

CHAPTER 2

LITERATURE REVIEW

2.1 Introduction

This chapter presents Transformer Faults including a review of general fault study in the power systems. Also, it discusses on importance of restricted earth fault protection as a one of power transformer protection functions. Then, different recent algorithms for restricted earth fault protection from various companies are illustrated. The presented Restricted Earth Fault algorithms are from General Electric (manuals and conferences), Siemens and ABB which are extracted from their Relay Manuals and Schneider Electric and Areva T&D are extracted from IEEE conferences.

2.2 Types of fault in transformer

In a power transformer the electrical windings and the magnetic core can cause mechanical forces during operation, for example:

- Expansion and contraction due to thermal condition
- Vibration
- result of magnetic flux is local heating
- Forces due to fault current
- Extreme heating due to overloading or incompetent cooling

These mechanical forces can cause declination and failure of the winding electrical insulation of transformer(IEEE, 2008a).

Transformer faults are generally can be classified into six categories (T&D, 2005):

1. Terminal and winding fault
2. On load tap changer fault
3. Core fault
4. Transformer equipments and tank fault
5. Not normal operating conditions
6. Uncleared external fault

The approximately proportion of faults due to each causes is illustrated in figure below (T&D, 2005)

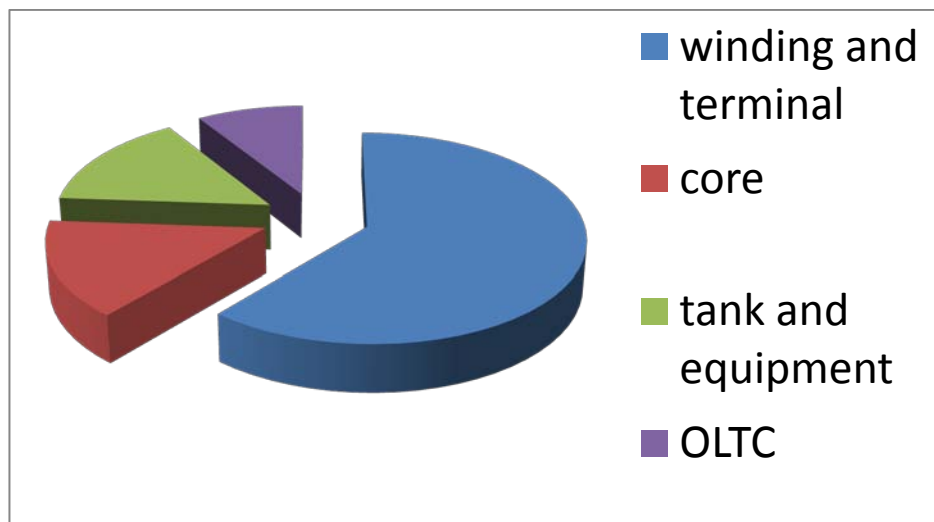


Figure 2.1: Transformer fault statistics (T&D, 2005).

2.2.1 Winding fault

Magnitude of a fault on a transformer winding is determined by (T&D, 2005):

- Impedance of source
- Neutral earthing impedance
- Reactance of transformer leakage
- Fault voltage

- Winding connection

2.2.1.1 Type of winding and terminals fault

Figure 2.2 illustrates type of fault that can be experienced (Robertson, 1982):

1. Earth fault on H.V side on external connections
2. Line to line fault on H.V on external connections
3. Internal earth fault on H.V windings
4. Internal line to line fault on H.V windings
5. Short circuit happened between turns in H.V windings
6. Earth fault on L.V side on external connections
7. Line to line fault on L.V on external connections
8. Internal earth fault on L.V windings
9. Internal line to line fault on L.V windings
10. Short circuit happened between turns in L.V windings
11. Earth fault on tertiary windings
12. Short circuit happened between turns in tertiary windings
13. Auxiliary transformer internal fault
14. Earth or line to line fault on L.V side of auxiliary transformer
15. Sustained system earth fault
16. Sustained system line to line fault

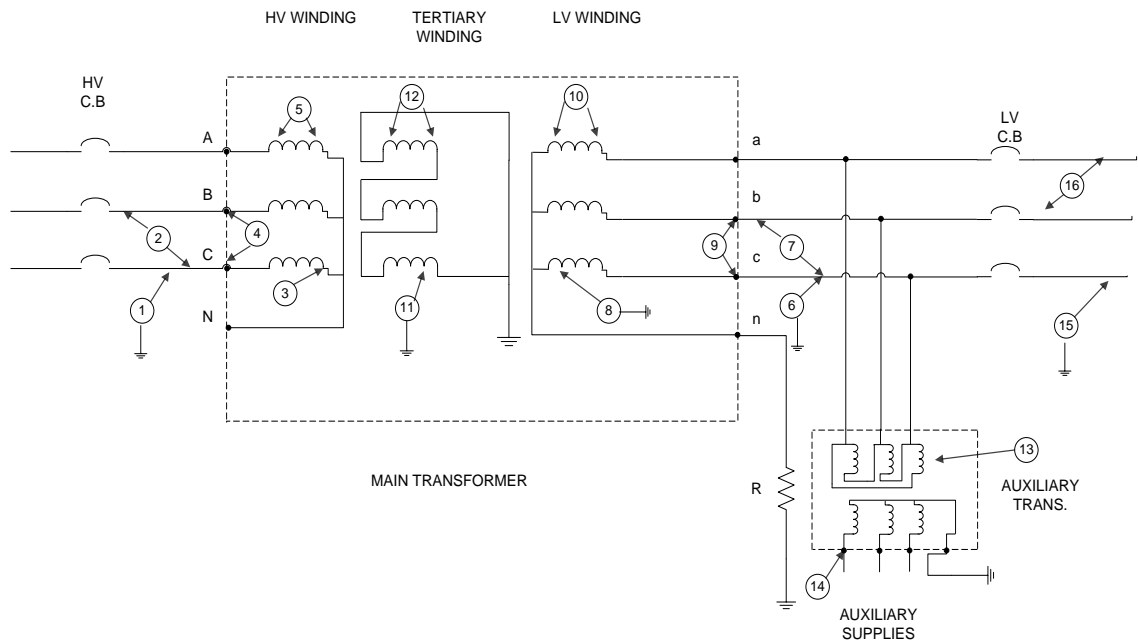


Figure 2.2: Transformer fault.

One of the main reasons of fault study and calculation is protection coordination so in following subchapter fault analysis discusses and focuses on most common faults which happen in a power transformer.

2.2.1.2 Fault study

Short circuit can be defined according 3 characteristics (Prévé, 2006):

1. Their origin it can be happened due to mechanical, electrical and operating error such as closing a switching device by mistake.
2. Their location, the short circuit may be generated inside or outside of equipment.
3. Their duration, which contains:
 - Self extinguished that means the fault disappears on its own
 - Transient which means the fault disappears due to protection device operates and does not reappear when the equipment is started up again.

- Permanent fault, means require cut faulty device from network with protection devices.

2.2.1.3 Different fault types

This section is illustrated percentage of different type of fault that may be occurred in power system (Hadi, 2007; Prév  , 2006; Schmidt, 2008).

1. Single line to ground fault which is included about 80% of power system faults.

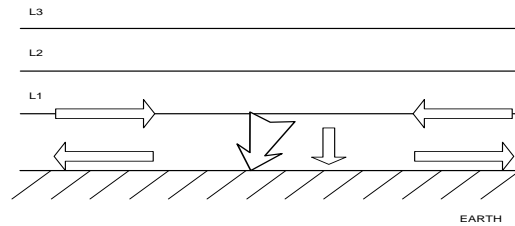


Figure 2.3: Single line to ground fault.

2. Line to line fault and double line to ground that is included 15% of power system faults.

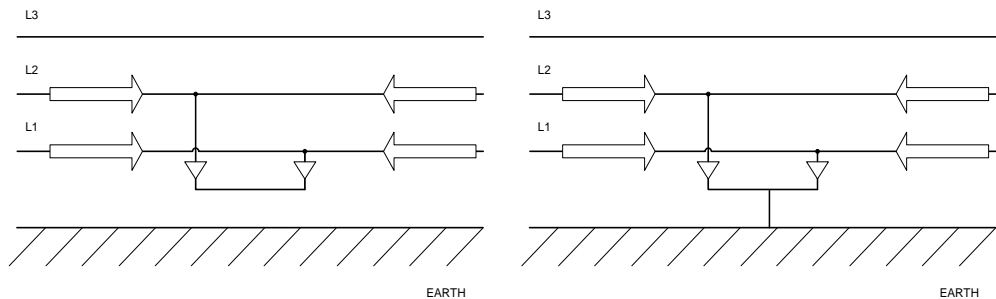


Figure 2.4: Line to line and double line to ground fault.

3. Three phase to ground fault that is included 5% of power system faults.

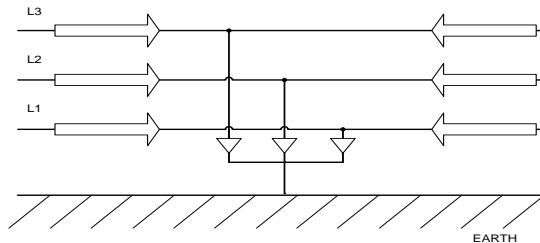


Figure 2.5: Three phase to ground fault.

This percentages show that single line to ground is the main phenomenon which is happened in power system network. Therefore in the next focus on this fault.

2.3 Back ground knowledge of short circuit calculation

This section discusses on unsymmetrical faults and how they have been converting to symmetrical components, after that will be discussed on how to calculate unsymmetrical faults by use of zero, positive and negative components.

2.3.1 Symmetrical components

C.L.Fortescue in 1918 suggested a method of symmetrical coordinates for solution of polyphase networks. It is proved each related unsymmetrical N Phases' system can convert to N system phases which are call symmetrical components (ABB; Cashmore, et al., 2006; Grainger & Stevenson, 1994; Hadi, 2007; IEEE, 2001; Schmidt, 2008; T&D, 2005; Willis, 2006).

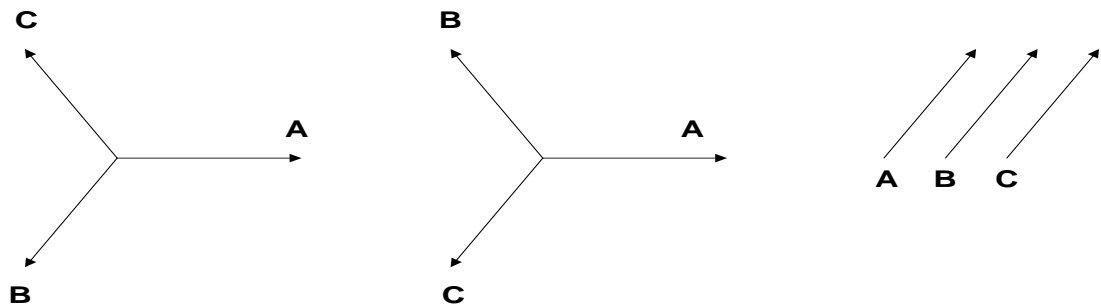


Figure 2.6: Symmetrical components, illustrate positive, negative, zero sequence.

Note, in this thesis I^1 , I^2 , I^0 are representing positive, negative and zero sequence.

2.3.1.1 Positive component

Positive sequence includes of balanced three phase currents and line to neutral voltages which are supplied by the system generators. Thus positive sequence sets are always equal in magnitude and are phase displaced by 120° .

For simplicity, we use a unite phasor for the angle displacement. It is called a with an angle displacement of 120° as a below:

$$a = 1\angle 120^\circ = -0.5 + j0.866$$

$$a^2 = 1\angle 240^\circ = -0.5 - j0.866 \quad (2.1)$$

$$a^3 = 1\angle 360^\circ = 1 + j0$$

From equation 2.1, it is clear that

$$1 + a + a^2 = 0 \quad (2.2)$$

From equation 2.1 positive sequence set for currents are:

$$I_a^1 = I_a^1 \angle 0^\circ = I_a^1$$

$$I_b^1 = I_a^1 \angle 240^\circ = a^2 I_a^1 \quad (2.3)$$

$$I_c^1 = I_a^1 \angle 120^\circ = a I_a^1$$

Note, for the voltages positive components are exactly like the currents.

2.3.1.2 Negative component

The negative sequence sets are also balance in magnitude and phase displacement (120°). The difference between negative and positive sequence is, if positive sequence is rotated clockwise, negative sequence rotate counter clockwise.

$$I_a^2 = I_a^2 \angle 0^\circ = I_a^2$$

$$I_b^2 = I_a^2 \angle 120^\circ = a I_a^2 \quad (2.3)$$

$$I_c^2 = I_a^2 \angle 240^\circ = a^2 I_a^2$$

Note, here also for the voltages negative components are same the current.

2.3.1.3 Zero component

The zero sequence components are equal in magnitude and same phase displacement.

$$I_a^0 = I_b^0 = I_c^0$$

$$V_a^0 = V_b^0 = V_c^0 \quad (2.5)$$

2.3.1.4 General equation

From C.L.Fortescue method, equations below are valid during all conditions in the network. According to the superposition theory we have:

$$I_a = I_a^1 + I_a^2 + I_a^0$$

$$I_b = I_b^1 + I_b^2 + I_b^0 \quad (2.6)$$

$$I_c = I_c^1 + I_c^2 + I_c^0$$

And also for the voltages we have:

$$V_a = V_a^1 + V_a^2 + V_a^0$$

$$V_b = V_b^1 + V_b^2 + V_b^0 \quad (2.7)$$

$$V_c = V_c^1 + V_c^2 + V_c^0$$

From the above equations, equations (2.3), (2.6), (2.7), equation below is achieved

$$\begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} I_a^0 \\ I_a^1 \\ I_a^2 \end{bmatrix} \quad (2.8)$$

2.3.2 Unbalance fault calculation

By using of symmetrical components, the accurate calculation of unbalanced fault is facilitated. The actual line currents are included fault, load, and circulating currents. Load and circulating currents are determined in pre fault condition. The superposition theory permits to add the fault currents to pre-fault currents to determine currents of each branch of network. Load current is relatively small instead of fault current and often it is neglected (Cashmore, et al., 2006).

According to ANSI standard, the steps to calculate unbalanced fault are as follows (Cashmore, et al., 2006):

1. Obtain sequence impedances on the equipment such as motors, generators and transformers and circuit such as line, cable and duct
2. Convert impedances to per unit value on a common apparent power (VA)
3. Construct positive, negative and zero sequence networks
4. Diminish the sequence networks (for simplify calculation)
5. According the fault type, connect the sequence networks
6. Calculate current of sequences
7. Calculate the fault and line current (voltages)

The power transformer sequence impedances are illustrated in figure 2.7 which is important at fault study because it shows how the fault current circulates.

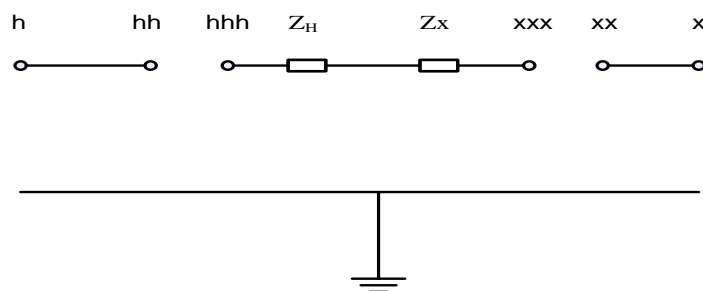


Figure 2.7: Sequence network for transformer.

Thus according figure 2.7, at table 2.1, it is illustrated connection for positive and zero sequence (negative sequence is same as positive sequence) in agreement with transformer connection windings.

Table2.1: Transformer sequence component connection (IEEE, 2008a).

Transformer connections		Positive or negative sequence		Zero sequence	
Winding H	Winding L	Winding H	Winding L	Winding H	Winding L
Delta	Wye	Short hh to hhh	Short xx to xxx	Short hhh to ground	Open xxx to xxx
Delta	Solidly grounded wye	Short hh to hhh	Short xx to xxx	Short hhh to ground	Short xx to xxx
Delta	Wye (grounded through Z_{gnd})	Short hh to hhh	Short xx to xxx	Short hhh to ground	Connect xx to xxx through $3Z_{gnd}$
Delta	Delta	Short hh to hhh	Short xx to xxx	Short hhh to ground	Short xxx to ground
Wye	Wye	Short hh to hhh	Short xx to xxx	Open hhh to hh	Open xx to xxx
Wye	Solidly grounded wye	Short hh to hhh	Short xx to xxx	Open hhh to hh	Short xx to xxx
Wye	Wye (grounded through Z_{gnd})	Short hh to hhh	Short xx to xxx	Open hhh to hh	Connect xx to xxx through $3Z_{gnd}$
Solidly grounded wye	Solidly grounded wye	Short hh to hhh	Short xx to xxx	Short hh to hhh	Short xx to xxx
Solidly grounded wye	Wye (grounded through Z_{gnd})	Short hh to hhh	Short xx to xxx	Short hh to hhh	Connect xx to xxx through $3Z_{gnd}$
Wye (grounded through Z_{gnd})	Wye (grounded through Z_{gnd})	Short hh to hhh	Short xx to xxx	Connect hh to hhh through $3Z_{gnd}$	Connect xx to xxx through $3Z_{gnd}$

2.3.3 Single line to ground fault

As it mentioned in section 2.2.1.3, the most common winding fault in transformers is single line to ground fault. Thus this research is focus on this kind of fault (ABB; Grainger & Stevenson, 1994; Hadi, 2007; Horowitz & Phadke, 2008; IEEE, 2001; Paithankar, 1997; Schmidt, 2008; Willis, 2006). Figure 2.3 has been illustrated this kind of fault, suppose to phase a is connected to ground so $I_b = I_c = 0$ in steady state condition, thus from equation 2.8

$$\begin{bmatrix} I_a^0 \\ I_a^1 \\ I_a^2 \end{bmatrix} = 1/3 \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \begin{bmatrix} I_a \\ 0 \\ 0 \end{bmatrix} = 1/3 \begin{bmatrix} I_a \\ I_a \\ I_a \end{bmatrix} \quad (2.9)$$

$$I_0 = I_1 = I_2 = 1/3 I_a \quad (2.10)$$

$$3I_0 Z_f = V_0 + V_1 + V_2 = -I_0 Z_0 + (V_a - I_1 Z_1) - I_2 Z_2 \quad (2.11)$$

Which gives

$$I_0 = \frac{V_a}{Z_0 + Z_1 + Z_2 + 3Z_f} \quad (2.12)$$

$$V_1 = V_a - \frac{V_a Z_1}{Z_0 + Z_1 + Z_2 + 3Z_f} \quad (2.13)$$

$$V_0 = \frac{V_a Z_0}{Z_0 + Z_1 + Z_2 + 3Z_f} \quad (2.14)$$

$$V_2 = \frac{V_a Z_2}{Z_0 + Z_1 + Z_2 + 3Z_f} \quad (2.15)$$

As a result the fault current I_a is

$$I_a = 3I_0 = \frac{3V_a}{Z_0 + Z_1 + Z_2 + 3Z_f} \quad (2.16)$$

From equations 2.11 and 2.16 when the single line to ground fault happens, therefore the equivalent circuit is:

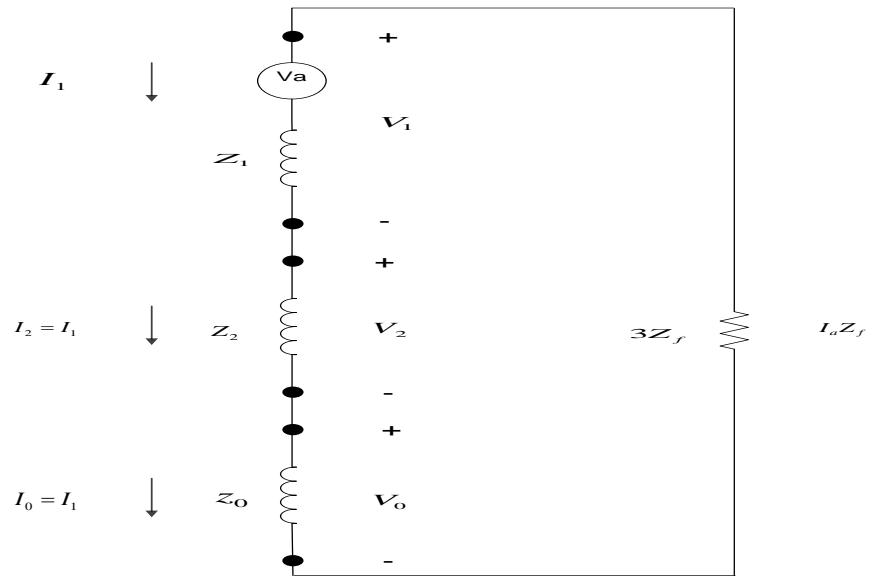


Figure 2.8: Equivalent circuit of the single line to ground fault (steady state).

Figure 2.9 shows how voltage and current at ground fault for relays are collected.

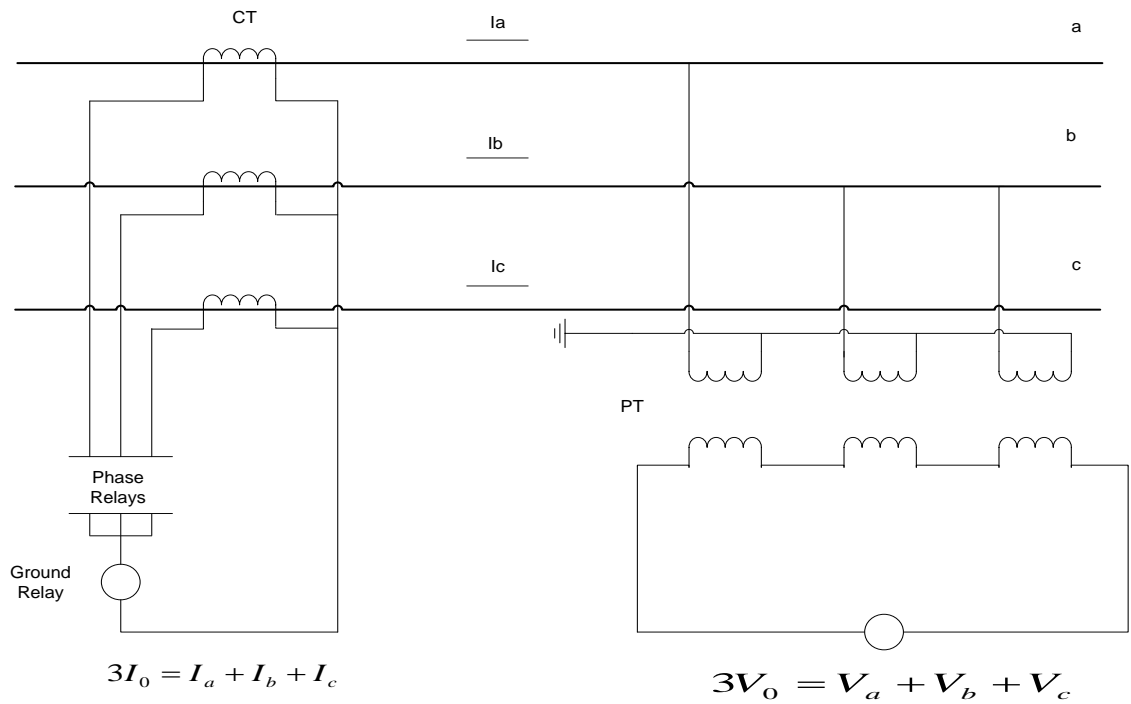


Figure 2.9: Zero sequence current and voltage of ground fault protection.

2.4 Transformer windings protection

There are three characteristics to detect transformer internal faults:

1. increase of the phase currents
2. Increase of the differential current
3. Engender gas by the fault arc

When one of the above causes occurs, the transformer should be isolated from network immediately to avoid extensive damage and also to keep system stable and power quality (Guzman, J.Alture, & Benmonyal, 2004).

Figure 2.10 illustrates the simple differential relay connection (IEEE, 2008a)

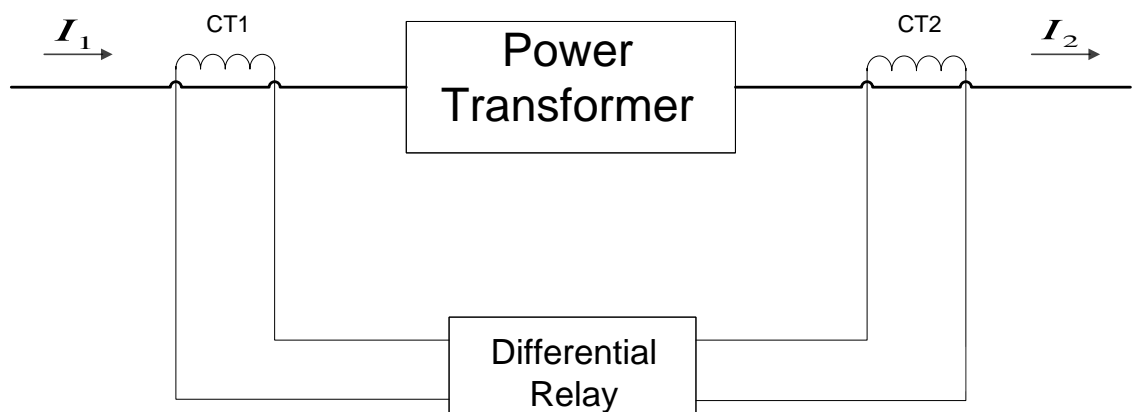


Figure 2.10: Differential relay diagram.

There are three general methods in the above current differential scheme detections:

1. Time over current relay with or without an instantaneous trip unit
2. Percentage differential relays with restraint motivated by the current going into and out of the protection zone
3. Percentage differential relays with restraint motivated by harmonics

2.4.1 Differential protection using time over current relays

Time-delay over current relays are used for extreme overload, or external fault. The pickup setting usually is 115% of maximum acceptable current. This protection relay must be coordinated with the low side of transformer (Horowitz & Phadke, 2008).

Over current relay without restraining point are almost never used due to below condition that causes false operation:

- Mismatch error or saturation error of CTs or over excitation of power transformers
- Energizing the transformer causes Magnetizing Inrush Current

To restrain false operation for saturation and inrush current, this relay should use time delay which means in real faulty condition, it works with time delay. Thus it seldom is used for transformer protection (IEEE, 2008a).

According to the above discussion, for protecting power transformer (differential protection) is used percentage differential protection commonly. Hence, the theorem of restricted earth fault is the same as differential protection and is based on percentage differential protection.

2.4.2 Differential protection using percentage differential protection

Most of differential relays are based on current differential. Principle of current differential relays has been shown in figure 2.10. To simplify, it is assumed that power transformer ratio is 1:1 and both CTs have the same ratio (also same core class). If fault happens out of the protection zone, results of currents that flow from both current transformers have the same magnitude with opposite direction. Thus the current result

that comes in relay is zero which is shown in figure below (Hewitson, et al., 2005; Mason, 1956).

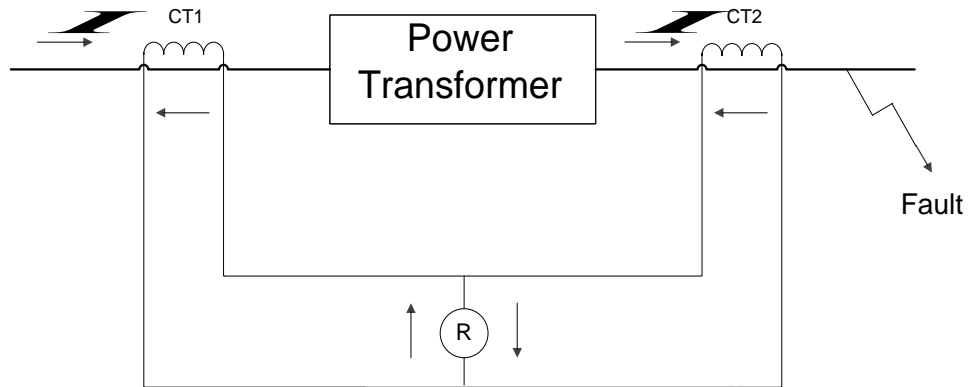


Figure 2.11: Currents direction for external fault.

Now, considering previous assumptions, fault has been occurred in protection zone. Currents that flowed from both current transformers have the same in magnitude and also have same direction (Hewitson, et al., 2005; Mason, 1956).

Figure 2.12 shows this condition

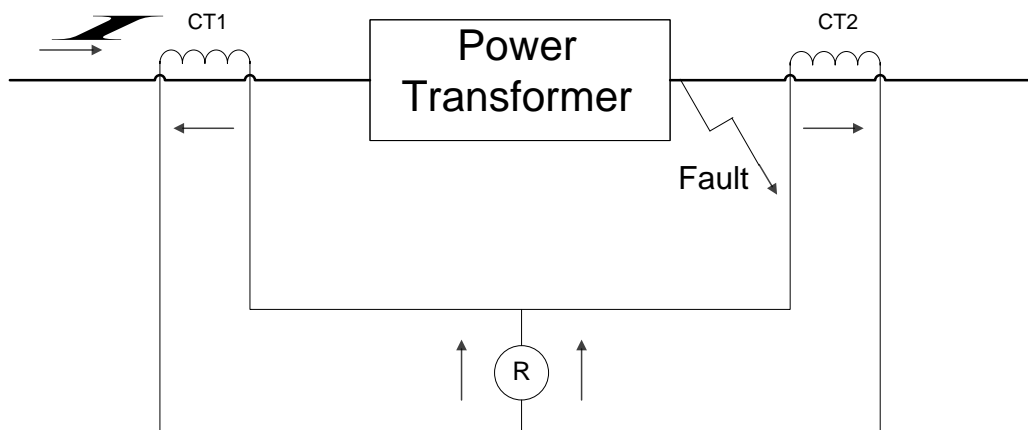


Figure 2.12: Currents direction for internal fault.

There are a few definitions (Guzman, et al., 2004; IEEE, 2008a; Mason, 1956; T&D, 2005; Tan & Wei, 2007), first of all differential current or operation current

$$I_{\text{diff}} = |I_1 + I_2| \quad (2.17)$$

Then, restraint current which is applied to transformer differential to ensure the relay keeps stability for external fault (there are different current combinations):

$$I_R = k|I_1 + I_2| \quad (2.18)$$

$$I_R = k(|I_1| + |I_2|) \quad (2.19)$$

$$I_R = \max(|I_1|, |I_2|) \quad (2.20)$$

In above equations, k is a constant value that is usually 0.5 or 1.

In this relay, the ratio of the differential operation current and restraint current has a constant value of percentage (reason of calling percentage differential protection). Figure 2.13 illustrates the operating area and restraining zone in percentage differential protection (Mason, 1956).

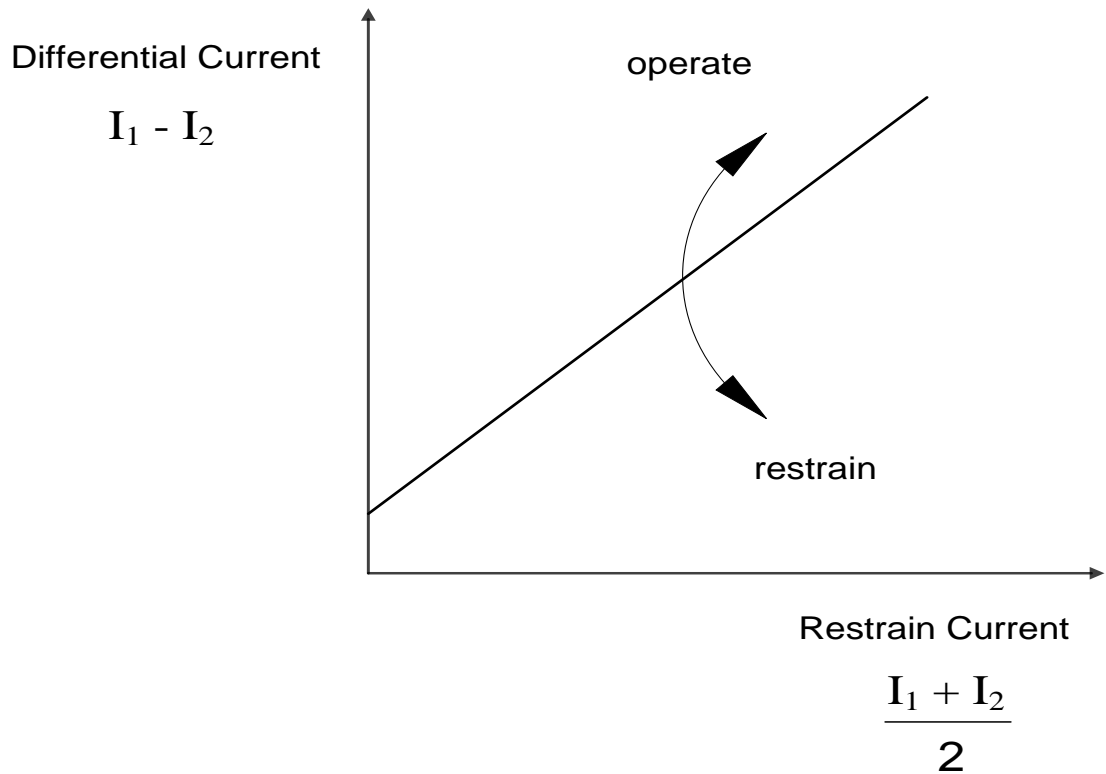


Figure 2.13: Percentage differential operating characteristic curve.

Figure below shows the power transformer with three windings and how it is connected to percentage differential relays for protecting it.

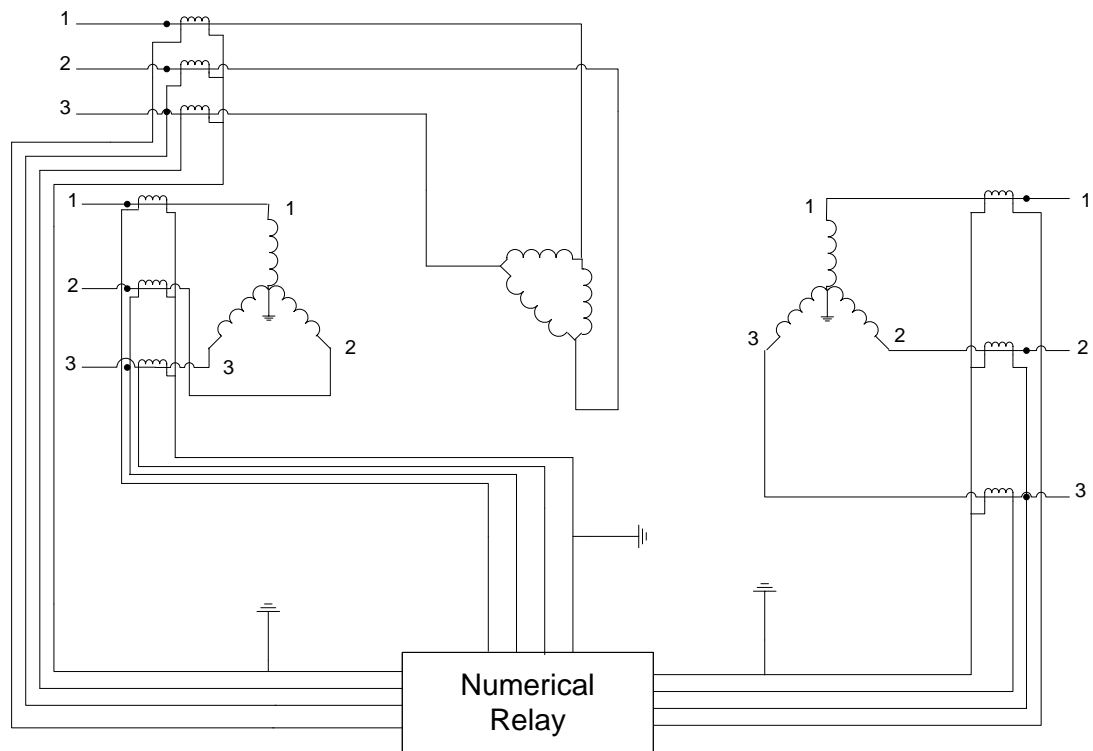


Figure 2.14: Connection for three windings transformer.

The theory part of three windings transformer for percentage differential relay is similar as the two windings transformer.

Note, REF relays are based on the percentage differential protection that is mentioned.

2.5 Why using Restricted Earth Fault protection

This section is studied about how can achieve more sensitivity for power transformer windings in earth fault conditions and at the end is discussed about benefits of using protection function restricted earth fault. Assume, earth fault happens at power transformer windings. Magnitude of earth fault current depends on the method of earthing such as solidly earth or resistance or reactance earth. Also winding transformer

structure affects earth fault current (ABB; G.Ziegler, 2008; IEEE, 2001; Robertson, 1982; Siemens; T&D, 2005) .

2.5.1 Classification of system grounding

IEEE standard 242-1986 defines grounded system as “A grounded system is intentionally grounded by connecting its neutral or one conductor to ground, either solidly or through a current-limiting impedance. Various degrees of grounding are used ranging from solid to high impedance, usually resistance” (IEEE, 2001);

Figure 2.15 shows the grounded and ungrounded systems and relationship between their voltages (IEEE, 2001).

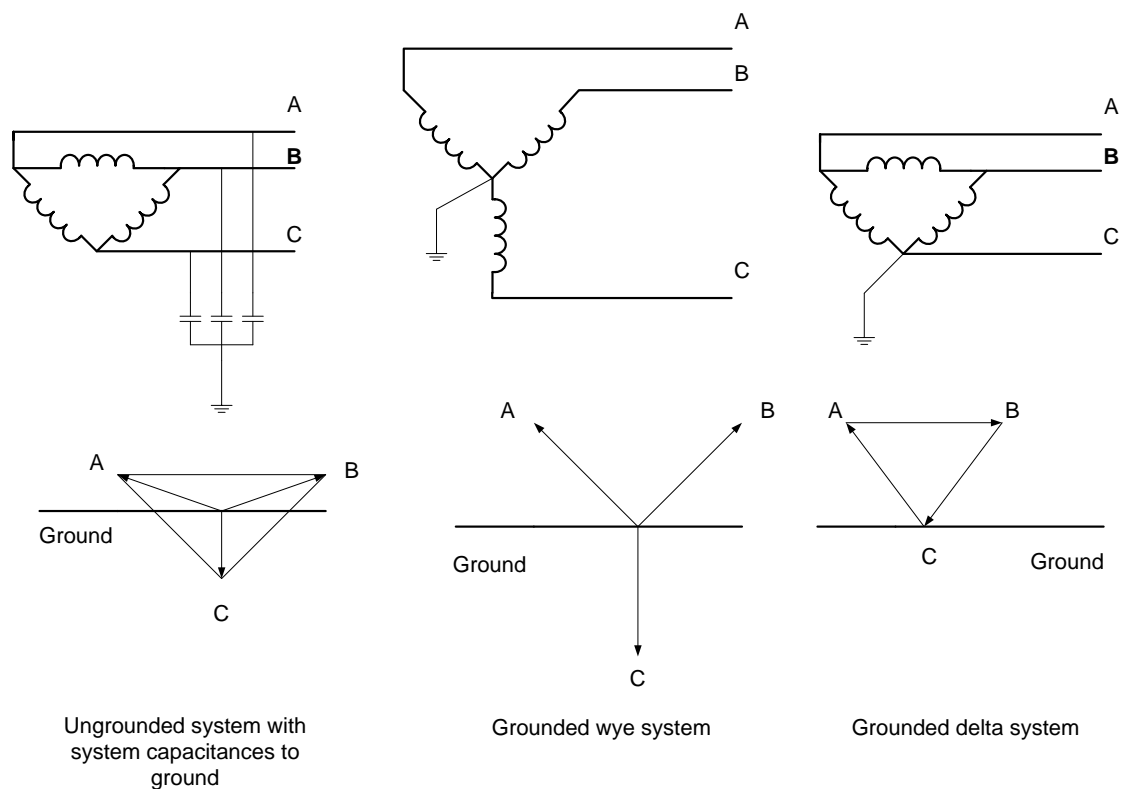


Figure 2.15: Grounded and ungrounded systems.

According Swedish standard, different kinds of system grounding are (ABB):

1. System with an isolated neutral point

2. Coil (reactance) earthed system
3. Earthed system

According IEEE standards (ANSI/IEEE 141.1986 & 242.2001) different kinds of grounding power system are (ABB; IEEE, 2001):

1. Solidly grounding
2. Low resistance grounding
3. High resistance grounding
4. Ungrounded

2.5.1.1 Solidly grounding

Neutral point of power system network is connected to the ground in at least one point without inserting impedance (ABB). Most of industrial power systems are solidly grounded (IEEE, 2001). Figure 2.16 shows sample of system structure of solidly grounded.

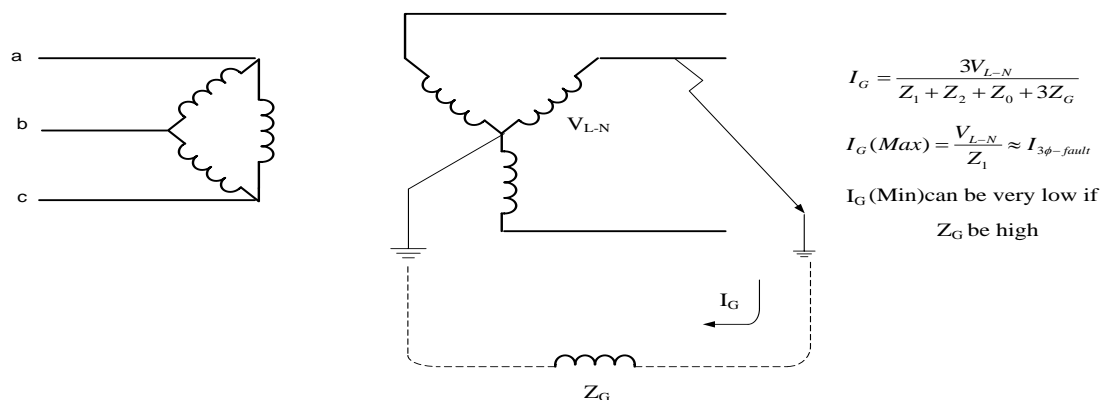


Figure 2.16: Solidly grounded network.

2.5.1.2 Low resistance grounding

This kind of grounding is used only on medium voltage systems and it is not use on low voltage systems. In this section the neutral point is connected to ground by low resistance resistor. This resistor is used to limit the magnitude of short circuit current

but it should allow the current magnitude to be detected by sensitive relays. This kind of grounding is used commonly in 3.3 KV to 11 KV systems which often have directly motors connected. Figure 2.17 illustrates this kind of grounding (IEEE, 2001):

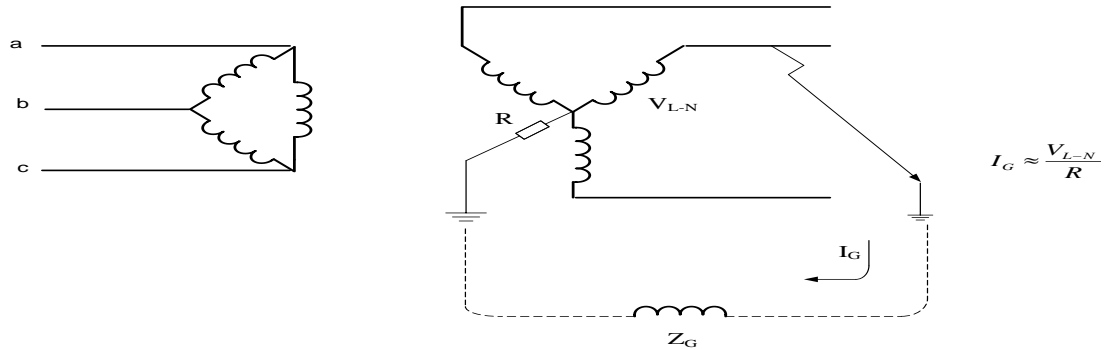


Figure 2.17: Low impedance grounded network.

2.5.1.3 High impedance grounding

The configuration which is going to be discussed is like the low impedance grounding. It limits current of fault to ground low magnitude. It helps to increase the possibility of the ground fault current by using ground fault sensitive relays (IEEE, 2001).

2.5.1.4 Ungrounded system

When, the system is not connected to ground, there is not any way for circulating fault current. The ground fault current is a few amperes which charge capacities, which is shown at figure 2.18 (IEEE, 2001).

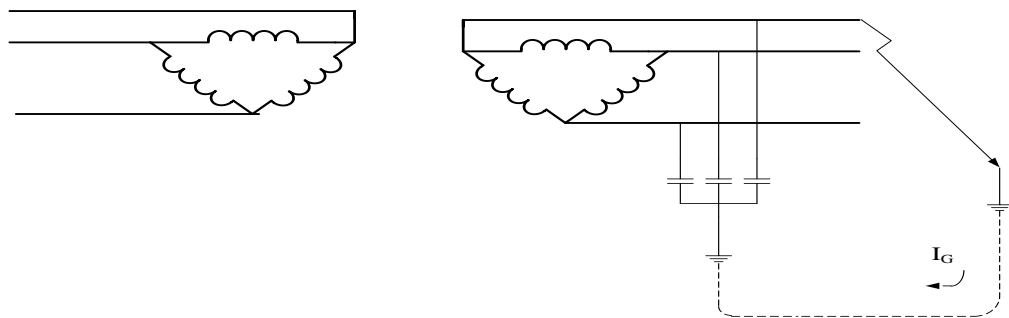


Figure 2.18: Ungrounded system.

After discussing on grounding system, the transformer winding earth fault with different grounding system will be investigated and the reason of Restricted Earth Fault protection will be studied.

2.5.2 Transformer winding earth fault

Transformer winding earth fault can be divided into three types that will be presented in the following sections.

2.5.2.1 Solidly earthing

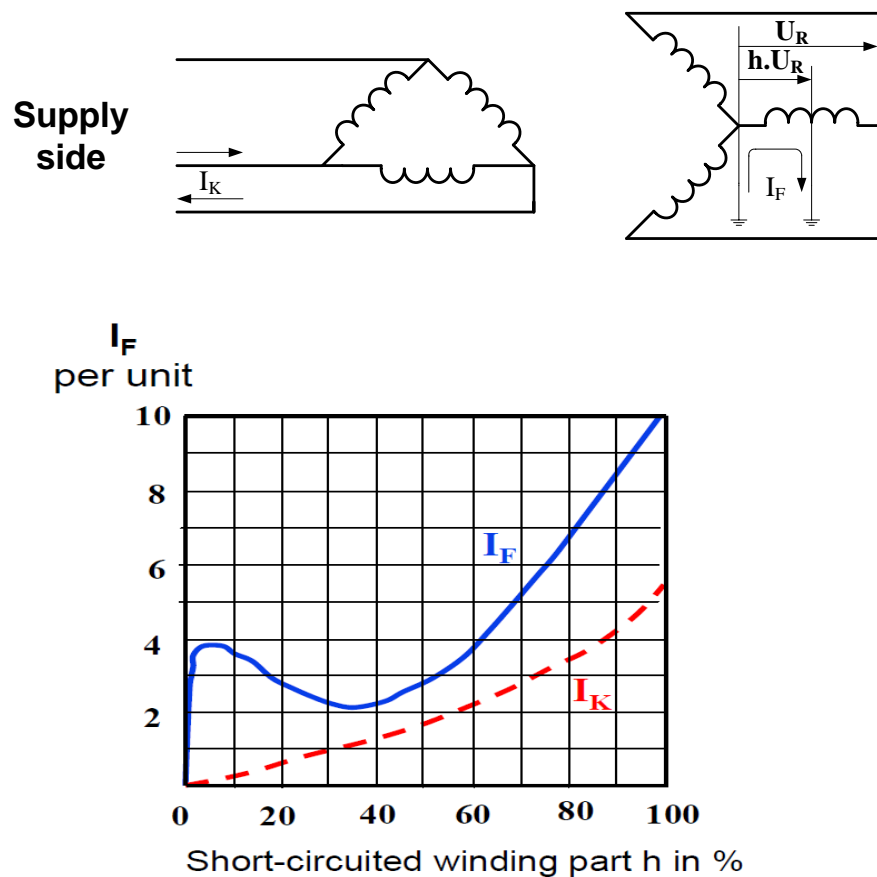


Figure 2.19: Star connection-solidly earthing (G.Ziegler, 2008).

As shown in figure 2.19, the fault current depends only on transformer winding impedance. Whatever the fault occurs near to neutral point, the h is decreasing and inductance also is decreasing, thus the fault current be very higher than the line current.

2.5.2.2 Resistance or reactance earthing

In this case earth fault current is directly proportional to the position of fault that occurred at winding. Figure 2.20 shows the system network and a curve that illustrates characteristics of line and fault current (G.Ziegler, 2008; Robertson, 1982; T&D, 2005).

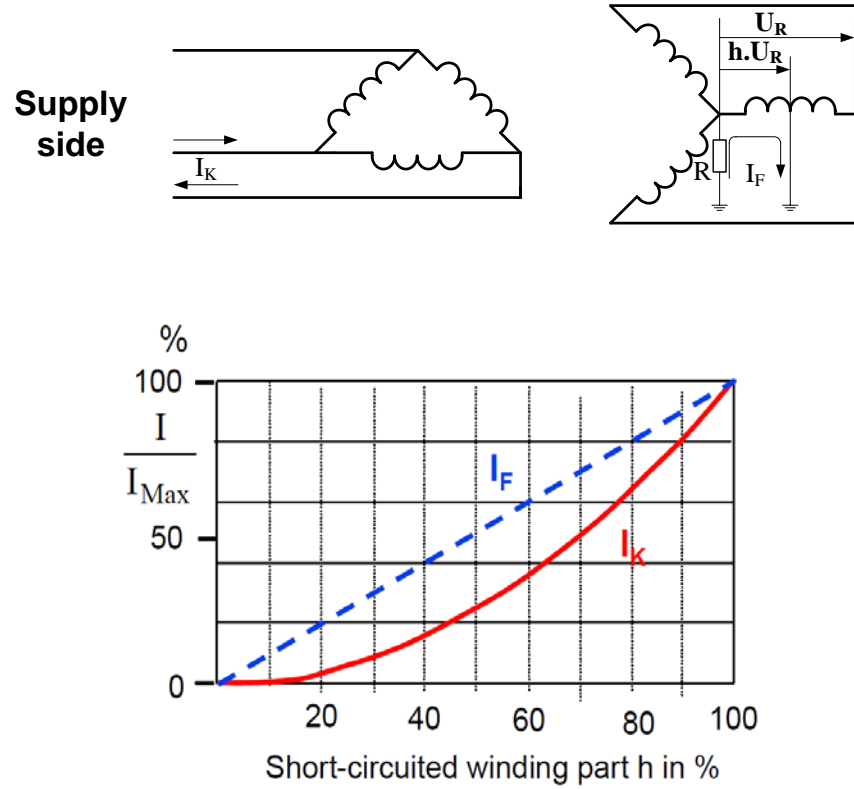


Figure 2.20: Resistance or reactance earthed neutral (G.Ziegler, 2008).

As it illustrated in figure (2.20), fault current at star side is

$$I_F = \frac{h.U_R}{R} \quad (2.21)$$

$h.U_R$ proportion to the fault point and illustrates the voltage between fault point and star point. Thus the current at the delta side is

$$I_K = \frac{h.w_2}{w_1} . I_F = h . \frac{U_{2n}}{U_{1n} \cdot \sqrt{3}} . I_F$$

$$\Rightarrow I_k = h^2 \cdot \frac{1}{\sqrt{3}} \cdot \frac{U_{2n}}{U_{1n}} \cdot \frac{U_R}{R} \quad (2.22)$$

The curve of figure 2.20 shows, according section 2.5.1.3 the fault current at the start pint linearly changes to the short circuit winding part (h).

2.5.2.3 Earth fault in delta winding

This type of earth fault at Delta connection in power transformer is shown at figure 2.21. It shows the fault current becomes six times of the line current (as it illustrated with vectors).

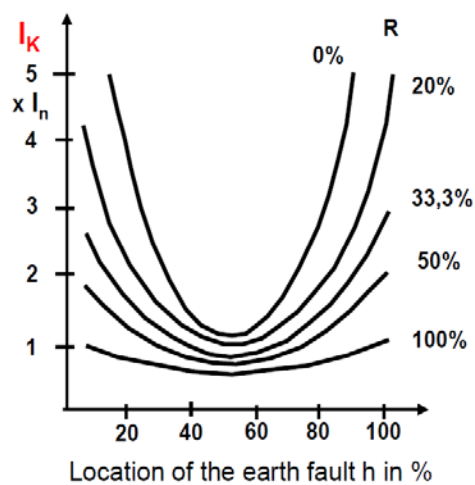
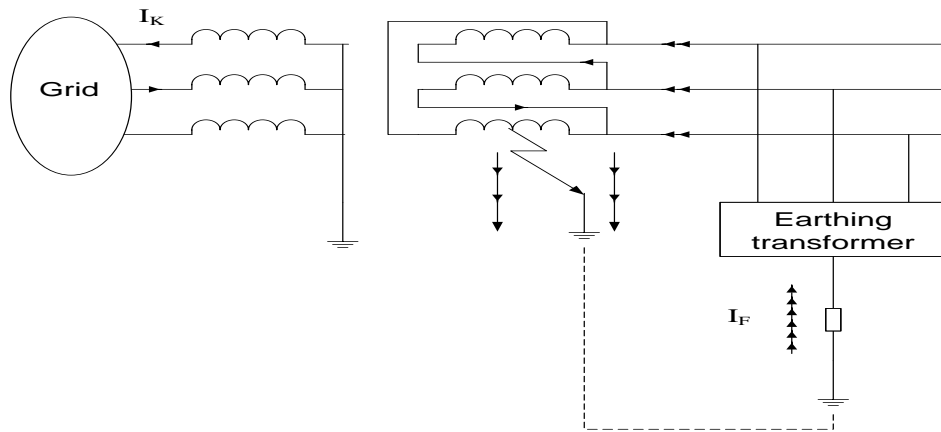


Figure 2.21: Earth fault in delta connection (G.Ziegler, 2008).

2.5.3 Using Restricted Earth Fault protection function

Importance of REF Relays is achieved when the fault happens near to neutral point. When internal fault has happened at resistance earthed power transformer, the fault current that flowed from CT may be relatively low and can not affect the differential protection. Thus, for protecting power transformer winding, another protection function except of differential protection function is needed.

REF is a unit protection scheme for one winding of power transformer which is grounded. Figure 2.22 shows the amount of winding protected against the fault setting. This graph demonstrates 2 curves, one relates to REF protection and another is Differential protection (Iran electric distribution co, 1995; Robertson, 1982; T&D, 2005).

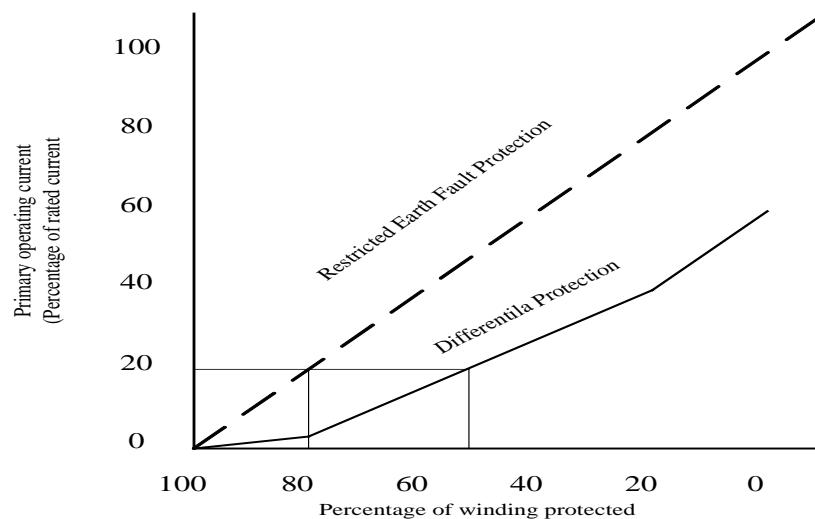


Figure 2.22: Percentage of winding protected between REF and differential relay (T&D, 2005).

A delta-star power transformer winding connection is assumed that star connection with one per unit resistance is grounded. According to the figure 2.22 if the percentage of rated primary operating current be 20%, the differential relay protects near 45% of winding but REF relay protects more than 78% of winding.

2.6 Review of Restricted Earth Fault algorithms

In this subchapter, different algorithms from different companies will be reviewed.

These algorithms are based on different companies, namely:

1. Siemens
2. General Electric Multilin
3. Areva T&D(New algorithm)
4. Schnider electric
5. ABB

These are five of important companies which produce REF protection relay, however there are other companies that produce REF relays but the base of all algorithms is the same as the above companies. Most of these companies information are confidential.

2.6.1 Siemens

One of the giant producers in power system protection equipment is Siemens Company. The new generation of Siemens relays is called SIPROTEC4. The different relays that have REF function are divided in 2 groups:

1. Standard function: all standard function of REF relays are high impedance restricted earth fault which contain 7SJ80-7SJ61-7SJ62-7SJ63-7SJ64-7VH60
2. Optional: 7SD5 AND 7SD610 are line differential protection with low impedance restricted earth fault protection. Also 7UT612-7UT613 and 7UT63 use for transformer protection (low impedance REF). Thus this thesis will be concentrated on transformer protection relay types (7UT613&7UT63)(Siemens, 2008).

According 7UT613-63 manual, this type of relay cannot protect auto transformer (Kasztenny & Kulidjian, 2000; Siemens). At first, some definition will be presented that came from Siemens that is used to describe Siemens algorithm.

2.6.1.1 Function description

Star point current, I_{SP} , is the current which flows at star point CT and residual current is

$$3\bar{I}_0 = \bar{I}_{L1} + \bar{I}_{L2} + \bar{I}_{L3} \quad (2.23)$$

At normal condition, I_{SP} is zero and residual current ($3I_0$) is almost zero. According to the fault position (inside or outside of protection zone) the current which flows into protection zone is called positive in direction. Thus, if fault occurs in protection zone, the residual current will be more or less in phase with the star point current. When earth fault occurs outside of the protection zone, star point current is like the inside protection zone fault flows equal current, but the residual current is with the same magnitude but in opposite phase compare to the star point current. These current directions are shown in figure 2.23 a and b (Kasztenny & Kulidjian, 2000; Siemens).

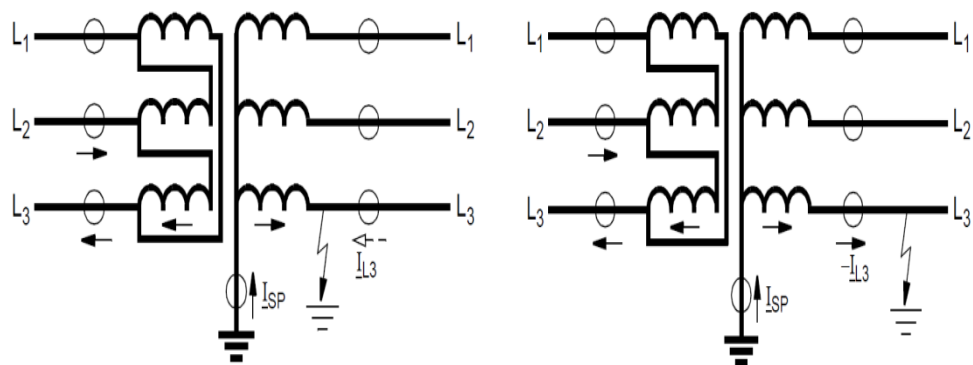


Figure 2.23: (a)earth fault inside protection zone (left), (b)earth fault outside protection zone (right) (Kasztenny & Kulidjian, 2000; Siemens).

2.6.1.2 Operation algorithm

This algorithm compares the fundamental of star point wave form which is called as $3\bar{I}_0'$ in the following, with fundamental of sum of three phase current wave (residual current) which is designated $3\bar{I}_0''$ in the following.

Note, the most important point is $3\bar{I}_0'$ dose tripping command.

Figure 2.24 shows the connection on restricted earth fault relay to the network.

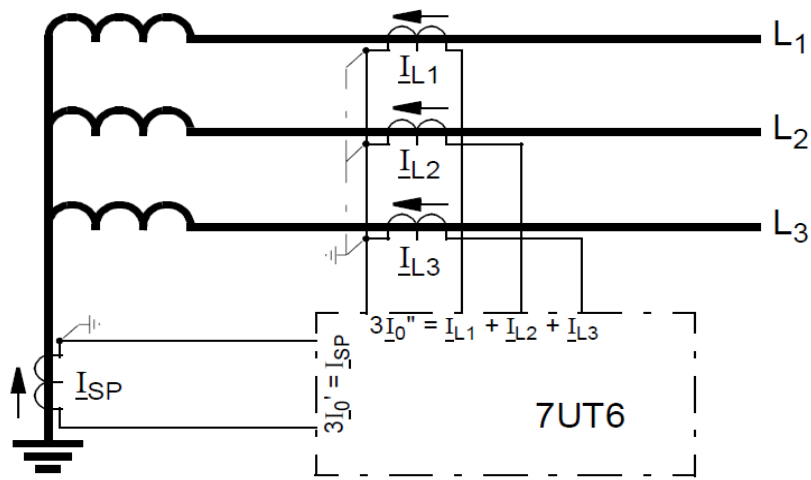


Figure 2.24: Connection principle of restricted earth fault protection (Kasztenny & Kulidjian, 2000; Siemens).

$$3\bar{I}_0' = \bar{I}_{SP} \quad (2.24)$$

$$3\bar{I}_0'' = \bar{I}_{L1} + \bar{I}_{L2} + \bar{I}_{L3} \quad (2.25)$$

A trip effect current

$$I_{REF} = |3\bar{I}_0'| \quad (2.26)$$

Restraining or stabilization current is

$$I_{REST} = k.(|3\bar{I}_0' - 3\bar{I}_0''| - |3\bar{I}_0' + 3\bar{I}_0''|) \quad (2.27)$$

Where, “k” is stabilization factor.

It is possible to increase of tripping. Figure 2.25 illustrates the operating curve of restricted earth fault protection which is tripping area proportional to the $\sum|I|$.

$$\sum|I| = |I_{L1}| + |I_{L2}| + |I_{L3}| + |I_{SP}| \quad (2.28)$$

Thus the slope of stabilizing curve can be set (Kasztenny & Kulidjian, 2000; Siemens).

Normally differential protection does not require “pickup” or “fault detection” function, but restricted earth fault protection like all protection functions, needs pickup and fault detection. When the fundamental wave form of the differential current exceeds 85% of the pickup value, fault detection is indicated (Kasztenny & Kulidjian, 2000; Siemens).

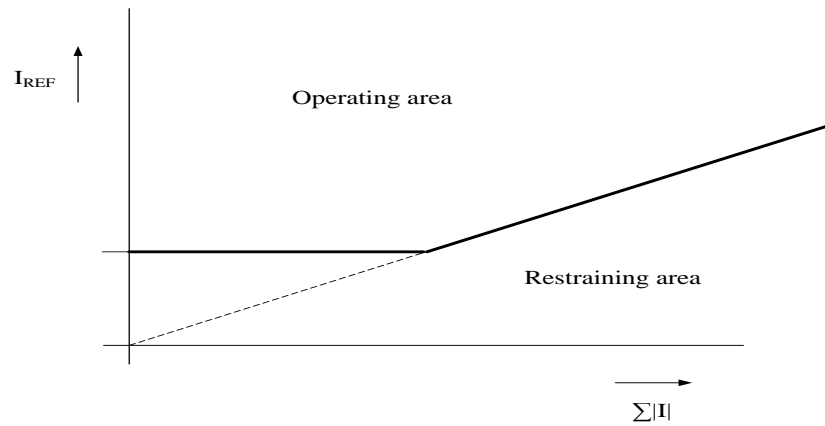


Figure 2.25: Operating and restraining areas (Kasztenny & Kulidjian, 2000; Siemens).

2.6.2 GE Multilin (Bogdan Kasztenny)

Figure 2.26 shows there are two different kinds of configuration for power transformers, single breaker (a) and a breaker and half (b).

Discussed in the following at REF algorithms for each one of these system configuration (Kasztenny & Kulidjian, 2000; Kasztenny, et al., 2004).

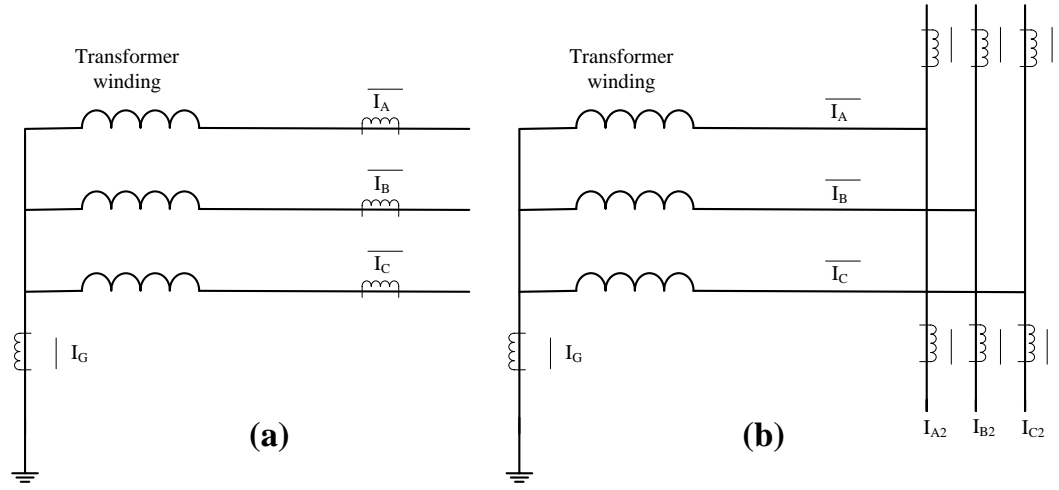


Figure 2.26: Transformer REF connection-(a) single breaker, (b) one and half breaker.

2.6.2.1 Operation algorithm for single breaker

To avoid mal-operation of the restricted earth fault protection, a unique definition of the restraining current is needed with high sensitivity to internal faults.

In the GE algorithm,

2.6.2.1.1 Differential current

Differential current or operating current is defined as follow: (Kasztenny & Kulidjian, 2000; Kasztenny, et al., 2004).

$$I_D = |I_G + I_N| = |I_G + I_A + I_B + I_C| \quad (2.29)$$

Where

I_D is differential current

I_G is ground current

$I_N = I_A + I_B + I_C$ is residual current (three time the zero sequence current)

$| |$ symbolizes for phasor magnitude

2.6.2.1.2 Restraining current

Stability and security of the REF algorithm depends on the way of producing the restraint current. In this algorithm symmetrical component is used to produces restraint signal for various fault types. Restraint current must be maximized during external fault (Kasztenny & Kulidjian, 2000; Kasztenny, et al., 2004).

Restraint current for single breaker is

$$I_{R_aux} = \max(|I_{R0}|, |I_{R1}|, |I_{R2}|) \quad (2.30)$$

Where

I_{R_aux} is an intermediate restraint current,

I_{R0} is an auxiliary restraint current which is based on zero sequence current and it keeps REF stable on external ground fault,

I_{R1} is an auxiliary restraint current which is based on positive sequence current and it keeps REF stable on load conditions, external three phase balanced and near balanced fault,

I_{R2} is an auxiliary restraint current which is based on negative sequence current and it keeps REF stable on line to line faults.

2.6.2.1.3 Zero sequence restraint

It is a vectorial difference between the ground and residual current.

$$I_{R0} = |I_G - I_N| = |I_G - (I_A + I_B + I_C)| \quad (2.31)$$

2.6.2.1.4 Positive sequence restraint

Positive sequence restraint current is created as follow

If $|I_1| > 1.5$ pu of phase current of the CTs then

$$\text{If } |I_1| > |I_0| \quad \text{then} \quad |I_{R1}| = 3. (|I_1| - |I_0|) \quad (2.32)$$

$$\text{Else} \quad |I_{R1}| = 0$$

$$\text{Else} \quad |I_{R1}| = \frac{1}{8} \cdot |I_1|$$

2.6.2.1.5 Negative sequence restraint

Negative sequence restraint current is created as follows

$$I_{R2} = 3 \cdot |I_2| \quad \text{or} \quad I_{R2} = |I_2| \quad (2.33)$$

At equation 2.33, multiplier of 3 is used normally. However, in some phenomena such as Inrush current multiplier of 1 is used. To avoid undesirable effect of equations 2.33 with 2.30 uses a filter that shows at figure 2.27 (it will be discussed more in the next chapter) (Kasztenny & Kulidjian, 2000; Kasztenny, et al., 2004).

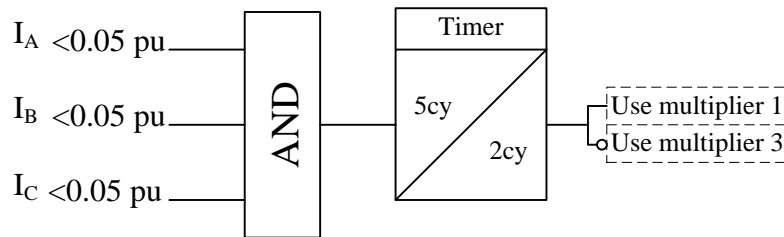


Figure 2.27: Logic controlling negative restraint .

Effective restraining current which is exponentially decaying ($I_{R(k)}$) is the maximum magnitude of I_{R_aux} at this time and I_{R_aux} at previous time multiply by a constant (A) which is:

$$I_{R(k)} = \max(|I_{R_aux(k)}|, A \cdot |I_{R(k-1)}|) \quad (2.34)$$

Where

K is a constant for time

A is a decaying factor which $A < 1$.

Note: in this algorithm A is selected 50% decay in about 15 power cycles.

Figure 2.28 shows the characteristic curve of REF relay according mentioned algorithm which is selected a single slope function with an independent pick up setting (Kasztenny & Kulidjian, 2000; Kasztenny, et al., 2004).

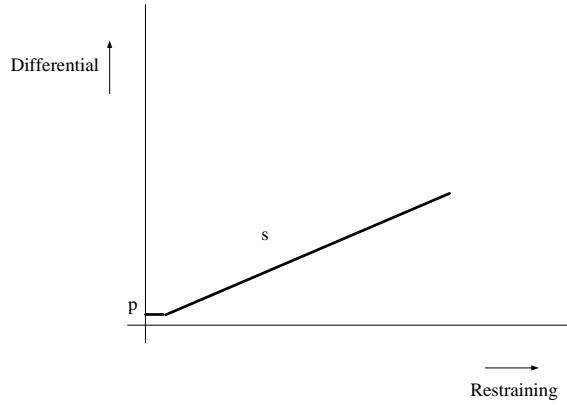


Figure 2.28: Setting of the REF characteristic.

2.6.2.2 Operation algorithm for a breaker and half

For a breaker and half system configuration, figure 2.26(b), all formulas are like the one breaker system configuration, but they should be attended to both current flow ways.

$$I_D = |I_G + I_{N1} + I_{N2}| = |I_G + I_{A1} + I_{B1} + I_{C1} + I_{A2} + I_{B2} + I_{C2}| \quad (2.35)$$

$$I_{R0} = |I_G - (I_{N1} + I_{N2})| = |I_G - (I_{A1} + I_{B1} + I_{C1} + I_{A2} + I_{B2} + I_{C2})| \quad (2.36)$$

$$I_{R2} = \max(I_{R2-BREAKER-1}, I_{R2-BREAKER-2}) \quad (2.37)$$

$$I_{R1} = \max (I_{R1-BREAKER-1} , I_{R1-BREAKER-2}) \quad (2.38)$$

2.6.3 New restricted earth fault protection (Areva T&D)

In this method first discusses on tow slope characteristics and after that it advises single slope characteristic that is cooperation with Areva T&D (Tan & Wei, 2007).

2.6.3.1 REF with dual slope percentage restraint

The most commonly REF algorithm are dual slope restraint characteristics which illustrates in figure 2.29. The differential current is vector summation of all measured phase and residual current (neutral current).

$$I_{diff,G} = |\max (I_A , I_B , I_C) + I_Y| \quad (2.39)$$

Bias current is half of scalar summation of maximum phase currents and residual current.

$$I_{bias,G} = \frac{1}{2} |\max(I_A, I_B, I_C)| + |I_Y| \quad (2.40)$$

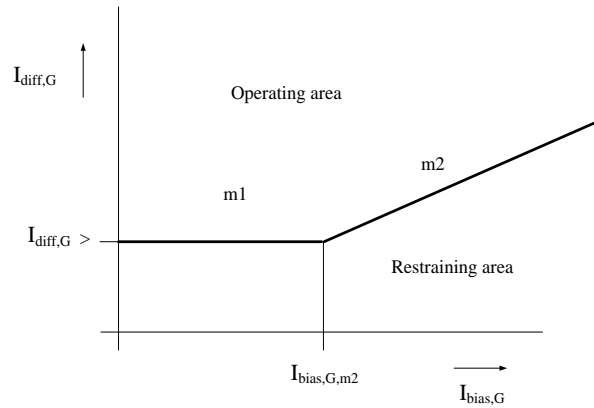


Figure 2.29: Dual slopes relay characteristic.

The restraint current for fault that the bias current is less than $I_{bias,G,m2}$ (knee point) at curve 2.29 is

$$I_{\text{restraint,G}} = m_1 I_{\text{bias,G}} + I_{\text{diff,G}} > \quad \text{condition: } I_{\text{bias,G}} \leq I_{\text{bias,G,m2}} \quad (2.41)$$

And restraint current of the other zone which I_{bias} is greater than the knee point, is

$$I_{\text{restraint,G}} = m_2 \cdot I_{\text{bias,G}} - (m_2 - m_1) \cdot I_{\text{bias,G,m2}} + I_{\text{diff,G}} > \quad \text{condition: } I_{\text{bias,G}} > I_{\text{bias,G,m2}} \quad (2.42)$$

Relay will operate when

$$I_{\text{diff,G}} \geq I_{\text{restraint,G}} \quad (2.43)$$

Where

$I_{\text{diff,G}}$ is ground differential current

$I_{\text{bias,G}}$ is bias current

$I_{\text{diff,G}} >$ is pickup setting

$I_{\text{bias,G,m2}}$ is knee point bias current

m_1 is slope 1

m_2 is slope 2

I_Y is measured residual current or neutral current.

The typical setting for m_1 is zero and pickup setting is 10% of nominal current. At this condition the relay is sensitive to see ground fault. The knee point is usually between 100% and 200% of nominal current (Tan & Wei, 2007).

This algorithm at some conditions operates falsely (it will explain at next chapter). Also this algorithm influences from CT saturation and Inrush current.

2.6.3.2 Suggested algorithm

Areva suggests a new algorithm that it has achieved by changing standard definitions.

$$I_{diff,G} = K_{amp,N} \cdot (I_A + I_B + I_C) + K_{amp,Y} I_Y \quad (2.44)$$

$$I_{bias,G} = K_{amp,N} |I_A + I_B + I_C| \quad (2.45)$$

$$I_{res,G} = 1.005 \cdot I_{bias,G} + I_{diff,G} \quad (2.46)$$

To be sure of the stability in the case of unbalanced three phase current, the coefficient of 1.005 will be multiplied.

Figure 2.30 shows the relevant algorithm characteristic curve. The slope is 1.005 and for operation, the current should flow in star point, current exceed the pickup setting value plus 0.5% for three phase unbalancing. Otherwise the relay stays in straining area and does not operate (Tan & Wei, 2007).

For operation, the following calculation should be fulfilled

$$I_{diff,G} \geq I_{res,G} \quad (2.47)$$

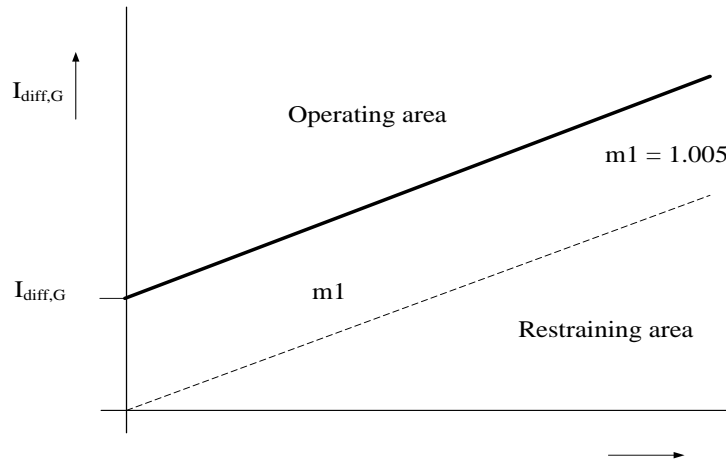


Figure 2.30: REF suggested characteristic curve.

2.6.4 Schneider low impedance REF

The Schneider protection relays call SEPAM. According to (Bertrand, Gotzig, & Vollet, 2001), differential current is

$$I_d = I_a + I_b + I_c + I_n \quad (2.48)$$

The restraint current is

$$I_r = I_a + I_b + I_c \quad (2.49)$$

With this assumption, phase currents are positive when flowing to transformer and neutral current is positive when flowing to ground.

This relay operates when

- I_d exceeds than I_{d0} (pickup) which is between 5% and 50% of transformer rated current
- I_d/I_r exceeds than 1.05

Figure 2.31 shows the operation and restraint area in SEPAM Schneider relays

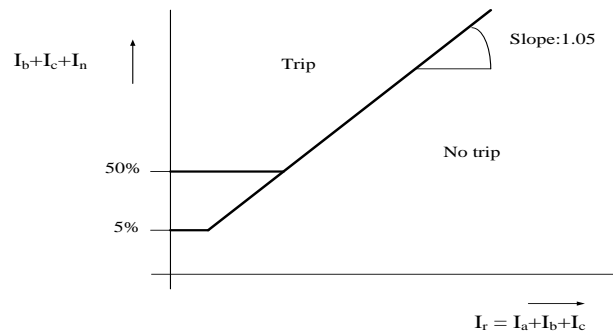


Figure 2.31: SEPAM REF tripping characteristic.

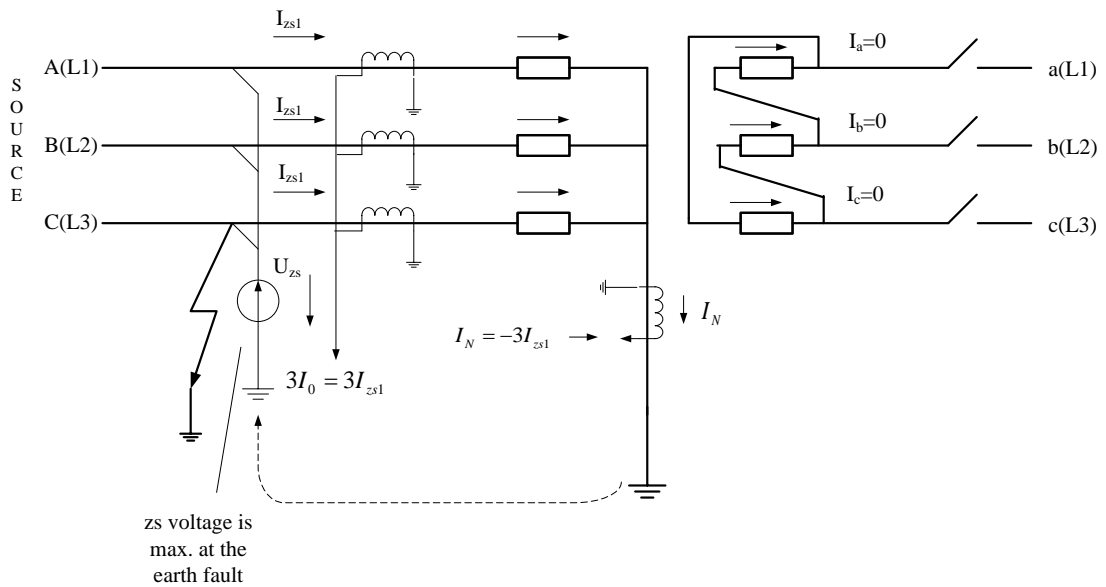
The principle of good stability in CT saturation is that if REF protection located at primary side, because of the dc inrush current, the phase CTs go to saturation area and cause false operation of REF. Otherwise, if REF protection located at secondary side, a three phase fault outside of protection zone can go the CTs to saturation area. Thus for these two condition, because there is not any flowing current at neutral, I_n equal to zero, thus $I_r = I_d$ and the SEPAM relay stay stable.

For the external fault, the restraint current increases to ensure stability of REF relay.

$$I_r(\text{external fault}) = I_a + I_b + I_c + I_n/3 \quad (2.50)$$

2.6.5 ABB

In this part, RET 670 ABB relay manual is studied (ABB). In this relay at the first step, fundamental frequency component of input currents are extracted. Thus, other zero sequence components such as 3rd harmonics are suppressed. Then the residual current phasor is vectorically added to neutral current. Figure 2.32 shows that the fault happened out of protection zone and vectorial summation of residual current and neutral current.



For external fault

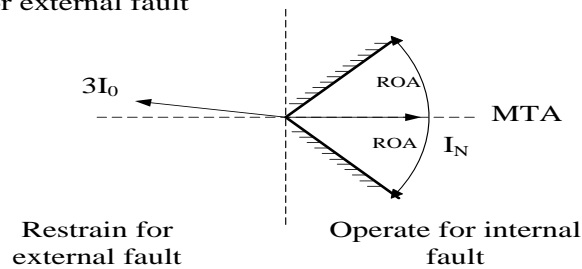


Figure 2.32: Currents at an external earth fault.

And figure 2.33 shows the internal earth fault and vectorial summation of neutral current and residual current.

I_N current at neutral as a fundamental frequency phasor

$3I_0$ residual current

Figure 2.34 shows the function block and tables 2.2 and 2.3 show the definition of inputs and outputs current and signal for a breaker and a half system configuration(also it can use for one breaker system).

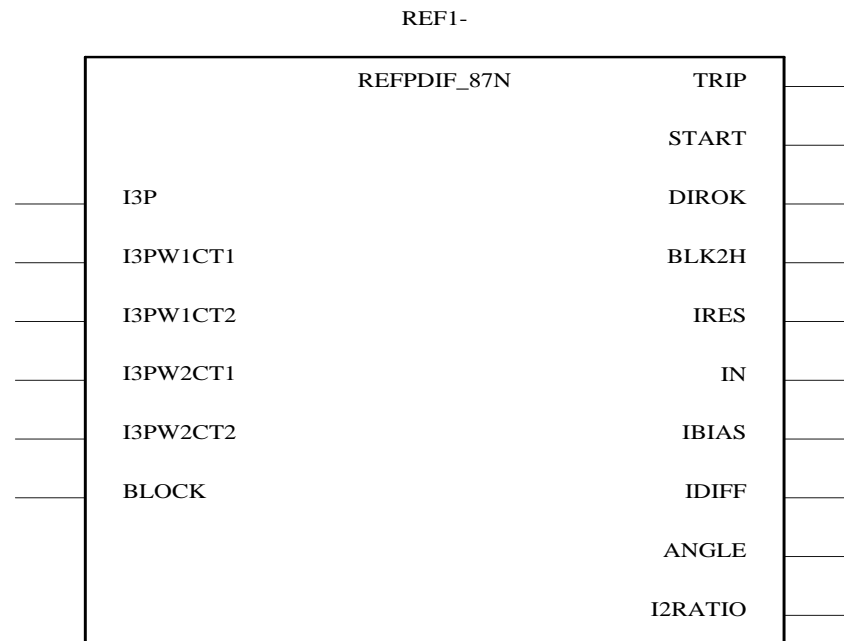


Figure 2.34: REF function block.

Table 2.2: Input signal for REF.

signal	Description
I3P	Group signal for neutral current input
I3PW1CT1	Group signal for primary CT 1 current input
I3PW1CT2	Group signal for primary CT 2 current input
I3PW2CT1	Group signal for secondary CT 1 current input
I3PW2CT2	Group signal for secondary CT 2 current input
BLOCK	Block of function

Table 2.3: Output signal for REF.

Signal	Description
TRIP	Trip by restricted earth fault protection function
START	Start by restricted earth fault protection function
DIROK	Directional criteria has operated for internal fault
BLK2H	Block due to 2 nd harmonic
IRES	Magnitude of fundamental frequency residual current
IN	Magnitude of fundamental frequency neutral current
IBIAS	Magnitude of bias current
IDIFF	Magnitude of fundamental frequency differential current
ANGLE	Direction angle from zero sequence feature
I2RATIO	Second harmonic ratio

$$I3PW1 = I3PW1CT1 + I3PW1CT2 \quad (2.52)$$

At one and a half breaker, bias current is the maximum of the following 5 currents.

$$current[1] = \max(I3PW1CT1) \cdot \frac{1}{CTFactorPr i1} \quad (2.53)$$

$$current[2] = \max(I3PW1CT2) \cdot \frac{1}{CTFactorPr i2} \quad (2.54)$$

$$current[3] = \max(I3PW2CT1) \cdot \frac{1}{CTFactorSec1} \quad (2.55)$$

$$current[4] = \max(I3PW2CT2) \cdot \frac{1}{CTFactorSec2} \quad (2.56)$$

$$current[5] = I_N \quad (2.57)$$

According to the bias current definition, if the differential current is more than the bias current the relay operates, otherwise it does not operate.

2.6.5.2 Algorithm of the restricted earth fault protection (REF)

According to the ABB relay technical reference manual type RET670, there are 9 steps for REF algorithm:

1. If neutral current (I_N) is less than 50% of the minimum base sensitivity current (I_{dmin}), only service values are calculated, then exit REF protection.

Table 2.4: Bias characterize of the REF.

Default sensitivity $I_{dmin}(zone1)$	Maximum base sensitivity $I_{dmin}(zone1)$	Minimum base sensitivity $I_{dmin}(zone1)$	End of zone 1	First slope	Second slope
% I_{rated}	% I_{rated}	% I_{rated}	% I_{rated}	%	%
30	4	100	125	70	100

2. If neutral current is more than 50% of I_{dmin} , then determine bias current.
3. Determine operating current or differential current as a phasor and calculate magnitude of differential current.
4. If the point of I_{bias} and I_{diff} is inside of operating area at relay characteristic curve set the trip counter to 1. Otherwise, reset the trip counter to 0.
5. If trip request counter is 0, search for a heavy external earth fault. If the neutral current at least is 50% of bias current, the external current happened and a flag sets until the external earth has been cleared. The external earth fault flag reset if neutral current decrease less than 50% of base sensitivity current I_{dmin} . Any search for external fault cancels if trip counter change to 1.
6. When external fault happened, the REF is desensitized and additional temporary trip is needed.
7. If I_{diff} and I_{bias} are inside of operating area, the trip request is more than 0 and directional check can be made. The directional check is made if residual current

is more than 3% of the bias current. If the directional cannot be executed, Thus direction is not comfortable for tripping.

8. The ratio of 2nd harmonic to fundamental is calculated. If this value is more than 60% then the trip request counter is zero.
9. Finally, if the trip request counter is equal to 2 or more than 2 and bias current is at least 50% of highest bias current or $I_{biasmax}$ (measured during the disturbance) then the REF block set TRIP to 1. Otherwise the TRIP signal is 0.