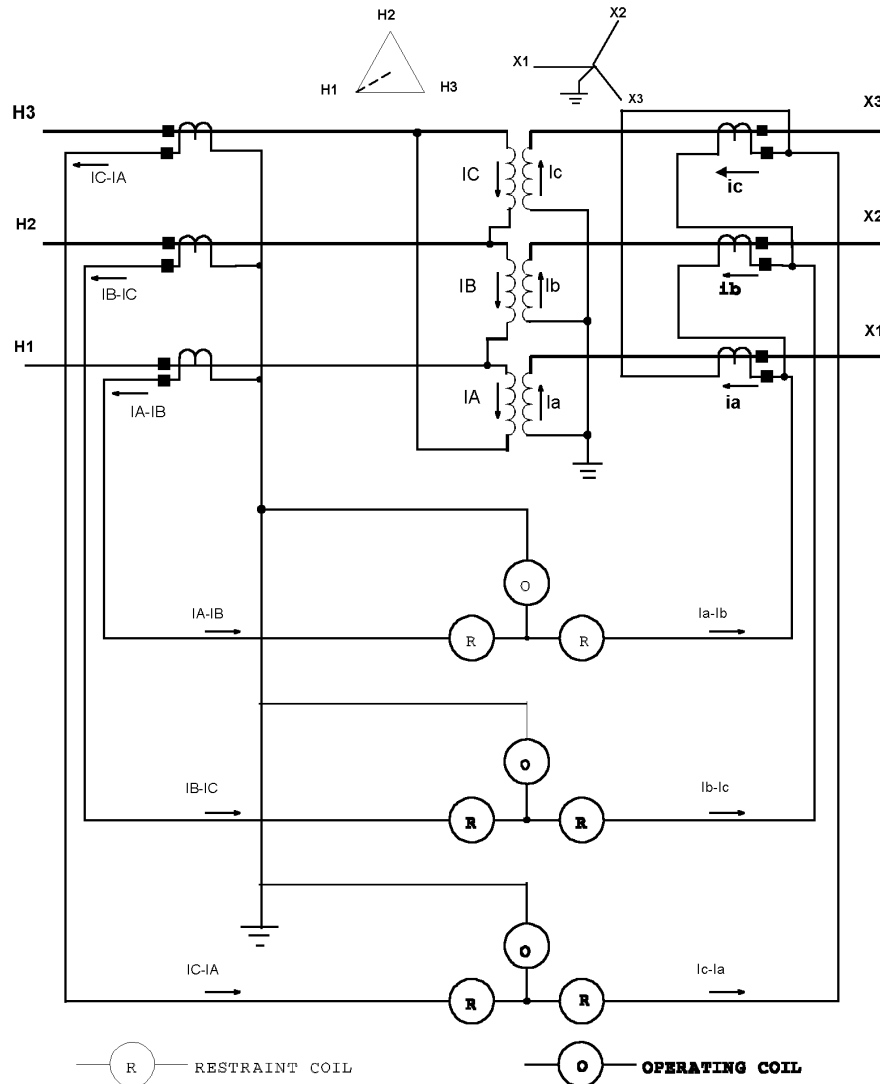


Figure 3—Typical schematic connections for percentage differential protection of a Δ -Y transformer

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. The curve allows even larger percentage mismatches, up to approximately 70%, during heavy through-currents.

High-voltage power transformers present several possibilities for current mismatch as seen by the differential relay. These mismatches, caused by different sources, can add to or offset each other, thus making the total mismatch hard 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.

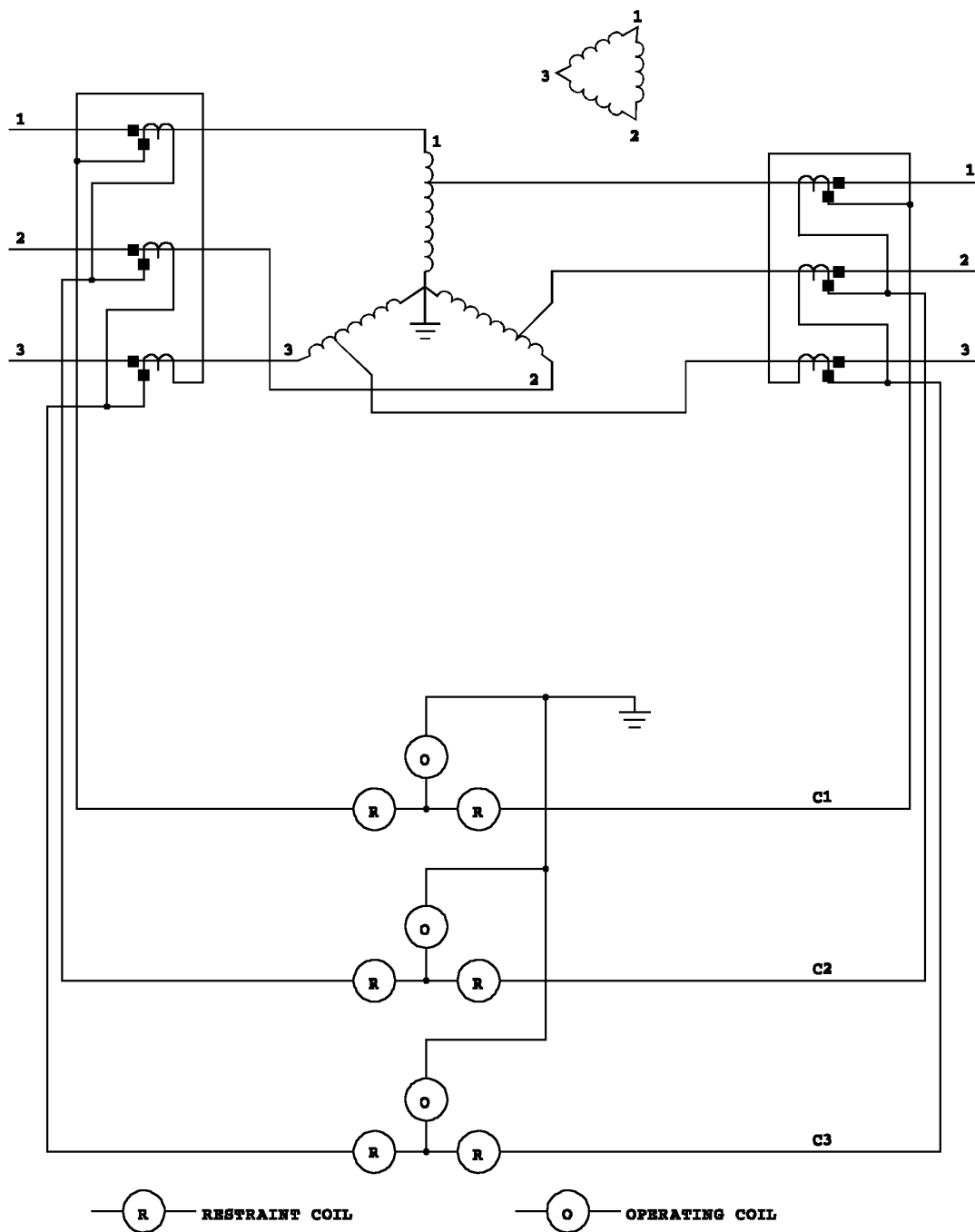


Figure 4—Typical schematic connections for percentage differential protection of a Y autotransformer with an unloaded tertiary

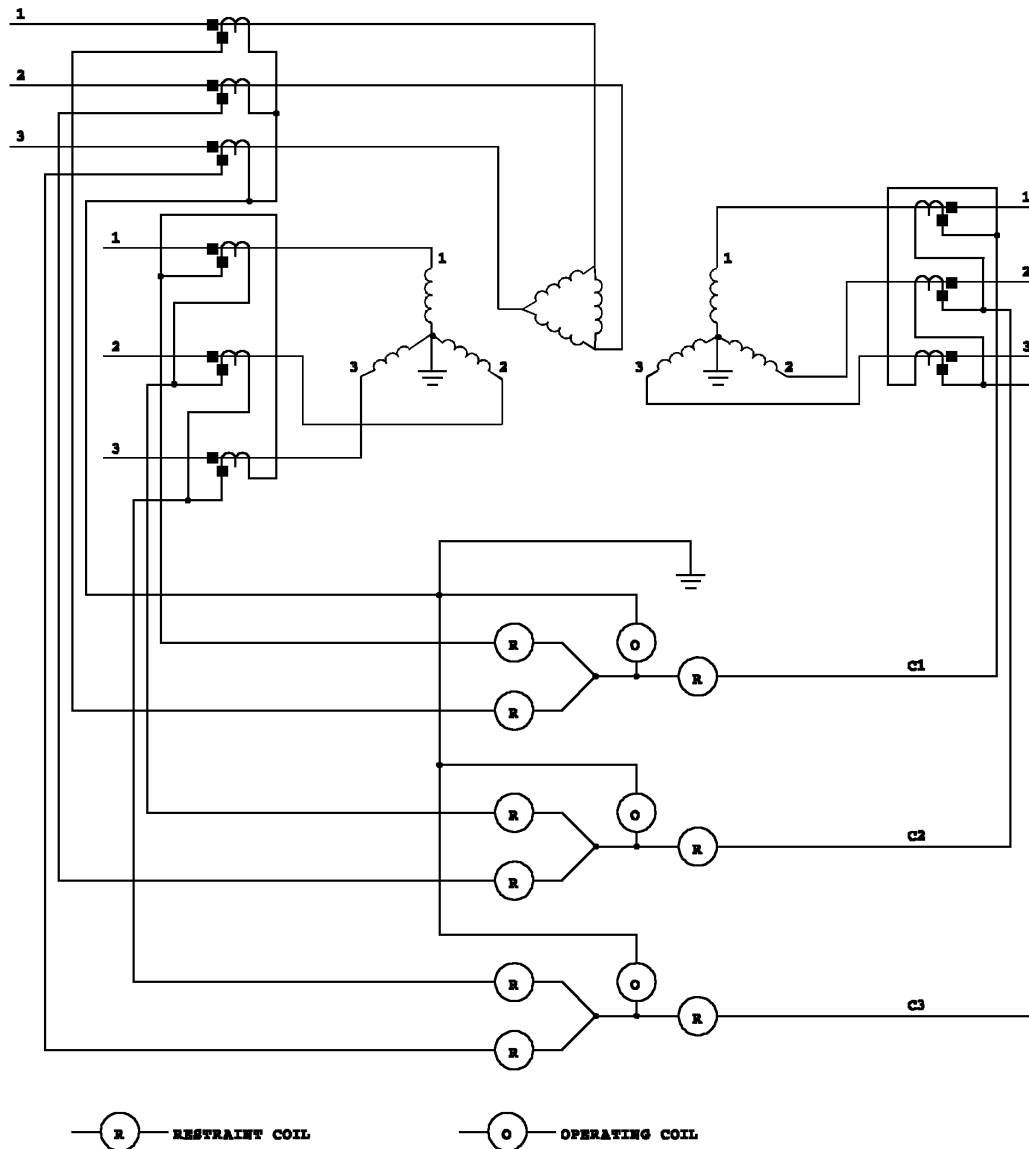


Figure 5—Typical schematic connections for percentage differential protection of Y-Δ-Y transformer with a loaded Δ tertiary

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 138–69 kV transformer could use 600:5 CTs on the 138 kV side and 1200:5 CTs on the 69 kV side.

For Y-Δ transformer connections, the 30° phase shift can be compensated for by proper connection of the CT secondaries, but the current ratio difference is affected by the $\sqrt{3}$ multiplier for currents leaving the Δ CT secondary connection. Alternatives are available when it is not possible to match the high-voltage current ratio with a ratio of standard available CT primary current ratings. Some relays are built with internal current taps to compensate for current input ratio differences. Special-ratio auxiliary CTs are sometimes used to compensate for the ratio differences.

Second, a large contribution to current mismatch is the application of load tap changers (LTCs) for voltage regulation. A typical LTC range of $\pm 10\%$ in voltage creates a $\pm 10\%$ variation in current. This is a substantial mismatch for which the differential must not operate.

Last, a third contributor to current mismatch is the difference in performance of CTs applied to the 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 discussed above. 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 difference current in the operate coil or element of the differential relay.

6.2.3 Differential protection using percentage differential relays with inrush restraint

The addition of some type of restraint that recognizes the characteristics of the inrush current provides greater sensitivity when a power transformer is energized.

6.2.3.1 Harmonic restraint

Harmonic restraint is used to avoid undesired tripping of the percentage differential relay by the inrush current when the transformer is energized. In addition, harmonic restraint allows more sensitive settings and greater speed. These relays utilize frequency-selective circuits responsive to at least the second harmonic current, which is present in all transformer energizing surges, to restrain or greatly reduce the sensitivity of the relay during the time the inrush current exists. Several designs utilize other harmonics in addition to the second harmonic to develop the restraint.

The purpose of all of these designs is to provide a relay that properly restrains regardless of the amount of inrush and yet permits relatively high-speed operation if an internal fault occurs during the inrush period. Another design objective is to not have excessive restraint resulting from the harmonic distortions of the CT secondary currents. This can happen as a result of CT saturation during a severe internal fault even when the presence of CT saturation causes the appearance of harmonics. To provide protection for this condition, frequently the differential harmonic restraint relay will also include an unrestrained instantaneous relay unit. The unrestrained instantaneous relay unit is set above possible transformer inrush current but below the current that might result in CT ac saturation. The usual factory setting is 8 to 10 times the tap value. Refer to IEEE Std C37.110-1996 for considerations regarding ac and dc saturation of CTs.

Another consideration in the use of harmonic restraint relays is the performance during transformer overexcitation (see 5.5.3). Whether 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, rectifier transformers, where relatively high levels of odd harmonics are normally present, would be better protected by the harmonic restraint relays using only the second harmonic. The relay application engineer should check the Bibliography, Annex B, for assistance in defining specific transformer protection objectives and hence the 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 (0.01–0.05 s versus 0.1–0.2 s for the percentage restraint type)
- c) Lower pickup (10–50% of transformer rating versus 40–100% for the percentage restraint type)

Occasional false trips by harmonic restraint differential relays have been observed when transformers with connected transmission lines were energized. Analysis of magnetizing inrush current waveforms for this configuration showed noticeable reduction in harmonic content compared to energizing the transformer

isolated from the line. The same point-on-wave closing signal was used for proper comparison. It was concluded that insufficient inrush harmonic content for this configuration was the cause of false trips. The relays sensitivity to harmonics was increased.

Harmonic restraint relays can be improved by using time-limited cross-blocking. In cross-blocking, one phase with sufficient harmonics can restrain the whole unit; sufficient harmonics in all three phases are not required. This feature can be limited to inrush current by using a time limitation, since harmonic restraint can cause trip delays on internal faults with CT saturation.

6.2.3.2 Inrush restraint using the zero-current time period of the current waveform

Another type of relay uses the period of the inrush waveform when the current magnitude is equal to the normal magnetizing current to identify the inrush condition. These relays also use an instantaneous element that is set to about 4 times rated current. Because the instantaneous element detects both the polarity and the magnitude of each loop of the inrush waveform, no operation occurs when the inrush is of a unidirectional nature (magnitude of up to 15 times rated current) or of the bidirectional nature (up to 3.5 times the rated current).

6.2.4 Unit generator transformer sets

On cross-compound generators, the fields may be applied while the generators are on turning gear, or at speeds of 15–35% 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, therefore, protection is required for all of the unit system. 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. Unit voltage per unit frequency (V/Hz) relaying may be required to protect the transformer from damage due to overexcitation (see 8.2.4 for further details).

6.2.5 Generator station service

Where a start-up 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, hence, failure of the differential to operate. An additional CT with a high ratio, supplying an overcurrent relay with 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 and the generator and the step-up transformer. It should be noted, however, that the relay sensitivity for the unit auxiliary transformer faults may be low because of the high CT ratios. If additional sensitivity is desired, time and instantaneous overcurrent relays are utilized on the high side of the auxiliary transformer.

6.2.6 Multiple-winding transformer differential

Differential relays for transformers with three or more windings are available in the percentage differential and harmonic restraint relay types. Multiple-winding transformers frequently have different capacity ratings on 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 small windings' ratings can be

greater than the main (input) winding rating. Care should be taken in selecting CT ratios and selecting differential relay current balancing taps. 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 the high side and one other winding is studied at a time.

6.2.7 Parallel transformers

A major disadvantage of using one differential relay to protect two transformers is the reduction in sensitivity. The CT ratios are selected on the basis of total kilovoltamperes (kVA), and hence, the sensitivity for each transformer is less than one-half what it would be if individual protection were provided. When a transformer is energized in parallel with an already-energized transformer (see 5.5.2), 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.

6.2.8 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 volts per hertz condition and, therefore, an overexcitation event. This could also occur in transmission systems where large reactive load is tripped from a transformer with the primary winding remaining energized.

When the primary winding of a transformer is overexcited and driven into saturation, more power 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 ratio and phase shift, will perceive this as a current differential between the primary and secondary windings and, therefore, will operate. This would be an undesirable operation, as no internal fault would exist, with the current imbalance being created from the overexcitation condition.

Three methods have been applied to prevent false transformer differential operations when overexcitation occurs. These methods would be in addition to the second harmonic or gap detection principle used for inrush detection and restraint (described in 5.5.2).

- a) 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.
- b) Since overexcitation manifests itself with the production of odd harmonics, and since the third harmonic (and other triplens) may be effectively cancelled in Δ transformer windings, use the level of fifth harmonic as a restraining quantity in the differential relay.
- c) Use a modified differential scheme that extracts and uses the third harmonic exciting current from the transformer Δ winding to restrain the differential relay (described in 12.1).

6.2.9 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 6. 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 Δ tertiary winding. It should be noted that with this type of scheme no protection is afforded for faults occurring in the Δ tertiary winding. Where the terminals for this winding are not brought out to supply load, one corner of the Δ can be connected between the end of one phase of the main winding and its neutral CT. This connection is shown in Figure 6. 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. This scheme does not provide protection for phase faults or turn-to-turn faults in the tertiary winding.

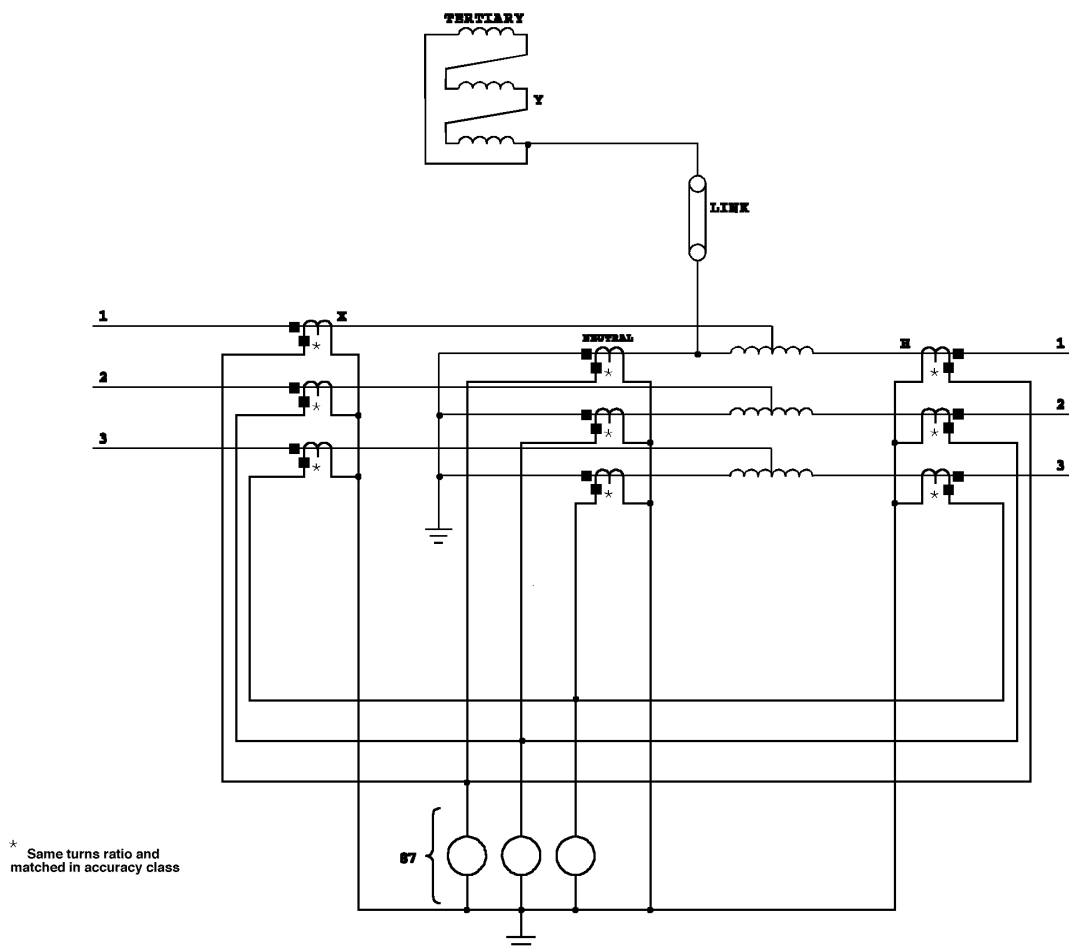


Figure 6—Typical schematic connections for high-impedance differential protection of a Y autotransformer with unloaded tertiary

Where the tertiary winding is used to supply load, the Δ winding corner connection cannot be used. Hence, separate protection is required. The tertiary winding overcurrent protection is described in 6.3.3.

6.2.10 CT 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 C37.110-1996). If saturation will occur, burdens and CT capability should be matched so that both 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.

6.3 Overcurrent relay protection

A fault external to a transformer can result in damage to the transformer. If the fault is not cleared promptly, the resulting overload on the transformer can cause severe overheating and failure. Overcurrent relays (or fuses, see 6.1) may be used to clear the transformer from the faulted bus or line before the transformer is damaged. On some small transformers, overcurrent relays may also protect for internal transformer faults, and on larger transformers, overcurrent relays may be used to provide relay backup for differential or pressure relays. Thermal relays (Clause 8) may also be used to protect transformers from harmful overload. However, thermal relays often are used for alarm only. Coordination examples are included in Annex A.

6.3.1 Phase time overcurrent

Time overcurrent relays are inexpensive, simple, and reliable protective devices. Since sensitive settings and fast operation are usually not possible with overcurrent relays, they will provide limited protection for internal transformer faults. Since the pickup value of phase overcurrent relays must be high enough to take advantage of the overload capabilities of the transformer and be capable of withstanding energizing inrush currents, insensitive settings result. Fast operation is not possible, since the transformer relays should coordinate with load-side protection, including dealing with reclosing cycles and service restoration inrush. Where time overcurrent relays are used for primary transformer protection, extensive damage to the transformer from an internal fault may occur.

Settings of phase overcurrent relays on transformers involve a compromise between the requirements of operation and protection. The pickup setting should be high enough to permit overloading the transformer when necessary, but the higher the setting, the less the protection. A setting of 125–150% of maximum kVA nameplate rating of a transformer is common, although higher values are sometimes used. On multiple-rated transformers, a higher setting may be necessary so as to utilize the full capability of the transformer at the higher forced-cooling rating.

If overcurrent protection (relays or fuses) is applied only to the high-voltage (Δ) side of a Δ –Y grounded transformer, it can have a problem providing sensitive fault protection for the transformer and still coordinating with low-side protective devices. For low-voltage (Y side) phase-to-phase faults, the high-side line current will be 115% of the low-voltage per unit fault current. For low-voltage (Y side) phase-to-ground faults, the high-side line current will be only 58% of the low voltage per unit fault current (see Figure 7, Figure A6, Figure A7, and Figure A8 in Annex A). When the Y 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 Y is grounded through a reactor.

The time setting should coordinate with relays on downstream equipment. Transformers are mechanically and thermally limited in their ability to withstand short-circuit current for finite periods of time. For proper backup protection, the relays should operate before the transformer is damaged by an external fault. (Refer to Annex A for the transformer through-fault current duration limits and relay setting examples.) Solid-state or microprocessor-based relays with special features such as fast reset should be evaluated for coordination with downstream devices.

In setting transformer overcurrent relays, the short-time overload capability of the transformer in question should not be exceeded. Low values of 3.5 or less times normal base current may result from overloading rather than faults. For such cases see IEEE C57.91-1995, since allowable time duration may be different

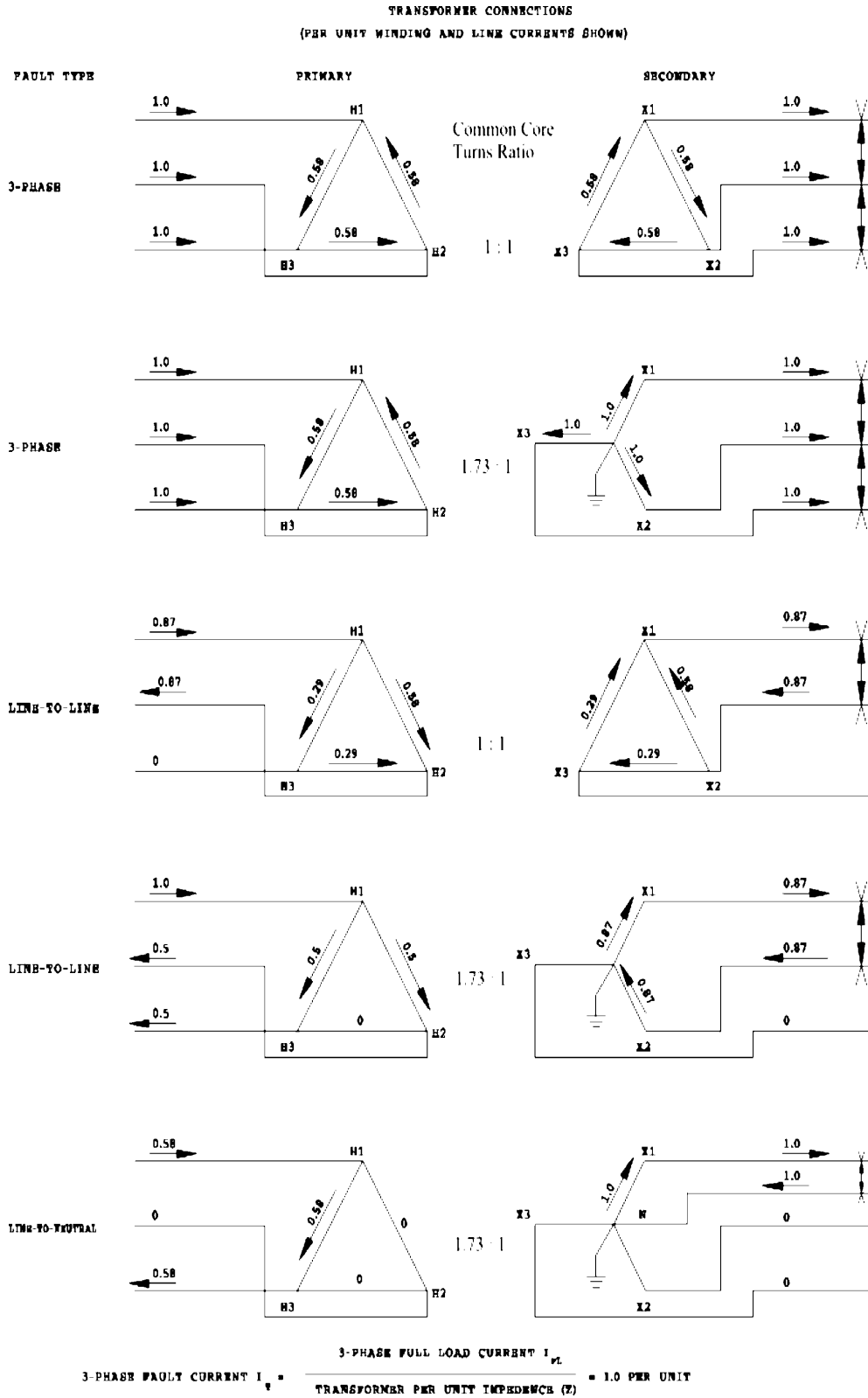


Figure 7—Line and transformer winding currents for Δ-Δ and Δ-Y connected transformers