

TRANSFORMER PROTECTION APPLICATION GUIDE¹

This guide focuses primarily on application of protective relays for the protection of power transformers, with an emphasis on the most prevalent protection schemes and transformers. Principles are emphasized. Setting procedures are only discussed in a general nature in the material to follow. Refer to specific instruction manuals for your relay. The references provide a source for additional theory and application guidance.

The engineer must balance the expense of applying a particular protection scheme against the consequences of relying on other protection or sacrificing the transformer. Allowing a protracted fault would increase the damage to the transformer and the possibility of tank rupture with a consequent oil fire and consequent personnel safety risks. There is no rule that says what specific protection scheme is appropriate for a given transformer application. There is some tendency to tie protection schemes to the MVA and primary kV of a transformer. While there is some validity to this approach, there are many other issues to be considered. Issues to be considered include:

- The severity of personnel safety concerns and the possibility that a given protection scheme can reduce these risks.
- The danger to nearby structures and processes if a transformer fails catastrophically and the possibility that a given protection scheme can reduce the possibility of such a failure.
- An overall view of the economic impact of a transformer failure and what can be done to reduce the risk, including:
 - The direct economic impact of repairing or replacing the transformer.
 - The indirect economic impact due to production loss.
 - Repair time vs. complete replacement time.
 - The availability of backup power feed or emergency replacement transformers, and the cost of each option.
 - The possibility that a given protection scheme can reduce the damage and resultant repair time, or that it can change a replacement into a repair.

Some specific applications that affect protection are: A tap changer flashover can ordinarily be repaired in the field, but if this fault is allowed to evolve into a winding fault, the transformer will need to be shipped to a repair facility; hence, protection that can rapidly sense a tap change fault is desirable. A high magnitude through fault (external fault fed by the transformer) shakes and heats a transformer winding, and the longer the through fault lasts, the greater the risk of it evolving into an internal transformer fault; hence, fast clearing for close-in external faults is part of the transformer protection scheme. Some transformers are considered disposable and readily replaced, reducing the need for advanced protection schemes. Transformer protection commonly includes some coverage of external bus and cable, and faults in these zones may expose personnel to arc flash hazards. Slow clearing protection schemes may be unacceptable from an arc flash exposure perspective. Fires in an indoor transformer may have high risk of catastrophic facility damage and even higher personnel safety risks, increasing the need for advanced high speed protection. The proximity of flammable process chemicals increases a need for protection schemes that reduce the risk of a tank fire. The failure of a transformer used in a large base load unit-connected generator may cause extended generation-replacement costs; even the loss of a small station service transformer can cause a notable disruption of generation and high economic consequences. Similar economic impacts may also exist at industrial sites. Some transformers are custom designs that may have long lead times, increasing the need for advanced protection schemes.

¹ Extract from Basler Electric Publication
Transformer Protection Application Guide
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1. Failure Statistics

Table I lists failures for six categories of faults (IEEE C37.90, “Guide for Protective Relay Applications to Power Transformers, Ref. 1). Winding and tap changers account for 70% of failures. Loose connections are included as the initiating event, as well as insulation failures. The miscellaneous category includes CT failure, external faults, overloads, and damage in shipment. An undisclosed number of failures starts as incipient insulation breakdown problems. These failures can be detected by sophisticated online monitoring devices (e.g. gas-in-oil analyzer) before a serious event occurs.

	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

Table I - Failure Rates, Ref. 1.

2. Protection Example and General Concepts

The reader interested in additional information, advanced or unusual application advice, and detailed settings guidance should refer to Ref. 1. This document includes extensive references and bibliographies. Also, Ref. 2 and 3, textbooks on protective relaying, contain chapters on transformer protection, and Ref. 4, another IEEE standard, includes good overall protection schemes where a transformer is the interface point between a utility and an industrial customer.

There are three general categories of protective relay technology that arise in the discussions to follow:

- **Electromechanical:** uses magnetic flux created from current and voltage to create torques on movable disks and relays, which is the source of the term “relay.” Usually single device number functionality.
- **Solid State:** uses low voltage analog signals created from sensed currents and voltages; uses discrete electronics and basic logic circuits; may contain a basic microprocessor for logic and some math. Usually single or dual device number functionality.
- **Numeric:** a multifunction, programmable logic relay; digitizes sensed current and voltage, then calculates an RMS or phasor equivalent value; uses a high-end microprocessor. Usually incorporates many device number functions.

All Basler Electric relays are solid state or numeric.

Table II lists some common ANSI device numbers associated with transformer protection. A numeric relay generally contains many implementations of these devices within its programming, and each instance of a device is referred to, herein, as an “element” in the relay. For example, while the Basler BE1-CDS220 is primarily a transformer differential relay (hence, includes the 87

device in elements named 87P and 87N), it also includes nine independent implementations of the 51 overcurrent device, called the 51P, 151P, 251P, 51Q, 151Q, 251Q, 51N, 151N, and 251N elements as well as many other device functions.

Figure 1 shows extensive use of relays that would be representative of a large industrial load. This will be used for discussions in some of the material that follows. There are two 115 kV feeds to two 30 MVA transformers that are resistance grounded on the 13 kV side, limiting ground fault current to about 400A from each transformer. In other applications, a reactor is used, and in some applications, the ground fault current is limited to less than 10A. In a typical utility application, transformers are connected directly to ground, but occasionally a small reactor is placed in the transformer neutral that limits ground fault current to approximately the same level as three phase faults. In this example system, the protection scheme described applies to solidly grounded (as well as impedance grounded) systems, except the effect of ground impedance results in the addition of protection functions not required on a solidly grounded system.

The phase and ground differential (87P and 87N, Section 4) and sudden pressure relay (63, Section 6) provide the primary transformer fault protection. The suite of overcurrent elements (51, Section 8) is generally considered backup transformer protection, or for protection of the bus and backup protection for the feeder relays. These elements are part of the transformer protection in that they limit the accumulated damage that occurs from a transformer feeding high current into downstream faults. The 67N relay offers an alternative to the 87N function. Hot spot monitoring (49, Section 9) is indicated, but is likely an alarm only scheme.

If there is a possibility of over voltage on the units due to local generation or a transformer being placed at the end of a long line (the "Feranti" effect), voltage relays (24 and 59, Section 4.4.4) may be included. Another possible backup protection scheme is low voltage (27) or unbalanced voltage detection (47). If there is local generation, to help detect islanding conditions an over/under frequency (81, O/U) relay may be installed, though an 81 may not be considered a transformer protection element.

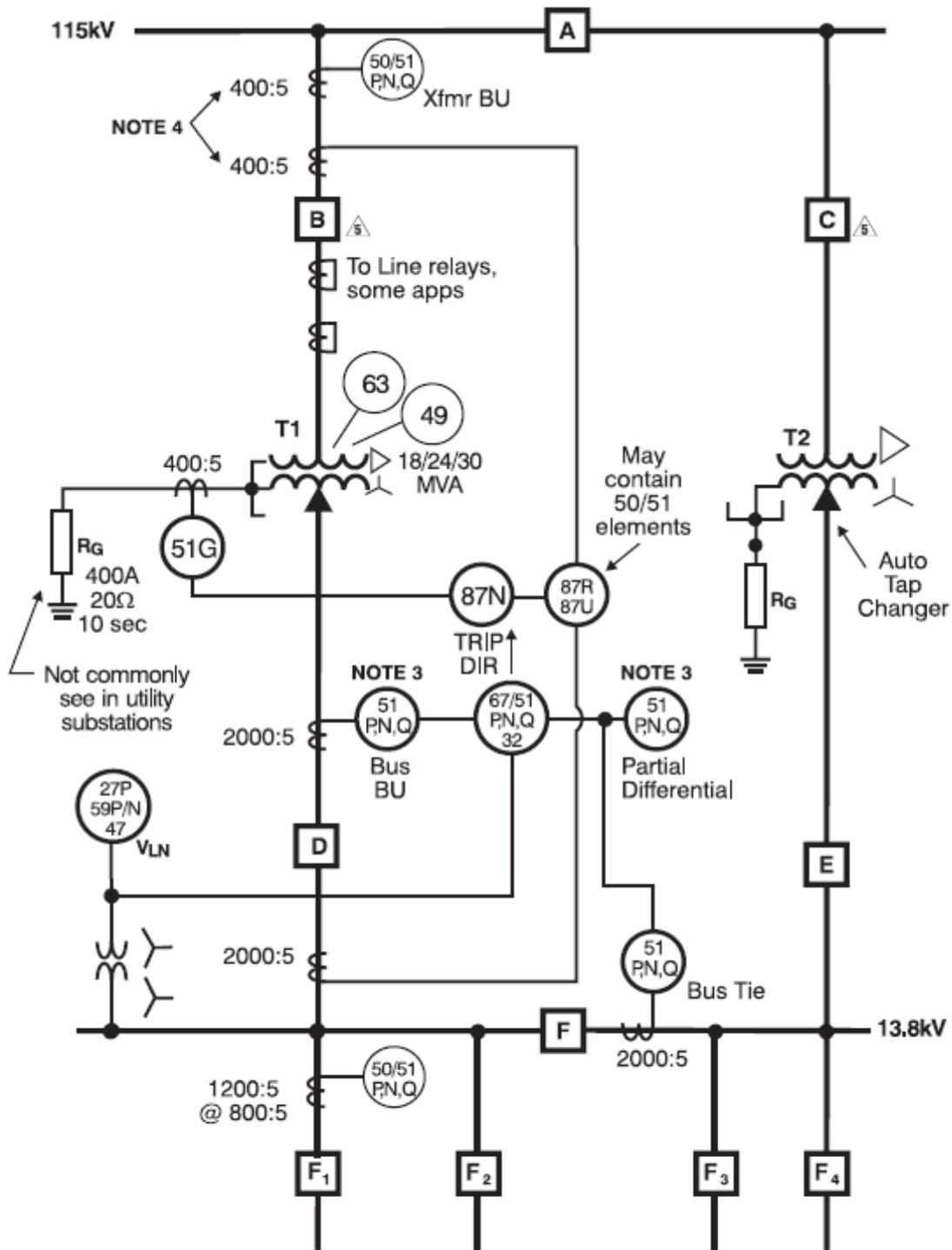
Directional overcurrent relays and directional power (67/50, 67/51, and 32, respectively, Section 8.4) respond to load current circulating through the 13 kV buses when the 115kV breaker A is open and the 13.8kV tie is closed. The elements may also respond to faults in the transformer near the secondary bushings. If the transformers can be operated in parallel, the elements also provide a means to sense tap changers that have become out of step with one another. If there is generation in the 13.8kV system, sensitive 67 elements can sense a small generator backfeeding a 115kV fault.

The primary and secondary relaying would sometimes be configured to feed their own lockout relays (86) to help ensure that protection is available even with a failure of one 86 relay or its dc feed.

The protection scheme in Fig.1 does not utilize fuses. Fuses normally would be seen only on lower MVA transformers than indicated. See Section 3.

Transformers of the indicated MVA normally would have their oil tested for dissolved gasses (Section 7) as part of routine maintenance. Larger transformers may have continuous on-line monitoring equipment.

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NOTES:

- 1) 13.8kV Bus Differential Protection scheme may also exist.
- 2) Breaker Failure schemes may also exist, especially at 115kV.
- 3) Partial Differential replaces bus backup and bus tie in some applications. See Section 8.2.
- 4) CTR selection based on load and fault duty, See Section 10.2.1.
- 5) Depending on the application and arrangement, breakers B and C may be circuit switchers.

Figure 1 - Protection Example

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Device	Description	Comment
24	Volts/Hz	For overexcitation detection. Similar to 59 but the pickup is proportionate to frequency. Typically an inverse time characteristic.
27II 27In	Undervoltage	II = line to line In = line to neutral (or line to ground. Note neutral may be isolated from ground in some systems.)
32	Power Element	Used to sense power backfeed through transformer
47	Negative sequence overvoltage	Usually defined by: $V_2 = (V_{an} + a^2V_{bn} + aV_{cn})/3$. ($a=1.120$). It is also possible to define V_2 in terms of V_{II} . Some relays define the 47 in terms of a manufacturer-specific voltage unbalance measurement rather than in terms of V_2 .
49	Thermal	Typically top oil temperature RTD.
51P	Phase Time Overcurrent	A 51 by itself usually refers to phase time overcurrent, but adding the P gives additional clarity.
51G	Ground Time Overcurrent, measured by dedicated window CT, or CT on transformer neutral	Herein: Ground refers to current on a transformer ground/neutral bushing or current from a window CT that wraps all three phases (and possibly also wraps a neutral bus if one exists).
51N	Neutral Time Overcurrent = 3I _o = Phase CT Residual	Neutral refers to the phase current summation ($I_n = I_a + I_b + I_c$), which is the equation used for 3I _o in numeric relays and which is also the summation of the 3 phase CTs ("residual").
51Q	Negative Sequence Time Overcurrent	Defined by: $I_2 = (I_a + a^2I_b + aI_c)/3$
50P 50G 50N 50Q	Instantaneous Overcurrent P, G, N, Q have same meaning as for the 51.	In some relays, a 50 has the option of being time delayed; hence, it becomes, a definite time element and may be renamed 50TP, 50TG, 50TN, or 50TQ.
59II 59In 59N	Overvoltage	II, In = line-line or line to neutral/ground. N refers to V ₀ or 3V ₀ sensing, depending on the manufacturer. $V_0 = (V_{an} + V_{bn} + V_{cn})/3$.
63	Sudden Pressure	There may be separate devices for the tap changer and main tank.
67/50x 67/51x	Directional control, directional instantaneous directional time overcurrent	x refers to P, G, N, or Q. The 67 by itself is used inconsistently in the industry. Herein, for clarity, a 67 is a sensitive forward/reverse polarizing bit that controls the 50 and 51 element, and the dual term 67/50x or 67/51 is used.
86	Lockout Auxiliary	Most transformer trips are directed to a lockout relay.
87P	Phase Differential	Comprised of several functional elements. See text for description. Many variations by relay and manufacturer.
87U	Unrestrained Differential	Monitors phase differential. Trips when magnitude is much greater than maximum inrush levels.
87N	Ground Differential	Sometimes referred to as a "Restricted Earth Fault" sensing element. It is more commonly applied on systems with impedance in the transformer neutral for the purpose of limiting ground fault current.

Table II - ANSI Device Numbers (C37.2)

3. Fuses

Fuses are economical, require little maintenance, and do not need an external power source to clear a fault, which is of great cost and maintenance benefit. As discussed above, MVA of a transformer is an imperfect guide to the appropriate level of transformer protection, but it may be noted that fuses are probably the predominant choice for transformers below 10 MVA. Under 3MVA, breakers on the high side are seen only in special applications (e.g., some small generation sites may use a high side breaker).

The use of fuses creates some notable protection compromises. Fuses are not as precise in operating characteristics. Characteristics change slightly with temperature, pre-fault loading, and reclose timing. Fuses are subject to gradual damage from heavy through faults, leading to an eventual fast trip for a low magnitude fault. Usually only one or two fuses blow, which introduces single-phasing conditions to downstream loads. Single phasing causes very high negative sequence voltage and current and low VIn or VII voltages. The resultant voltage may be worse than no voltage due to the overheating that it can cause to certain types of equipment, such as three phase motors.

Fuses are insensitive and relatively slow except at very high current levels. Fuses will not sense low level faults, such as near the neutral of the transformer, and hence trip only after the fault has evolved into a high current event. To allow short overloads, a transformer fuse is typically selected to carry 150-300% of the transformer rated current (see NEC article 450, Ref. 5). Most fuses can carry over 125% of rated current for very long times, and just begin to reliably trip for faults in the range of 150-200% of the fuse rating, and at this level generally take tens of seconds to trip. The effect is that a fuse might carry current in the range of 3 to 5 times transformer rated current for an extended period. At moderate currents, fuses are still relatively slow. For instance, a fuse must be able to carry inrush current without damage. A classical measure of inrush current is 12x full load current for 0.1 second. Due to slow clearing for faults at low magnitude, when a fuse is used, the transformer is at higher risk for being irreparable after an internal fault and at higher risk of failing in some catastrophic manner, such as a fire.

In some protection schemes, the transformer high side overcurrent protection scheme is considered backup protection for faults downstream of the secondary protection elements. The low sensitivity of fuses means they are poor at backing up secondary overcurrent protection devices, especially for faults remote from the transformer secondary and especially for ground faults on delta/wye transformer banks. See Section 10.3 for a discussion on the current ratios seen across delta wye transformer banks.

A fuse has some protection benefits. If fault current is extremely high, a fuse can be faster than a breaker and can clear faults within 0.5-2 cycles after inception. The fastest type, called a "current limiting fuse" (CLF), available at medium and low voltages, can clear a fault in half a cycle and can reduce the first half cycle peak current to a level notably below the available fault current. The CLF fuse can be damaged by inrush current if not properly selected. If a fuse is selected that has fast clearing at peak currents, it can clear a fault faster than any circuit breaker; hence, at high fault currents, a fuse downstream of a circuit breaker tends to coordinate with the upstream breaker better than two breakers in series. This application is seen most commonly in an industrial low voltage application where two breakers in series sometimes are found to both be operating in an instantaneous trip zone. In a transmission application, when a high voltage fused transformer is placed as a tap on a transmission line, coordination is not easily achieved. The transmission line impedance relay, operating in its Zone 1 reach, frequently will be committed to a trip within 1-1.5 cycles after a fault begins; hence, the transmission line may trip ahead of or simultaneously with a fuse on a transformer.

It is recommended that, on fused transformers, protection should employ a low-side circuit breaker with phase and ground overcurrent relays for backup protection of secondary faults. Ideally, the relay also should have negative sequence overcurrent (46), negative sequence overvoltage (47), and line to ground undervoltage (27In), for sensing unbalanced system operation in the event of a single or double fuse operation on the transformer primary. Be aware that, in a radial power flow

application, relays on the transformer secondary relay will not respond to a transformer fault, except possibly a 27 or 47 relay can sense resultant voltage degradation.

4. Differential Relaying (87)

Differential relays sense the unbalance in the flow of currents in various apparatus or buses. In the absence of a fault in the protected zone, this unbalance tends to be small and the flows into the zone are closely matched to the flows leaving. Accordingly, such relays can be more sensitive than phase overcurrent relays and need not be delayed to coordinate with other relays during external faults, except for some issues associated with transient CT saturation, to be discussed below.

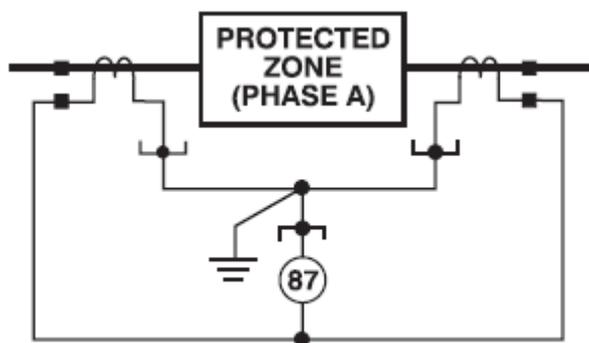


Figure 2 - Basic Differential Concept

The simplest implementation of differential protection, as seen in Fig. 2, merely parallels the CTs on all the connections to the zone, and the relay monitors the current summation. This concept is applied on basic bus protection schemes. The 87 device for this application feasibly can be simply a 51 device, though a 51 normally would be configured to be neither extremely sensitive nor fast due to issues with CT transient performance under the presence of DC offset in the primary current.

The basic differential concept above will not work with transformers. When the protected zone in Fig. 2 is a transformer, there are several additional components, seen in Fig. 3, that are required, or at least commonly implemented, for proper performance:

- Current Matching Scheme
- Through Current Restraint and Minimum Operate Logic
- Delta/Wye Compensation Logic (may be implemented in CT connections rather than in the relay)
- Magnetizing Inrush Blocking Scheme, commonly using harmonics
- Unrestrained Differential Scheme (not in some basic or early electromechanical relays)

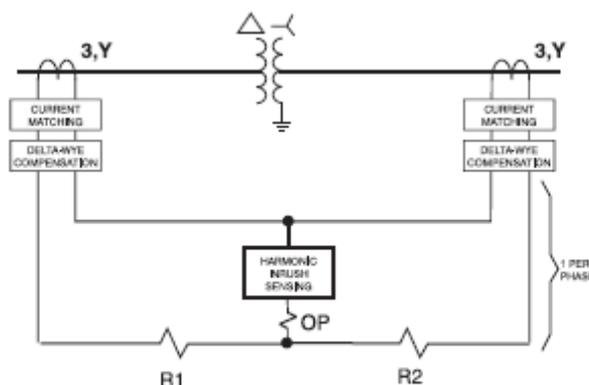


Figure 3 - Transformer Differential Concept

4.1 Current Matching Scheme

The relay’s current matching scheme allows different currents on each input to the relay to be seen as effectively the same current. In electromechanical relays, the scheme uses tapped transformers (hence, the source of the term “tap”), where each tap adjusts the number of turns used on the input transformer, so that, for instance, 4.6A on input 1 (at a tap of 4.6) gives just as much magnetic flux as 3.5A on input 2 (at a tap of 3.5). In solid state relays, the tap, typically (as in the BE1-87T) is composed of switches that change the resistance on the secondary of the sensing CT circuit. For instance, a two input solid state relay set at taps 4.6 and 3.5 might be designed so that 4.6A and 3.5A on each respective input will both cause a 100mV internal voltage signal. Hence, $4.6A = 3.5A$ as far as the remainder of the relay circuitry is concerned. On numeric relays (i.e., microprocessor based relays that convert incoming currents to digital signals), the current matching scheme uses mathematics and varying multiplication factors.

A typical concept for setting the taps for a two winding transformer is to analyze the current seen at the relay for the peak power rating of the transformer. For instance, in Fig. 1, assume the CT ratios as shown (discussed further in Section 10.2) and, the Full Load Amps (FLA) in the lines at 30MVA is 151A at 115kV, and 1255A at 13.8kV, and the CT secondary current is 1.883A and 3.138A, respectively. Depending on the relay design, the delta compensation may require that the current on the Wye side be multiplied by $\sqrt{3}$ (e.g. the CDS-2x0 relays do not require the $\sqrt{3}$ factor, but the BE1-87T does). For this example, let us assume a BE1- CDS220 is in use, so we do not need the factor. The ratio of the taps is the critical factor, not the specific taps. The minimum tap of the BE1- CDS220 is 2, so we use taps of 2.00 and 3.33. The ratio of currents ($3.138/1.883$) is 1.667, and the ratio of taps ($3.33/2.00$) is 1.665, so the error that the relay sees due to tap ratio not matching the current ratio will be quite small. In electromechanical relays, the tap selection is much more limited, and resultant error seen by the relay tends to be substantially more significant.

Current matching in three winding transformer applications must, in effect, be analyzed two windings at a time. One assumes identical power in windings 1 and 2 (and 0 in winding 3), which sets taps 1 and 2, and then one assumes identical power in windings 1 and 3 (and 0 in winding 2), which sets tap 3. This will force winding 2 and 3 taps to work correctly for the case of power flowing from winding 2 to winding 3. In this approach, the constant power that is assumed can appear to be more than winding 2 or 3 can handle, but since this power level does not flow in actual application, the high current flow seen in the calculations does not affect the validity of the setting.

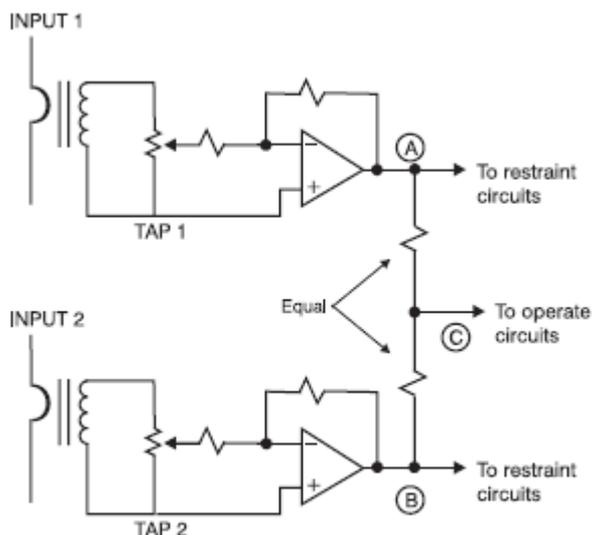


Figure 4 - Current Matching in a Solid State Relay

Figure 4 shows the conceptual implementation of current matching in the BE1-87T for a single phase transformer. Relays of other designs will use parallel concepts appropriate for their design. When installed per the relay instruction manual, the current will flow in opposite polarity on input 1 and input 2. The taps will be set so that the magnitude of the voltage presented to the op-amps is

the same RMS value. The voltage at point C, the summation point, will be at the midpoint between A and B, and in normal operation, since A and B are opposite in polarity but equal in magnitude, the voltage at C will be 0 throughout the current sine wave, indicating no error current. If current at input 1 increases, voltage at A increases, but not B, and now point C sees a voltage above 0. Depending on the relay settings, the relay may trip.

Current matching settings normally are calculated under the assumption that the load tap changer is at the nominal / neutral position. The relay percentage restraint and minimum operate settings then are configured to accommodate the unbalance current that the relay will see when the load tap changer is at the full boost or buck position, and commonly with some additional accommodation for the no-load tap being changed from nominal.

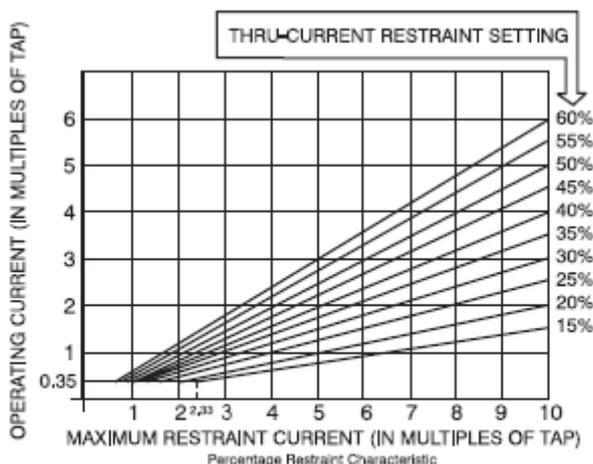
The BE1-87T has a current matching ("tap") range of 2 to 8.9A. The BE1-CDS relays have matching ranges from 2 to 20A. The wider range of the numeric relay can be helpful in installations where small transformers are placed on buses with high short circuit duty (the high short circuit duty forces one to use higher CT ratios than would be chosen just on load current level criteria).

4.2 Percentage Restraint and Minimum Operate

Typically, there is some small difference in the summation of the sensed currents so that, even after appropriate tap settings, currents sensed by the relay do not sum to an effective 0A. The error (or difference) current becomes the operate current which, if it rises too high, will cause relay operation. The operate current arises due to dissimilar CT performance during a through fault or large load inrush (especially during transient CT saturation due to DC offset); differences in the transformer no-load tap that is in use vs. the no-load tap assumed when the relay settings were calculated; the operation of the transformer auto tap changer (if there is one); transformer steady state excitation requirements; and inrush excitation current that has decreased below the harmonic excitation blocking levels but has not actually decayed to a negligible value. Several of these types of errors create an operate current that rises proportionately with through current. Because the error rises with load current, a fixed level for the operate pickup generally is not acceptable.

To compensate for operate current rising during high load currents or through faults, the 87 logic includes a restraint function. As through current increases, the restraint function causes an increase in the level of operate current required for a trip. Each current input is monitored and becomes part of the overall restraint of the relay. The concept is referred to in many documents as a percentage restraint characteristic because the logic can be described by: "The operate current must be ##% of the restraint current before a differential trip is declared."

The concept as implemented in the BE1-87T is seen in Fig. 5, where operating (or "differential") current is plotted against the maximum (i.e., largest) restraint current. The scaling is in "multiples of tap." The slope of the characteristic can be set from 15 to 60%. The relay becomes desensitized at the higher restraint currents in order to remain secure in the presence of the various sources of error previously mentioned.



*Figure 5 - BE1-87T Restraint vs. Operate
(BE1-CDS-2x0 similar).*

Note in Fig. 5 the horizontal axis is in "maximum restraint current." This allows the best-performing CT to be used for the restraint decision. The BE1-CDS2x0 has the option to use average restraint rather than maximum restraint, though maximum restraint is the preferred setting.

Relays from other manufacturers use other restraint algorithms. For instance, some relays on the market desensitize the relay at a greater slope during very high through current, using a "dual slope" approach. The BE1-CDS2x0 relays use an alternative approach via an algorithm that desensitizes the relay during high currents, but only when a CT saturation detection logic scheme is declared true.

Figure 5 also shows the minimum operate feature. Independent of the through current restraint, there must be a certain magnitude of operate current before a trip is issued. This feature helps prevent false tripping due to several issues, such as when inrush excitation current has decreased below the harmonic excitation blocking levels. The minimum operate current is fixed in the BE1-87T and adjustable in the BE1-CDS2x0.

The "total mismatch" line in Fig. 6 represents the sum of the imperfect relay-tap match (i.e., the discrete increments available for the relay taps may not be the ideal setting) plus the effect of the power transformer no-load and load (i.e., auto) taps not being at the setting used when calculating settings. The mismatch line is offset by the transformer exciting current, which produces its own unbalance. Fig. 6 shows the BE1-87T slope characteristics at the two extremes of slope setting (15 and 60%), as well as the related safety margins at the critical point where the slope characteristic meets the minimum operate current. The two lines intersect at approximately full load current on the restraint axis, but the meeting point reduces with increased slope setting and increases with minimum operate current. A side issue to be aware of is that, if high prefault load is flowing through the transformer, some of the load current continues to flow during the fault and acts to increase the restraint level.

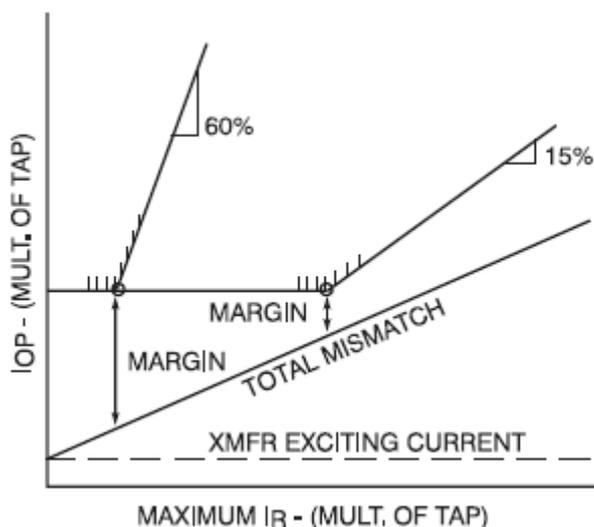


Figure 6 - Percentage Restraint Margin

4.3 Delta/Wye Compensation

A delta wye bank introduces a phase shift in balanced voltages and currents of typically $\pm 30^\circ$, depending on system rotation and transformer connections. In electromechanical relays, the common approach to the delta wye winding compensation is to connect the CTs in wye-delta, as seen in Fig. 7. Note the CT on the delta transformer winding is connected in wye, and the CT on the wye transformer winding is connected in delta. The same concept could be used with solid state and numeric relays, but normally such relays have internal delta wye compensation logic. The preferred approach is to connect CTs in wye and allow the relay to perform the delta wye compensation. The BE1- 87T relay performs the delta wye compensation electronically via analog circuitry, and the BE1- CDS2x0 performs the compensation via mathematical processes, thereby removing the need to connect any CTs in delta.

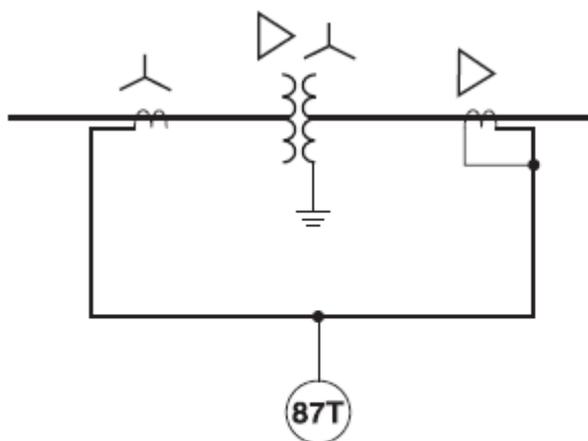


Figure 7 - Delta Wye Compensation with CT Connections

There are several benefits to connecting the CTs in wye. With wye CTs, metering and event reports give actual line currents, rather than the summation of two phases as seen in delta CTs. Power metering is more accurate when CTs are in wye. Wye connections allow monitoring ground current in the lines and the use of ground relays. A wye connection also reduces lead burden for a phase fault. The worst case is for a 3-phase fault with delta CTs. Per Fig. 8, the lead burden voltage as seen by delta CTs is magnified by a factor of three times relative to the burden that would be seen with wye CTs (note current in the leads is higher by 1.732 factor, and that the CT is across two phase leads, hence seeing higher voltage compared to being across phase to neutral). See Appendix A of the BE1-87T instruction manual for a more in-depth analysis of this issue.

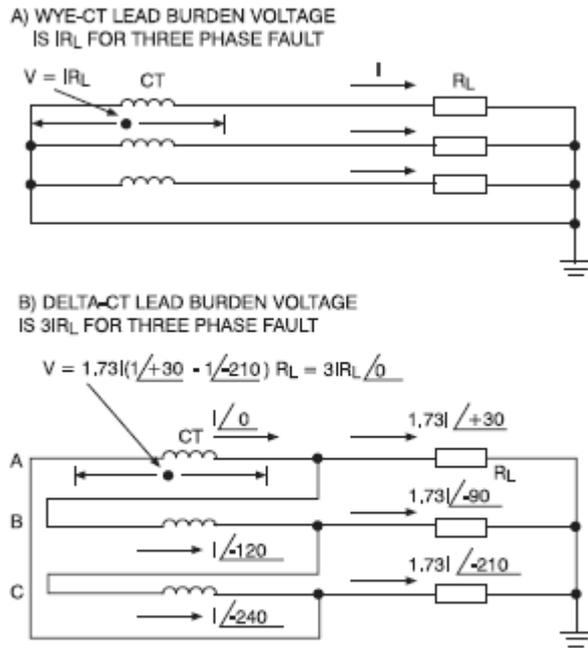


Figure 8 - Increased CT Burden from Delta CT Connection

It is essential that the delta compensation in either the CT connection or internal to the relay's algorithms be of a type that matches the transformer connection. For example, if a "DAB" delta is used, the compensation needs to be DAB, not DAC. Incorrect selection of DAB vs. DAC compensation is a common source of trouble during the commissioning stage and, on lightly loaded transformers, can be a source of misoperations seen long after initial startup. The difference between a DAB and DAC delta is seen in Fig. 9. The figure is drawn to show delta connections but also to represent the phasor diagrams of system voltages with balanced ABC phase rotation (i.e., the secondary wye windings are drawn in a direction that represents ABC positive sequence phase rotation phasors, and the primary delta windings are then drawn in phase with their corresponding wye windings). Note in the two cases, the polarity of the A phase element is either a) connected to the nonpolarity of phase B (referred to as a DAB connection) or b) connected to the non-polarity of phase C (referred to as a DAC connection). For balanced voltages as seen in the figure, the resultant V_{AN} phasor on the wye side either a) lags the delta V_{AN} phasor (DAB connection), or b) leads the delta V_{AN} phasor (DAC connection).

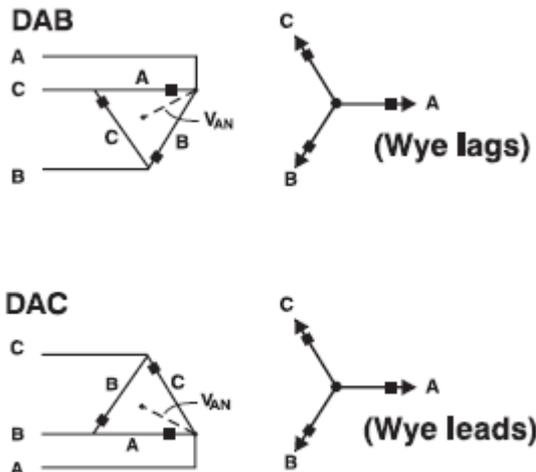


Figure 9 - DAB vs. DAC Delta

These two methods to connect a delta have very large effects on which phases on the delta side see current during a wye side fault. For example, examine the wye side faults seen in Fig. 10. Note that, for the DAB delta, the wye side A phase to ground fault creates current in the lines A and B on

the delta side, but for a DAC delta, the wye side A phase to ground fault creates currents in lines A and C on the delta side.

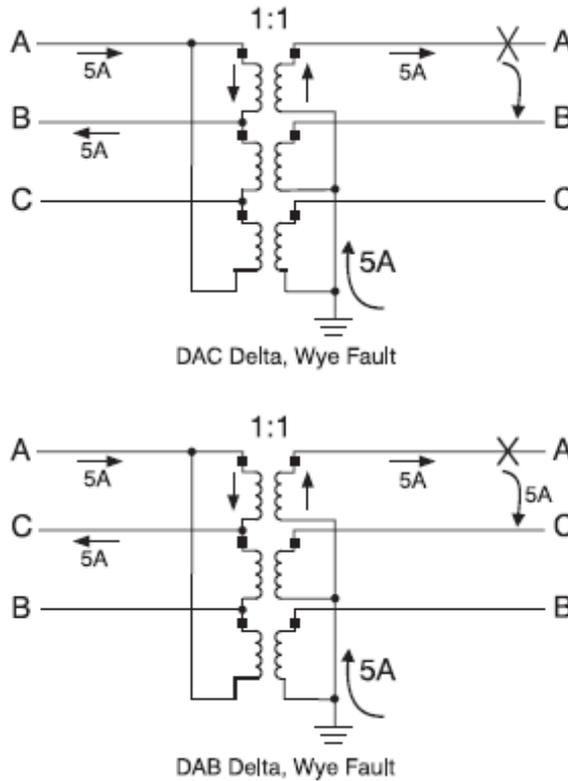


Figure 10 - DAB vs. DAC during a Wye Side Fault

The difference between DAB and DAC deltas is, to some extent, the result of how one assigns phase names to the lines connected to the transformer. In Fig. 10, the difference between the DAB and DAC transformers is simply created by swapping the B and C phases on the wye side, which also changed phase naming on the delta side. Hence, though no internal wiring was changed on the transformer, how one named the phase leads and windings was changed, and this renaming causes long-ranging consequences on transformer phase shift and extensive confusion for the relay and substation engineer. Delta/wye compensation as seen in Fig. 9 is the most common type of transformer phase shift found in the industry, but there are many other three phase transformer winding configurations. Section 4.7 discusses the matter further.

An example using CTs for compensation is seen in Fig. 11. Note that the delta is connected DAC and that the CTs on the wye side are also connected DAC.

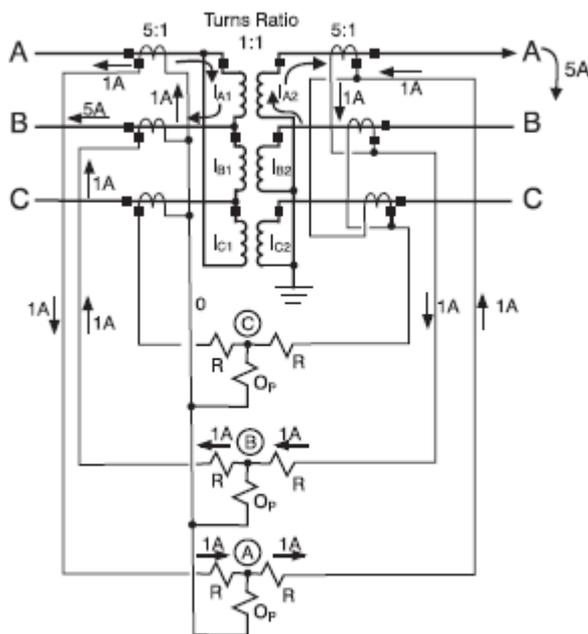


Figure 11 - DAC Compensation Using CT Connections

Figure 11 adds a valuable insight into how a solid state or numeric differential relay compensates for transformer delta/wye connections. It is a common misunderstanding that delta/wye compensation involves a phase shifting algorithm in the relay that simply reverses the 30° phase shift seen in balanced currents. Another misconception occasionally seen is that the relay compensation involves removing zero sequence current from the wye side currents. Neither is true.

The numeric and solid state relay is actually doing, in math or electronics, the same thing being done with CT connections in Fig. 11. Note the differential element does not see the actual current in any one winding of the transformer, but all three differential comparators monitor current in two phases of the transformer at a time. Let us name Ia1, Ib1, and Ic1 as the currents in the transformer delta (not the leads to the transformer), and Ia2, Ib2, and Ic2 are the currents in the wye windings. Note the relay's A, B, and C comparators monitor these sets of currents:

- A comparator: Ia1-Ic1 to Ia2-Ic2
- B comparator: Ib1-Ia1 to Ib2-Ia2
- C comparator: Ic1-Ib1 to Ic2-Ib2

The numeric and solid state relay performs the same compensation by adding and subtracting currents in a process that mimics the effect of the delta CT connections seen in Fig. 11. Note there is no deliberate phase shift or zero sequence removal algorithm, though, in effect, this happens. For a more complete description of compensation in numeric relays, see Ref. 6.

4.4 Inrush Detection and Trip Blocking

Transformer inrush refers to the transient exciting current resulting from a sudden change in the exciting voltage. This occurs at the instant of energization, after the clearing of an external fault (recovery inrush), or during the inrush period of another nearby transformer (sympathetic inrush) (Ref. 7).

Inrush current appears as operate current to a differential relay so the relay must either a) have sufficient time delay and insensitivity to the distorted wave so as to not see the event (of course, this is the undesirable answer) or b) take advantage of the inrush's distinctive waveform to sense the event and block tripping. The most common means to sense inrush is via the use of harmonic content in the operate quantity. The second harmonic predominates in inrush currents (Ref. 7) and is used in most transformer differential relays, either alone or in combination with other nonfundamental components, though there are other waveshape monitoring schemes in a couple

relays in the market. The harmonic sensing relays most commonly block operation if the harmonic(s) in the operate leg exceed(s) a given percentage of the fundamental component, though some relays on the market use the harmonic to increase the restraint current. Some relays (e.g. Basler products) use a scheme that uses total harmonic current in all three phases in the analysis of every phase, and some use a cross blocking scheme, where if one phase is blocked, all phases are blocked. In the BE1-87T, the percentage settings are fixed, but in the BE1- CDS2x0, the harmonic restraint level is a user setting.

4.4.1 Energizing Inrush

Energization inrush is caused by remanence (residual flux) in the core and the point in the voltage waveform when a transformer breaker closes. If the instantaneous voltage at energization calls for flux of the same polarity as the remanence, the core is driven into saturation, creating peak exciting currents that can exceed ten times rated exciting current. As a comparison, normal steady-state excitation current is about 0.01 to 0.03 times rated.

In Fig. 12 the steady-state flux at the instant of energization matches the residual flux, so no transient current flows.

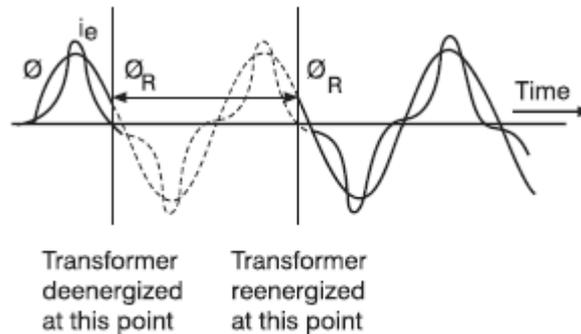


Figure 12 - Energization without Inrush

In contrast, in Fig. 13, the steady-state flux at energization is at its negative peak. Combined with a positive remanence, this condition produces the maximum level of transient current. The inrush current is actually much larger in relation to steady-state current than indicated by Fig. 13, in order to keep the figure to a reasonable size.

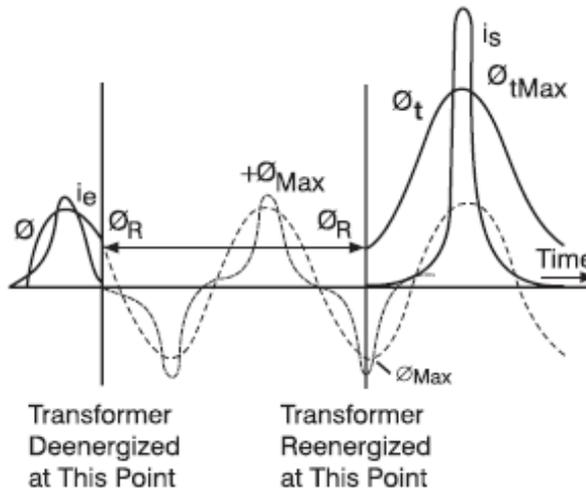


Figure 13 - Energization with Inrush

Figure 14 shows a typical inrush waveform. Note the dead/flat spot where almost no current is flowing as the core exits and then re-enters the saturated region. The alternating flat to high peak current contains the second harmonic that a relay uses to recognize the existence of an inrush condition.

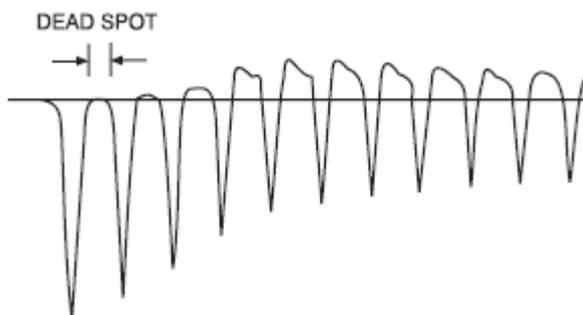


Figure 14 - Energization Waveform

Note in the first two to three cycles of Fig. 14's waveform, there is an effective DC component of the waveform. This DC is causing a flux buildup in the CT steel and a partial saturation of the core. After about 3 cycles, the flat/dead spot rises above the 0 current axis, and the component of current above the 0 current axis is roughly equal to current below the axis, indicating the CT is no longer producing any DC offset (even though DC may exist on the primary), but it is still reproducing at least some of the AC components, though in a possibly distorted fashion. In extreme cases, the CT can saturate during the first cycle, so the flat spot in the current waveform never remains at the 0 current level for any duration. The decay rate of successive primary-current peaks depends upon the amount of resistance in the source and the nonlinear inductance of the transformer.

In three phase transformer differential relays, the differential relay has the ability to monitor harmonic levels in all three phase differential comparators at the same time; hence, it makes a decision that an inrush condition exists on a three phase basis, rather than on a per phase basis. This feature is found in the Basler BE1-87T and BE1-CDS2x0.

4.4.2 Recovery Inrush

A recovery inrush occurs at the clearing of an external fault as a result of the sudden increase in voltage from the depressed and unbalanced level that exists during the fault. This voltage transient causes a flux transient, with accompanying abnormally high exciting current. The current level is less than that seen during transformer energization.

4.4.3 Sympathetic Inrush

The current I_p in Fig. 15 shows sympathetic inrush current in transformer T1, resulting from the energization of an adjacent transformer T2. The decaying DC component of current I_e flowing in T2 develops a drop in the source impedance R_s and X_s , producing pulses of inrush current I_p on the alternate half cycles. Note the delayed buildup of I_p . The severity of the sympathetic inrush is a function of the level of DC voltage drop across the source impedance. A common set of differential relays should not be used to protect both T1 and T2 transformers in Fig. 15 if they can be switched separately. The sum of the two transformer currents, I_s , may not contain sufficient harmonics to restrain the relays once transformer T1 saturates severely.

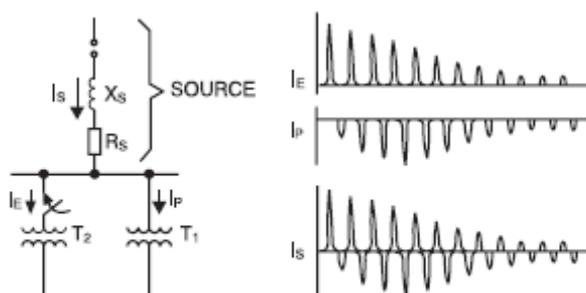


Figure 15 - Sympathetic Inrush

4.4.4 Overexcitation

Overexcitation results from excessive voltage or below-normal frequency or a combination of the two, such that the volts/Hz exceed rated. Fig. 16 shows three situations where overexcitation can occur: short line and a long line unloaded transformer condition and long line with load connected. In addition, an interconnected system can experience a dynamic overvoltage following a protracted fault as a result of generator fields going to their ceiling or following load shedding. All of these scenarios involve essentially balanced conditions, so phase to phase and phase to ground voltages increase. Substantial phase to ground overvoltages can also occur on sound phases during a ground fault on impedance grounded systems. In these cases, delta windings or wye-ungrounded windings will not be overexcited, since the line to line voltages will not increase.

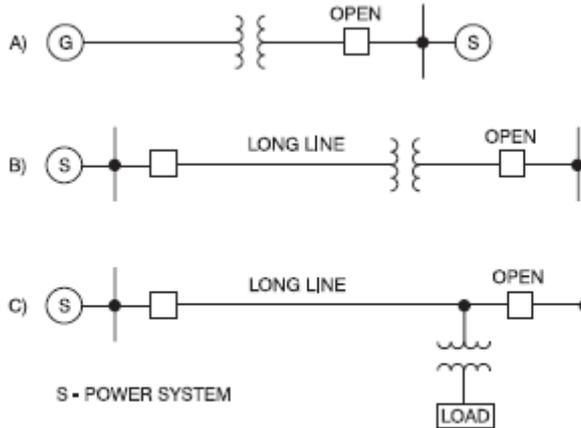


Figure 16 - Systems with Transformer Overvoltage Risk

The increase in transformer exciting current with increased excitation voltage is illustrated in the dashed curve in Fig. 17. The transformer will tend to become overheated due to increased excitation current, hysteresis losses, and eddy currents. The increased exciting current produces operating current in the differential relay, but an operation of this relay is not desirable, since immediate response is not necessary. The power system should be allowed time to correct itself. Also, a differential operation indicates a transformer failure, requiring unnecessary investigation and delayed restoration of the transformer. Accordingly, where sustained overexcitation is a concern, a separate volts/Hz relay should be applied (24). The volts/Hz function is available in the BE1-CDS240, BE1- 1051, BE1-951 and BE1-IPS relays.

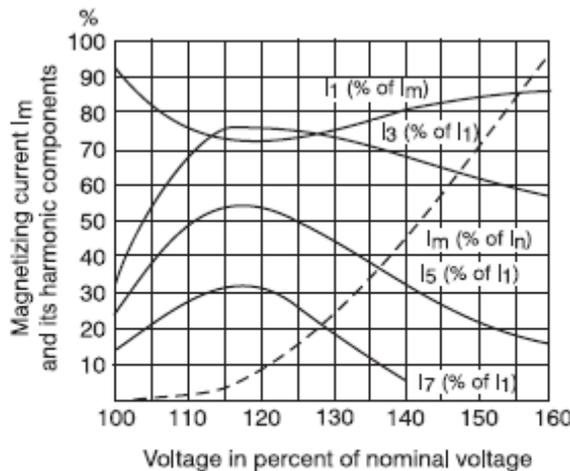


Figure 17 - Transformer Excitation Current vs. Excitation Voltage

The solid curves of Fig. 17 illustrate the variation in fundamental frequency excitation current (I_1) as a percentage of total current (I_m), and harmonic content (I_3 to I_7) as a percentage of the

fundamental current (I_1), as voltage rises, for balanced system voltages. If the transformer is connected in delta, the third harmonic would exist but remain within the delta windings as a "circulating current" that would not be seen by CTs on the lines to the transformer. When a delta winding is energized, all triplen frequency currents (triplen = odd multiples of 3, such as third, ninth) are blocked from exiting the delta because they are in phase with each other, similar to the manner in which a delta cannot supply fundamental frequency zero sequence current. Accordingly, the lowest odd harmonic available to a relay monitoring the lines outside the delta is the fifth. The BE1-87T restrains if the fifth harmonic exceeds 35% of the fundamental, and the fifth harmonic restraint is a user setting in the BE1-CDS2x0. In Fig. 17, a setting of 35% will restrain the relay from operation over the voltage range of about 104 to 138% of nominal voltage. With normal system operation, the power system could be operated continuously at 105% and dynamically as high as about 115% during a severe disturbance, so the 5th harmonic blocking will prevent tripping for these high system voltages.

If there is load current in the transformer, e.g. Fig. 16(c), any mismatch current will increase the fundamental component of operate current and, hence, will reduce the percent of fifth harmonic level in the operating current. The relay may not be restrained by the fifth harmonic. However, the transformer loading increases the through current restraint level and tends to bring down the overexcitation to a level where the operating current is below pickup.

Should the transformer become faulted during the high excitation condition, the relay will operate if the operate current is sufficient to reduce the fifth harmonic component below the relay's restraint level. Such a reduction occurs both because of the reduced excitation level caused by the fault current and the increased fundamental-frequency operate current.

Voltages in excess of 138% can follow full-load rejection of hydro units. However, generator speed will be correspondingly high, so the volts/ Hz value will not significantly exceed normal.

4.5 Unrestrained Differential Element

The unrestrained element, commonly referred to as an 87U, responds to the operating or differential current but with no restraint functionality. It acts as a high speed trip during severe internal faults. Its only means of differentiating an internal fault from inrush is the magnitude of the current involved; therefore, it must be set above the largest expected inrush current. It must also not operate for dissimilar saturation of CTs caused by DC offset during high current external faults. For these reasons, the unrestrained element setting is set fairly insensitive. For example, the 87U typically is set to trip for differential current that is on the order of 30-100 times the minimum operate setting of the restrained differential element.

In some relays, the 87U element responds strictly to fundamental frequency currents in the operate leg, yet other relays may respond to the full spectrum of frequencies in the operate leg, including the DC component. Since the 87U needs to be set above inrush, and the inrush is rich in harmonics and DC, one needs to know how the relay is designed in order to make an appropriate setting for the 87U element. For instance, the current fed to the 87U element in the BE1-87T relay is not filtered to remove DC or harmonic content and so it responds to all currents that come into the relay. However, the 87U in the BE1-CDS2x0 responds only to the fundamental frequency component in the operate leg, which means the 87U in the BE1-CDS2x0 typically is set lower compared to the 87U in the BE1-87T. The appropriate settings for the 87U element are discussed in the respective instruction manuals.

4.6 Connection Examples

Fig. 18 provides application examples for two-, three-, and four-restraint cases. The relay derives restraint signals separately from each set of CT inputs. In Fig. 18(a) the relay protects a deltawye transformer, with the CTs connected in delta on the wye-winding side. These CTs could be connected in wye when using a BE1-CDS2x0 or a 3 phase style BE1-87T when using the internal delta compensation functions of the relay.

A three-input relay protects the autotransformer in Fig. 18(b). All CTs should be connected in delta, or the relay internal compensation should be set up in delta, since the autotransformer contains an

internal unmonitored delta winding that couples the phases. Due to the delta winding, for a phase to ground fault, the delta can cause current to flow on an unfaulted phase. For example, assume a 230/115kV transformer with an A phase to ground 115kV external fault. Due to the delta winding, current may flow on B and C at the 115kV level and possibly not at all at the 230kV level. This will look like a B and C phase internal fault to the relay if no delta compensation is applied. Delta compensation prevents the misoperation.

In autotransformer applications, the tertiary is primarily used to create a zero sequence source, but it is used in some applications for station service power. The tertiary commonly is not included in the transformer differential CT summation, because the station service load is too small to be sensed by the transformer differential relay and with the intent that fuses will only operate for a station service transformer fault. Since the tertiary is ungrounded, a ground fault on the tertiary leads or load is sensed by voltage based relays that monitor line to ground voltages or V_0 voltage. Sometimes no tertiary ground fault detection scheme is applied under the anticipation that the risk is low, and that the VTs and relay needed to sense a ground fault would cause more problems and faults than will ever occur in the transformer. When a second ground fault occurs, it is seen as a phase to phase fault. The resulting phase to phase fault on the tertiary leads or loads is sensed as an internal transformer fault and, hence, is cleared by an 87 or 51 element trip.

Note the high voltage winding in the autotransformer in Fig. 18(b) is connected to two breakers, and each breaker is brought to its own restraint, R1 and R2. This is a desirable practice when large through-faults from one side of the substation to the next, flowing through the two breakers, could possibly cause unequal CT performance. The unequal CT performance would appear as 100% operate current to the relay. If each CT were on its own restraint, the relay would see high restraint and not trip.

However, only the summation of the CTs should be used for restraint when a low MVA transformer is placed on a bus with relatively heavy through current in the high voltage breakers seen in Fig. 18(b). For example, if the full load current for the transformer in Fig. 18(b) was only 20% of the normal load flowing in each of the high voltage breakers, going from one side of the figure to the other, a relay that restrains based on the individual breaker currents as seen by R1 and R2 could see 5pu restraint just from load flow (assuming the load flow was not affected by the fault) and tend toward non-operation except for very high magnitude transformer faults. To address this issue, the BE1-CDS240 has the option to restrain on either the individual currents seen in R1 and R2 or on the summation of current in R1 and R2.

The relay Fig. 18(c) protects the combination of a bus and transformer. In this application, any radial load feeders may have their CTs connected in parallel and connected to a common restraint input. Paralleling of CTs on non-source circuits can be safe, within the thermal limitations of the relay. In this case there is no loss of restraint for external faults, since these circuits contribute no fault current.

Source circuit CTs can also be paralleled, but it must be done judiciously. Ideally, any breaker that could be a substantial source to through fault current should be on a dedicated restraint winding. Hence, in Fig. 18(c), the bus tie, the feeder to the generator bus, and the lead to the high side of the transformer all have their own restraint windings.

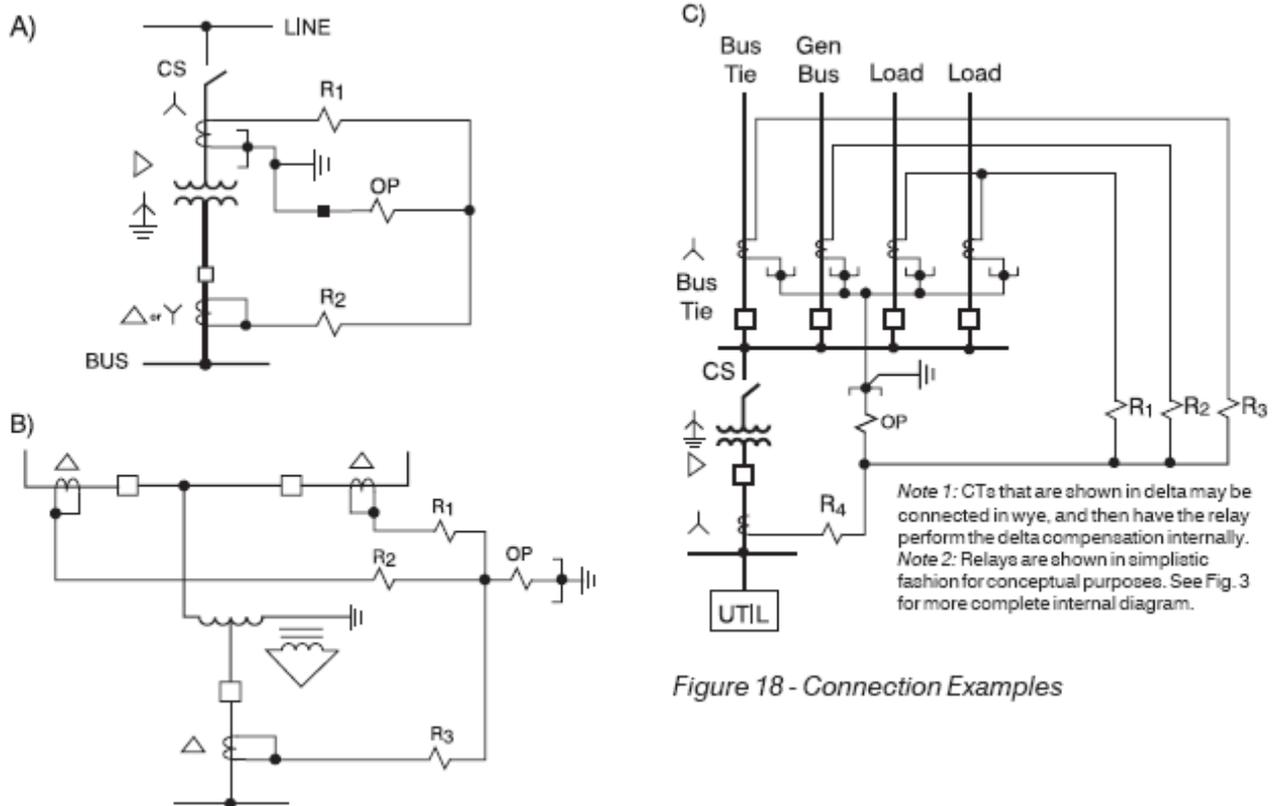


Figure 18 - Connection Examples

Fig. 19 shows a poor application of CT paralleling, using a two-restraint relay for the bus/transformer combination. Here three sets of CTs are paralleled and connected to a common restraint winding R1, but where line 1 is a source to the bus (e.g., a bus tie). Suppose CT 1 misperforms and delivers 50A rather than the ideal 60A. The relay sees 10A of restraint and 10A of operate; hence, it trips (Fig. 19b). If breaker 1 had been on its own restraint and circuits 2 and 3 had been in parallel, the relay would have seen 60A restraint and 10A operate, and it would not have tripped (Fig. 19c).

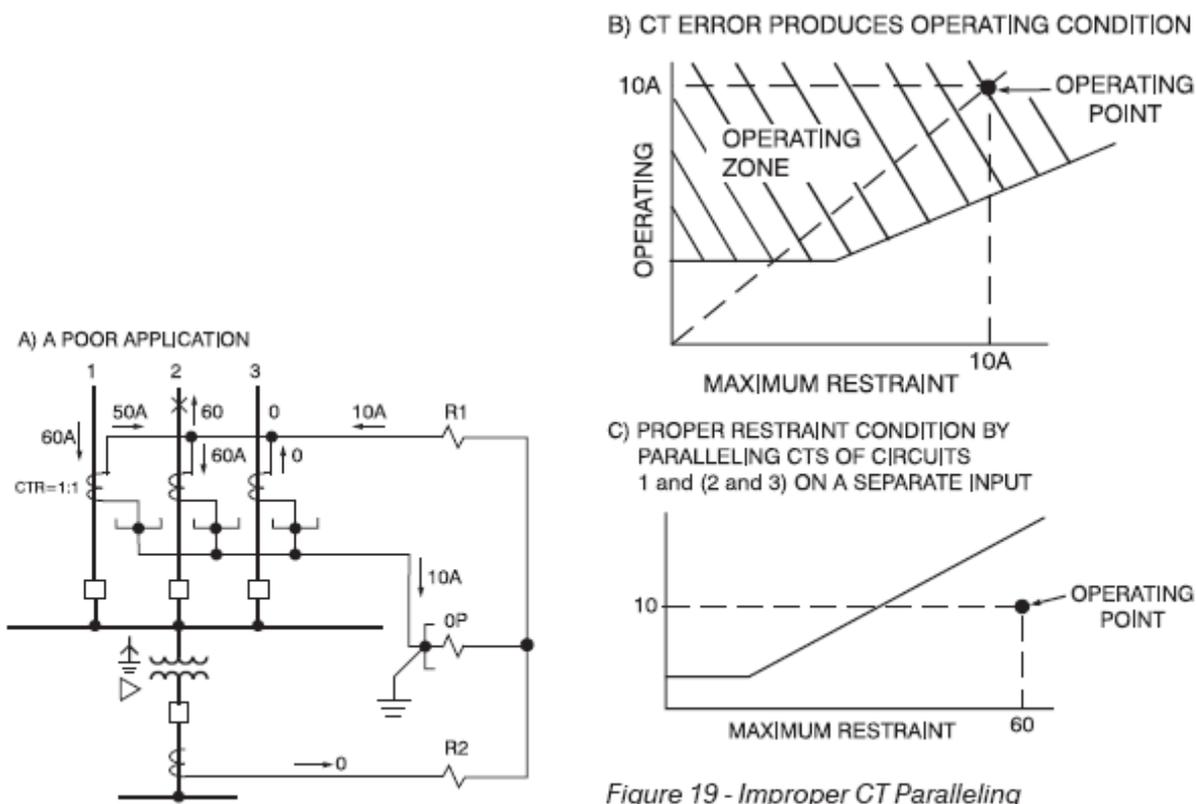


Figure 19 - Improper CT Paralleling

4.7 Alternate Transformer Connections and Associated Compensation

The proper configuration of the CT compensation connection was the major difficulty in transformer installations through the mid 1990s. However, with the advent of solid state and numeric relays that perform the compensation internally, the difficulty has moved to inside the relay. To complicate the matter, modern relays have been made flexible enough to compensate for more than the common delta-wye transformer with $\pm 30^\circ$ phase shifts. There are many transformers that are connected in alternate methods, especially outside the U.S., creating any phase shift in 30° increments. For instance, Zig-Zag windings, seen mainly in grounding banks in the U.S. market, are sometimes used as power transformer windings to introduce phase shifts that may be unusual to some engineers. Modern numeric relays need to be able to compensate for any physically possible phase shift in a process sometimes referred to as "around the clock compensation." Reference 6 analyzes the various arrangements possible for transformer connections and reviews the mathematics of how numeric relays, such as the BE1-CDS240, compensate for these multiple possible scenarios.

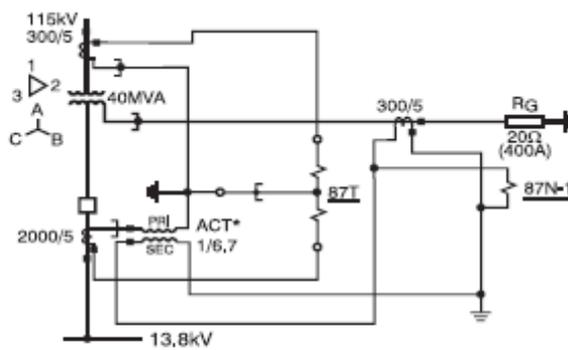
4.8 Ground Fault Sensing

Ground faults on delta windings connected to a solidly grounded power system are relatively easy to sense, but time delays must be used when set highly sensitive. Transient CT saturation due to DC offset during inrush and high through fault currents tends to create a false residual current, so a time delay is needed that is appropriate for the expected inrush duration and sensitivity setting. Ground faults on ungrounded systems must be detected via zero sequence voltage (59N) and phase to ground voltage relays (27In and 59In).

On wye windings, where impedance grounding limits the ground fault current to levels below the sensitivity of the phase differential, ground faults in the transformer need special detection schemes. The concept is sometimes referred to as "restricted earth fault" protection. Two classical approaches for a sensitive ground fault protection scheme are a) differentially connected overcurrent relay that monitors ground currents flowing into the two sides of a wye winding, and b) a directional ground relay that compares the phase relationship of ground current on each side of the winding. Both concepts are available in numeric relays such as the BE1-CDS2x0 (concept a),

and the BE1-951/IPS (concept b). However, the classical approaches are beneficial because they give a more immediate understanding of the technical concepts.

In the classical approach to a differentially connected overcurrent relay, the auxiliary CTs are required to balance the residual ground current from the phase CTs and the ground current as seen on the neutral of the transformer. In Fig. 20, the 20Ω resistor limits ground fault current to 400A. The 2000:5 CT has 1A in its residual connection. The aux CT multiplies the current by 6.7. The 300:5 CT on the transformer neutral also has 6.7A secondary but is wired to be opposite in polarity so that the summation of currents is 0 (approximately, given normal error levels in the CTs). The relay does not operate. If the fault had been internal, the summation would have been above 0.



* Note: In numeric differential relay, the ACT is replaced by internal mathematical algorithms.

Figure 20 - Ground Differential, Classical Approach

The 51/87N relay pickup in Fig. 20 possibly is set for 0.5A based on a neutral current contribution of 0.67A relay current for a ground fault 10% from the neutral end of the wye winding. Such a fault will yield 40A primary and 0.67A secondary. For this 40A fault, the 2000:5 CTs will only push 0.10A into the 87P relay, well below the allowed minimum pickup of the 87P relay. Other 13.8 kV ground sources, where available, increase the level of relay current for an internal fault. However, the protection must cover the case with no added current contribution.

One must keep track of burdens quite closely when using aux CTs. The secondary burden on the aux CT in Fig. 20 will be magnified by the square of the current ratio, or 44 times, as seen on the primary. However, while the ohmic burden can be very high, the ground current level is limited by the grounding impedance. For example, a 0.5 ohm secondary burden reflects to a 22 ohm primary burden, but the maximum current on the 2000:5 CTs is just 400A/400:1 CTR= 1A secondary for an external line-ground fault, yielding a burden voltage on the 2000/5 CTs of $1 \times 22 = 22V$.

An overcurrent relay used for the 87N function will move toward tripping if the fault is internal, for which the currents will no longer balance. Such protection must use a delay (e.g. 30 cycles) to ride through the false residual current resulting from the dissimilar performance of the phase CTs during a phase fault, especially during the DC offset period of a through fault and during transformer inrush. In an impedance grounded system, the phase fault current can be 100 times the maximum level of ground fault current. Thus, it does not take much difference in the performance of the phase CTs to create a relatively substantial false residual current. For example, in Fig. 21, a 1200 Amp phase A to B external fault generates only 28A rather than the ideal 30A in one of the CTs. The aux CT multiplies this to 13.3A in the 51/87N relay. If the pickup of the 51 element had been the aforementioned 0.5A, this false residual of 13.3A would become 27 times pickup, giving a fast but erroneous trip.

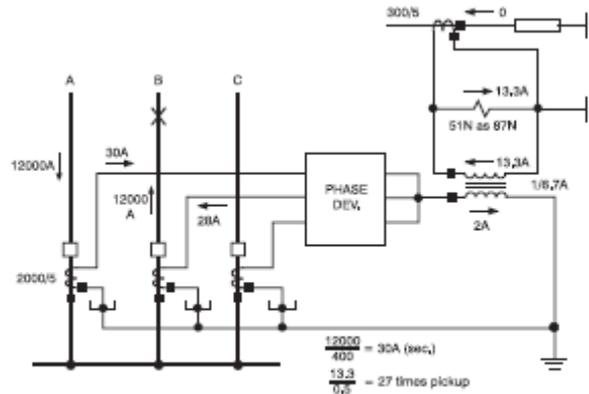


Figure 21 - Example False Ground Differential During Phase to Phase Fault

The 51/87N function in Fig. 21 could be replaced with a percentage differential function for increased security against CT misoperations, which is effectively done in a modern numeric differential relay, such as the BE1-CDS2x0. A numeric relay would also negate the need for the aux CT. Such relays have the capability to calculate 3I₀ current from the phase CTs inputs and multiply by the appropriate factor to allow comparison to the current from a CT in the neutral of the transformer without the use of an aux CT, and to perform the percentage differential function. Using a percentage differential approach gives added security to the trip decision, but a percentage differential relay for the ground differential function still can be insecure during external phase to phase faults and must be set with some level of time delay, since the neutral current contributes negligible restraint during phase faults.

An alternate method to sense internal ground faults is to compare the phase relationship of 3I₀ in the phase CTs to the ground current on the transformer neutral. An internal ground fault and an external ground fault will be marked by a 180° phase shift of the two currents in relation to one another. A BE1-67N relay is used to compare the two currents in Fig. 22. Because the residual current is highly distorted and the waveform varies from cycle to cycle, directional operation is intermittent. Each time the directional element resets, it resets the time-overcurrent element. The operate leg, terminals 7 and 8, may have a pickup and time delay set to keep false operations from occurring. Classically, a solid state BE1-67N has been used, but a numeric BE1-951 or BE1-IPS relay also can perform the function.

In Fig. 22, the aux CT is used to bring the ground current as measured by the phase CTs to a level that is measurable by a 5A nominal relay. In a modern numeric relay such as the BE1-951 and BE1-IPS, the ground/aux CT input may be selected to be rated at 1A and connected to monitor the phase residual, and the phase CT inputs can be selected to be rated at 5A and connected to the transformer neutral CT. In this approach, the aux CT could be eliminated from the scheme.

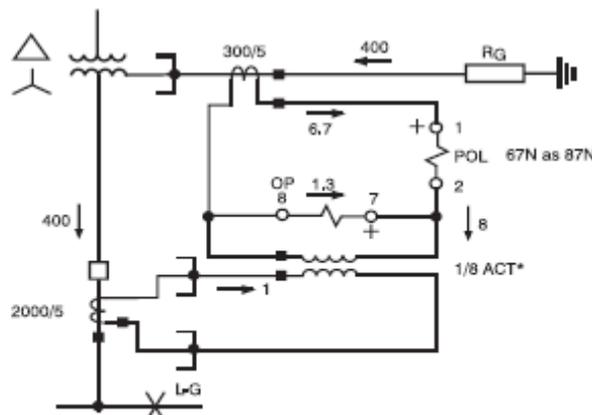


Figure 22 - BE1-67N as ground directional relay

5. Turn-to-Turn Faults

Phase differential relays may detect a turn-to-turn fault because the fault changes the transformer turns ratio. Ground differential relays do not respond to such faults. A neutral overcurrent relay may see fault current if an external ground source exists and the resultant voltage unbalance creates an excessive load unbalance. For an impedance grounded system, most of the fault current probably will be contributed by the delta-side source. A single turn fault may produce a total less than rated current (Ref. 8). A turn-to-turn fault may not be detectable initially. However, a sudden pressure relay (SPR) may give early detection. The SPR will detect any abnormality that generates a sudden increase in pressure due to gas generation (e.g. arcing due to a loose connection).

6. Sudden-Pressure Relays (63)

Figure 23(a) shows a SPR that detects an increase in gas pressure, typically applied on gas-cushioned transformers of about 5 MVA and higher. The gas pressure is generated by an arc under the oil, producing decomposition of the oil into gas products. The change in pressure actuates bellows 5 closing microswitch contact 7. Equalizer port 8, much smaller than the main port 4, prevents bellows movement for slow changes in gas pressure due to ambient temperature changes and load cycling.

Figure 23(b) shows use of the break contact of the microswitch (63) in conjunction with auxiliary relay 63X. This circuit prevents tripping for a flashover of the make contact of 63.

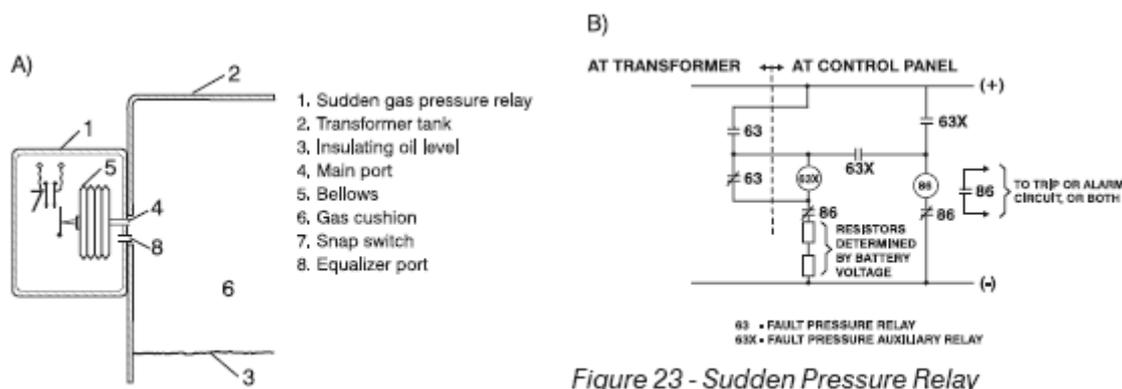


Figure 23 - Sudden Pressure Relay

An alternate design similar to that of Fig. 23(a) mounts the relay within the oil either in gascushioned or in conservator-type transformers.

There are separate sudden pressure devices for use in auto tap changer compartments, but such devices need to be designed so they do not operate under the presence of the normal arcing and mechanical operations that occur within the tap changer.

The SPR is designed to respond only to arcs within the oil. While more sensitive than a differential relay, the SPR is not as fast as the differential relay for some faults. Since redundancy of protection is the mark of a good protection scheme, both relays should be applied.

Some users have experienced misoperations of sudden pressure relays. During high-current external faults, winding movement generates an oil pressure wave that can tend to cause relay operation. Earthquakes have been reported to cause operation. As a result, some users connect them only to alarm. Their security has improved by installing them on stiffer sections of the tank and by adding current supervision logic (e.g., block 63 trip for any high current level that may be indicative of an external fault that could cause high winding movements; if the fault is internal, differential relays can be assumed to trip rapidly). Security can also be improved by performing regular maintenance to ensure they are calibrated properly and not failing or drifting in a manner that makes them excessively sensitive. There have been cases where a relay operation has been a precursor to transformer failure; e.g., a relay that operates for an external fault may be an indication of winding stabilization blocks that have come loose.

Conservator-type power transformers do not have a gas cushion within the main tank. Instead, the cushion resides in a separate auxiliary tank. A gas accumulator relay ("Bucholz") can be installed in the pipe connecting the main and auxiliary tank to detect the generation of gas. This relay has two elements, an accumulator alarm and a trip function. The accumulator, which stores a portion of the gas, provides an alarm for slowly developing conditions. A baffle in the pipe actuates the trip element for relatively fast gas flow to the auxiliary tank.

7. Monitoring for Incipient Problems

The oil in large transformers is normally checked, as part of routine maintenance, for the existence of abnormal chemicals and gasses that are created as a result of oil contamination, insulation breakdown, and internal arcing. A number of on-line devices has been developed in recent years to detect incipient conditions that threaten serious consequences. These include gas-in-oil analysis, acoustic partial discharge detection, moisture sensor, tapchanger- operation supervision, and pump/fan supervision.

Reference 9 reviews gas in oil analysis, and Ref. 10 reviews online monitoring schemes. The website where these articles are found has an extensive collection of other good articles on oil analysis and transformer operation.

8. Overcurrent Relays

Fig. 1 shows a number of overcurrent relays. When an 87P is in place in this application, the 50/51P on the primary side is considered backup protection. In a radial distribution application, the overcurrent relays on feeders and buses are also part of the transformer protection scheme since they limit the duration of out of zone faults.

The discussions below include references to 50/51Q elements. The Q refers to elements that respond to negative sequence current components. See Section 8.5.

8.1 50/51 Transformer Backup

The CTR for this application is a compromise between full load current and limiting current in the CT during faults near the transformer bushings. See Section 10.2 for a discussion on the CT selection in this case.

In Fig. 1, the 50P and 50Q elements would be set at approximately 150% to 200% of the current that will be sensed at 115kV for a 13.8kV three phase and phase to phase fault. These elements must not trip for low side faults. A setting in this range normally would be above the inrush current of the transformer. For instance, assume an impedance of 7%, implying a secondary fault will cause, at most, 14.3pu fault current. A setting of 150% would imply a 50P setting of 21.4pu. This is higher than the typical inrush current. Some resources mention inrush current reaching as high as 25xFLA, but this is typically only the first half cycle, is very harmonically rich and contains a high DC offset. Relays responding strictly to fundamental frequency currents (e.g., most modern numeric relays) will see an inrush that is less than a relay that responds to the harmonic and DC component of inrush. The relay sensing algorithms need to be part of the setting thought process. This same concept was also previously discussed in reference to the 87U element, Section 4.5.

Since the 115kV winding on T1 is delta, no ground current should be seen at the transformer backup, so 50/51N elements in the relay can be set fairly sensitive and fast. However, there may be some transient false residual due to CT error during transformer inrush or 13.8kV faults, so the 50/51N elements need to be time delayed somewhat, possibly about 4 times the system L/R time constant. Due to the long duration of inrush current and its associated DC offset component, highly sensitive ground current pickup levels should be delayed substantially longer. In power system cycles, the L/R time constant is:

$$T.C., \text{ cycles} = (X/R \text{ ratio of } Z_{\text{fault}})/(2*\pi)$$

where Z_{fault} refers to the system source impedance looking back from the high side of the transformer.

The 51P relay time element must be set to carry the maximum expected load current. Since a transformer is capable of carrying considerable overload for a short period, a high pickup is normally called for (e.g. twice the forced-cooled rating). The time unit should coordinate with the 51P Bus Backup relay or the 51P Partial Differential relay (Section 8.2), depending on which is in use.

The 50/51P operating time needs to be faster than the through-fault (external fault) withstand capability of the transformer (Fig. 26). See Ref. 1 for additional transformer damage curves. Figure 26 illustrates both "frequent" and "infrequent" limits and recognizes the cumulative effect of these stresses. Transformers on systems with underground feeders likely have fewer faults relative to systems with long overhead wires. Higher magnitude faults would be less common, and lower magnitude faults would be more common, especially on systems with long feeders.

Because of its high pickup and slow operation, the 51P element provides relatively poor protection (compared to other relaying schemes) for transformer winding and tap changer faults. Accordingly, this element is not a good substitute for differential and sudden pressure relays. The consequences of a slow cleared fault include the threat of an oil fire due to a ruptured tank or bushing explosion and the higher internal damage that will occur. Removal generally is necessary for even a fast cleared winding fault. This is not the case for a tap-changer flashover that is cleared before winding damage.

8.2 Bus Backup, Bus Tie, and Partial Differential 51 Relays (and 50T)

The overcurrent element at this level does not directly protect the transformer, but it performs a service of limiting the duration of faults that will cause cumulative damage to the transformer, as discussed in the previous section relative to the transformer damage curve.

Breaker D, Fig. 1, would be considered the Bus Main breaker, but the 51 relay on this breaker would be considered the Bus Backup relay under the understanding that there would be some dedicated bus protection scheme in place, such as a bus differential (87B) or the interlocked 50 elements discussed below.

A 50 element normally is not used in these relays due to coordination issues with feeder relays. However, a 50T (a 50 element with a small time definite time delay) is sometimes used in the bus backup relay in a bus protection scheme that interlocks the bus and feeder relays. In the scheme, the bus backup 50 element is delayed long enough for a feeder relay to communicate back to the bus relay, telling it, "Do not trip, I see a fault on my feeder."

The partial differential 51 element in Fig. 1 measures the sum of the transformer and bus-tie breaker currents. Such a connection is appropriate with a normally-closed bus-tie breaker. When the bus tie is closed, the partial differential sees the full current going to a feeder fault; hence, it more directly coordinates with the feeder relays than a relay that only monitors the current in a single transformer. A relay such as the bus backup or bus tie that sees only a portion of the current will trip slow relative to the partial differential relay given the same pickup level.

If the bus main and bus-tie breakers are interlocked to prevent the secondary of both transformers from being tied together, the bus tie overcurrent relay is coordinated to be slower than a feeder relay but faster than the bus backup relay. This adds an extra level of overcurrent protection in the TCC curve that effectively makes either the transformer relay slower or the feeder relay faster, which adds a compromise to the TCC coordination scheme. If a dedicated high speed bus protection scheme is in place (e.g., bus differential or the aforementioned interlocked bus 50 element scheme), the coordination compromise associated with including the bus tie in the TCC is subject to question.

In substations with multiple operating modes, such as run with and without the tie closed, smart relays that can change settings on the fly can be utilized. This feature is found in modern numeric overcurrent relays with multiple settings groups, such as the BE1-951, BE1-IPS, BE1-851, and BE1-700C.

8.3 Transformer Neutral Overcurrent

The transformer neutral overcurrent relay in Fig. 1 primarily backs up the bus and transformer protection scheme and faults on the lead between the transformer and the 13.8kV bus. In the absence of the 87N application, in impedance grounded systems the relay provides the primary ground fault protection for faults close to the neutral on the transformer low voltage winding. The relay also backs up the 87T, depending upon the sensitivity of the 87T to ground faults. The relay must coordinate with the bus backup 51N to allow the latter to clear a bus fault first without tripping one or both transformers.

If the 13.8kV bus tie can be closed with both transformers in service, the transformer neutral relays on both transformers will operate for a 13.8kV winding or lead fault, unless a 67N or 87N, Section 4.8, is provided that is configured for faster clearing.

8.4 67/51 and 32 Relays

The 67/51P relay operates for current (and, to some extent, power) flowing from the transformer low side toward the high side, i.e., backfeed. Such flow could occur if the 115kV tie breaker opens and both transformers remain energized, and the 13.8kV bus tie is closed. Reverse flow also can occur with or without the 115kV tie breaker closed, with local 13.8kV generation. Reverse current flow also can occur during a transformer fault. When backfeed under fault conditions is the concern, the 67/51P element is the appropriate element to use (rather than a 32). A 67/50P element also may be appropriate, but the 50 element should be time delayed slightly if there is any chance of transient backfeed during load swings or when paralleling with the other transformer. Since normal load flow is toward the low side, the 67/51P can be set more sensitively than bus backup 50/51 and may also be faster.

A reverse looking 67/51P has some ability to trip for forward faults and load flow. The element's maximum torque angle (MTA) typically is skewed for fault detection, as seen in Fig. 24. In Fig. 24, the MTA of the relay has been set very low, maybe 10°. Note the relay sees ±90° from the MTA as a forward current flow. In this example, the 67/51P element reaches very little into the opposite plane. If the relay MTA had been set at the more typical 45° to 80° setting, the reverse looking element would reach well into the plane of forward power flow and, hence, would be at greater risk of tripping for normal load flow. To prevent this risk, one practice is to set the 67/51P element pickup high enough so that it will not pick up for any normal load flow conditions or use a directional power element, the 32, to sense actual power flow toward the transformer.

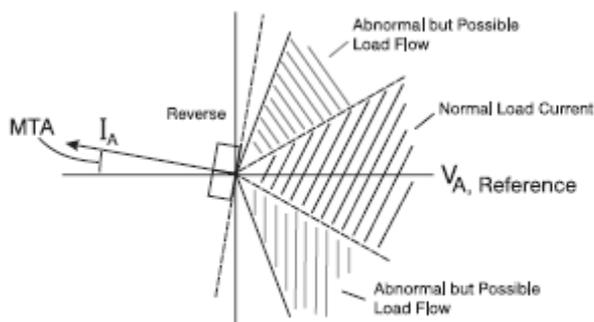


Figure 24 - 67 Element MTA vs. Load Flow

The 32 device is designed to be very selective in the direction of power flow. Ideally it is nonresponsive to VAR flow, though heavy VAR flow in some relay designs can swamp the relay sensing algorithms and reduce sensitivity to true power flow. In fault conditions, watt flow may be low and the sensed current may be mostly VARs. Coupled with the reduced sensitivity of the 32 element to watt flow in some designs under the presence of high VAR flow, a 32 may respond poorly to fault conditions, so a 32 element normally is not used for fault detection. Hence, the overall solution to sensing current backfeeding into the transformer is both a 67/51P and a 32 element. Both of the 67/51 and 32 functions may be found in the BE1-IPS and BE1-951.

Numeric relays such as the BE1-951 and BE1- IPS relays do not have the limitation mentioned above relative to sensing watt flow under the presence of high VAR flow.

Recall also that a 67N, looking for ground current flowing toward the transformer, as discussed previously in Section 4.8, is a means of sensing transformer ground faults. In Section 4.7, the directional element used the phase angle relationship of $3I_0$ in the phase leads vs. I_g in the transformer neutral. However, a 67N relay more commonly is configured in the design stage to see only local phase voltages ($I-I$ or $I-n$, depending on design or configuration) and phase currents and may not have access to transformer neutral current. The directional decision for current flow is most commonly either current vs. quadrature voltage (solid state relays) or V_2 vs. I_2 (numeric relays). See Refs. 2 and 11 for a technical description of how these two directional elements are designed, as well as other supporting information in regard to the 67 element.

8.5 Negative Sequence Overcurrent

The advent of and high use of numeric relays that readily calculate negative sequence current (I_2) has resulted in an increased use of negative sequence overcurrent relaying. The device is named 50/51Q herein, but sometimes referred to as the 46 device. The problem with the term 46 is that it is unclear as to whether a 51 or 50 device is referred to.

The benefit of a 51Q in delta wye transformer applications is that the I_2 component of fault current is identical, on a per unit basis, on both sides of a delta/wye transformer (see Section 10.3 and Fig. 25). The 51Q on the high side of a delta/wye transformer easily can be coordinated with 51Q elements on the low side for phase to phase and phase to ground faults. Unlike phase overcurrent elements, the 51Q does not need to be set above load current levels and instead would have a pickup similar, on a per unit basis, to a ground overcurrent element on a solidly grounded system.

The drawback of the 50/51Q is that it adds some level of work to the coordination analysis. If set below load current, recall a 51Q may need to coordinate with downstream phase overcurrent devices that do not monitor I_2 , and that will only trip when current rises above normal load current, such as fuses. One must compare the 51Q response to the 51N relays as well as these phase overcurrent elements.

9. Thermal Protection (49)

Conventional thermal relays measure the oil temperature and transformer current to estimate the hot-spot temperature. They provide an indication and means for controlling pumps and fans. Typically, these devices provide two temperature sensing levels for control and a third, higher temperature, sensing level for alarm or tripping.

Recently developed fiber optic sensors, incorporated in the transformer winding, provide a direct method of measuring the hot-spot temperature. About four of these sensors would provide good coverage.

10 Associated Issues

10.1 Harmonics During CT Saturation

Saturation of CTs happens in terms of AC and DC components of current. The AC saturation effect refers to the ability of a CT to reproduce symmetrical current conditions. The DC saturation effect refers to the saturation that occurs when the current contains the decaying DC component associated with a fault, magnetizing inrush, motor starting, or generator synchronizing. A CT that experiences negligible distortion under symmetrical AC conditions might become saturated and give a severely distorted output when a DC component exists (Reference 12 is a good resource but hard to access. Reference 13 provides a somewhat more accessible but less detailed discussion of the matter).

While faults generally produce the most current, other conditions, such as a motor starting, produce much slower DC decay than occurs for a fault. A smaller DC current that persists longer can also produce DC saturation. For these external disturbances, unequal times to saturation, and

saturation level, in various CTs results in false operating current. Either the harmonic restraint or the percentage differential restraint (fundamental frequency characteristic) prevents unwanted tripping for this condition.

Under high symmetrical current conditions that drive a CT to AC saturation (e.g., an attempt by a CT to drive current that in turn causes voltage above the CT's kneepoint), CT distortion generates odd harmonics but no even harmonics. A CT experiencing DC saturation during an asymmetrical fault develops both even and odd harmonics. If a relay is designed to restrain on odd harmonics (e.g. 5th), it may fail to operate if the harmonic content from the saturated CT exceeds the relay's threshold for restraint. Relays that restrain on even harmonics may be temporarily restrained until the DC decays enough to allow the CT to perform again correctly. High-set unrestrained elements (87U) supplement the restrained elements, so that high current faults, where CT saturation can be severe, can be cleared independent of any harmonic restraint. For satisfactory protection, harmonic generation by the CTs should not exceed the restraint level for a current below the unrestrained element pickup. Poor CT quality can detract materially from the reliability of the differential relay.

10.2 CT Ratio and CT Accuracy Selection

Let "Ks" be the ratio of a CT kneepoint to the burden voltage. The knee point herein refers to the 45° slope point on the CT excitation curve. The burden voltage in this ratio is the RMS (AC only, no DC) voltage in the CT loop during a maximum level fault, and where the CT internal resistance is included in the CT loop resistance. If one does not have CT excitation curves, a likely satisfactory substitute for the knee point is to assume that the knee point is equal to the C class of the CT (though in practice, the knee point ranges from about 70-150% of the C class). The higher the Ks value, the better the CT performance. The purpose is to give a high level of margin in the CT rating so that it can provide reasonable ability to reproduce the DC offset in a fault.

For differential protection, a good objective is $K_s=8$ or higher for a current at the unrestrained pickup level during all out-of-zone faults. For inzone faults, a K_s of 2 is desirable. Some resources suggest a K_s of "1+X/R" (where X/R is found from the system impedance looking back from the fault location) will give reasonably good assurance of limited risk of DC offset induced saturation. Reference 13 contains a derivation of the 1+X/R factor. High K_s values called for by the 1+X/R factor can create a demand for CT performance that is sometimes difficult to meet.

It is difficult to generalize about when it is important for CTs to be highly rated for an application and, hence, have a high K_s . It is always very desirable to have a K_s well above 1, but obtaining a CT resistant to DC offset effects may be hard to justify. For instance, in a phase overcurrent application, transient CT saturation due to DC offset will cause only a small delay in tripping speed, so the effect of CT error is generally small; hence, a low K_s is likely satisfactory. However, if a sensitive ground overcurrent relay is connected in the residual of the phase CTs, the effect of CT saturation is to false trip, so a selected CT must be very well rated and able to reproduce substantial DC offset without saturating, hence calling for a high K_s .

10.2.1 Selection of CT ratio in Figure 1

Issues with CT performance under fault current commonly arise when a relatively low MVA transformer is placed on a powerful bus. This cause is an incongruent demand between selecting a CT ratio that allows good reproduction of full fault current without excessive CT secondary current, and selecting a CT ratio that allows the secondary current to be some measurable level during normal load conditions.

For instance, in the system seen in Fig. 1, the load current at 30MVA and 115kV is 151A, implying a CTR of about 200:5 would work well. However, suppose the fault duty at 115kV was 15,000A. If we wish to limit CT secondary current to maybe 100A, a CTR of about 800:5 would be selected. However, at 800:5, the FLA from the CT would only be 0.94A, which implies measuring accuracy would suffer at light load conditions. A CT actually can carry quite a bit more than 100A for a short period, so a compromise selection of 400:5 was chosen for the example.

The burden and CT voltage rating must be checked during peak fault currents. Assume a 1200:5 CT is used but tapped at 400:5. Assume the full winding C class is C400, and the internal resistance is 0.6 ohms. At a tap of 400:5, the effective C class is C133, and one can assume that the kneepoint is roughly 130V for lack of an appropriate excitation curve. Since we are using only 1/3 of the CT windings, the internal resistance is 0.2 ohms. Assume external burden is 0.4 ohms. Given our assumed 15,000A fault, the secondary current, if the CT operates ideally, is 187.5A. This is quite high, but most CTs can withstand it for short periods. The short time rating of CTs may not be published in common literature, and the manufacturer should be consulted on the short time current rating of the CT (typically given for maximum primary current for 1 second with a shorted secondary), especially if fault current rises above 100A secondary and delayed tripping will be utilized at this current level. The voltage drop in the CT resistance and external burden is $187.5 \times (0.2 + 0.4)$ or 112.5V. This gives a Ks of about 1.15. The CT is at risk of entering into saturation, especially if any DC exists in the current. We have a relatively weak CT for the application. Our choice is to either raise the CT ratio and limit accuracy during normal loads, raise the CT C class to C800, or accept the Ks value with the assumption that the CT is rated well enough to reproduce the current to allow the unrestrained differential element to rapidly clear the fault. This becomes an engineering judgment decision beyond the scope of this document.

Next, we need to analyze what occurs in the same CT during an out of zone secondary fault. Assume the transformer impedance is 8% on the unit's 18MVA base. For a three phase fault, the current at 115kV will be about 1/0.08pu, or 1130A at 115kV. This gives us 14.1A from the CT at 400:5, and the voltage in the CT loop (at 0.6 ohms) is only 8.5V and, given a knee point of 130V, the Ks is about 15, which should work well under very high DC offset conditions. This gives added reason to accept the CT as is.

10.3 Delta-Wye Winding Effects on Primary Current

For delta/wye transformers, fault current as seen on the primary for secondary ground faults is substantially lower than for secondary phase to phase and three phase faults. As those who have worked in fault analysis are aware, lines on the delta side of delta/wye banks see 0.577 per unit current for secondary ground faults, compared to the current seen by the line during three phase faults on the secondary of the same magnitude. The 0.577 factor for ground faults occurs because ground faults are single phase events; hence, the current is multiplied across the transformer by the transformer turns ratio, rather than by the line-line voltage ratio (the turns ratio on a delta wye bank is $1/\sqrt{3}$ relative to the line to line voltage ratio).

Figure 25 shows the per unit phase and sequence component currents seen on the delta side for various wye side faults, for a DAB delta transformer. Note that positive and negative sequence magnitudes are the same on both sides of the transformer but shifted in opposite directions.

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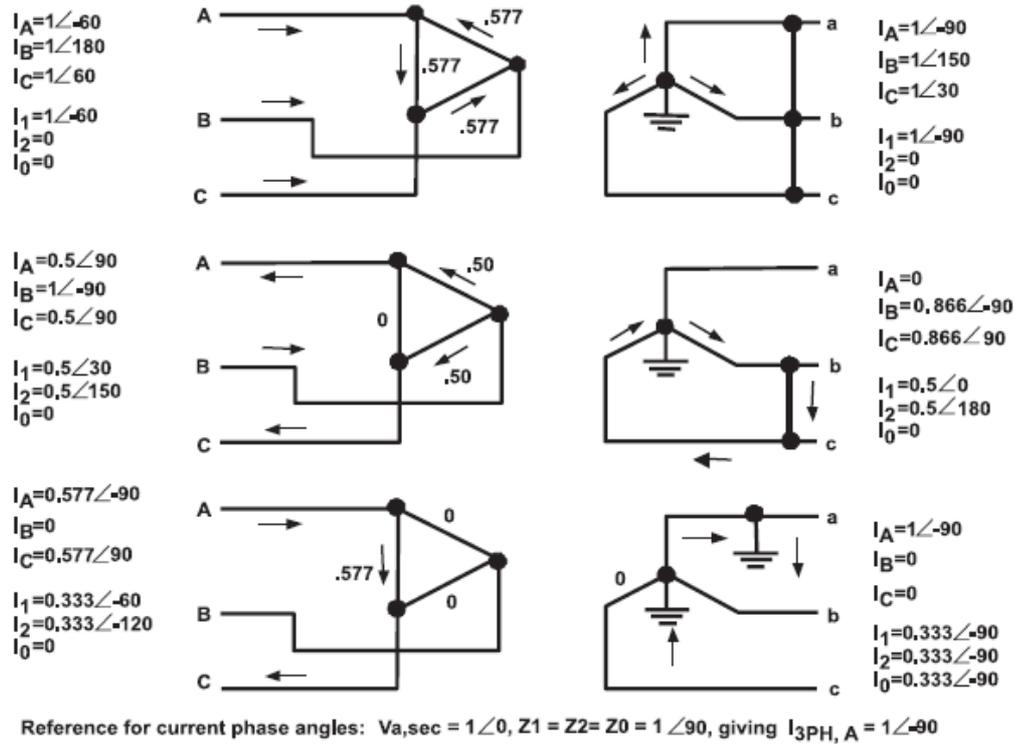


Figure 25 - Delta Side Currents for Wye Side Faults

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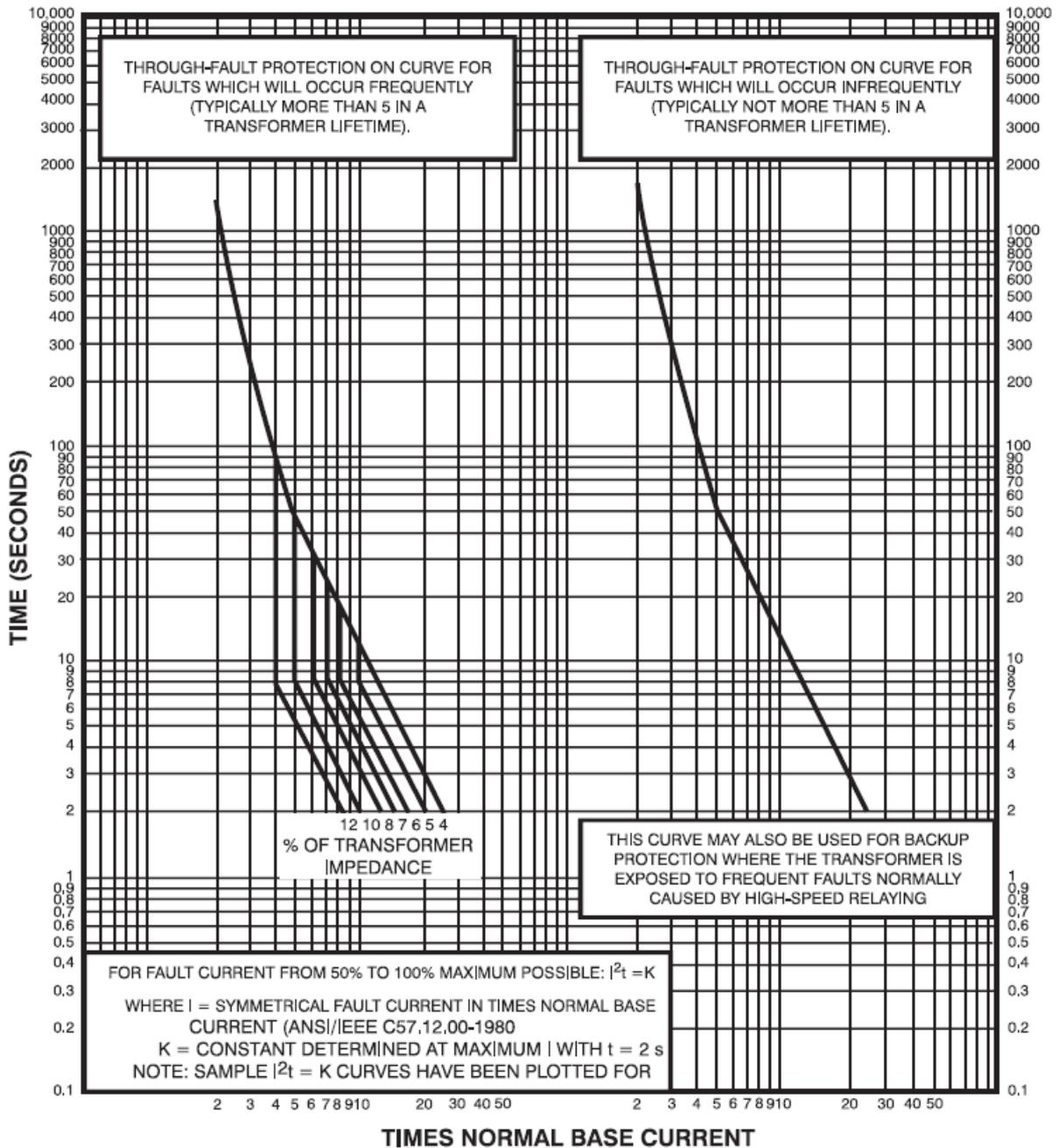


Figure 26 - Example Transformer Damage Curve

REFERENCES

Reference 1 provides a reference and bibliography section of almost 100 articles and IEEE Standards on almost every topic associated with

transformer protection and is recommended for review for one who is making a career in protective relaying. Web searches will invariably find even more references. The IEEE Xplore warehouse of technical articles is another resource for one who has appropriate subscriptions to IEEE.

One should also review the instruction manuals for various Basler relays, and the variety of Application Notes and Technical papers available at www.basler.com. Besides Basler's resources, other manufacturers, engineering companies, and government agencies provide articles and application guides associated with transformer protection.

Publication dates and/or revision levels of the texts and standards listed are not supplied, as these are routinely updated; the latest revision should generally be sought out.

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