Protection, Study

By: Mohamed A. Numair

1 CONTETNS

2 INTRODUCTION TO POWER SYSTEM

2.1 Relaying

Relaying is the branch of electric power engineering concerned with the <u>principles of design</u> and <u>operation</u> of relay

*that **detects** abnormal power system conditions,*

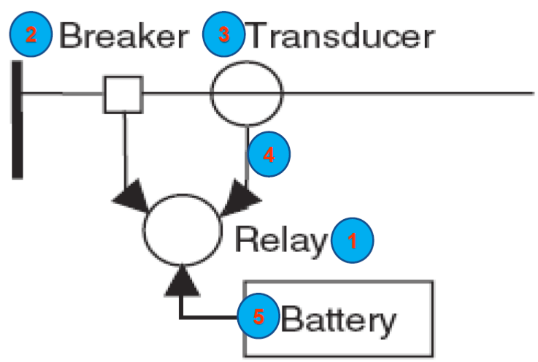
and ***initiates** corrective action as quickly as possible*

in order to return power system to its normal state.

<u>NOTE :</u>

relay response times are of the order of a few milliseconds

2.2 Elements of a protection system

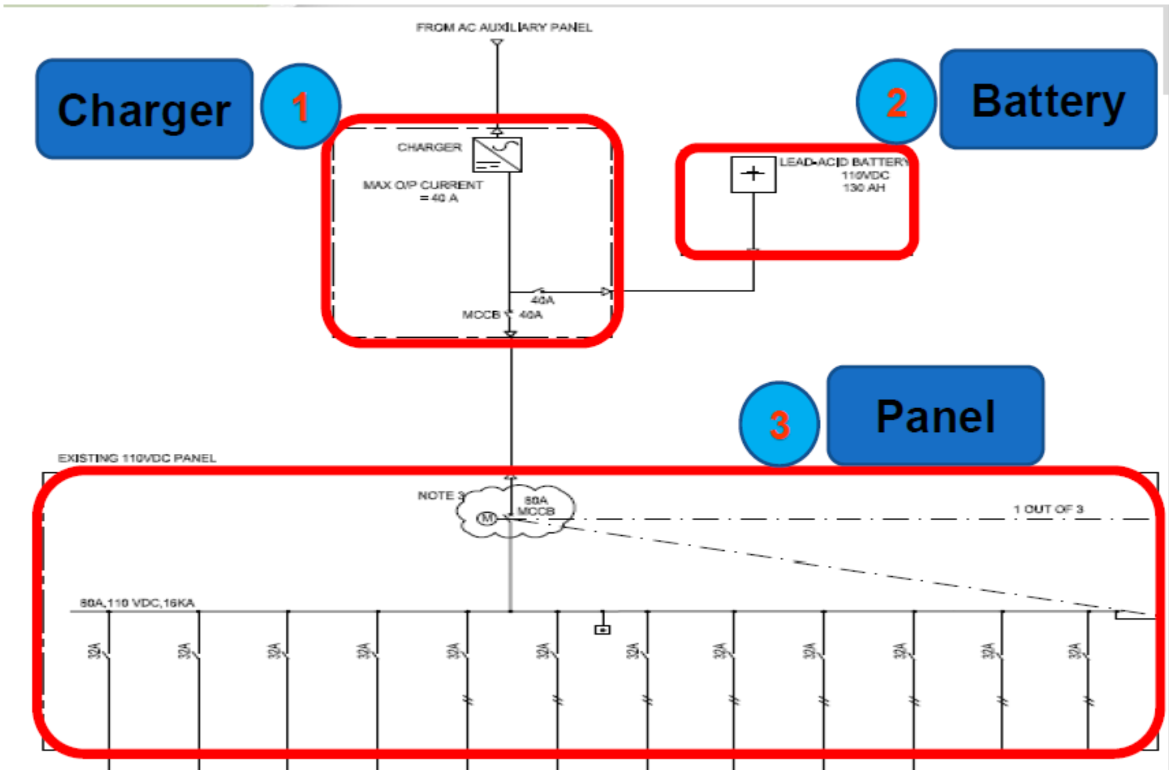


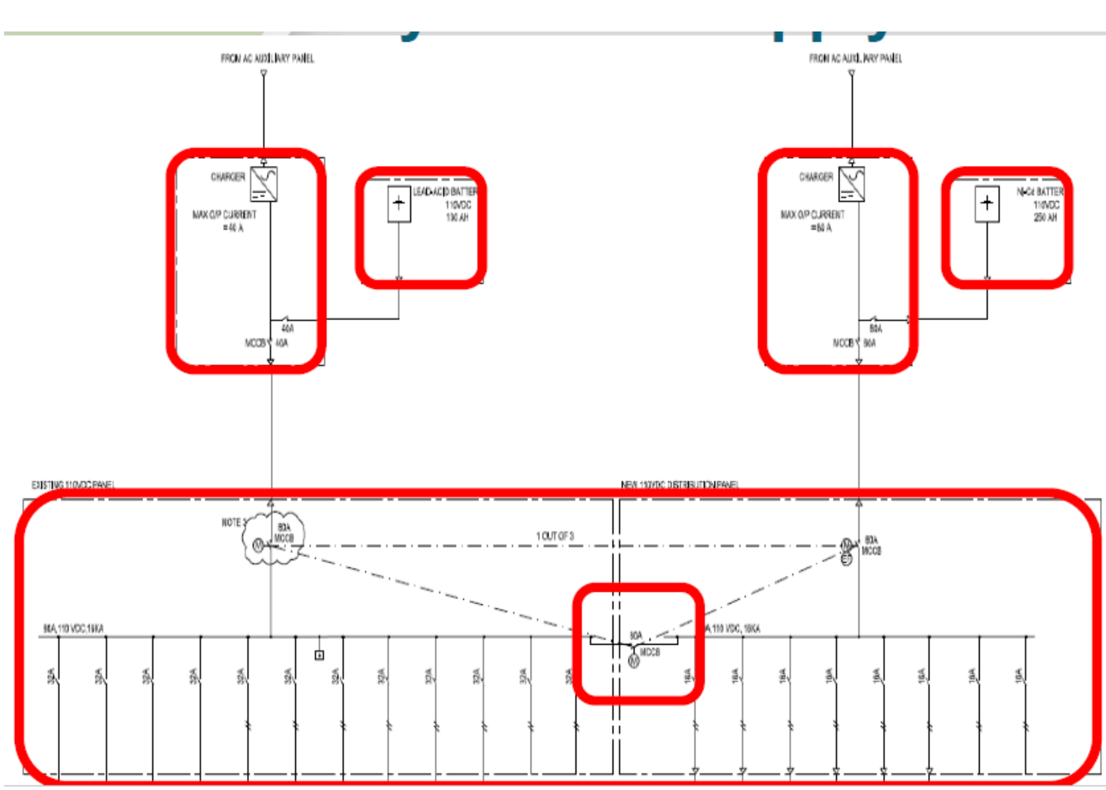
1- Relays
2- Circuit Breakers
3- Transducers (CTs & VTs)
4- Communication
5- Auxiliary Source (Battery)

Operation steps

- Transducers send signals about system
- Relay <u>Processes to determine (</u>Healthy or Fault)
- Relay <u>Action</u> sent to CB
- CB if fault happens it trips

2.3 Battery and DC supply





2.4 Circuit Breakers

1. Dead Tank (Oil CB)
2. Live Tank (SF6 CB -sulfur hexafluoride-)

2.4.1 Dead Tank

- This Tank is bonded to grounding grid
- CTs can be placed on both sides of CB
- These CTs are not stand alone they are attached to CB **Bushings**

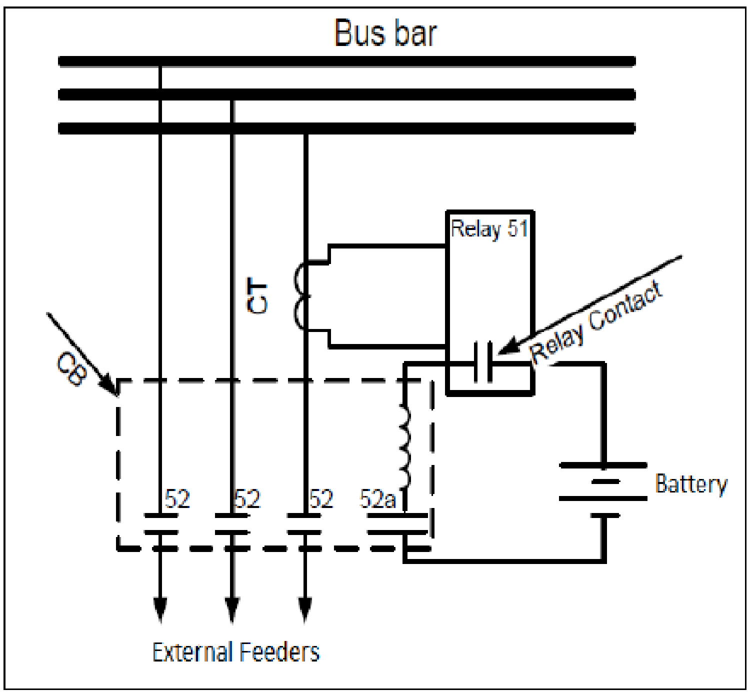
2.4.2 Live Tank

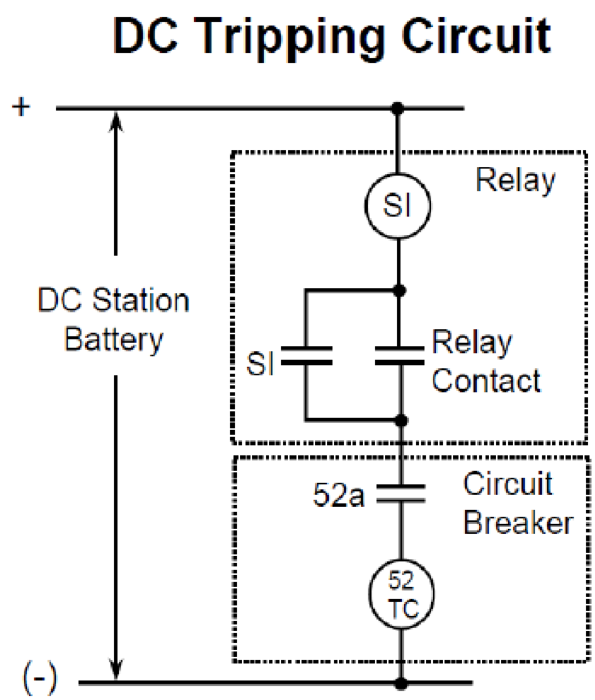
- This Tank is **not** bonded to grounding grid
- CTs are placed on one side of CB
- These CTs are stand alone

2.4.3 Voltage Classification

LV (< 1kV)	- Miniature CB (MCB) 125 V - Molded Case CB (MCCB) 2000 V - Air CB (ACB)
MV (1kV: 66kV)	- Vacuum CB (VCB) - SF6 CB
HV (> 66kV)	- SF6 CB - Oil CB (Dead tank, Live Tank)

2.5 DC Tripping Circuit





2.6 Nature of Relaying (Basic Objectives of System Protection)

Reliability	Assurance that the protection will **perform correctly**
Selectivity	**Maximum** continuity of service with **minimum** system disconnection
Speed of Operation	**Minimum fault duration** and consequent equipment damage and system instability
Simplicity	**Minimum protective equipment** and associated circuitry to achieve the protection objective
Economics	Maximum protection at **minimal total cost (3-5 % of total cost)**

2.6.1 Reliability

2.6.1.1 Dependability

the measure of the certainty that the relays will operate correctly for all the faults for which they are designed to operate

See Example Slide 1 P.17

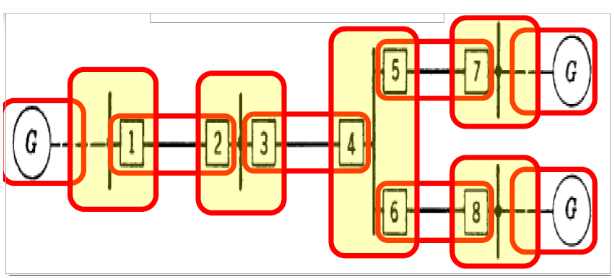
2.6.1.2 Security

the measure of the certainty that the relays will not operate incorrectly for any fault.

2.6.2 Selectivity (Protection Zones)

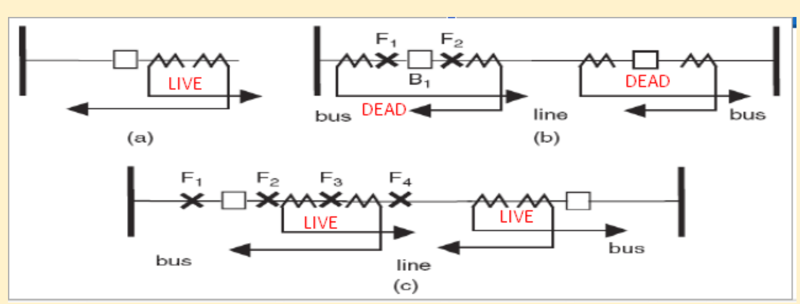
A protective zone is the **separate zone** which is established around each system element. Such as generators, transformers, lines, busbars, cables, capacitors … etc.

No part of the system is left unprotected. All power system elements must be included by at least one zone. Zones of protection must **overlap** to prevent any system element from being unprotected.



See Example S1/P.23

NOTE : Impact of CB tank type on protection Zone



2.6.3 Relay Speed

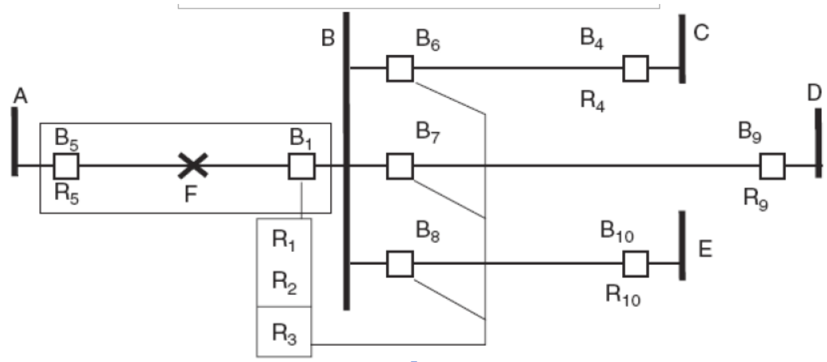
Instantaneous:	These relays operate as soon as a secure decision is made. No intentional time delay is introduced to slow down the relay response.
Time Delay :	An intentional time delay is inserted between the relay decision time and the initiation of the trip action.

2.6.4 Simplicity (Primary and Backup)

The main protection system for a given zone of protection is called the **primary protection**.

It is essential to clear the fault by some alternative protection system. These alternative protection systems are referred to as **duplicate**, **backup, Redundant** or **breaker-failure** protection systems.

Backup must be slower and it can be local backup or remote backup removed more elements



2.7 Relaying Performance

2.7.1 Correct

- At least one of the primary relays operated correctly,
- None of the backup relays operated to trip for the fault,
- The trouble area was properly isolated in the time expected.

Over many years and today close to 99% of all relay operations are correct.

2.7.2 Incorrect

- **misapplication of relays**
- **incorrect setting**
- **personnel errors,**
- **equipment problems** or failures
- (relays, breakers, CTs, VTs, station battery, wiring, pilot channel, auxiliaries, and so on).

2.7.3 No Conclusion

It refers to circumstances during which one or more relays have or appear to have operated, such as the CB tripping, but **no cause can be found**. No evidence of a power system fault or trouble, nor apparent failure of the equipment, can cause a frustrating situation.

2.8 Sheet 1

1. For the system in Figure 1, the fault at **F** produces these differing responses at various times

- R_1B_1 and R_2B_2 operate.
- R_1B_1, R_2, R_3B_3, and R_4B_4 operate.
- R_1B_1, R_2B_2 , and R_5B_5 operate.
- R_1B_1, R_5B_5, and R_6B_6 operate.

Analyze each of these responses for fault **F** and discuss the possible sequence of events that have led to these operations. Classify each response as being correct, incorrect, appropriate, or inappropriate. Note that 'correct-incorrect' classification refers to relay operation, whereas 'appropriate-in appropriate' classification refers to the desirability of that particular response from the point of view of the power system. Also determine whether there was a loss of dependability or a loss of security in each of these cases.

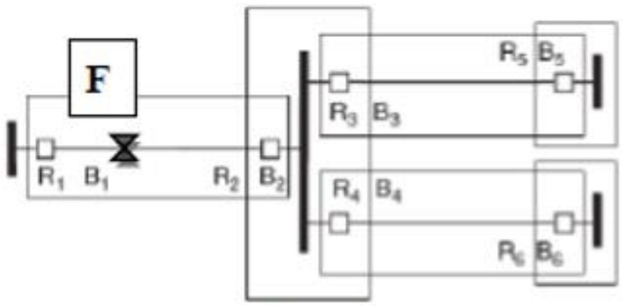


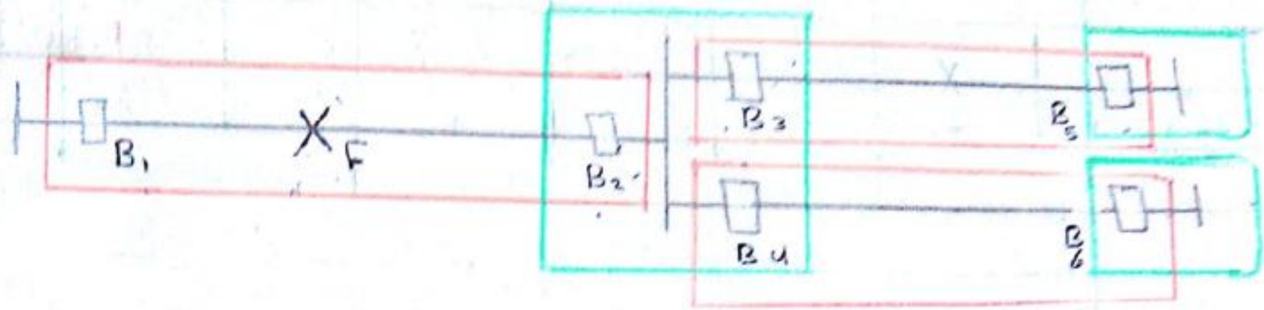
Fig. 1

- Correct
- aPPro Praite

لوال Primary مفصلش وال Puck up فصل
يفصل ال Primary فقط من ناحية ال
Power system أفضل حتى تكون minimum isolation Part.

- For F
  - B_1 and B_2 oPerate ∴ dePendable.
  - iF B_1 or B_2 doesn't oPerate
    ∴ This one is undePendable
  - B_1 and B_2 and B_3 oPerate
    ∴ un secure Beacuse of B_3 but dePendable

(1)



1) $R_1 B_1$, $R_2 B_2$
2) $R_1 B_1$, R_2 , $R_3 B_3$, R_4 B_4
3) $R_1 B_1$, $R_2 B_2$, $R_5 B_5$
4) R_1 B_1 , R_5 B_5 , R_6 B_6

Solution	correct	APP.	depend	secure
1	✓	✓	✓	✓
2	✓	X	X	✓
3	X	X	✓	X
4	✓	X	X	✓

2. In the system shown in Figure 2.a and 2.b, it is desired to achieve overlap between the zones of protection for the bus and the transmission line. Show how this may be achieved through the connection of CTs to appropriate protection systems.

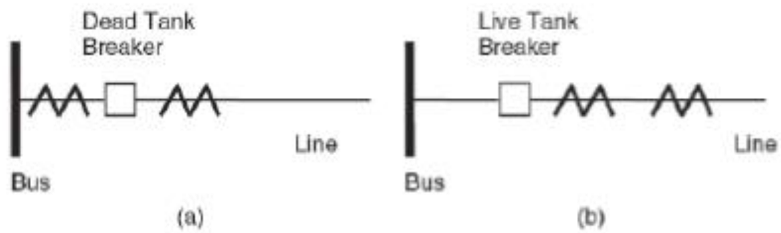
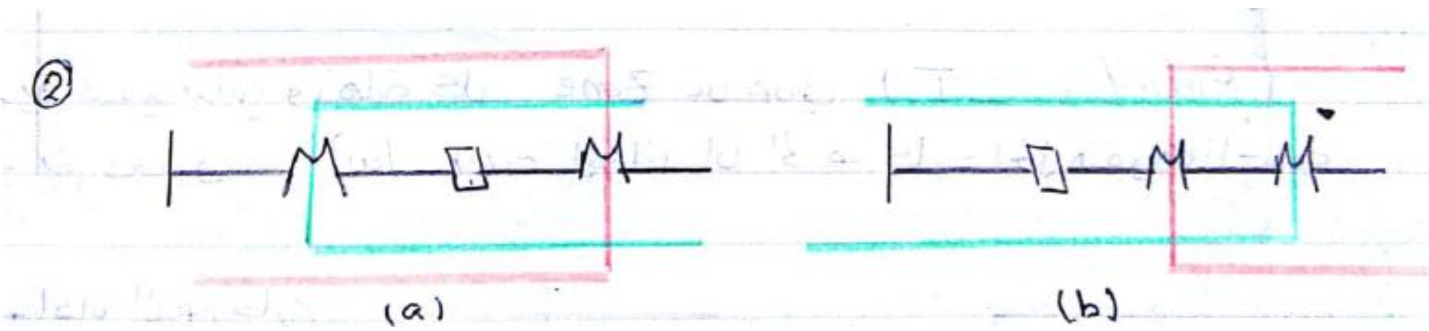


Fig. 2



3. In the part of the network shown in Figure 3, the minimum and the maximum operating times for each relay are 0.6 and 2.0 cycles (of the fundamental power system frequency), and each circuit breaker has the minimum and the maximum operating times of 2.0 and 6.0 cycles. Assume that a safety margin of 3 cycles between any primary protection and back-up protection is desirable. P_2 is the local backup for P_1, and P_3 is the remote backup. **Draw** a timing diagram to indicate the various times at which the associated relays and breakers must operate to provide a secure (coordinated) backup coverage for fault **F**.

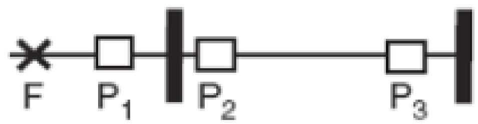
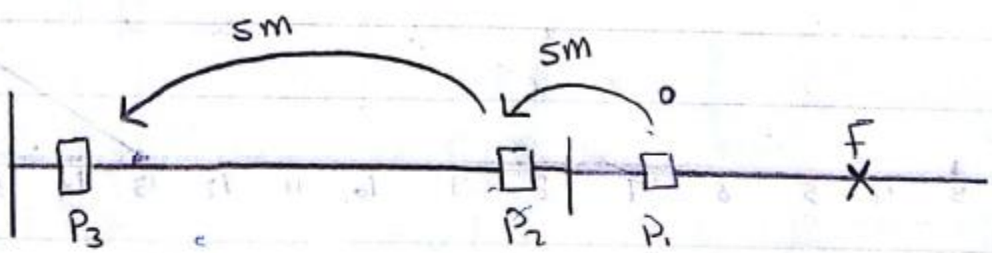


Fig. 3



. min and max operating time For Relay 0.6 – 2 cycle.

. " " " " For C.B 2 – 6 cycle.

. safety margin 2 cycle.

- Draw The timing Diagram For The Relay and C.B operation to Fault F ?

$R_1 = 1$ cycle $\quad B_1 = 2$ cycle

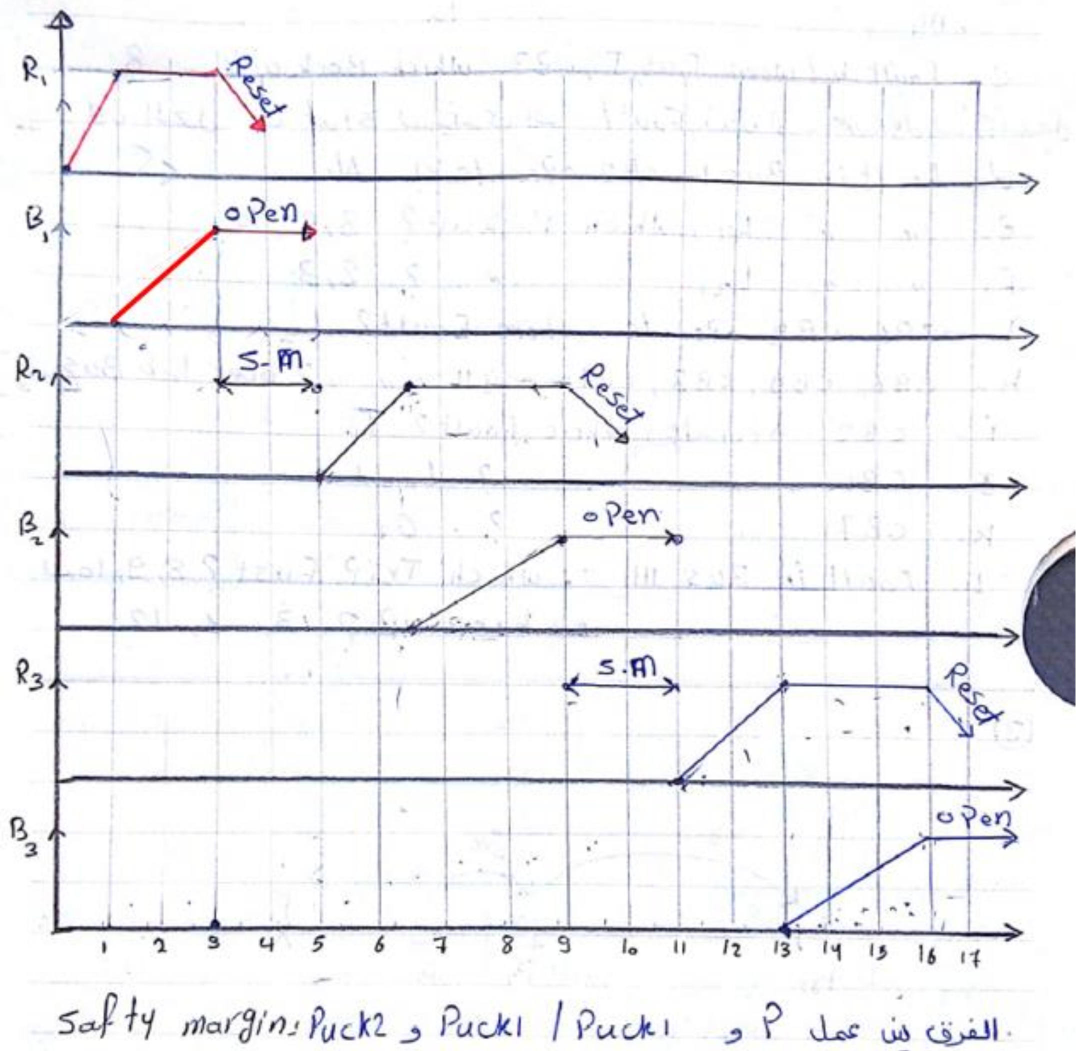
$R_2 = 1.5$ cycle $\quad B_2 = 2.5$ cycle انا اللي بفرضهم

$R_3 = 2$ cycle $\quad B_3 = 3$ cycle. ان لم يزكرو.

P_1 ال local Puck up $\leftarrow P_2$

P_1 ال Remote Puck up $\leftarrow P_3$

يوجد زمن s.m للتأكد من أن ا فشل وإن ال Fault في ال zone الخاصة بة.



الفرق بين عمل P و Puck1 / Puck1 و Puck2 :Safty margin.

* Relay عملية استقبال الاشارة تتم في زمن ≃ 0.6 وليس 0

Date

C.B يأخذ زمن لفتح الدائرة 6-2
حيث أنه عند مرور التيار يولد مجال يجذب Plunger .
كل فيزا لها 2-Pole واحدة ثابت والاخر متحرك عند الفتح بيكون فى
فرق جهد فتوصل حيث ان الجهد بيكسر العزل. not completely open
مادة العزل تستطيع أن تتغلب على الجهد فى زمن هذا الزمن هو زمن
التشغيل

4. **For the system shown in Figure 4, the following circuit breaker are known to operate. Assuming that all primary protection has worked correctly, where is the fault located in each of these cases?**

- **B_1 and B_3**
- **B_3, B_4, B_1, B_5, and B_7**
- **B_7 and B_8**
- **B_1, B_3, B_5 and B_7.**

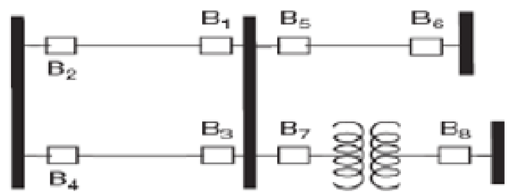
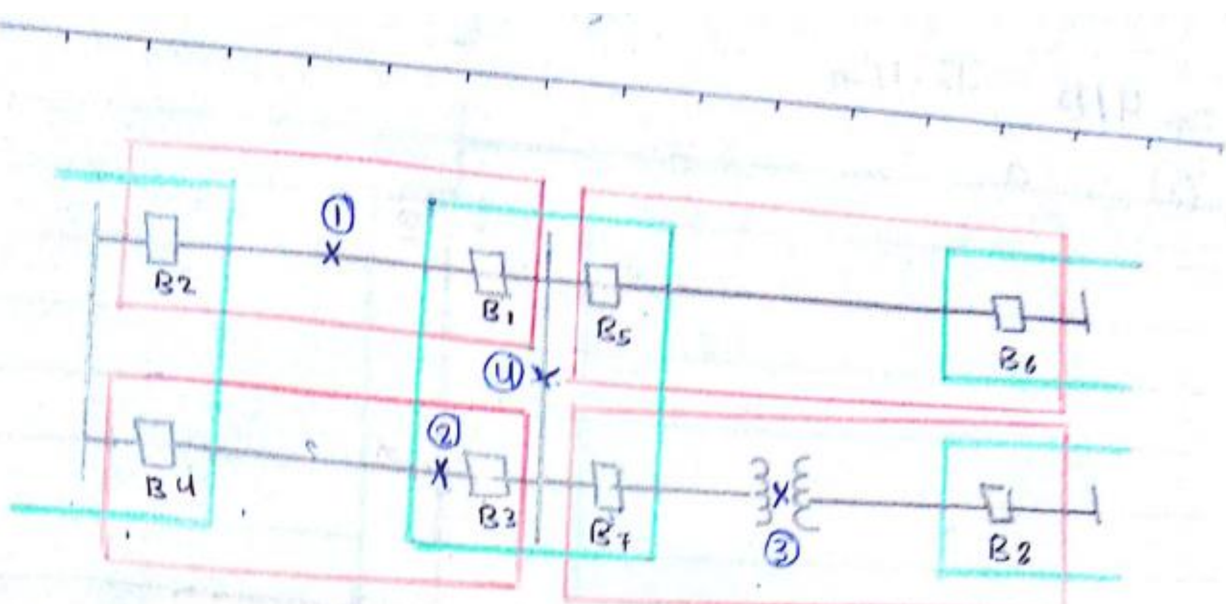


Fig. 4

(4)



1- B_1, B_2

2 - B_3, B_4, B_1, B_6, B_7

3- B_7, B_8

4- B_1, B_3, B_5, B_7

T.L

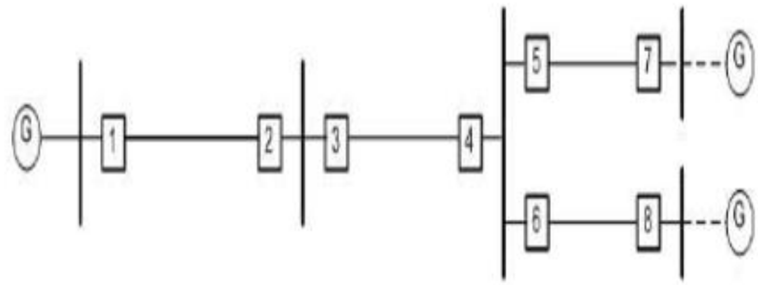
over Lap

Transformer

Bus bar

5. **The portion of a power system shown by the one-line diagram of the following figure, with generating sources back of all three ends, has conventional primary and backup relaying. In each of the listed cases, a short circuit has occurred and certain CBs have tripped as stated. Assume that the tripping of these breakers was correct under the circumstances. Where was the short circuit? Was there any failure of the protective relaying, including breakers, and if so, what failed? Draw a sketch showing the overlapping of primary protective zones and the exact locations of the various faults.**

Case	Breakers tripped
A	4, 5, 8
B	3, 7, 8
C	3, 4, 5, 6
D	1, 4, 5, 6
E	4, 5, 7, 8
F	4, 5, 6



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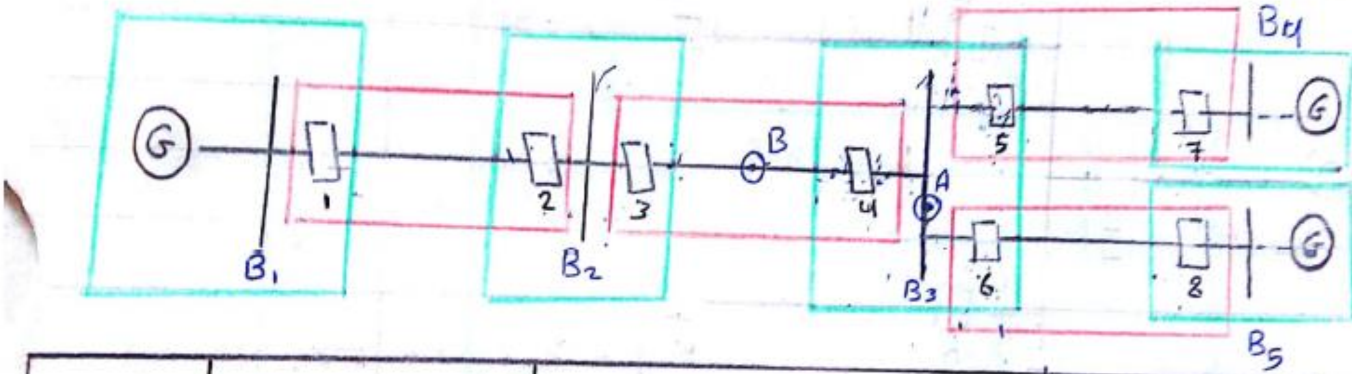


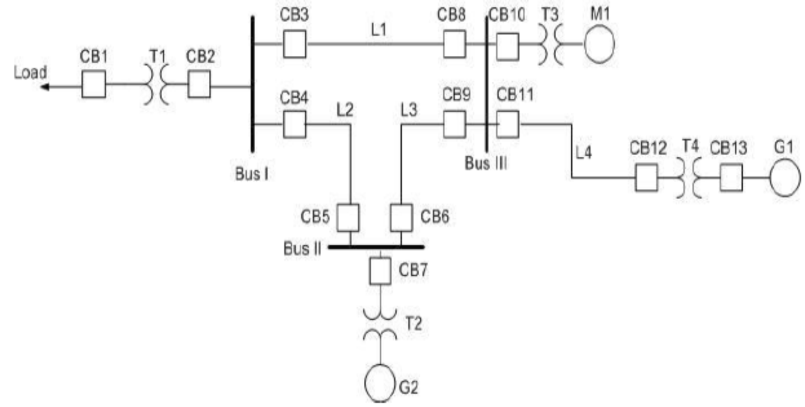
Case	Breakers. Tripped	Fault	Failed
A	4, 5, 8	Bus 3	6
B	3, 7, 8	over lap ($T.L_2$, B_3)	4, 5, 6
C	3, 4, 5, 6	〃	no Fail
D	1, 4, 5, 6 ?	〃	2, 3
E	4, 5, 7, 8 قبل	over lap ($T.L_3$, B_3)	6
F	4, 5, 6	bus 3	no Fail

6.

a. Circle the zones of protection for the following power system?

b. State which CBS trip for a fault at :

- L_1
- Bus II
- Bus III
- G_2
- T_4
- Load
- M_1



c. For a fault on Bus I and CB_3 fails which CB operate as backup.

d. Does CB_2 need to operate for a Bus I fault ?

e. For a fault on L_4 which CBs backup CB_{11} ?

f. For a fault on L_2 which CBs backup CB_4 ?

g. CB_6 and CB_9 trip, where was the fault ?

h. CB_6, CB_9, CB_8, CB_{10}, and CB_{11} trip, where was the fault ?

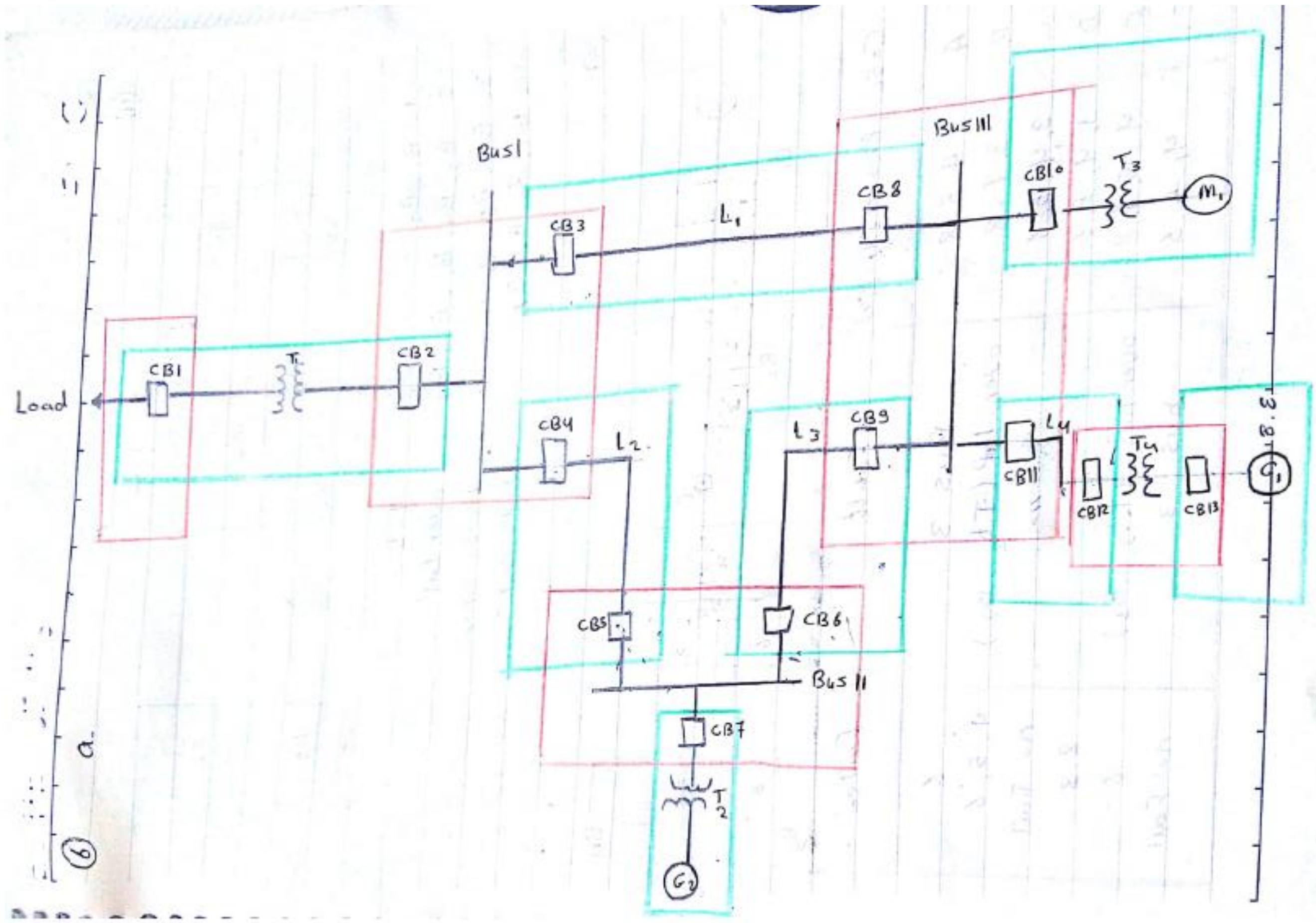
i. CB_2 trips, where was the fault ?

j. CB_1 trips, where was the fault ?

k. CB_7 trips, where was the fault ?

l. For a fault on Bus III, which CBs:

- Trip first.
- If the ones which should trip first don't. Which ones should trip next.


Bus I
Bus III
CB10
T_3
M_1
CB8
L_1
CB3
CB1
T_1
CB2
Load
CB4
L_2
L_3
CB9
L_4
CB11
T_4
CB12
CB13
G_1
CB5
CB6
Bus II
CB7
T_2
G_2

b- • L_1 — 3, 8

• Bus II — 5, 6, 7

• Bus III — 8, 9, 10, 11

• G_2 — 7

• T_4 — 12, 13

• Load — 1

• M_1 — 10

c- Fault between Bus. I, CB3 which Back up?! 8

لو الحل static لا يفرق الـ Fault لكن لو dynamic لـ 3 يفصل كذ

d- Fault in Bus I, CB2 operate?! No

e- " " L_4, which Backup? 8, 9, 10

f- " " L_2, " " ? 2, 3

g- CB6, CB9 operate, where Fault? L_3

h- CB6, CB9, CB8, CB10, CB11, " " ? over lab Bus_{III}, L_3

i- CB2 operate, where Fault? T_1

j- CB1 " " ? Load

k- CB7 " " ? G_2

L- Fault in Bus III • which Trip First? 8, 9, 10, 11

• back up? 3, 6, 12

3 RELAY OPERATING PRINCIPLES

3.1 Methods of Fault Detection

1. Level detection.
2. Current in abnormal path.
3. Current balance. (Differential)
4. Phase angle comparison. (Directional)
5. Change of parameters (Distance relay).
6. Harmonic content.
7. Frequency sensing.
8. Buchholz relay.
9. Non-electrical quantities.

3.1.1 Level detection

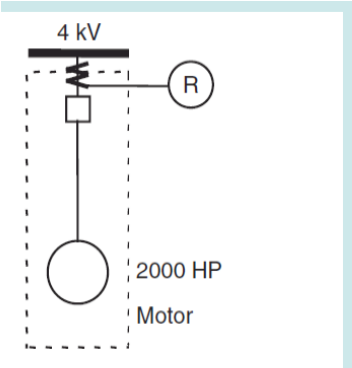
3.1.1.1 Current magnitude

This method is based on that: "**fault current** magnitudes are almost always **greater than** the **normal** load **currents** that exist in a power system"

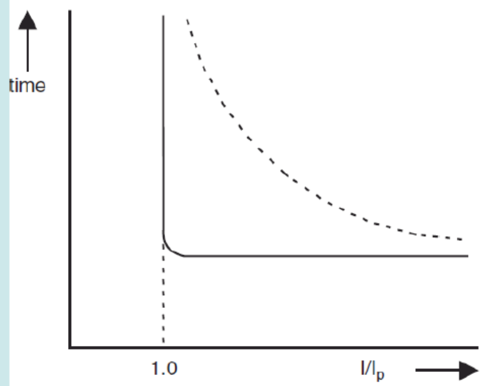
$$I_{fault} < I_{set} \rightarrow Relay\ won't\ trip$$
$$I_{fault} > I_{set} \rightarrow Relay\ will\ trip$$

$$I_{FL}$$
$$I_{Max} = overload\ \% * I_{fl}$$

$$I_{set} \geq k\, I_{Max} \ : (K = 1.25 \sim 2\ )$$



Overcurrent protection of a motor



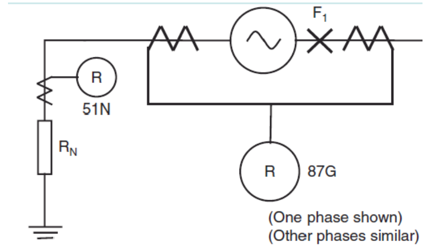
Characteristic of a level detector relay

3.1.1.2 Voltage magnitude (27)

$$V_{set} \leq 0.85\, V\_rated$$

3.1.2 Current in abnormal path

In balanced system, neutral wire carries a zero current. So **any current in neutral due to fault or abnormal conditions can be detected**. According to the unbalance in the system, setting value is selected to be a threshold for this abnormal condition**. 10% of full-load current** is recommended value for most systems.



3.1.3 Current balance (Differential comparison)

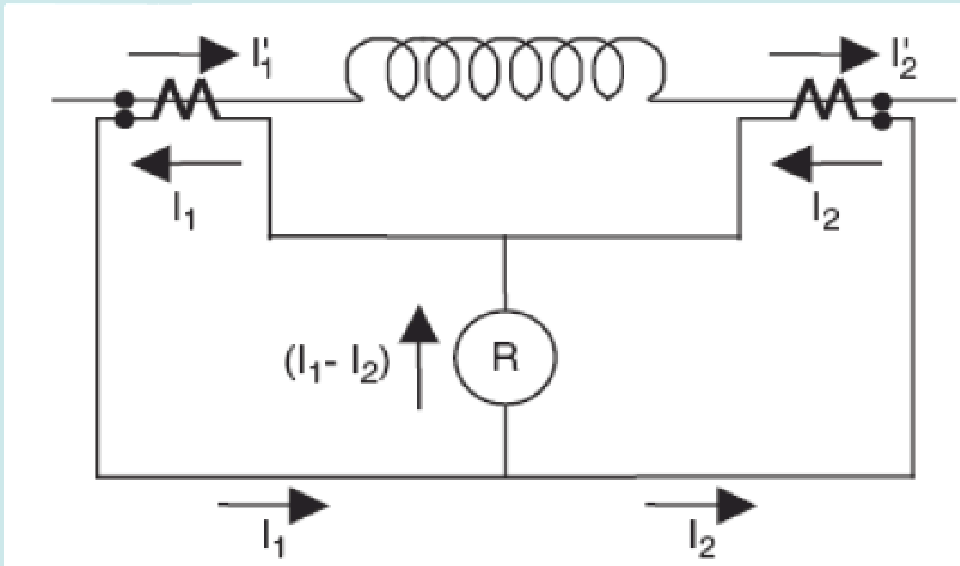
3.1.3.1 *Current Differential comparison principle applied to a generator winding*

Healthy or External Fault:

$I_1 = I_2$

Internal Fault:

$I_1 \neq I_2$



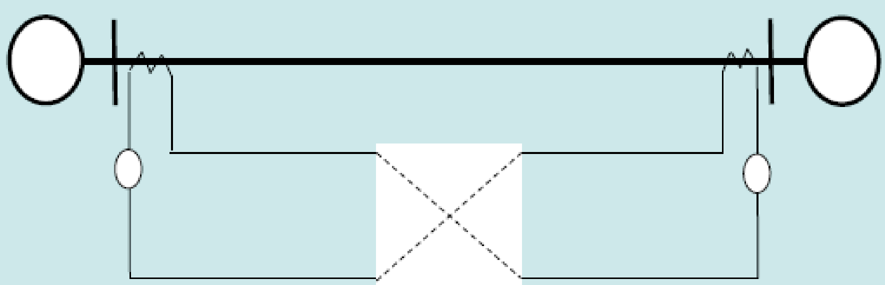
3.1.3.2 *Voltage differential comparison principle applied to a feeder circuit*

Healthy or External Fault:

$V_1 = V_2$

Internal Fault:

$V_1 \neq V_2$

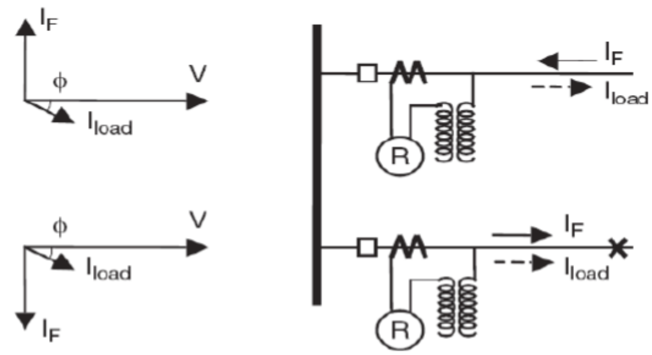


3.1.4 Phase angle comparison (Power +Direction) (Directional)

Phase angle comparison is commonly used to determine the direction of a current with respect to a reference quantity.

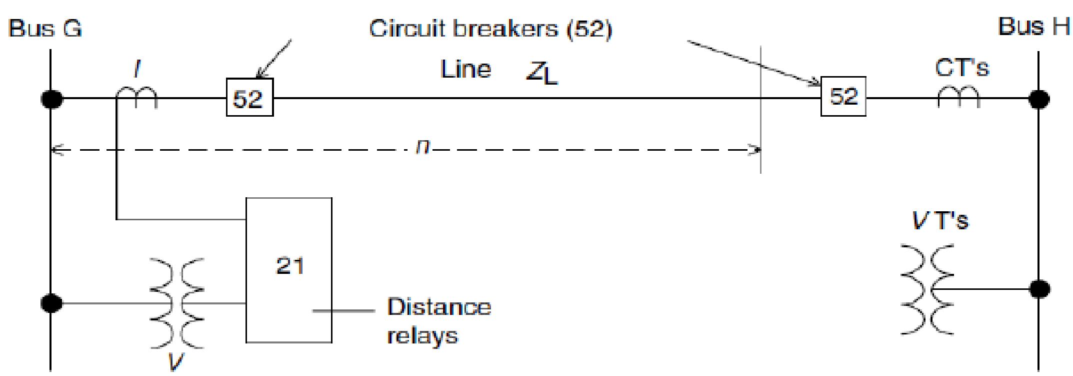
For normal power flow the phase angle between the voltage and the current will be approx.= **±Φ.**

When power flows in the opposite direction, this angle will become (180 ± Φ).



3.1.5 Change of parameters (Distance relay)

The distance relay compares the local current with the local voltage. This, in effect, is **a measurement of the impedance** of the line as seen from the relay terminal. An impedance relay relies on the fact that the **length** of the line (i.e. its distance) for a given conductor diameter and spacing determines its impedance.



$$Z_R \geq \ Z_{set}\ Healthy$$
$$Z_R < Z_{set}\ \ i\ increase\ due\ to\ Fault$$
$$Z_{set} = k\ Z_{line} \quad : \ (\, k < 1\,)$$
$$from\ Z_R\ we\ can\ determine\ fault\ distance$$

3.1.6 Harmonic Content

Harmonics may occur during abnormal system conditions, such as
the **odd harmonics** associated with **transformer saturation**,
or transient components caused by the **energization of transformers**.

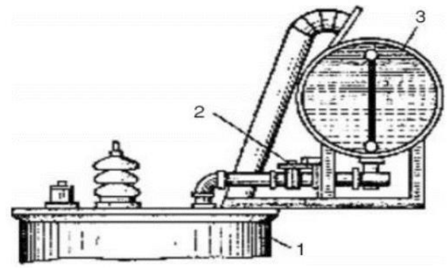
These abnormal conditions can be detected by sensing the harmonic content through **filters** in electromechanical or solid-state relays, or by **calculation** in digital relays.

3.1.7 Frequency sensing

Normal power system operation is at 50 or 60 Hz. Any deviation from these values indicates that a problem exists. Frequency-sensing relays may be used to take corrective actions which will bring the system frequency back to normal.

3.1.8 Buchholz relay

Mounting of a Buchholz relay on a power oil-filled transformer.

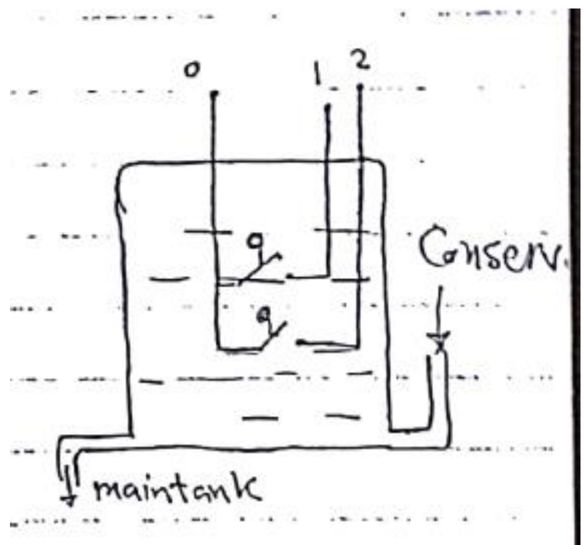


1 – Transformer tank;

2 – Buchholz relay;

3 – oil expansion tank (conservator).

0-1 alarm
0-2 Trip



3.1.9 Non-electrical quantities

3.2 Relay Designs

1. Electromechanical relays
2. Solid-State relays
3. Digital relays

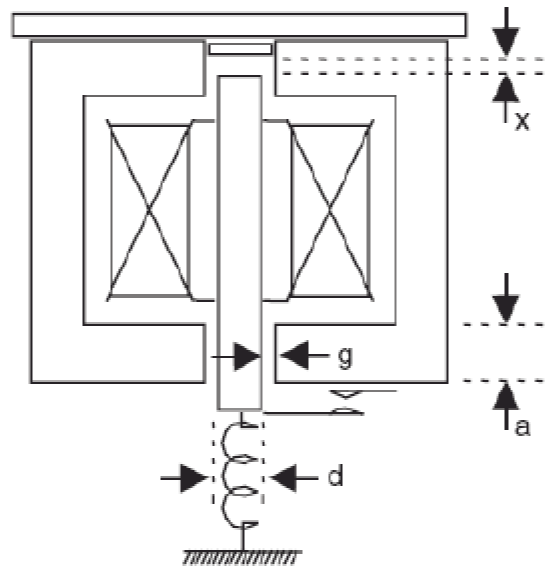
3.2.1 Electromechanical relays

The actuating forces were created by a combination of the

input signals, stored energy in **springs** and **dashpots**.

Electromechanical	
Magnetic **Attraction**	Magnetic **Induction**
1. Plunger (solenoid) 2. attracted armature 3. Balanced beam	1. Induction disc 2. Induction cup
The plunger-type relays are usually driven by a **single** actuating quantity,	the induction-type relays may be activated by **single or multiple** inputs.

3.2.1.1 Plunger-type relays (MAGNETIC)



With no current in the coil, the plunger is held partially outside the coil by the force **Fs** produced by a spring.

Let x be the position of the plunger tip inside the upper opening of the coil.

When the coil is energized by a current i, the energy W(λ, i) and the co-energy W'(i, x) stored in the magnetic field are given by:

$$W(\lambda, i) = W'(i, x) = \frac{1}{2}Li^2$$

$$L = \frac{\mu_0 \pi d^2 N^2}{4\left(x + \frac{gd}{4a}\right)}$$

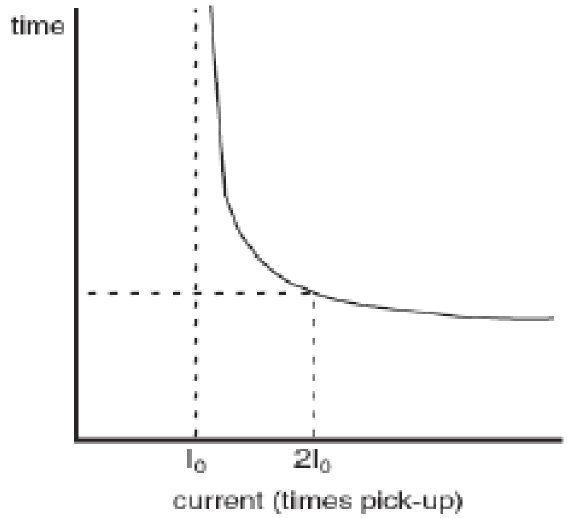
The force which tries to pull the plunger inside the coil is given by:

$$F_m = \frac{\partial}{\partial x}W'(i, x) = K\frac{i^2}{\left(x + \frac{gd}{4a}\right)^2}$$

The plunger moves when Fm exceeds Fs.

The value of the current **(Ip)** at which the plunger just begins to move – known as **the pickup setting of the relay** – is given by:

$$I_p = \sqrt{\frac{F_S}{K}} \times \left(x_o + \frac{gd}{4a}\right)$$

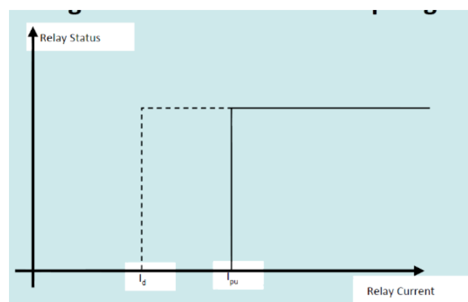


The general shape of the relay C/C, i.e. its operating time plotted as a function of the current through the coil.

The plunger travels some distance,

from x0 to x1, before it closes its contacts and hits a stop**.**

The energizing current must drop below a value I_d, known as the **dropout current,** before the plunger can return to its original position x_o.



Plunger-type Relay hysteresis C/C

$$I_d = \sqrt{\frac{F_S}{K}} \times \left(x_1 + \frac{gd}{4a}\right)$$

3.2.1.1.1 Applications of plunger type relays:

- They can be used **in ac and dc circuits**, because their torque is proportional to I2.

- They **are fast relaying**. They have fast operation and fast reset because of small length of the travel and light moving parts.

- They are described as **instantaneous**. Their operating time does not vary with current. *-Note*

- **High operating speeds** are possible. One modern relay has **0.5 msec** of operating time.

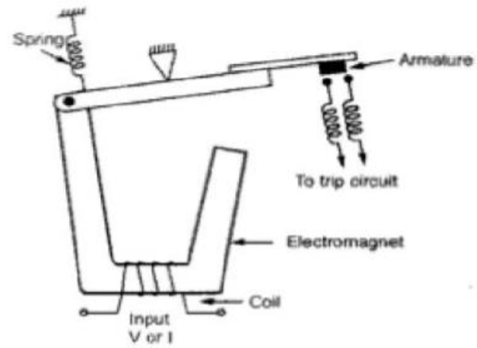
NOTE : Slow operation can be obtained by delaying in building up or decreasing of flux in magnetic circuit by fitting copper around the

3.2.1.2 Attracted Armature-type relays (MAGNETIC)

There are two types of structure available for attracted armature type relay which are;
1- hinged armature type **2- polarized moving iron type.**

In attracted armature type, there exists a laminated electromagnet which carries a coil. The **coil** is energized **by the operating quantity** which is proportional to the circuit voltage or current. The armature or a **moving iron** is subjected to the magnetic force produced by the **operating quantity**.

NOTE : The force produced is proportional to the square current hence these relays can be used for ac as well as dc.



Error! Use the Home tab to apply 0 to the text that you want to appear here. – 1Hinged Armature type Relay

- The minimum current at which the armature gets attracted to close the trip circuit is called **pickup current.**

- Generally, the **number of tapings** is provided on the relay coil with which its turns can be as per the requirement. This is used to **adjust the set value** of an operating quantity at which relay should operate.

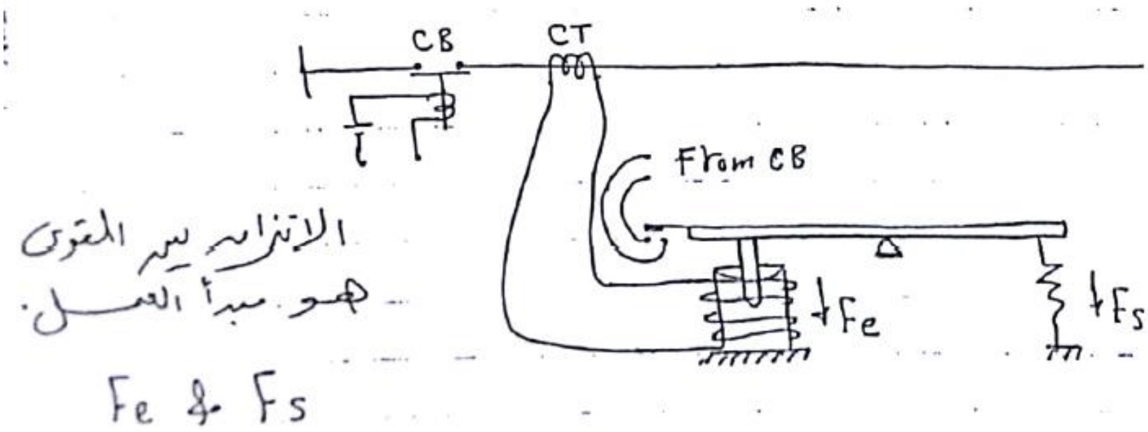
- An important advantage of such relays is their **high operating speed**. In modern relays an operating time as small as **0.5 msec** is possible.

$$F_e = K_e i^2$$
$$F_s = K_s$$
$$F_e > F_s \Rightarrow Trip$$
$$K_e i^2 = K_s$$
$$I_{set} = \sqrt{\frac{K_s}{K_e}}$$

Also suffers from Hysterisis so it has a dropout current

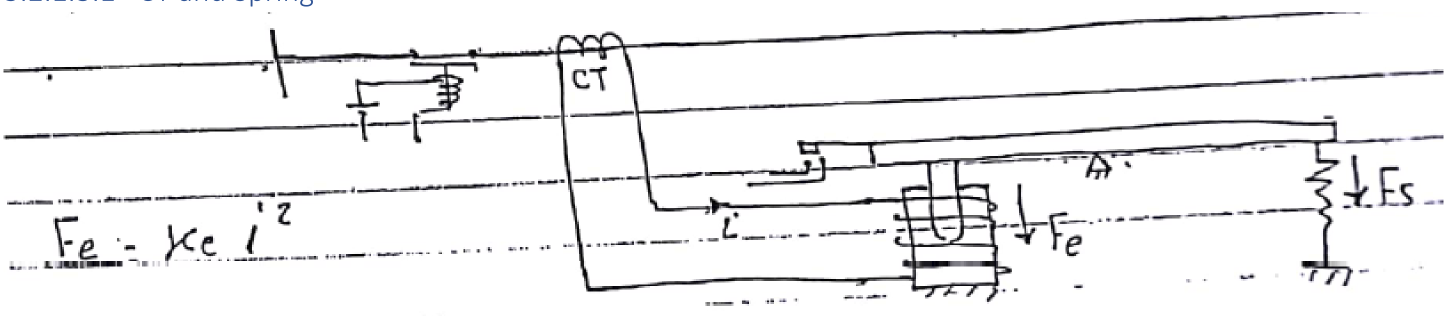
$$Pickup\ ratio = \frac{I_{dropout(reset)}}{I_{set}}$$

3.2.1.3 Balanced Beam

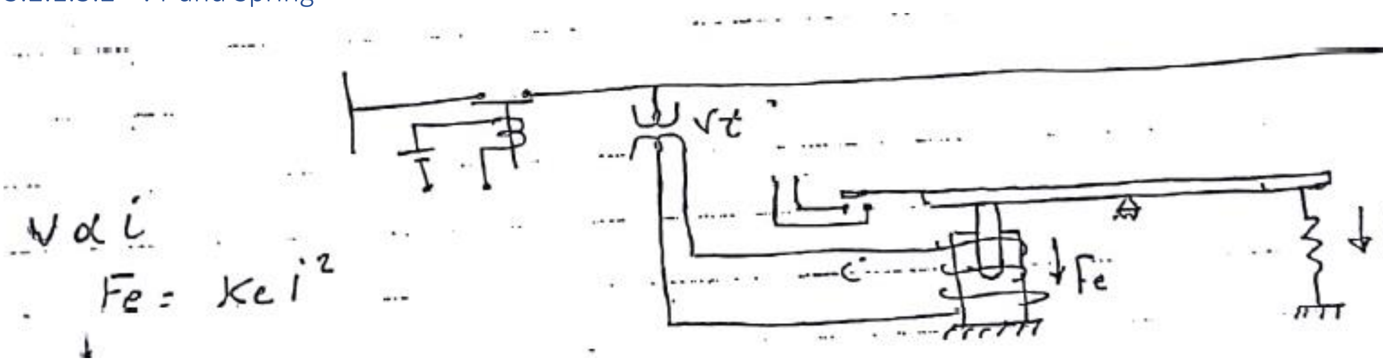


Has many shapes

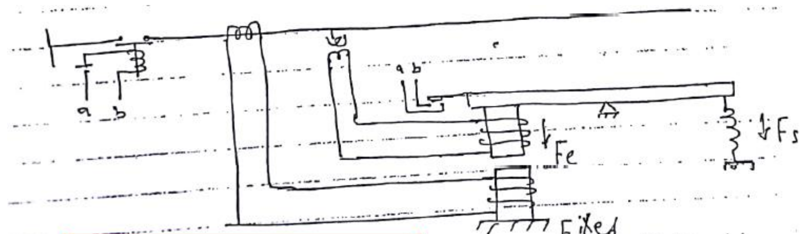
3.2.1.3.1 CT and Spring



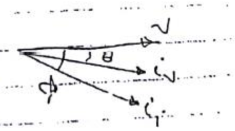
3.2.1.3.2 VT and Spring



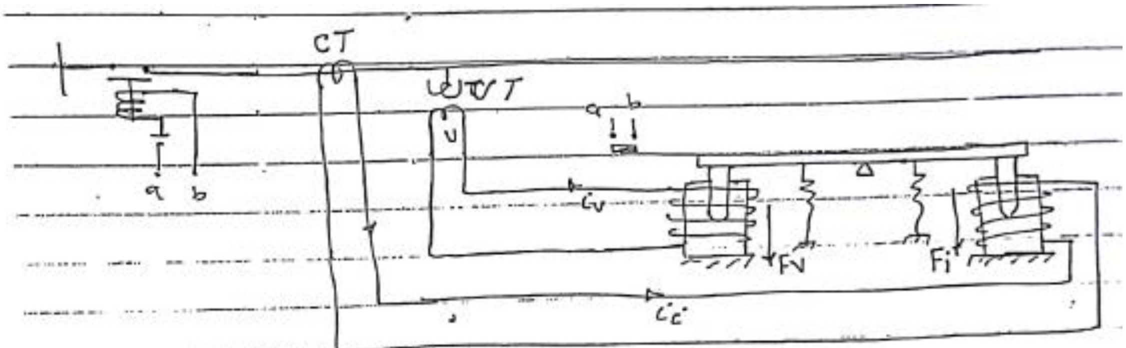
3.2.1.3.3 Watt element and Spring



$$\boxed{Fe = k\, v\, i \cos(\phi - \theta)}$$



3.2.1.3.4 VT and CT



$F_i = k_i i^2$ & $F_v = k_v v^2$ $\qquad v \propto i_v$

at balanced $\quad k_i i^2 = k_v v^2$

$$\frac{v}{i} = \sqrt{\frac{k_i}{k_v}} \qquad \boxed{\underline{\underline{Z\ set}} = k\sqrt{\frac{k_i}{k_v}}} \qquad k \leq 1$$

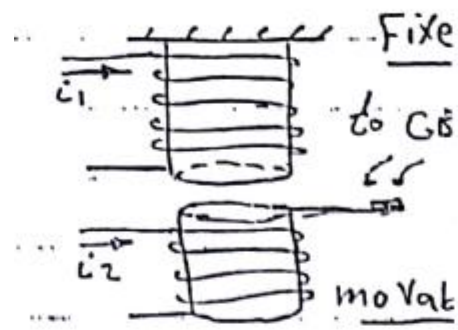
قل ZR عن Zset تلامس a,b $\leftarrow \uparrow i \leftarrow$ S.C

$$|Z| = \sqrt{R^2 + X^2}$$

Mho Relay $\qquad$ off set Mho Relay $\qquad$ Plane Impedance Relay

$Z = 0$

3.2.1.4 Mutually Interface coils

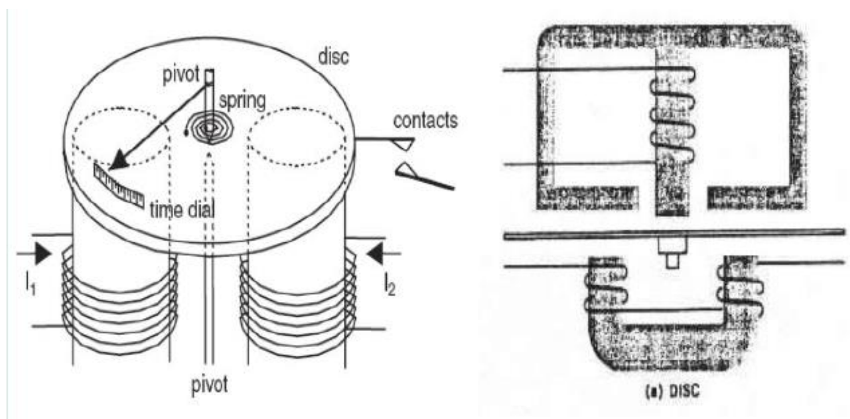


$$F_e = K_e \, i_1 i_2 \cos\theta$$

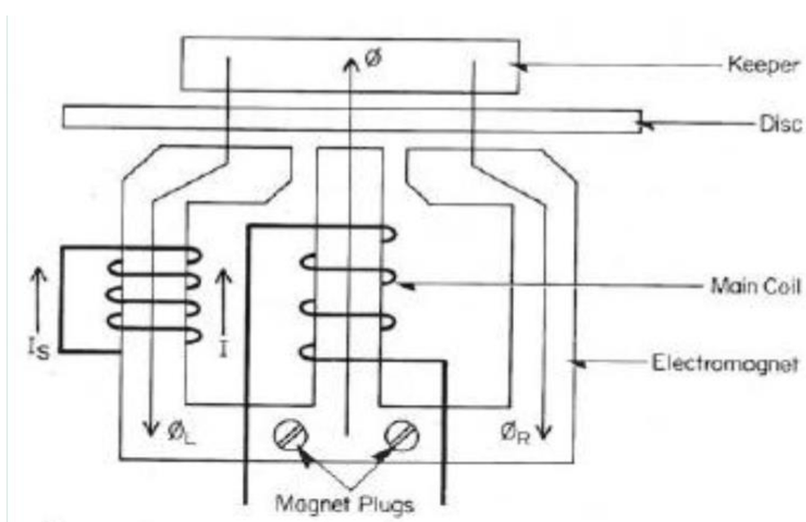
Two coils in series → overcurrent Relay

3.2.1.5 Induction-type relays (INDUCTION)

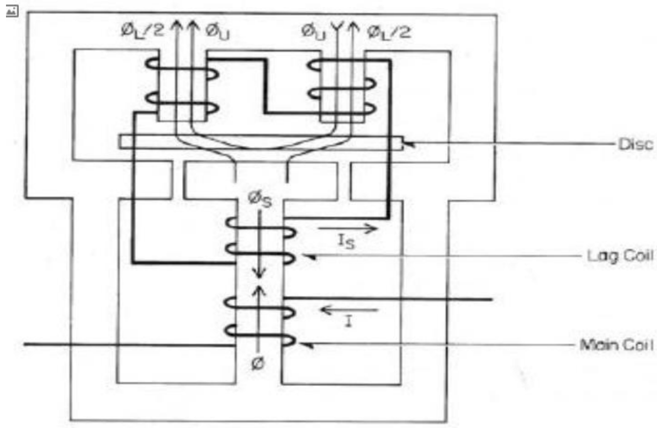
- These relays are based upon the **principle** of operation of a **single-phase AC motor**.
- As such, they cannot be used for DC currents.
- Two variants of these relays are fairly standard: one with an **induction disc** and the other with an **induction cup.**



Error! Use the Home tab to apply 0 to the text that you want to appear here.—2Principle of construction of an induction **disc** relay. Shaded poles and damping magnets are omitted for clarity



(a) The "E" Unit



(b) The "OA" Unit

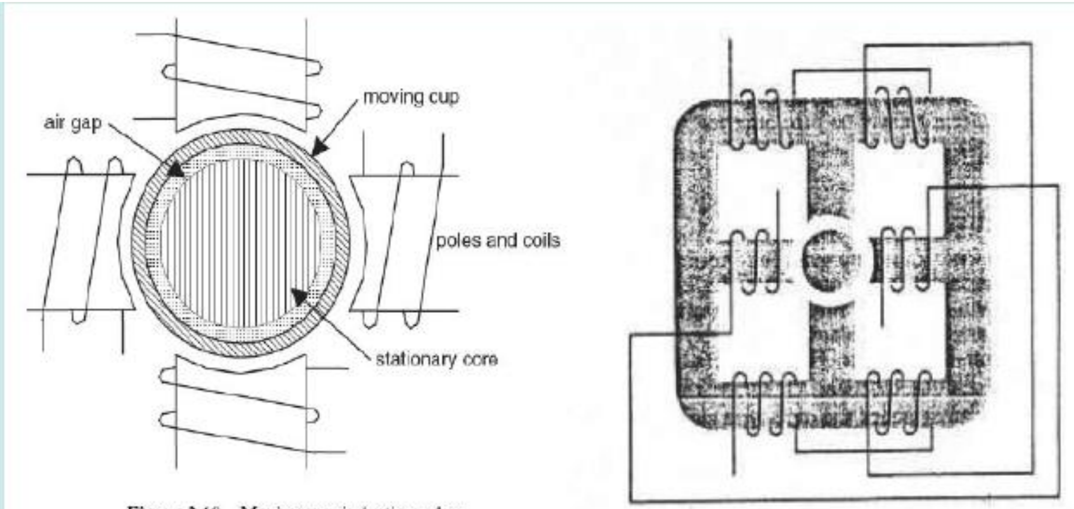


Figure 2.10 Moving cup induction relay

(b) CUP

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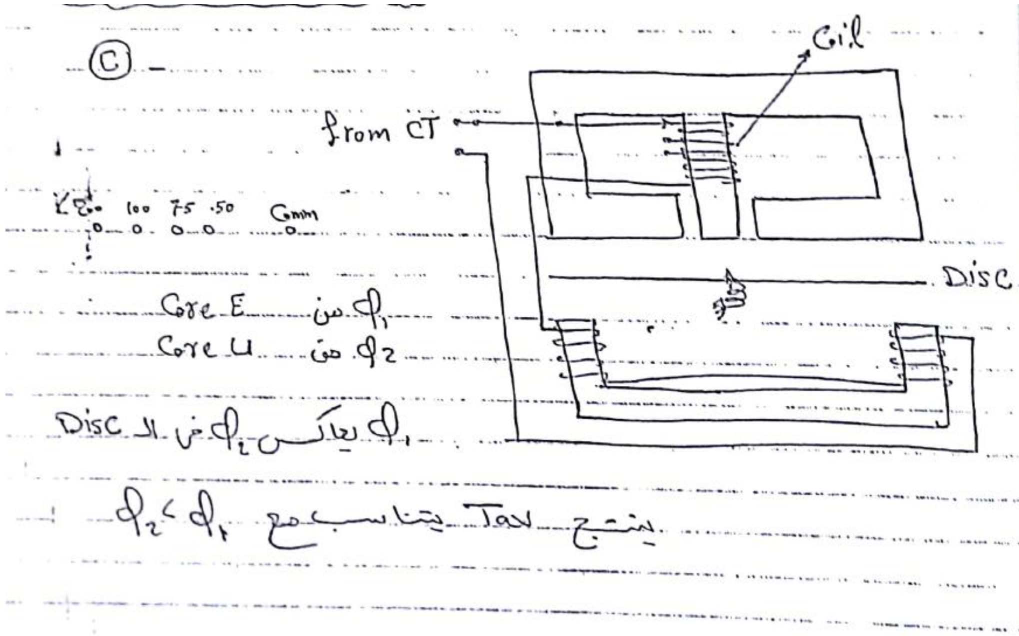
3.2.1.5.1 One coil relay

One coil and shape pole

3.2.1.5.2 U , E



3.2.1.5.3 Two Coils and Disc

Induction-type relays require **two sources of alternating magnetic flux** in which the moving element may turn.

- The two fluxes must have a **phase difference between them**; *otherwise, no operating torque is produced.*
- **Shading rings** mounted on pole faces may be used to provide one of the two fluxes to produce motor action.
- In addition to these two sources of magnetic flux, other sources of magnetic flux – such as permanent magnets – may be used to provide special **damping** characteristics.

Let us assume that the two currents in the coils of the relay, i1 and i2, are sinusoidal:

$$i_1(t) = I_{m1} cos\omega t \qquad \& \qquad i_2(t) = I_{m2}\cos(\omega t + \theta)$$

If $\boldsymbol{L_m}$ is the mutual inductance between each of the coils and the rotor, each current produces a flux linkage with the rotor given by:

$$\lambda_1(t) = L_m I_{m1}\cos\omega t \qquad \& \qquad \lambda_2(t) = L_m I_{m2}\cos(\omega t + \theta)$$

Each of these flux linkages in turn induces a voltage in the rotor, and since the rotor is a metallic structure with low self-inductance, a rotor current in phase with the induced voltages flows in the rotor.

Assuming the equivalent rotor resistance to be $\boldsymbol{R_r}$**,** the induced rotor currents are given by

$$i_{r_1}(t) = \frac{1}{R_r}\frac{d\lambda_1}{dt} = -\frac{\omega L_m I_{m1}}{R_r}\sin\omega t$$

$$i_{r_2}(t) = \frac{1}{R_r}\frac{d\lambda_2}{dt} = -\frac{\omega L_m I_{m2}}{R_r}\sin \omega t + \theta$$

• Each of the **<u>rotor currents interacts with the flux</u>** produced by the other coil, producing a force.

• The two forces are in **opposite directions** with respect to each other, and the **net force**, or, what amounts to the same thing, the **net torque τ**, is given by

$$\tau \propto (\lambda_1 i_{r2} - \lambda_2 i_{r1})$$

Substituting for the flux linkages and the rotor currents, and absorbing all the constants in a new constant K, we can write

$$\tau = K I_{m1} I_{m2}[\cos \omega t\ \sin(\omega t + \theta) - \cos(\omega t + \theta) \sin \omega t\ ]$$

$$\boldsymbol{\tau = K\ I_{m1} I_{m2}\ sin\theta}$$

3.2.2 Solid-state relays

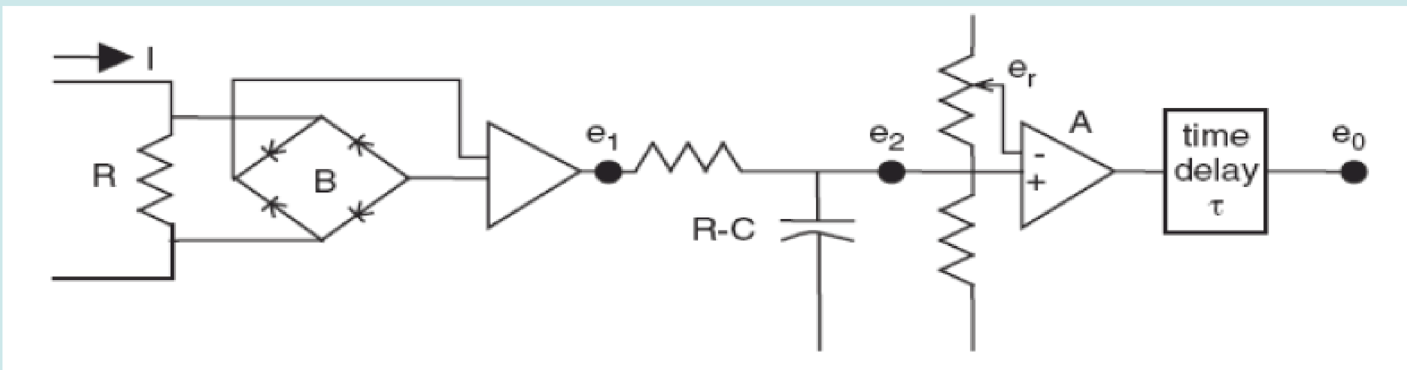
- Solid-state relays are **designed**, **assembled** and **tested** <u>**as a system**</u>. This puts the overall **responsibility** for proper operation of the relays on the **manufacturer**.

- In many cases, especially when special <u>equipment</u> or <u>expertise</u> <u>for assembly</u> and wiring is required, this results in more <u>reliable equipment at a lower cost.</u>

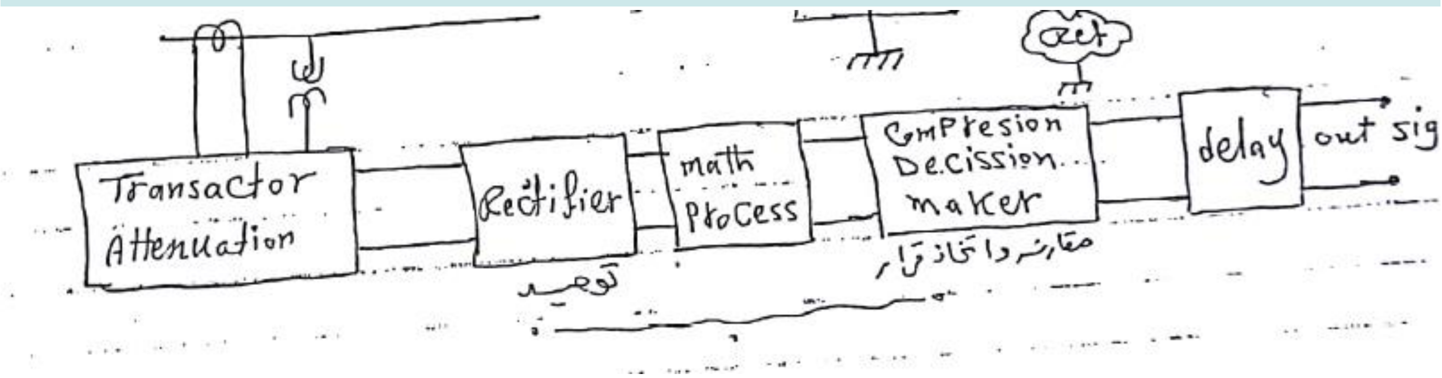
- Solid-state relay circuits may be divided <u>into two categories</u>:
<u>analog</u> circuits and <u>digital</u> logic circuits.

- There is a **great variety** of circuit arrangements which would produce a desired relaying characteristic.

- It is impossible, and perhaps unnecessary, to go over relay circuit design practices that are currently in use.



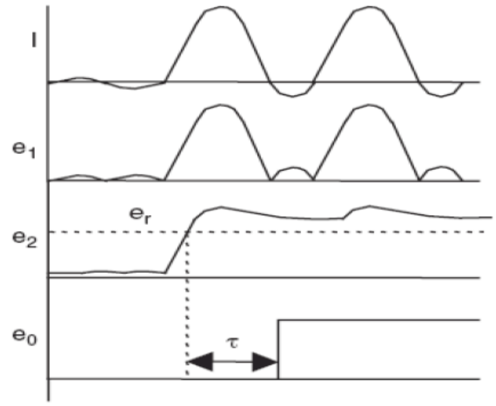
Possible circuit configuration for a solid-state instantaneous overcurrent relay



1. The input current I is passed through the resistive shunt R, full-wave rectified by the bridge rectifier B, filtered to remove the ripple by the R–C filter and applied to a high-gain summing amplifier A.

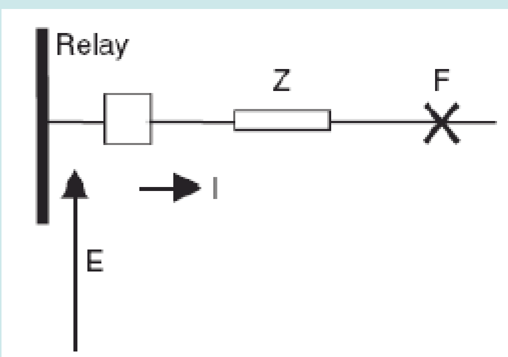
2. The other input of the summing amplifier is supplied with an adjustable reference voltage $\boldsymbol{e_r}$.

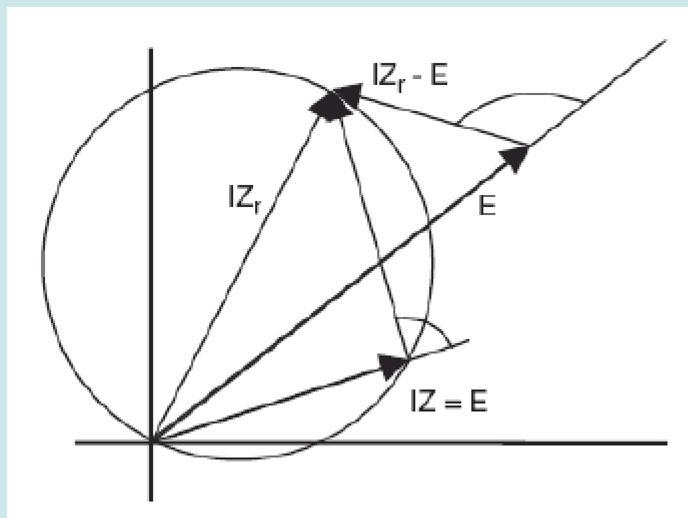
3. When the input on the positive input of the summing amplifier **exceeds** the reference setting, the **amplifier <u>output goes high</u>**, and this step change is delayed by a time-delay circuit, in order to provide immunity against spurious transient signals in the input circuit.



Error! Use the Home tab to apply 0 to the text that you want to appear here. —4Waveforms of a solid-state instantaneous overcurrent relay

3.2.2.1 Solid-state distance (Mho) relays

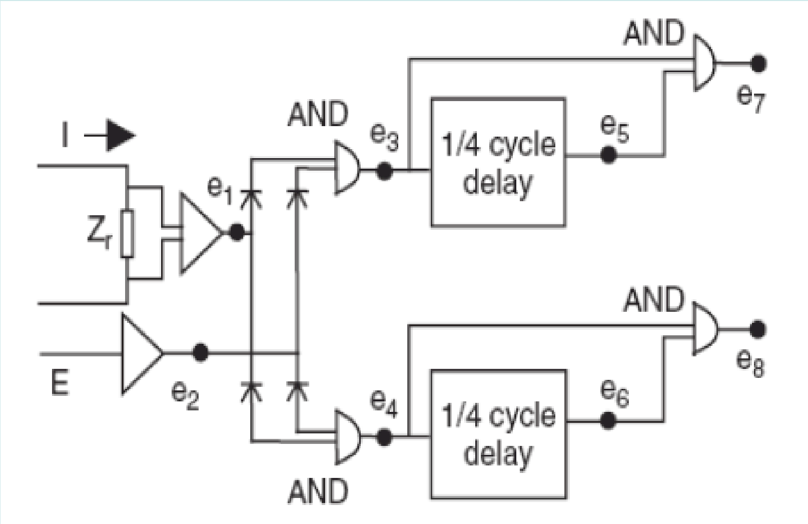




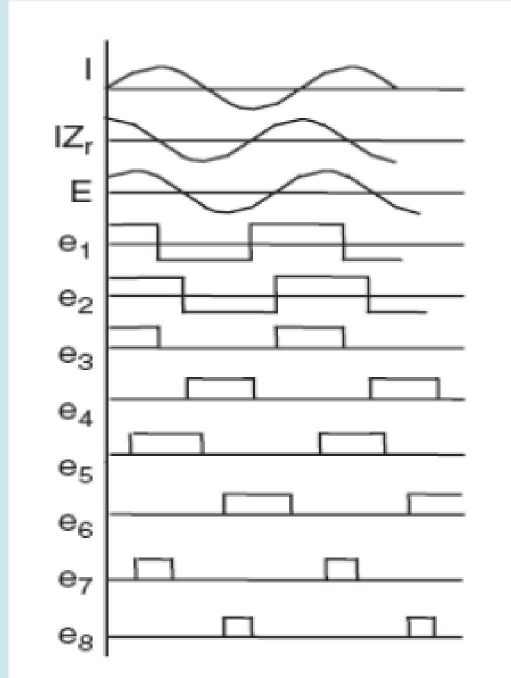
Distance protection of a transmission line

Phasor diagram for a mho distance relay

Solid-state distance (Mho) relays

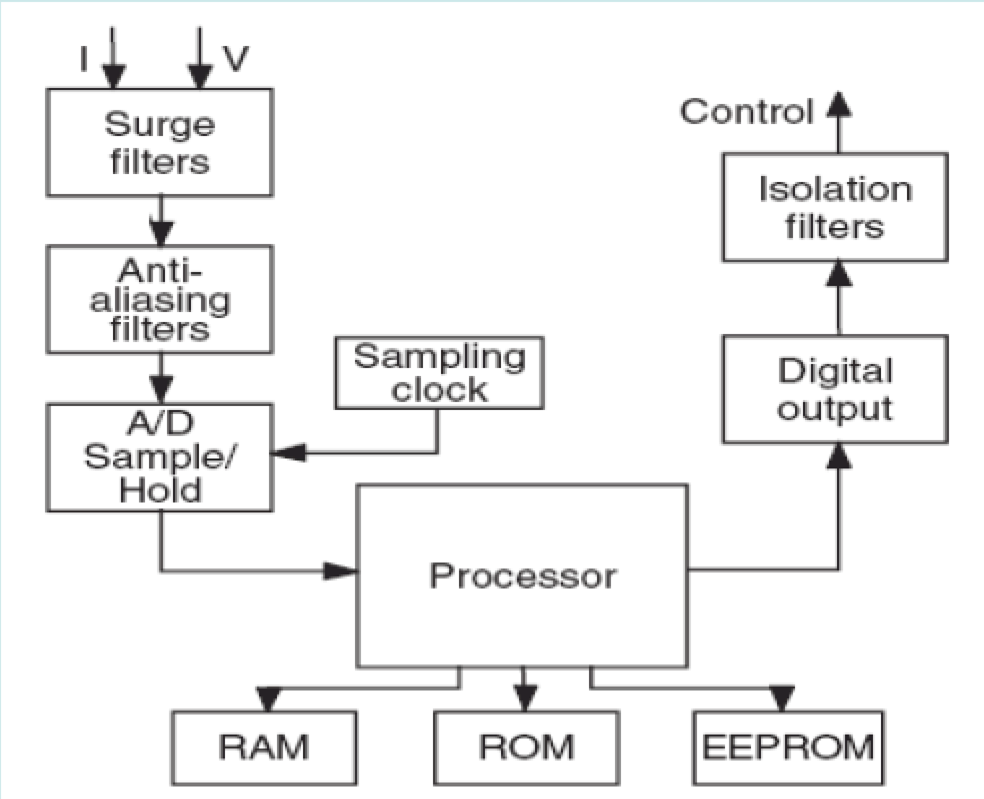


Possible circuit configuration for a solid-state distance relay



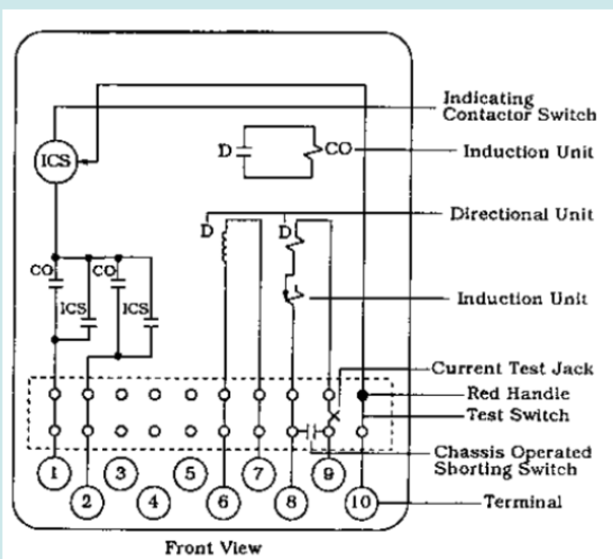
Waveforms in the circuit

3.2.3 Computer relays



Major subsystems of a computer relay

Typical internal schematic for a switch board mounted relay. (The circuit shown is for the CR directional time overcurrent relay)



3.3 Sheet2

1. Draw the protective zones for the system shown in Figure 1. Which circuit breakers should open for a fault at the following cases?

Case	Fault location
A	**P1**
B	**P2**
C	**P3**

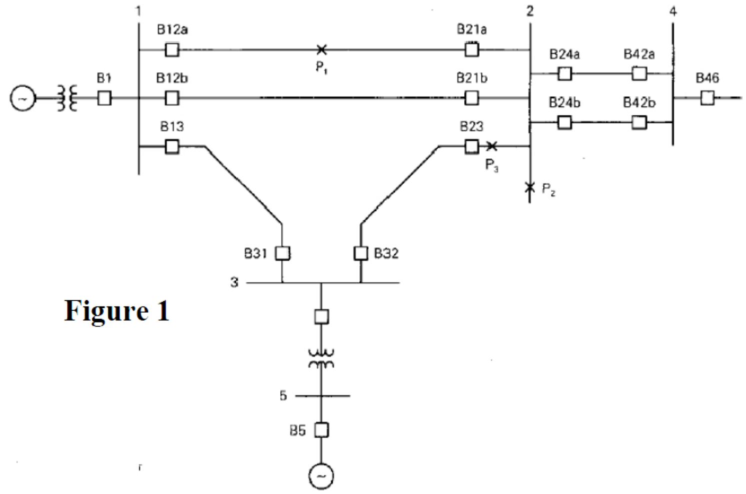


Figure 1

Super Easy

A : 12a & 21a
B : 21a – 21b-23-24a-24b

C : 21a – 21b-23-24a-24b- 32

2. Consider the transmission line connected to a generator as shown in Figure 2. The impedance data for the generator and the line are given in the figure. A relay to be located at terminal A is to detect all faults on the transmission line. Assume a pre-fault voltage of 1.0 pu, and allow for a possible steady-state overvoltage of 1.2 pu during normal operation. Determine the pickup settings for an overcurrent relay and an under voltage relay to be used as fault detectors for this circuit. Allow a sufficient margin between the normal conditions and the pickup settings to accommodate any inaccuracies in relay performance. Assume the maximum load current to be 1.0 pu.

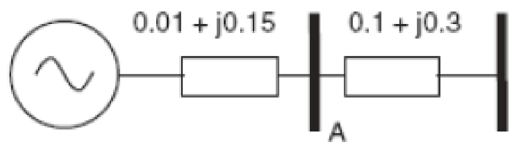
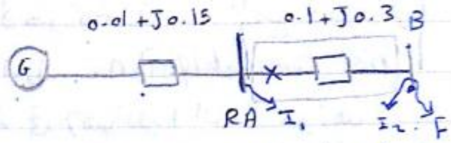


Figure 2

2 - Given



- Pre Fault voltage $1 \angle 0°$ Pu
- allowable max Voltage 1.2 Pu during normal operation
- The max load current is 1Pu.

Req.: Determine I_{set} IF The RA is over current Relay
〃 V_{set} IF RA IS under voltage Relay.

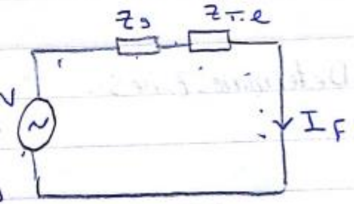
over current R ⊗ بيحمى T.L من زيادة التيار

$I_{Load\,max} < I_{set} < I_{Fault}$ $\quad I_1 > I_2$

$\downarrow$
1Pu

أثناء Fault هنحسب عند القيمة الاقل
عند B Fault

3_Phase Fault



$$I_F = \frac{V}{Z_g + Z_{TL}} = \frac{1}{0.01 + J0.15 + 0.1 + J0.3}$$

Prefault نستخدم $V = 1\angle 0$ لانه
ويعطى أقل تيار Fault لو 1.2 هيعطى تيار أكبر

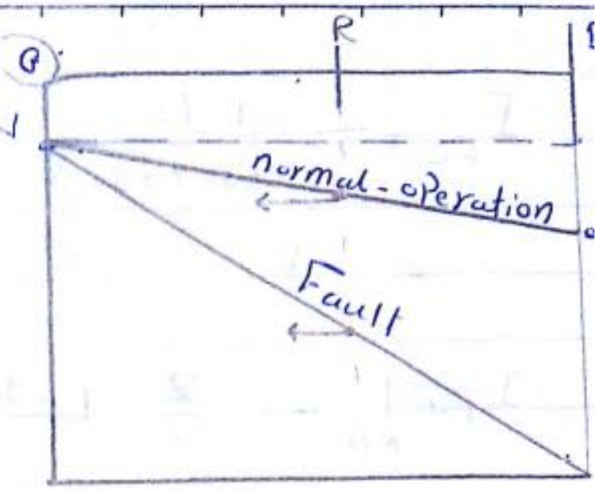
$I_F = 2.16$ Pu

$$1 \text{ Pu} < \underset{1.25 \;\;\; 0.5}{I_{set}} < 2.16$$

Iset يحقق الجزئين

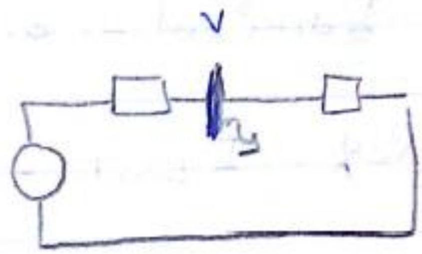
$I_{set} = 1.5$ Pu.

Fault و normal الفرق بين الجهد في



$V = I_{set} * Z$

$V_{normal} = I_{L} \cdot I * Z_y$



$V_{Fault} = I_{L} \cdot I_F * Z_y$

$V_{set} = 1 - 1.5 * Z_y$

$V_{Fault} < V_{set} < V_{normal}$

3. **Consider the power system shown in Figure 3. The pu impedances of the two line sections and the generator are shown in the figure. Concentrating on three-phase faults only, assume the relay at bus A is set to pickup for a fault at bus C. Assuming that the pickup setting is equal to one-third of the fault current, what is the pickup setting of this relay? If the dropout to pickup ratio for the relay is 0.1, what is the maximum load current at bus B for which the relay will drop out after the fault at bus C is cleared by the protection at B? Recall that after the protection at B clears the fault at C, the current seen by the relay at A is equal to the load connected to bus B, and if the relay does not drop out at this current level, the relay at A will trip its breaker on the load current.**

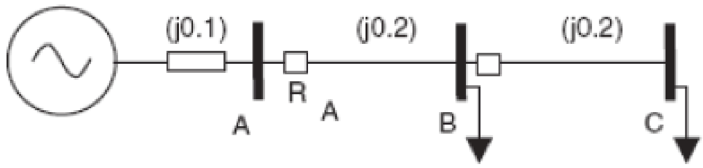
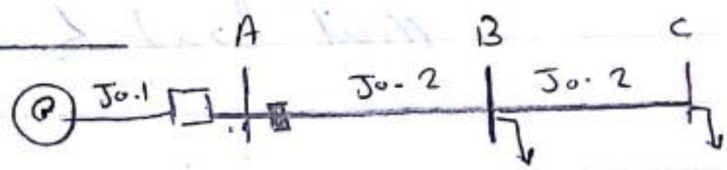


Figure 3

(3)



Assume $I_{pu}|_{RA} = \frac{1}{3} I_{FC}$

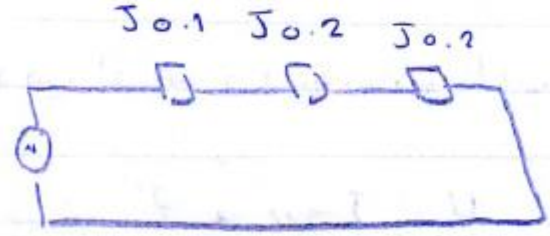
$$\frac{I_{dropout}|_{RA}}{I_{pu}|_{RA}} = 0.1$$

Req.:- max load current at Bus B for which the Relay RA will drop out.

اشتغل Relay وعيزاة نفصل تانى Reset لازم نوصل لتيار
I drop out (electromagnetic Relay) فهو نخفض
لل (B-H) مش يرجع فى نفس المسار, وإنما يرجع على مسار
آخر للتخلص من الفيض فى القلب الحديدى I drop out للتغلب على Hysteresis

$$I_{FC} = \frac{1 \angle 0}{J0.1 + J0.2 + J0.2}$$

$$= 2$$



$$I_{pu}\Big|_{RA} = \frac{2}{3} \angle -90 \ pu$$

$$I_{drop\,out} = 0.1 * \frac{2}{3} = \frac{1}{15} \ pu.$$

Req.:- $I_{Load} = I_{drop\ out} \Rightarrow$ Reset

$I_{Load} > I_{drop\ out} \Rightarrow$ no- Reset

$\therefore$ max load $\leqslant I_{drop\ out} = \frac{1}{15}$ pu.

اول وآخر مسألة. ~~#~~

4. In the part of the network shown in Figure 4. Determine the zones of protection.

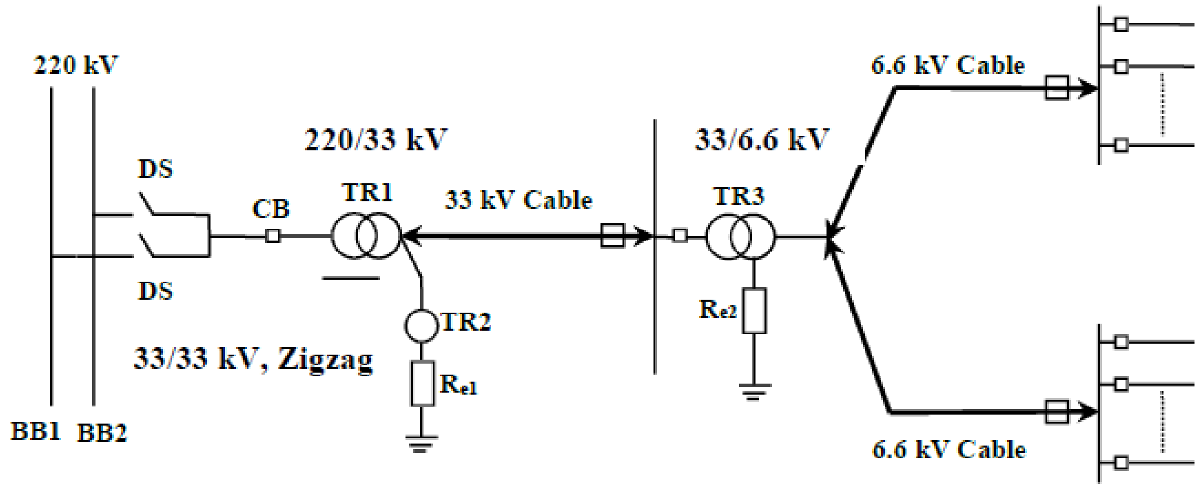


Figure 4

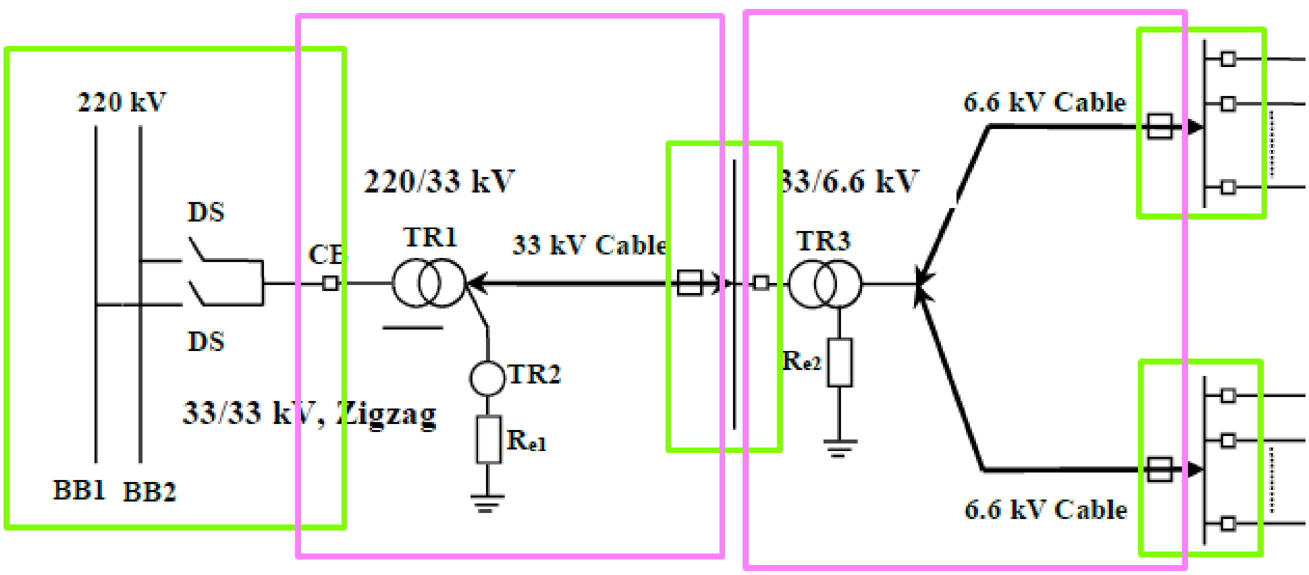


Figure 4

5. **Explain the following terms related to protective relays:**

i) Pickup **ii) Dropout or Reset** **iii) Plug setting multiplier**
iv) Time setting multiplier **v) Relay burden** **vi) Overreach**

Pickup	The minimum current at which the armature gets attracted to close the trip circuit is called **pickup current.**
Dropout – Reset	**For electromagnetic relay ,The energizing current must drop below a value** I_d, known as the **dropout current,**. Due to hysteresis it's calculated by dropout ratio = Id/Ipu
Plug setting multiplier	
Time setting multiplier	
Relay burden	
overreach	

4 CURRENT AND VOLTAGE TRANSFORMERS

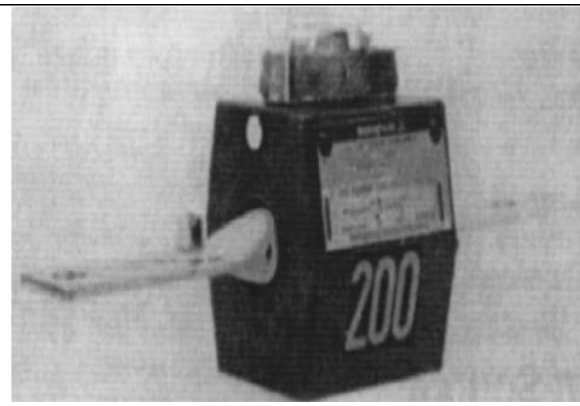
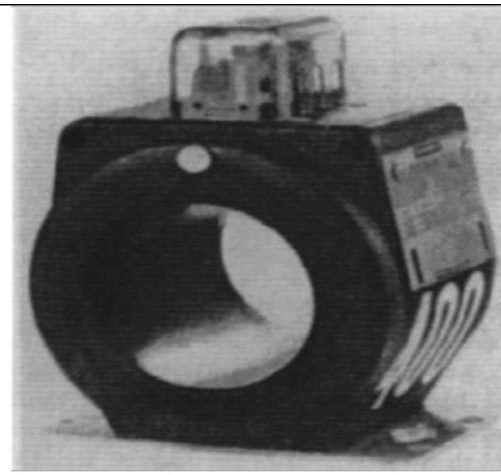
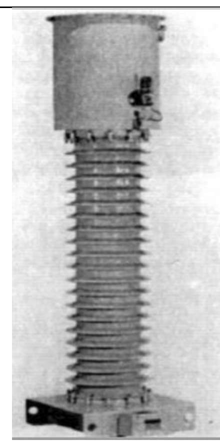
Their **functions** is
to transform power system currents and voltages to lower magnitudes,
and to provide galvanic isolation between the power network
and the relays and other instruments connected to the transducer secondary windings

Transducers	
(1) Metering	(2) Protection

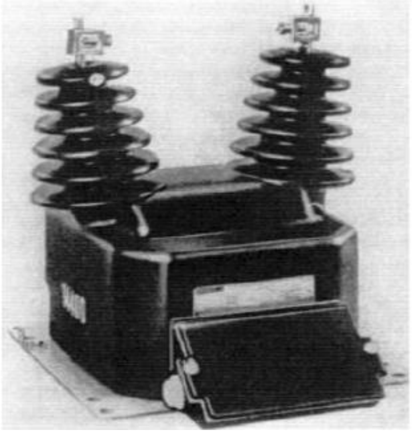
Rating of Transducers Secondary Windings	
For CTs	**For VTs**
1 A or 5 A	120 V LL
CTs are designed to withstand fault currents for a few seconds	VTs can withstand over voltages (20% above the normal value)

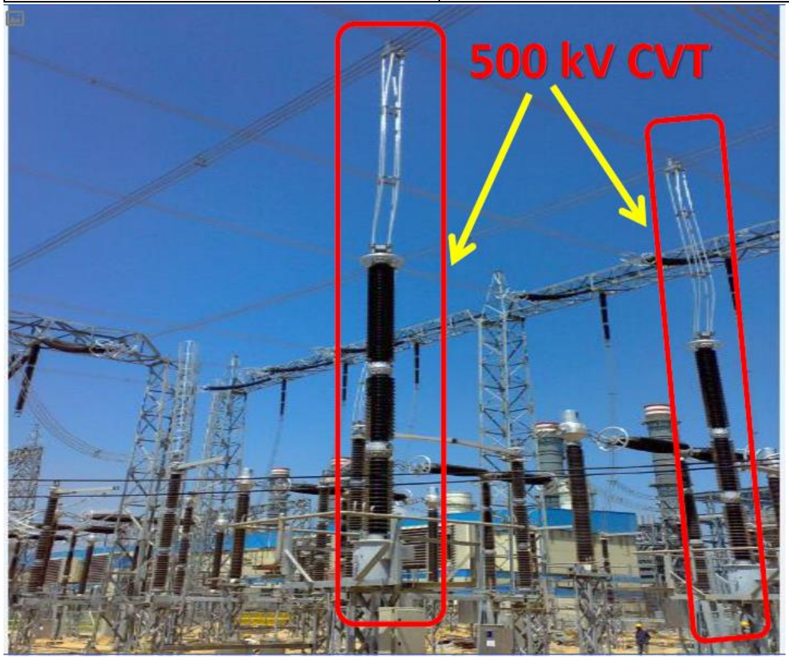
4.1 Current Transformers Types

(magnetically coupled, multi-winding transformers)

Bar Type	
through-type	
A 230 kV oil-filled CT	

4.2 Voltage Transformers Types

	magnetically coupled	capacitive voltage divider
Low Voltage System		N/A
High Voltage System	N/A	

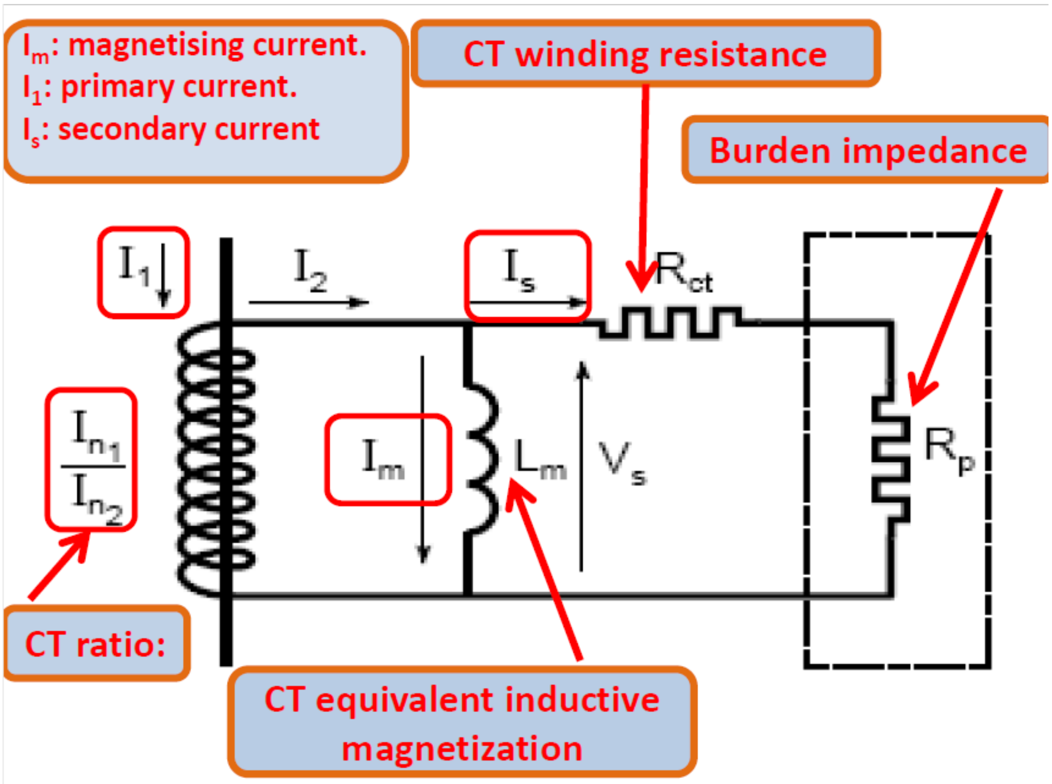


We take voltage divided on the last section of the bushing so it will be a divided voltage with ground is the reference which will, which will be more economic in isolating the VT equipment

4.3 Steady-State Performance of Current Transformers

Here we will study a **<u>single primary, single secondary, magnetically coupled transformers</u>**

It's equivalent circuit

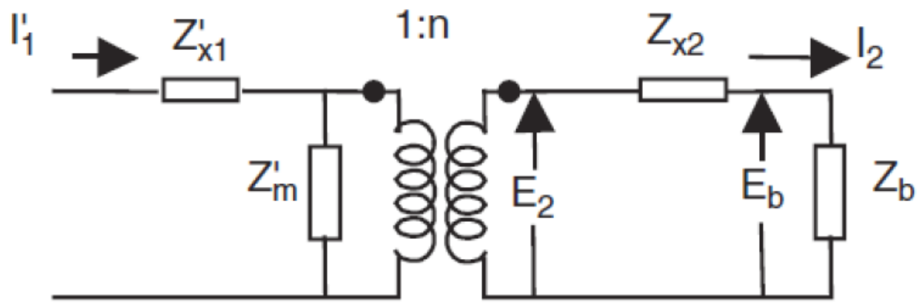


4.3.1 Equivalent Circuit and Burden Impedance Zb

Z_b = Impedance of all the relays and meters + Impedance of the leads from CT to these equipment

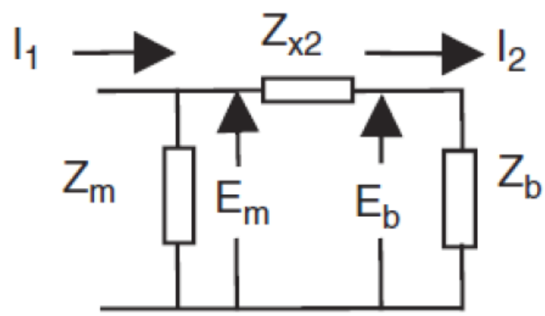
Measured	
Ohm	VA
Sum of all devices' impedance	$25Z_b$ Or Z_b

4.3.1.1 Referring



$$I_1 = \frac{I_1'}{n}$$

$$Z_m = n^2 Z_m'$$



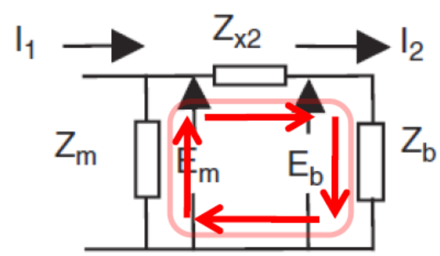
4.3.1.2 Transformer Error

Apply KVL for loop 1

$$E_m = E_b + Z_{x2} I_2$$

$$I_m = \frac{E_m}{Z_m}$$

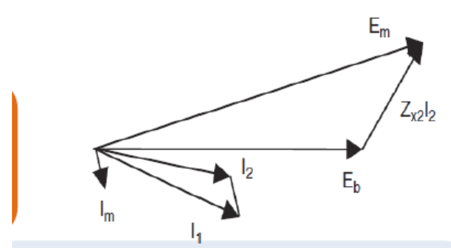
$$I_1 = I_2 + I_m$$



So the per-unit current transformation error

$$\boldsymbol{\varepsilon = \frac{I_1 - I_2}{I_1} = \frac{I_m}{I_1} = \frac{Z_b + Z_{x2}}{Z_m + Z_b + Z_{x2}}}$$

<u>NOTE</u> the ideal case $\varepsilon = 0$ **when** $I_1 = I_2$



4.3.1.3 Ratio Correction Factor R

is defined as the **<u>constant</u>** by which the name plate turns ratio n of a current transformer must be <u>multiplied</u> to obtain the <u>effective turns ratio</u>.

$$R = \frac{1}{1 - \varepsilon}$$

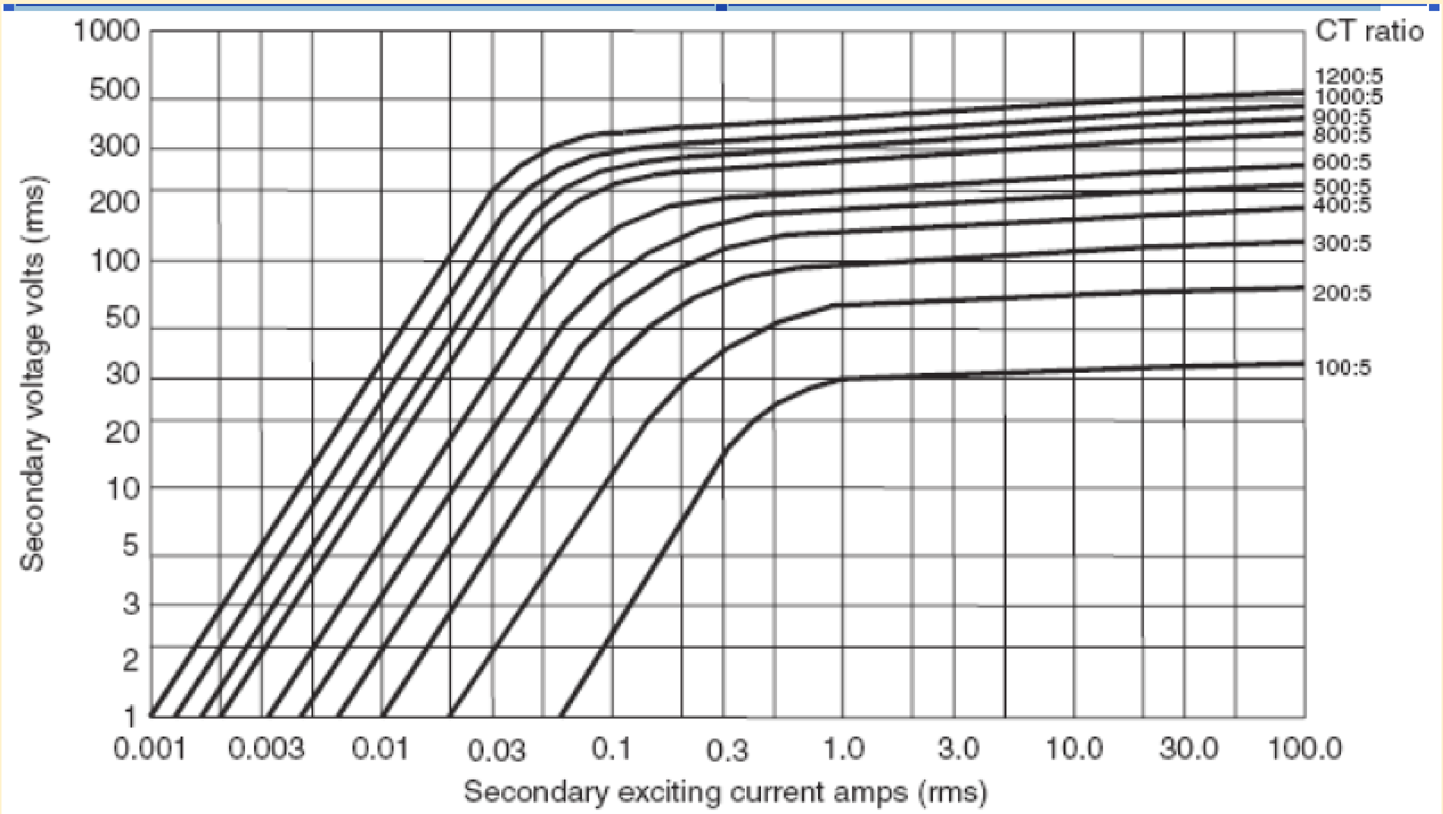
Example 1 Lec3,4 P.19

NOTE **Although ε and R are complex numbers, it is sometimes necessary to use these values as real numbers equal to their respective magnitudes.**

NOTE **if the burden and the magnetizing impedances of the CT are constant, the per unit CT error**

NOTE **ε and R factors depend upon the magnitude and phase angle of the burden and magnetizing impedances.**

NOTE **Since the magnetizing branch of a practical transformer is nonlinear, Zm is not constant, and the actual excitation characteristic of the transformer must be taken into account in determining the factor R for a given situation.**



4.3.2 CT Multiratios

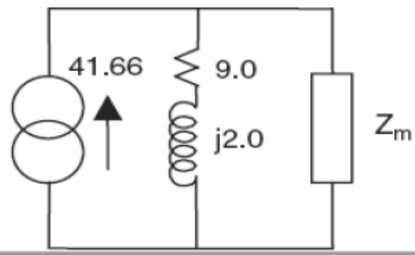
Table 3.1 Standard current transformer multiratios (MR represents multiratio CTs)

600 : 5 MR	1200 : 5 MR	2000 : 5 MR	3000 : 5 MR
50 : 5	100 : 5	300 : 5	300 : 5
100 : 5	200 : 5	400 : 5	500 : 5
150 : 5	300 : 5	500 : 5	800 : 5
200 : 5	400 : 5	800 : 5	1000 : 5
250 : 5	500 : 5	1100 : 5	1200 : 5
300 : 5	600 : 5	1200 : 5	1500 : 5
400 : 5	800 : 5	1500 : 5	2000 : 5
450 : 5	900 : 5	1600 : 5	2200 : 5
500 : 5	1000 : 5	2000 : 5	2500 : 5
600 : 5	1200 : 5		3000 : 5

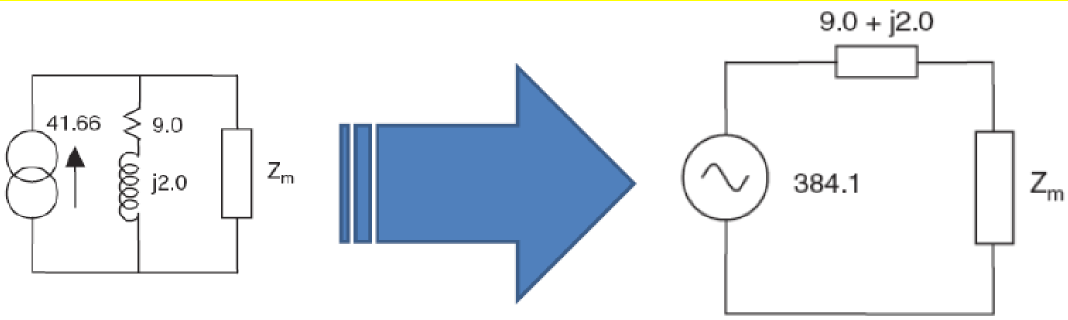
Example 2

Consider a CT of 600:5, and the magnetizing characteristic corresponding to this ratio in previous Figure. Calculate the current in its secondary winding for a primary current of 5000 A, if $\mathbf{Z_b}$ is (9 + j2) Ω and the secondary leakage impedance is negligible. The impedance angle of the magnetizing branch is 60◦.

A current source of **5000 × 5/600 = 41.66 A** in parallel with the burden, and connected across the nonlinear Z_m,



The corresponding Thevenin equivalent consists of a voltage source of **41.66 × *(*9 + j2*)* = 384.1∠12.53◦ volts**, in series with the burden.



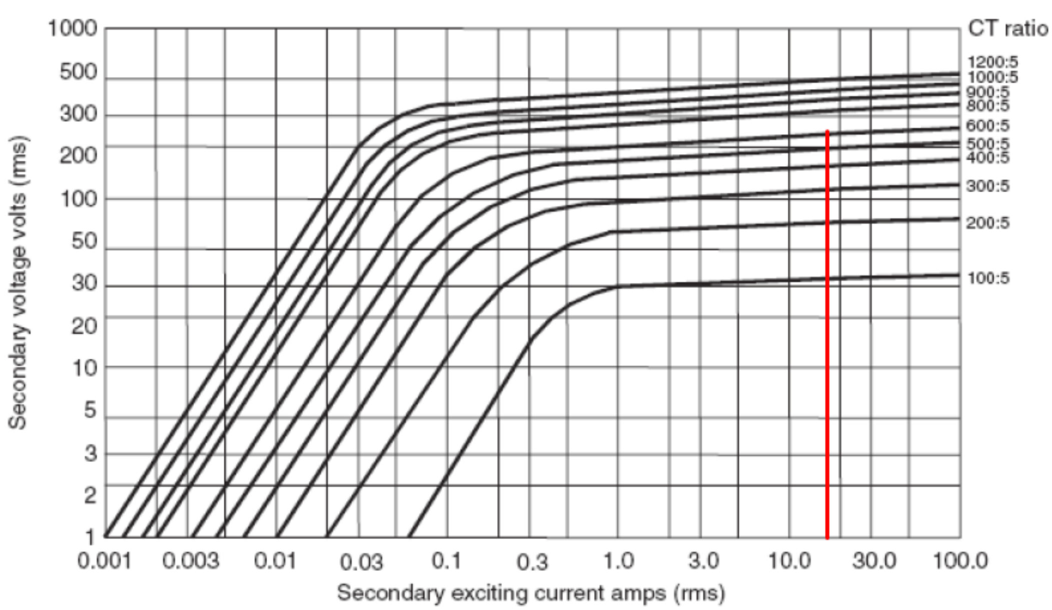
$$I_m = \frac{384.1}{[|Z_m| \times (0.5 + j0.866) + (9.0 + j2.0)]}$$

$$E_2 = I_m Z_m$$

These two equations may be solved to produce values of E_2 and I_m in terms of $|Z_m|$ as the parameter.

$\lvert Z_m \rvert$	$\lvert I_m \rvert$	$\lvert E_2 \rvert$
∞	0	384.1
100	3.61	361.0
10	21.82	218.2

Plotting the curve of these values on magnetization curve, it is found to intersect the magnetizing characteristic at $\boldsymbol{I_m = 17}$ A, $\boldsymbol{E_2 = 260}$ V. Finally, reworking the equations to find the phase angles of the currents, the various currents are: $\boldsymbol{I_1 = 41.66\angle 0^\circ}$ (in that case, $\boldsymbol{E_{th} = 384.1\angle 12.5^\circ}$), $\boldsymbol{I_m = 17\angle{-29.96^\circ}}$ and $\boldsymbol{I_z = 28.24\angle 17.5^\circ}$. The error $\boldsymbol{\varepsilon}$ is therefore $\boldsymbol{0.408\angle{-29.9^\circ}}$ and the ratio correction factor $\boldsymbol{R = 1.47\angle{-17.5^\circ}}$.

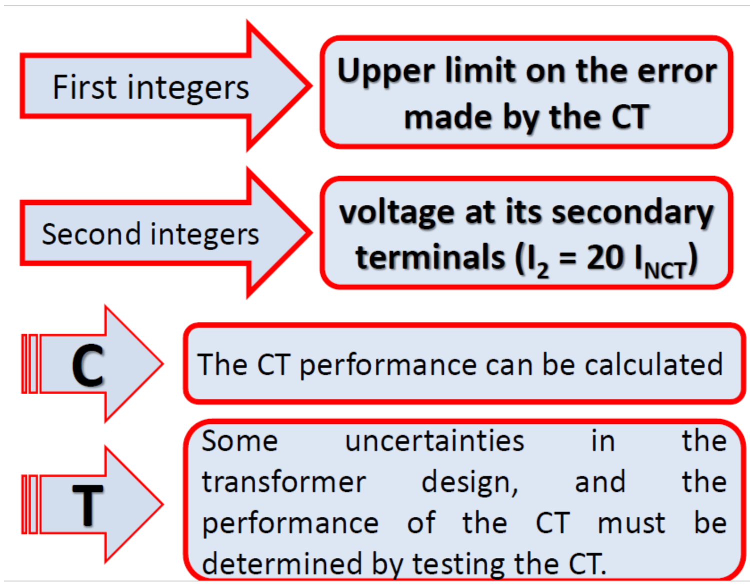


This CT is in severe saturation at this current and at the burden chosen. In practice, it must be used with much smaller burdens to provide reasonable accuracies under faulted conditions.

4.4 Standard Class Designation

It is defined by the American National Standards Institute (ANSI) and the Institute of Electrical and Electronics Engineers (IEEE). Designation of a CT consists of two integer parameters, separated by the letter 'C' or 'T': for example, **10C400 or 10T300.**

<u>**The first integers**</u> describe **the upper limit on the error made by the CT** when the **voltage** at its secondary terminals is **equal to the second integer**, while the current in the transformer is **20 times its rated value.**



<u>Example</u> The 600:5, 10C400 CT, will have an error of less than or equal to 10% at a secondary current of 100(5*20) A for burden impedances which produce 400 V or less at its secondary terminals.

Example 3 Lec3,4 P30 (600:5 , $10C400, I_1 = 5000$)
Idea :

$$Z_m = \frac{400}{0.1 * 100} \, and \; I_2 = 5000 * \frac{5}{600}, then \; I_m = I_2 * \varepsilon = I_2 * 0.1 = 4.16 \;\; so \; E_2 = I_m Z_m,$$

$$Z_{b\,Max} = \frac{E_2}{I_{2s}} = \frac{167}{41.66 - 4.16}$$

We assumed

1- I_m *is in phase with* I_1 *and* I_2

2-Linear magn. Ch/c

This assumption are justifiable

<u>IEC:</u> $5\,P10$ *5 error when 10 times rated current passes*

4.5 Polarity markings on CT windings

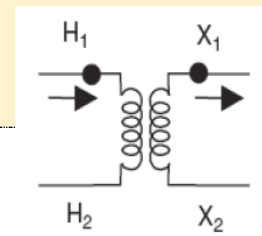
Polarity markings of transformer windings are a means of describing the relative directions in which the two windings are wound on the transformer core.

The terminals identified by solid marks indicate the starting ends of the two windings, meaning that if these are considered to be the starting points, and we trace the two windings along the transformer core, both windings will go around the core in the same sense (i.e. counterclockwise or clockwise).

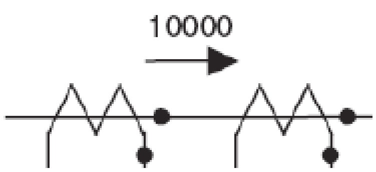
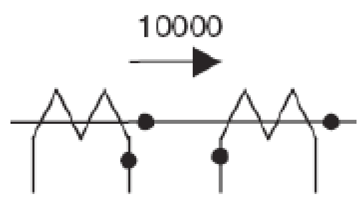
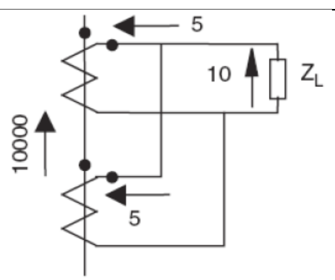
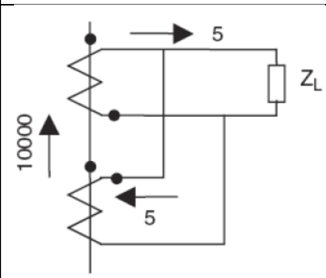
I1 will produce I2, where the magnitudes of I1 and I2 are in inverse proportion to the turns ratio, and their phase angles will be as indicated by the polarity markings.

In a transformer, if one of the winding currents is <u>considered to be flowing into the marked</u> terminal, the current in the other winding <u>should be considered to be leaving its marked terminal.</u>

An alternative way is to label the primary winding terminals H1 and H2, and the secondary winding terminals Xl and X2. H1 and X1 may then be assumed to have the polarity mark on them.



<u>NOTE</u> The current transformer is considered as a constant current source of I_2 as determined by I_1. If I1 is zero, I2 also must be zero, and the secondary winding of such a CT may be considered to be open-circuited.

<table>
<tr><td colspan="2">If the primary current is 1000 A, and the two CT ratios are 1000 : 5. Determine the burden current for the following two cases.</td></tr>
<tr><td></td><td></td></tr>
<tr><td></td><td></td></tr>
<tr><td>the current in the burden

impedance ZL is 10 A.</td><td>the current in the burden

impedance ZL is zero.</td></tr>
</table>

4.6 Special connections of current transformers

4.6.1 Auxiliary current transformers

They are used to provide an **adjustment to the overall current transformation ratio**.

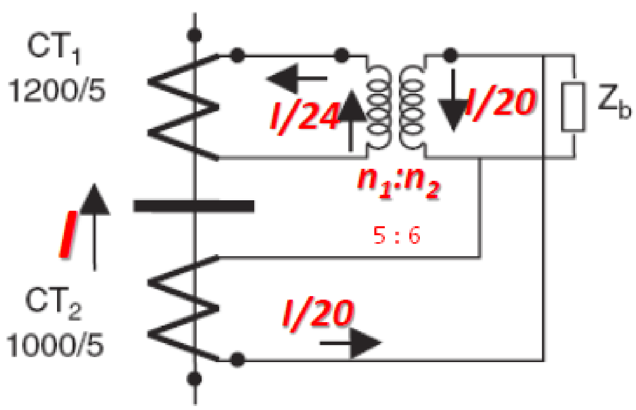
Auxiliary CTs with **multiple taps**, providing a variable turns ratio, are also available.

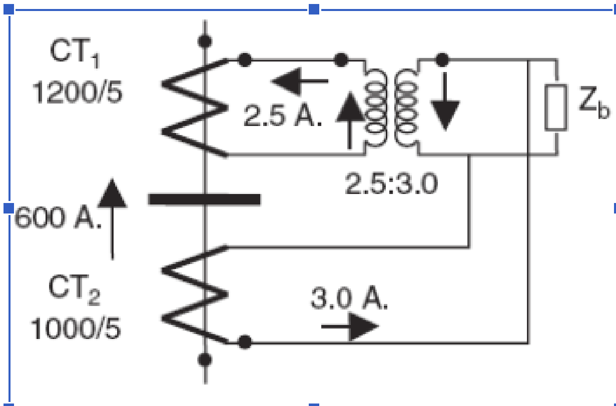
The burden connected into the secondary winding of the auxiliary CT is reflected in the secondary of the main CT, according to the normal rules of transformation:

If the auxiliary CT ratio is 1 : n, and its burden is Z_1, it is reflected in the main CT secondary as $\frac{Z_1}{n^2}$.

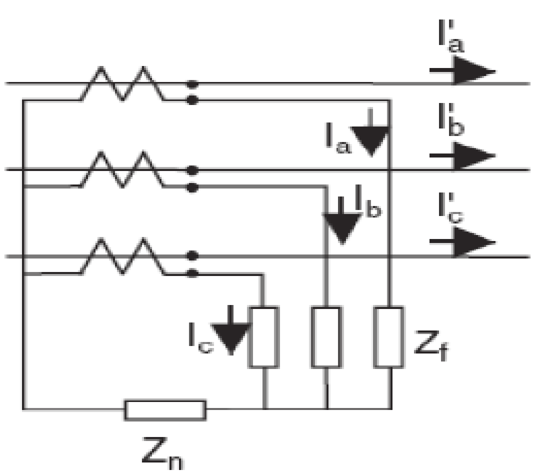
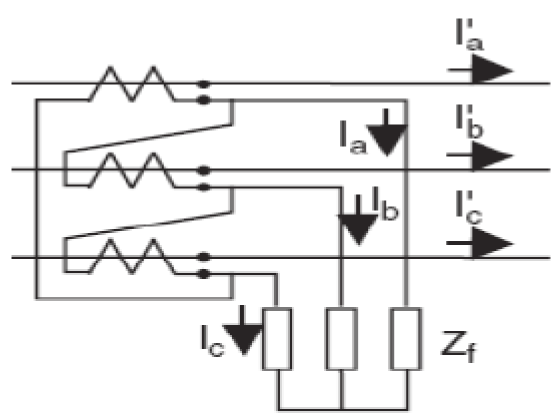
The auxiliary CT makes its own contributions to the overall errors of transformation.

In particular, the possibility that the auxiliary CT itself may saturate should be taken into consideration.



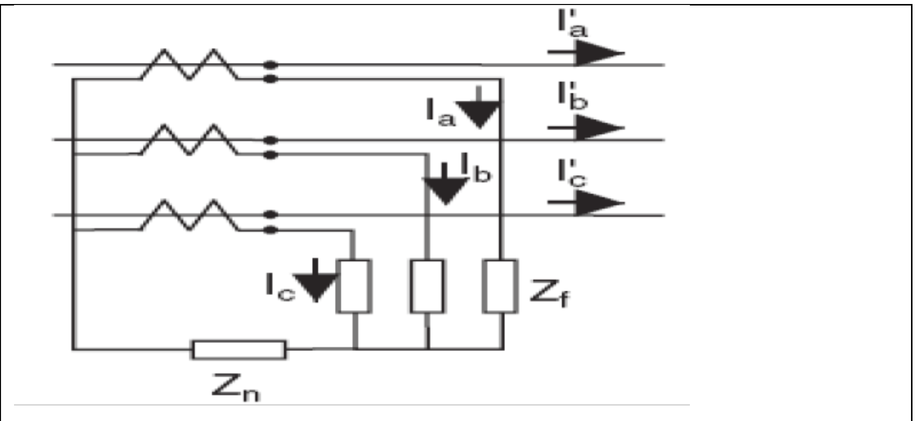
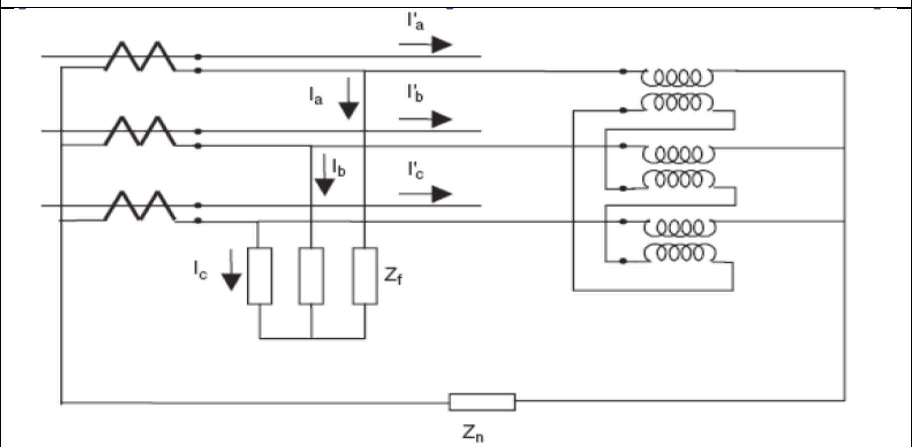


4.6.2 Wye and delta connections

Wye	Delta
	

Ia , Ib and Ic are **proportional** to Ia' , Ib' and Ic'. **No phase shifts** are introduced by this connection.	a **phase shift of 30◦** is introduced between the primary currents and the currents supplied to the burdens.

4.6.3 Zero-sequence current shunts

1	Each of the phase burdens Zf carries phase currents, which include the positive, negative and zero-seq components.	
2	Sometimes it is desired that the zero-sequence current be bypassed from these burdens. This is achieved by connecting **auxiliary CTs** which provide an alternative path for the zero-sequence current.	

4.6.4 Flux-summing CT

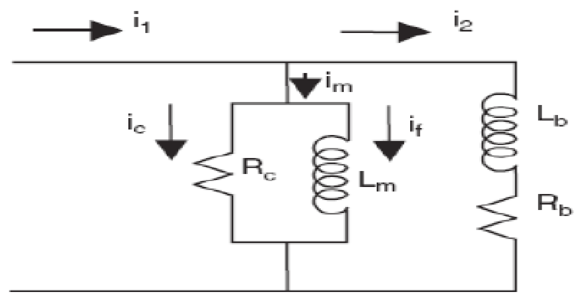
If three phase conductors are passed through the window of a toroidal CT, the secondary current is proportional to $(I_a + I_b + I_c) = 3I_0$.

Since this arrangement effectively sums the flux produced by the three phase currents, the CT secondary contains the **true zero-sequence current**.

4.7 Transient performance of current transformers

When faults occur, the current magnitudes could be much larger, the fault current may have DC components and there may be remanence in the CT core. All of these factors may lead to **saturation of the CT** core, and cause significant **distortion of the secondary current waveform**.

Consider the sum of the secondary leakage impedance, lead impedance and load impedance – given by $Z_b = (R_b + j\omega L_b)$.



$$i_1(t) = I_{Max}\left[cos(\omega t-\theta) - \varepsilon^{-\frac{t}{T}} cos\,\theta\right] \qquad for\ t>0$$
$$= \quad 0 \qquad\qquad for\ \ t<0$$

θ : is the angle on the voltage wave where the fault occurs

$$v_2 = \frac{R_c R_b}{R_c + R_b}\frac{1}{s+\frac{1}{\tau}}\,I_1$$

$$\tau = \frac{R_c L_m + R_b L_m}{R_b R_c}$$

$$\lambda = I_{\max}\cos\theta\frac{R_c R_b}{R_c + R_b}\left\{\varepsilon^{-t/\tau}\left[-\frac{\tau T}{\tau - T} + \tau(\sin\varphi\cos\varphi\tan\theta - \cos^2\varphi)\right]\right.$$
$$\left. + \varepsilon^{-t/T}\left(\frac{\tau T}{\tau - T}\right) + \tau\frac{\cos\varphi}{\cos\theta}\cos(\omega t - \theta - \varphi)\right\}$$

$$i_2 = \frac{1}{B_b}\frac{d\lambda}{dt}$$
$$= I_{\max}\cos\theta\frac{R_c}{R_c + R_b}\left\{\varepsilon^{-t/\tau}\left[-\frac{T}{\tau - T} + (\sin\varphi\cos\varphi\tan\theta - \cos^2\varphi)\right]\right.$$
$$\left. - \varepsilon^{-t/T}\left(\frac{\tau}{\tau - T}\right) - \omega\tau\frac{\cos\varphi}{\cos\theta}\sin(\omega t - \theta - \varphi)\right\}$$

$$\varphi = \omega\tau.$$

Example 3.5

Consider the case of a purely resistive burden of 0.5 Ω being supplied by a current transformer with a core loss resistance of 100 Ω, and a magnetizing inductance of 0.005 H. Let the primary current with a steady-state value of 100 A be fully offset. Let the primary fault circuit time constant be 0.1 s. For this case

$$i_1 = 141.4 \times \epsilon^{-10t} - 141.4\cos(\omega t)$$

$$\theta = \pi,\ R_c = 100,\ R_b = 0.5,\ T = 0.1 \text{ s}$$

hence

$$\tau = \frac{(100 + 0.5) \times 0.005}{100 \times 0.5} = 0.01005$$

$$\omega\tau = 377 \times 0.01005 = 3.789$$

and

$$\varphi = tan^{-1}(3.789) = 75.21^\circ = 1.3127 \text{ rad}$$

Substituting these values in equations (3.15) and (3.16) gives

$$\lambda = -0.7399\varepsilon^{-99.5t} + 0.786\varepsilon^{-10t} - 0.1804\cos(\omega t - 1.3127)$$

$$i_2 = 147.24\varepsilon^{-99.5t} - 15.726\varepsilon^{-10t} + 136.02\sin(\omega t - 1.3127)$$

These expressions for i_1, i_2 and λ have been plotted in Figure 3.8. When the burden is inductive, L_b cannot be neglected, and the expressions for i_2 and λ are far more complicated. Essentially, additional time constants are introduced in their expressions. It is usual to solve such circuits by one of the several available time-domain simulation programs.

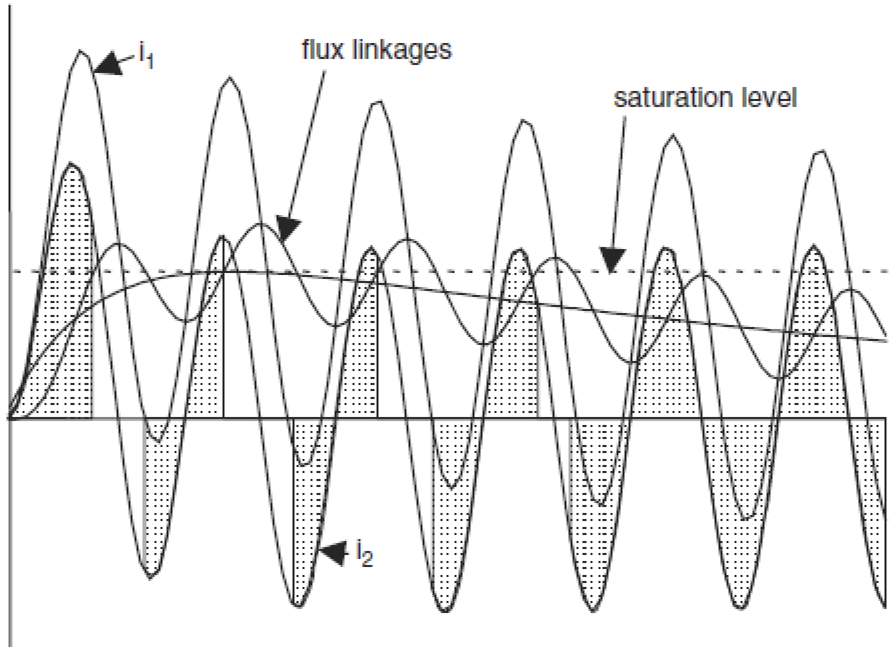
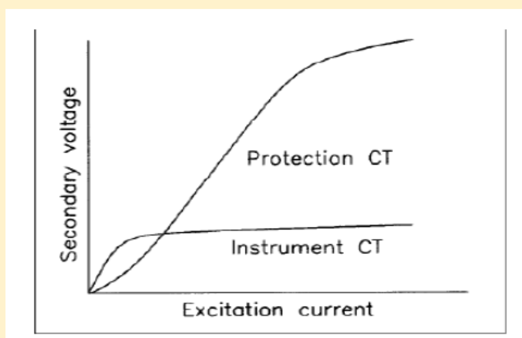


Figure 3.8 Primary and secondary currents and core flux linkages of a CT

Note it's a main difference between protection CT and instrument CT is that protection CT is designed to withstand large fault current without saturating



NOTES

- The DC component in the fault current causes the flux linkages to increase considerably above their steady state peak.

- The dotted line represents the flux level at which the transformer core goes into saturation.

- Thus, for the duration that λ is above the dotted line, it is held constant at the saturation level, and the magnetizing inductance Lm becomes zero.

the secondary current for this period also becomes zero.

- I2 of a CT may not represent I1 faithfully if the CT goes into saturation, and hence relays which depend upon I2 are likely to mis-operate during this period.

- The possibility of CT saturation must be taken into account when designing a relaying system.

4.8 Linear couplers and electronic current transformers

Linear couplers are CTs without an iron core. The magnetizing reactance of these transformers is linear, and is very small compared to that of a steel-cored CT.

The linear coupler operates as a current-to-voltage converter**: the voltage is a faithful reproduction** of the primary current.

The **transformation ratio is practically constant.**

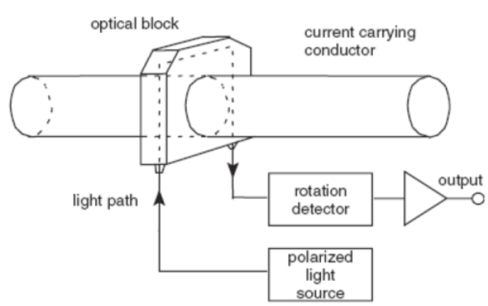
The main use of linear couplers is in applications where saturation of the CT presents a major problem (**bus protection applications).**

4.8.1 Advantages of electronic CTs

1. They are linear,
2. They have a very wide dynamic range.
3. They do not include oil as an insulating medium, they do not constitute a fire hazard.
4. They are also smaller in size and require less space in a substation.

4.8.2 Disadvantages of electronic CTs

1. They do require a power supply to operate
2. Various electronic circuits required to sense and amplify the signals.



5 VOLTAGE TRANSFORMERS

VTs are normal transformers with the primary winding connected directly to the HV, and with one or more **secondary windings** rated at the **standard** voltage of **69.3 V for LN** voltages or **120 V for LL** voltages.

Their performance, equivalent circuit and phasor diagrams are similar to those of a power transformer.

We may consider such transformers to be error-free from the point of view of relaying.

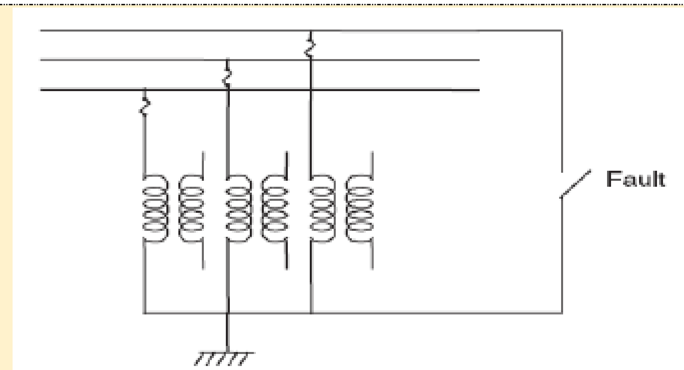
VTs are usually used for low-, medium- and high-voltage systems.

VTs are rather expensive, especially at EHV (345 kV or above).

At EHV, capacitive voltage transformers CVT, are the more usual sources for relaying and metering.

There is a problem with VTs when used on ungrounded (or high-impedance grounded) power systems.

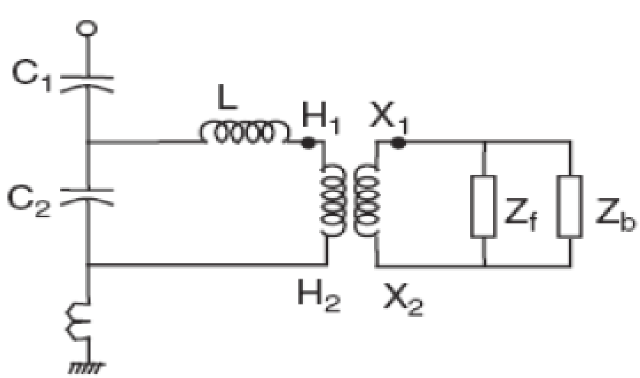
When SLG occurs, the VTs connected to the unfaulted phases are subjected to a voltage equal to the LL voltage. **This drives one of VTs into saturation.**

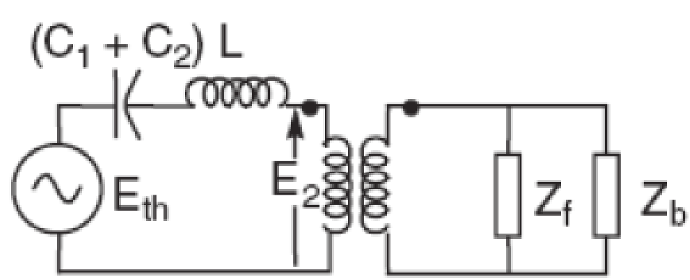


Blown fuse in a VT on ungrounded systems

5.1 Coupling Capacitor VT

String of capacitors is used as a potential divider between the HV and ground, and a tap provides a reduced voltage of about **1 to 4 kV**.





The tap point is connected to a transformer through an inductance.

Zb is burden impedance.

Zf is a **damping circuit** for suppressing ferro resonance.

The current drawn by Zf and Zb is relatively small under normal conditions.

Consider the Thevenin equivalent circuit of the capacitive divider, where

$$E_{th} = E_{pr} * \frac{C_1}{C_1 + C_2}$$

$$\mathrm{Z_{th}} \propto (C_1 + C_2)$$

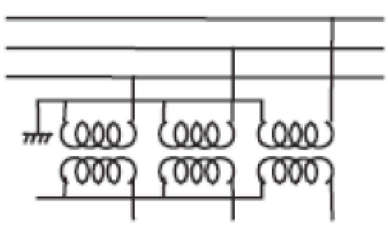
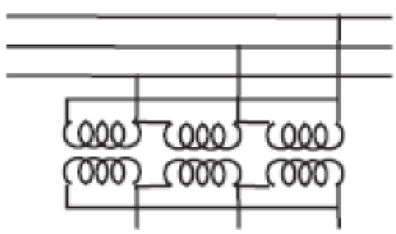
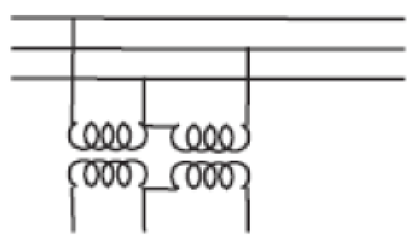
$$E_2 = E_{th} - I_1 \left[j\omega L + \frac{1}{j\omega(C_1 + C_2)} \right]$$

E2 will have a **phase angle error**, unless the inductance L is in **resonance** with (C1 + C2) at f = 50 Hz.

$$\boldsymbol{L = \frac{1}{\omega^2} \frac{1}{C_1 + C_2}}$$

VTs are marked to indicate polarity. Terminals of same polarity are identified by dots, or by labels H1, H2 and Xl, X2.

Windings of 3-Φ VTs may be connected in Y , in Δ or in open Δ, as needed in each application.

Y	Δ	$Open\ \Delta$
		

5.2 Electronic voltage transformers

Electronic voltage transformers have not been developed to the same extent as electronic current transformers.

The main difficulty arises because a voltage measurement needs a reference point, and hence both HV terminal as well as the ground terminal must be included in the measuring device.

Nevertheless, some progress in making a practical electronic voltage transformer has been made in recent years.

5.2.1 CVT Advantages

Solves switching problem (opposes sudden change in voltage)

Helps in catching unsymmetrical faults as we measure $\frac{V_a+V_b+V_c}{3} \neq 0 \therefore\ unbalanced$

5.2.2 Disadvantage of CVT

Distorts output wave (can be solved by resonance and Z_f or electronic)

5.2.3 Breakdown Pulse Voltage

It's a parameter of the most pulse voltage during switching the VT can withstand

$$220\ kV \rightarrow BPV\ 1050\ kV$$
$$400\ kV \rightarrow 1460\ kV$$

5.2.4 Accuracy class

$$VT\ error = \epsilon = \frac{k_n * V_s - V_p}{V_p} \qquad (k_n \rightarrow ratio)$$

5.2.5 VT Parameters

- Turns ratio
- No of secondary core – connection
- Burden (VA)
- Type (CVT, IVT)
- Breakdown Pulse Voltage
- Accuracy class

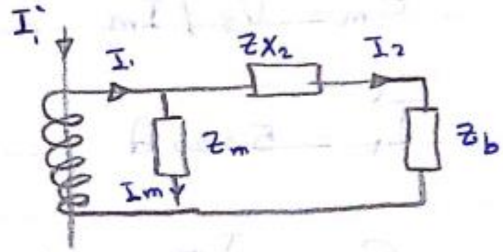
5.3 Sheet 3

1. Prove that $R = \frac{1}{1-\varepsilon}$ where R is CT correction factor and ε is per unit current transformer error.

① Prove That $R = \frac{1}{1-\epsilon}$

CTR "current Transformer ratio" $= n$ $\quad \frac{600}{5}, \frac{300}{3}$

$$\epsilon = \frac{I_m}{I_1}$$



التيار المفروض يكون I_1 ولكن أصبح I_2 نتيجة وجود Z_m سحبت تيار I_m لذلك في معامل تصحيح R.

$$I_2 = \frac{I_1'}{nR} \qquad \text{لو} \quad I_1 = \frac{I_1'}{n}$$

$$I_2 = \frac{I_1}{R} \qquad \therefore R = \frac{I_1}{I_2}$$

$$\epsilon = \frac{I_1 - I_2}{I_1} = 1 - \frac{I_2}{I_1}$$

$$\epsilon = 1 - \frac{1}{R} \qquad \therefore R = \frac{1}{1-\epsilon}$$

$$\epsilon = \frac{I_m}{I_1} = \frac{\cancel{I_1}\,(Z_{X_2} + Z_b)}{\cancel{I_1}\,(Z_{X_2} + Z_b + Z_m)}$$

Z_{X_2} لو مذكرتش تهملها، Z_b تعريف حمل جهاز الـ Protection.

2. **Consider a CT with a ratio of 600/5 and class of 10C400. Determine the maximum burden when the primary current is 5000 A. (assume linear magnetic circuit)**

(2) CTR = 600/5 and class 10 C 400 Determine max burden when the Primary current is 5000 A (assume Linear magnetic circuit)

10 C 400

$\epsilon = 10\% \rightarrow 20\, I_{NCT} \rightarrow V_s = 400\,V$

$\epsilon = \frac{I_m}{I_1}$; $0.1 = \frac{I_m}{20 * 5}$ $\therefore I_m = 10\,A$ #

$Z_m = V_s / I_m = 400/10 = 40\,\Omega.$

$I_1' = 5000\,A$ $\therefore I_1 = \frac{5000 * 5}{600} = 41.6\,A$

$\epsilon = \frac{I_m}{I_1}$; $0.1 = \frac{I_m}{41.6} \Rightarrow \therefore I_m = 4.16\,A$ #

$V_s' = Z_m I_m = 40 * 4.16 = 166.4\,V.$ #

$Z_b = \frac{V_s}{I_2}$

$I_2 = I_1 - I_m = 41.6 - 4.16 = 37.44\,A$

$Z_b = \frac{166.4}{37.44} = 4.4\,\Omega.$ #

3. **Consider a CT with a ratio of 500/ 5, a secondary leakage impedance of (0.01 + j0.1) Ω and a resistive burden of 2.0 Ω. If the magnetizing impedance is (4.0 + j15), determine**
   - **i- CT error and correction factor.**
   - **ii- Write a computer program to calculate and plot the correction factor for change in burden up to 7 Ω.**

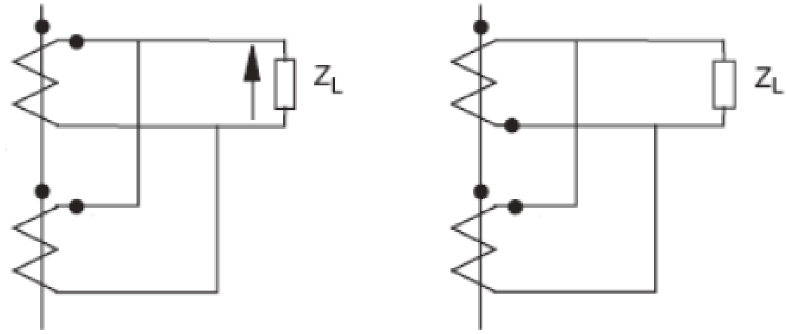
(3) $CTR = 500/5$, $Z_{X_2} = 0.01 + J0.1\ \Omega$

$R_b = 2\Omega$, $Z_m = 4 + J15\ \Omega$ Determine ϵ, R?!

$$\epsilon = \frac{Z_{X_2} + Z_b}{Z_{X_2} + Z_b + Z_m} = \frac{0.01 + J0.1 + 2}{0.01 + J0.1 + 2 + 4 + J15} = 0.1288 \angle -65.4$$

$$R = \frac{1}{1 - \epsilon} = 1.046 \angle -6.77$$

4. **Two ideal CTs with ratios of 300/5 and 600/ 5 are connected as shown in Figure (a) and (b). If the primary current is 3000 A and the burden is 1 ohm what are the voltages at the secondary terminals of the current transformers in the two cases?**

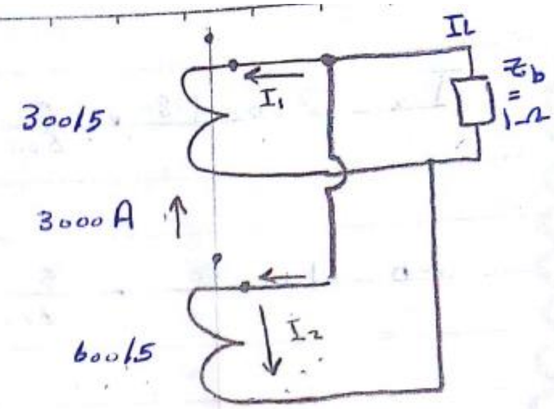


(a) (b)

(4)

• هيقابل ال dot وهو داخل ملف ال Primary

• يقابل ال dot وهو خارج من ال secondary



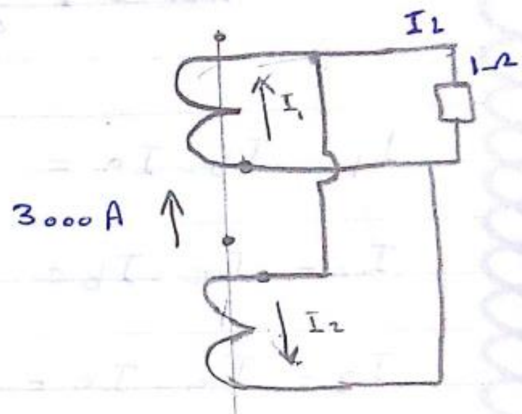
V_{sec} ?!

$I_1 = 3000 * \frac{5}{300} = 50 A$

$I_2 = 3000 * \frac{5}{600} = 25 A$

$I_L = I_1 + I_2 = 75\ A$

$V_{sec} = Z_b * I_L = 75 V.$

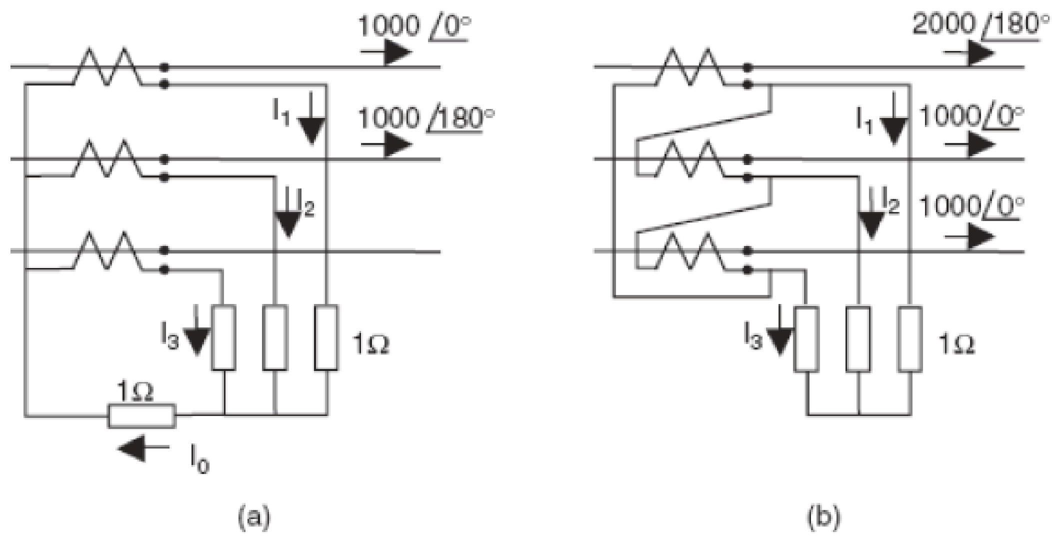


الحالة الثانية

$I_1 - I_2 = I_L = 25\ A$

$V_{sec} = Z_b * I_L = 25 V$

5. **Three ideal CTs with ratios of 600/ 5 are connected in a star and a delta configuration as shown in Figure (a) and (b) respectively. For the primary currents shown in each case, what are the currents I_1, I_2, I_3 and I_0?**



(5) I_1, I_2, I_3, I_0 ?!

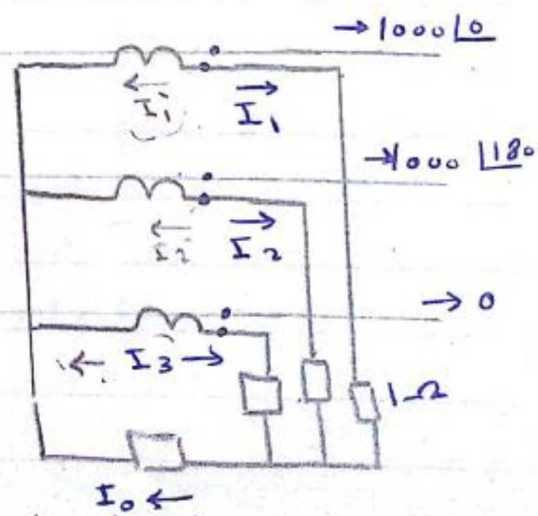
CTR = 600/5.

$I_3 = 0$

$I_1 = -1000 * \frac{5}{600} = -8.3 \angle 0^\circ$ A

$I_2 = -1000 * \frac{5}{600} = -8.3 \angle 180^\circ$

$I_0 = I_1 + I_2 + I_3 = 0$.



$I_a = 2000\angle 180 * \frac{5}{600}$

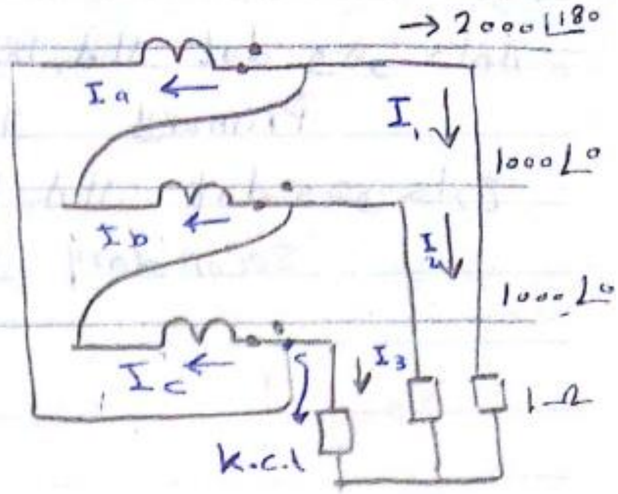
$=$

$I_b = 1000\angle 0 * \frac{5}{600}$

$=$

$I_c = 1000\angle 0 * \frac{5}{600}$

$=$

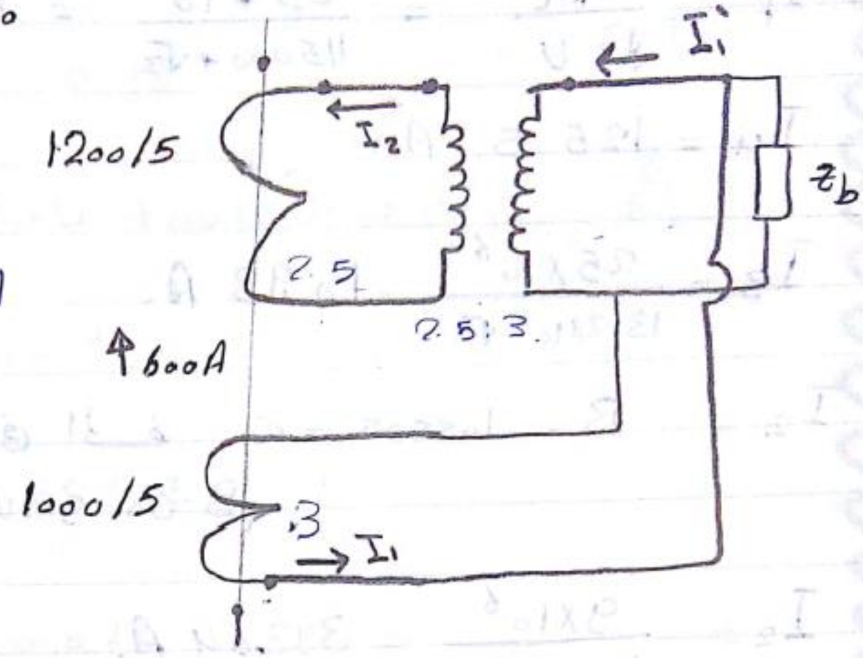


$I_1 = I_b - I_a =$

$I_2 = I_c - I_b =$

$I_3 = I_a - I_c =$

suggest what's do to have zero current in the burden?!



$I_2 = 600 * \frac{5}{1200} = 2.5\ A$

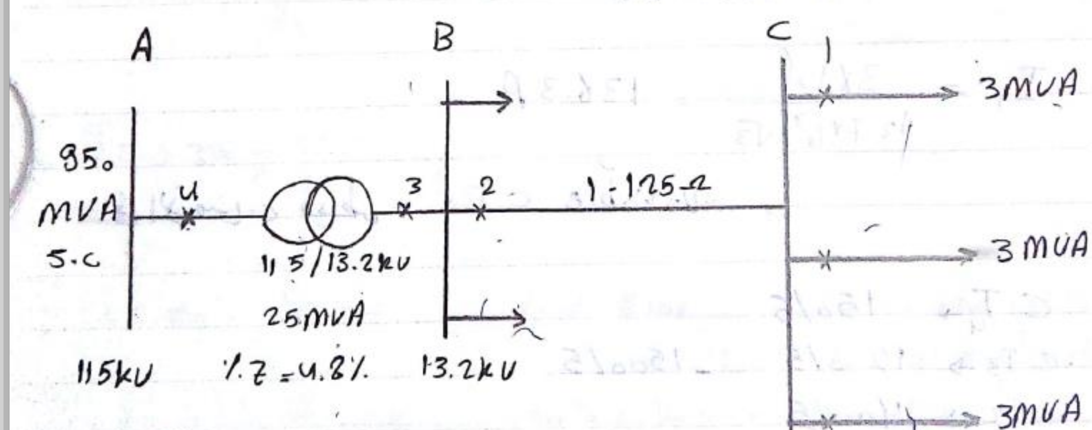
$I_1 = 600 * \frac{5}{1000} = 3\ A$

$I_b = I_1 + I_B'$

$I_b = 0 \qquad I_1 = I_B'$.

تعامل مثل C.T بمقلوب النسبة ليصير

$n = 2.5 : 3$ كـ لنسبة التيارات



Req:- [1] The Nominal current at each C.B

[2] The 3-Ph short circuit current level at C.B's

[3] select a CTR for each C.T at C.B's.

$$I_F = \frac{S_{F.L}}{\sqrt{3}\, V} = \frac{25 * 10^6}{115000 * \sqrt{3}} = 125.5\ A$$

$$I_4 = 125.5\ A$$

$$I_3 = \frac{25 \times 10^6}{13.2 \times 10^3 \sqrt{3}} = 1093\ A.$$

I_2 : B - losses = C اما تحسب losses فى الـ C او C يتغذى بـ 9mVA من B

$$I_2 = \frac{9 \times 10^6}{13.2 \times 10^3 \sqrt{3}} = 393.64\ A.$$

C.Ratio تحدد من Full load current وليس I_F

$$I_1 \Rightarrow V_C = V_B - I_{F_2} * 1.25\ \Omega$$
$$= 12.7\ kV$$

$$I_1 = \frac{3 \times 10^6}{12.7 \times 10^3 \sqrt{3}} = 136.3\ A.$$

فى الأمتحان يعطى available C.T

$C.T_4 \rightarrow 150/5$

$C.T_3 \rightarrow 1200/5 \quad - 1500/5$

$C.T_2 \rightarrow 400/5$

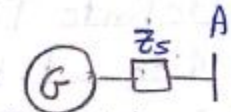
$C.T_1 \rightarrow 150/5$

$$I_{s.c\,4} = \frac{S_{s.c}}{\sqrt{3}\, V} = \frac{950 \times 10^6}{\sqrt{3} * 115 \times 10^3} = 4769.415\ A$$

$S_b = 25\ MVA$, $U_{bI} = 115\ kV$, $U_{bII} = 13.2\ kV$

$$Z_{bII} = \frac{U_{bII}^2}{S_b} = 6.96$$

Impedance of Bus A ال ماقبل ال Fault ال لخط



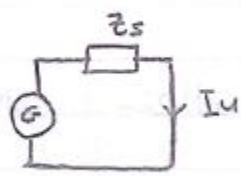
مينفعش اعتبرها صفر

$$Z_s = \frac{U_{L}^2}{MVA_{s.c}} = 13.9\ \Omega$$

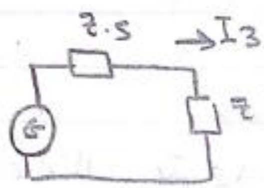
$$Z_{bI} = \frac{115^2}{25} = 529\ \Omega$$

$$Z_s|_{pu} = \frac{13.9}{529} = 0.026\ Pu.$$

$$Z_{T.L} = \frac{1.125}{6.96} = 0.16\ Pu.$$



$$I_{s.cu} = \frac{1\angle 0}{Z_s} = 38...$$



$$I_{s.c3} = \frac{1\angle 0}{0.026 + 0.48} =$$

(1) $I_{s.c2} = I_{s.c3}$ load static تيارات مغيرة بالنسبة للـ

3-φ fault فيتم اهمالهم.

$$I_{s.c1} = \frac{1\angle 0}{0.026 + 0.048 + 0.16}$$ تدخل في الاعتبار لو Fault حصل بمقاومة كبيرة

$= 4.27\ Pu.$

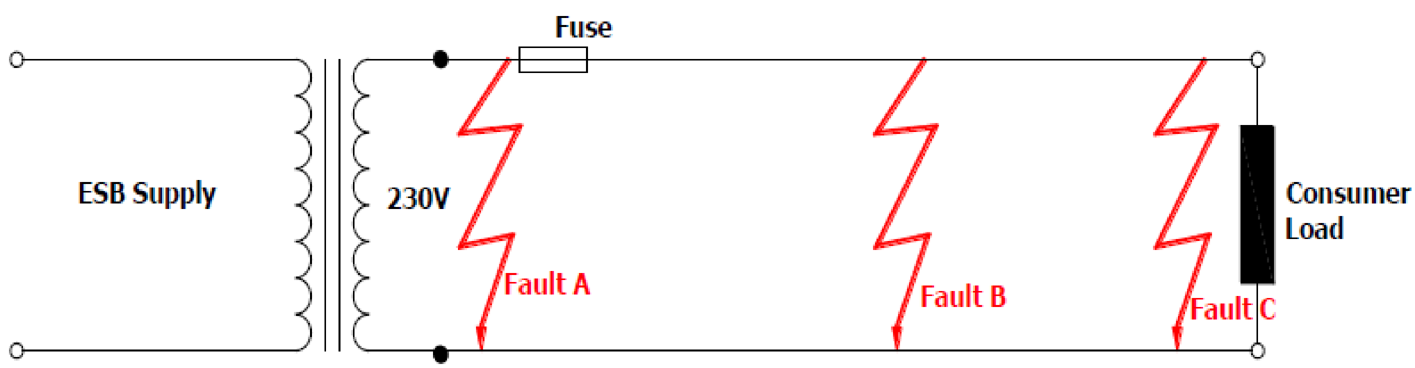
5.4 End of Sheet3

6 NONPILOT OVERCURRENT PROTECTION OF TL

Over current is caused by 2 reasons

1	2
Overload	Short Circuits
Is where too much current is drawn down an electrically healthy circuit ; there is no fault in the circuit. A properly designed circuit will interrupt an overload before any damage is done to the circuit	Is where a fault of a small impedance occurs between live conductors. The value of current will depend on where the fault occurs. Longer runs of cable have a significant **attenuating** effect on fault current.

6.1 Short Circuit



The SCC is dependent upon:

1 The circuit **voltage**

2 The total **impedance** of the circuit including the supply transformer

Distribution faults occur on one phase, on two phases, or on all three-phases.

Single-phase faults are the most common. Almost **80%** of the faults measured involved only one phase either in contact with the neutral or with ground.

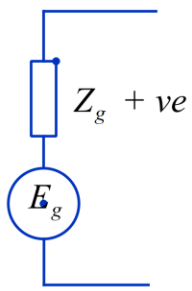
Fault	Percentage
One phase to neutral	63%
Phase to phase	11%
Two phases to neutral	2%
Three phase	2%
One phase on the ground	15%
Two phases on the ground	2%
Three phases on the ground	1%
Other	4%

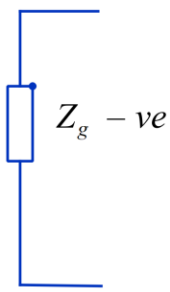
6.2 Fault Calculation

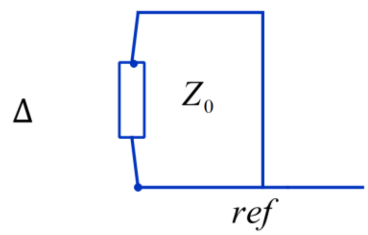
6.2.1 Symmetrical Components:

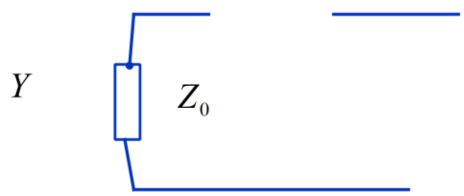
GENERATOR & MOTOR

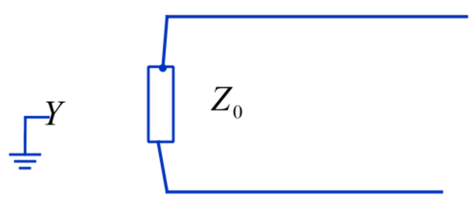
+VE Seq. -VE Seq. Zero Seq

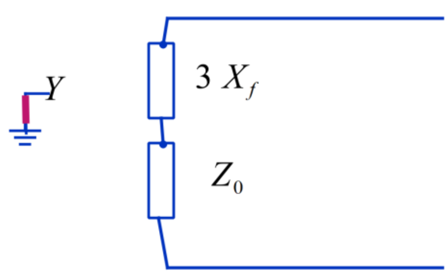












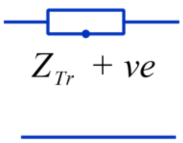
T.L & Static Load

+ ve Seq | − ve Seq | Zero Seq

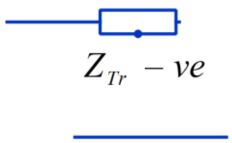
Z_{TL} $+ve$ | Z_{TL} $-ve$ | $Z_{TL}\,0$

Transformer

+ ve Seq | − ve Seq | Zero Seq



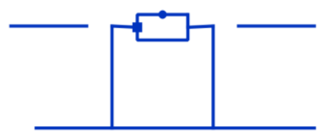
Z_{Tr} $+ve$



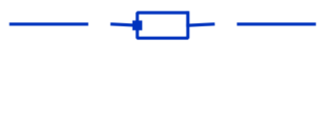
Z_{Tr} $-ve$

Z_0

$\Delta \quad \Delta$

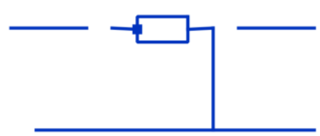


$Y \quad Y$

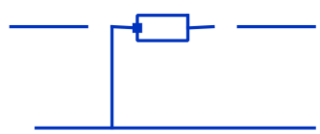


$Y \quad \Delta$

$Y \quad \Delta$

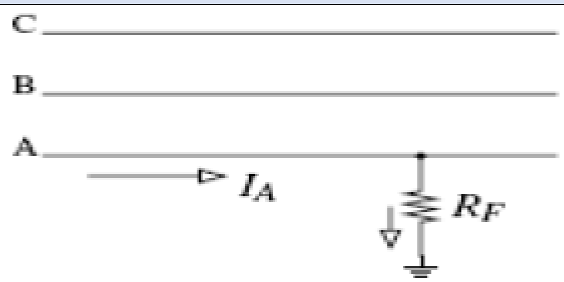
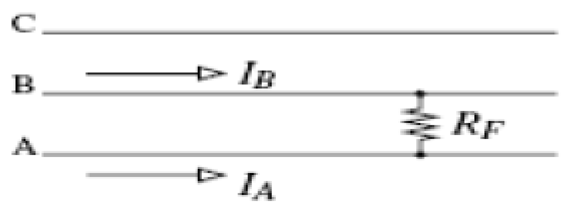
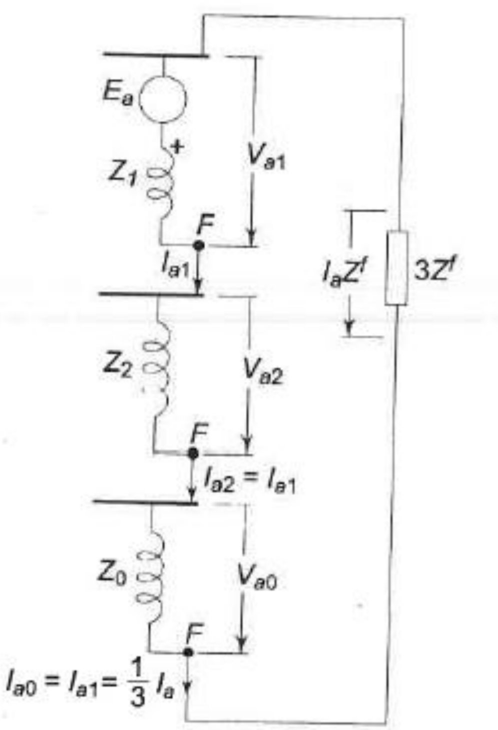
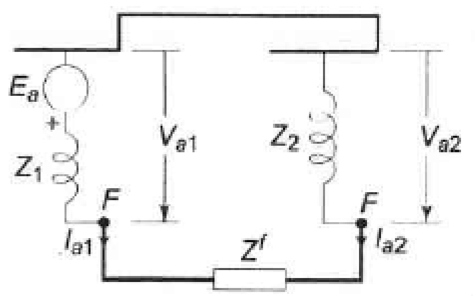


$\Delta \quad Y$

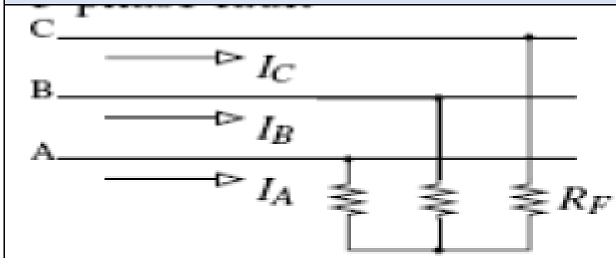


6.2.2 Faults Types

Assume Z1=Z2=Z3

Line-to-ground fault (LG)	Line-to-line fault (LL)
	
$I_A = \dfrac{V_{LN}}{\dfrac{2Z_1 + Z_0}{3} + R_F}$ 	$I_A = -I_B = -j\dfrac{\sqrt{3}\,V_{LN}}{2Z_1 + R_F}$  (b)

<table>
<tr><td></td><td></td></tr>
<tr><td>3ph Fault</td><td>Line to line to ground fault (LLG)</td></tr>
<tr><td>



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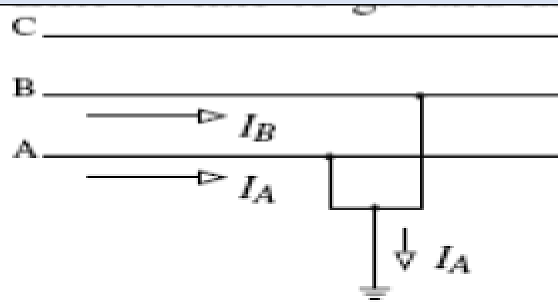


</td></tr>
<tr><td>

$$I_A = \frac{V_{LN}}{Z_1 + R_F}$$

</td><td>

$$I_A = -j\sqrt{3}\,\frac{Z_o - aZ_1}{Z_1(Z_1 + 2Z_0)}\,V_{LN}$$

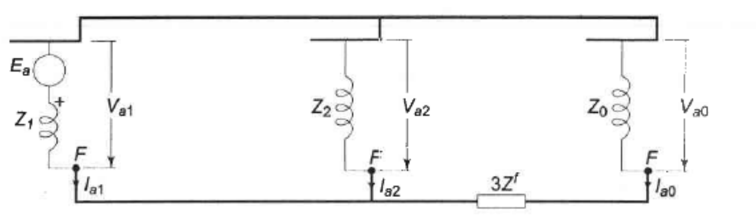
$$I_B = j\sqrt{3}\,\frac{Z_o - a^2 Z_1}{Z_1(Z_1 + 2Z_0)}\,V_{LN}$$

$$I_G = \frac{-V_{LN}}{\frac{Z_1 + 2Z_o}{3}}$$

$$\boldsymbol{I_{a1} = \frac{E_a}{\left(Z_1 + \frac{Z_2(Z_0 + 3Z_f)}{Z_2 + Z_0 + 3Z_f}\right)}}$$

$$\boldsymbol{I_{a0} = -I_{a1} * \frac{Z_{th-ve} + Z_f}{Z_{th-ve} + Z_{th+ve} + 3Z_f}}$$

$$\boldsymbol{I_f = 3I_{a0}}$$



</td></tr>
</table>

6.3 The protective devices for TL protection are:

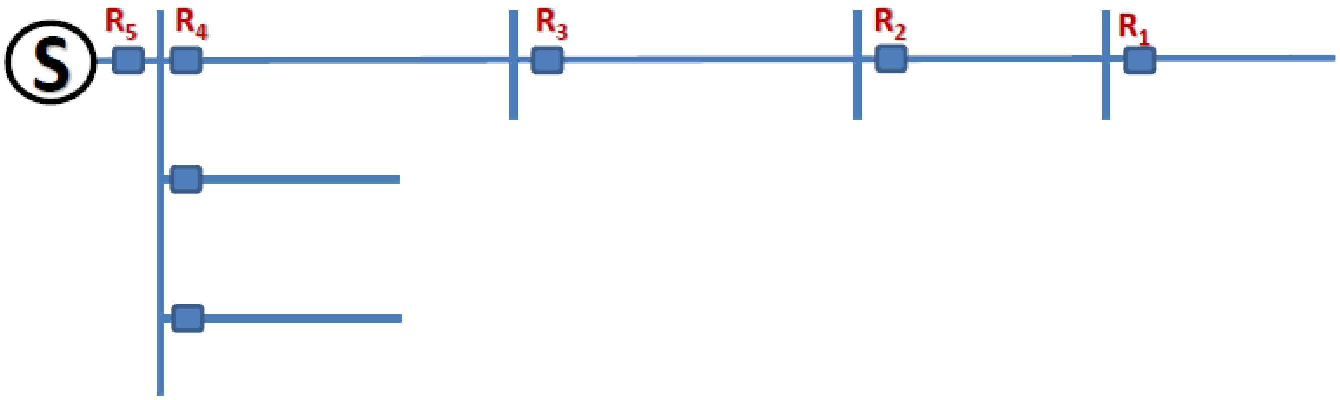
1- Fuses
2- Sectionalizes & Reclosers
3- Instantaneous overcurrent
4- Inverse, Time delay overcurrent
5- Directional overcurrent
6- Distance
7- Pilot

<u>ANSI Relays Code</u>

Overload	49
Time Delay	51
Instant.	50
Circuit Breaker	52
Differential Relay	87(G, T, …)
Distance Relay	21

7 OVERCURRENT PROTECTION

Maximum SC current is at generator terminals by going further the less the SC current gets



Max SC Current	18 kA	14 kA	10 kA	6 kA

7.1 Types

7.1.1 Time Graded Protection - Definite Time Overcurrent Relays (DTOCR)

7.1.2 Current graded protection - High Set Instantaneous Overcurrent (HSIOC)

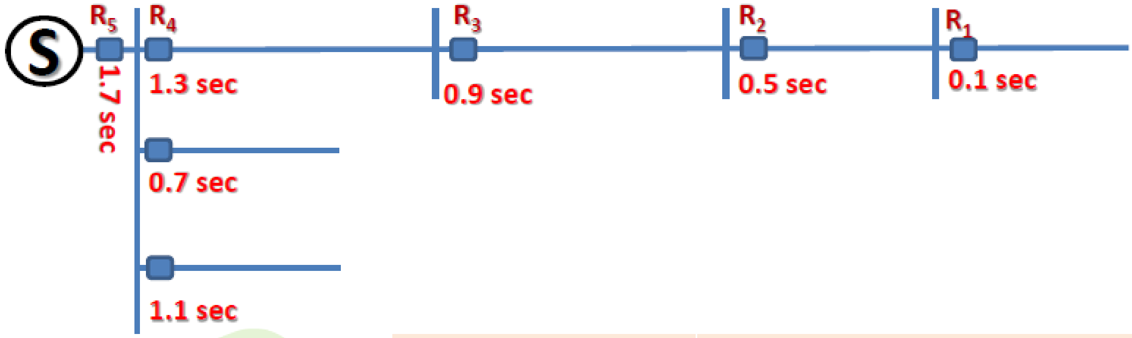
Setting current must be larger than max full load current

Has problems of: over-reach and under-reach

7.1.3 Time-Current graded protection -Inverse, time-delay Overcurrent relays

These relays has 2 values to be set 1- Current 2- Time

7.2 Definite time Overcurrent DTOCR

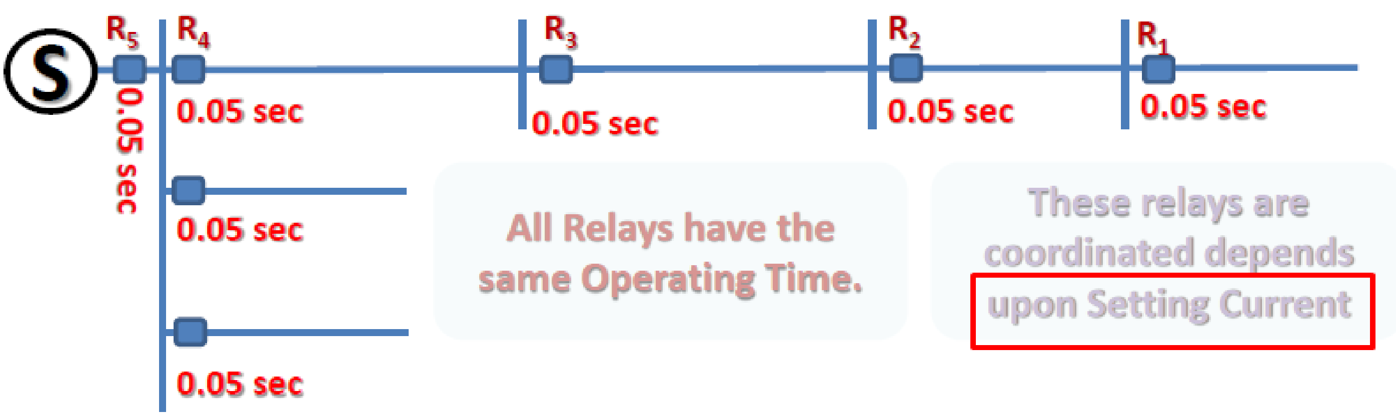


Fault Clearing Time increase although fault current increases

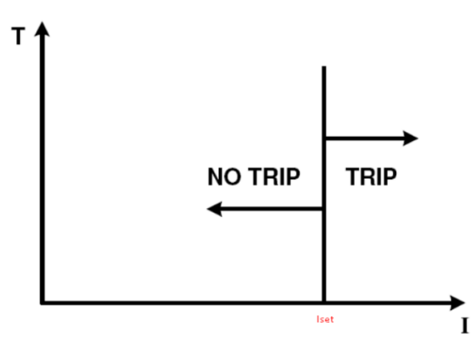
Very Dangerous

SC Current	Relay Operating Time
< 6 kA	0.1 sec
6 kA – 10 kA	0.5 sec
10 kA – 14 kA	0.9 sec
14 kA – 18 kA	1.3 sec

7.3 High Set Instantaneous Overcurrent HSIOC



Setting Current for these relays shall be higher enough to avoid the mal operation which may occur due to Overreach.



7.3.1 Over-Reach

Is when a relay operates for a fault out of its zone, opposite ***under-reach***

Its causes:

1- DC offset
2- System impedance change

7.3.2 Setting rules

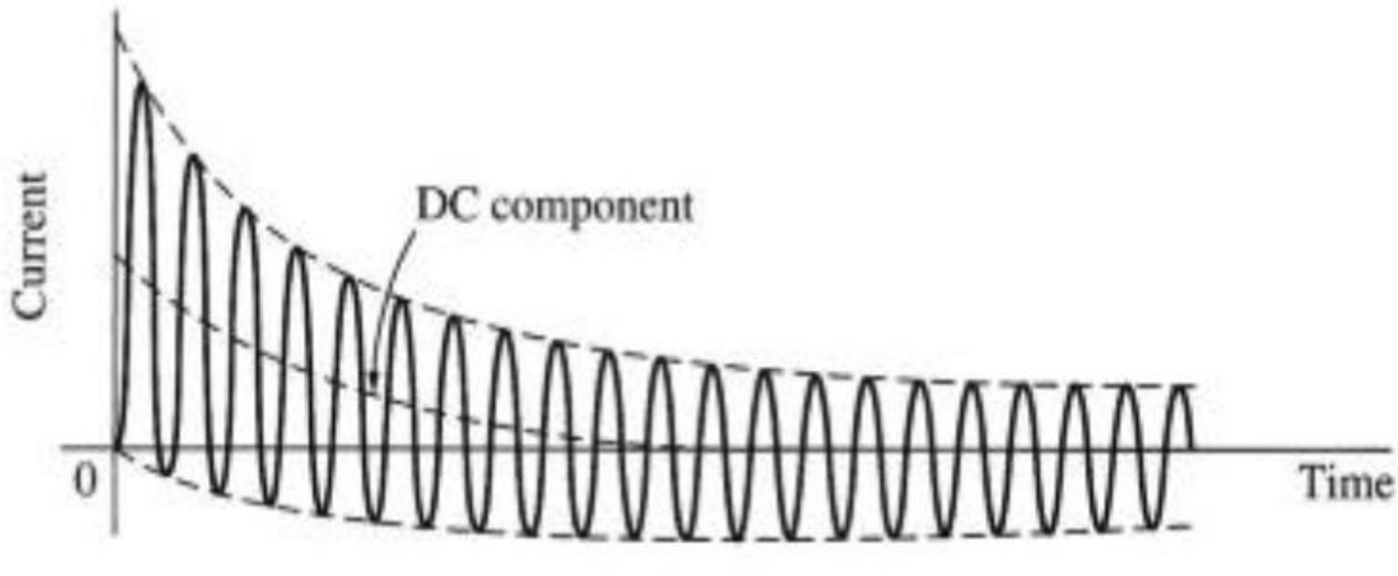
The instantaneous relay must not see beyond its own line section.

The values for which it must operate are very much **higher than even emergency loads.**

It is therefore common to **set**

an instantaneous relay about **125–135% above the maximum** value for which the relay should not operate, **and 90% of the minimum value for which the relay should operate.** $\mathbf{1.25}\boldsymbol{I_{max_{not\ operate}}} < \boldsymbol{I_{set}} < \mathbf{0.9}\,\boldsymbol{I_{f_{should\ operate}}}$ $\left(\boldsymbol{I_{set}} = \mathbf{1.35}\,\boldsymbol{I_{faultMax}}\right)$

7.3.2.1 DC Offset



Phase b

$$i(t) = I_m \sin(\omega t + \alpha - \theta) - I_m \sin(\alpha - \theta)\, e^{-\frac{t}{\tau}}$$

$$\%\ age\ transient\ overrach = \frac{I_1 - I_2}{I_2}$$

I2 is the rms value of symmetrical SC current which cause the relay to pick up.

I1 is the rms value of asymmetrical SC current achieved due to the existence of offset.

So,

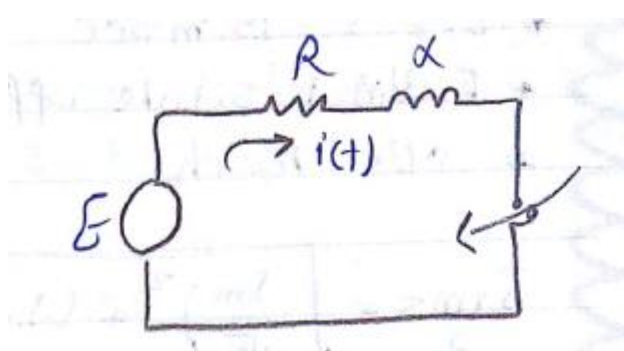
$$E = V_m \sin(\omega t + \alpha)$$

$$i(t) = I_m \sin(\omega t + \alpha - \theta) + A\, e^{-\frac{t}{\tau}}$$

$\alpha - incident\ angle$

$\theta -\ TL\ angle\ \tan^{-1}\left(\frac{\omega L}{R}\right) \cong 90$

$A - I_m \sin(\alpha - \theta)$



For fully-offset (α = 0) and ideal instantaneous ($t_{op} = 0$)

$$I_1 = I_{rms}\sqrt{3}$$

$$\%\ age\ transient\ overrach = \frac{\sqrt{3}-1}{1} = 0.73$$

For fully-offset (α = 0) and practical instantaneous ($t_{op} \neq 0$)

$$I_1 = I_{rms}\sqrt{1 + 2e^{-\frac{2t}{\tau}}}$$

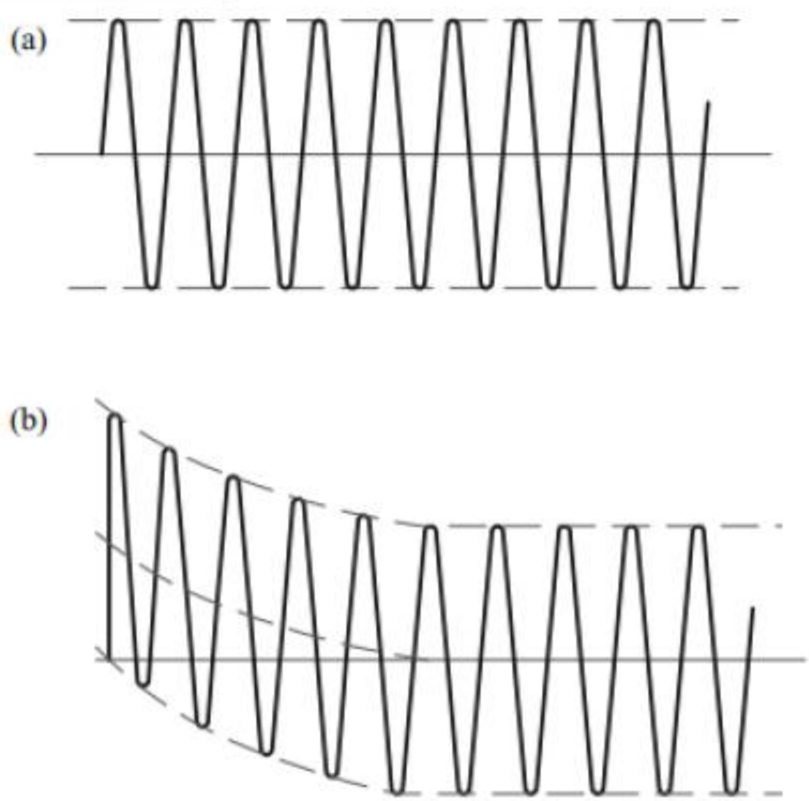
$$\%\ age\ transient\ overrach = \frac{\sqrt{1 + 2e^{-\frac{2t}{\tau}}} - 1}{1}$$

$$I_2 = I_{rms} \qquad I_1 = \sqrt{(I_{rms})^2_{ac} + (I_{rms})^2_{dc}}$$

$$I_1 = \sqrt{I^2_{rms} + \left(I_m \sin(\alpha - \theta)\, e^{-\frac{t}{\tau}}\right)^2}$$

$$I_1 = \sqrt{I^2_{rms} + \left(\sqrt{2} I_{rms} \sin(\alpha - \theta)\, e^{-\frac{t}{\tau}}\right)^2}$$

$$I_1 = I_{rms}\sqrt{1 + 2(\sin(\alpha - \theta))^2 e^{-\frac{2t}{\tau}}}$$



Variation of fault current with time: (a) $\alpha - \phi = 0$; (b) $\alpha - \phi = -\pi/2$

$A = -I_m \sin(\alpha - \theta)$

$\alpha = 0$

$A = I_m$

Full Positive off

$\alpha = 90$ = theta (phi)

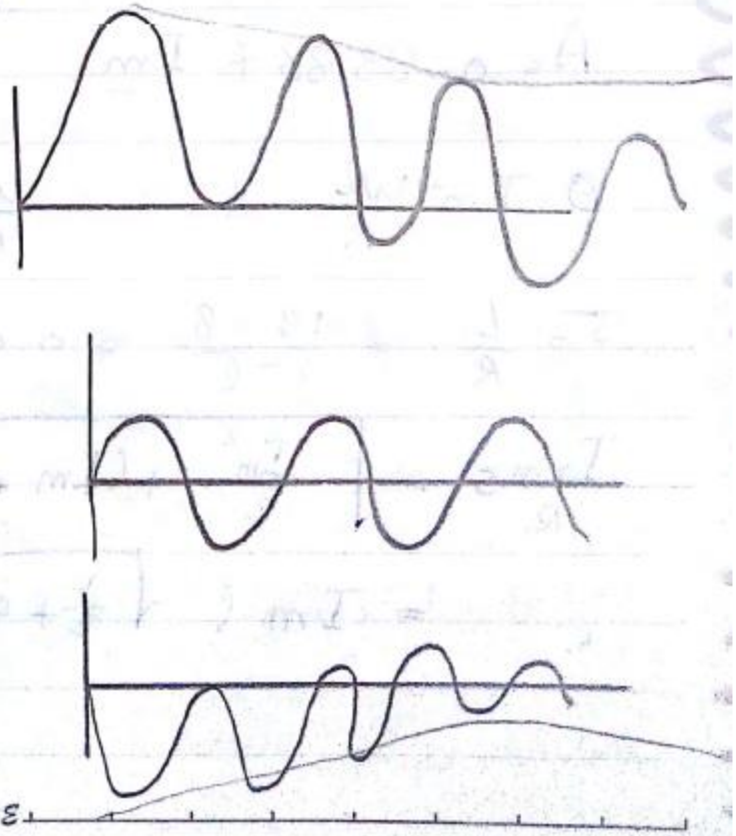
$A = 0$ أنضف حالة

No - Dc offset

$\alpha = 180$

$A = -I_m$

Fully negative off



Example

Given

$$t = \tau = 15mS$$

Fully Positive offset $(means\ A = I_{Max}, \alpha = 0)$
Over reach

$$I_1 = \sqrt{\left(\frac{I_m}{\sqrt{2}}\right)^2 + (I_m e^{-1})^2} = X\, I_m$$

$$over\ reach = \frac{\left(X - \frac{1}{\sqrt{2}}\right)}{\frac{1}{\sqrt{2}}}$$

7.3.3 In Problems

$$I_{fl} < I_{set} = 1.5 I_{fl} < I_{fault} = 2 I_{set}$$

Not to overreach

$$I_{set} = 1.35\ I_{remote-end}$$

$$I_{FR(point)} \geq 2.7\ I_{f_{remote-end}}$$

مسئلة: إمتحانات

over reach?

relay response time = 20msec t I_{rms_R} $\sqrt{t}$

$\alpha = 30$

$\theta = 87^\circ$

$A = -I_m \sin(\alpha - \theta) = A = -I_m \sin(30 - 87)$

$A = 0.83867\ I_m$

$\theta = \tan^{-1}\frac{wL}{R} = 87 \quad \therefore \frac{wL}{R} = 19.08 = \frac{2\pi f L}{R}$

$\tau = \frac{L}{R} = \frac{19.08}{2\pi f} = 0.060737$

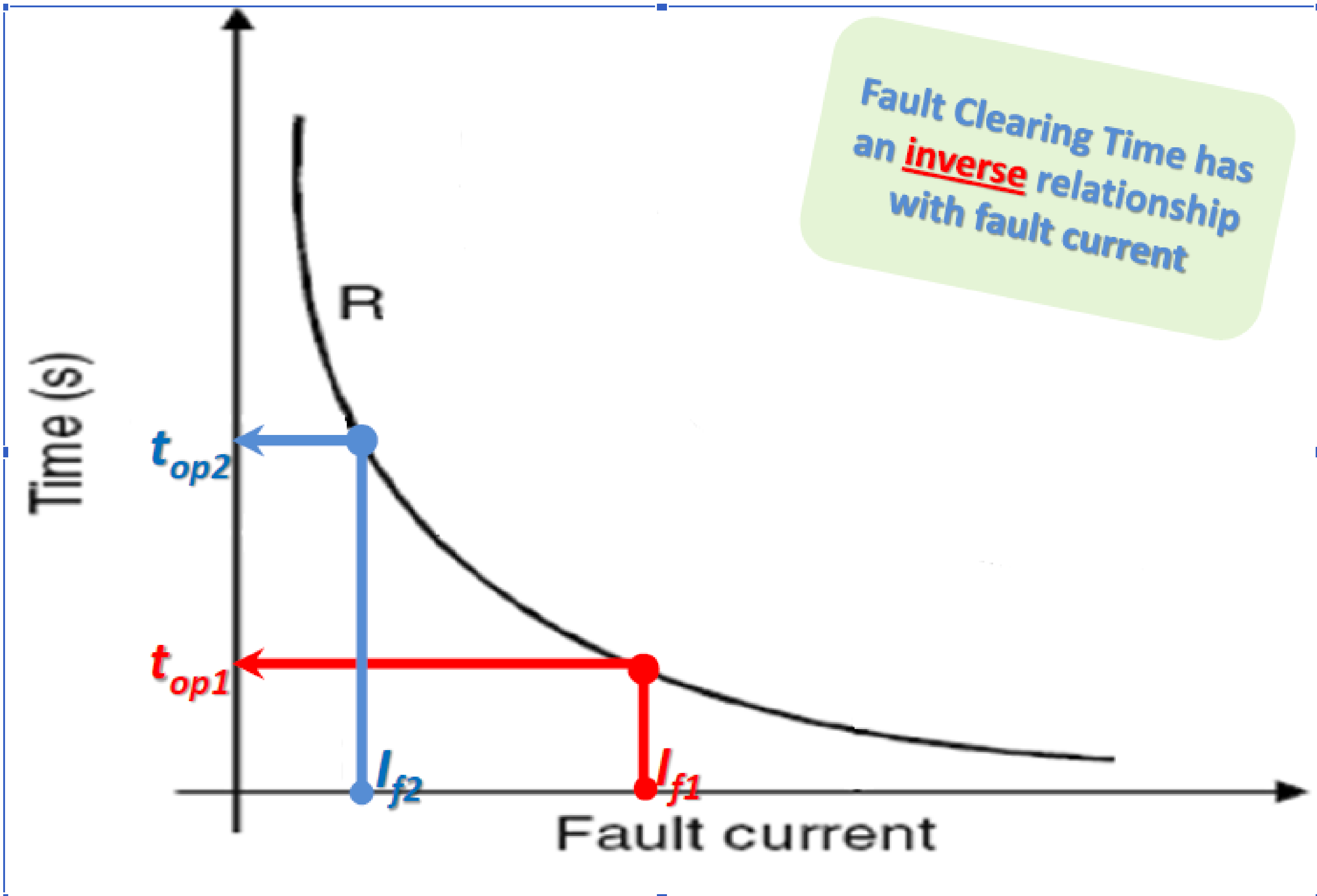
$I_{rms_R} = \sqrt{\frac{I_m^2}{2} + \left(I_m * 0.83867\ e^{-20\times10^{-3}/0.060737}\right)^2}$

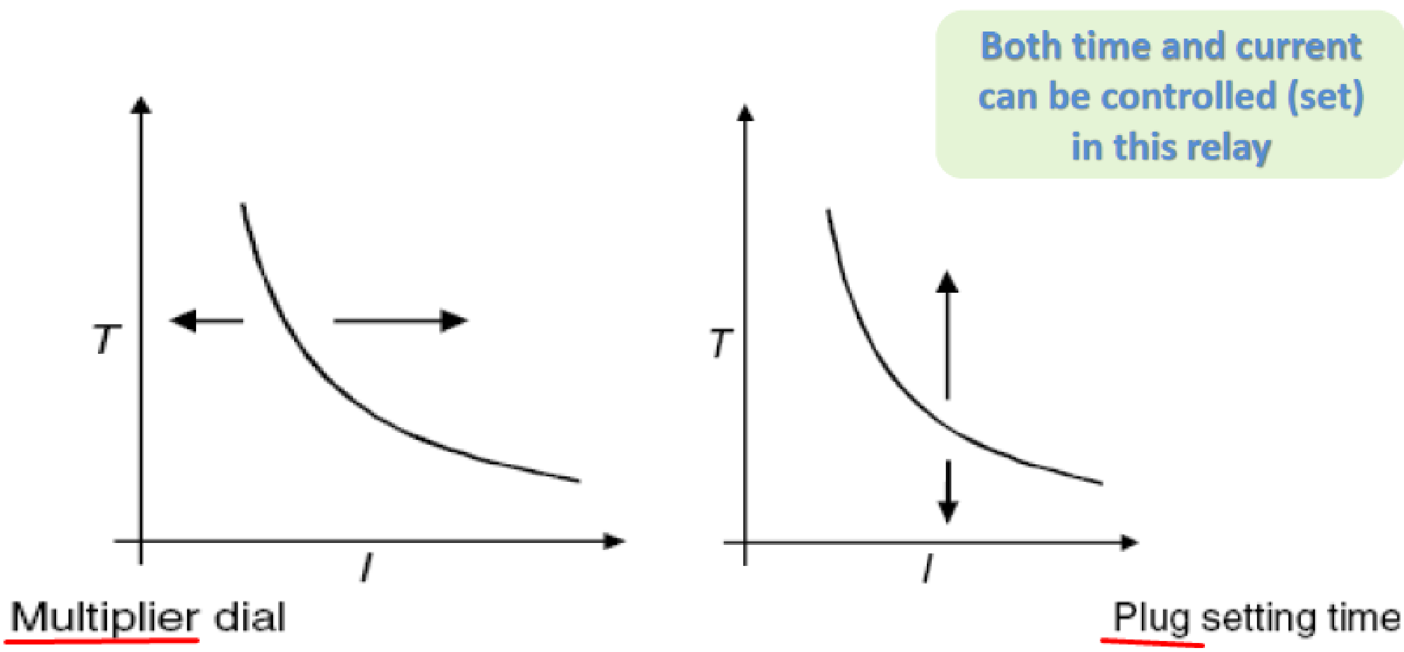
$= I_m \left(\sqrt{\frac{1}{2} + 0.36405} \right. = 0.929\ I_m$

7.3.3.1 System Impedance

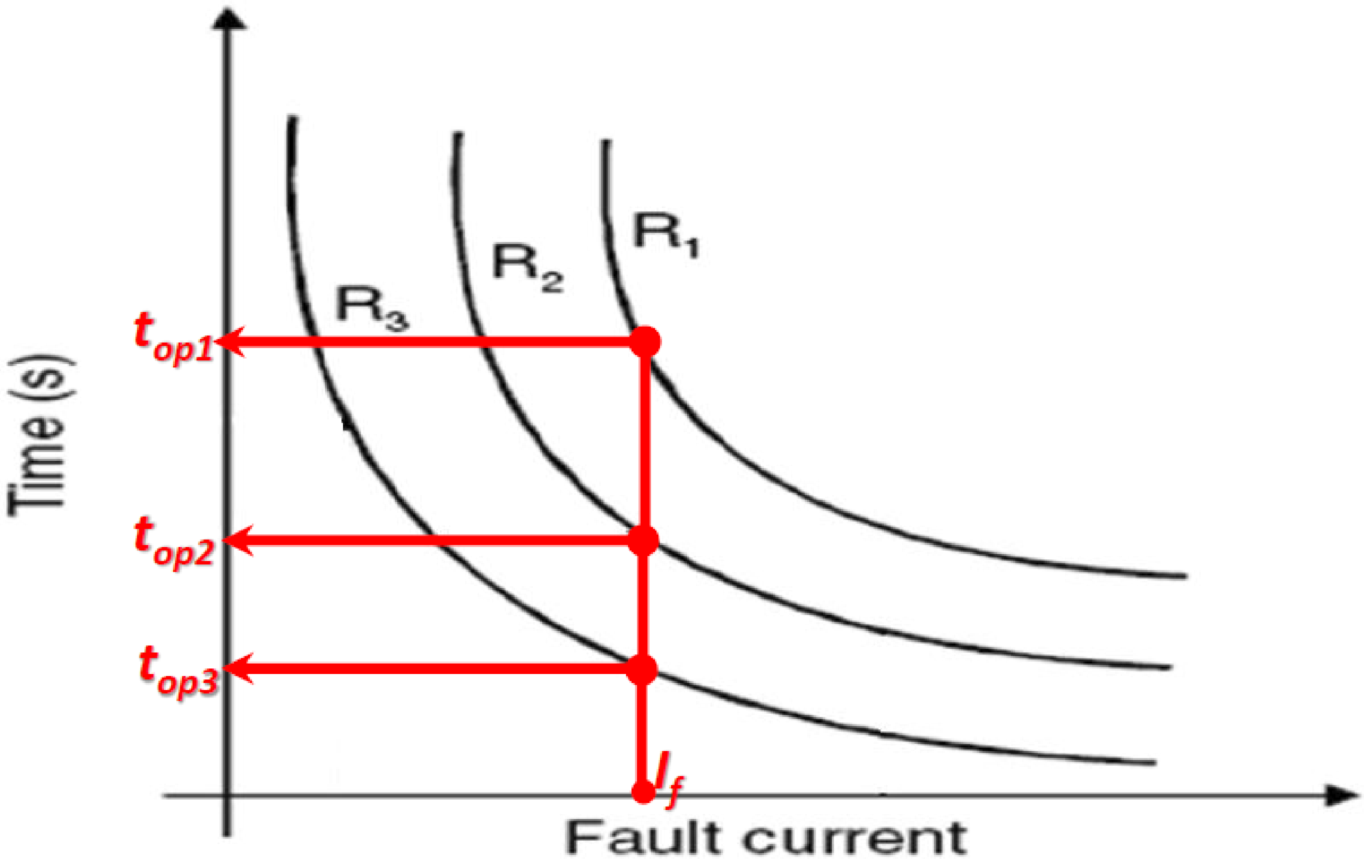
MISSING EQUATION??????or naah

7.4 Inverse, time-delay Overcurrent relays

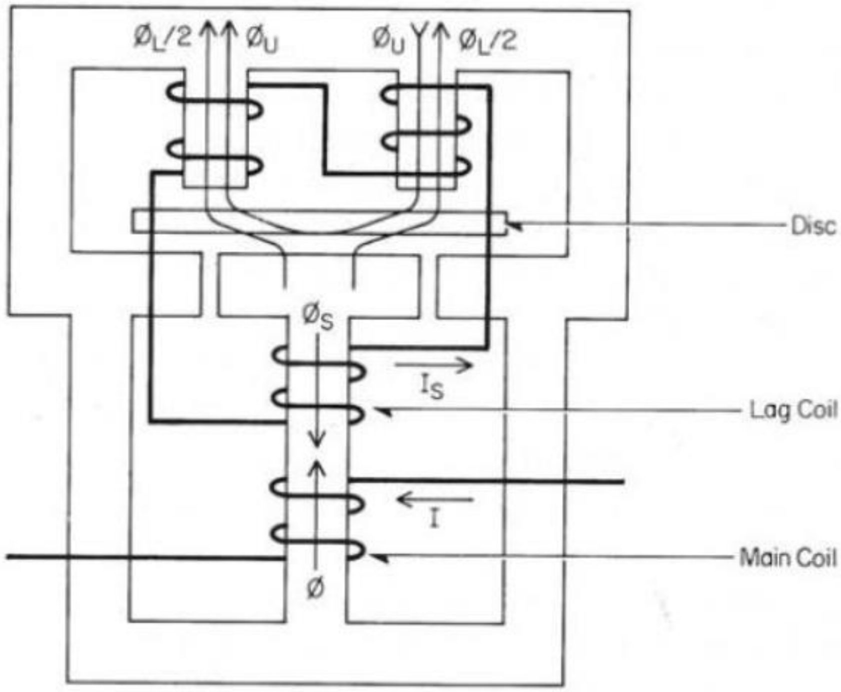


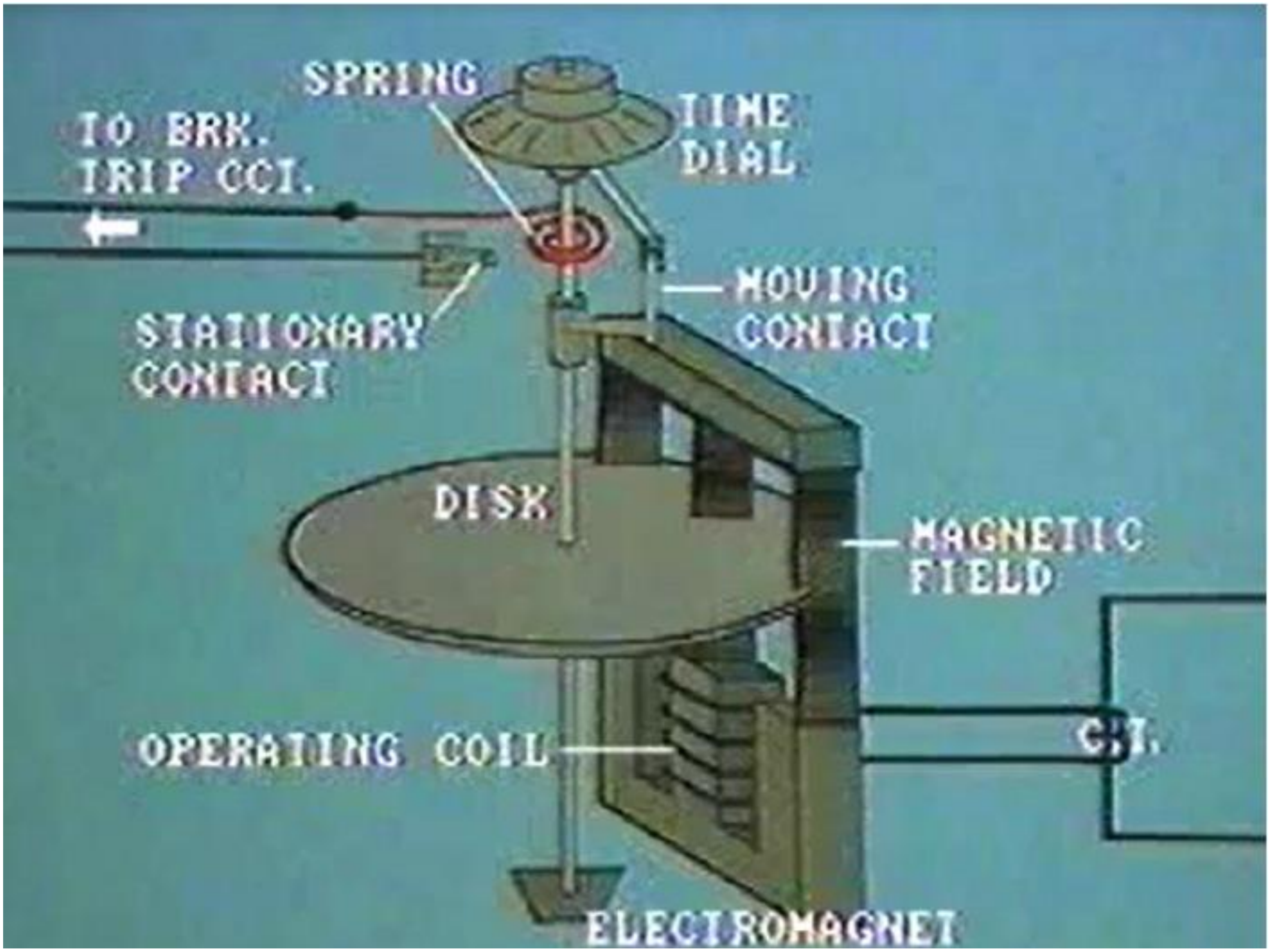


For same set current multiple relays operate at different times

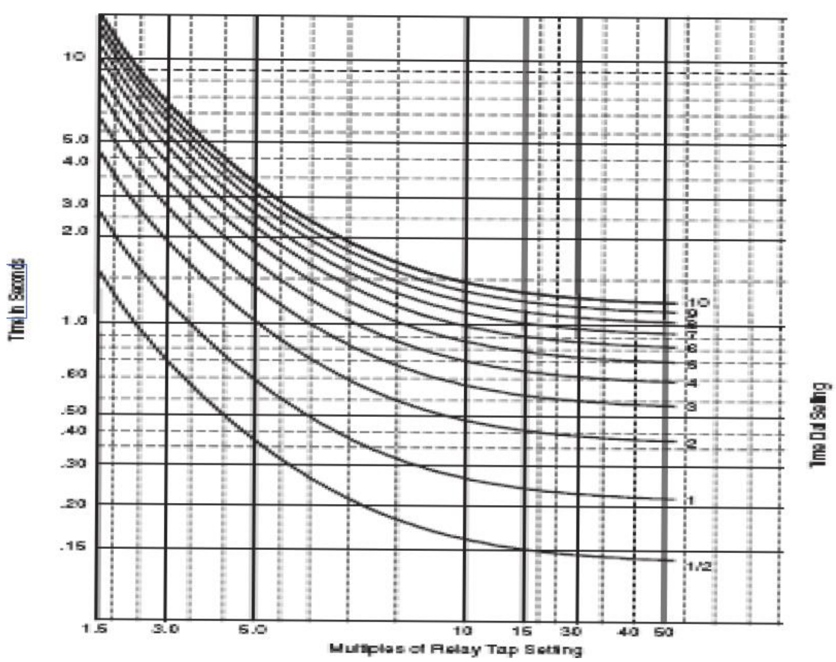


7.4.1 Construction of relay



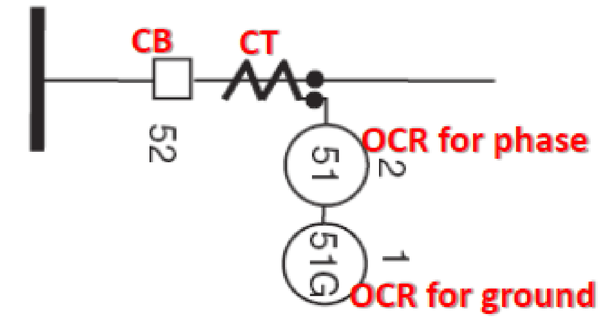


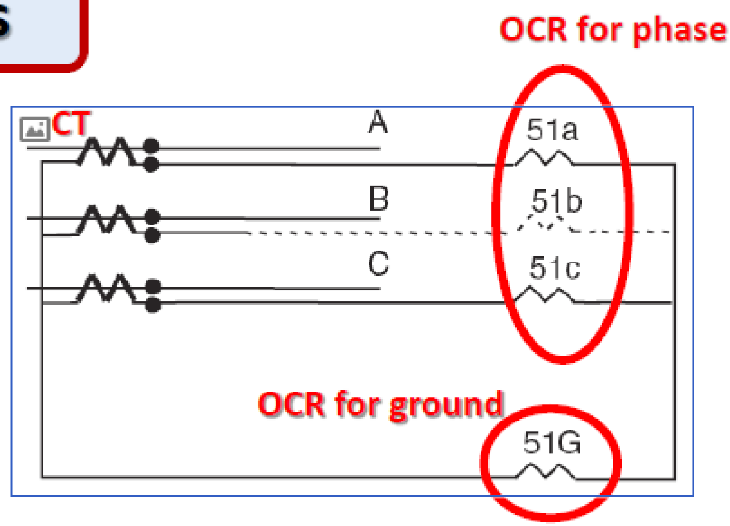
<u>When current increase the disk rotates quicker then it sends a signal to CB in less time</u>

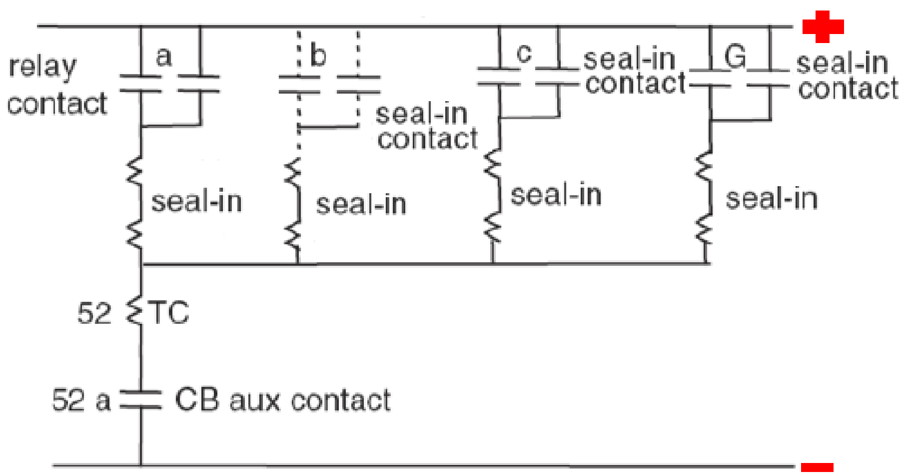


7.5 AC and DC connections

AC and DC connections







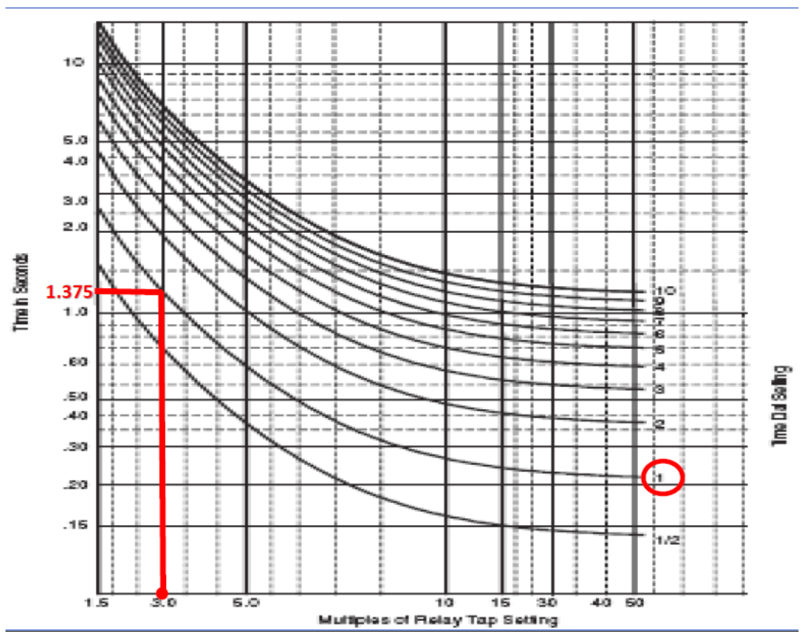
7.6 Overcurrent Problems (Curve Method)

In Ex1 and Ex2 : given Multiple and Lever setting (TDS) – required : operating time

Example 1:

Determine the operating time for a relay with a **4.0 A** pickup, time dial setting of **1.0** and **12.0 A** operating current.

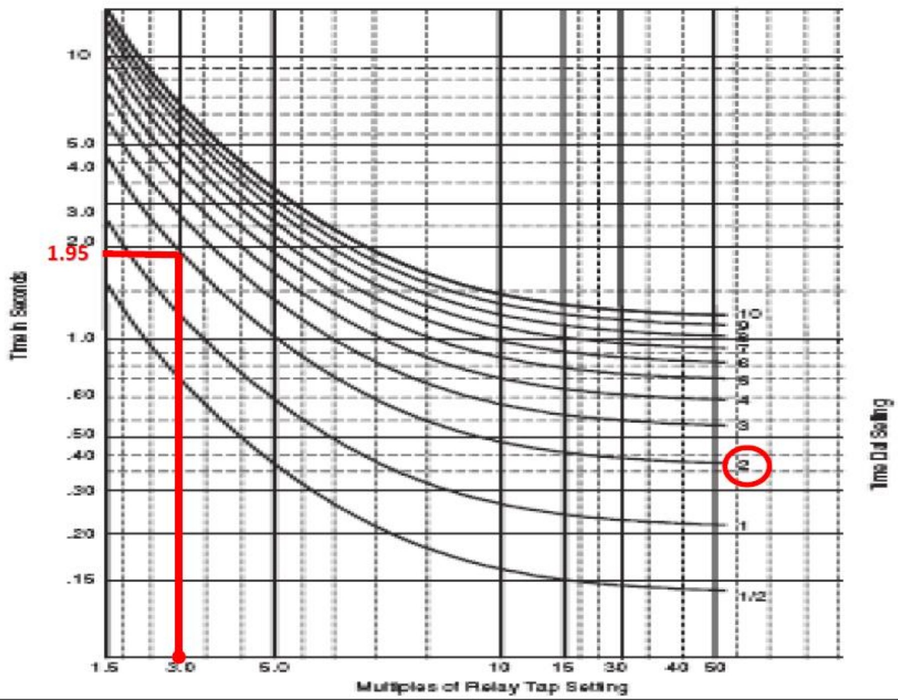
The input current of 12 A corresponds to a value of 12/4 = **3 pu**. Using this value from the curve and the corresponding curve for the time dial setting of **1.0** gives us an operating time of <u>**1.375 s**</u>.



Example 2

Determine the operating time for a relay with **5.0 A** pickup, time dial setting **of 2.0** and **15.0** A operating Current.

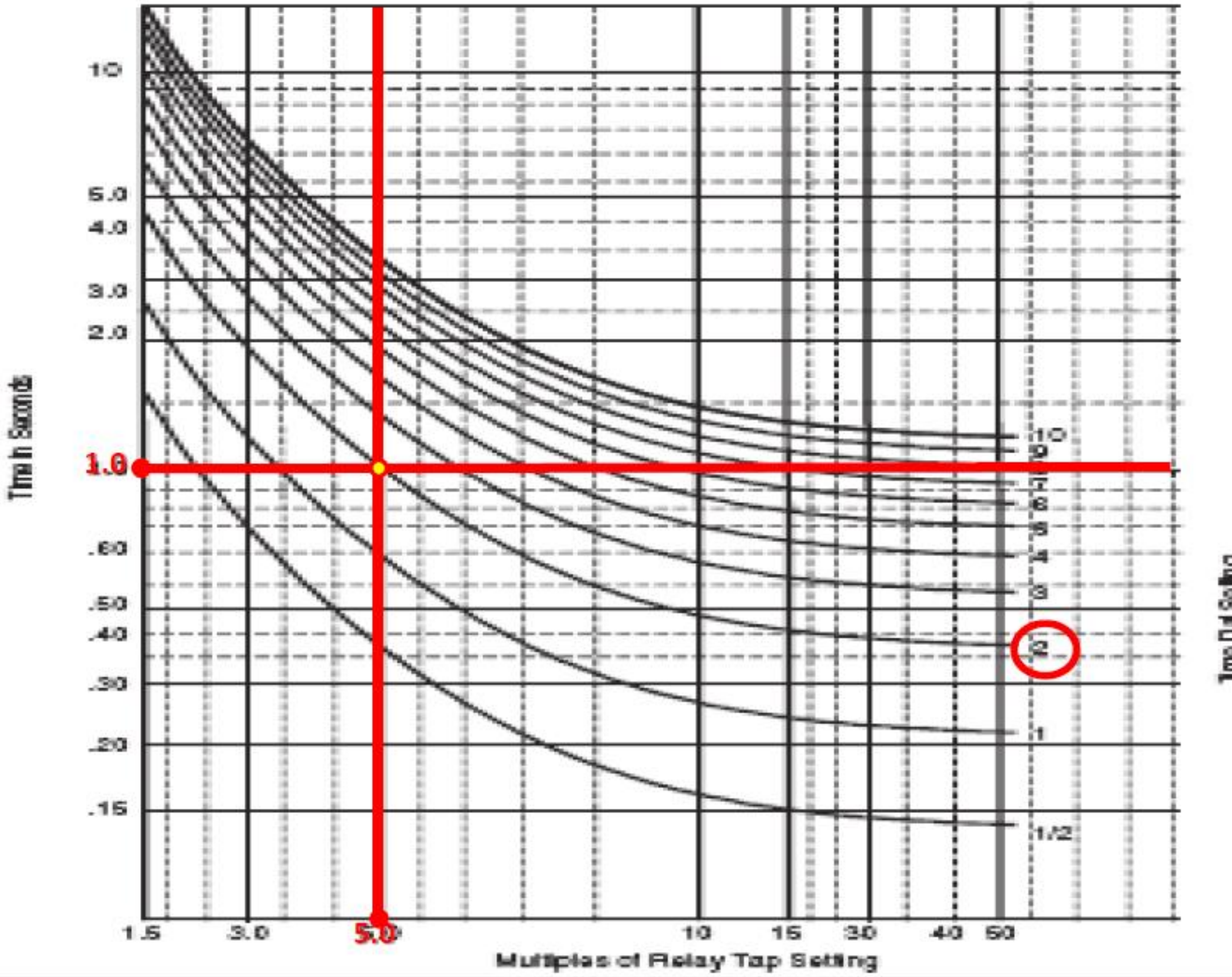
The input current of 15 A corresponds to a value of 15/5 = **3 pu**. Using this value from the curve and the corresponding curve for the time dial setting of **2.0** gives us an operating time of **1.95 s.**



In Ex3,4,5 : given current , operating time – required : the Dial Curve (time-delay lever setting)

Example 3
Determine the time-delay lever setting to achieve an operating time of 1.0 s for a relay set at 10.0 A pickup and an operating current of 50.0 A.

The input current of 50.0 A corresponds to a value of 50/10 = **5 pu**. Using this value on the abscissa and the operating time of **1.0 s** on the ordinate, the corresponding time dial curve **is 2.0.**

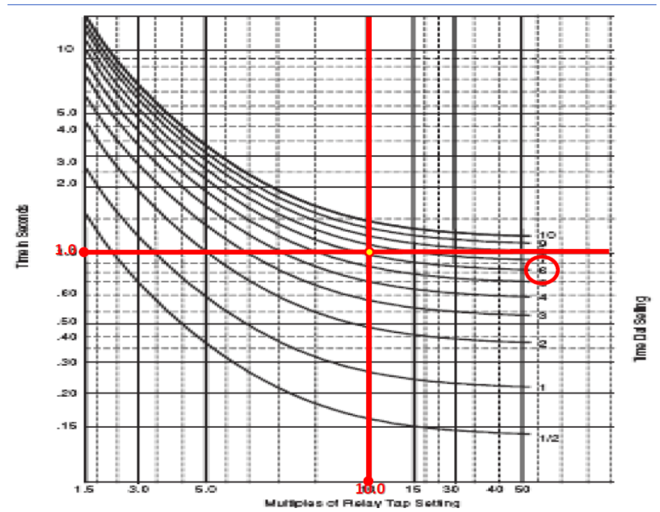


Time in Seconds
10
5.0
4.0
3.0
2.0
1.0
.60
.50
.40
.30
.20
.15
1.5
3.0
5.0
10
15
30
40
50
Multiples of Relay Tap Setting
10
9
7
6
5
4
3
2
1
1/2
Time Dial Setting

Example 4

Determine the time-delay lever setting to achieve an operating time of 1.0 s for a relay set at 5.0 A pickup and an operating current of 50.0 A.

The input current of 50.0 A corresponds to a value of 50/5 = **10** pu. Using this value on the abscissa and the operating time of **1.0 s** on the ordinate, the corresponding time dial curve is 6.0.

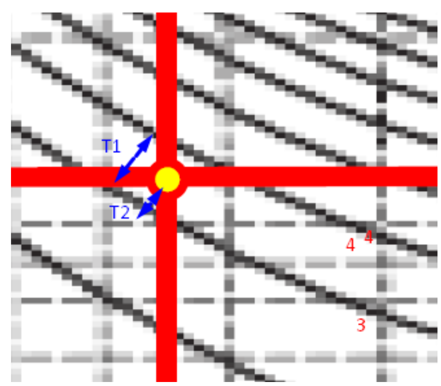


Example 5 IMPORTANT (INTERPOLATION)

Determine the time-delay lever setting to achieve an operating time of 1.0 s for a relay set at 5.0 A pickup and an operating current of 37.5 A.

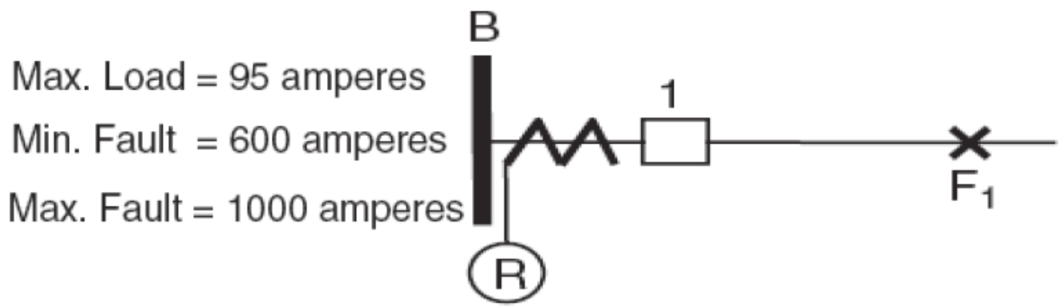
The input current of 35.0 A corresponds to a value of 37.5/5 = **7.5 pu**. Using this value on the abscissa and the operating time **of 1.0 s on** the ordinate, the corresponding time dial curve is 3.5.

$$\boldsymbol{interpolation \frac{T_1}{T_2} = \frac{4-3}{N-3}}$$



Example 6

Determine the CT ratio, pickup and time dial settings for the relay at breaker 1, assuming that no coordination with any other relay is required.



Select a CT ratio to give 5.0 A secondary current for maximum load,

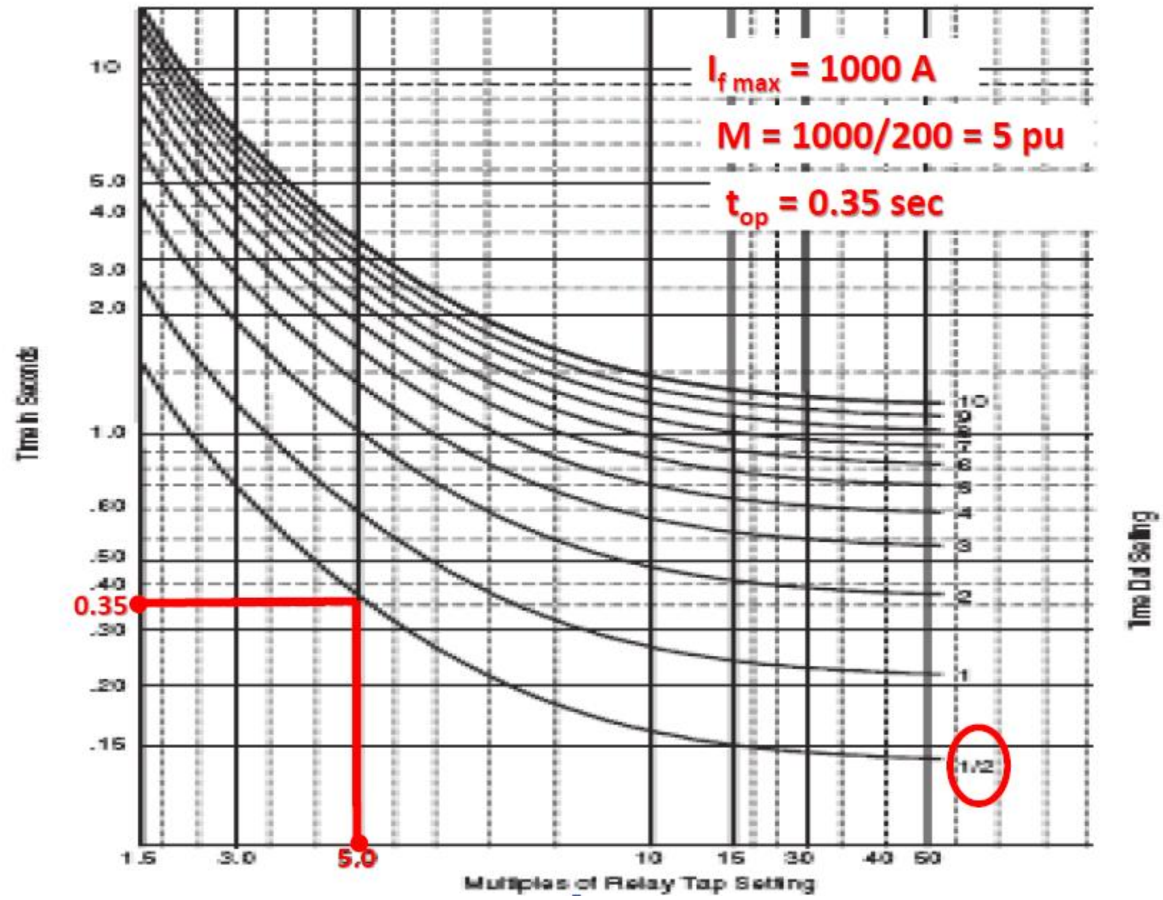
i.e. 95/5 = 19 : 1. We select the nearest standard CT ratio of 20 : 1 or 100 : 5.

The relay pickup setting should be bracketed by twice the maximum load and one-third of the minimum fault. $2I_{maxload} < I_{Set} < \frac{1}{3}I_{minfault}$

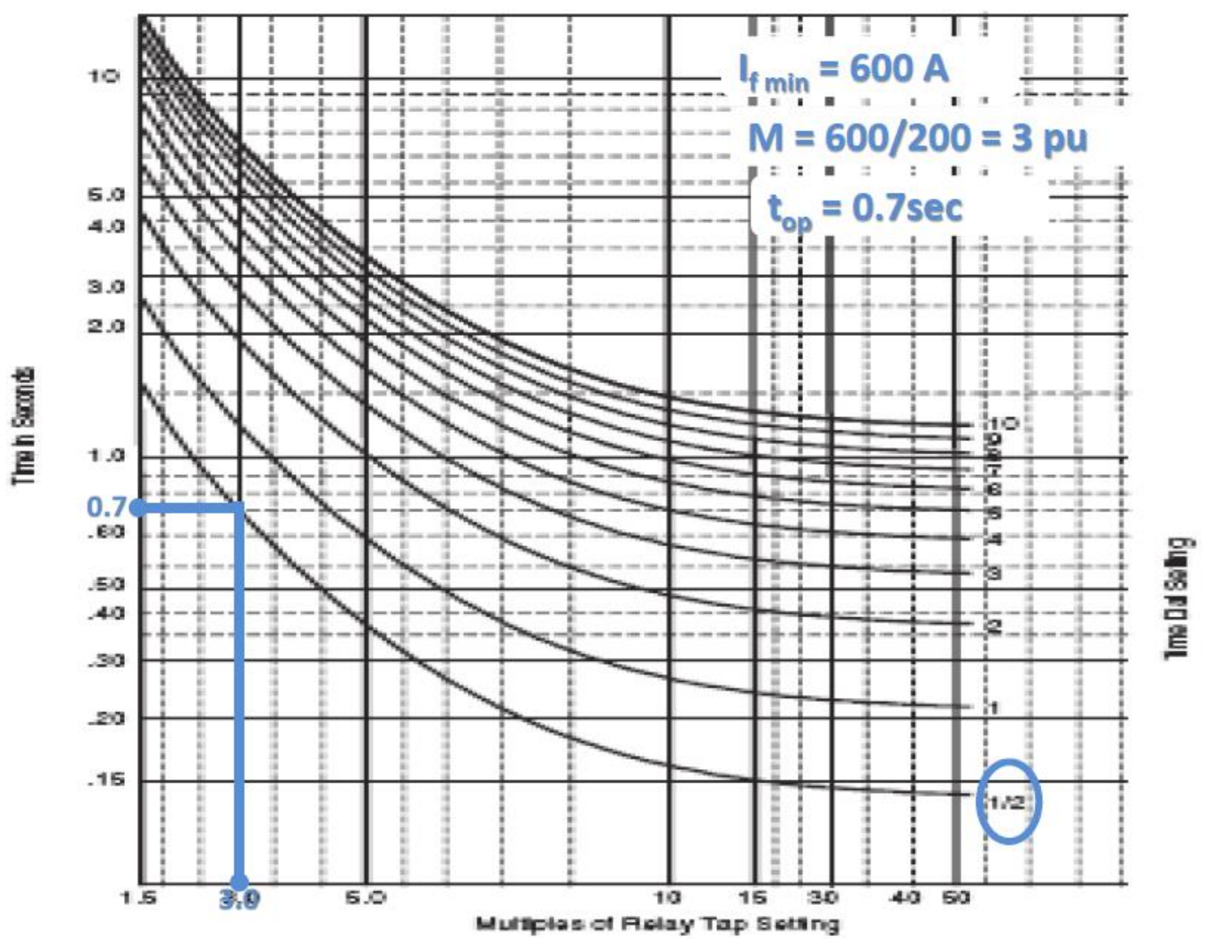
Using the actual CT ratio, twice maximum load is 190 A divided by 20(CT turns ratio), or a relay current of 9.5 A. say 10 A

Assuming the relay has taps 4.0, 6.0, .., 12.0, we would select the 10.0 A tap,
giving a primary current relay pickup of 200 A. *(twice * taps * relay current at max load)) 2*10*10*

No coordination is required, so one can set the time delay at the **lowest dial setting** (fastest time) of 0.5



$I_{f\,max}$ = 1000 A
M = 1000/200 = 5 pu
t_{op} = 0.35 sec
0.35
5.0
Time in Seconds
Time Dial Setting
Multiples of Relay Tap Setting



$I_{f\,min}$ = 600 A
M = 600/200 = 3 pu
t_{op} = 0.7sec
0.7
3.0
Time in Seconds
Time Dial Setting
Multiples of Relay Tap Setting

7.7 Standard Inverse Overcurrent relays

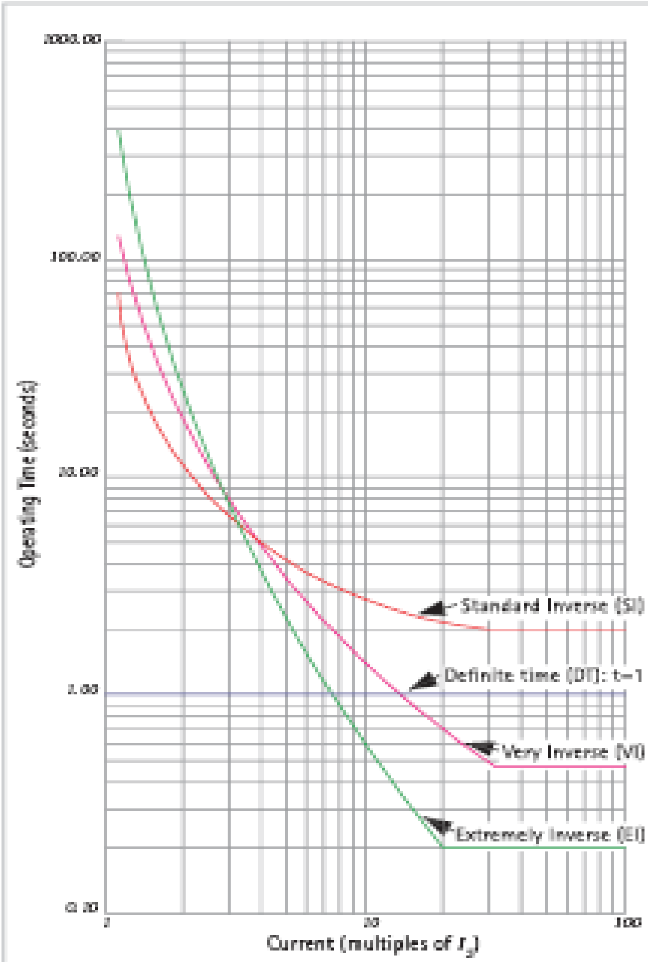
Relay Characteristic	Equation (IEC 60255)
Standard Inverse (SI)	$t = TMS \times \frac{0.14}{I_r^{0.02} - 1}$
Very Inverse (VI)	$t = TMS \times \frac{13.5}{I_r - 1}$
Extremely Inverse (EI)	$t = TMS \times \frac{80}{I_r^2 - 1}$
Long time standard earth fault	$t = TMS \times \frac{120}{I_r - 1}$

(a): Relay characteristics to IEC 60255

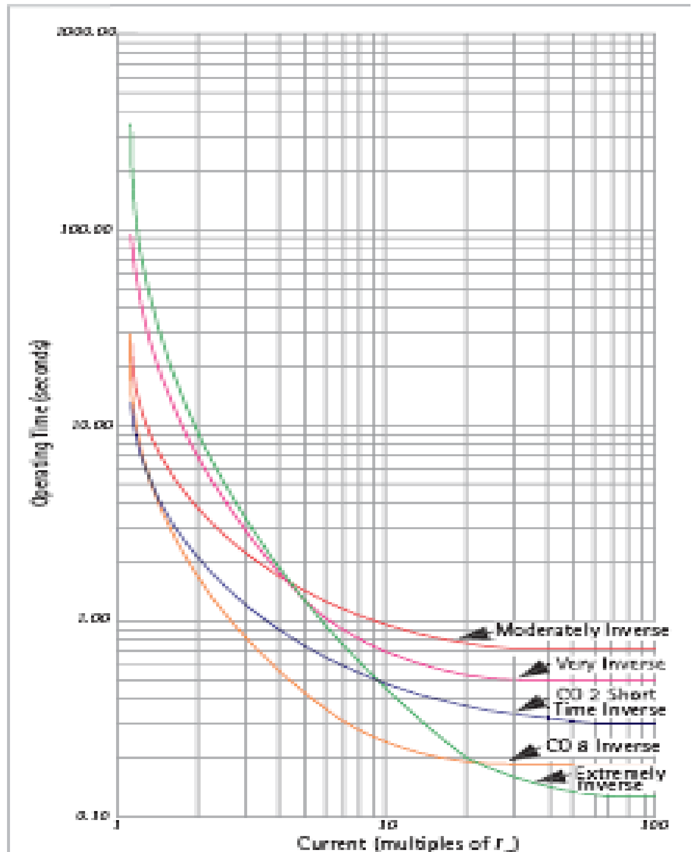
Relay Characteristic	Equation (IEC 60255)
IEEE Moderately Inverse	$t=\frac{TD}{7}\left\{\left(\frac{0.0515}{I_r^{0.02}-1}\right)+0.114\right\}$
IEEE Very Inverse	$t=\frac{TD}{7}\left\{\left(\frac{19.61}{I_r^2-1}\right)+0.491\right\}$
Extremely Inverse (EI)	$t=\frac{TD}{7}\left\{\left(\frac{28.2}{I_r^2-1}\right)+0.1217\right\}$
US CO8 Inverse	$t=\frac{TD}{7}\left\{\left(\frac{5.95}{I_r^2-1}\right)+0.18\right\}$
US CO2 Short Time Inverse	$t = \frac{TD}{7}\left\{\left(\frac{0.02394}{I_r^{0.02} - 1}\right) + 0.01694\right\}$

$I_r = (I/I_s)$, where I_s = relay setting current
TMS = Time multiplier Setting
TD = Time Dial setting

(b): North American IDMT relay characteristics



(a) IEC 60255 characteristics ; TMS=1.0



(b) North American characteristics; TD=7

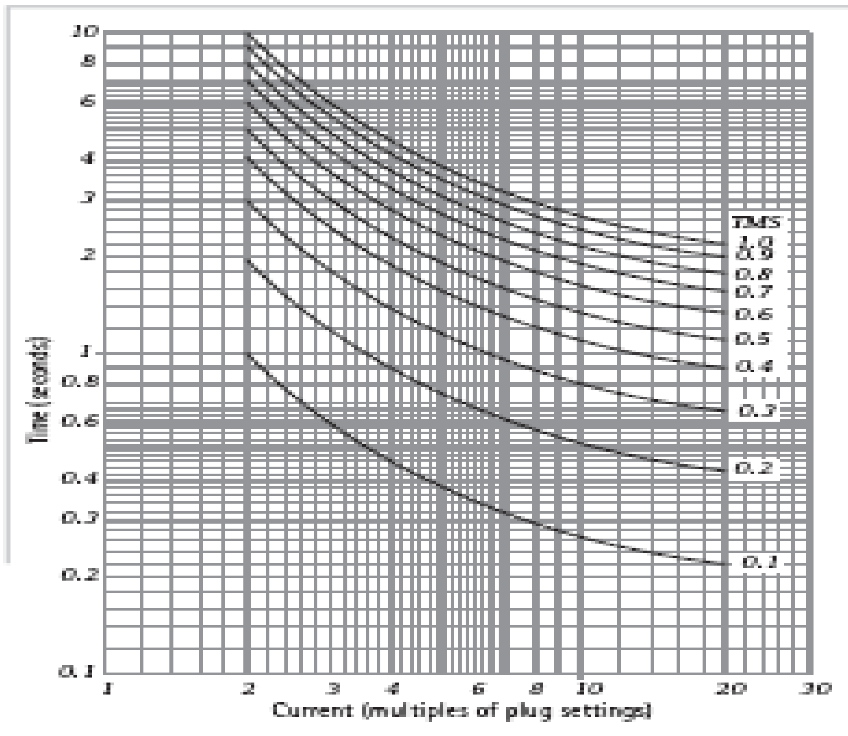
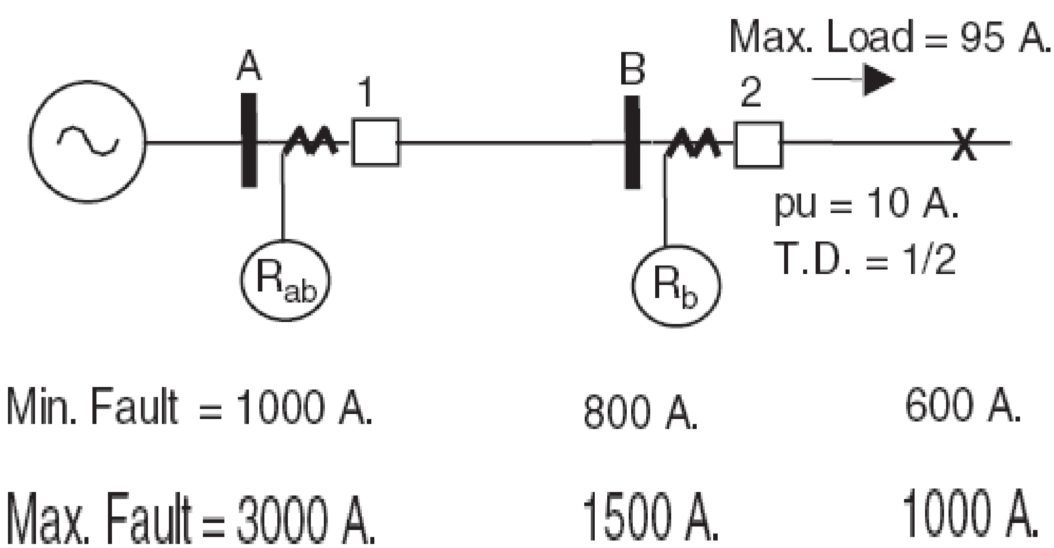


Figure 9.5: Typical time/current characteristics of standard IDMT relay

Example 1

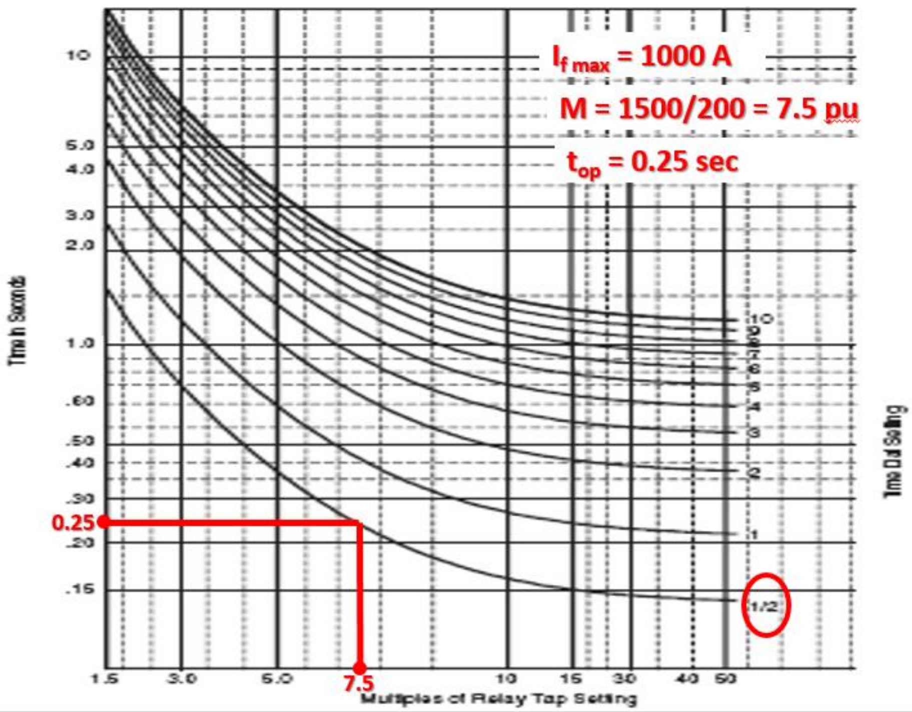
Determine the CT ratio, pickup and time dial settings for the relays shown in the following circuit.



For R_b

- Select a CT ratio to give 5.0 A secondary current for maximum load, i.e. 95/5 = 19 : 1. We select the nearest standard CT ratio of 20 : 1 or 100 : 5.
- **The relay pickup setting should be bracketed by twice the maximum load and one-third of the minimum fault.**

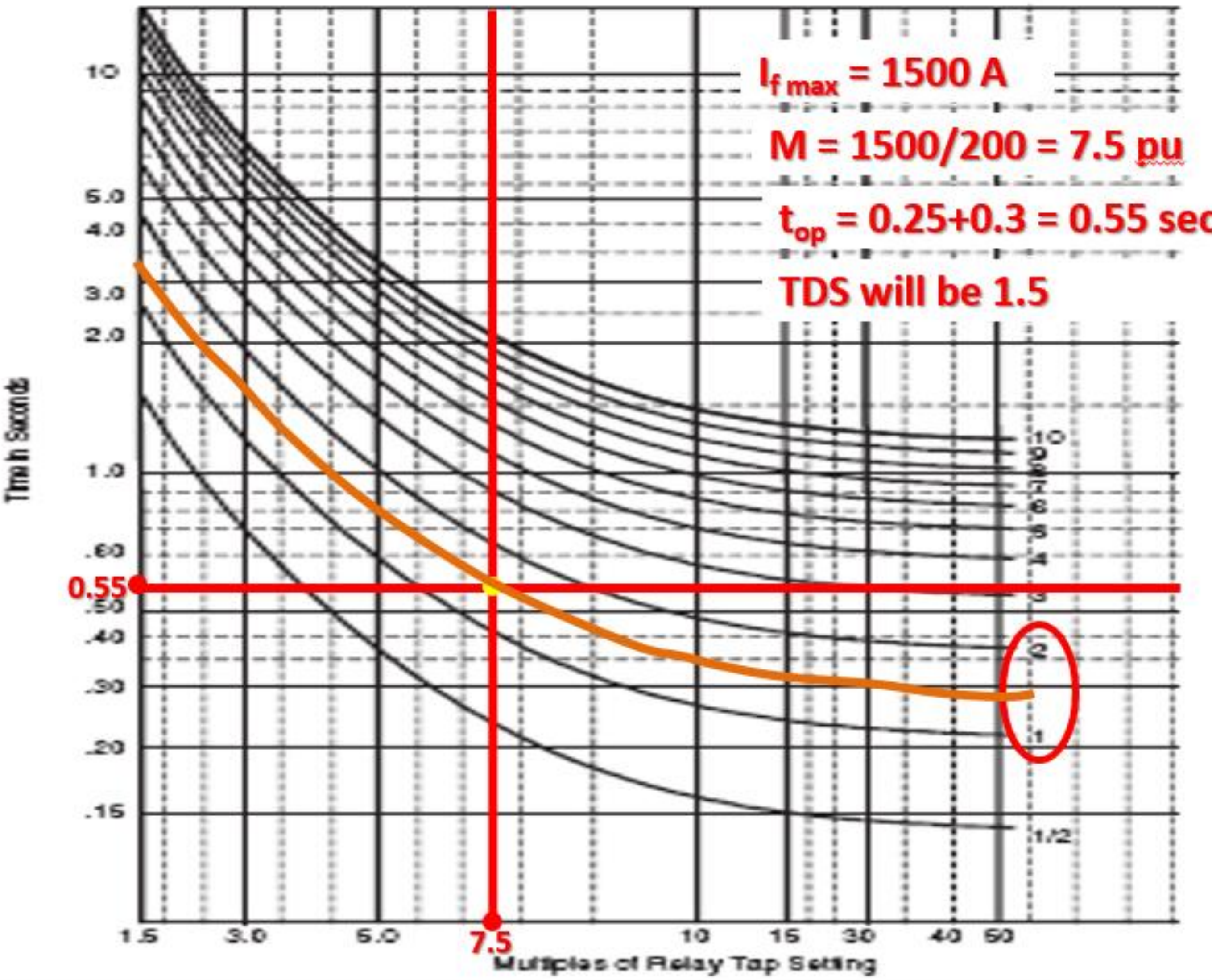
- **Assuming the relay has taps 4.0, 6.0, .., 12.0, we would select the 10.0 A tap, giving a primary current relay pickup of 200 A.**
- **No coordination is required, so one can set the time delay at the lowest dial setting (fastest time) of 0.5**



For R_{ab}

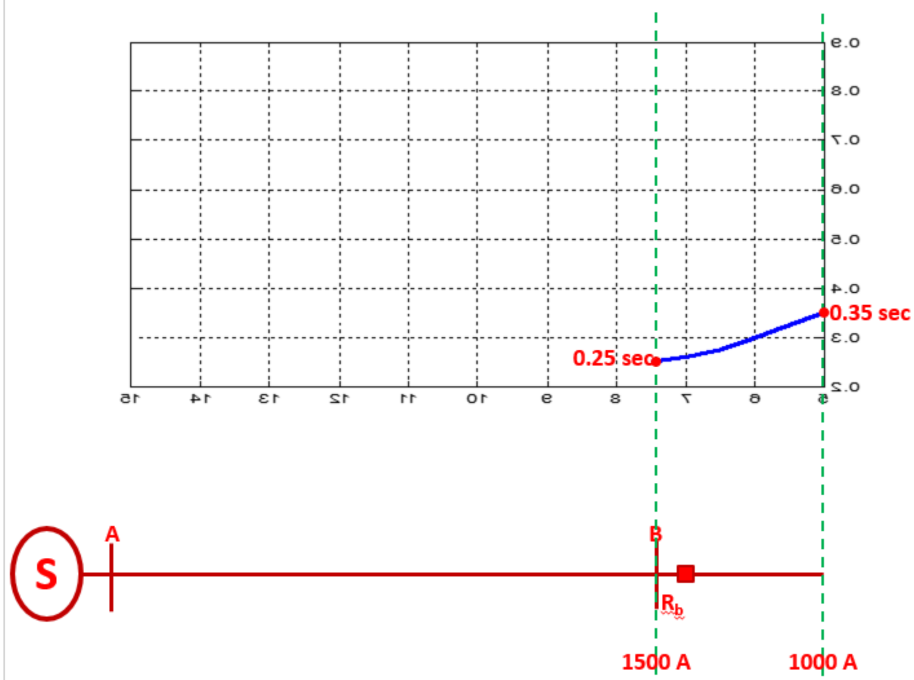
- R_{ab} should be set for the same pickup current, i.e. it sees the same faults, but is set at a slower (higher) time dial.
- **The operating time of R_b for the max fault current at bus B (1500 A) divided by its pickup setting (200 A) or 7.5 pu and the 0.5 time dial. This is seen to be 0.25 s.**
- **Add 0.3 s coordinating time and R_{ab} operating time should be 0.55 s.**
- **For a fault current of 1500 A at bus B and pu of 200 A, the multiple of the tap setting is 7.5 pu and the operating time is 0.55 s.**

- **Interpolating between the time dial setting curves of 1 and 2 gives a setting of 1.5.**

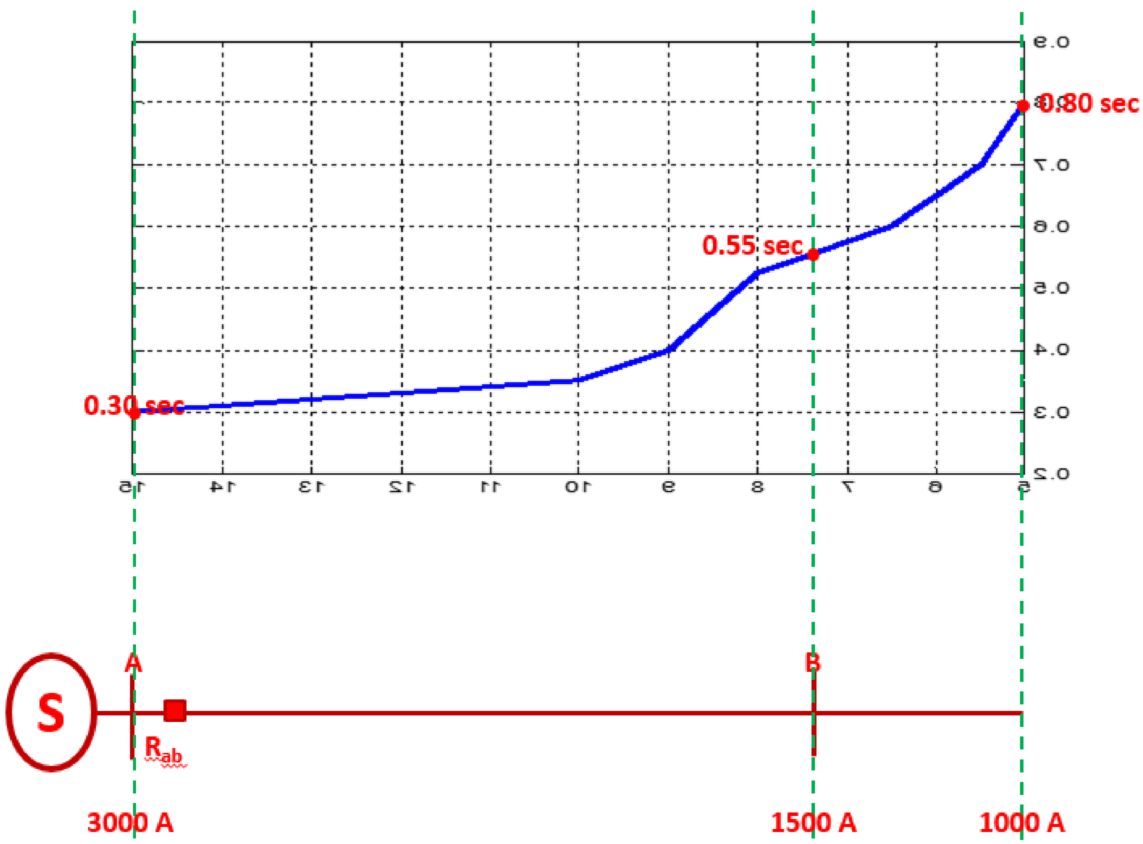


ADD SLIDES FROM 57 to 77 from Lec 5

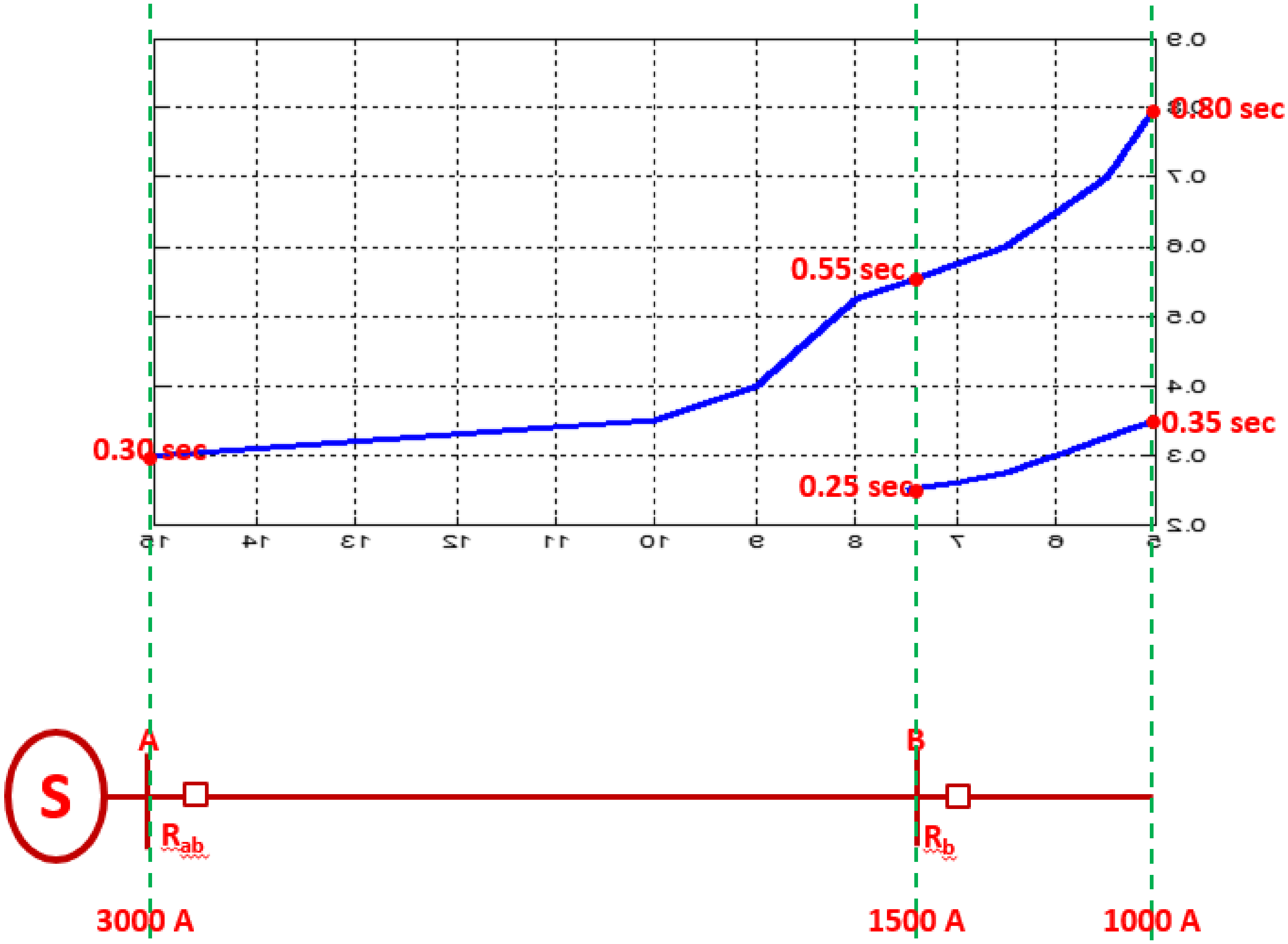
Rb


0.35 sec
0.25 sec
S
A
B
R_b
1500 A
1000 A

Rab


0.80 sec
0.55 sec
0.30 sec
S
A
B
R_{ab}
3000 A
1500 A
1000 A

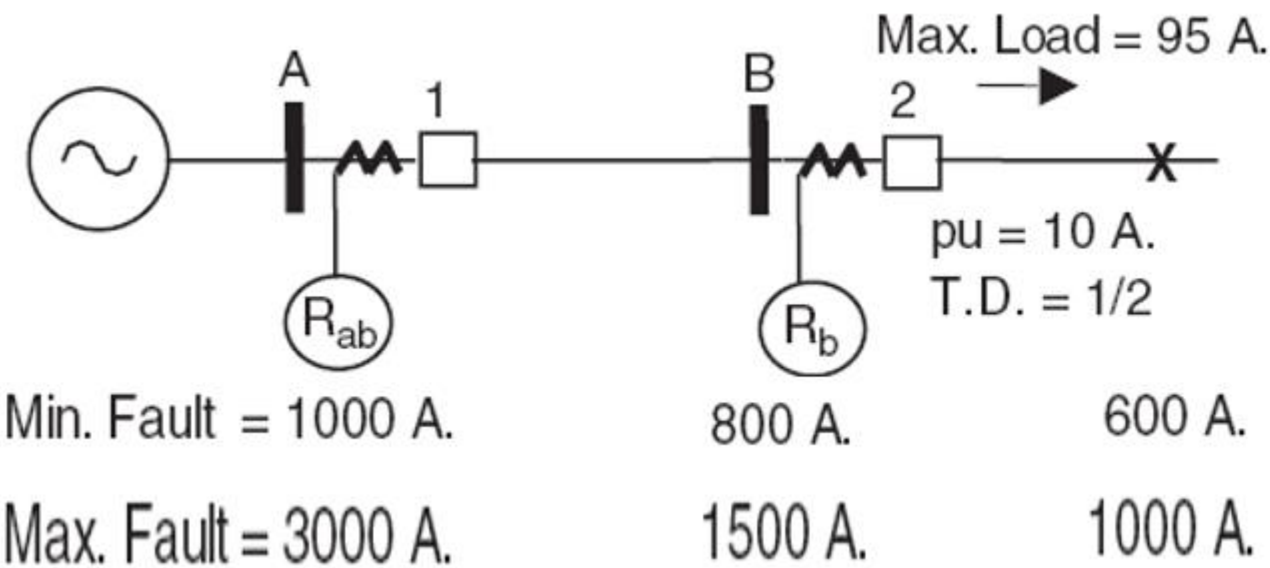
BOTH



0.80 sec
0.55 sec
0.35 sec
0.30 sec
0.25 sec
S
A
B
Rab
Rb
3000 A
1500 A
1000 A

Example 2

Set the instantaneous relays at buses A and B. For the relays shown in the following circuit.



<u>For Rb</u>

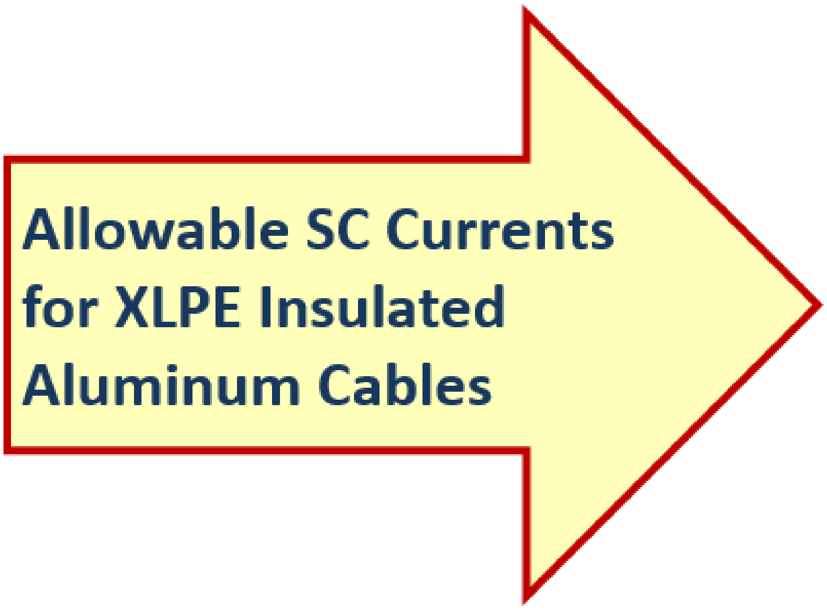
- To avoid overreaching the terminal at the end of the line, Rb should be set at 135% of the maximum fault at that location, i.e. Rb = 135% × 1000 A = 1350 A. The pickup of Rb is 1350/20 = 67.5 A.
- **The minimum fault at bus B is 800 A, divided by the relay pickup of 1350 A, giving a multiple of pickup of 0.59 the relay will not operate.**
- **<u>Check to see how the relay performs at the maximum current of 1500 A. 1500/1350 gives 1.11; barely above pickup</u>.**
- **An instantaneous relay would not be recommended in this situation.**

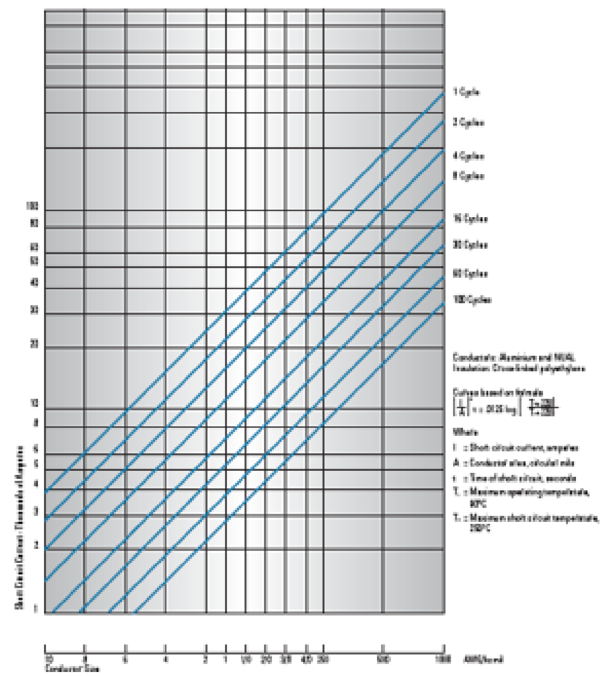
<u>For R_{ab}</u>

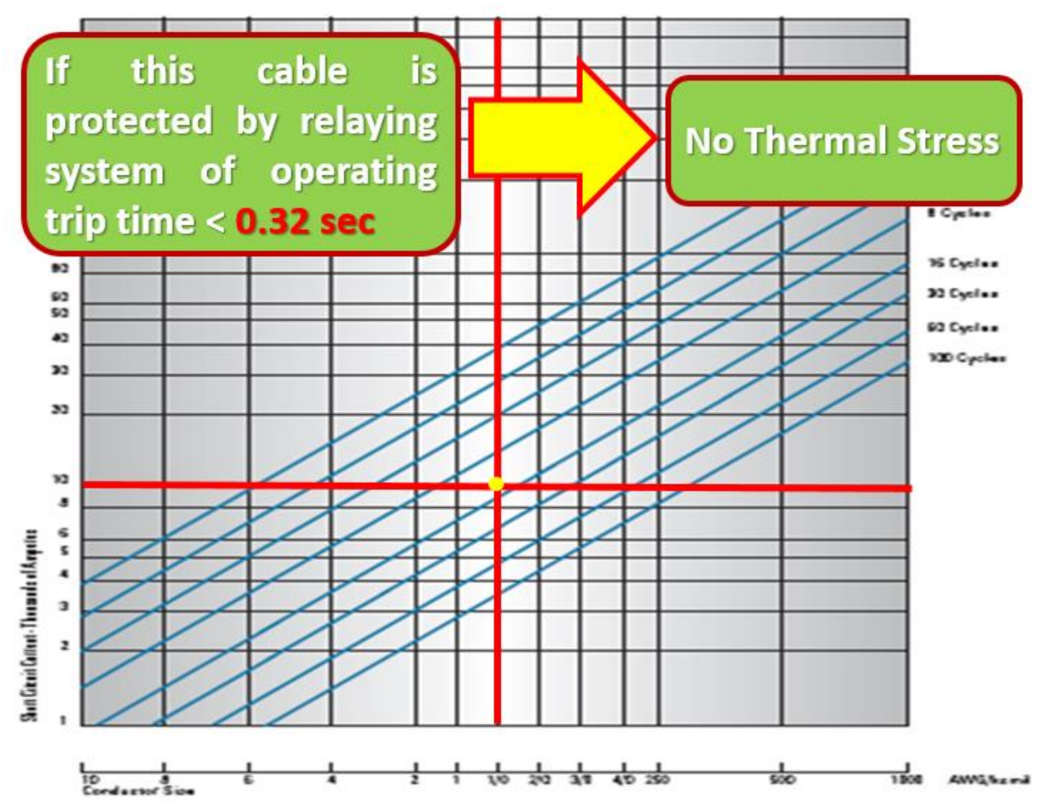
- Avoid overreaching bus B by setting R_{ab} = 135% times the max current at that bus, i.e. 1.35 × 1500 A = 2025 A.
- Check the secondary current by dividing the primary current by the CT ratio: 2025⁄20 = 101.25 A. Current over 100 A may cause saturation of the magnetic components and is too high for electromechanical relays. Select the next highest standard CT ratio of 40/1.
- Check the performance of the relay at minimum and maximum current at bus A. Pickup at 1000 A is 1000⁄2025 = 0.49. The relay will not pick up. Pickup at 3000 A, however, is 3000⁄2025 = 1.48 and the relay will pick up.

The decision whether or not to use an instantaneous relay depends upon the clearing time of the time delay overcurrent relay. The fact that the clearing time of the instantaneous relay will only occur at the maximum bus fault also indicates that there may be very little advantage to be gained with the instantaneous relay. However, if the source connected to bus A is an actual generator, not a system equivalent, then faster clearing at the maximum fault current is justified and an instantaneous relay would be used.

- Example 3
- Specify the allowable time for 1/0 AWG Aluminum Cable carrying a fault current of 10 kA.

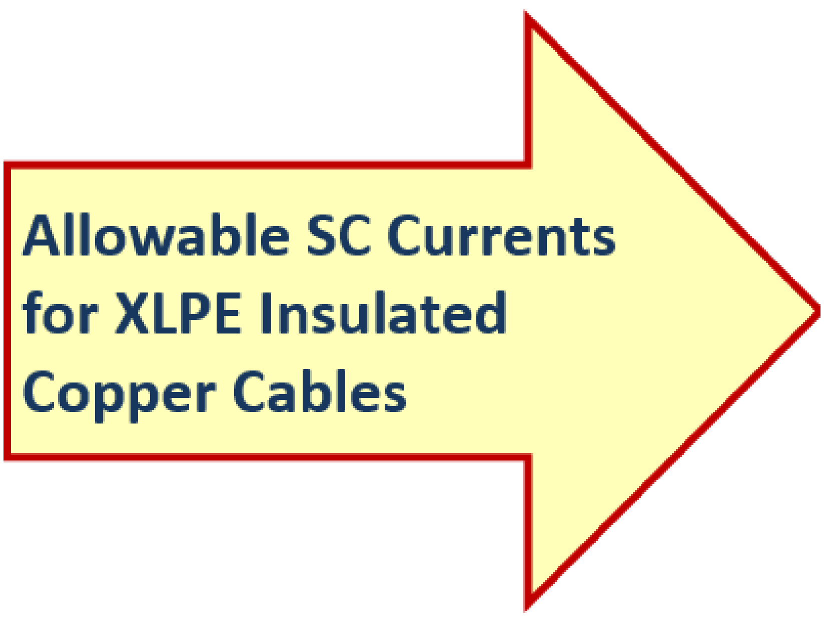


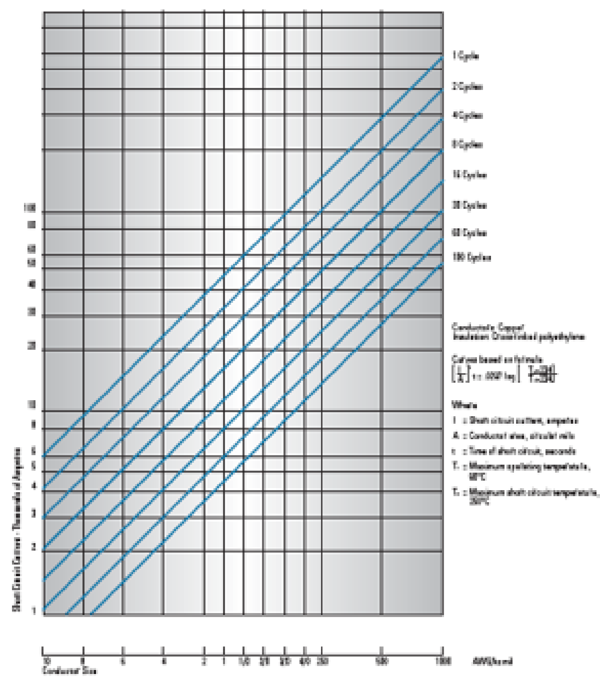


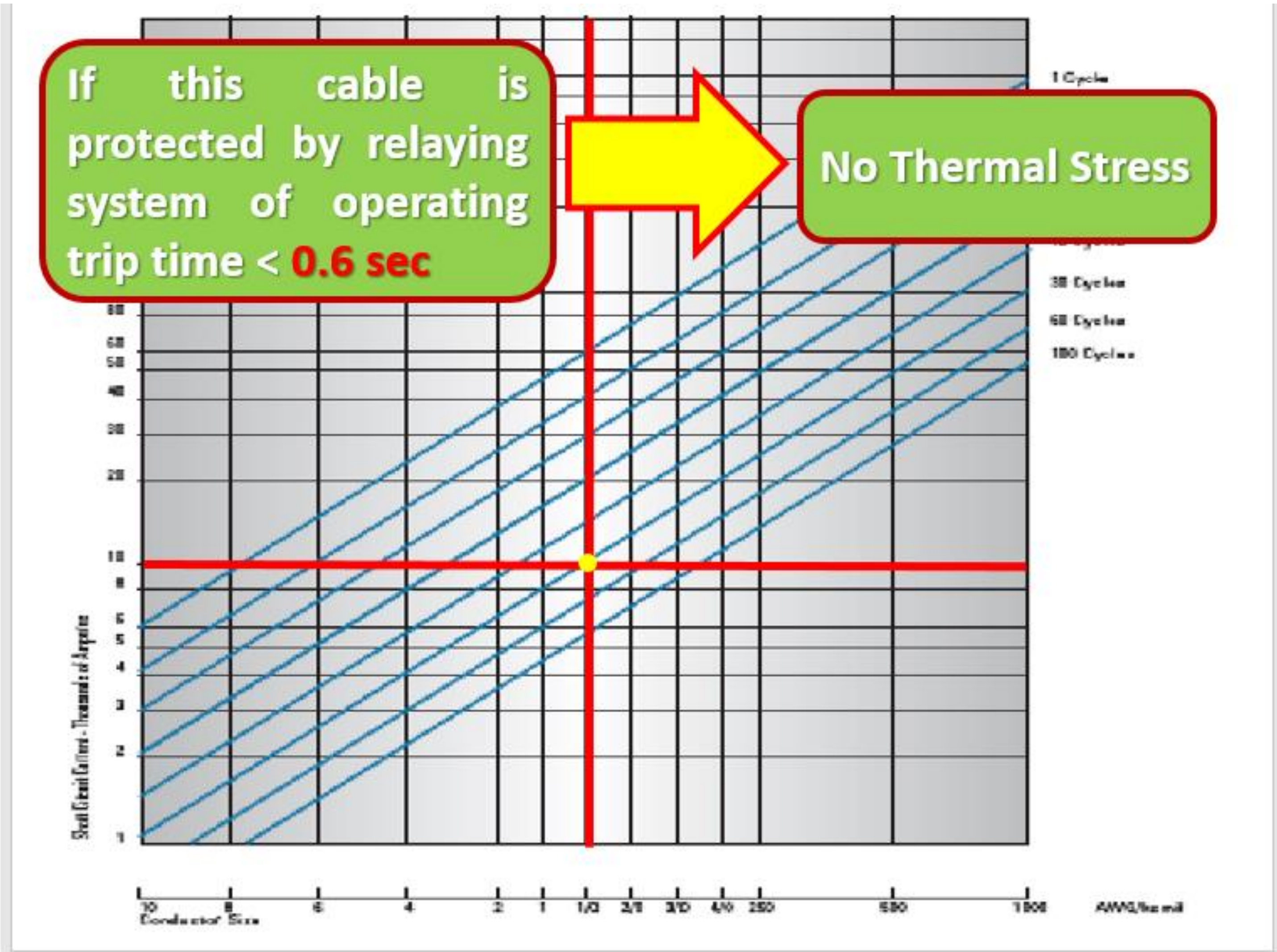


Example 4

Specify the allowable time for 1/0 AWG Copper Cable carrying a fault current of 10 kA.






If this cable is protected by relaying system of operating trip time < 0.6 sec
No Thermal Stress
1 Cycle
30 Cycles
60 Cycles
100 Cycles
Short Circuit Current - Thousands of Amperes
Conductor Size
AWG/kcmil
10
8
6
4
2
1
1/0
2/0
3/0
4/0
250
500
1000

7.8 Overcurrent Problems (Equation Method)

7.8.1 Type One overreach calculations

$$I_{fl} < I_{set} = 1.5 I_{fl} < I_{fault} = 2 I_{set}$$

Not to overreach

Check sections p 21

$$if \;\; I_{FR(point)} \geq 2.7 \, I_{f_{remote-end}} \; then \; it \; can \; be \; inst.$$

$$for \; inst \; I_{set} = 1.35 \, I_{remote-end}$$

7.8.2 Coordination problems

We have TDS (time dial setting) (curve number) and PSM (Plug setting multiplier) (p.u. of Ipu)

$$t_{op} = \frac{A}{\left(\frac{I_f}{I_{pu}}\right)^B - 1} * TDS$$

For Normal

$$\boldsymbol{t_{op} = \frac{0.14}{\left(\frac{I_f}{I_{pu}}\right)^{0.02} - 1} * TDS}$$

	A	B
Normal	0.14	0.02
Very	?	?
Extremely	?	?

$$T(s) = \frac{K}{\left(\frac{I}{Is}\right)^{\alpha} - 1} \; X \;\; TMS$$

where
T = operating time in s
TMS = time multiplier setting
I = value of actual secondary current
Is = value of relay current setting
α and K are constants.

Type of curve	α	K
Normal Inverse	0.02	0.14
Very Inverse	1.0	13.5
Extremely Inverse	2.0	80.0
Long-time Inverse	1.0	120.0

$$PSM \geq \frac{1.1765 * I_{fl}}{I_{NCT}}$$

$$check\ stansards\ (0.25 - 0.75 - 1 - 1.25 - 1.5\ \ldots + \mathbf{0.25})$$

Required top or TDS

For first we need no coordination $so\ TDS = 0.5$

We get PSM as up (say 1)

We say we work on $I_{f_{primary}}$ so we get $I_{PU}\ for\ primary = \left(PSM * I_{NCT}\left(100\ for \frac{100}{5} ct\right)\right) = 1 * 100$

We get it's t_{op} from up equation

We get $t_{op_2} = t_{op1} + 0.3$(SM)

Get $I_{f2}\ same\ I_f$

Get $PSM = \frac{1.1765 I_{fl2}}{I_{NCT2}}$

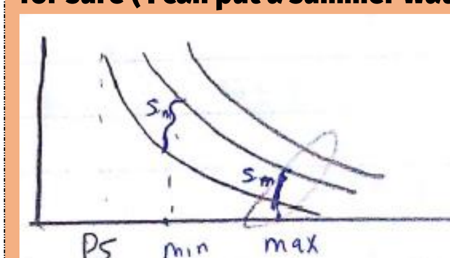
Get $I_{pu2} = 1.1765 * I_{fl2}$

We have top2 and Ipu

Get TDS

BIG NOTE

We add SM to the max fault not minimum because if I make sure at max SM is satisfied then at minimum it's for sure (I can put a summer watermelon in my belly) that SM is also satisfied



7.9 Sheet 4

1. Estimate the amount by which the setting of 15 ms high set relay is affected by a fully offset primary system current.

$$\alpha = 0 \text{ fully offset}$$

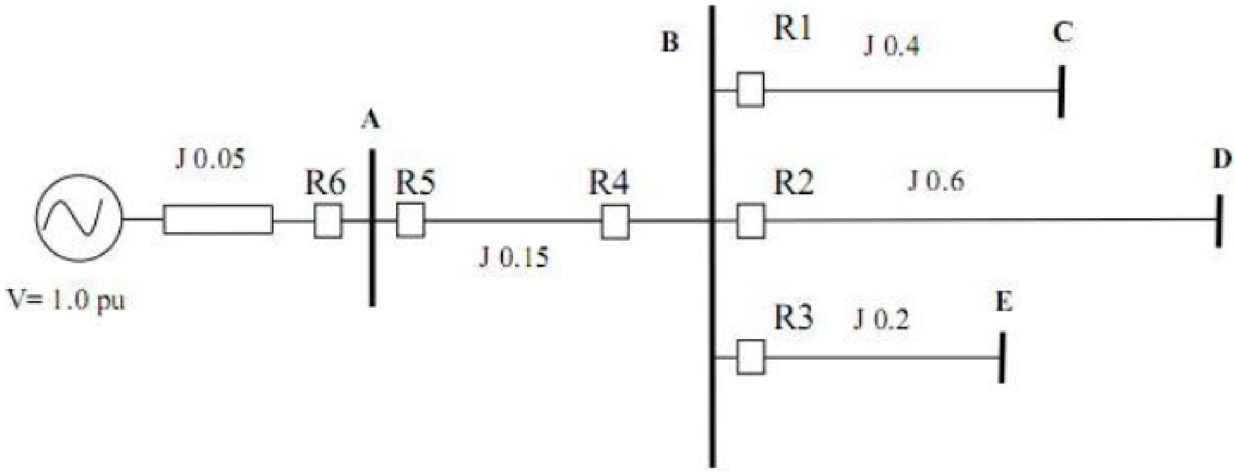
$$t = 15 * 10^{-3}$$

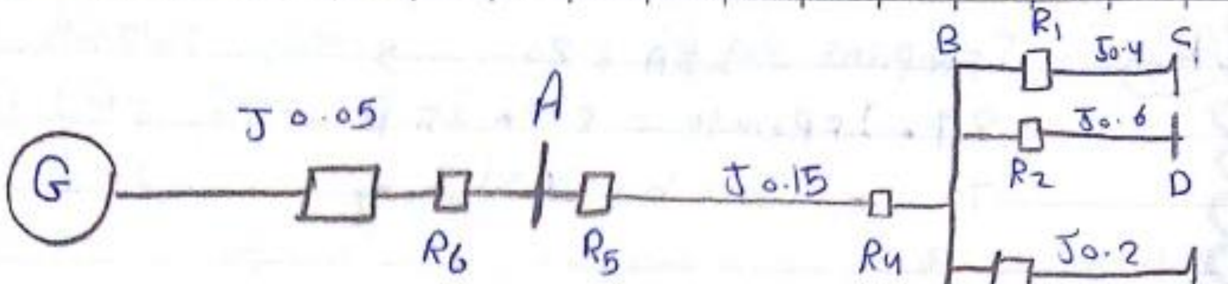
$$over\ reach\ \% = \frac{1 - \sqrt{1 + 2e^{-\frac{2*15*10^{-3}}{\tau}}}}{1}$$

So we have to consider this over reach for the setting

2. **For the system shown**

- **Mention the relays that can be used as Instantaneous type and give the reasons?**
- **Choose the setting of all relays as definite time type.**
- **For different fault cases at mid-point of system feeders, mention the relays that will operates as instantaneous and definite time types, then choose its operating time**





1) metion which Relay can be Inst

2) Choose The setting of all Relay if it DT.

$$I_{\substack{FR \\ \text{Point}}} \geqslant 2.7\, I_{F\,\text{remote end}}.$$

$$I_{FA} = \frac{1\angle 0}{J0.05} = 20\ pu$$

$$I_{FB} = \frac{1\angle 0}{J0.05 + 0.15J} = 5\ pu$$

$$I_{FC} = \frac{1\angle 0}{J0.05 + 0.15J + J0.4} = 1.67\ pu$$

$$I_{FD} = \frac{1\angle 0}{J0.05 + 0.15 + J0.6} = 1.25\ pu$$

$$I_{FE} = \frac{1\angle 0}{J0.05 + J0.15 + J0.2} = 2.5\ pu.$$

R_1 $I_{FR\,Point} = I_{FB} = 5\ pu$ > → Can be Inst.

$2.7\ I_{Fremote} = 2.7 * I_{FC}$

R_2 $I_{FR\,Point} = I_{FB} = 5\ pu$ > → Can be Inst

$2.7\ I_{Fremote} = 2.7 * 1.25$

R_3 $I_{FR\,Point} = I_{FB} = 5\ pu$

$2.7\ I_{FRemote} = 2.7 * 2.5$ | Can not be Inst

R_4, R_6 → can not be Remote. ضوء ملحق (ل)

R_5 $I_{FR\,Point} = I_{FA} = 20$ >

$2.7 * I_{FRemote} = 2.7 * I_{FB}$.

* Can be Inst.

[b] safty margin. 0.3

$R_1 = R_2 = R_3 = 0.1$ sec

$R_4 = 0.1 + 0.3 = 0.4$ sec.

$R_5 = 0.4 + 0.3 = 0.7$ sec

$R_6 = 0.7 + 0.3 = 1$ sec

③ For different case at mid Point fault (Inst, DT).

(R_1 . Inst, DT = 0.1)

(R_2 . Inst, DT = 0.4)

(R_3 DT = 0.1)

(R_4 (DT) = 0.4)

(R_5 . Inst. DT = 0.7)

(R_6 . DT = 1)

BC

$R_1 \rightarrow$ Inst. 50 msec)

$R_1 \rightarrow$ DT (0.1 sec)

$R_4 \rightarrow$ DT (0.4 sec)

$R_5 \rightarrow$ DT (0.7 sec)

$R_6 \rightarrow$ DT (1 sec)

BD

$R_2 \rightarrow$ Ins (50 msec)

$R_2 \rightarrow$ DT = 0.1

$R_4 \rightarrow$ DT = 0.4

$R_5 \rightarrow$ DT = 0.7

$R_6 \rightarrow$ DT = 1

BE

$R_3 \rightarrow$ DT = 0.1

$R_4 \rightarrow$ DT = 0.4

$R_5 \rightarrow$ DT = 0.7

$R_6 \rightarrow$ DT = 1

AB

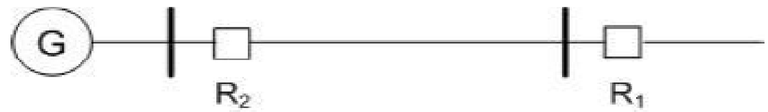
$R_5 \rightarrow$ Inst (50)

$R_5 \rightarrow$ DT = 0.7

$R_6 \rightarrow$ DT = 1

R_4 هنا ما في ال fault اصلا

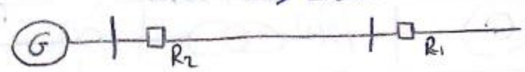
3. **Choose time multiplier settings for the relays at R_1 and R_2.**



	R_2	R_1
	6000 A	**4000 A**
	5000 A	**2500 A**

Max and Min phase fault currents are shown.
Time multiplier setting TSM (time dial setting TDS) for R_2 = 150%, and for R_1 = 125%.
CT ratio at R_2 = 500/5, and at R_1 =500/5.
Plug setting is in steps of 25% to 200%

→ Down stream



CTR	500/5	500/5
PS	150%	125%
Fault current	6000A	4000A
		TDS = 0.3

SM = 0.35 Req: $TDS|_{R_2}$?!

$R_1 \Rightarrow t_{oP_1} = \frac{0.14}{\left(\frac{I_F}{I_{pu}}\right)^{0.02} - 1} TDS = 1.11$

$I_{pu} = PSM * I_{NCT} = 1.25 * 500 = 625$ A

$T_{oP_2} = T_{oP_1} + S.M$
$= 1.46$ sec.

$t_{oP_2} = \frac{0.14}{\left(\frac{I_F}{I_{pu}}\right)^{0.02} - 1} TDS$

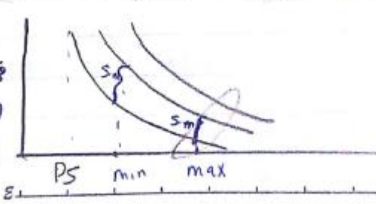
$I_{pu} = 1.5 * 500 =$

$\therefore TDS =$

نفس المثال

→ max Fault	6000 A	4000
min Fault	5000 A	2500 TDS = 0.3

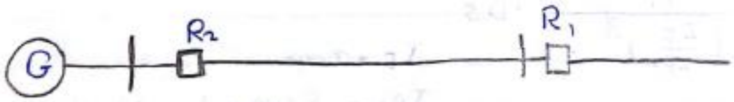
في حالة ما كلهم هيفصلو عند t=0
عشان ال max هنضمن ال S.M min
لكن العكس لأ لذلك تشتغل عند max



4. Choose time multiplier settings for the relays at R_1 and R_2.

2000 A **1000 A**

Phase fault currents are shown.
Load current, through R_2 = 200 A, and through R_1 = 75 A.
CT ratio at R_2 = 200/5, and at R_1 =100/5.
Plug setting is in steps of 25% to 200%



I_F	2000 A	1000 A
I_{FL}	200 A	75 A
CTR	200/5	100/5

PSM → 25% → 200%
TDS ?

R_1 → TDS = 0.5 sec

$$t_{op} = \frac{A}{\left(\frac{I_F}{I_{pu}}\right)^B - 1} \text{ TDS}$$

$I_{pu} = PSM * I_{NCT}$.
$PSM \geq \frac{I_{FL}/0.25}{I_{NCT}} \geq 0.88$.
$PSM = 100\%$
I_F Primary ∴ I_{pu} Primary $100/5$

$I_{pu} = 1 * 100 = 100$ A
$t_{op} = 1.49$ sec   رقم كبير لأن TDS كبيرة
المفروض تكون 0.05
saf-ty M
$t_{op})_{R_2} = 1.49 + 0.3 = 1.79$

R_2 :-

$$1.79 = \frac{A}{\left(\frac{I_F}{I_{PU}}\right)^B - 1} TDS$$

$I_F = 2000$

$I_{PU} = PSM \cdot I_{N.CT}$ 200

$$PSM = \frac{I_{F.L}/0.83}{I_{N.CT}} = 1.17 \Rightarrow 1.25$$

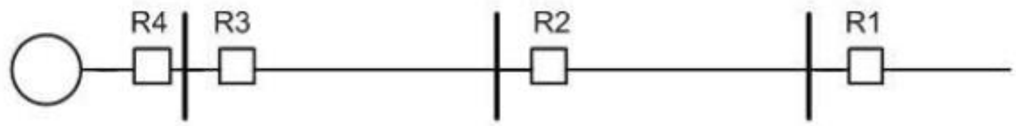
$TDS = 0.55$ sec. $\Rightarrow 0.6$ sec

R_2: $TDS = 0.5 = TDS\ R_1$?!

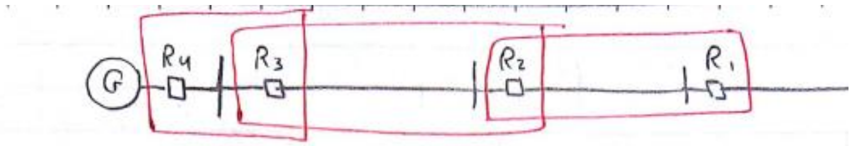
يبقى نشتغل على منحنى تانى خالص مختلف

normal Inverse ليس $\leftarrow R_2$

5. Calculate PSM and TDS for all relays.(SM=0.2sec)



CT	600/5	300/5	200/5	100/5
Full load (A)	400	250	200	75
Fault current (A)	4000	4000	3000	1000



C.T	600/5	300/5	200/5	100/5
F.l	400	250	200	75
Fault	4000	4000	3000	1000

لو TDs طلعو زى بعض نغير
0.02 / 0.14 في القانون

TDs, PSM ?!

$TDS_1 = 0.5$

step
$0.25 \rightarrow 2,$

$$PSM_1 = \frac{I_{F.L}}{0.85 * I_{N.CT}} \geq \frac{75}{0.85 * 100} = 0.8823 = 1$$

$$t_{oP_1} = \frac{0.14 * 0.5}{\left(\frac{1000}{100}\right)^{0.02} - 1} = 1.485.$$

$$t_{oP_2} = T_{oP_1} + \overset{0.2}{S.M} = 1.785 = 1.685 Sec.$$

$$P_{S.M_2} = \frac{200}{0.85 * 200} \geq = 1.176 = 1.25.$$

$$\frac{1}{TDS_2} = \frac{0.14}{\left[\left(\frac{3000}{1.7*200}\right)^{0.02} - 1\right] * t_{oP_2}}$$

$TDS = 0.61 = \quad = 0.7$

$$t_{oP_2} = \frac{0.14}{\left(\frac{3000}{1.7*200}\right)^{0.02} - 1} * 0.7 = 1.965$$

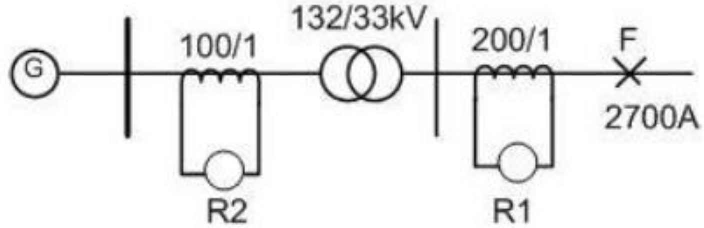
$t_{oP_3} = t_{oP_2} + S.M$

6. **The following Figure shows the part of a typical power system. If for the discrimination, the time grading margin between the relays is 0.35 sec., calculate the time of operation of relay 1 and time setting multiplier for relay 2. The time setting multiplier of relay 1 is 0.3.**

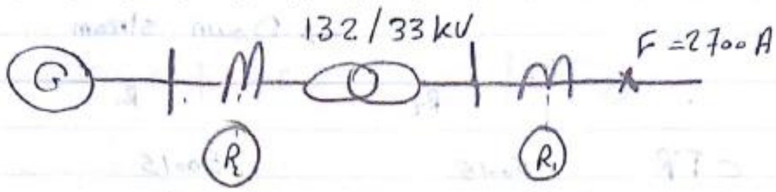
	R_2	R_1
CT ratio	**500/5**	**500/5**
PS	**150%**	**125%**
Fault current	**6000 A**	**4000 A**

Same same

7. **Calculate the time setting for R_1 and R_2 for the fault at F, TDS=0.15 for R_1. Plug setting of 100% for the two relays and SM=0.4 sec**



7



CTR	100/1	200/1
TDS	?	TDS = 0.15
PSM	100%	100%

S.M = 0.4 sec.

$I_{pu_1} = PSM * I_{NCT}$

$= 1 * 200 = 200$

$t_{op_1} = \frac{0.14}{\left(\frac{2700}{200}\right)^{0.02} - 1} * 0.15 = 0.393$

$t_{op_2} = S.m + T_{op_1} = 0.793$

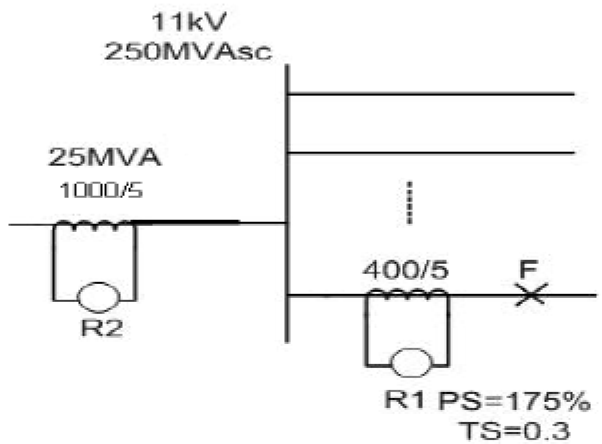
$0.793 = \frac{0.14}{\left(\frac{I_F}{I_{pu}}\right)^{0.02} - 1} * TDS_2$

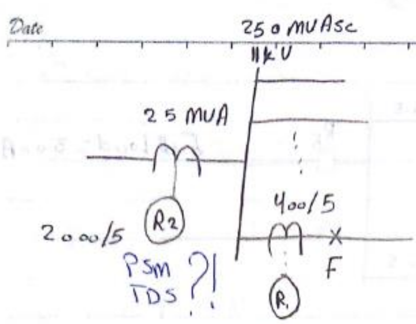
$I_{pu} = 1 * 100 = 100$

$\boxed{I_{F_2} = I_{F_1} * \frac{33}{132} = 675}$ الفكرة

$TDS_2 = 0.22 \simeq 0.25$

8. For the network in the following figure, calculate the setting of R_2.





PSM = 175%

TS = 0.3

S.M = 0.5 sec

Calculate setting For R_2:

$$I_F \text{ at } R_1 = \frac{MVA_{s.c}}{\sqrt{3}\,V} = \frac{250\times10^3}{11\sqrt{3}} = 13122\ A$$

$$PSM \geq \frac{I_{F.L}/0.85}{I_{N,S}}$$

$$I_{F.L} = \frac{S}{\sqrt{3}\,V} = 1312.2\ A$$

$$PSM = 100\%$$

$$I_{pu} = PSM \times I_{N\,CT} = 2000\ A$$

$$t_{oP_1} = \frac{0.14}{\left(\frac{13122}{I_{pu}}\right)^{0.02} - 1} \cdot TDS$$

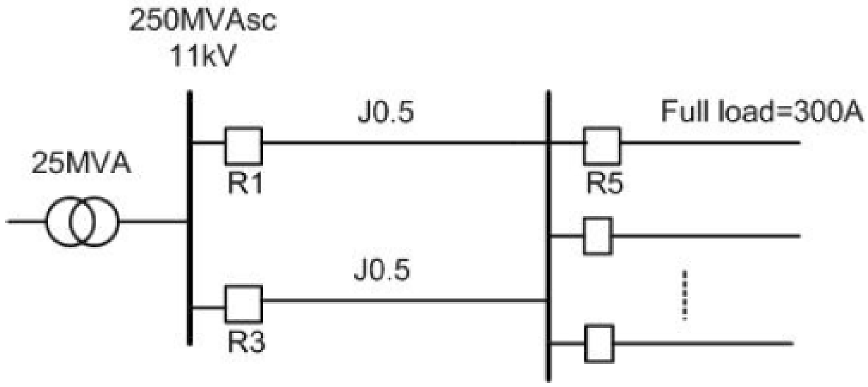
$$t_{oP_2} = T_{oP_1} + S.M$$

$I_{F_1} = I_{F_2} \Rightarrow$ Bus نفس ال

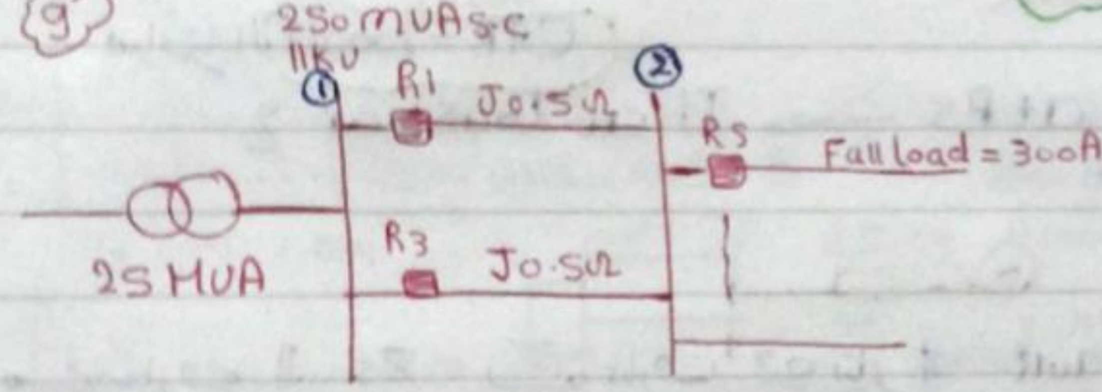
$$t_{oP} = \frac{A}{\left(\frac{I_F}{I_{pu}}\right)^B - 1} \; TDS$$

TDS =

9. **For the network in the following figure, CT ratios available 300/5, 400/5, 500/5, 600/5, 1000/5, 2000/5, and 3000/5. D R5 is not required to be coordinated with any downstream relay. Calculate the setting of R1, R3, and R5.**



(9)



$S_m = 0.4$ sec

CT available ⇒ 300/5 - 400/5 - 500/5 - 600/5

1000/5 - 2000/5

*Calculate (R5, R1, R3) Setting

$$t_{op1} = \frac{0.14}{\left(\frac{}{1.25 * I_{300}}\right)^{0.02} - 1} * 0.05 =$$

$$P_{sm} \geq \frac{300/0.85}{300} = 1.176 \simeq 1.2\ s$$

note عشان تعرف ال CT عند Relay هتشوف :

ال fL عند ال R لو Ifl=300A وفي بـ $\boxed{300/5}$

خد الأقرب والأكبر.

$I_{fl} =$

$S_{rated\,main} = 25\ MVA$

$I_{fl} = \dfrac{25 \times 10^6}{\sqrt{3} \times 11 \times 10^3} = 1312.159\ A$

الحاكم ال Source

1000/5 CT

هات Ifl لـ R_1 هيطلع 656A

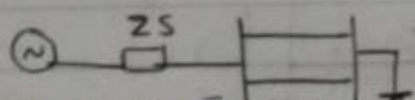
Ifl لـ R_2 656 A

note ال worest case فرضًا R_1 او R_3

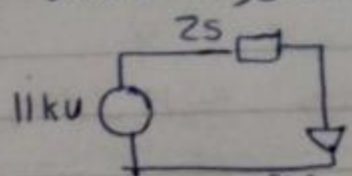
$I_{fl3} = \dfrac{I_{fl}}{Source}$ or $I_{fl1} = \dfrac{I_{fl}}{Source}$ مشتغلش بيقا

ساعتها ال CTR = 2000/5

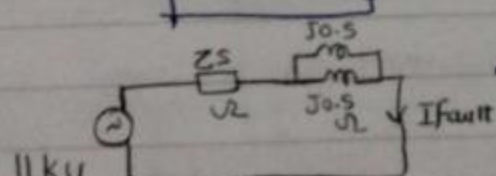
* I_{fault} at R_5 → If at busbar 2



مش عارف ال Zs بسبب عارف قيمة تيار ال fault



$ZS = \dfrac{V_{LL}^2}{S\,MVA_{s\text{-}c}} \rightarrow 11kV$



. $I_{fault} = 8450\ A \rightarrow$ at R_5

ال $R_1 \leftarrow 8450$

مش هيقا تانيه

ها خرجوا من ال Source 8650 هيتجزئوا كده

R_3 , R_1 ويرجعوا تتجمعوا تاني في R_5

$I_{f R_1, R_3} = \dfrac{I_f}{2} = 4225A$

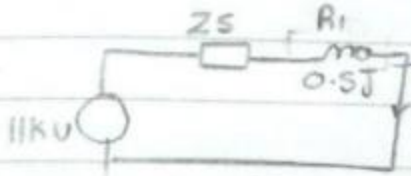
sema

worest Case

* one feeder exist — Case 2

لوواحد feeder بس الموجود ال Totalimp

هيغير قال If هيتغير



$I_f = 6454A$

If الـ ثانيه R1 هو ده

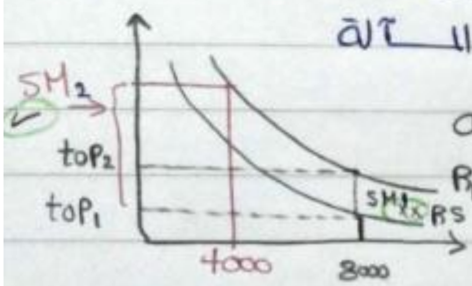
ولو R3 بس ال موجود هيكون $I_{f3} = 6454A$

note لو ال impedance ل R1, R3 مختلفين هحسب ال If لكل واحده

$TDS_5 = 0.05$

مفروض $TDS_{1,3}$ يكونوا فوقيه

عاوز If الهبأ بي الآلة



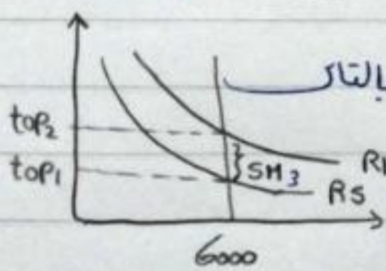
at case1

• دغلط لاستكام RS ثابت R1

ال 8000 ← R1 كدا ثابت RS

4000A فلازم ال SH تكون الأكبر

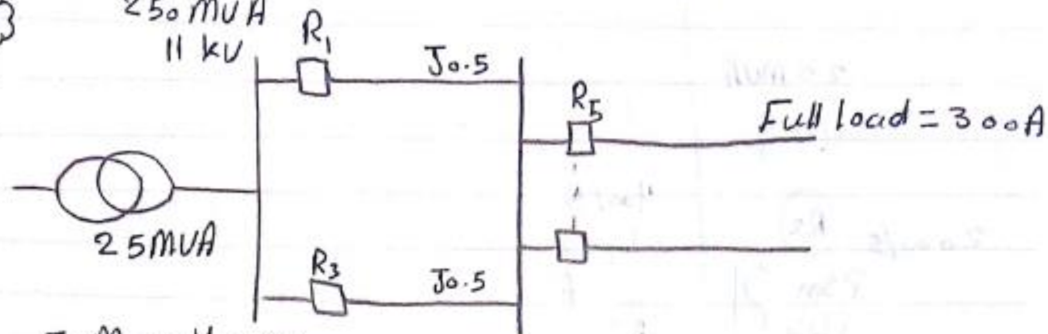
• لازم أحقق ال SH الصغير وبالتالي هحقق ال SH الكبير



يعني لو حققت ال SH_3 كده هكون حاسيات حققت ال SH_2

$I_f = 6000$ A هو ده المبدأ بي الحل

(9)



S.M = 0.4 sec

avaliable CTR :- 300/5 - 400/5

500/5 - 600/5

1000/5 - 2000/5

3000/5

setting $R_{1,3,5}$?!

CTR → $I_{F.L}$

PSM → I_{FL} @ CTR — Full load ⇐ setting C.T

TDS → I_{Fault} — Fault واسوء حال تشغيل وليس

2-Parallel ممكن واحد يز.ع

$I_{F.L_5} = 300\,A$ — ويتم التشغيل بواحد فقط

CTR = 300/5

$PSM \geq \frac{300 \times 0.85}{300} = 1.17$

PSM = 125 %

$I_{F.L} = \frac{S}{\sqrt{3}\,V} = \frac{25 \times 10^3}{\sqrt{3} \times 11} = 1312.2\,A$

$I_{FL_1} = I_{F.L_3} = \frac{I_{F.L}}{2} = \frac{1312.2}{2} = 656$ — Case:1 2 Feeder

Case 2: one Feeder

$I_{F\,e\,R_1} = 1312.2$

بناخد الأسود

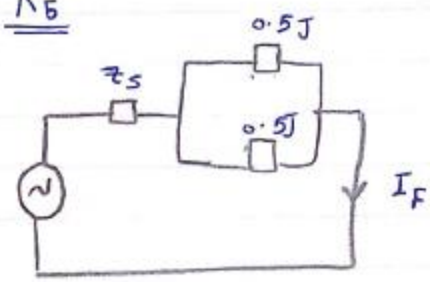
$I_{F\,e\,R_3} = 1312.2$

$C.T \Rightarrow R_1, R_3 = 2000/5$

$$PSM = \frac{1312.2/0.85}{2000} = 0.77 = 1$$

② Fault Calculation: $\underline{R_5}$

$$Z_S = \frac{V_{LL}^2}{S\,MVA_{s.c}} = \frac{(11)^2}{250} = J0.484\,\Omega$$



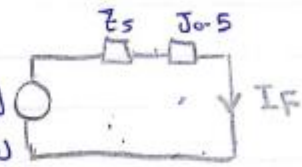
$$I_F = \frac{11000/\sqrt{3}}{J0.48 + \frac{J0.5}{2}} = 8650\,A.$$

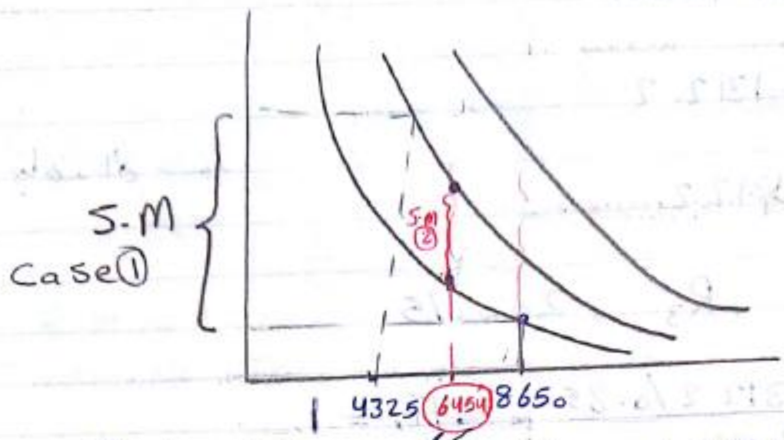
Case 2 (Feeder 1)

0.5 ≠ 0.5 لو ② نفسه

$I_F = 6454A$

لو اختلفت نحسب لكل واحد





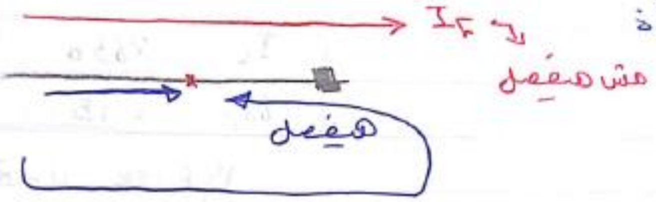
Case ② لضمان S.M لجميع الحالات. نشتغل عند

$R_x, R_y \rightarrow$ exist (ocR).

لو حصل F_2 . 1,3 هيفصلو أو x,y هيفصلو
مش هعرف احدد مكان ال Fault وال system كله هيفصل
معنيش إمكانية .

* $R_x, R_y \rightarrow$ exist directional ocR

$R_x, R_y \Leftarrow$ مهما كانت قيمة التيار مش هيفصل إلا في حالة زاوية معينة إتجاه



$X, Y \Leftarrow$ ليس مع Coordinate مع R_5.

(Setting)

$F_1 \rightarrow R_x \rightarrow R_3$ (Puck up)
$R_y \rightarrow R_1$ (Puck up)
$\Big\} \rightarrow R_1, R_3$ (Puck up) R_5

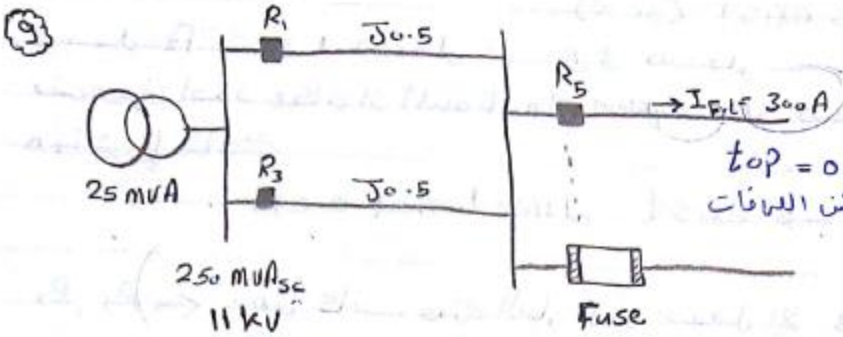
ال Coordination مع R_5 و R_x, R_y
هنحسب top لـ R_5 و R_x و R_y وصافر الأخطاء .

$$t_{oP_{R_5}} = 0.22 \text{ sec}$$

$R_x, R_y \Rightarrow CTR = 300/5$ given . هنختار أقل قيمة
$PSM = 50\%$ لإنه مش هيفرق على قيمة التيار
اقل قيمة في المسأله إنه لم يعطى لنا ← 50%

$$t_{oP_{x,y}} = \frac{0.14}{\left(\frac{I_F}{I_{p.u}}\right)^{0.02}} \times TDS$$

(9)



$t_{op} = 0.22$ sec
من الحل في البريكشن اللي فات

→ worst case

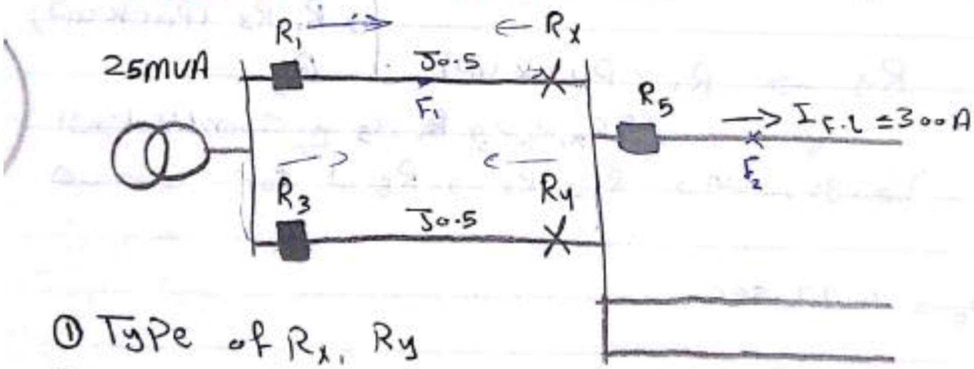
I_F	8650	6450
t_{op}	0.15	0.4

$t_{op} = 0.4$

هنشتغل على R_5 ولا Fuse ؟!
(Fuse) ← الأبطأ وليس الأسرع...

$$* \; t_{op_{R_1}} = t_{op_{Fuse}} + S.M$$

Report → الحل كامل.



① Type of R_x, R_y
② setting of all Relays (PSM, TDS).

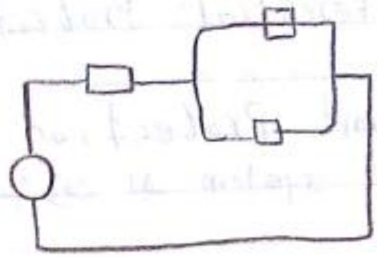
over current Relay (OCR)
R_x, R_y → not exist

لو حصل F_1 هيفصلو R_1 و R_3
ال system كله هيفصل وال F_1 حصل في T.L واحد

$I_F = 8652$

$I_{FR_x} = I_{FR_y} = \frac{8652}{2}$

$= 4326.\ A.$



Two. Cases لايوجد هنا

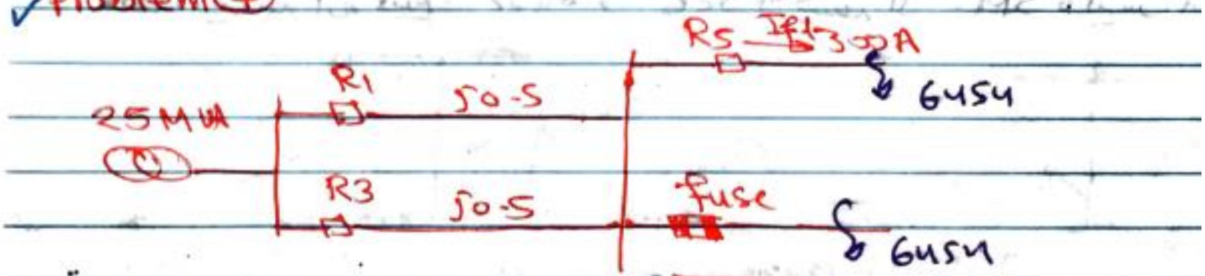
لأن لو T.L واحد معنيش

عكس إتجاة للتيار

$TDS = 0.5$

Report :- → كاملة

Problem (7)



IF	8650	6450
top	0.15	0.4

* نفس المسألة من حيث اختيار C-T ratio و PSM
  - two Feeder
  - one Feeder (Worst Case)

---

fuse
recloser
over current

$top)_{Rs} = 0.24 sec$

* R_1 بينتظر R_s اذا حدث عندها F وينتظر الFuse اذا حدث عنده الFault
* نقوم بحل F عند Rs و عند Fuse لتحصل على زمنين تشغيل ونأخذ الأكبر أي الأبطأ في التشغيل.
* حصلنا على تيار الworst Cond من المسألة السابقة وهو 6454 A

$top)\ Rs = 0.24 sec$

$top)\ Fuse = 0.45 sec$ (from table)

$\therefore top)\ R_1 = 0.4 + 0.35 = 0.75 sec$

(أي نعتمد على الأبطأ ليترك الفرصة لكل الحالات تعمل قبل ...)

7.10 Fuses

7.10.1 Definition

Fuse : الفيوز أو المصهر هو أداة أو عنصر كهربائي لحماية الأجهزة ضد ارتفاع التيار الكهربائي وهو من العناصر الأساسية والبسيطة حيث يتكون من سلك معدني ينصهر عندما يتجاوز التيار المار فيه القيمة المحددة لهذا السلك وبالتالي يقطع الدائرة الكهربائية

7.10.2 Function

أهم وظائف الفيوز

حماية المعدات وعناصرها الكهربائية من خطر زيادة التيار - عزل جزء من المعدة أو الدائرة الكهربائية عن باقي الأجزاء لحمايتها عند الأخطاء

أول استخدام لهذا العنصر كان على يد المخترع الكبير توماس أديسون

7.10.3 CONSTRUCTION

يتكون المصهر في أبسط صوره من سلك دقيق قصير من معدن مركب في حامل معزول ، وينصهر السلك إذا زاد التيار المار به عن قيمة معينة وبذلك تفتح الدائرة.

7.10.4 Parameters

7.10.4.1 التيار المقنن Rated carrying current

التيار المقنن للمصهر ، هو أكبر تيار يمكن أن يمر في المصهر دون أن ينصهر. وتعتمد قيمة هذا التيار على الارتفاع المسموح به في درجة حرارة موصلات المصهر كذلك على تقادم المصهر بسبب الأكسدة.

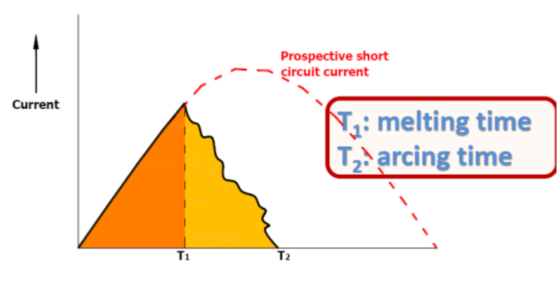
7.10.4.2 تيار الصهر Fusing current

تيار الصهر هو أقل تيار يسبب صهر معدن المصهر

<u>ويعتمد على العوامل الآتية:</u>

- شكل المقطع - مساحة المقطع- الطول المادة- حجم ومكان أطراف المصهر- التاريخ السابق للمصهر- نوع الغلاف-أسلاك المصهر مجدولة أم لا

7.10.4.3 التيار المتوقع وتيار القطع Prospective and cut off current



7.10.4.4 زمن الصهر Prearcing time (Melting time)

هو الزمن المقاس بين بداية زيادة التيار في الدائرة الموضوع بها المصهر وبداية حدوث القوس الكهربي

7.10.4.5 زمن دوام القوس الكهربي Arcing Time

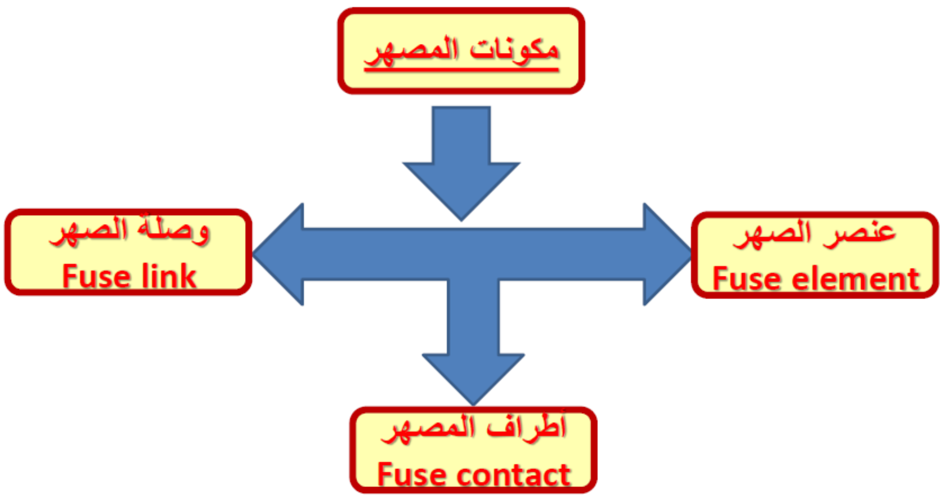
هو الزمن المقاس بين بداية حدوث القوس الكهربي واللحظة التي يصل فيها قيمة التيار المار بالدائرة للصفر أي تفتح الدائرة

7.10.4.6 زمن التشغيل الكلي Total operating time

هو مجموع زمن الصهر وزمن دوام القوس الكهربي

7.10.4.7 مقنن الجهد Voltage Rating

وهو أعلي جهد يمكن للمصهر أن يعمل عليه بأمان وتصنف المصهرات عادة بالنسبة للجهد إلى مصهرات جهد منخفض (حتى600 ف ومصهرات جهد متوسط وعالي) أعلي من600 ف وحتى100 ك ف)



7.10.4.8 عنصر الصهر Fuse element

وهو مصنوع من مادة معدنية ذات أشكال وأبعاد معينة بحيث يكون انصهارها سريعًا بالنسبة لباقي مكونات الشبكة ويصنع بمادة من الفضة أو النحاس أو الألومنيوم أو الرصاص أو بعض السبائك الأخرى ذات درجة حرارة انصهار منخفضة

7.10.4.9 وصلة الصهر Fuse link

ويوجد داخلها عنصر الصهر والمواد المستخدمة في إطفاء القوس الكهربي الناشئ عن انصهاره بالإضافة إلى أي أجزاء أخري مساعدة

7.10.4.10 أطراف المصهر Fuse contact

وتستعمل في تثبيت المصهر في الدائرة وتوصيله كهربيًا بها

7.10.5 Distribution System Fuses

7.10.6 اختيار المصهرات

يجب اختيار المصهر بحيث يعمل بطريقة سليمة وآمنة فى حالات التشغيل العادي وفترات قصر الدائرة ويتم الاختيار بصفة عامة تبعًا للمقننات التيار والجهد مع الاستعانة بالجداول والمنحنيات الخاصة بالمصهر ويراعي عند الاختيار ما يلي-:

أ- يجب أن يتحمل المصهر نسبة **من تجاوز الحمل** بصفة مستمرة دون أن تتغير خصائصه أو أن يفتح الدائرة ويجب ألا تقل هذه النسبة عن10 %من تيار الحمل.

ب- يجب اختيار المصهر ذي أقل مقنن تيار ممكن **بحيث يتحمل التيار المقنن وتجاوز** الحمل المسموح به وذلك بغرض الانتقاء والتمييز

ت- تتحدد قيمة مقنن تيار القطع بحيث تكون أكبر من **أعلي قيمة متوقعة لتيار القصر** ويجب ملاحظة أنه إذا زاد تيار القصر عن سعة القطع أدي ذلك إلى انفجار المصهر ونشوب حريق

ث- يجب **ألا يقل** تيار القصر في الدائر التي يتم حمايتها بالمصهر **عن ثلاثة أمثال التيار** المقنن للمصهر وذلك حتى يمكن الاعتماد على هذا المصهر في فتح الدائرة باعتمادية عالية

ج- يراعي عند استعمال مصهرات لحماية أجهزة لها خاصية ارتفاع التيار العابر كتيار بدء التشغيل في المحركات أو تيار المغنطة المندفع في المحولات ، أن تكون هذه المصهرات **ذات تأخير زمني** حتى يمكن اختيار التيار المقنن المصهر قريباً من التيار المقنن الجهاز) أعلي قليلا (دون أن يفتح المصهر الدائرة بسبب التيار المندفع.

ح- يراعي **عدم** استعمال مصهرين على **التوازي**

خ- نظرً ا للقدرة العالية للمصهرات في الحد من التيار فيجب الانتباه جيدًا **لمتانتها الميكانيكية** وسلامة تثبيتها

7.10.7 التنسيق بين المصهرات

يعتمد الاختيار السليم للمصهر وكذلك عملية الحماية والتنسيق على المعلومات والبيانات المرفقة مع المصهر والتي يعدها مصنع المصهرات وتعطي هذه البيانات على صور مختلفة كالمنحنيات على النحو التالي

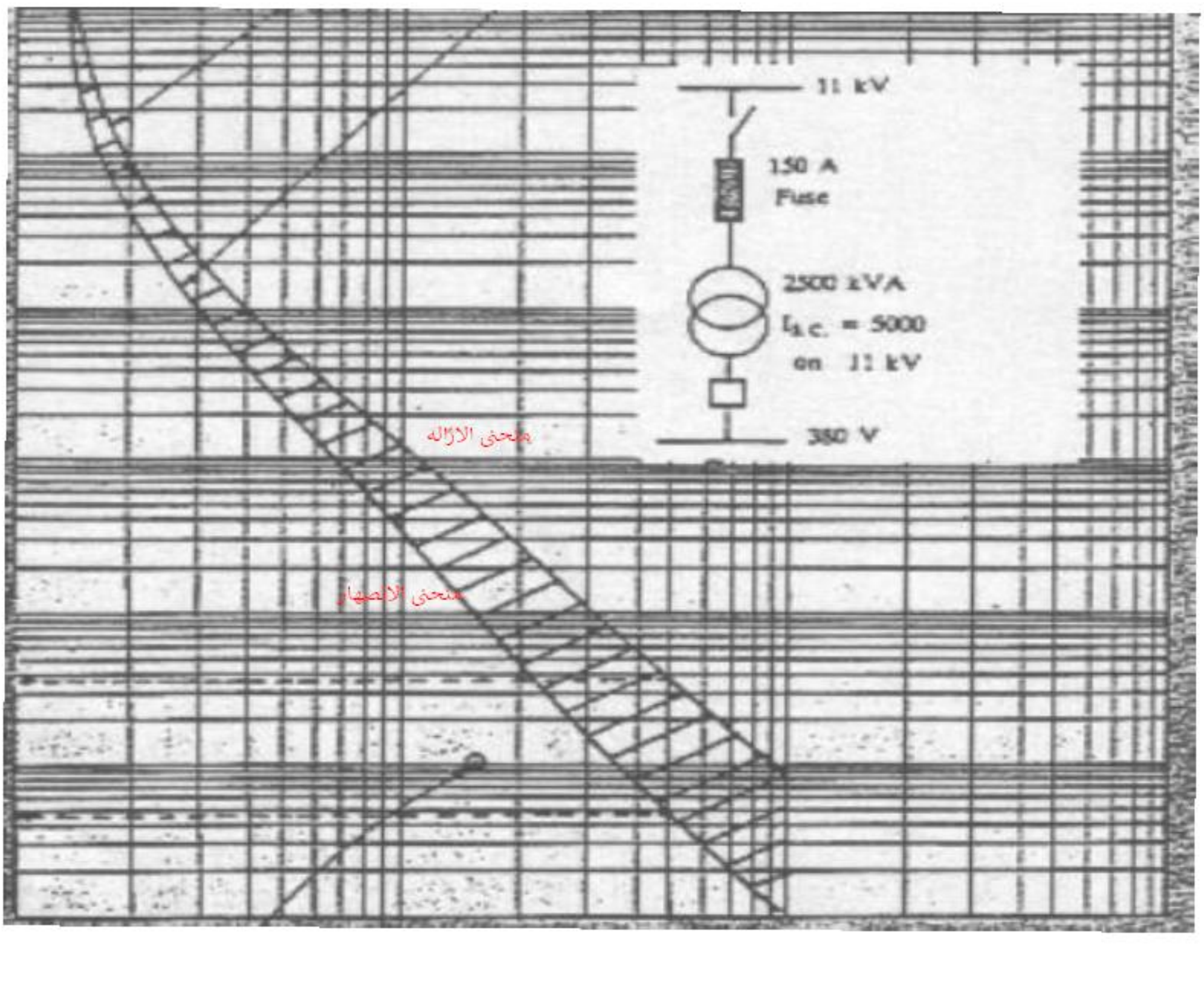
7.10.7.1 منحنيات الزمن - التيار

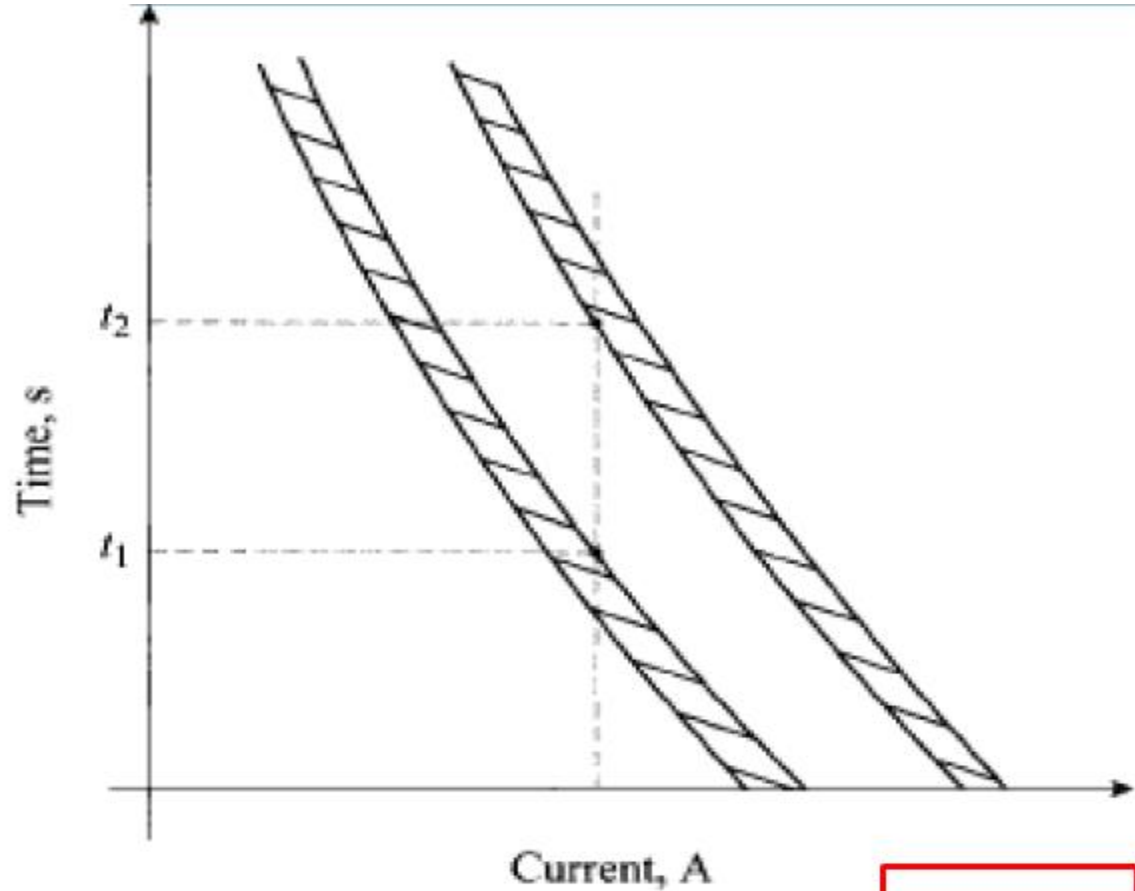
7.10.7.1.1 منحني الانصهار

ويعطي العلاقة بين قيمة تيار القصر والزمن المنقضي من لحظة القصر وحتى تمام انصهار عنصر المصهر

7.10.7.1.2 منحني الإزالة

ويعطي العلاقة بين قيمة تيار القصر والزمن المنقضي من لحظة القصر وحتى تمام إزالة القصر وإطفاء القوس الكهربي . ويلاحظ دائمًا أن منحني الإزالة يكون أعلي منحني الانصهار بزمن يساوي فترة دوام القوس





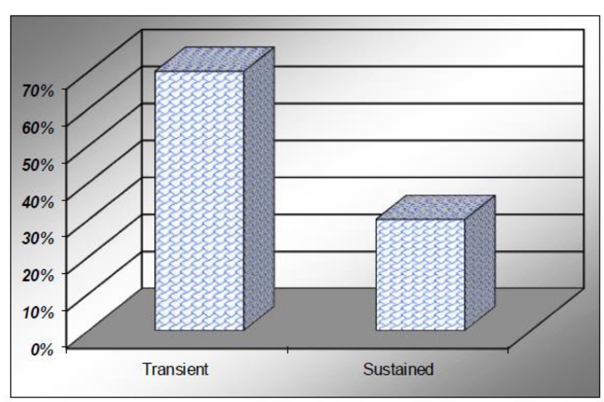
Criteria for fuse-fuse co-ordination: $\boxed{t_1 < 0.75\ t_2}$

7.11 the faults in power system are classified as

7.11.1 – Permanent Faults

7.11.2 Transient Faults

Studies of faults on overhead distribution lines have shown **that 65% - 85%** of faults are of a transient (temporary) nature

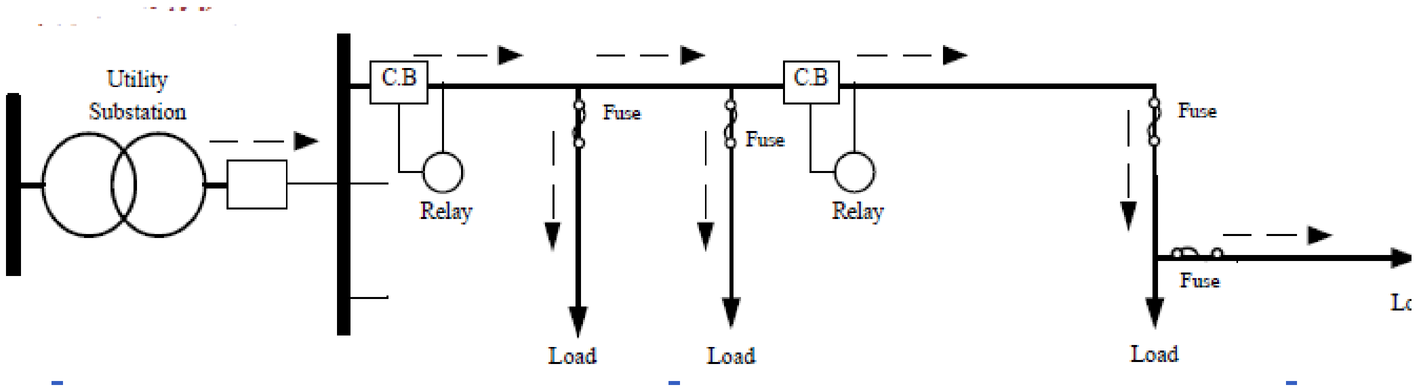


7.12 Auto-Recloser

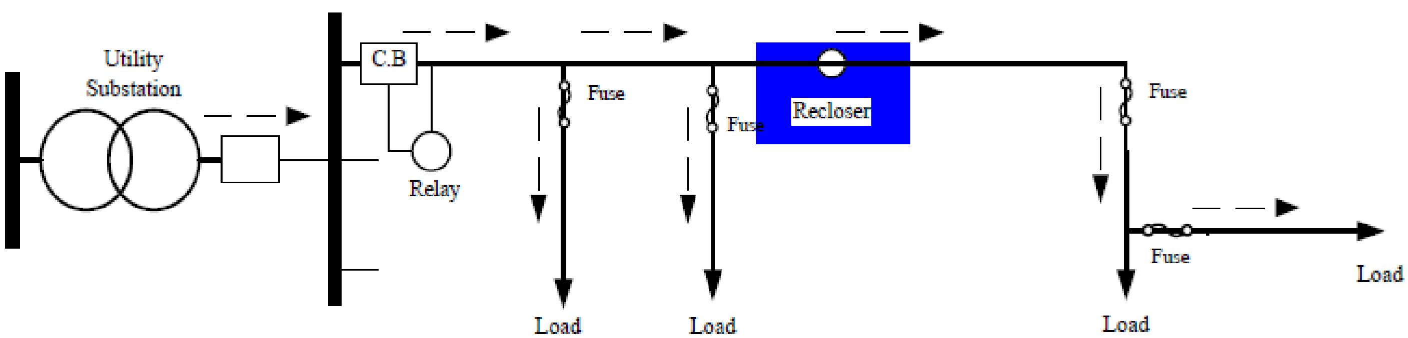
The distribution system is in general radial in design, The distribution system is responsible for delivering electricity

from distribution substations to consumers Distribution protection is basically overcurrent protection This protection type is simple and works very well with radial networks

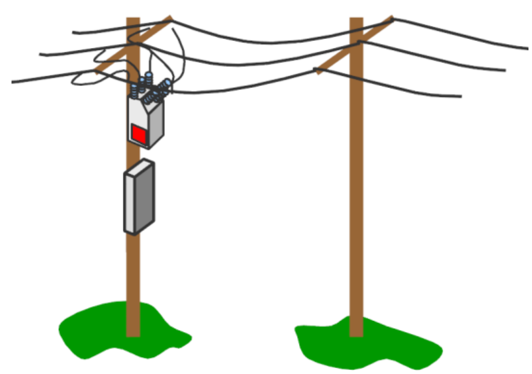
The protection system in distribution systems is based on coordination of relay–relay on incoming feeder and fuse–fuse on laterals



<u>BUT Since 80% of all faults in distribution systems are temporary, reclosers are necessary</u>



7.12.1 What is a Recloser ?



- A Recloser is a Circuit Breaker along with protection system:
- For overhead power lines
- Designed to RECLOSE on to a fault.
- <u>Terminology</u>
- The **"auto-reclose"** cycle
- Will detect a fault and open for a pre-programmed time, before closing again automatically
- This cycle can be repeated 4 times

- **Lockout typically on the fifth trip**

7.12.2 A/R Location

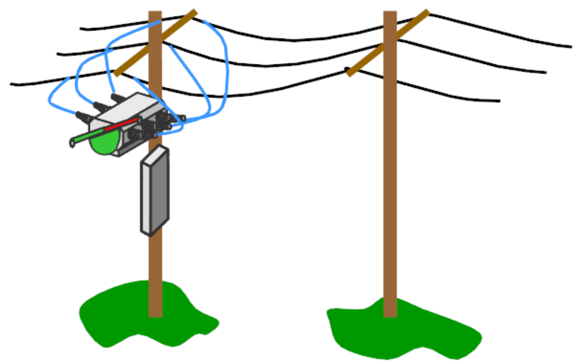
Recloser can be used anywhere on a system where Recloser ratings are adequate for the system requirements logical location are: -

1- In **substation** as the primary feeder protection Devices.

2- On the lines at a **distance from a substation**, to sectionalize **Long feeders** and thus prevent outage of the entire feeder when a permanent fault occurs near the end of the feeder.

3- On the **taps** of **main feeders** – to protect the main feeder from interruption and outages due to faults on the taps.

7.12.3 What is a Sectionaliser ?



- A Sectionaliser is a switch along with control unit:

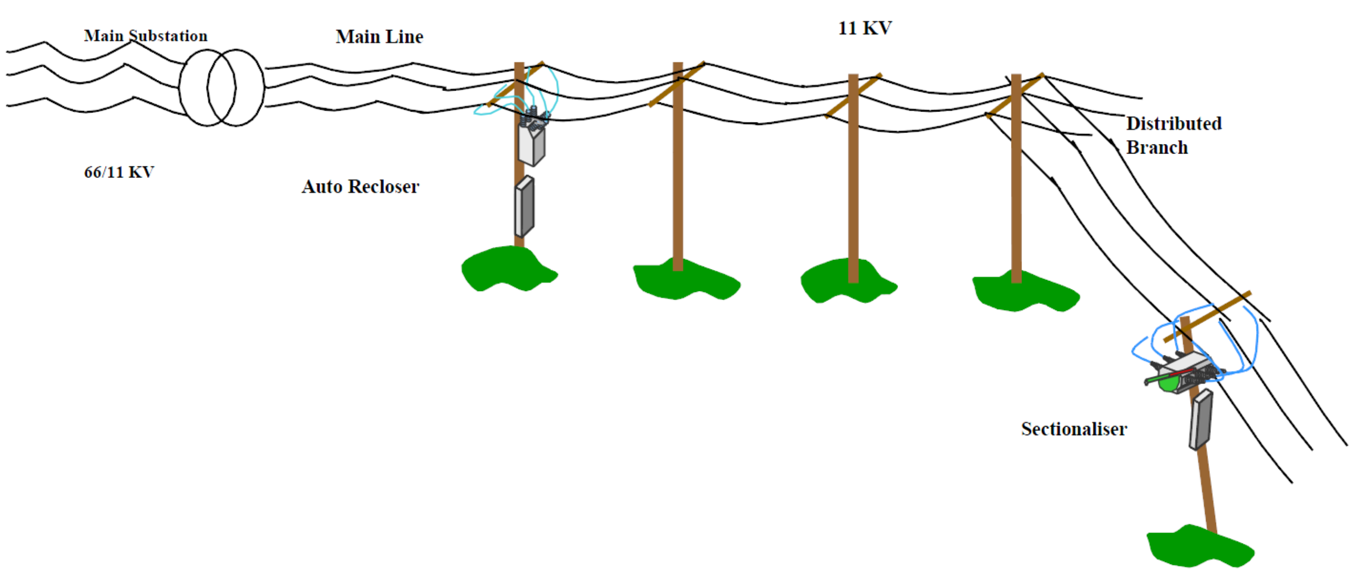
– It is used in conjunction with an upstream "Recloser" or "circuit breaker"

– It **counts the interruption created by a Recloser** during a fault sequence.

– On a preset count

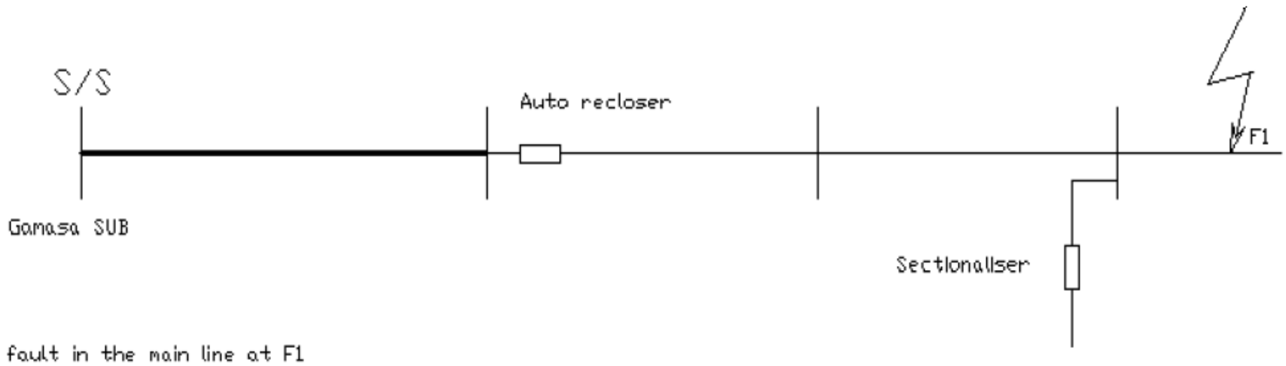
- **trips during the dead time** of the upstream Recloser
- Isolates a faulty network section

7.12.4 Location of AR & Sectionaliser

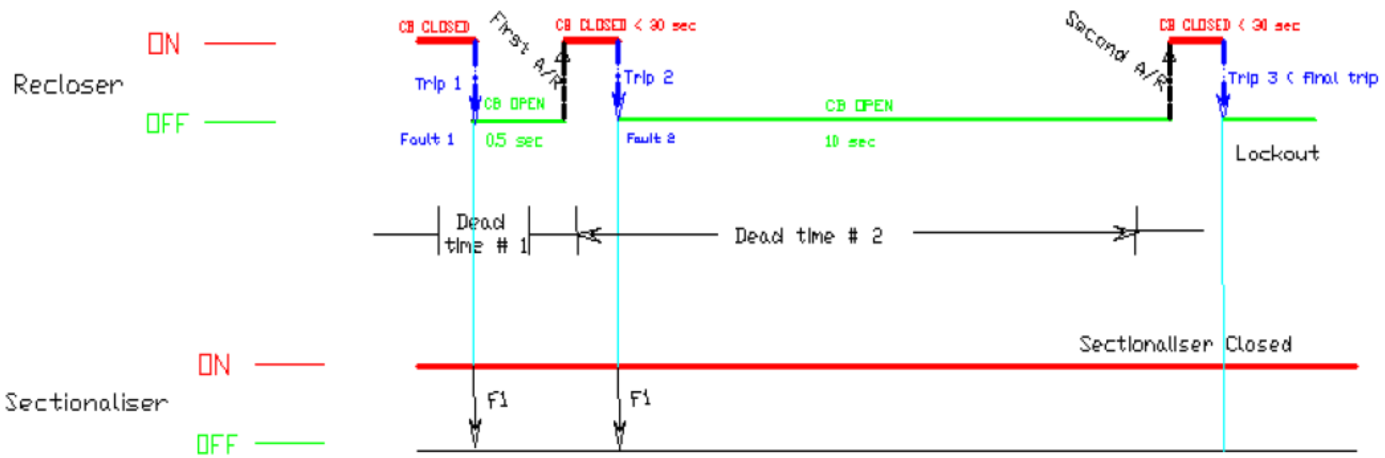


7.12.5 Operation of The Auto-Recloser & The Sectionalizer

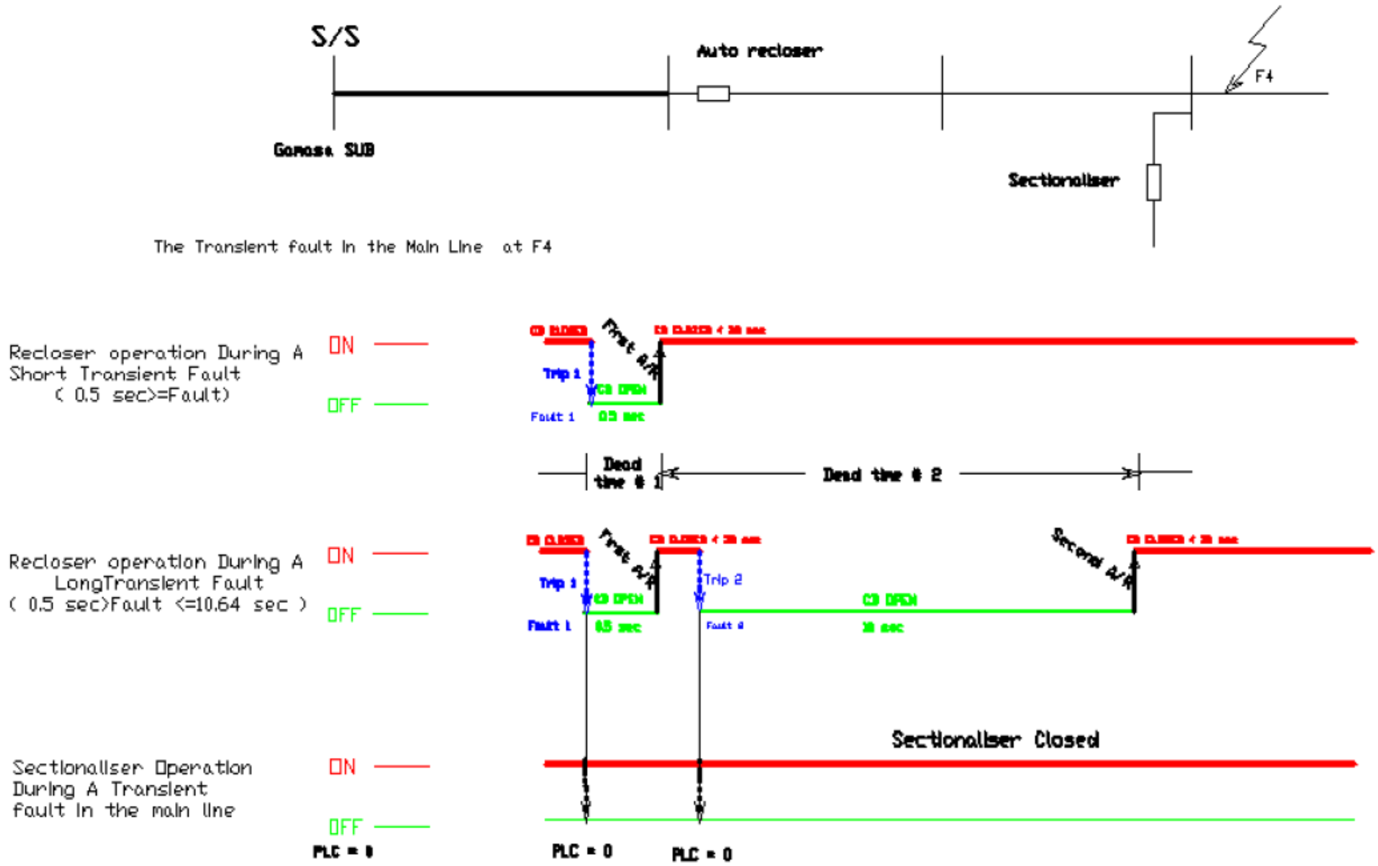
7.12.5.1 Sustained Fault in the Main Line or in anther lateral branches.



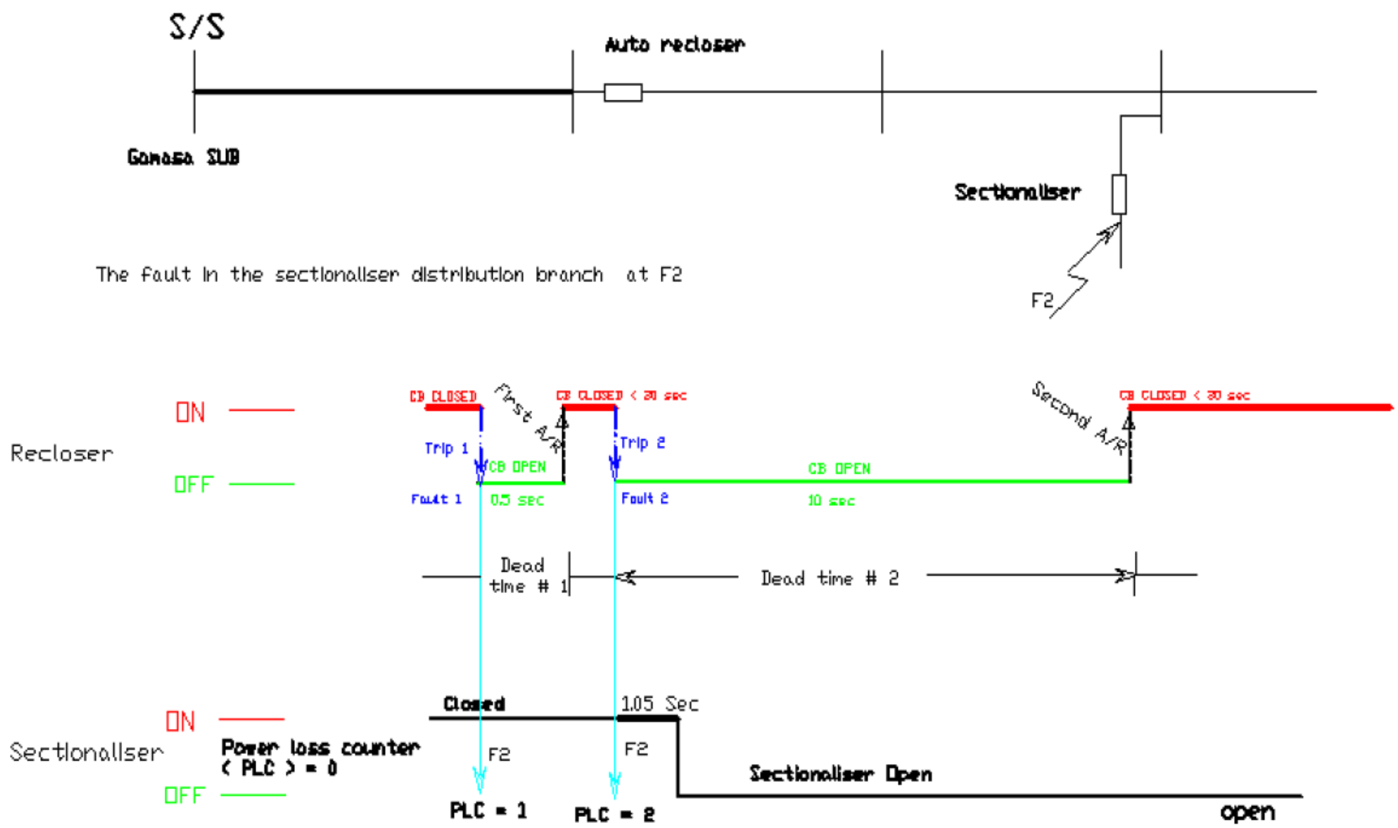
The fault in the main line at F1



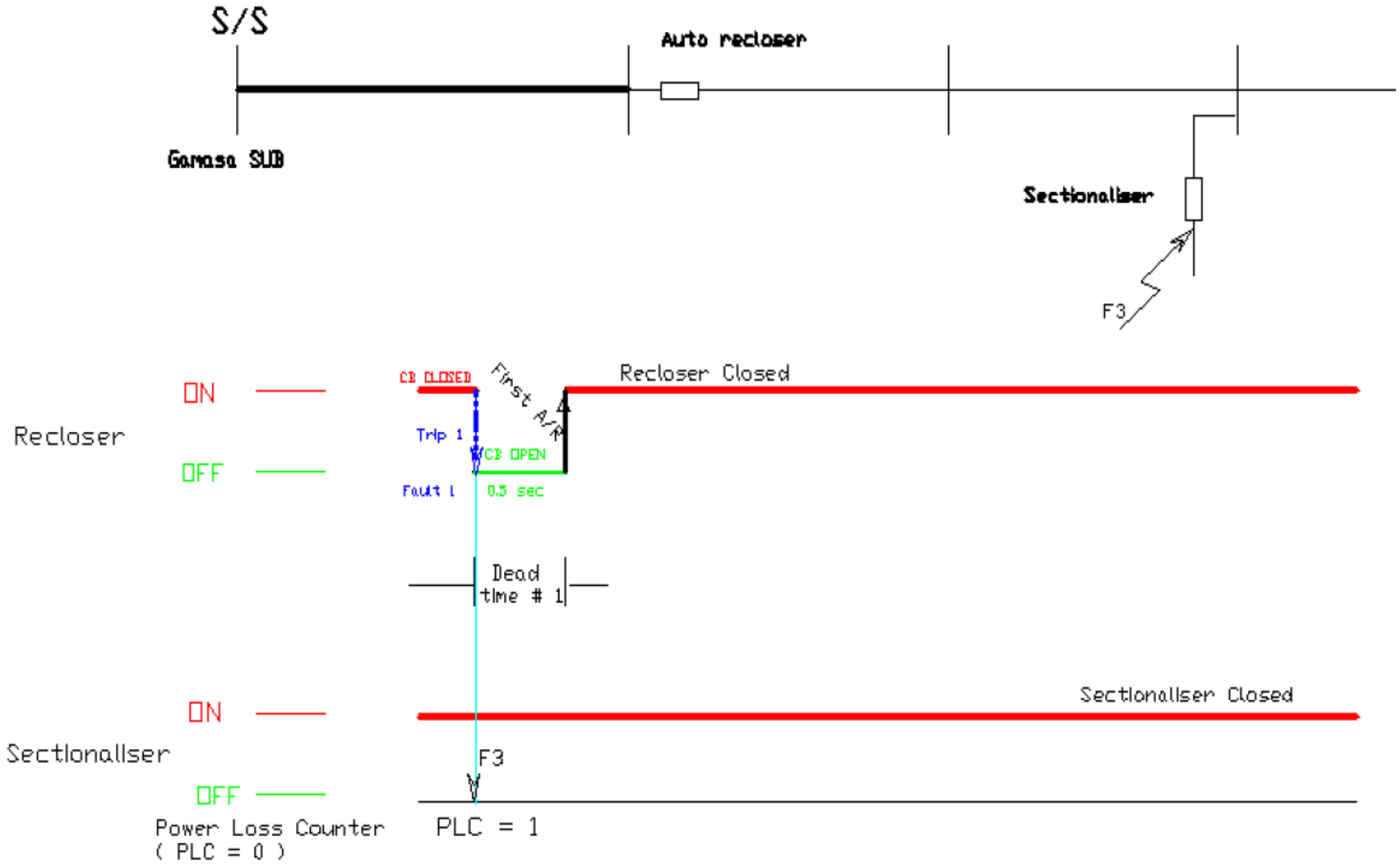
7.12.5.2 Transient Fault in the Main Line.



7.12.5.3 Sustained Fault in the Sectionaliser Branch.

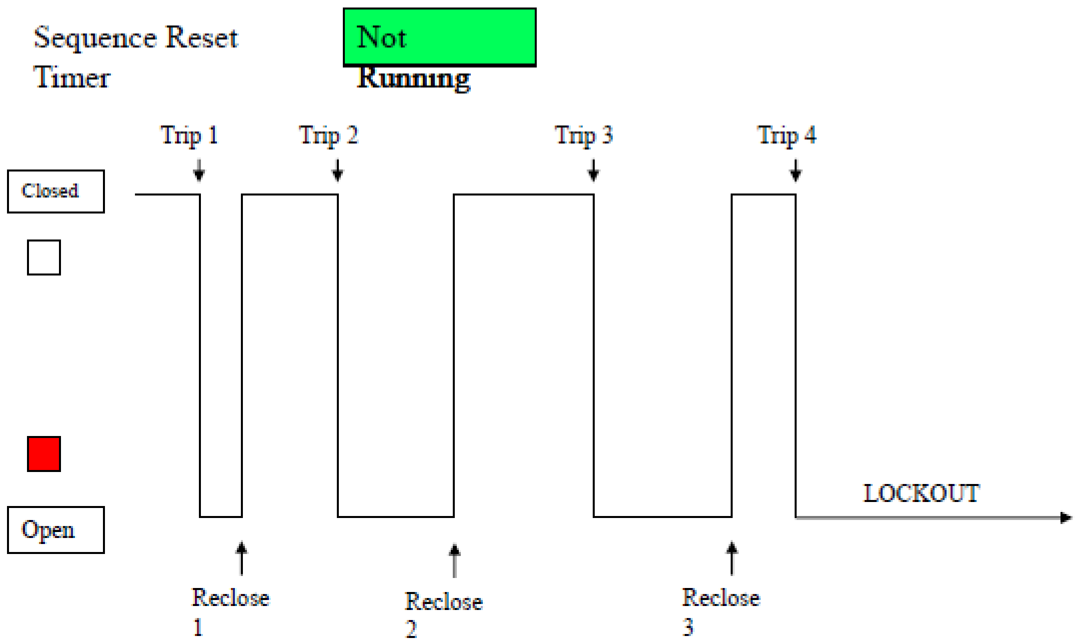


7.12.5.4 Transient Fault in the Sectionaliser Branch.

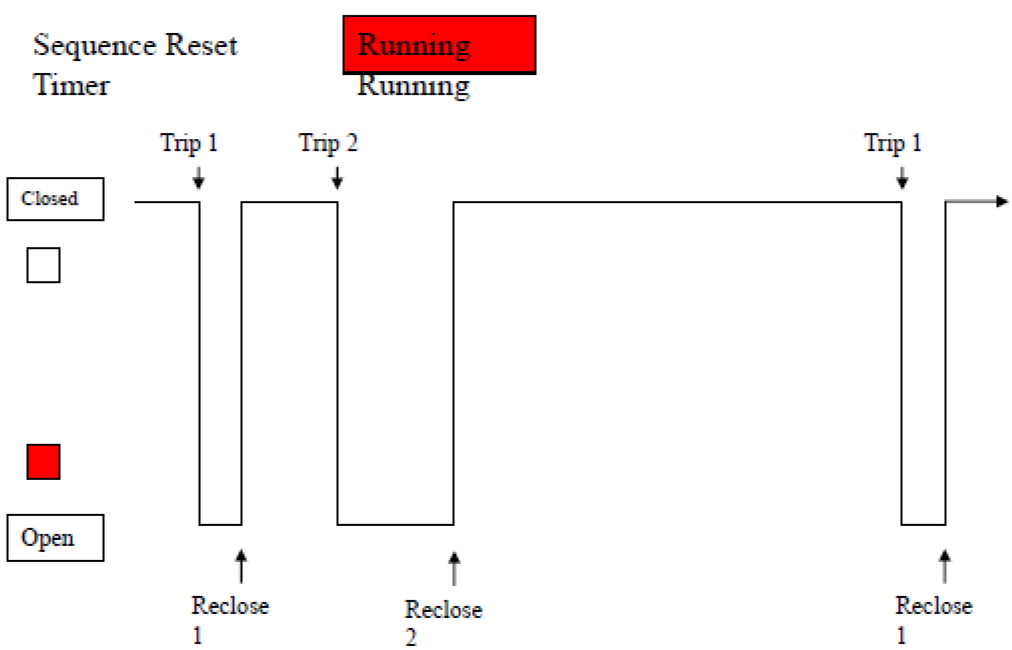


7.12.6 Reclose Sequence 4 Trips to Lockout

7.12.6.1 Not cleared so it locksout

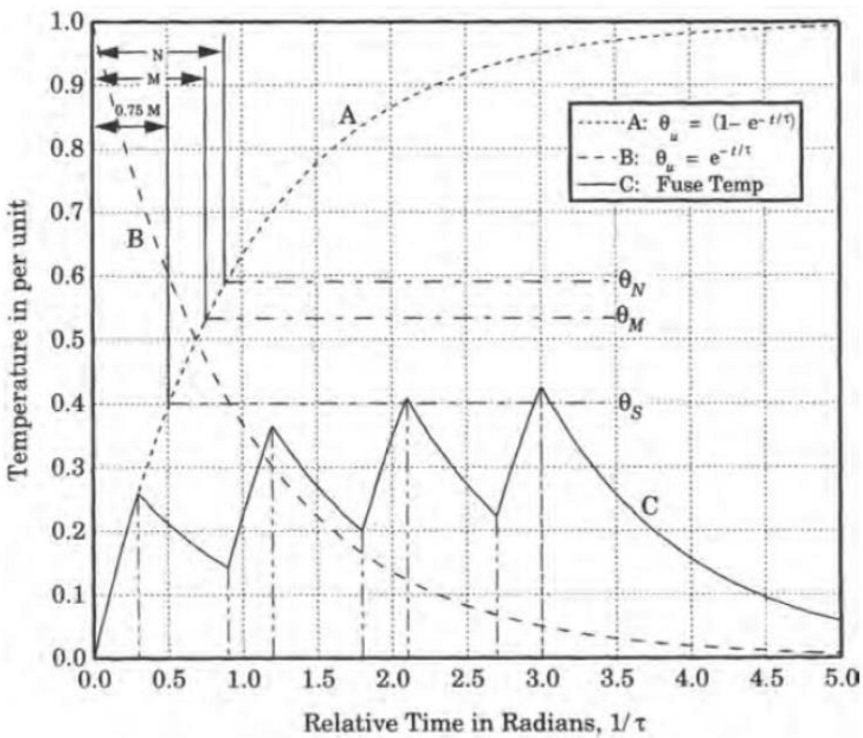


7.12.6.2 Cleared fault after 2nd



7.13 Recloser-fuse co-ordination

The criteria for determining recloser-fuse co-ordination depend on the relative locations of these devices, i.e. whether the fuse is at the source side and then backs up the operation of the recloser that is at the load side, or vice versa. These possibilities are treated in the following paragraphs.



7.13.1 Fuse at the source side

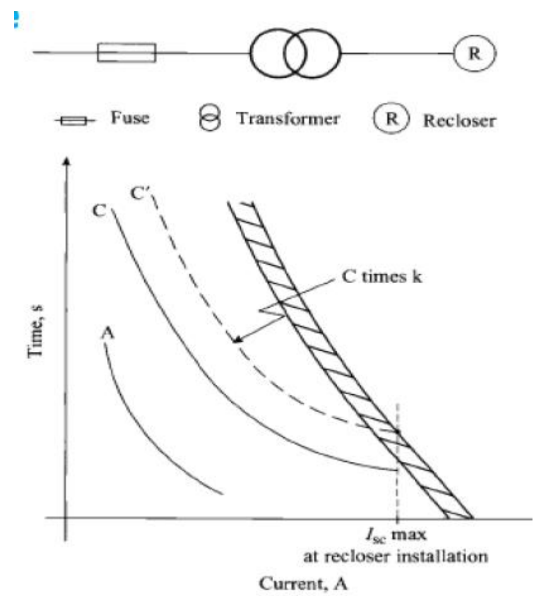
When the fuse is at the source side, all the recloser operations should be faster than the minimum melting time of the fuse. This can be achieved through the use of multiplying factors on the recloser time/current curve to compensate for the fatigue of the fuse link produced by the cumulative heating effect generated by successive recloser operations.

هنا مش عاوز الفيوز يتحرق خالص ! طالما الريكلوجر قفل يبقى الفولت ورا عنده هو الفيوز جنب الصبلاي يتحرق ويقطع الدنيا كلها ليه ! حرام !

k factor for source-side fuse link

Reclosing time in cycles	Multipliers for:		
	two fast, two delayed sequence	one fast, three delayed sequence	four delayed sequence
25	2.70	3.20	3.70
30	2.60	3.10	3.50
50	2.10	2.50	2.70
90	1.85	2.10	2.20
120	1.70	1.80	1.90
240	1.40	1.40	1.45
600	1.35	1.35	1.35

The *k* factor is used to multiply the time values of the delayed curve of the recloser.



7.13.2 Fuse at the load side

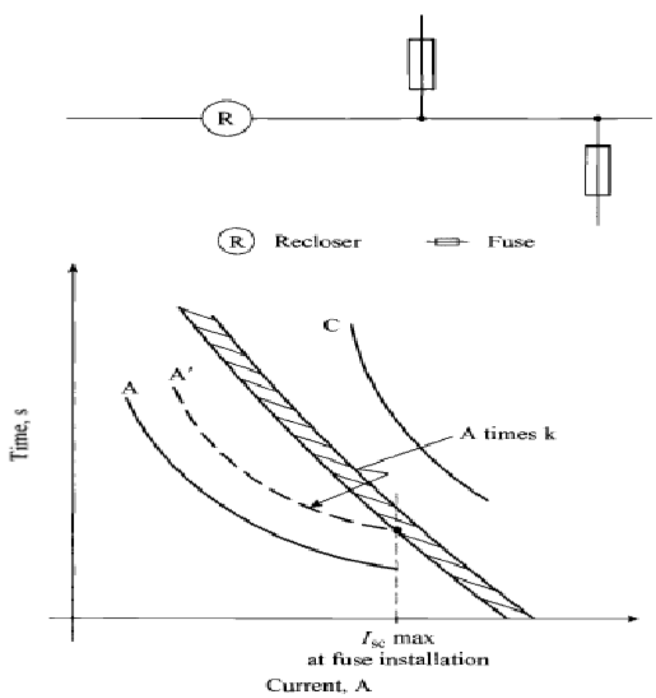
- The minimum melting time of the fuse must be greater than the **fast curve(A)** of the recloser <u>times the multiplying factor.</u>

- The maximum clearing time of the fuse must be smaller than the delayed curve of the recloser without any multiplying factor; the recloser should have at least two or **more delayed operations to prevent loss of service in case the recloser trips when the fuse operates**.

يعني هنا هخلي قفلتين قبل ما الفيوز يتحرق ندي فرصه للفولت يمشي

ممشاش ؟ يبقى الفيوز يولع بجاز ويشيله

طب الريكلوجر قافل ! لا ما في دورتين متاخرين هيبصوا ويشوفوا لو الفيوز فصل الفولت يبقى نخلي الريكلوجر يشغل الدنيا السليمه تاني



Criteria for recloser and load-side fuse coordination

k factor for the load-side fuse link

Reclosing time in cycles	Multipliers for:	
	one fast operation	two fast operations
25–30	1.25	1.80
60	1.25	1.35
90	1.25	1.35
120	1.25	1.35

The *k* factor is used to multiply the time values of the recloser fast curve.

8 APPLICATION OF OVERCURRENT RELAY

Motor Protection:

- Used against overloads and short-circuits in stator windings of motor.
- Inverse time and instantaneous overcurrent phase and ground
- Overcurrent relays used for motors above 1000 kW.

Transformer Protection:

- Used only when the cost of overcurrent relays are not justified.
- Extensively also at power-transformer locations for external-fault back-up protection.

Line Protection:

- On some sub transmission lines where the cost of distance relaying cannot be justified.
- primary ground-fault protection on most transmission lines where distance relays are used for phase faults.
- For ground back-up protection on most lines having pilot relaying for primary protection.

Distribution Protection:

Overcurrent relaying is very well suited to distribution system protection for the following reasons:

- It is basically simple and inexpensive.
- Very often the relays do not need to be directional and hence no PT supply is required.
- It is possible to use a set of two O/C relays for protection against inter-phase faults and a separate Overcurrent relay for ground faults.

8.1 Instantaneous Overcurrent relay (Define Current)

Application: This type is applied to the **outgoing feeders.**

8.2 Definite Time Overcurrent Relays

Application:

Definite time overcurrent relay is used as:

1. Back up protection of distance relay of transmission line with time delay.
2. Back up protection to differential relay of power transformer with time delay.
3. Main protection to outgoing feeders and bus couplers with adjustable time delay setting.

8.3 Inverse Time Overcurrent Relays (IDMT Relay)

8.3.1 Normal Inverse Time Overcurrent Relay

Most frequently used in utility and industrial circuits. especially applicable where the fault magnitude is mainly dependent on the system generating capacity at the time of fault.

8.3.2 Very Inverse Time Overcurrent Relay

It's used when Fault Current is dependent on generation of fault not fault location.

8.3.3 Extremely Inverse Time Overcurent Relay

Application:

- Suitable for protection of distribution feeders with peak currents on switching in (refrigerators, pumps, water heaters and so on).
- Particular suitable for grading and coordinates with fuses and re closes
- For the protection of alternators, transformers. Expensive cables, etc.

8.3.4 Long Time Inverse Overcurrent Relay

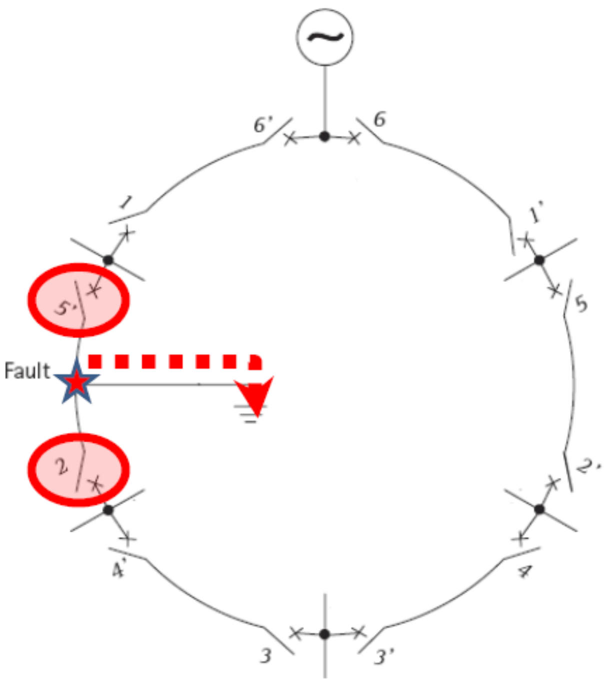
The main application of long time overcurrent relays is as backup earth fault protection.

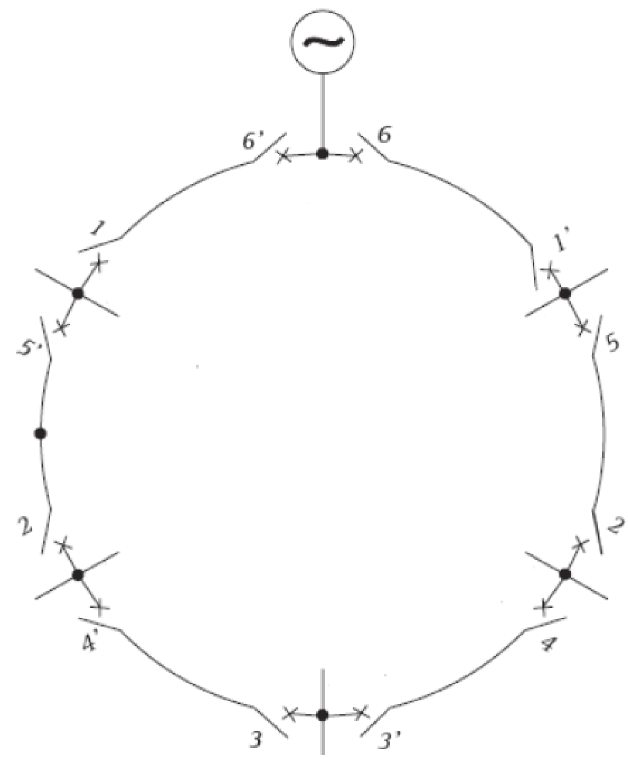
9 DIRECTIONAL OVERCURRENT RELAY

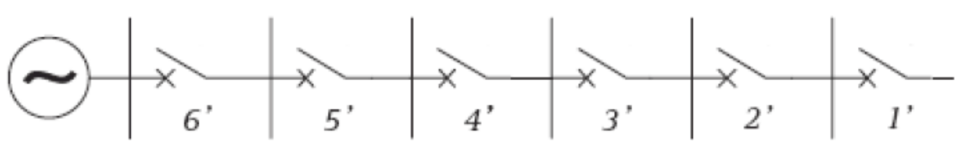
Usage: When fault current can flow in both directions through the relay location.

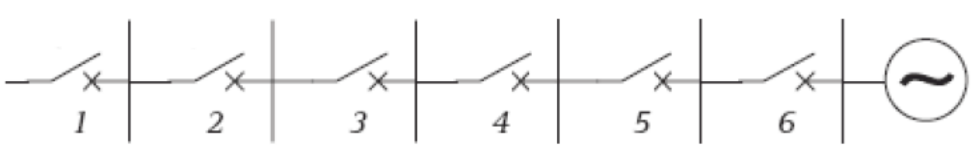
HOW : This facility is provided by use of **additional voltage inputs** to the relay.

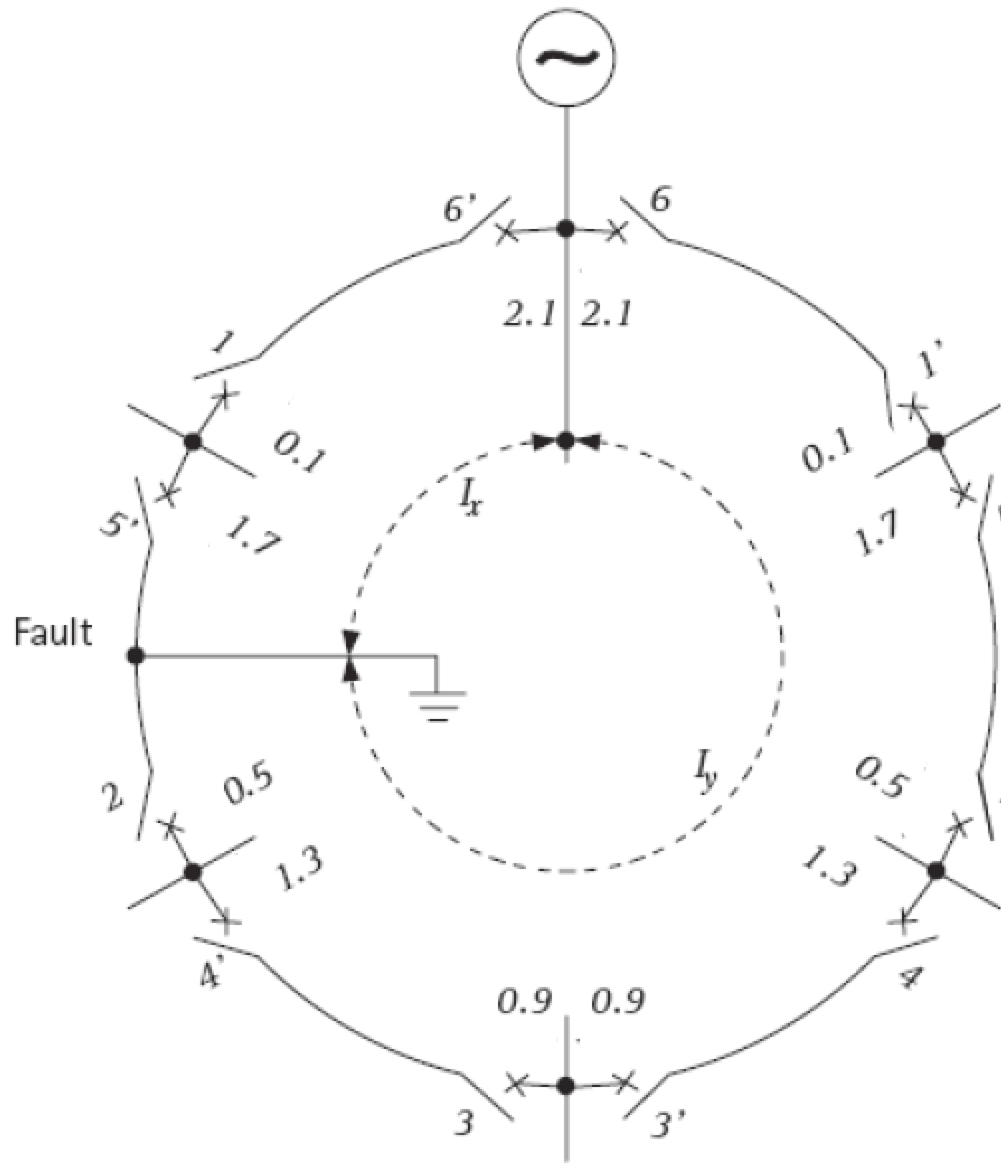
9.1 Ring Mains







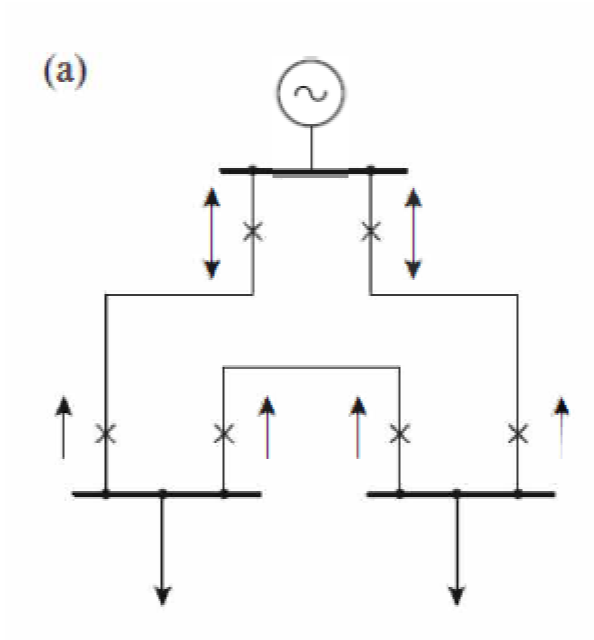




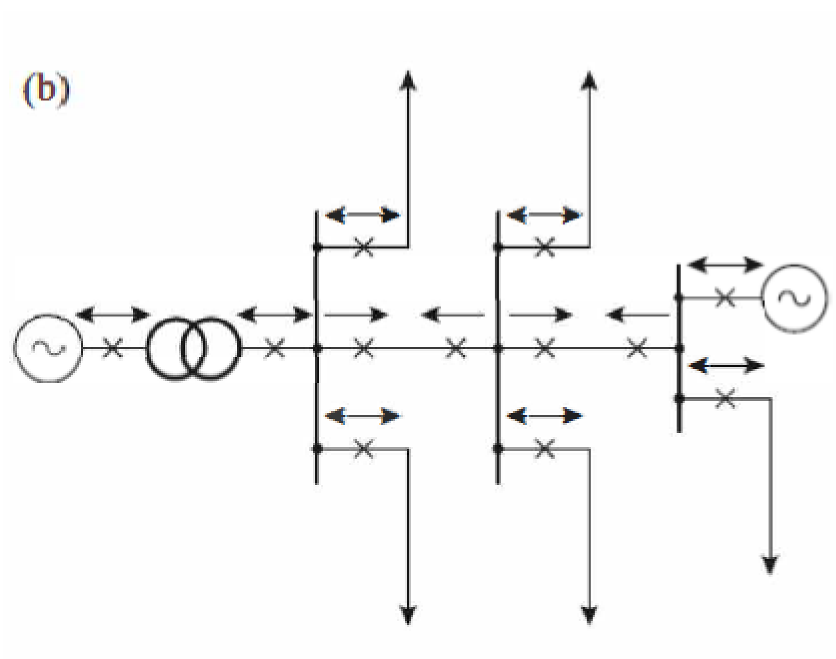
6'
6
2.1
2.1
1
1'
0.1
0.1
5'
5
1.7
1.7
I_x
Fault
I_y
2
2
0.5
0.5
1.3
1.3
4'
4
0.9
0.9
3
3'

9.2 Application of directional overcurrent relays

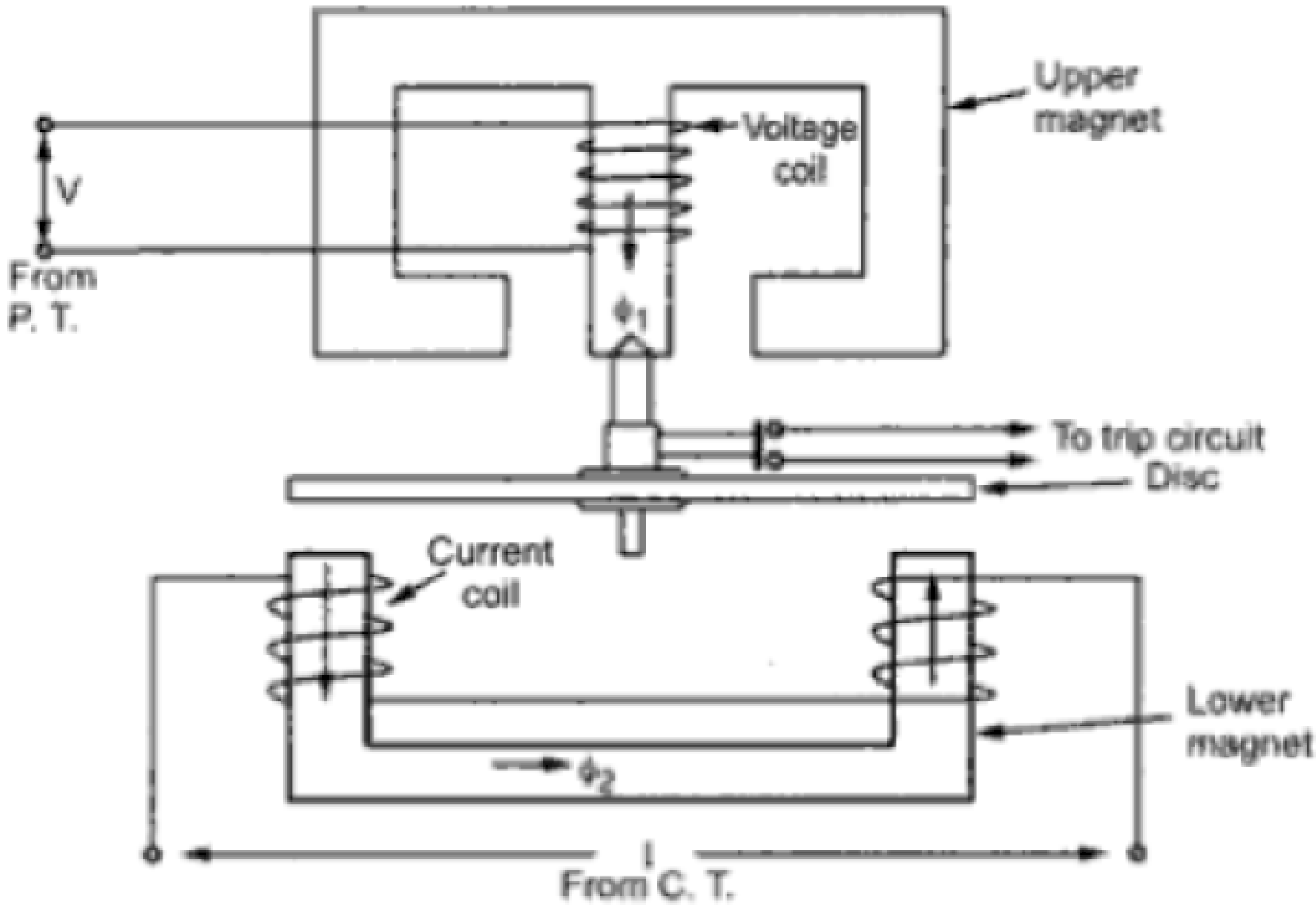
(a) Ring system



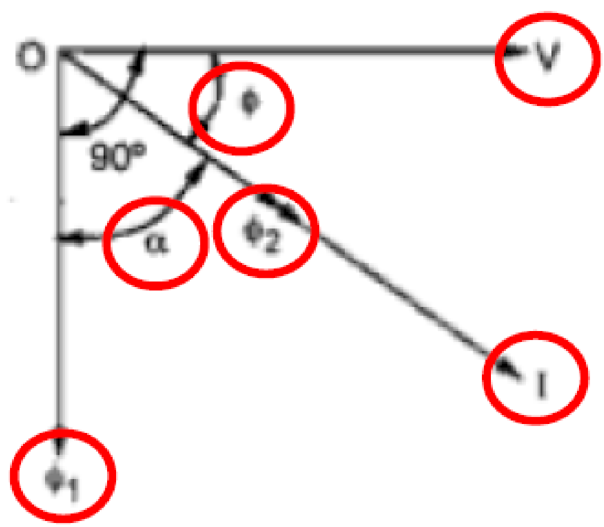
(b) Multi-source system



9.3 Directional Power Relay



Operation



$$T \propto \phi_1 \phi_2 \sin \alpha$$

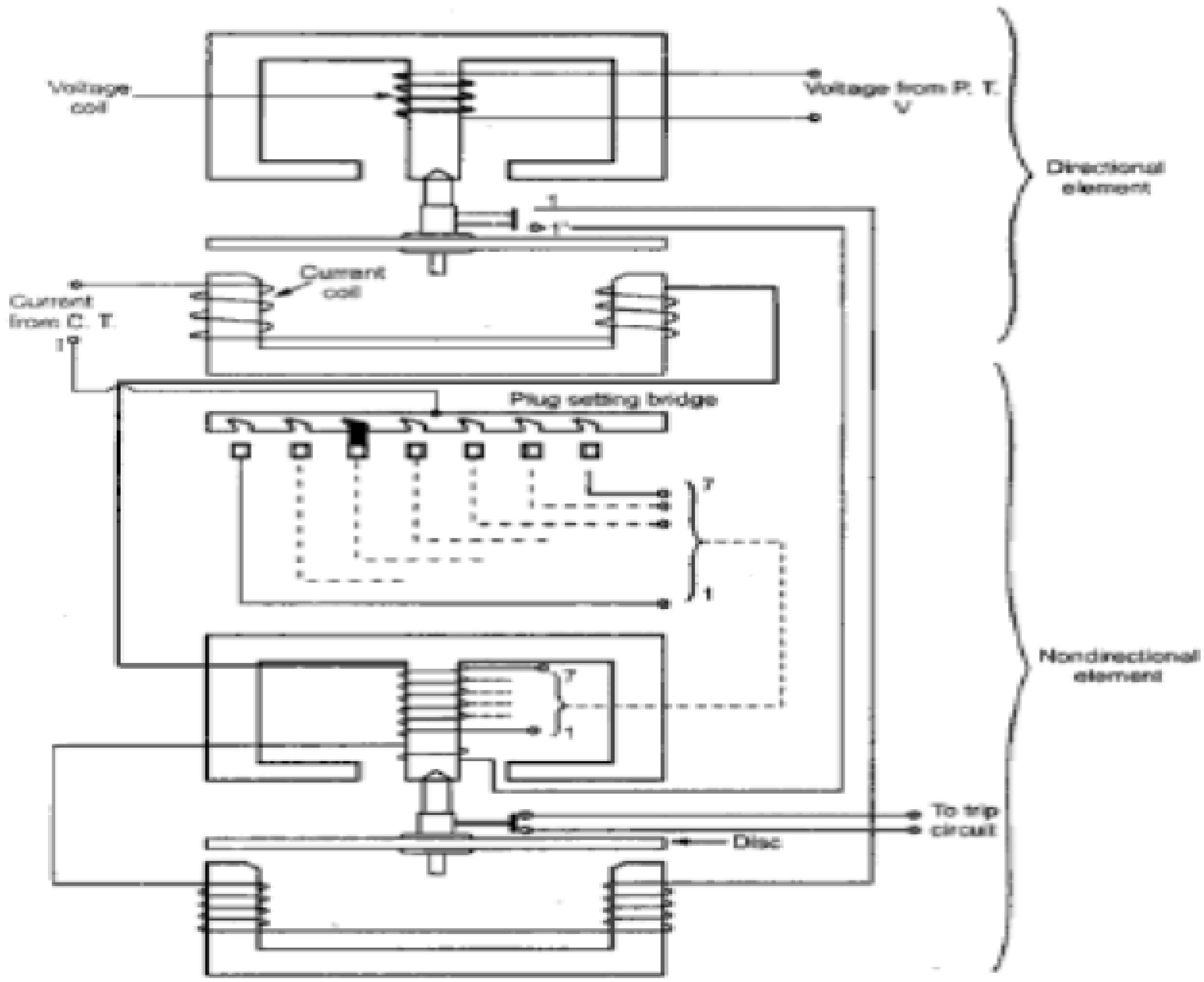
$$\phi_1 \propto V$$

$$\phi_2 \propto I$$

$$\alpha \ = 90 - \phi$$

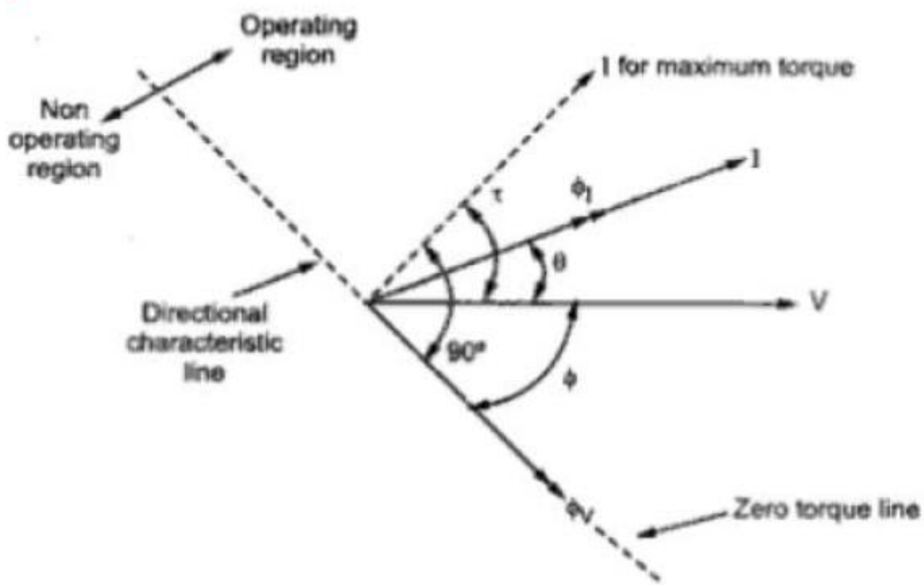
$$T \propto VI \sin(90 - \phi)$$

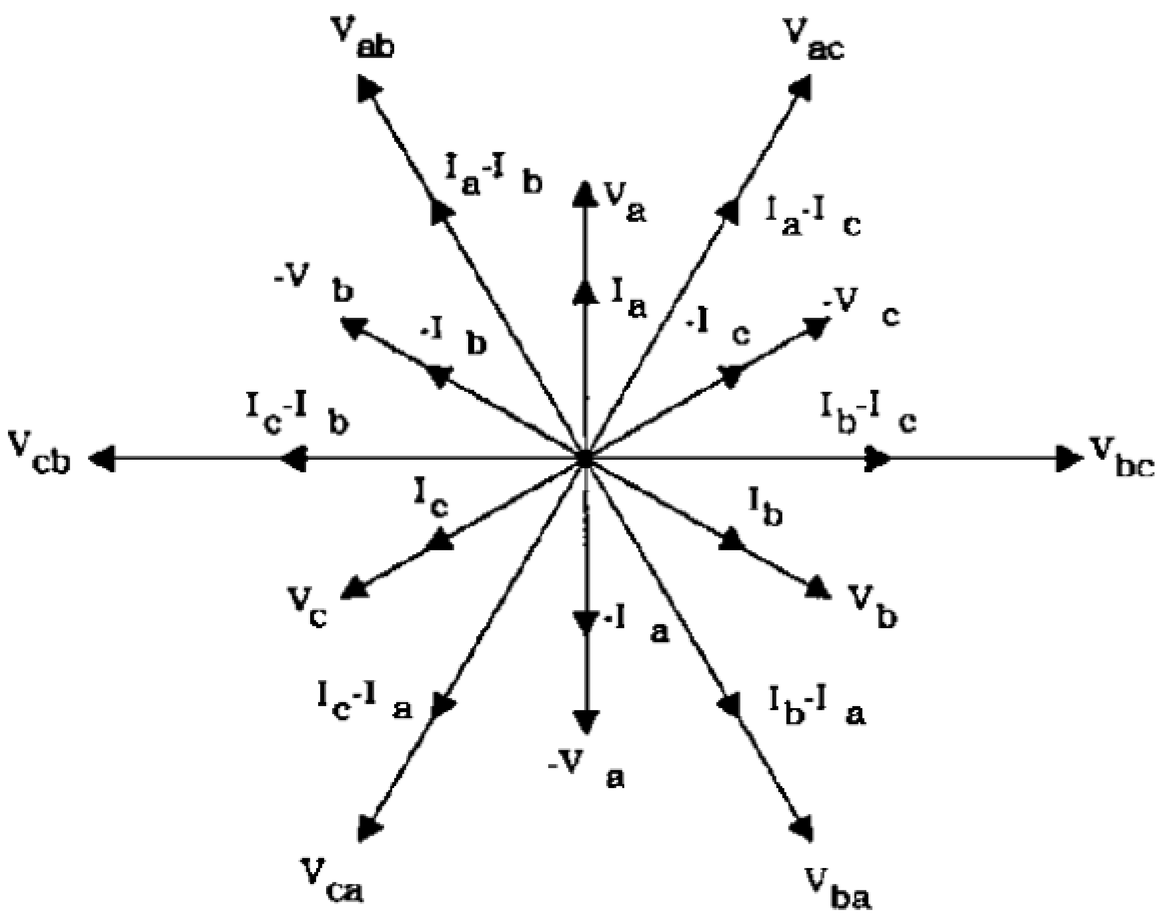
$$T \propto VI \cos \phi \ \propto Power\ in\ circuit$$



Voltage coil
Voltage from P. T.
V
Directional element
Current coil
Current from C. T.
I
Plug setting bridge
7
1
Nondirectional element
To trip circuit
Disc

9.3.1 Operation





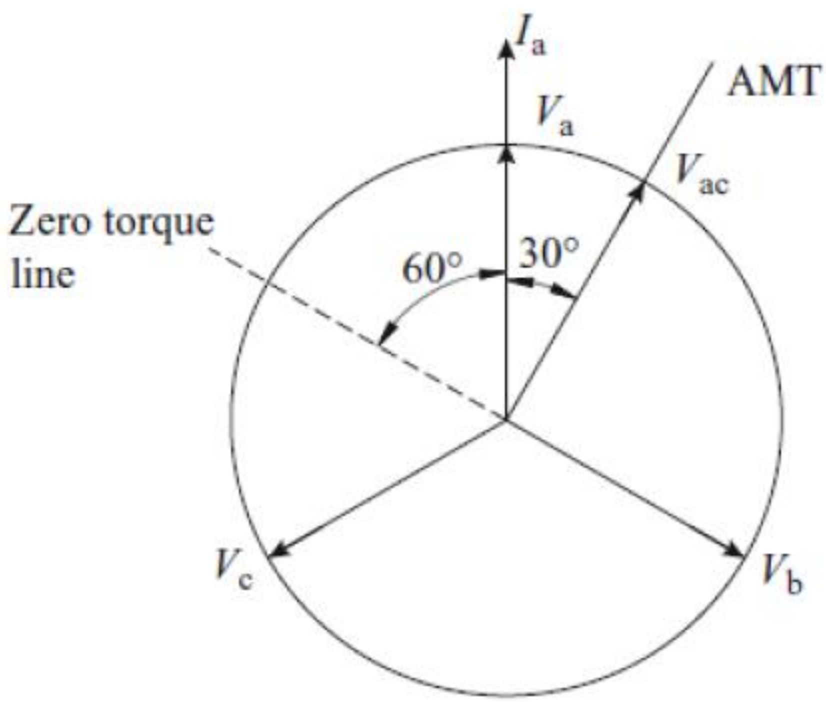
9.4 Relay connections

9.4.1 30° Connection (0° AMT)

Feeding the relays:

Φ_A :	I_a, V_{ac}	Φ_B :	I_b, V_{ba}	Φ_C :	I_c V_{cb}

Maximum torque: when the phase current lags the phase-neutral voltage by 30°.
Angle of operation: current angles from 60° leading to 120° lagging.

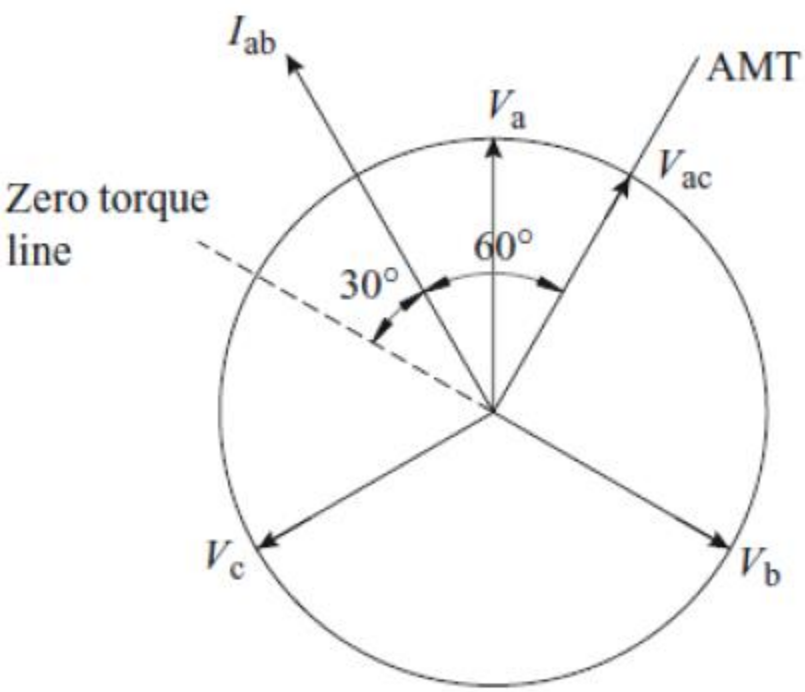


9.4.2 60° connection (0° *AMT*)

Feeding the relays:

Φ_A :	I_{ab}, V_{ac}	Φ_B :	I_{bc}, V_{ba}	Φ_C :	I_{ca} V_{cb}

Maximum torque: when the current lags the phase-to-neutral voltage by 60°. I_{ab} lags V_{ac} by 60°. I_a lags V_a by 60° at unity power factor.
Angle of operation: current I_{ab} from 30° leading to 150° lagging, or I_a leading 30° or lagging 150° at unity power factor.

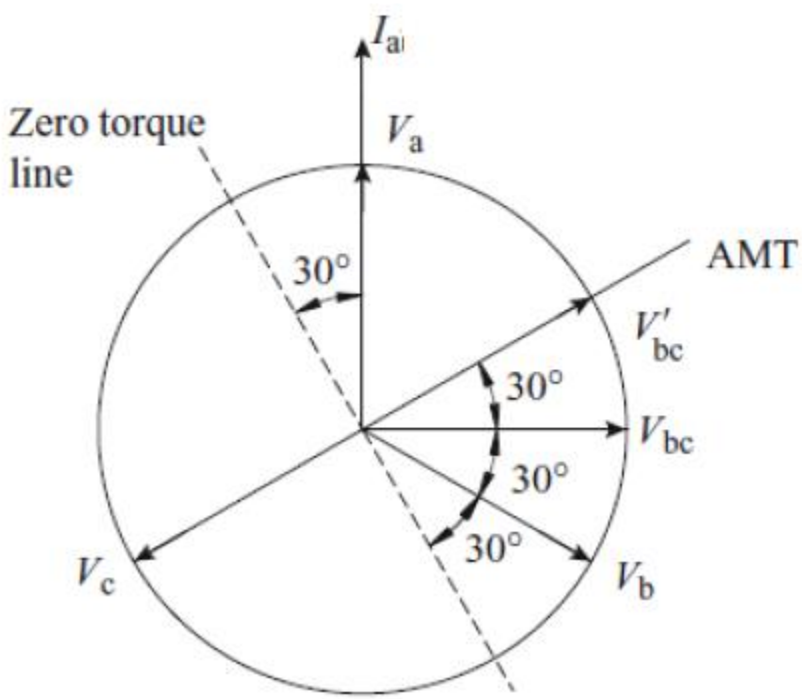


9.4.3 90° Connection (30 ° AMT)

Feeding the relays:

$\Phi_A: \; I_a, \; V_{bc}+30°$ $\qquad \Phi_B: \; I_b; \; V_{ca}+30°$ $\qquad \Phi_C: \; I_c \; V_{ab}+30°$

Maximum torque: when the current lags the phase-to-neutral voltage by 60°
Angle of operation: current angles from 30° leading to 150° lagging.

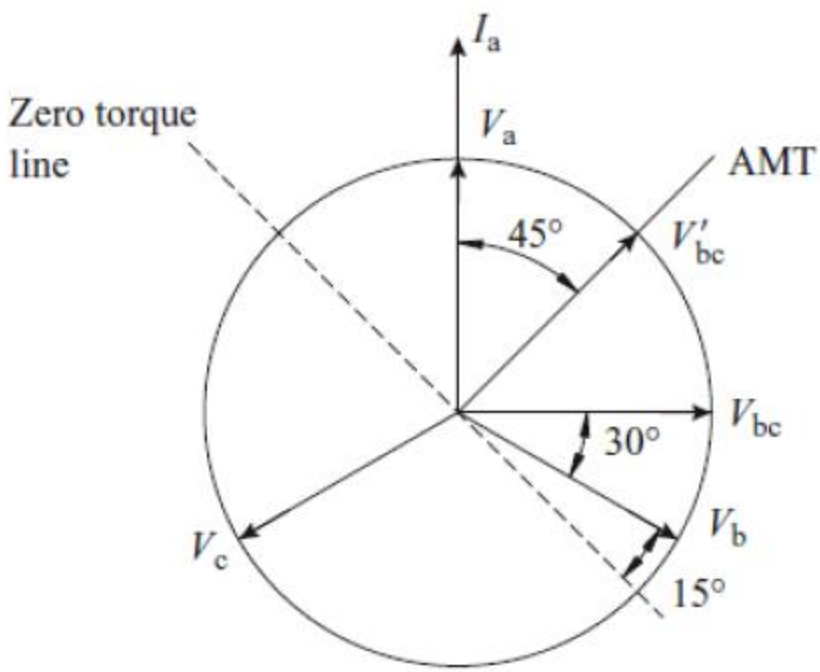


9.4.4 90° connection (45° AMT)

Feeding the relays:

Φ_A: I_a, $V_{bc} + 45°$ Φ_B: I_b, $V_{ca} + 45°$ Φ_C: I_c, $V_{ab} + 45°$

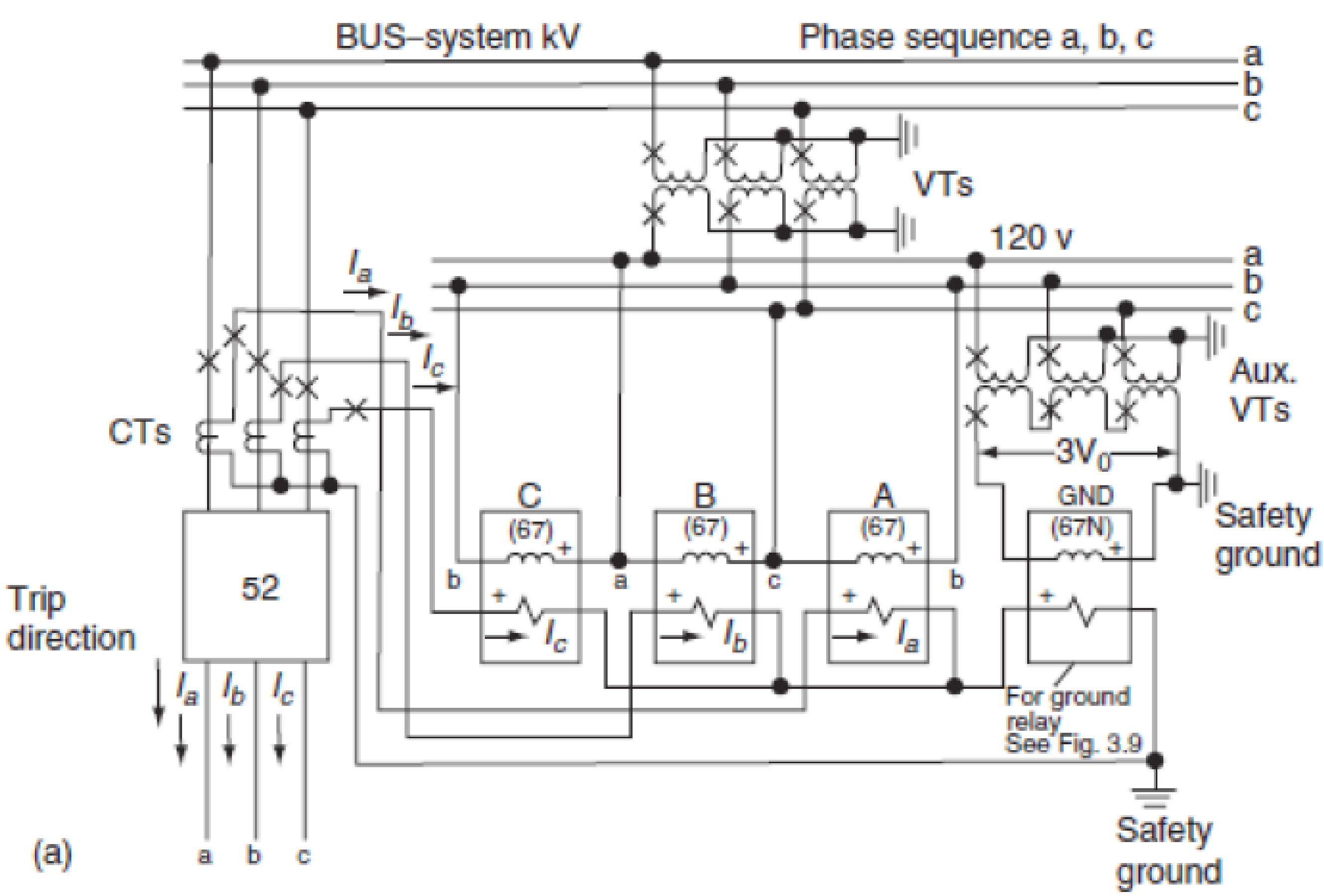
Maximum torque: when the current lags the phase-to-neutral voltage by 45°.
Angle of operation: current angles from 45° leading to 135° lagging.



9.4.5 RECAP :

Connection +			Unit Type	Phase A		Phase B		Phase C		Maximum Torque When *
				I	V	I	V	I	V	
1	30°		Watt	I_a	V_{ac}	I_b	V_{ba}	I_c	V_{cb}	I lags 30°
2	60°	Δ	Watt	$I_a - I_b$	V_{ac}	$I_b - I_c$	V_{ba}	$I_c - I_a$	V_{cb}	I lags 60°
3	60°	$\curlywedge$	Watt	I_a	$-V_{cg}$	I_b	$-V_{ag}$	I_c	$-V_{bg}$	I lags 60°
4	90°		Cylinder	I_a	V_{bc}	I_b	V_{ca}	I_c	V_{ab}	I lags 60°

9.4.6 90–60 CONNECTION FOR PHASE-FAULT PROTECTION



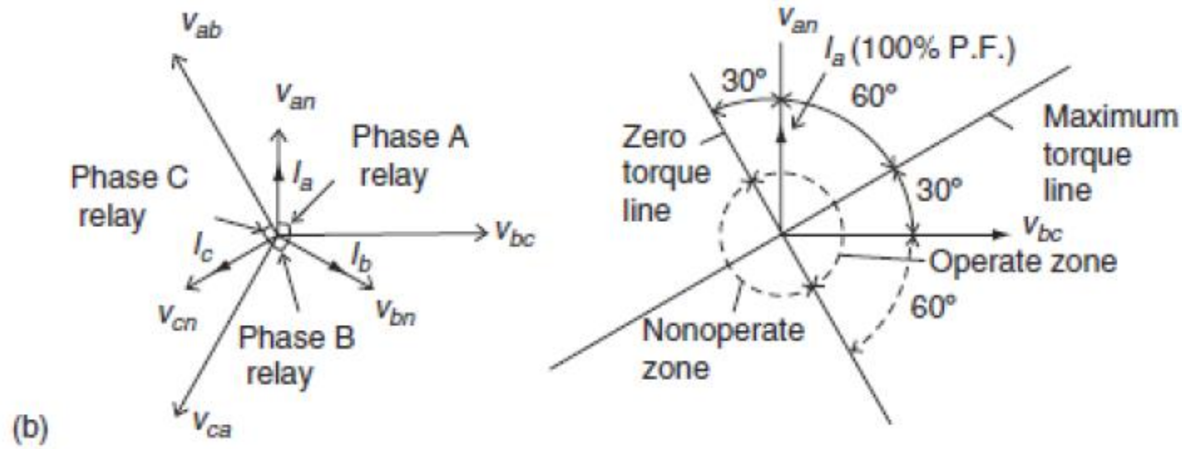


FIGURE 3.8 (a) Typical three-line connections for phase-fault directional sensing using the 30° unit of Figure 3.7a. (b) Connections also show the ground-fault directional sensing using the 60° unit of Figure 3.7b. More details and phasor diagram are shown in Figure 3.9.

9.4.7 DIRECTIONAL SENSING FOR GROUND FAULTS: VOLTAGE POLARIZATION

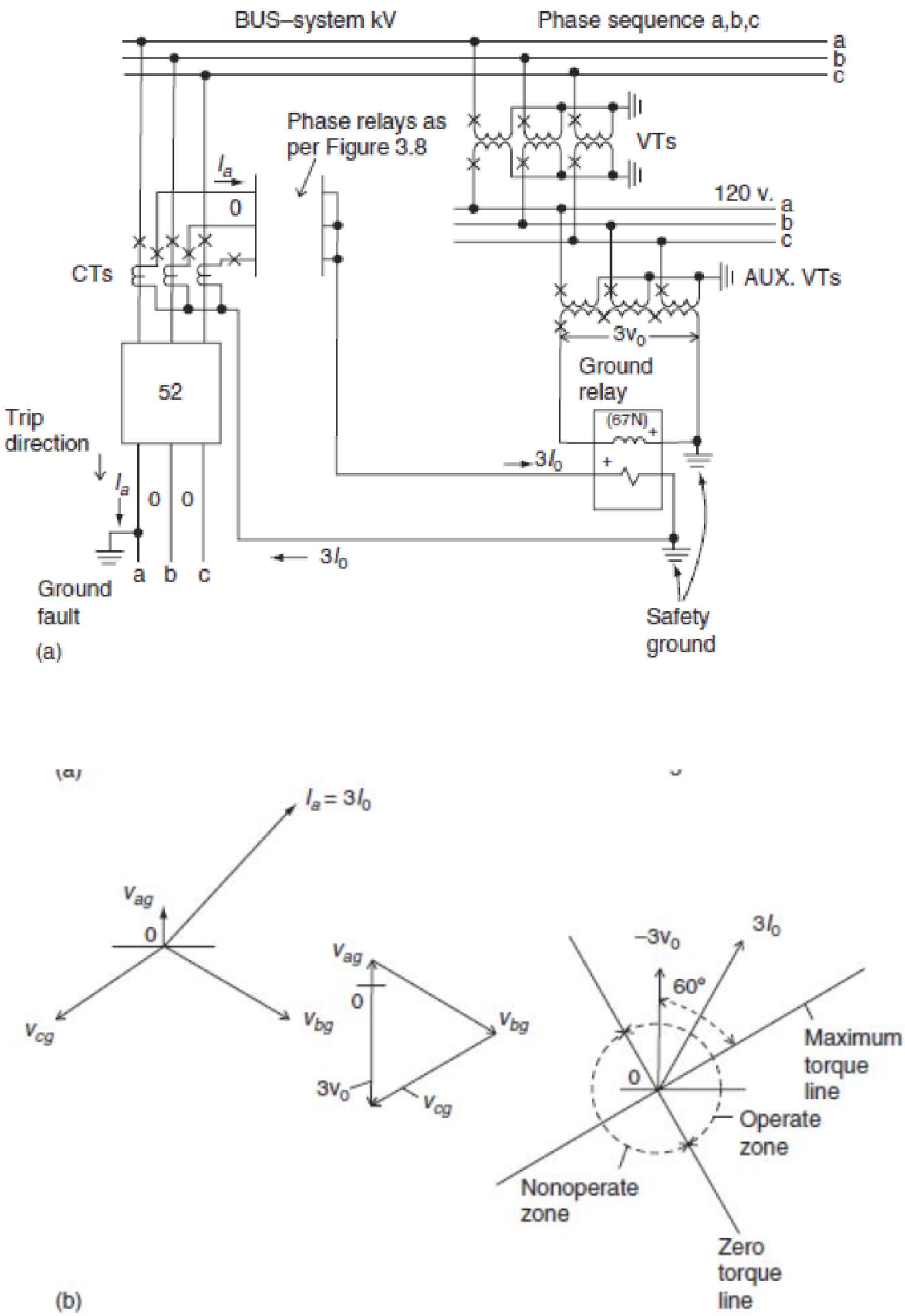


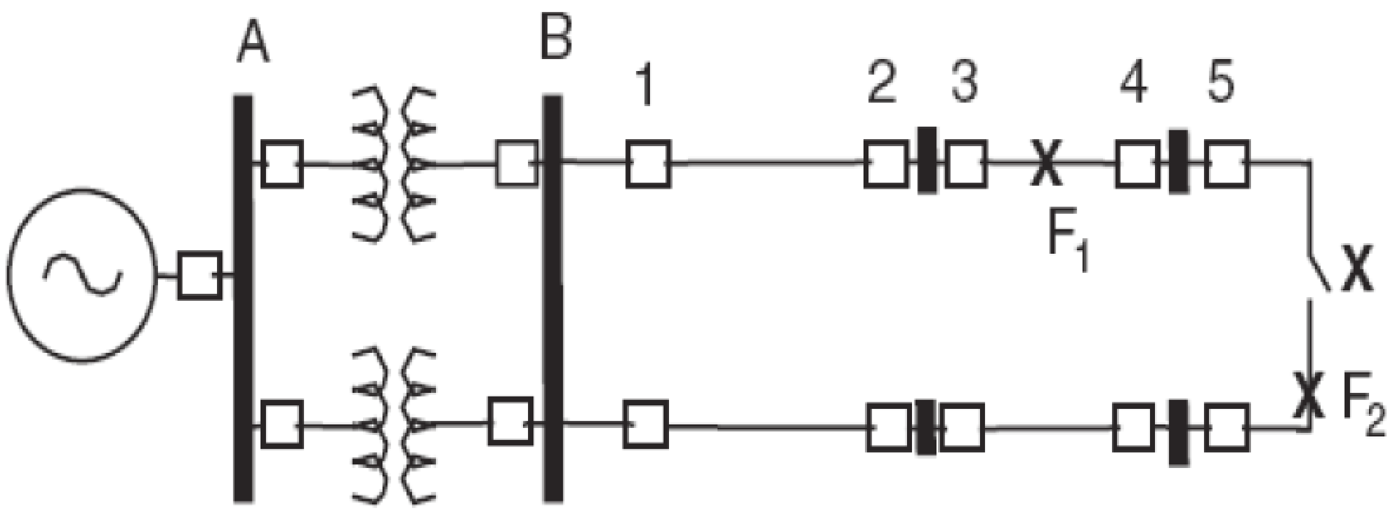
FIGURE 3.9 Typical three-line connections for ground-fault directional sensing with voltage polarization using the 60° unit of Figure 3.7b.

Directional overcurrent relaying is necessary for multiple source circuits. It would be impossible to obtain correct relay selectivity through the use of a nondirectional overcurrent relay in such cases. If the same magnitude of the fault current could flow in either direction at the relay location, coordination with the relays in front of, and behind, the nondirectional relay cannot be achieved except in very unusual system configurations. Therefore, overcurrent relaying is made directional to provide relay coordination between all of the relays that can see a given fault.

Directional relays require **two inputs,** the operating current and a reference, or polarizing, quantity (either voltage or current) *that does not change with fault location.*

To illustrate the need for directionality, refer to Figure 4.12. As a radial system (switch X open), circuit breakers (4) and (5) receive no fault current for a fault at F1. In fact, for this system configuration, breaker (4) is not required. In the loop system (switch X closed) we cannot set relays at (4) above those at (5) to be selective for a fault at F2, and still maintain coordination between (4) and (5) for a fault at F1. Directional relays are required. Occasionally, a point in the loop can be found

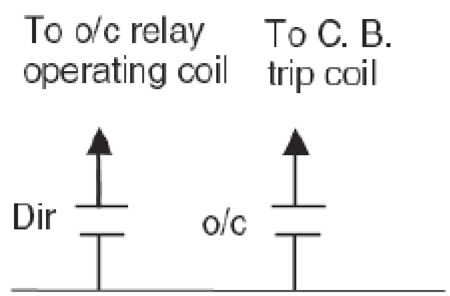
when there is sufficient difference between a fault in the forward direction and one in the backward direction so that the settings alone can discriminate between them. For this to be a safe procedure usually a ratio of 4 : 1 between forward and reverse faults would be required.



9.4.8 There are two approaches to providing directionality to an overcurrent relay.

9.4.8.1 Directional control.

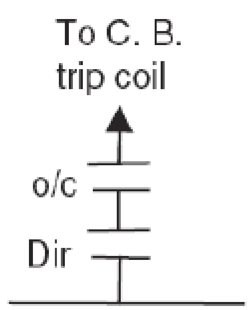
As shown in Figure 4.13(a), the design of the relay is such that the overcurrent element will not operate until the directional element operates, indicating that **the fault is in the tripping direction.** In electromechanical relays this is done by <u>using the directional element contact in series with the overcurrent element coil</u> so no torque can be developed until the directional element contact is closed.



Directional control
(a)

9.4.8.2 Directional overcurrent.

as shown in Figure 4.13(b), this relay has independent contacts, connected in series with the circuit breaker trip coil. **Both relay contacts must close before a trip output is obtained.**



Directional o/c
(b)

9.4.8.3 Directional control versus directional overcurrent relays

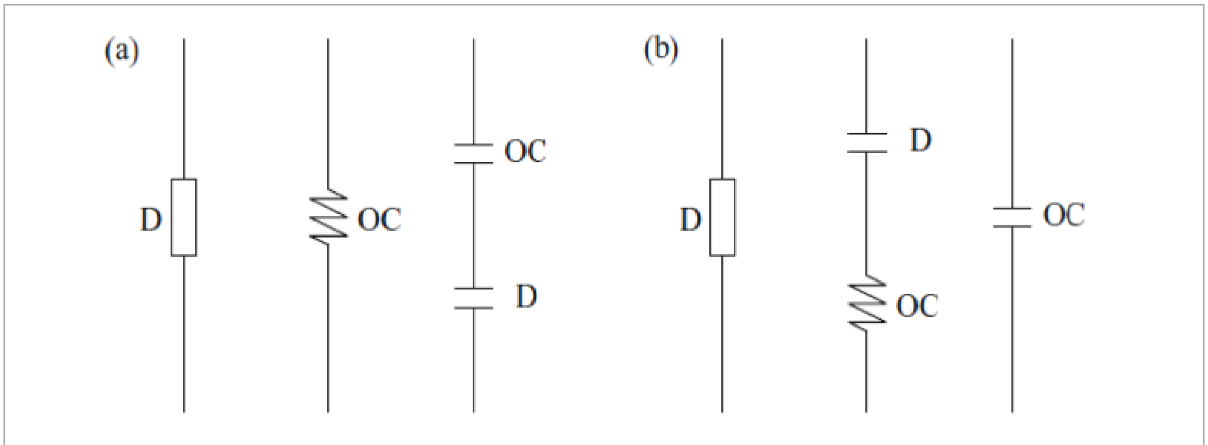
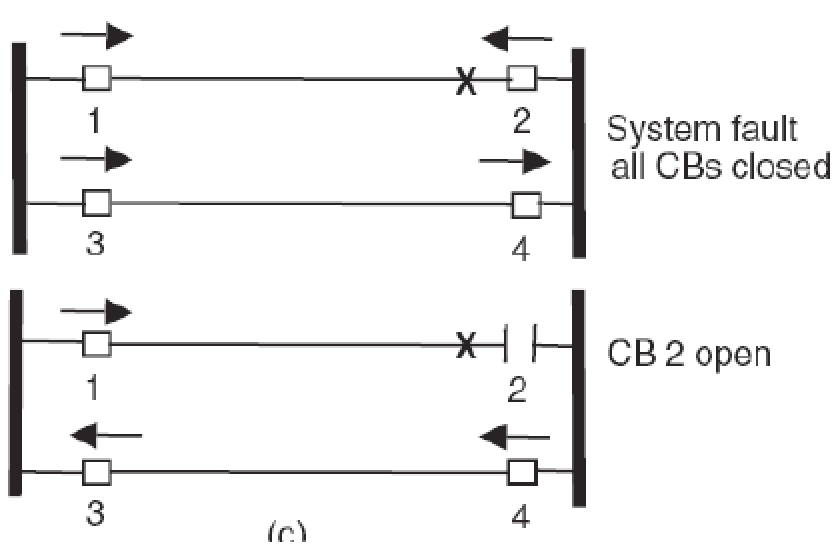


Figure 7.2 Obtaining the direction of power flow: (a) by supervision; (b) by control



The directional control relay is more secure. Referring to Figure 4.13(c), with the directional overcurrent design, if a fault occurs in the non-trip direction, as it does for breaker (4), the overcurrent element can pick up from the contribution in that direction. Only the directional element prevents a trip of breaker (4). If we assume that breaker (2) opens before breaker (1), which is possible, then the reversal of fault current through circuit breaker (4) will cause a race between the overcurrent element opening and the directional element closing.

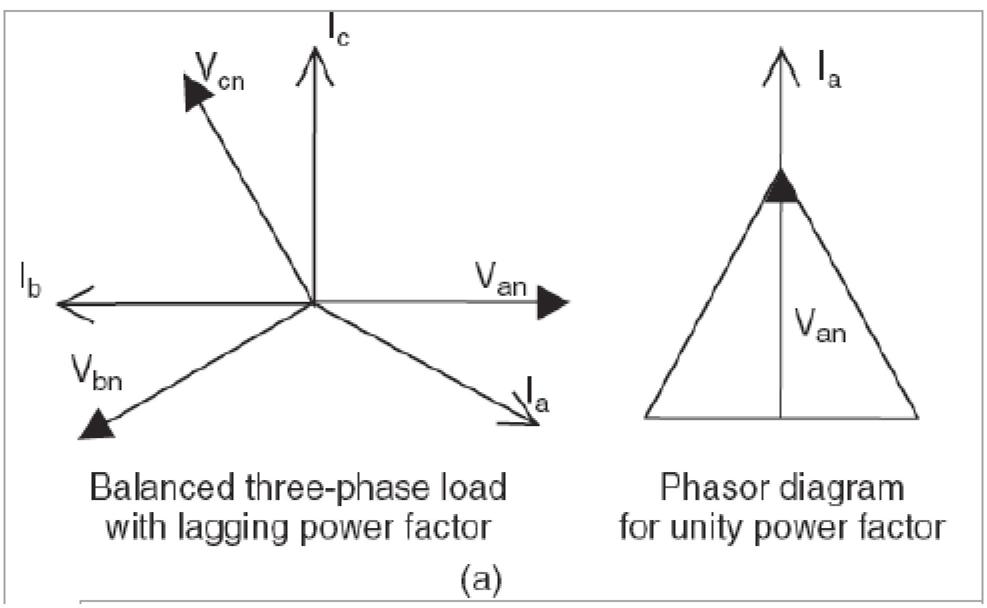
If the directional element wins the race, i.e. it closes its contacts before the overcurrent relay resets, there will be a false trip. With the directional control design, this situation cannot occur since the overcurrent relay is controlled by the directional contact and will not pick up when the fault is in the non-trip direction. At breaker (3), although the directional contact will pick up with all breakers closed, the overcurrent relay will not time out since it must coordinate with breaker (2). On the one hand, it is more difficult to apply a directional control relay since the setting must consider the two elements operating together, instead of independently. The operating time of separate units is simply a function of the current in the overcurrent element of each unit; the pickup and time delay of the directional unit are so small that they can be neglected. On the other hand, the operating time of a directional relay is more complicated since it is a function of the product of its actuating and polarizing quantities and the angle between them.

For this reason, it is not recommended that directional control relays try to coordinate with overcurrent relays, even if the time curves are the same.

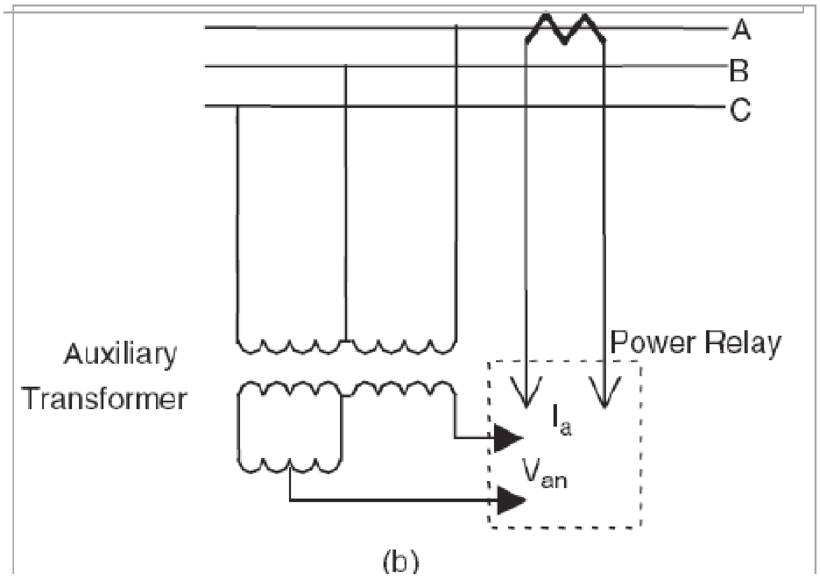
9.5 Polarizing

As described in section 2.2, the ability to differentiate between a fault in one direction or another is obtained by comparing the phase angle of the operating current phasor, which varies directly with the direction of the fault, and some other system parameter that is not dependent on the fault location. This constant parameter is referred to as the polarizing quantity. For phase relays, the polarizing quantity is, almost invariably, the system voltage at the relay location. Depending on the voltage and current connections, a directional relay will operate either for normal load current or fault current. In an electromechanical relay, the maximum torque on an induction disc occurs when the two torque-producing fluxes are 90◦ apart in time and space. The space criterion is easily obtained by the location of the flux-producing

or protective applications where we are concerned with conditions other than short circuits, power directional relays are required. These relays operate under conditions of balanced load and relatively high power factor. The voltage and current phasors are approximately in phase with each other and of constant magnitude, as shown in the balanced load case of Figure 4.14(a). Power relays are polarized by a voltage of the circuit, e.g. Van compared to the operating current Ia as shown in the phasor diagram for a power relay. These connections are chosen so that maximum torque in the relay occurs under unity power factor load. The relay will then pick up for power flowing in one direction and will reset for the opposite direction of power flow. The relay is designed to make the necessary 900 flux displacement. This connection requires a phase-



—5 Phasors for power relays



Power relay connections without phase-to-neutral voltage available

9.5.1 Fault directional relays

he more usual case, however, involves protection during short circuits. For directional relays applied to operate during a fault, it is important to remember two facts.

1. The system voltage will collapse at the point of the short circuit (Vb in Figure 4.15). Therefore to obtain sufficient torque under fault conditions, the polarizing voltage must not include the faulted phase.

2. The fault power factor is low, i.e. the current lags the voltage by nearly 90◦. The choice of connections to obtain correct directional discrimination for unbalanced faults is restricted to those shown in Figure 4.16. It is possible to determine the best connection of the three for any given set of system and fault conditions by analyzing the phasors within the relay for the most probable conditions of load angles, faults and the effect of arc resistance. If any of these conditions change, the preferred connection will also change. Since it is not possible to wire the relay for all of the possible variations, it is necessary to select the best compromise for the widest range of possibilities. Of the three shown, the 90◦ connection is usually preferred.

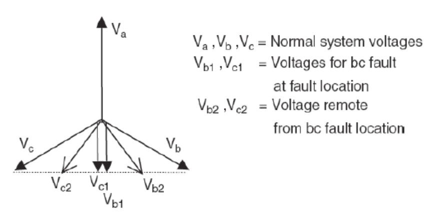


Figure 4.15 Phase voltages for bc fault

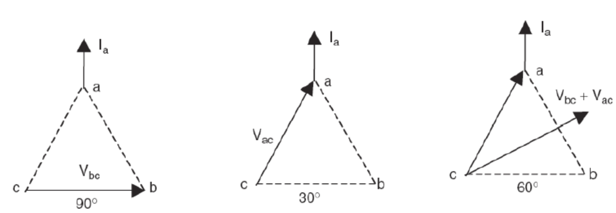


Figure 4.16 Conventional connections for directional phase relays

9.5.2 Potential polarizing

For ground faults, the operating current is derived from the residual circuit of the phase CTs

(In = 3I0). Since the current can be derived from any phase that is faulted, it is necessary to obtain a related voltage to obtain a correct directional response. As with phase relays, whenever a directional relay is involved, two facts must be known: **the magnitude and the direction of the fault.** Both factors may be combined in a single product-type relay or in separate elements such that the directional element controls the overcurrent element. For ground directional indication, a reference is necessary to determine whether the line current is into or out of the protected line. The zero-sequence voltage (3E0) can be used since it is always in the same direction regardless of the location of the fault. This is called potential polarizing and can be obtained across the open corner of a wye-grounded, broken delta potential transformer, as shown in Figure 4.17. The vector

sum of the three line-to-neutral voltages Ea + Eb + Ec = 3E0, which is zero for balanced conditions or for faults not involving ground. The magnitude of 3E0 during line-to-ground faults depends on the location of the fault, the impedance of the ground circuit and the ratio of the zero-sequence impedance to the positive-sequence impedance. If two winding potential transformers are used they are usually connected wye-grounded–wye-grounded to provide metering and relaying potential. In this case 3E0 is obtained from an auxiliary potential transformer, as shown in Figure 4.18.

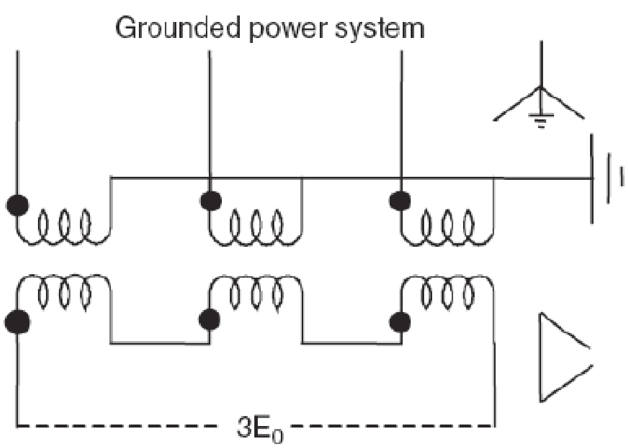


Figure 4.17 Potential transformer polarizing

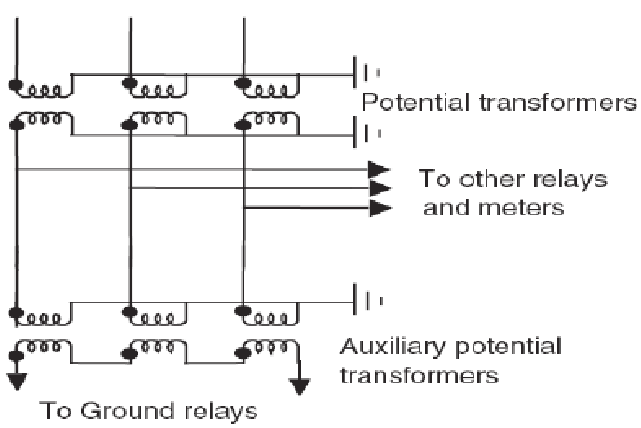


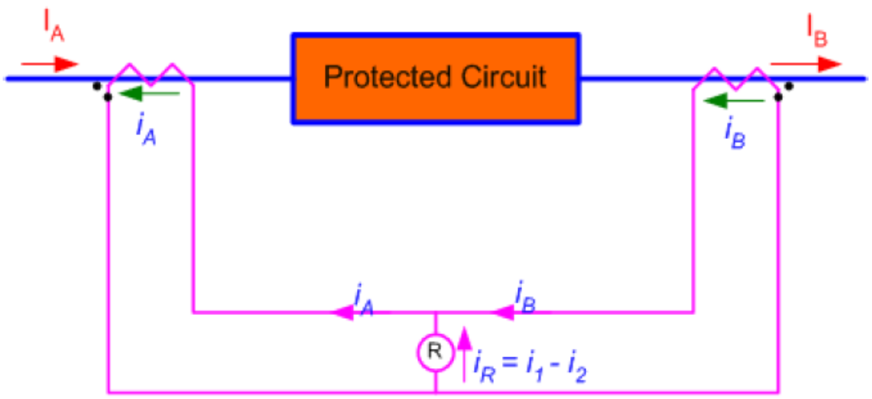
Figure 4.18 Auxiliary transformer polarizing

10 DIFFERENTIAL PROTECTION

10.1 There are three category schemes:

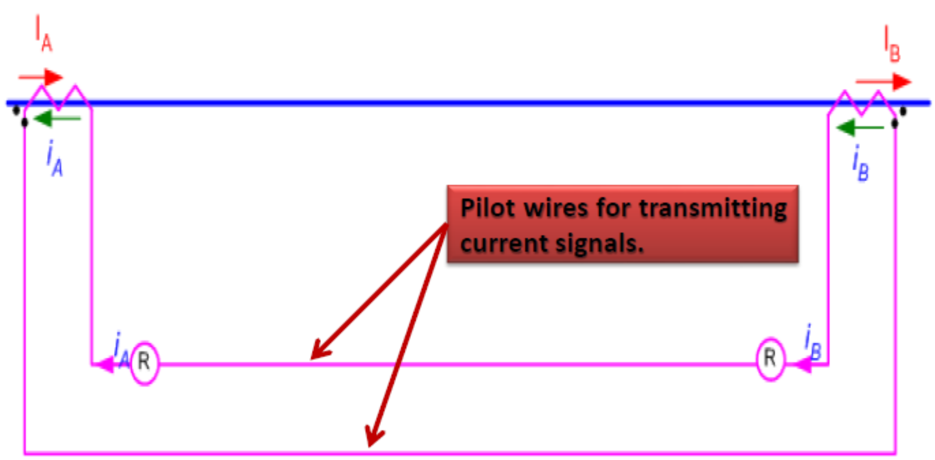
10.1.1 the ends of the protected zone are close to each other

In this category a single relaying point is used



10.1.2 It is applied where there is geographical separation between the ends of the protected zone

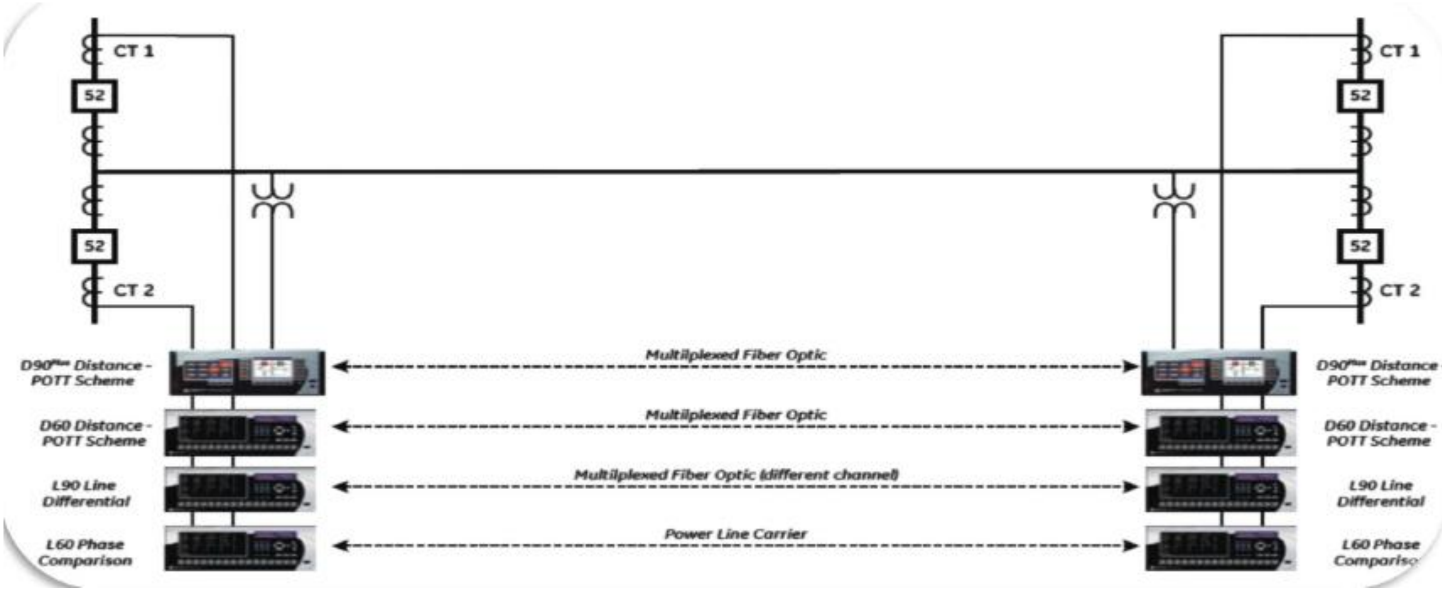
where a pilot wires can be used.



10.1.3 If the distance between the ends of the protected zone is longer than the limits of using pilot wires.

PLC (Power Line Connectors) can be used.

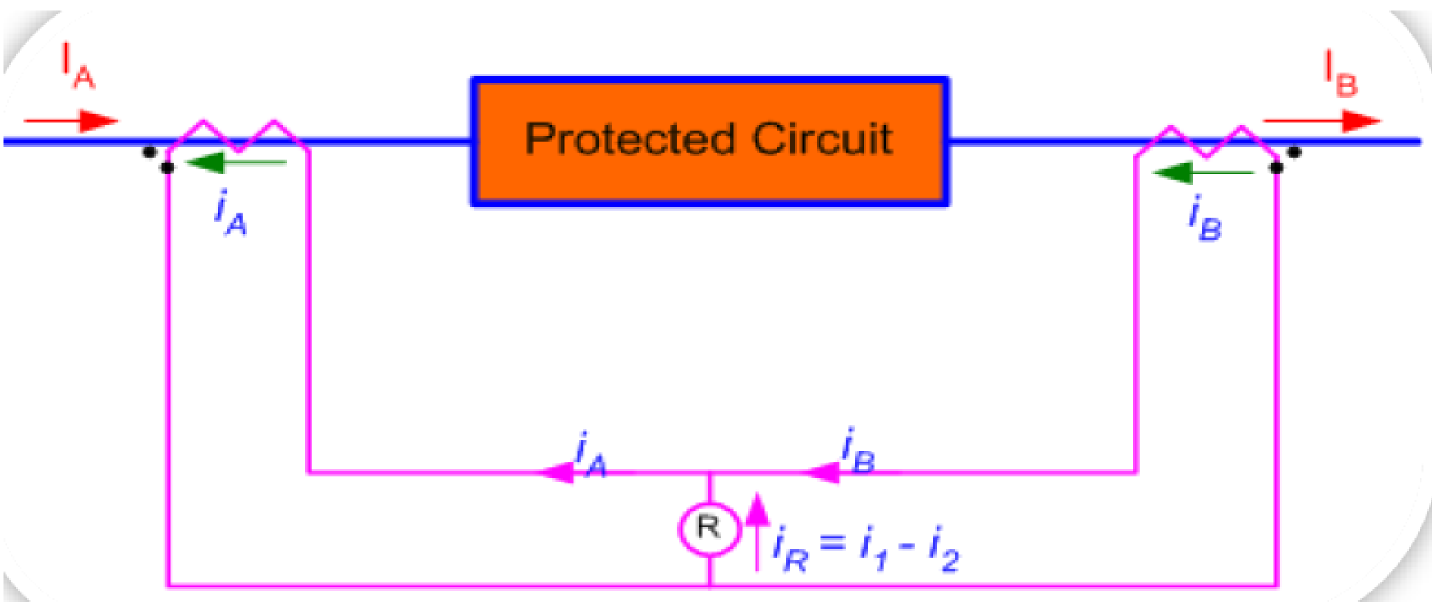
This category is designated as <u>composed distance carrier</u> scheme which operate eventually as differential protection whoever, it is *not best on circulating scheme.*



We will study first type only

10.2 Single Relaying Point Scheme

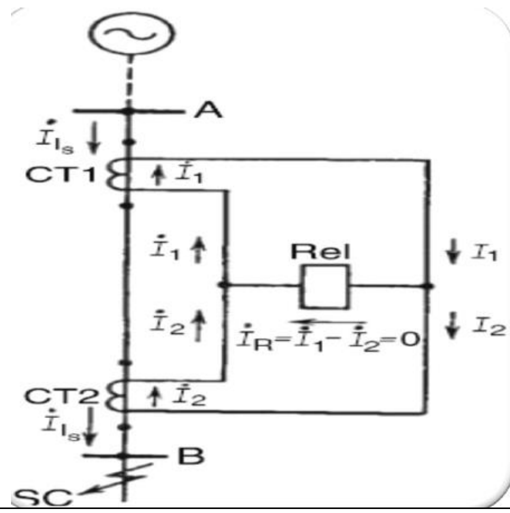
It depends on the relay being connected to the center point of a balance system.



Under all load and through (external) fault conditions, the relay will not operate.

<table>
<tr>
<td>HEALTHY
or
EXTERNAL
FAULT</td>
<td>No current in the relay

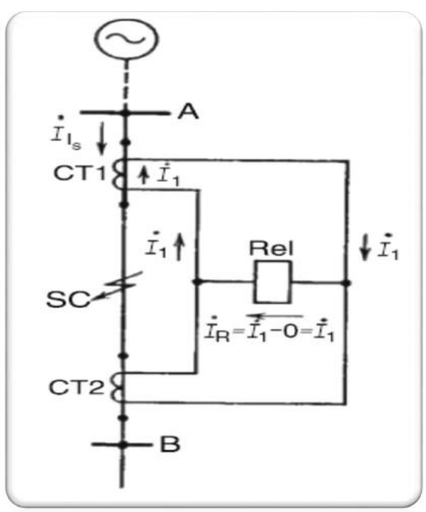
$$I_1 = I_2$$
$$V_R = V_{EF} = 0$$

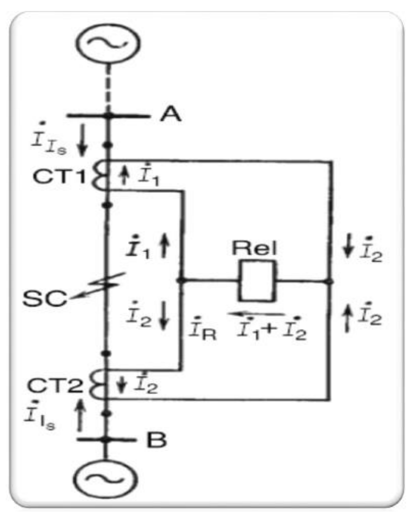


</td>
</tr>
<tr>
<td>INTERNAL
FAULT</td>
<td>Under internal fault conditions, the relay will operate.

For internal fault condition , current will pass in the relay

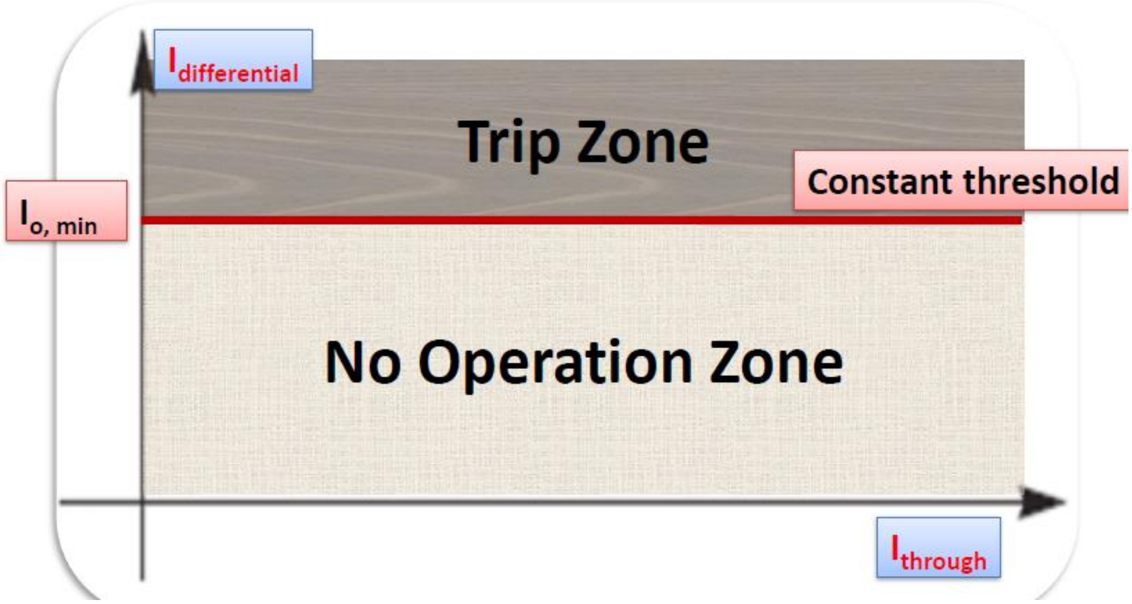
$$I_1 \neq I_2$$
$$if\ I_1 - I_2 > I_{set}$$





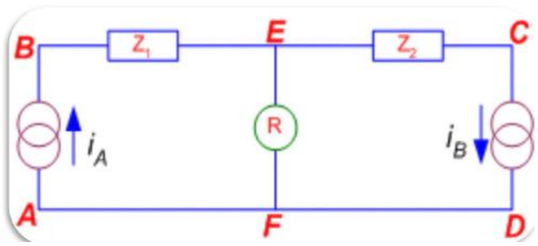
</td>
</tr>
</table>

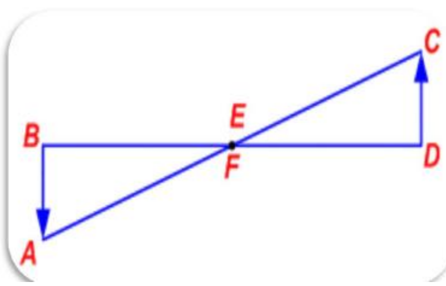
10.2.1 Operating C/Cs of this type is



10.2.2 The secondary circuit of CTs can be simplified as:

1. Lead from CT1 to the relay (go and return) will be burden for CT1
2. Lead from CT2 to the relay (go and return) will be burden for CT2
3. If IA in CT1 is the same as IB in CT2 then all the voltage produced across CT1 will be dropped across the loop BEFA and that produced by CT2 will be dropped across the loop CEFD.



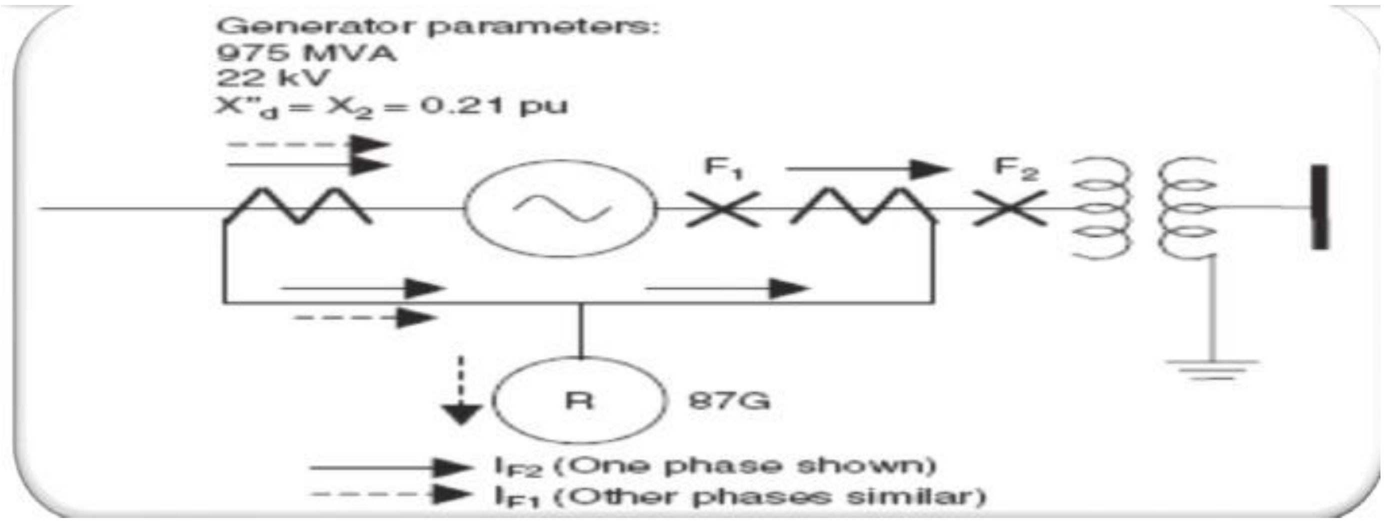


10.2.3 Advantages and disadvantages

Advantage	Differential relays are very desirable since no coordination is used.
Disadvantages	But, CTs are ideal when Is (CT secondary current) versus Ip (CT primary current) is linear. But; 1. The lead between the relay and each CT differs from one to another. 2. Difference in CTs C/Cs due to manufacturing and operation. This mismatch in CTs forced us to make **Iset > 0**

10.2.4 Example

Consider the power system shown in accompanied Figure which represents a unit-connected generator prior to being synchronized to the system and protected with an overcurrent relay connected as a differential relay. Determine the maximum load, select a CT ratio for the generator differential, calculate the relay operating currents for a three-phase fault at F1 and F2 and set the relay. Assume there is no CT error.



<u>*Solution*</u>

Full-Load Current

$$I_{FL} = \frac{975 * 1000}{\sqrt{3} * 22} = 25587\ A$$

So, CT ratio <u>30000/1</u>

Relay will be set at $I_{o_{Min}} = 0.2\ pu$

Three-Phase Fault Current

$$I_F = \frac{1}{0.21} \times 25587 = 121842.9\ A$$

So, Relay Response

<u>When fault at F1</u>

$$I_R = I_F \times CT\ ratio = \frac{121842.9}{\frac{30000}{1}} = 4.061\ A$$

$$I_R > I_{omin} \rightarrow The\ relay\ will\ operate$$

When fault at F2

Assume no error in CT $I_R = 0$

$$\boldsymbol{I_R < I_{omin} \rightarrow the\ relay\ will\ not\ operate}$$

Repeat previous problem assuming that the line-side CT has an error of 10% of its secondary current. Set the overcurrent relay so it will not operate for an external fault.

Relay response

When fault F2

$$I_R = 0.1 \times 121842.9 \times \frac{1}{30000} = 0.406\ A$$

$$I_R > I_{omin}$$

This operation is not correct (it mustn't operate for external) it's caused by an error in CT

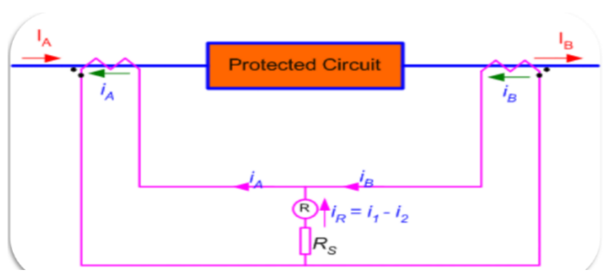
10.3 Stability and Sensitivity

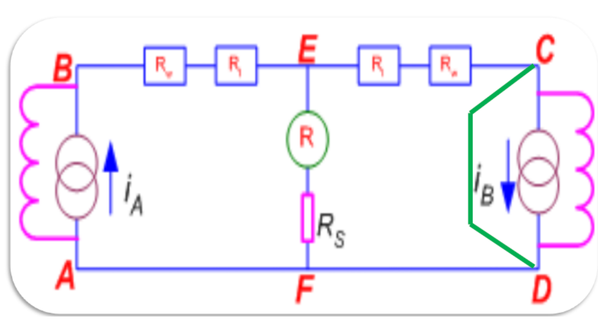
The Stability	for external fault is the maximum through fault current at which the relay remains inoperative
The Sensitivity	for internal fault is the minimum internal fault current at which the relay just operates.

$$stability\ ratio = \frac{I\_F_{Max_{ext}} stability}{I\_F_{Min_{int}} sensitivity}$$

$$= \frac{themax.through\ fault\ at\ which\ therelay\ remains\ unoperative}{the\ min.internal\ fault\ at\ which\ therelay\ just\ picks\ up}$$

10.3.1 Stability Calculation:





1- Assume
- Fault external
- One CT is fully saturated
- The other is ideal

2- Draw the eqv. Crkt
ct's are current source
fully saturated is SC link

3- From circuit notice that

$$\boldsymbol{V_R = \frac{I_F}{N}\ (R_l + R_{w2})}$$

R_l *lead resistance from relay to CT*
R_{w2} *secondary resistance of saturated CT*

10.3.2 Relay types used in differential operation:

10.3.2.1 Current operated relay: (Low impedance relay)

Voltage drop on relay resistance can be neglected

$$I_{set} = \frac{V_R}{R_s}$$

10.3.2.2 2 Voltage operated relay: (High impedance relay)

$$I_{set} = \frac{V_R - V_o}{R_s}$$

Since Iset is specified for the relay, then the stablizing resistance RS can be calculated as follows:

$$\boldsymbol{R_s = \frac{V_s - V_o}{I_{set}} = \frac{1}{I_{set}}\left(\frac{I_{FA}}{N_A}\,(R_l + R_{w2}) - V_o\right)}$$

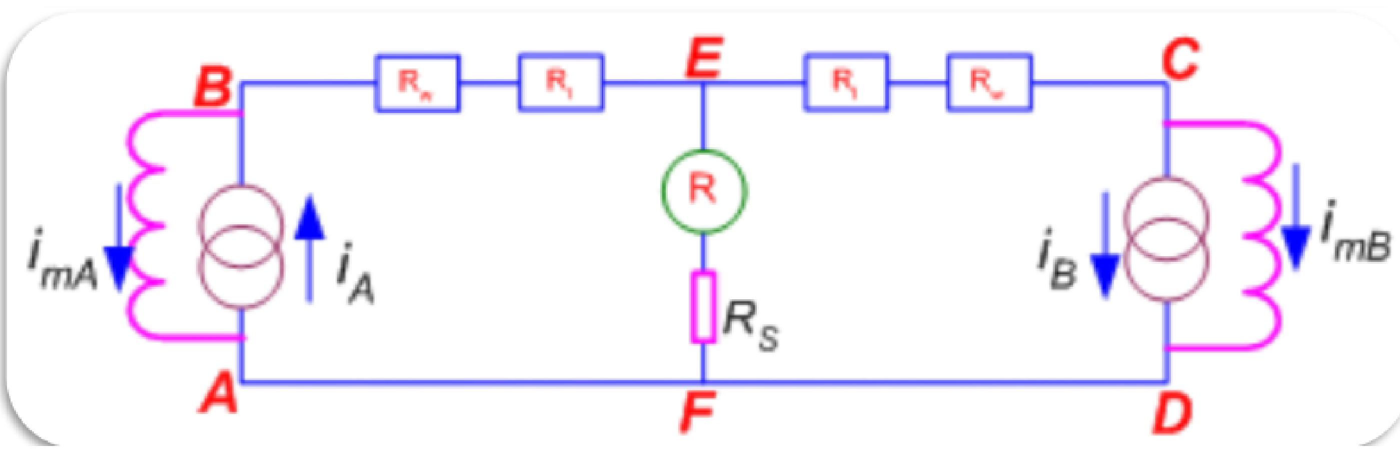
For current operated relay:

$$\boldsymbol{R_s = \frac{V_R}{I_{set}} = \frac{I_{FA}}{N_A I_{set}}\,(R_l + R_{w2})}$$

R_S improves the stability but reduces the internal fault sensitivity.

10.3.3 Sensitivity Calculation:

Consider an internal fault and fed only from one end and magnetizing currents of all CTs are fed from this excited CT and all magnetizing currents are equal. For example if the protection loop conditions only two CTs the equivalent circuit will be as given below.



Feeding from one point is the worst condition (IF, internal has the minimum value), for sensitivity calculation. Even if, there are another sources, we assume that they are disconnected.

$$I_F = N_A\,(I_{mA} + I_{mB} + I_{set})$$

$\boldsymbol{I_{mA}}, \boldsymbol{I_{mB}}$ *magnetizing current*

$\boldsymbol{I_F}$ *the minimum internal fault current to make the relay just picks up*

10.4 Biased Differential Protection

The stabilizing resistance R_S is a function of the maximum external fault current value. A higher value of R_S is required to stabilize the protection against the external fault when the system is reinforced.

An alternative is to provide an adjustable relay setting which can automatically turned to the correct setting for any value of fault current.

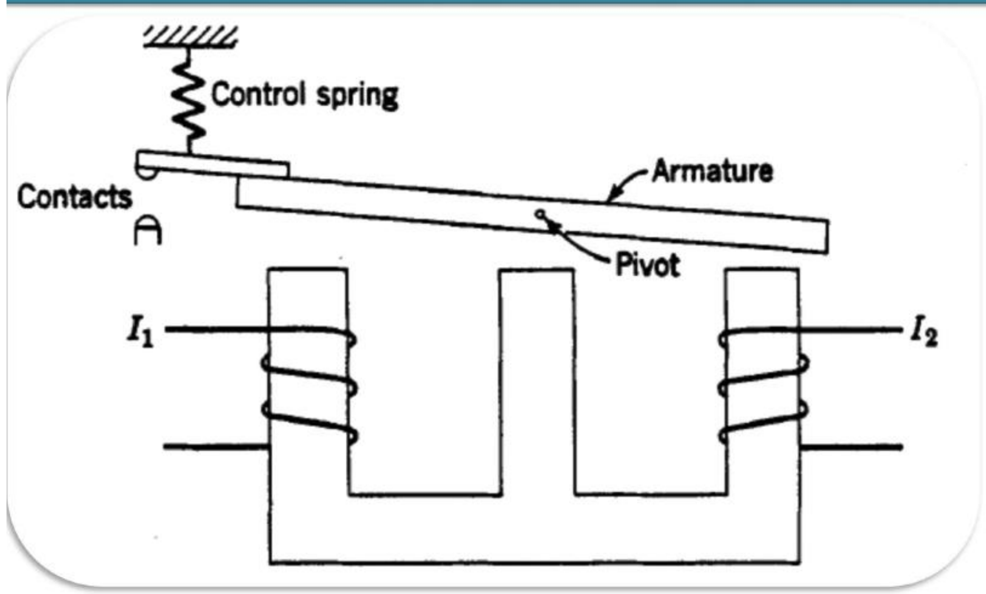
The later solution was introduced and designated as “differential protection with bias”

the relay setting increases in proportional to the external fault current which provide stability all over the fault current range keeping the relay sensitivity for internal fault at acceptable low level.

The overcurrent type of current-balance relay has one overcurrent element arranged to produce torque in opposition to another overcurrent element, both elements acting on the same moving structure.

Following figure shows schematically an electromagnetic-attraction “”balanced-beam” type of structure.

A balanced-beam type of current-balance relay.



If we neglect the negative-torque effect of the control spring, the torque equation of either type is:

$$T = K_1 I_1^2 - K_2 I_2^2$$

When the relay is on the verge of operating, the net torque is zero, and:

$$K_1 I_1^2 = K_2 I_2^2$$

Therefore, the operating characteristic is

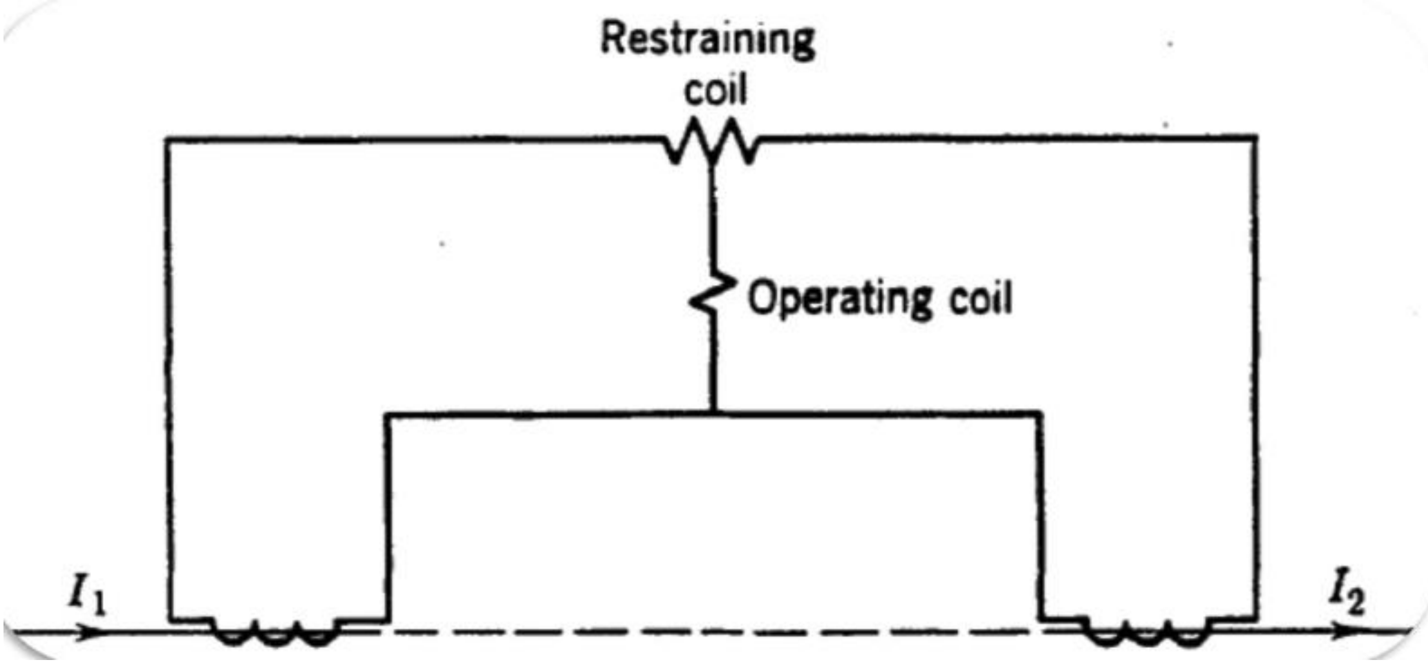
$$\boldsymbol{\frac{I_1}{I_2} = \sqrt{\frac{k_2}{k_1}} = constant}$$

So we have two types of currents

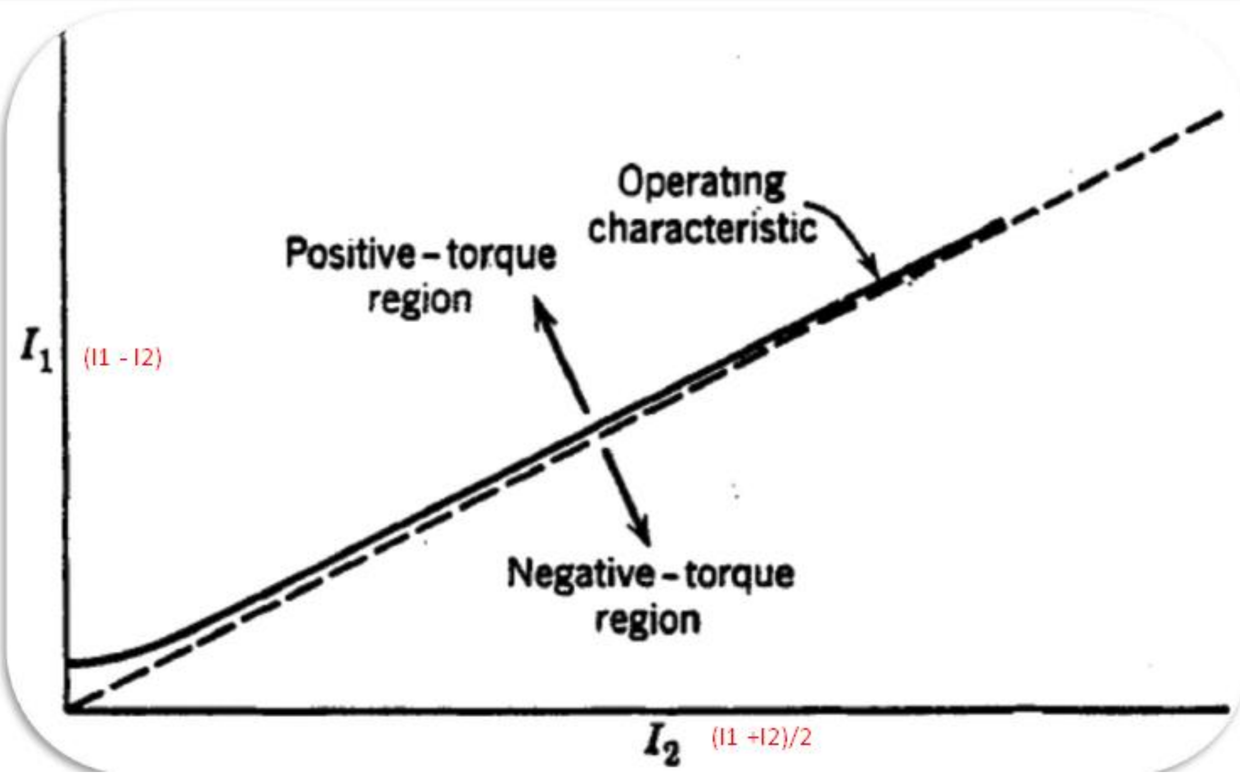
The Differential Current $\propto \ (I_1 - I_2)$

$$Eqv..current\ in\ the\ restraining\ coil\ \frac{I_1 + I_2}{2}$$

(eqv because it’s AT is $I_1 \frac{N}{2} + I_2 \frac{N}{2}\ \ equals \frac{I_1+I_2}{2}\ in\ N$)



The operating characteristic of such a relay, including the effect of the control spring, is shown in the .following fig



Thus, except for the slight effect of the control spring at low currents, the ratio of the differential operating current to the average restraining current is a fixed percentage, which explains the name of this relay. The term "through" current is often used to designate I2, which is the portion of the total current that flows through the circuit from one end to the other, and the operating characteristics may be plotted using I2 instead of (I1 + I2)/2, to conform with the ASA definition for a percentage differential relay

10.5 Compare.

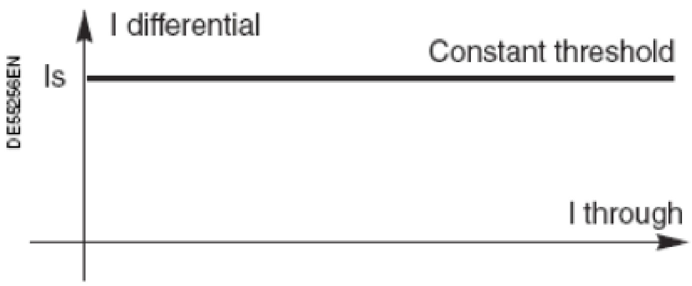


Fig. 3. Stability by resistance.

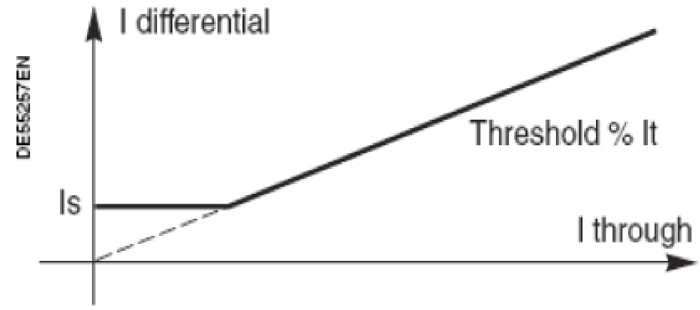


Fig. 5. Stability by restraint.

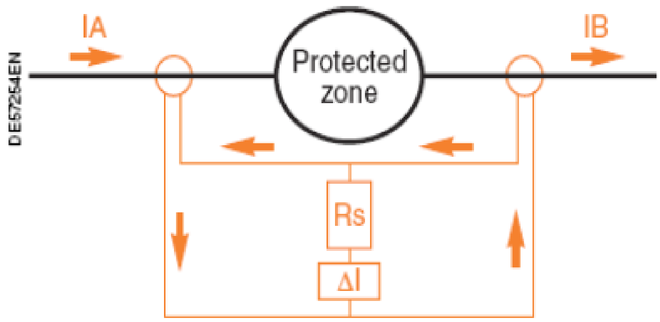


Fig. 2. High impedance differential protection diagram.

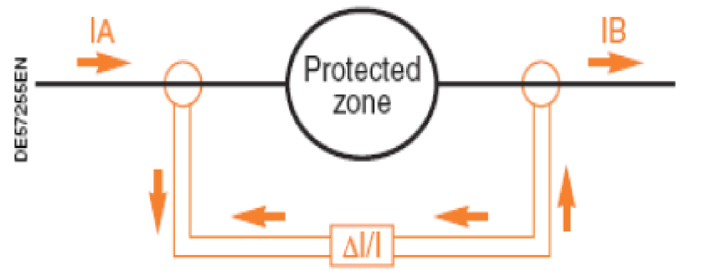


Fig. 4. Percentage-based differential protection diagram.

DR DIAA PART

11 DISTANCE PROTECTION

11.1 Introduction

DISTANCE RELAYS Respond to the impedance between the relay location and the fault location, because impedance per km is const. so, they respond to the distance to a fault on the transmission line

Any Relay type can be made to function as a distance relay by making appropriate choices of their design parameters

The R –X diagram is an indispensable tool for describing and analyzing a distance relay characteristic, and we will examine it initially with reference to a single-phase transmission line.

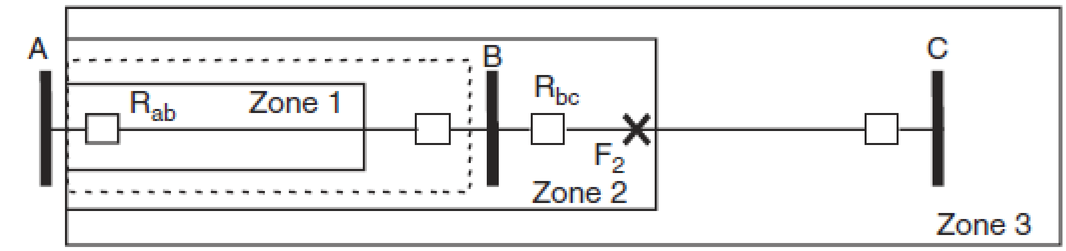
11.2 Stepped distance protection

Underreach	protection is a form of protection in which the relays at a given terminal do not operate for faults at remote locations on the protected equipment. This definition states that the relay is set so that it will not see a fault beyond a given distance
Overreach	protection is a form of protection in which the relays at one terminal operate for faults beyond the next terminal.

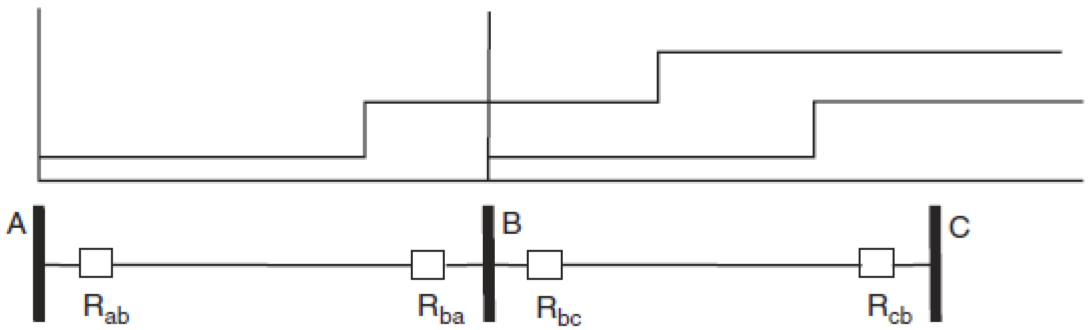
Note

-The added restriction placed on overreaching protection to avoid loss of coordination.

-Some uncertainty about its exact reach must be accepted. This uncertainty of reach is typically about 5 % of the setting



(a)



(b)

Perfect Zone	: dotted zone to operate instantaneously , But due to uncertainty we have to use stepped protection
Zone 1	is underreached of dotted zone , it's 0.85% of Zone , it's instant **0.1s**
Zone 2	It's 120% , it's of time **0.3 s** - for rest of TL1 - to backup zone 1 TL2
Zone 3	It's 150% , it's of time **1 s** - to fully backup Zone 1 of TL2

Considerations

1- if second TL is less than 20% then zone 2 and 3 will over reach as heck

2-Another consideration is the effect of the fault current contributions from lines at the intermediate buses. This is the problem of infeed, and will be discussed in greater detail later.
3- the zone 3 characteristic must provide protection against faults but should not operate for normal, albeit unusual, system conditions such as heavy loads or stability swings. Computer relaying makes provision for identifying heavy loads or stability swings through its load encroachment feature

Example 11.1

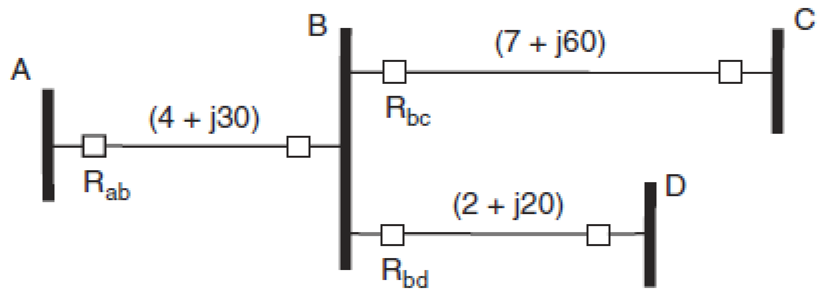


Figure 5.2 System for Example 5.1

$$Zone\ 1 = 0.85 \times (4 + j30) = (3.4 + j25.5)\Omega$$

$$Zone\ 2 = 1.2 \times (4 + j30) = (4.8 + j36)\Omega.$$

Check it doesn't overreach TL2's zone 1 ,

$$(4.8 + j36) - (4.0 + j30)] = (0.8 + j6) < 0.85 \times \overbrace{(2 + j\,20)}^{\text{shorter}} \quad \Omega\ (\ OK)$$

If not ok , such a case, one must set zone 2 to be a bit shorter, to make sure that it does not overreach zone 1ofRbd, or, if this is not possible, zone 2 of the relay Rab may be set longer than zone 2 of relay Rbd or it may be dispensed with entirely and only zone 3 may be employed as a backup function for the two neighboring lines

$$Zone\ 3 = \left[(4 + j30) + 1.5 \times \overbrace{(7 + j60)}^{\text{longer}}\right] = (14.5 + j120)\Omega$$

It's control (not in lec)

he control circuit connections to implement the three-zone distance relaying scheme are shown in Figure 5.3. The seal-in unit contact shown is typical for all three phases, and the seal-in coil may be combined with the target coils in some designs. The three distance measuring elements Z1,Z2 and Z3 close their contacts if the impedance seen by the relay is inside their respective zones. The zone 1 contact activates the breaker trip coil(s) immediately (i.e. with no intentional time delay), whereas the zones 2 and 3 contacts energize the two timing devices T2 and T3, respectively. Once energized, these timing devices close their contacts after their timer settings have elapsed. These timer contacts also energize the breaker trip coil(s). Should the fault be cleared before the timers run out, Z2,Z3,T2 and T3 will reset as appropriate in a relatively short time (about 1–4 ms).

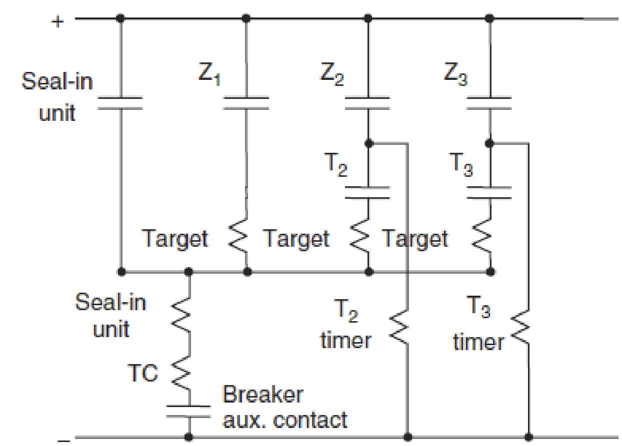


Figure 5.3 Control circuit for a three-zone step distance relay

We should remember that the zone settings for zones 2 and 3 are affected by the contributions to the fault current made by any lines connected to the intervening buses, i.e. buses B and C in Figure 5.1. This matter has been dealt with in the discussion of infeed and outfeed in section 4.3, and similar considerations apply here as well. The problem is caused by the different currents seen by the relays as a result of the system configuration. As shown in Example 4.6, the operating currents in the upstream relays change significantly if parallel lines are in or out of service.

11.3 R-X diagram

all electromechanical relays respond to one or more of the conventional torque-producing input quantities:

(a) voltage,

(b) current,

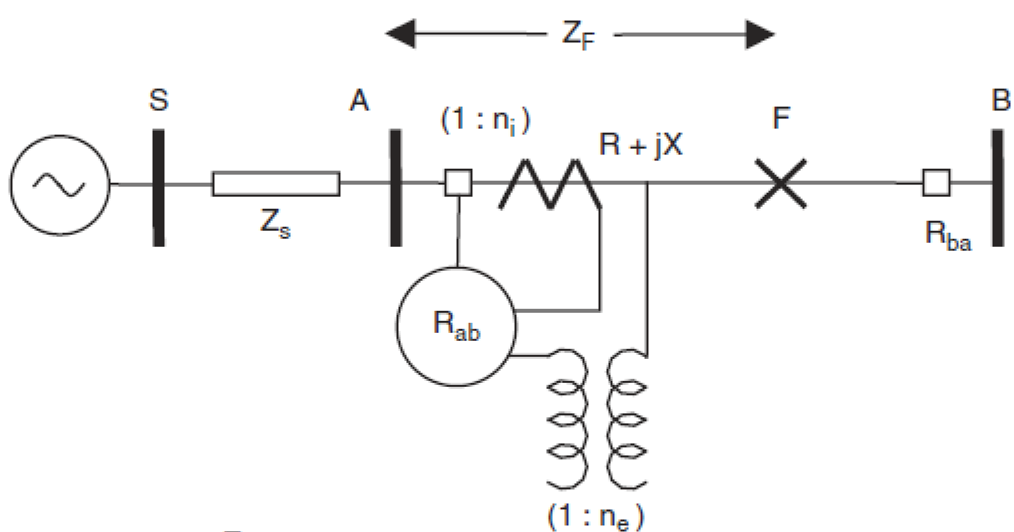
(c) product of voltage, current and the angle θ between them and

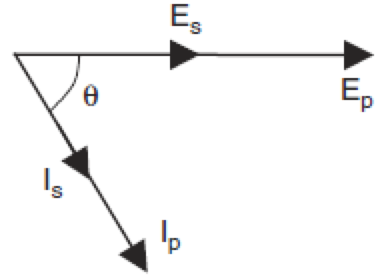
(d) a physical or design force such as a control spring.

Similar considerations hold for solid-state relays as well.

Advantages of R-X diagram

1- To avoid difficulty of three quantities (E,I, θ) we use R-X Diagram to deal with only 2 quantities They are [R-X] or [Z-θ]
2- allows us to represent both the relay and the system on the same diagram.





To calculate fault impedance

In primary

$$Z_{f,p} = \frac{E_p}{I_p}$$

But we use secondary in calculations

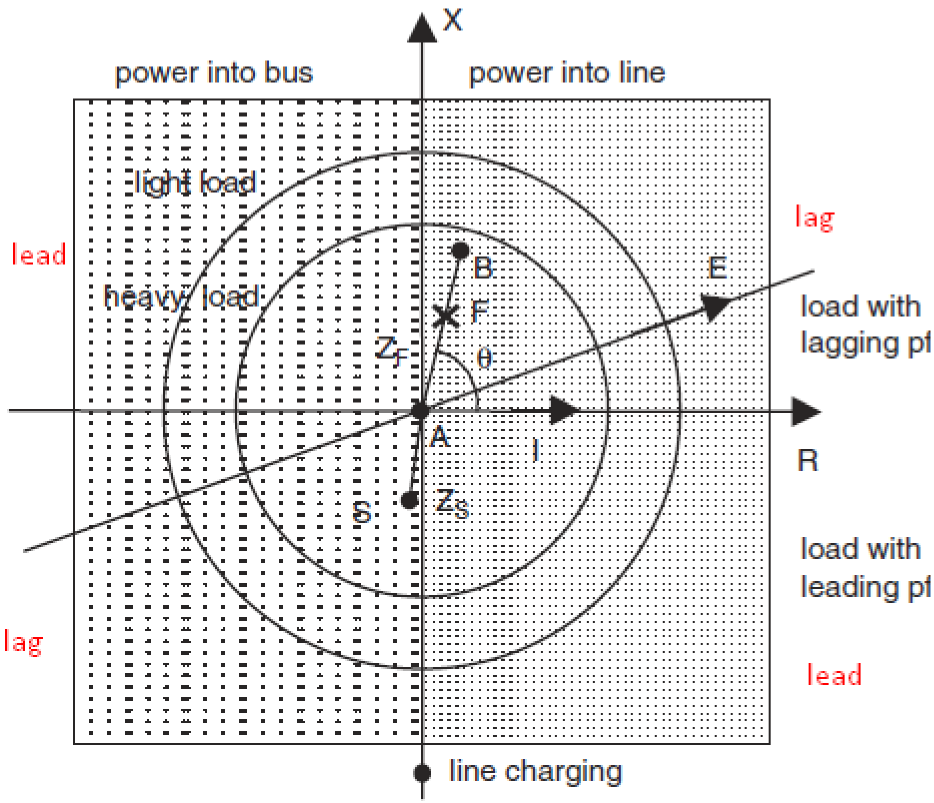
$$Z_{f,s} = Z_f = \frac{E_s}{I_s} = Z_{f,p} \frac{n_i}{n_e}$$

$$n_i \ ct\ ratio\ , n_e \ \ vt\ ratio$$

Example 11.2

CT with a turns ratio of 500 : 5 and a VT with a turns ratio of 20 000 : 69.3. Thus, the CT ratio ni is 100, while the VT ratio ne is 288.6. The impedance conversion factor ni/ne for this case is (100/288.6), or 0.3465.

11.3.1 R-X loci



This impedance may be plotted as a point on the complex R –X plane. This is the plane of (apparent) secondary ohms.

- One could view the impedance as the voltage phasor, provided that the current is assumed to be the reference phasor, and of unit magnitude. This way of looking at the apparent impedance seen by a relay as the voltage phasor at the relay location is often very useful when relay responses to changing system conditions are to be determined.
- For example, consider the apparent impedance seen by the relay when there is normal power flow in the transmission line. If the load current is of constant magnitude, and the sending end voltage at the relay location is constant, the corresponding voltage phasor,
- and hence the impedance, will describe acircle in the R –X plane.

- Lighter loads – meaning a smaller magnitude of the current – produce circles of larger diameters
- . Similarly, when the load power factor is constant, the corresponding locus of the impedance is a straight line through the origin. Figure 5.5 shows these contours for varying load current magnitudes and power factors.
- Note that when the real **power** flows **into** the **line**, the corresponding apparent impedances lie in the **right half** of the plane,
- while a **reversed power** flow maps into the **left half**-plane.
- Similarly **lagging** power factor load plots in the upper half-plane, while a leading power factor load plots in the lower half-plane.
- Zero power transfer corresponds to points at infinity.
- A line open at the remote end will have leading reactive current, and hence the apparent impedance will map at a large distance along the negative X axis.

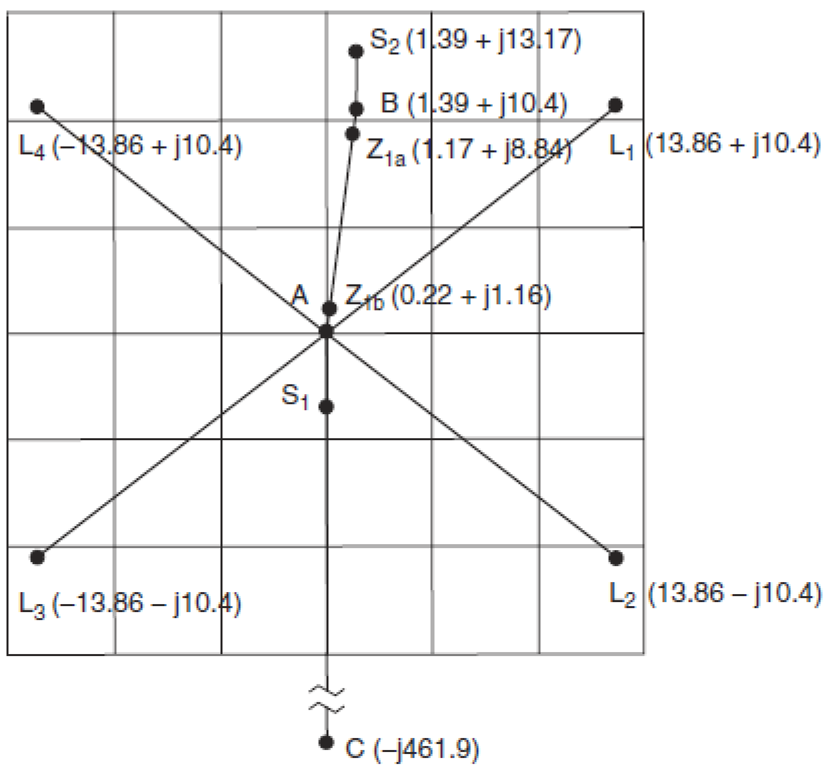
Now consider the fault at location F as shown in Figure 5.4. The corresponding apparent impedance is shown at F in Figure 5.5. As the location of the fault is moved along the trans-mission line, the point F moves along the straight line AB in Figure 5.5. Thus, the transmission line as seen by the relay maps into the line AB in the R –X plane. The line AB makes an angle θ with the R axis,

- where θ is the impedance angle of the transmission line.
- (For an overhead transmission line**, θ lies between 70◦ and 88◦,** depending upon the system voltage, the larger angles being associated with higher transmission voltages.) When the fault is on the transmission line, the apparent impedance plots on the line AB; for all other faults or loading conditions, the impedance plots away from the line AB. Often it is convenient to plot the source impedance Zs also on the R –X diagram, as shown in Figure 5.5.

Example 5.3

Let the rated load for the transmission line shown in Figure 5.4 be 8 MVA. This corresponds to 400 A at the rated voltage of 20 000 V. The apparent impedance corresponding to this load is $(20\,000/400) = 50\ \Omega$ primary. In terms of secondary ohms, this impedance becomes $50 \times 0.3465 = 17.32\ \Omega$. Thus, a load of 8 MVA at 0.8 pf lagging is $17.32 \times (0.8 + \mathrm{j}0.6) = (13.86 + \mathrm{j}10.4)\ \Omega$ secondary. This is shown as L_1 in Figure 5.6. A load of 8 MVA with a leading power factor of 0.8 is $(13.86 - \mathrm{j}10.4)\ \Omega$ secondary, which maps as point L_2. Similarly, 8 MVA flowing from B to A maps into L_3 and L_4 for leading and lagging power factors, respectively.

The line impedance of $(1.39 + \mathrm{j}10.4)\ \Omega$ secondary maps into point B while the zone 1 setting of $(1.17 + \mathrm{j}8.84)\ \Omega$ maps into the point Z_{1a}. A similar relay located at B would have its zone 1 map at Z_{1b}. If we assume the equivalent source impedances as seen at buses A and B to be j10 and j8 Ω primary respectively, they will be j3.46 and j2.77 Ω secondary respectively, as shown by points S_1 and S_2 in Figure 5.6. If the line-charging current is 15 A, the apparent impedance seen by the relay at A when the breaker at terminal B is open is $-\mathrm{j}(20\,000/15) = -\mathrm{j}1333\ \Omega$ primary, or $-\mathrm{j}461.9\ \Omega$ secondary. This is shown as the point C, on a telescoped y axis in Figure 5.6. The zones of protection of a relay are defined in terms of its impedance, and hence it is necessary that they cover areas in the immediate neighborhood of the line AB. As the load on the system increases, the possibility of it encroaching upon the protection zones becomes greater. Ultimately, at some values of the load, the relay is in danger of tripping. The R–X diagram offers a convenient method of analyzing whether this is the case. A fuller account of the loadability of a distance relay is considered in section 5.11.



11.4 Three-phase distance relays

there are ten distinct types of possible faults

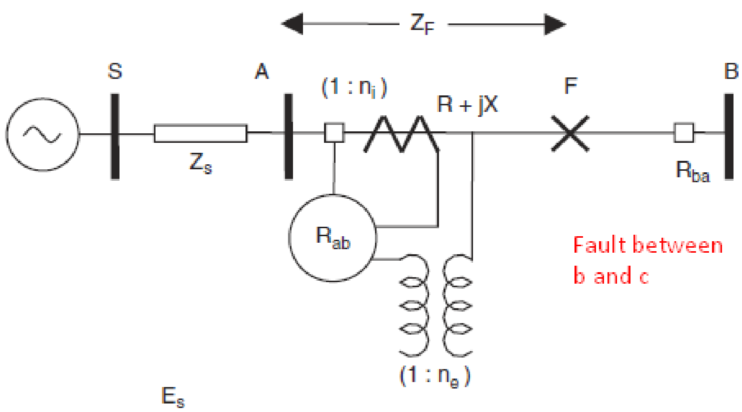
- a three-phase fault
- three phase-to-phase faults
- three phase-to-ground faults
- three double-phase-to-ground faults.

11.4.1 fundamental principle of distance relaying

that, regardless of the type of fault involved, the voltage and current used to energize the appropriate relay are such that the relay will measure the **positive sequence impedance** to the fault.

Then, zone settings of all relays can be based upon the total positive sequence impedance

11.4.2 Phase-to-phase faults (say b & c)



Step 1 : Draw Symmetrical Component Representation

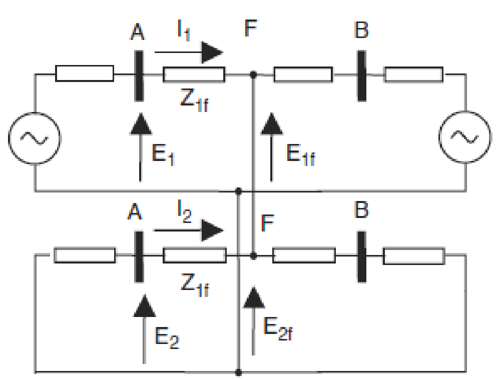


Figure 5.7 Symmetrical component circuit for b–c fault

$$E_{1f} = E_{2f} = E_1 - Z_{1f}I_1 = E_2 - Z_{1f}I_2$$

So,

$$Z_{1f} = \frac{E_1 - E_2}{I_1 - I_2}$$

For phase voltages (it has a matrix conversion)

Remember

$$\begin{bmatrix} \boldsymbol{V_a} \\ \boldsymbol{V_b} \\ \boldsymbol{V_c} \end{bmatrix} = \begin{bmatrix} \mathbf{1} & \mathbf{1} & \mathbf{1} \\ \boldsymbol{\alpha^2} & \boldsymbol{\alpha} & \mathbf{1} \\ \boldsymbol{\alpha} & \boldsymbol{\alpha^2} & \mathbf{1} \end{bmatrix} \begin{bmatrix} \boldsymbol{V_{a1}} \\ \boldsymbol{V_{a2}} \\ \boldsymbol{V_{a0}} \end{bmatrix}$$

$$E_b = E_o + \alpha^2 E_1 + \alpha E_2$$
$$E_c = E_0 + \alpha E_1 + \alpha^2 E_2$$

$$E_b - E_c = (\alpha^2 - \alpha)(\, E_1 - E_2)$$
$$I_b - I_c = (\alpha^2 - \alpha)(I_1 - I_2)$$

$$Z_{1f} = \frac{E_1 - E_2}{I_1 - I_2} = \frac{\boldsymbol{E_b - E_c}}{\boldsymbol{I_b - I_c}}$$

So, for that distance relay to measure phase to phase fault between 2 phases
Voltage Measure: Line-to-line voltage between phases b and c

Curent Measure: difference between the currents in the two phases

will measure the positive sequence impedance to the fault
similar cases of fault (a-b \ b-c \ c-a)

11.4.3 Phase-to-phase faults (say b & c & g) [same]

$$Z_{1f} = \frac{E_1 - E_2}{I_1 - I_2} = \frac{E_b - E_c}{I_b - I_c}$$

So, for that distance relay to measure phase to phase fault between 2 phases
Voltage Measure: Line-to-line voltage between phases b and c

Curent Measure: difference between the currents in the two phases

will measure the positive sequence impedance to the fault
similar cases of fault (a-b \ b-c \ c-a)

proof

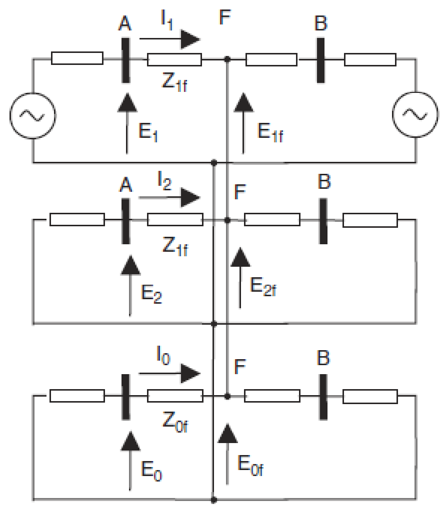


Figure 5.8 Symmetrical component circuit for b–c–g fault

$$\text{As } E_{1f} = E_{2f}$$

$$E_1 - I_{qf} Z_{1f} = E_2 - i_{2f} Z_{1f}$$
$$Z_{1f}\left(i_{1f} - i_{2f}\right) = E_1 - E_2$$

$$Z_{1f} = \frac{E_1 - E_2}{I_1 - I_2}$$

$$E_b = E_o + \alpha^2 E_1 + \alpha E_2$$
$$E_c = E_0 + \alpha E_1 + \alpha^2 E_2$$

$$E_b - E_c = (\alpha^2 - \alpha)(\, E_1 - E_2)$$
$$I_b - I_c = \ (\alpha^2 - \alpha)(I_1 - I_2)$$

$$Z_{1f} = \frac{E_1 - E_2}{I_1 - I_2} = \frac{\boldsymbol{E_b - E_c}}{\boldsymbol{I_b - I_c}}$$

11.4.4 Three-phase fault

Step 1 : Draw Symmetrical Component Representation

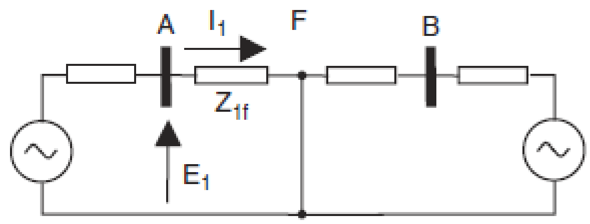


Figure 5.9 Symmetrical component circuit for a three-phase fault

$$E_1 = E_a = Z_{1f} I_1 = Z_{1f} I_a$$

$$E_2 = E_0 = 0$$
$$I_2 = I_0 = 0$$

Also,

$$E_a = E_1$$

$$E_b = \alpha^2 E_1$$

$$E_c = \alpha E_1$$

So,

$$Z_{1f} = \frac{E_a - E_b}{I_a - I_b} = \frac{\boldsymbol{E_b - E_c}}{\boldsymbol{I_b - I_c}} = \frac{E_c - E_a}{I_c - I_a}$$

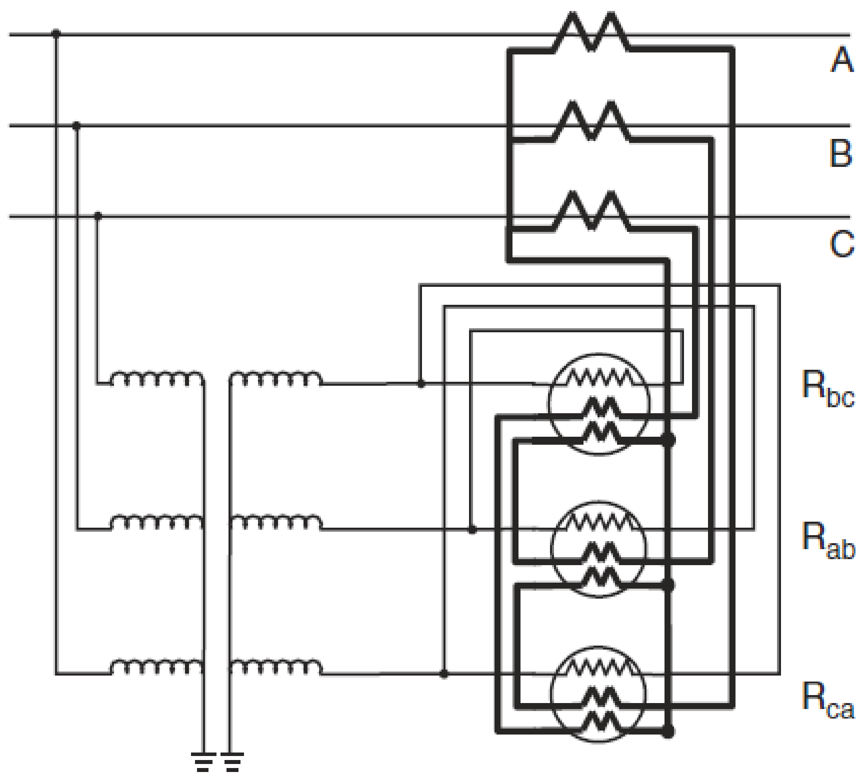
OMG!!

So, for that distance relay to measure phase to phase fault between 2 phases
Voltage Measure: Line-to-line voltage between phases b and c

Curent Measure: difference between the currents in the two phases

will measure the positive sequence impedance to the fault

11.4.5 So For the previous 3 types of fault we can connect the relays from CTs and VTs as follow



Current transformer and voltage transformer connections for distance relays for phase faults

he differences of phase voltages and currents used in equation are known as **'delta'** voltages and currents,

Relays energized by the delta voltages and currents respond to the positive sequence impedance to a multiphase fault

This configuratuion measure 7 cases of the 10 faults

double-phase (x3) double-phase-to-ground (x3)	1of 3 relay measure the Z_{+ve}(positive sequence impedance to the fault,)
Three phase fault(x1)	3 relays measure Z_{+ve}

11.4.6 Ground faults

Step 1 : Draw Symmetrical Component Representation

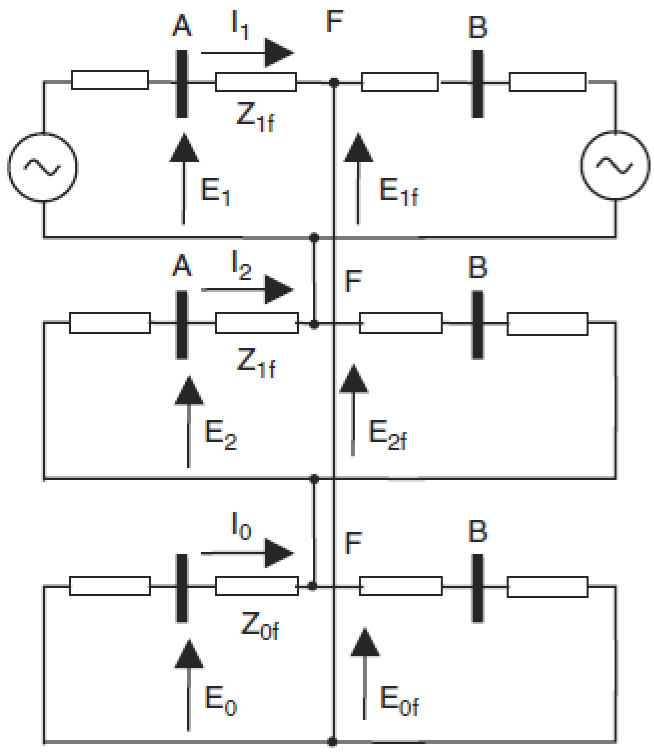


Figure 5.11 Symmetrical component circuit for an a–g fault

$$E_{1f} = E_1 - Z_{1f}I_1$$
$$E_{2f} = E_2 - Z_{1f}I_2$$
$$E_{0f} = E_0 - Z_{0f}I_0$$

The phase a voltage and current can be expressed in terms of the symmetrical components and the voltage of phase a at the fault point can be set equal to zero:

$$E_{AF} = E_{0f} + E_{1f} + E_{2f}$$
$$= (E_0 + E_1 + E_2) - Z_{qf}(I_1 + I_2) - Z_{0f}I_0 = 0$$
$$E_a - Z_{1f}I_a - (Z_{0f} - Z_{1f})I_0 = 0$$

Define currents

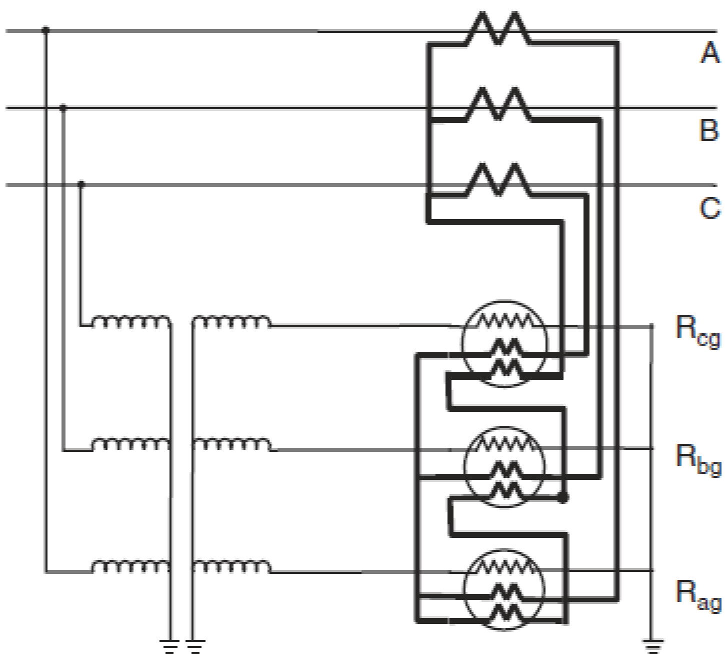
$$E_a = E_0 + E_1 + E_2$$
$$I_a = \ I_0 + I_1 + I_2$$
$$\boldsymbol{I'_a = I_a + \frac{(Z_{of} - Z_{1f})}{Z_{1f}} I_0 = I_a + \frac{Z_0 - Z_1}{Z_1} I_0 = I_a + mI_0}$$

Z_0	Zero sequence impedances of the entire line.
Z_1	Positive sequence impedances of the entire line.
m	compensation factor, which compensates the phase current for the mutual coupling between the faulted phase and the other two unfaulted phases real number for OHTL varies **1.5 and 2.5. A** a good average **2 A** corresponds to $Z_o = 3\,Z_1$

for a phase-a-to-ground fault

$$Z_{1f} = \frac{E_a}{I'_a}$$

it takes three ground distance relays to cover the three single-phase-to-ground faults.



NOTE :

or a three-phase fault, the compensated phase current becomes Ia, since there is no zero sequence current for this fault.

For this case, equation $\frac{E_a}{I'_a} = Z_{1f}$ **is identical to equation** $E_1 = Z_1 I_1 + Z_f(I_1 + I_2)$

hence the three ground distance relays also measure the correct distance to the fault in the case of a three-phase fault.

م الاخر الكونيفيجريشن الاخيره تنفع للحالتين بتاع الفيز تو جراوند او الثري فيز

Example 5.4

Consider the simple system represented by the one-line diagram in Figure 5.13. The system nominal voltage is 13.8 kV, and the positive and zero sequence impedances of the two elements are as shown in the figure. The zero sequence impedances are given in parentheses. We will verify the distance calculation equations (5.9) and (5.14) for three-phase, phase-to-phase and phase-to-ground faults.

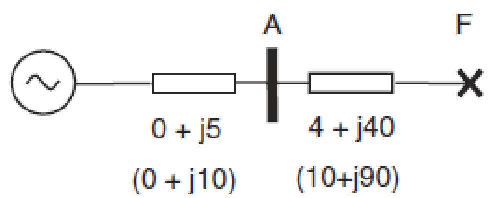


Figure 5.13 System for fault impedance calculation

Three-phase fault

For this case, only the positive sequence current exists, and is also the phase a current. It is given by

$$I_a = I_1 = \frac{7967.4}{4 + j45} = 176.36\angle 84.92^\circ$$

$7967.4 = (13\,800/\sqrt{3})$ is the phase-to-neutral voltage. The phase a voltage at the relay location is given by

$$E_a = E_1 = 7967.4 - j5 \times 176.36\angle 84.92^\circ = 7089.49\angle -0.63^\circ$$

Thus, the fault impedance seen by the relay in this case is

$$Z_f = \frac{E_a - E_b}{I_a - I_b} = \frac{E_a}{I_a} = \frac{7089.49\angle -0.63^\circ}{176.36\angle -84.92^\circ} = 4 + j40\ \Omega$$

Phase-to-phase fault

For a b–c fault

$$I_1 = -I_2 = \frac{7967.4}{2 \times (4 + j45)} = 88.18\angle 84.92^\circ$$

Also, $I_b = -I_c = I_1(\alpha_2 - \alpha) = -j\sqrt{(3)}I_1 = 152.73\angle -174.92^\circ$. And, $(I_b - I_c) = 305.46\angle -174.92^\circ$. The positive and negative sequence voltages at the relay location are given by

$$E_1 = 7967.4 - j5 \times 88.18\angle -84.92^\circ = 7528.33\angle -0.3^\circ$$

$$E_2 = j5 \times 88.18\angle -84.92^\circ = 440.90\angle 5.08^\circ$$

and the phase b and c voltages at the relay location are

$$\begin{aligned} E_b &= \alpha^2 E_1 + \alpha E_2 = 7528.33\angle -120.3^\circ + 440.90\angle 125.08^\circ \\ &= -4051.3 - j6139.3 \\ E_c &= \alpha E_1 + \alpha^2 E_2 = 7528.33\angle 119.7^\circ + 440.90\angle -114.9^\circ \\ &= -3916.09 + j6139.3 \end{aligned}$$

Thus, $E_b - E_c = 12279.37\angle -90.63^\circ$, and

$$\frac{E_b - E_c}{I_b - I_c} = \frac{12\,279.37\angle -90.63^\circ}{305.46\angle -174.92^\circ} = 4 + j40\ \Omega$$

Phase-a-to-ground fault

For this fault, the three symmetrical components of the current are equal:

$$I_1 = I_2 = I_0 = \frac{7967.4}{(0+\mathrm{j}10) + 2 \times (0+\mathrm{j}5) + (10+\mathrm{j}90) + 2 \times (4+\mathrm{j}40)}$$
$$= 41.75\angle -84.59^\circ$$

The symmetric components of the voltages at the relay location are

$$E_1 = 7967.4 - \mathrm{j}5 \times 41.75\angle -84.59^\circ = 7759.58 - \mathrm{j}19.68$$
$$E_2 = -\mathrm{j}5 \times 41.75\angle -84.59^\circ = -207.82 - \mathrm{j}19.68$$
$$E_0 = -(0+\mathrm{j}10) \times 41.75\angle -84.59^\circ = -415.64 - \mathrm{j}39.36$$

And the phase a voltage and current at the relay location are

$$E_\mathrm{a} = E_1 + E_2 + E_0 = 7136.55\angle -0.63^\circ$$
$$I_\mathrm{a} = I_1 + I_2 + I_0 = 125.25\angle -84.59^\circ$$

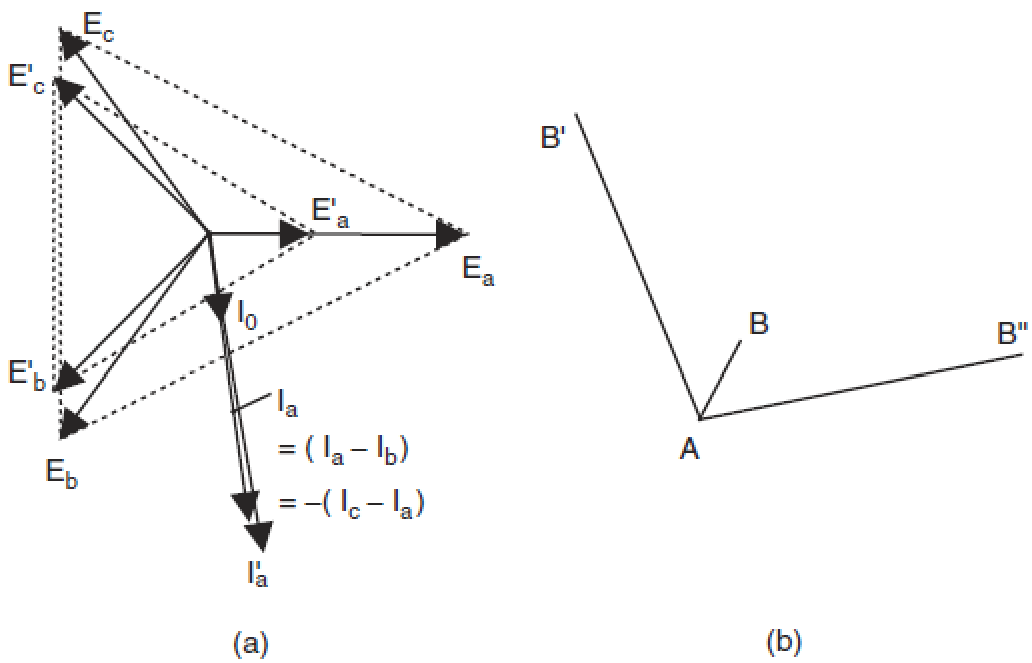
The zero sequence current compensation factor m is given by

$$m = \frac{Z_0 - Z_1}{Z_1} = \frac{1 - \mathrm{j}90 - 4 - \mathrm{j}40}{4 + \mathrm{j}40} = 1.253\angle -1.13^\circ$$

and the compensated phase a current is $I'_\mathrm{a} = I_\mathrm{a} + mI_0 = 177.54\angle -84.92^\circ$; and, finally

$$\frac{E_\mathrm{a}}{I'_\mathrm{a}} = \frac{7136.55\angle -0.63^\circ}{177.54\angle -84.92^\circ} = 4 + \mathrm{j}40\ \Omega$$

11.4.7 Relays in unfaulted phases



4 Phasor diagram for phase-a-to-ground fault: (a) voltages and currents; (b) apparent impedances

Fault at phase a , unloaded prefault

- current in phase a lags the phase a voltage by the impedance angle of the combination (Z1 + Z2 + Z0).
- Voltages of the unfaulted phases will change in magnitude and angle
- The compensated phase current as defined by equation $\boldsymbol{I'_a = I_a + mI_0}$ for this case (since $I_a = 3I_0$)is given by $I'_a = \left(1 + \frac{m}{3}\right) I_a$
- The phase distance relays use delta currents, and since $Ib = Ic = 0$, the three delta currents for this fault are $(I_a - I_b) = I_a, (I_c - I_a) = -I_a$ *and* $(I_b - I_c) = 0$. These delta currents and voltages are also shown in Figure 5.14.

Remember
that the impedance seen by any relay is <u>equal to its voltage</u> when the corresponding <u>current</u> is taken as a <u>reference</u> phasor of unit magnitude. Since the delta current for the b–c relay is zero for this fault, it sees an infinite impedance, and will not mis-operate.

we can visualize (relays a-b & c-a) response to this fault by redrawing the delta voltages Eab and Eca with Ia and −Ia as the reference unit phasors, and adjust the Es with factor $\left(1 + \frac{m}{3}\right)$

phase a voltage. This last adjustment is necessary because the phase a voltage is seen as the fault impedance with $I_a' = (1 + m/3)I_a$ as the unit of measurement, whereas E_{ab} and E_{ca} are the fault impedances seen by those two relays with $\pm I_a[= \pm I_a'/(1 + m/3)]$ as the units of measurement. Thus, the impedances seen by the a–g, a–b and c–a relays for the a–g fault are seen to be AB, AB′ and AB″, respectively, as shown in Figure 5.14. It should be clear that for a ground fault near the relay location, the a–b and c–a relays may mis-operate, if the protection zone covers AB′ and AB″ for small values of AB.

The analysis presented above must be modified to include the effect of prefault load. The load current will change the current phasors, and hence the impedances seen by the relays. Such effects are of less importance in a qualitative discussion, and the reader is referred to the reference cited[6] for a more detailed treatment of the subject.

11.4.8 Fault Resistance

There are two resitanced to be considered

1- Tower footing (5-50 Ω)
2- Arc resistance $R_{arc} = \frac{76\,V^2}{S_{sc}}$

V system voltage in kV

Ssc short-circuit kVA

This Resistance introduces error to measured , as for

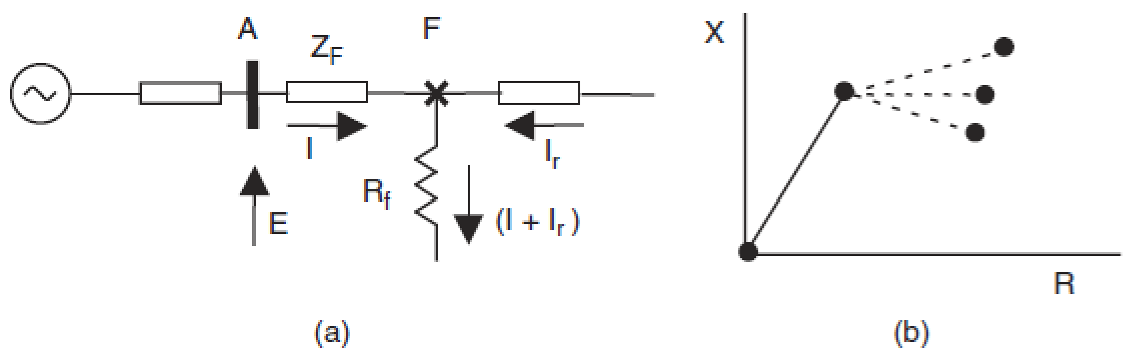


Figure 5.15 Fault path resistance, and its effect on the $R-X$ diagram

$$E = Z_f I + R_f(I + I_r)$$

So the relay sees the apparent impedance as follows

$$Z_a = \frac{E}{I} = Z_f + R_f\left(\frac{I_r}{I} + 1\right)$$

Since Ir may not be in phase with I , the fault resistance may contribute an error to the resistance as well as the reactance of the faulted line segment. This is illustrated in the R –X diagram in Figure

In order to accommodate the resistance in the fault path, it is necessary to shape the trip zone of a distance relay in such a manner that the region surrounding the apparent impedance is included inside the zone.

It will be seen in section 5.11 that different types of distance relay have differing ability of accommodating the fault resistance. It should be remembered that a larger area for the protection zone in the R –X plane accommodates greater fault path resistance, while it **also affects the loadability of the relay.**

11.5 Distance Relay Types

Four general relay types are recognized according to the shapes of their operating zones:

(1) impedance relays, (a)
(2) admittance or mho relays, (b)
(3) reactance relays (c)
(4) quadrilateral relays (d) solid state or computer relays

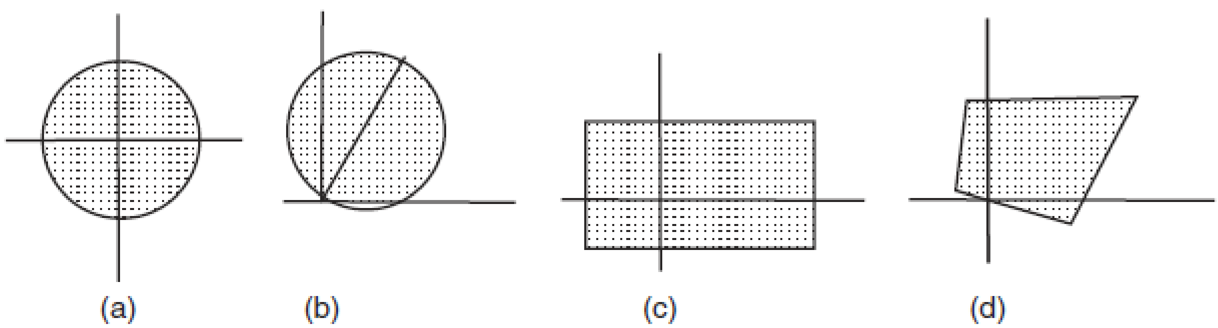


Figure 5.16 Types of impedance relay characteristics

For more complex we use 2 or more of the above with logical combination

11.6 Relay operation with zero voltage

Electromechanical relay torque equation can be tweaked to satisfy operation of 2 :

Directional Relay	$VI\sin(\theta+\phi)=0$
Mho Relay	$V=IZ_r\sin(\theta+\phi)$

At <u>V=0</u> both uncertaininty

<u>As for directional</u> it will be satisfied for any I and θ

<u>As for Mho</u> its operation will be uncertain angle between V and IZ_r cannot be determined

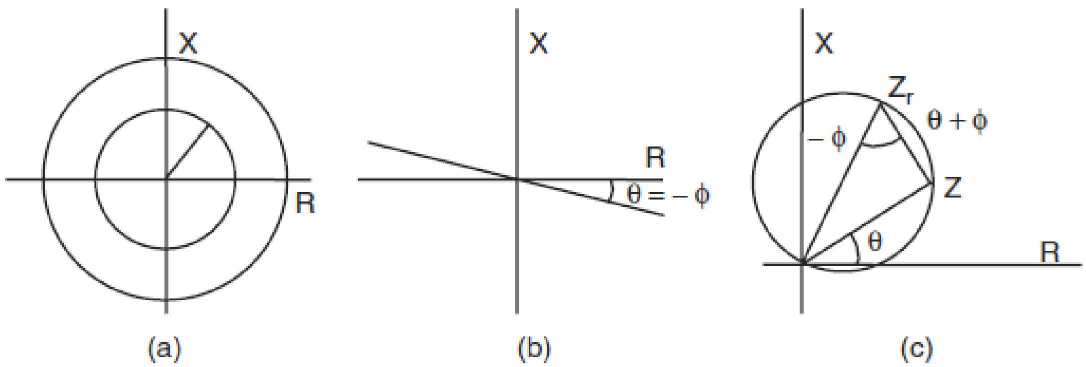


Figure 2.13 Characteristics obtained from the universal relay equation: (a) impedance relay; (b) directional relay; (c) mho relay

So at the case of zero voltage fault (Fault exactly at generation which is rare , only of grounding chains or switches are left connected)

<u>SOLUTION 1 :</u>

Memory Action

memory-action circuit in the voltage coil, which, due to a subsidence transient, will sustain the prefault voltage in the polarizing circuit for a few cycles after the occur-rence of the zero-voltage fault. The phase angle of the voltage impressed by the memory circuit on the voltage coil is very close to that of the voltage before the occurrence of the fault. Since the memory action is provided by a transient that may last only a few cycles, this feature can be used in high-speed relaying functions only.

Problem to Solution 1 :

if prefault is not normal voltage in case as would be the case if the transmission line is being energized after having been de-energized for some time, and line-side potential is being used for relaying) **no memory action is available.**

Solution 2 :

use intanetaneous relay to cover near generation

Problem to solution 2 :

as would be the case if the transmission line is being energized after having been de-energized for some time, and line-side potential is being used for relaying) no memory action is available.

Solution 3 :

common solution is to use an instantaneous overcurrent relay that is normally inoperative, but is made operative as soon as the breaker closes. The relay remains in the circuit for 10–15 cycles, allowing the breaker to trip in primary or breaker-failure time, after which the relay is removed from service. It is, of course, assumed that there is little likelihood of a backward fault occurring during the short time that the instantaneous relay is in the circuit.

Solution 4

Computer distance relay

In the case of computer-based distance relays, it is a simple matter to provide memory action by storing prefault data for as long a duration as one wishes. Thus, it may be possible to provide memory action for reclosing functions as well, when prefault voltage may not exist for several seconds prior to the reclosing action. Of course, one cannot use memory voltage functions over very long periods of time, as the phase angle of the memory voltage may no longer be valid due to small deviations and drifts in the power system frequency.

11.7 Polyphase relays

SKIPPED

11.8 Relays for multi-terminal lines

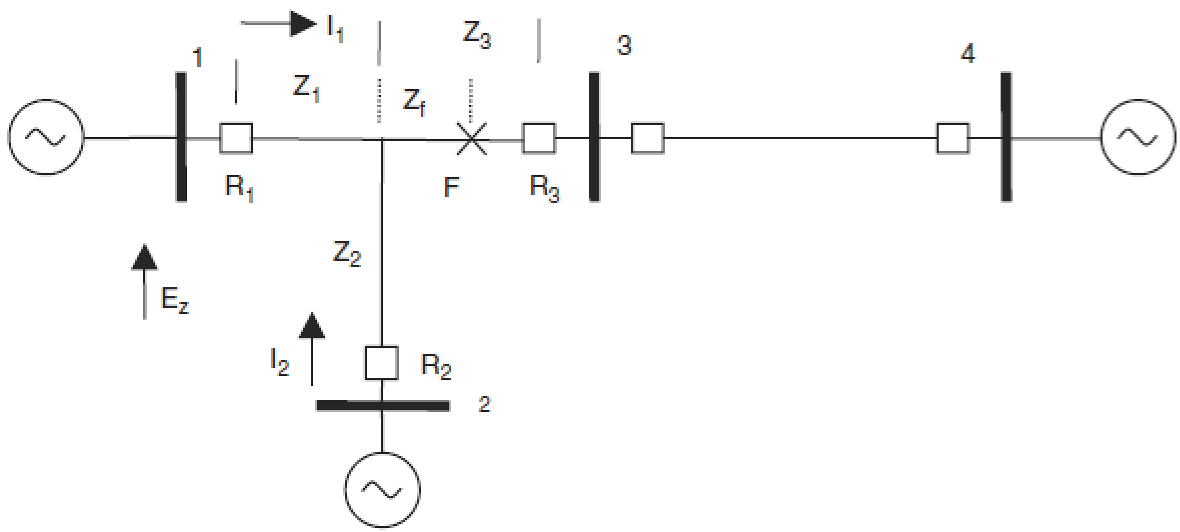


Figure 5.17 Effect of infeed on zone settings of distance relays

$$E_1 = Z_1 I_1 + Z_f\left(I_1 + \overbrace{I_2}^{\text{infeed current}}\right)$$

So,

$$Z_{app} = \frac{E_1}{I_1} = Z_1 + Z_f\left(1 + \frac{I_2}{I_1}\right)$$

underreaching zones are set with infeeds removed from consideration, and overreaching zones are set with the infeeds restored. These ideas are illustrated in the following example.

$$Zone\ 1 = 0.85\ (Z_{Line1})$$

$$Zone\ 2 = 1.2\left(Z_{line1_{BEFOREfault}} + \frac{I_1 + I_{infeed}}{I_1} * Z_{line1_{AFTERfault}}\right)$$

$$Zone\ 3 = \left[Z_{line1_{BEFOREfault}} + \frac{I_1 + I_{infeed}}{I_1} * Z_{line1_{AFTERfault}}\right] + 1.5\ \overbrace{\left(Z_{line} * \frac{I_1 + I_{infeed}}{I_1}\right)}^{\text{largest possibility path (must try)}}$$

If we add an additional bus

Then zone 1 is considered separate between 2 relays

Example 5.6

Consider the system shown in Figure 5.18. We may assume that the relative magnitudes of I_1, I_2 and I_3 remain unchanged for any fault on the system between the buses A through G. This is clearly an approximation, and in an actual study we must use appropriate short-circuit calculations

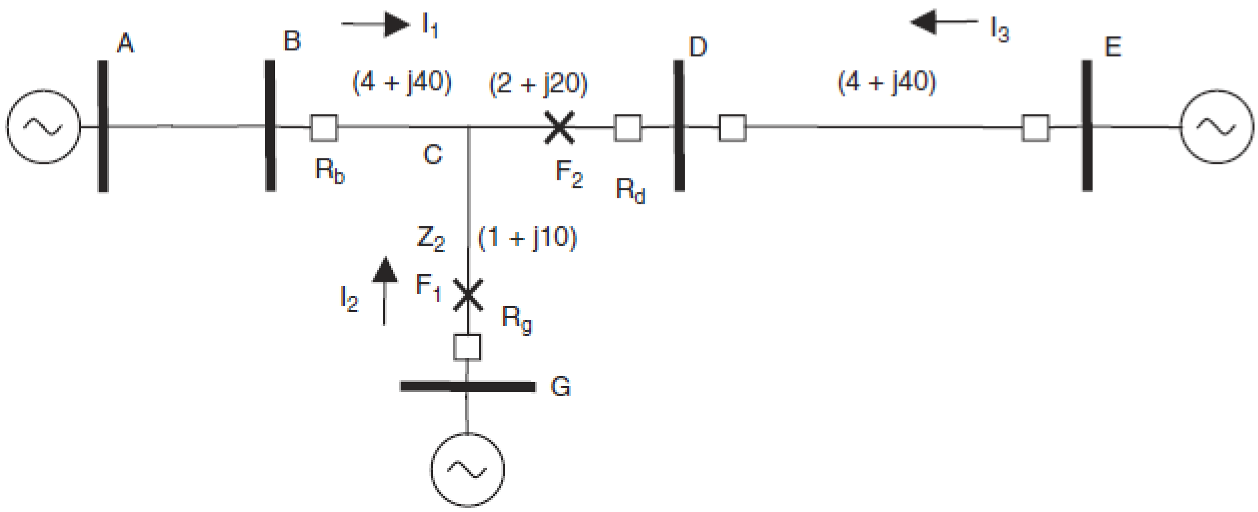


Figure 5.18 System with infeed for Example 5.6

for each of the faults. We are required to set the three zones of the relay R_b. It is assumed (as determined by the short-circuit study) that $I_2/I_1 = 0.5$.

Zone 1

This must be set equal to 85 % of the smaller of the two impedances between buses B and D, and B and G. Also, we will consider the infeed to be absent for setting zone 1. Thus, the zone 1 setting is $0.85 \times (4 + j40 + 1 + j10) = 4.25 + j42.5\ \Omega$.

Zone 2

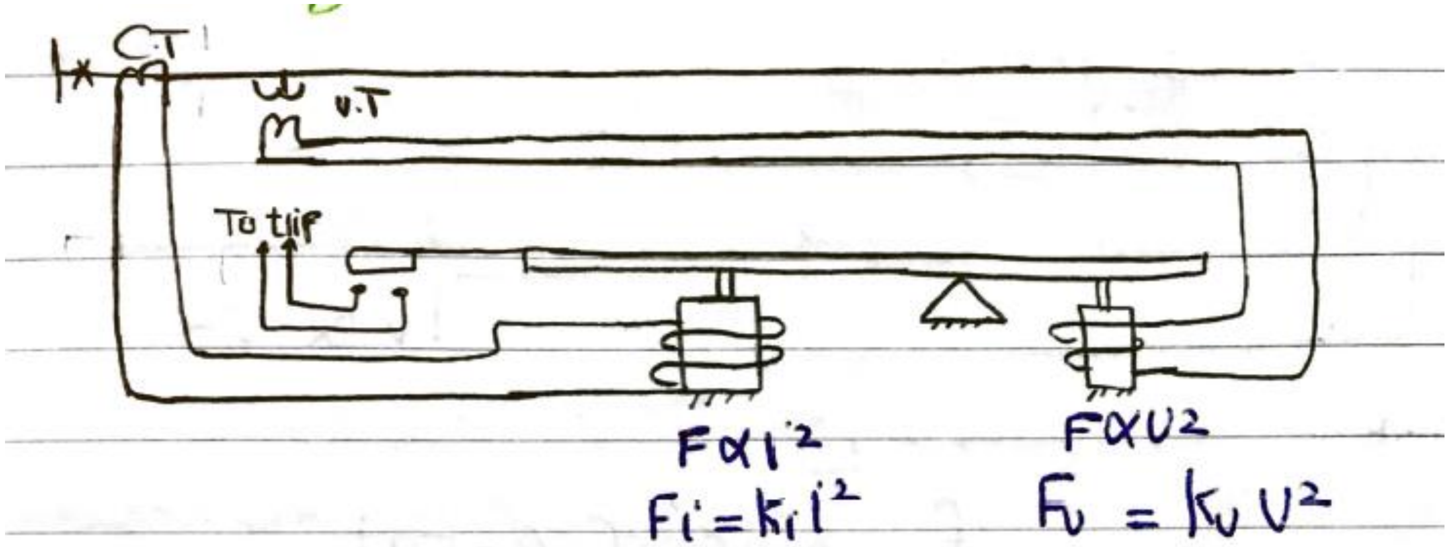
This is set equal to 120 % of the longer of the two impedances between buses B and D, and B and G. The infeed will be considered to be present, and will apply to the impedance of the segment C–D. Thus, the zone 2 setting is $1.2[4 + j40 + 1.5 \times (2 + j20)] = 8.4 + j84\ \Omega$.

Zone 3

Assuming that line D–E is the only one needing backup by the relay R_b, the zone 3 setting is obtained by considering the infeed to be in service. The apparent impedance of the line B–D with the infeed is $(4 + j40) + 1.5 \times (2 + j20) = 7 + j70\ \Omega$. To this must be added 150 % of the impedance of line D–E, duly corrected for the infeed. Thus, the zone 3 setting of R_b is $7 + j70 + 1.5 \times 1.5 \times (4 + j40) = 16 + j160\ \Omega$.

11.9 Distance Relay Types

11.9.1 Voltage coil and Current coil [DISTANCE (Impedance)RELAY]



CT is connected to a coil $\boldsymbol{F \propto i^2 \;\; ; F_i = k_i i^2}$

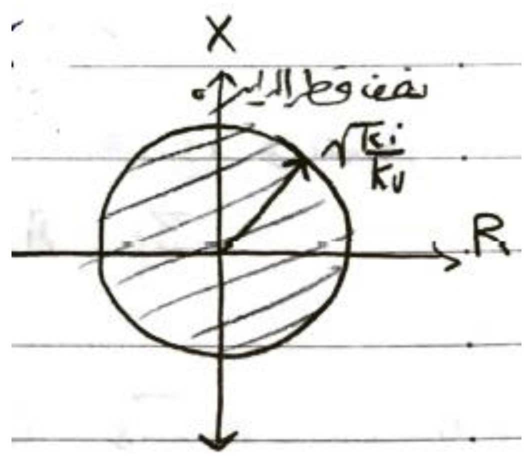
VT is connected to a coil $\boldsymbol{F \propto v^2 \;\; ; \;\; F_v = k_v\, v^2}$

$$k_i i^2 = k_v v^2$$

$$\frac{v^2}{i^2} = \frac{k_i}{k_v}$$

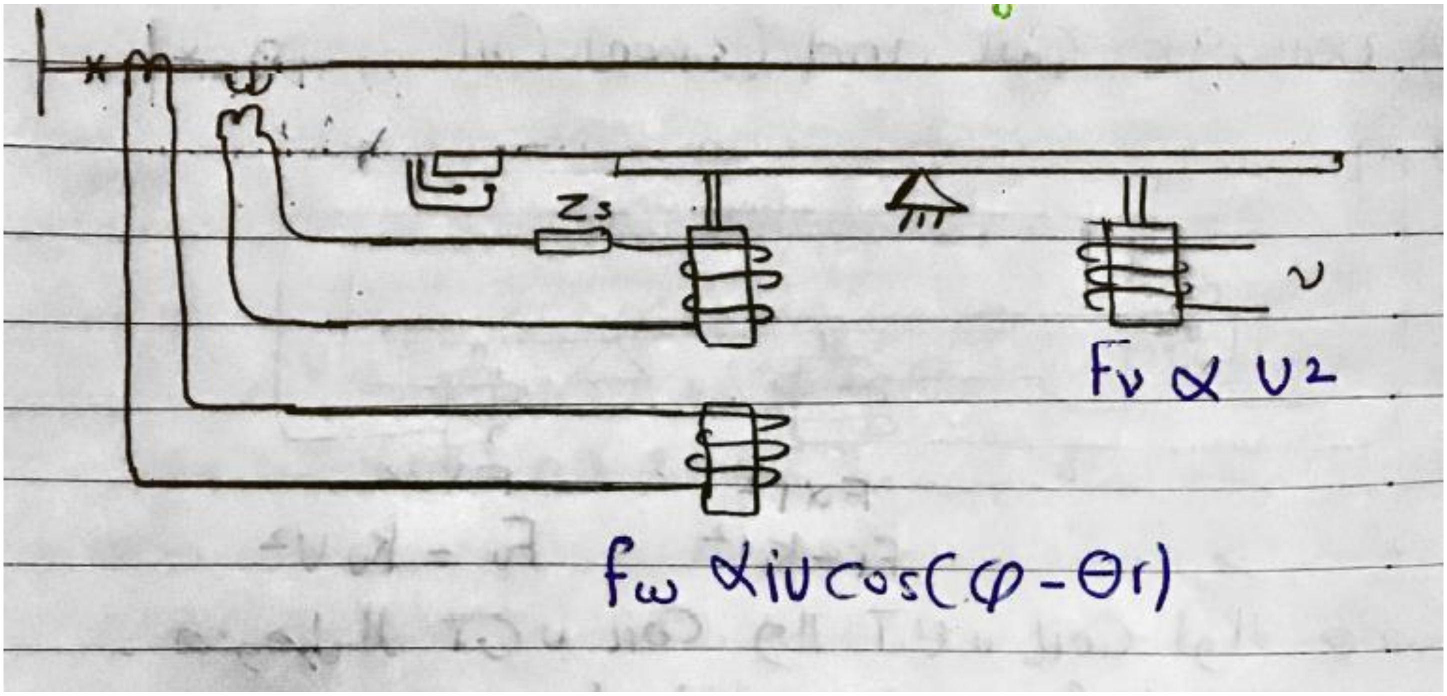
$$\frac{v}{i} = \sqrt{\frac{k_i}{k_v}} \qquad ; \qquad Z_b = \sqrt{\frac{k_i}{k_v}}$$

$$\boldsymbol{when\ Z_b < \sqrt{\frac{k_i}{k_v}} \quad \rightarrow trip}$$



No really used as it's a impedance relay (not distance) because it looks at both sides

11.9.2 Watt Element and Voltage coil (MHO Relay)



$$F_w \propto iv\cos(\phi-\theta_r)$$

Watt Element is connected to a coil $\boldsymbol{F_w} \propto iv\cos(\phi-\theta_r)$

VT is connected to a coil $\boldsymbol{F} \propto \boldsymbol{v^2}$; $\boldsymbol{F_v = k_v\, v^2}$

The force is from Voltage signal & Current Signal, so it will be $\propto vi$

$\boldsymbol{\phi}$: *PF angle*

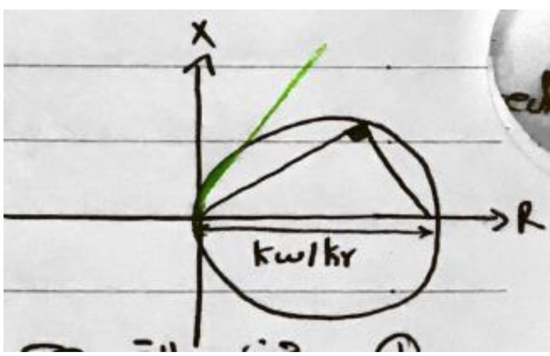
$\boldsymbol{\theta_r}$: *isss a set anglel by* Z_s *used to control the characteristics*

<u>For $\theta_r = 0$ there is Zs making no phase shift</u>

$$k_w v\, i\cos\phi = k_v\, v^2$$
$$Z_b = \frac{v}{i} = \frac{k_w}{k_v}\cos\phi$$

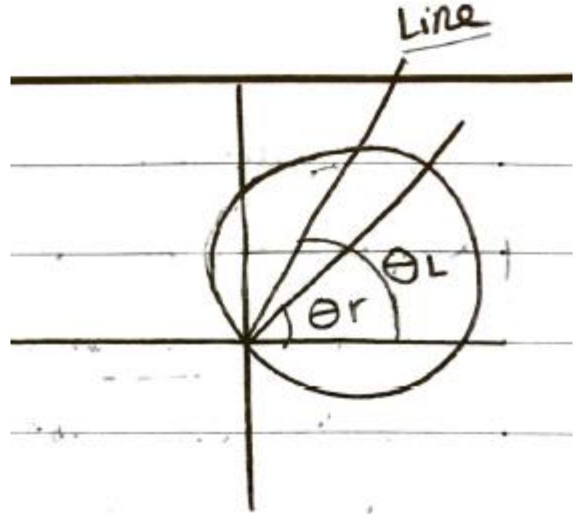
$$\phi = 0 \;\rightarrow Z_b = \frac{k_w}{k_v} \text{ will be on the R axis}$$

Now it covers only one direction,
but as $\theta = 0$ it doesn't cover loading conditions



Solutions

So we use Z_s to create θ_r to make it cover all loading conditions



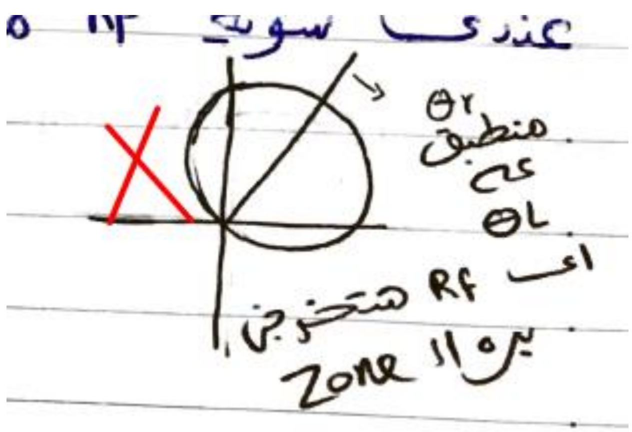
So we put

$$\theta_r \cong \theta_{line}$$
$$\cong 80 : 75 \;\; as\ X \gg R$$

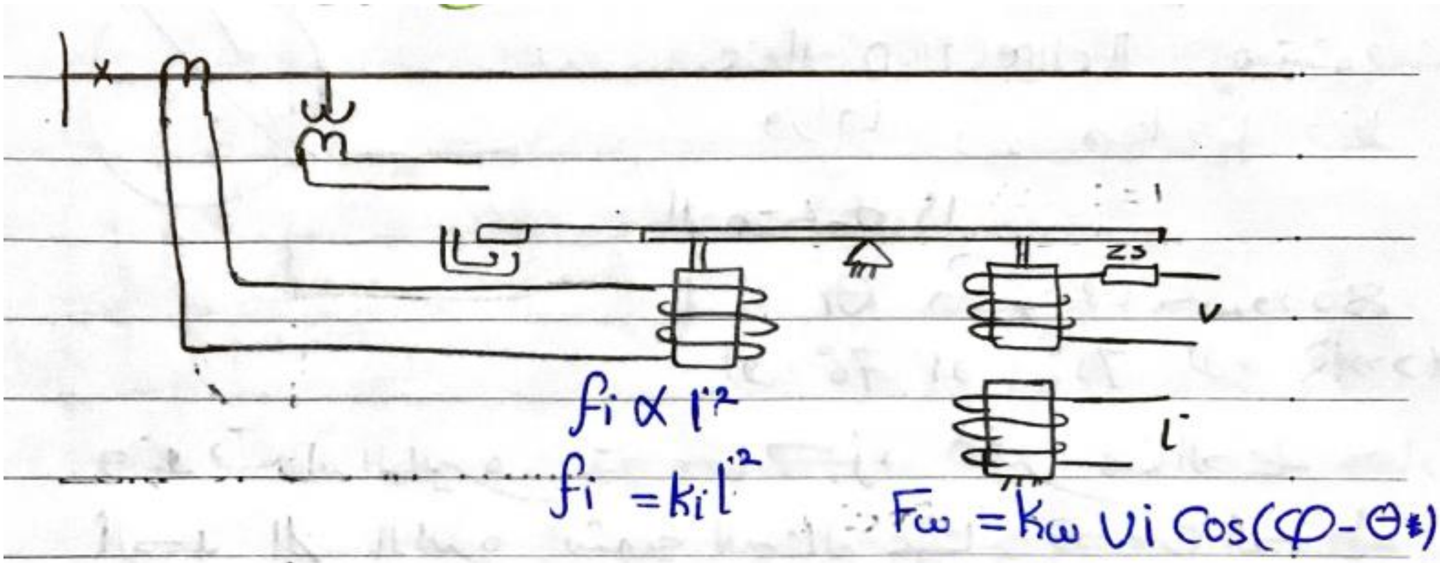
PRACTICALLY

$$we\ put\ \theta_r = \theta_{line} - 15°$$

SO THAT IF THERE IS <u>Rf</u> AT FAULT, we make sure it won't get the fault point out of the circle



11.9.3 Current coil and watt element [RESISTIVE or REACTANCE RELAY]



$$k_i i^2 = k_w v\, i \cos(\phi - \theta)$$

$$\frac{k_i}{k_w} = \frac{v}{i}\cos(\phi - \theta) = Z_b \cos(\phi - \theta)$$

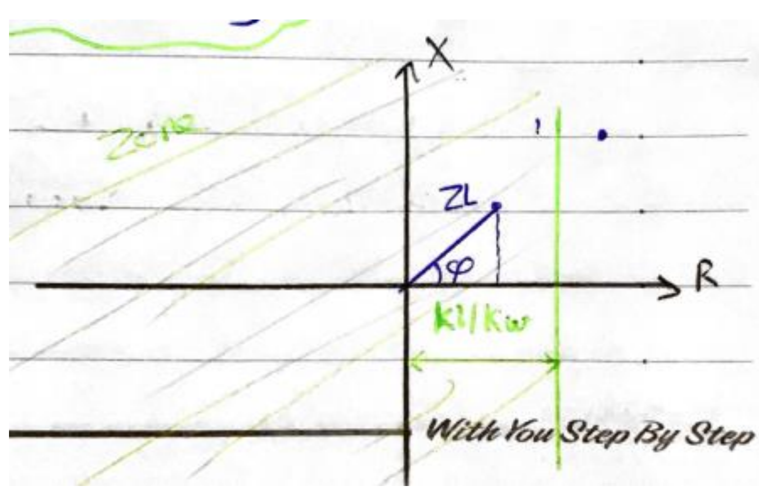
<u>For</u> $\theta = 0$

$$\therefore \frac{k_i}{k_w} = Z_b \cos\phi$$

Zone Condition $\frac{k_i}{k_w} > Z_b \cos\phi$

And because $Resistive\ component = Z_b \cos\phi$

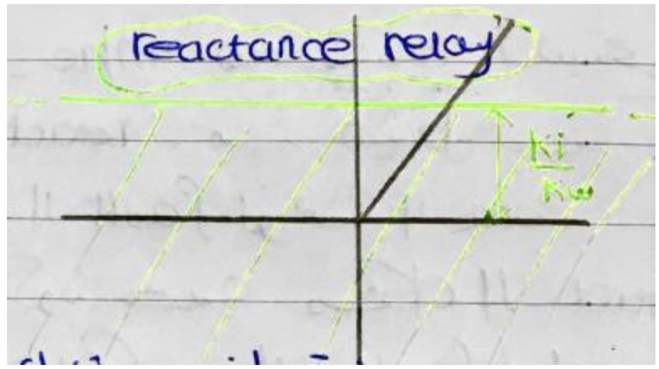
This relay is called <u>RESISTIVE RELAY</u>



For $\theta = 90°$

REACTANCE RELAY

$$\therefore \frac{k_i}{k_w} = Z_b \sin\phi$$



Disadvantages of (resistance / reactance) relay

1- **Not directional**
2- **Normal loadings are inside zone (it's to ∞)**

Advantages :

It can trip for any Rf

11.9.4 Reactance with MHO

Normally , we use **3 MHO zones**

HERE ,,

We use **1 MHO for 3 zones** **+ 2 Reactance**

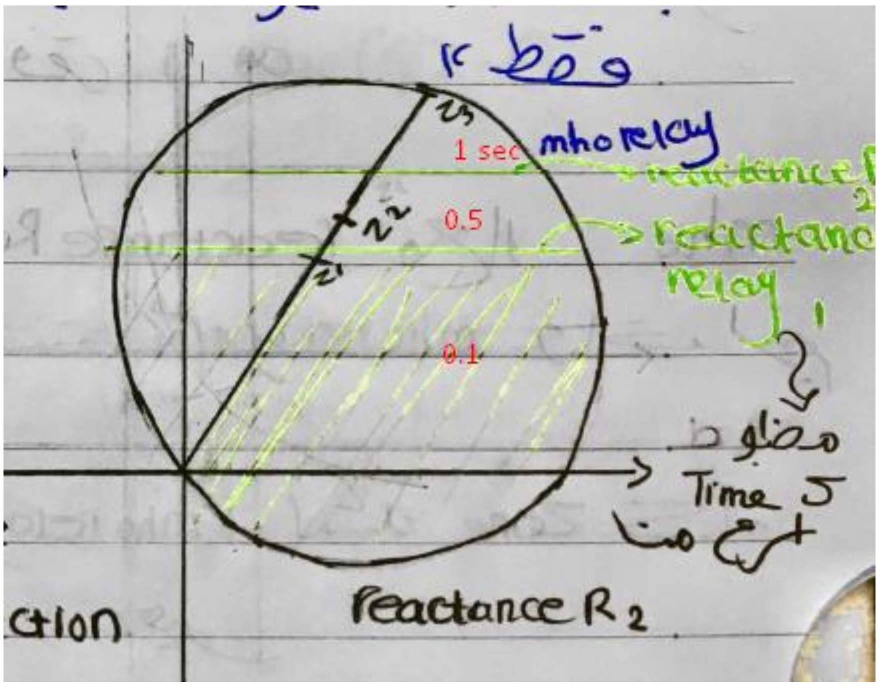
<u>Advatages:</u>

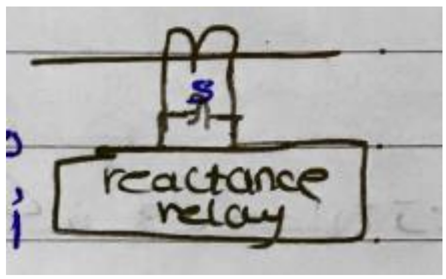
Now , we have increased margin for Rf

The reactance is now directional only

<u>Procedure :</u>

- Initially the reactance relay is deactivated
- Until there is a fault at the mho circle
- It then activated the reactance relay , if it sees fault it trips for
  Zone 1
  or Zone 2
- If the reactance relay doesn't trip for 1 sec the mho relay trips as zone 3 (backup)





11.10 Protection of parallel lines

The difficulty stems from the fact that the lines are mutually coupled in their zero-sequence circuits.

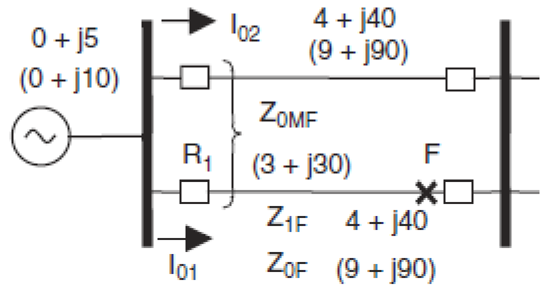


Figure 5.19 Fault on a mutually coupled transmission line

for phase a-g fault

$$E_{1f} = E_1 - Z_{1f} I_1$$
$$E_{2f} = E_2 - Z_{1f} I_2$$
$$E_{0f} = E_0 - Z_{of} I_{01} - Z_{omf} I_{02}$$

Before fault $E_{af} = 0$

$$E_{af} = E_{0f} + E_{1f} + E_{2f} = (E_0 + E_1 + E_2) - Z_{1f}(I_1 + I_2) - Z_{0f} I_{01} - Z_{0mf}\, I_{02} = 0$$
$$= E_a Z_{1f} I_a - \left(Z_{0f} - Z_{1f}\right) I_{01} - Z_{0mf} I_{02} = 0$$

So now taking effect of mutual of self and the parallel line

$$I_a' = I_a + \frac{Z_{of} - Z_{1f}}{Z_{1f}}\, I_{01} + \frac{Z_{0mf}}{Z_{1f}} I_{02}$$
$$= I_a + \frac{Z_0 - Z_1}{Z_1} I_{01} + \frac{Z_{0m}}{Z_1} I_{02} = I_a + m I_{01} + m' I_{02}$$

$$\boldsymbol{\frac{E_a}{I_a'} = Z_{1f}}$$

It should be noted that the current from a parallel circuit must be made available to the relay, if it is to operate correctly for a ground fault. This can be accomplished if the mutually coupled lines are connected to the same bus in the substation. If the two lines terminate at different buses, this would not be possible, and in that case one must accept the error in the operation of the ground distance function.

Example 5.7

Let the system shown in Figure 5.19 represent two mutually coupled transmission lines, with impedance data as shown in the figure. The zero-sequence impedances are given in parentheses, and the mutual impedance in the zero-sequence circuits of the two transmission lines is $(3 + j30)\ \Omega$. The rest of the system data are similar to those of Example 5.4. For a phase-a-to-ground fault at F, the transmission line impedance is divided by two because of the parallel circuit of equal impedance. Thus, the positive and negative sequence impedance due to the transmission lines in the fault circuit is $(2 + j20)\ \Omega$, while the zero-sequence impedance is $0.5 \times (9 + j90 + 3 + j30) = (6 + j60)\ \Omega$. The symmetric components of the fault current are given by

$$\begin{aligned} I_1 = I_2 = I_0 &= \frac{7967.4}{2 \times (0 + j5) + 0 + j10 + 2 \times (2 + j20) + 6 + j60} \\ &= 66.169\angle -85.23^\circ \end{aligned}$$

The currents seen by the relay are half these values because of the even split between the two lines, and $I_a = 3 \times \frac{1}{2} \times I_1 = 99.25\angle -85.23^\circ$. The zero-sequence currents in the two lines are

$$I_{01} = I_{02} = 33.085\angle -85.23^\circ$$

The zero-sequence compensation factors m and m' are given by (see equation (5.23))

$$m = \frac{9 + j90 - 4 - j40}{4 + j40} = 1.25 \quad \text{and } m' = \frac{3 + j30}{4 + j40} = 0.75$$

The compensated phase a current, as given by equation (5.23), is

$$I'_a = I_a + mI_{01} + m'I_{02} = 165.42\angle -85.23^\circ$$

The symmetrical components of the voltages at the relay location are given by

$$\begin{aligned} E_1 &= 7967.4 - j5 \times 66.169\angle -85.23^\circ = 7637.7 - j27.51 \\ E_2 &= -j5 \times 66.169\angle -85.23^\circ = -329.7 - j27.51 \\ E_0 &= -j10 \times 66.169\angle -85.23^\circ = -659.4 - j55.02 \end{aligned}$$

and the phase a voltage at the relay location is

$$E_a = E_1 + E_2 + E_0 = 6649.51\angle -0.95^\circ$$

Finally, the impedance seen by the relay R_a is

$$\frac{E_a}{I'_a} = \frac{6649.5\angle -0.95^\circ}{165.42\angle -85.23^\circ} = 4 + j40\ \Omega$$

Besides the effect of mutual coupling on the performance of the ground distance relay, some other relay operations may also be affected in the case of parallel transmission lines. Consider the two examples given below.

Incorrect directional ground relay operation

Consider the system shown in Figure 5.20. A ground fault on line 2 induces a zero-sequence current I_{01} in line 1. This current, in turn, circulates through the grounded neutrals at the two ends of the transmission line. The current at the A terminal of this line is out of the line, and into the bus. However, if the transformer neutral current is used for polarization of the directional ground relay, the operating and the polarizing currents will be in the same direction. This condition is identical to that corresponding to a fault on the line. Similarly, the condition at the end B of the line, with current in the transformer neutral and the line current once again in phase with each other, is indistinguishable from that due to an internal fault. The ground directional relays at both ends may be fooled into seeing this condition as an internal fault. The same false operating tendency would exist if potential polarizing were used. In other words, the phase of the polarizing quantity is not independent of the direction of current flow, as it is when a short circuit occurs.[6]

Incorrect phase distance relay operation

This problem is encountered when phase and ground distance relaying is used for protecting parallel transmission lines which are connected to common buses at both ends.[11] Consider the case of a simultaneous fault between phase a and ground on line 1, and between phase b and ground on line 2, as shown in Figure 5.21. This is known as a cross-country fault, and is generally caused by

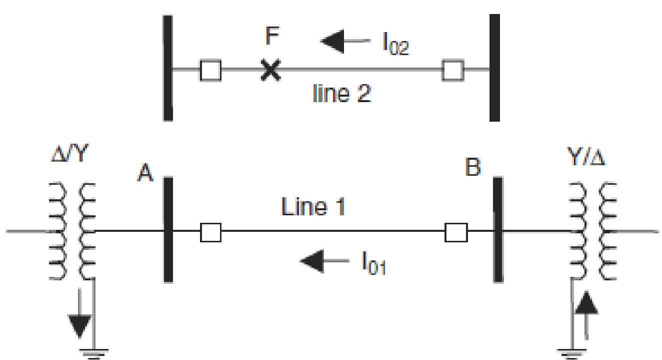


Figure 5.20 Current polarization error caused by induced current in a coupled line

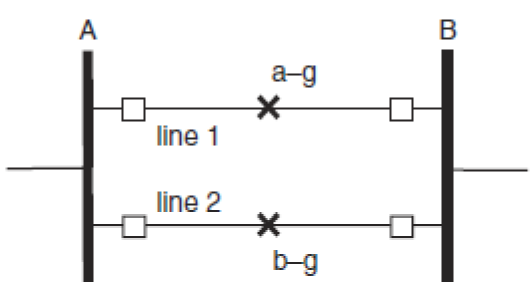


Figure 5.21 Simultaneous faults on parallel transmission lines

the fault arc from the first ground fault expanding with time, and involving the other transmission line in the fault. Such a fault produces fault current contributions in both phases a and b of both circuits, and may be detected as a phase a–b–g fault on both lines.

A multiphase fault will cause a three-phase trip of both circuits. This problem is particularly severe when single-phase tripping and reclosing are used. In this case, the correct and desirable operation would of course be a single-phase trip on each of the circuits, maintaining a three-phase tie between the two ends of the lines, although the impedances would be unbalanced. Reference 11 examines the calculations involved, and propose a solution involving a digital relay that uses currents and voltages from all six phases. Single-phase tripping and reclosing were discussed in Chapter 1. The possibility of failure of distance relays for such faults has been well recognized in Europe, where both double-circuit towers and single-phase tripping are common.

11.11 Effect of transmission line compensation devices

Series capacitors that are installed to increase load or stability margins, or series reactors that are used to limit short-circuit currents, can significantly affect the transmission line protection.

11.11.1 Series Capacitors

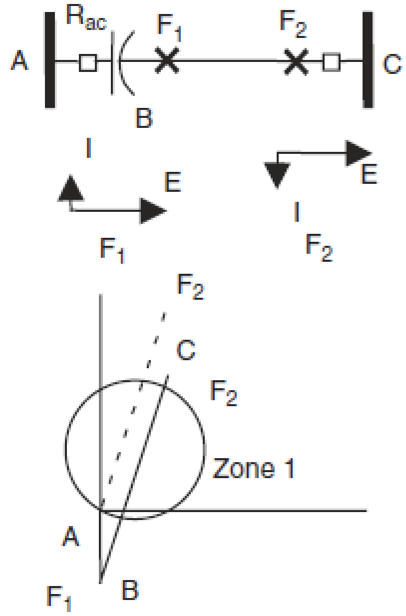


Figure 5.22 *R–X* diagram with a series capacitor

Because of capacitor the faults line is shifted downward from dash to the solid

So now for F1 point it won't operate

Solution

1- Shift Circle it self with line compensating devices
2- Use protective devices surge supressors around capacitors to remove it in case of fault
3- phase comparison relaying,

11.11.2 Series Reactors

Same problem but shift u

Solution

To remove it during fault

BUT

it will now overreach its desired protective zone. For instance, if the reactor shown in Figure 5.23 has an impedance of Zab = 10 □ and the line section BC has an impedance of j40 (ignoring the resistance), zone 1 at both ends would be set at 0.85 × (40 + 10) = 42.5 □. If the reactor is removed from service the line impedance would be 40 □. With the relays set for 42.5 □ they would see faults beyond the original zone of protection. This may be acceptable if the zone 1 overreach does not extend into the next line section.

Same but shift up

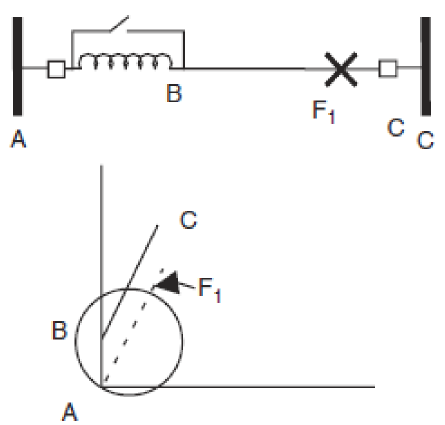


Figure 5.23 *R–X* diagram with a series reactor

11.11.3 Shunt devices

load current associated with the shunt devices that is seen by the line relays, but the margins used in differentiating between load and short-circuit currents is usually sufficient to avoid any problems. If a problem does exist, it is not too difficult to connect the CTs of the shunt devices, so that the load current is removed from the line relay measurement (Figure 5.24).

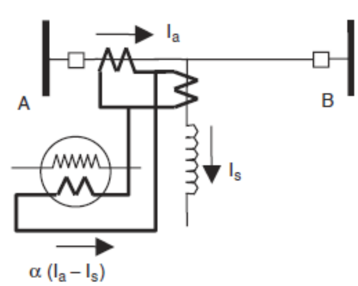


Figure 5.24 Compensation of shunt current in a relay

11.12 Load ability of Relay

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loadability limit of the relay : The value of load MVA at which the relay is on the verge of operation

in figure

ϕ: *load power factor angle*

θ : *the value of the apparent impedance at which the loading limit will be reached*

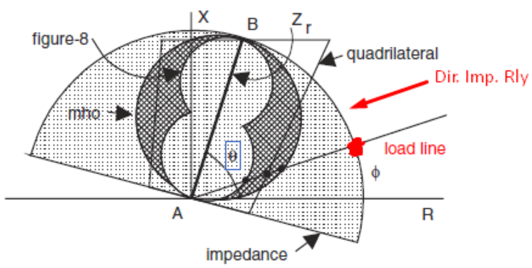
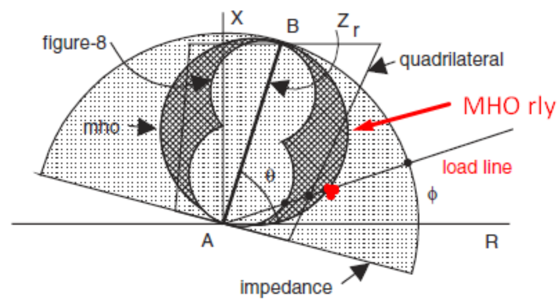
<table>
<tr><th>Directional Impedance Relay</th><th>MHO Relay</th></tr>
<tr><td>

Figure 5.25 Loadability of distance relays with different characteristic shapes</td><td>
</td></tr>
<tr><td>$Loadability = Z_r$</td><td>$Loadability = Z_r \cos(\theta + \phi)$
(note that a lagging power factor angle is considered to be negative).</td></tr>
<tr><td>$S_l, imp = 3\dfrac{E^2}{Z_p} = 3\dfrac{E^2 n_i}{Z_r n_v}$</td><td>$S_{l,moh} = 3\dfrac{E^2 n_i}{Z_r \cos(\theta + E\phi)\, n_v}$</td></tr>
</table>

E : *kilovolts (phase to neutral)*
n_v, n_i : *VT and CT ratios*

It is clear that the loadability of a mho relay is significantly greater than that of a directional impedance relay.

The loadability of a relay can be further increased by using

1- a **figure-of-eigh**t characteristic (**offset mho**),
2- or a **quadrilatera**l characteristic, as shown in Figure 5.25. The latter characteristic is achievable only with **solid-state** or **computer-based relays.**

Quadrilateral > Figure-8 > MHO > dir. impedance

Example 5.8

We will consider the loadability of the zone 1 setting of the relay from Example 5.2. (This will illustrate the principle of checking the loadability, although one must realize that the critical loadability, which provides the smaller limit, is that associated with the third zone.) The current and voltage transformer ratios for the relay were determined to be $n_i = 100$ and $n_v = 288.6$. The zone 1 setting is $1.17 + j8.84 = 8.917\angle 82.46°$. From equation (5.25), the loadability of an impedance relay is given by (the phase-to-neutral voltage is 20 kV)

$$S_{1,\mathrm{imp}} = 3 \times \frac{20^2 \times 100}{8.917 \times 288.6} = 46.63 \text{ MVA}$$

In the case of a mho relay, we must calculate the loadability at a specific power factor. Let us assume a power factor of 0.8 lagging. This corresponds to $\varphi = -36.870$. The angle of the line impedance is 82.46°. Thus, $(\theta + \varphi) = (82.46° - 36.87°) = 45.59°$. Using equation (5.26), the loadability of a mho relay for a 0.8 pf lagging load is

$$S_{1,\mathrm{mho}} = 3 \times \frac{20^2 \times 100}{8.917 \times 288.6 \times \cos 45.59°} = 66.63 \text{ MVA}$$

Of course, one must check the loadability of all the zones, but the zone 3 loadability, being the smallest, will usually be the deciding criterion.

11.13 Summary

In this chapter we have examined the protection of a transmission line using distance relays. Distance relays, both single-phase and polyphase, are used when changes in system configuration, or generating pattern, provide too wide a variation in fault current to allow reliable settings using only current as the determining factor. Distance relays are relatively insensitive to these effects. We have reviewed a number of characteristics that are available depending on the protection required. We have also discussed several common problems associated with nonpilot line protection, including