Overcurrent protection

Power System Protection

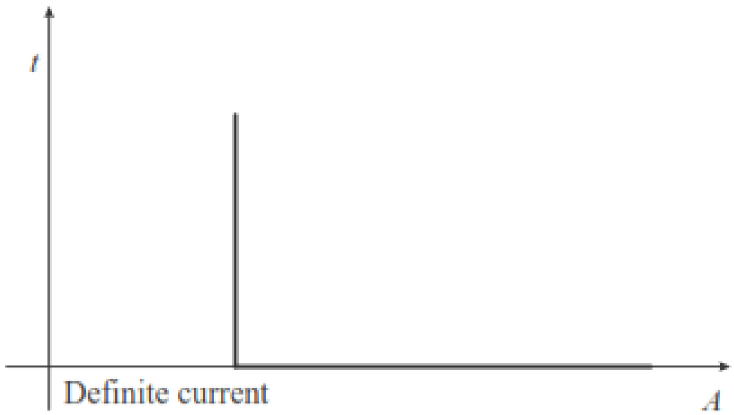
Abdul Basit

Types of overcurrent relay

- Overcurrent relays are classified on the basis of operating characteristics as:
  - definite current relay
  - definite time relay
  - inverse time relay

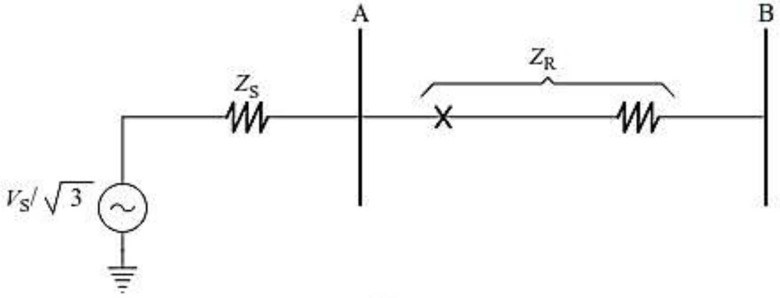
Definite Current Relay

- Relay operates instantaneously when current reaches a predetermined value.
- **<u>Settings</u>**:
  - Relay will operate for a low current value for substation furthest away.
  - Operating currents are progressively increased at each substation, moving towards the source
  - Relay with lower settings operates first
- **<u>Disadvantage</u>**:
  - Little selectivity at high values of short circuit current
  - Poor discrimination: difficulty in distinguishing fault current at near points location



Definite Current Relay

- Figure (a): impact of impedance on the short-circuit current.
- Figure (b): Fault current are same for faults at point F1 and F2 – difficult to obtain correct settings for Relay
  - Impedance of Transformer will produce difference between F2 and F3 – discrimination for fault current
- Relay settings based on maximum fault level conditions may not be appropriate during lower fault level.
- Relay settings based on lower value of fault could result in some breakers operating unnecessarily if the fault level increases.
- **<u>Consequence</u>**, definite-current relays are not used as the only overcurrent protection, but their use as an instantaneous unit is common where other types of protection are in use.

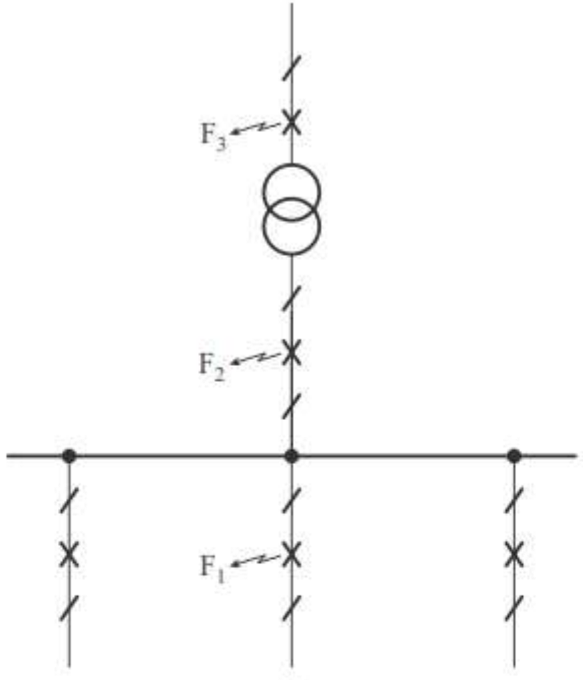


(a)

Z_R = Impedance of protected element

Z_s = Source impedance

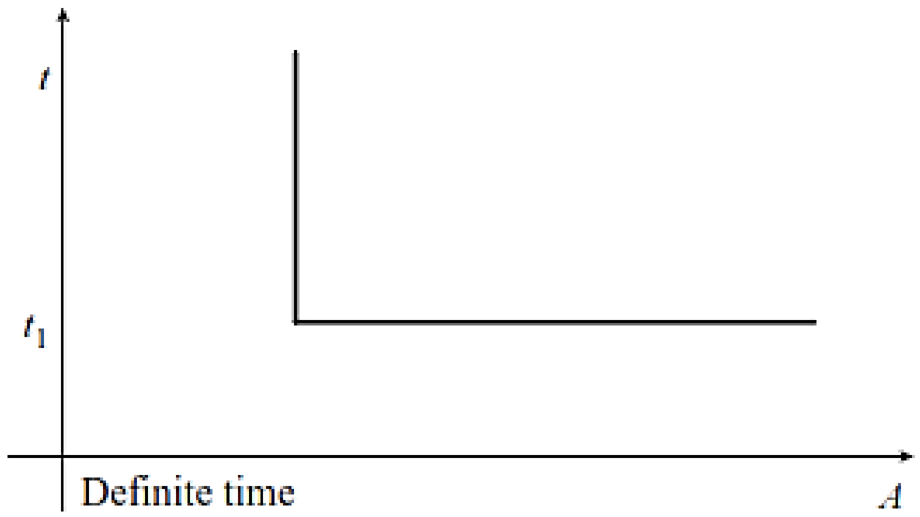
$$I_{SC(A)} = \frac{V_S}{\sqrt{3}}\frac{1}{Z_s}, \quad I_{SC(B)} = \frac{V_S}{\sqrt{3}}\frac{1}{Z_s + Z_R}$$

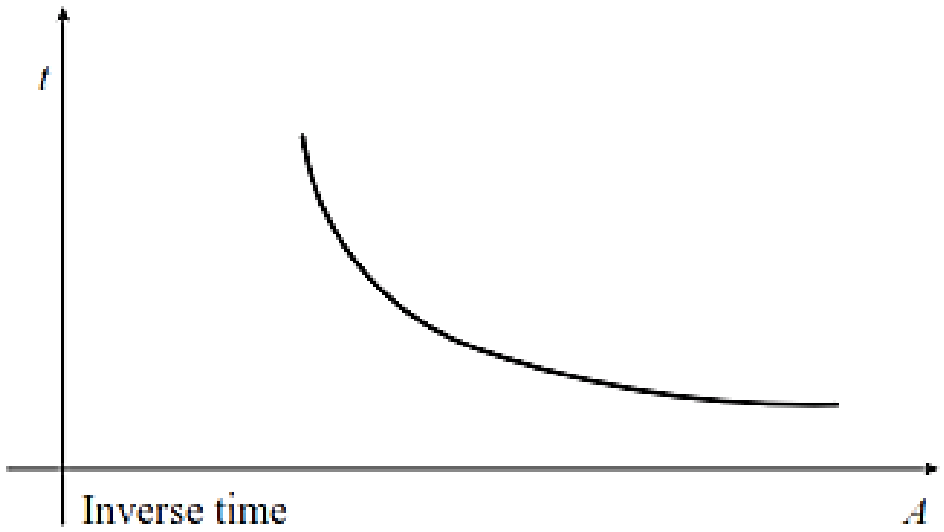


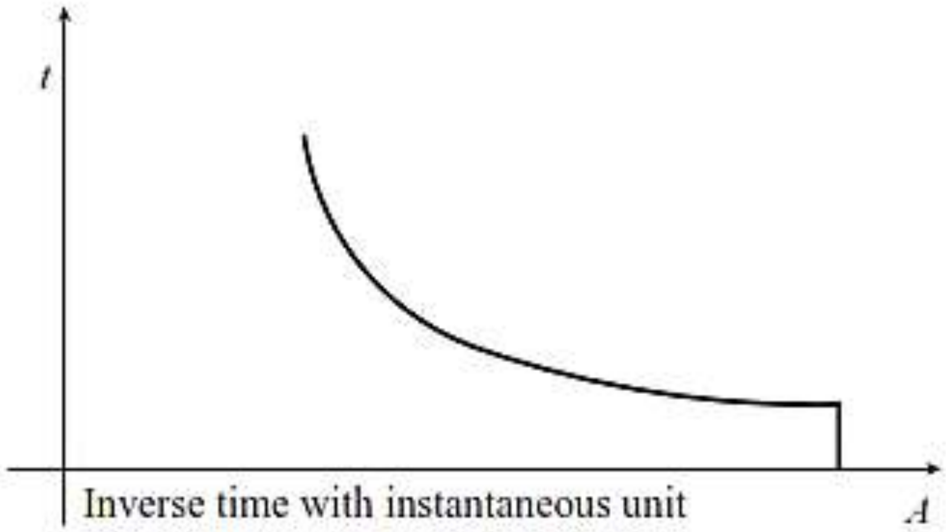
(b)

Definite-time/current or definite-time relays

- Relay used to cope with different levels of current by using different operating times.
- Discrimination margin is achieved by keeping the breaker nearest to the fault to trip in the shortest time, and then the remaining breakers are tripped in succession
  - Time discrimination in fixed steps makes the protection more selective
- **<u>Disadvantage:</u>** Faults near to the source, which result in bigger currents, may be cleared in a relatively long time.
- Relay settings: Current tap settings and Time Dial Settings


t
t_1
Definite time
A


t
Inverse time
A


t
Inverse time with instantaneous unit
A

Inverse-time relays

- Relays operate in a time that is inversely proportional to the fault current
- Advantage over definite-time relays:
  - for very high currents, much shorter tripping times can be obtained without risk to the protection selectivity.
- Inverse-time relays are classified in accordance with their characteristic curve that indicates the speed of operation
  - inverse, very inverse or extremely inverse.
- Inverse-time relays are also referred to as inverse definite minimum time (IDMT) overcurrent relays

Setting overcurrent relays

- Overcurrent relays are normally supplied with an instantaneous element and a time delay element within the same unit
- **Setting:** define the required time/current characteristic of both the time-delay and instantaneous units for phase relays and over current relays
  - three-phase short-circuit are used for setting phase relays
  - phase-to-earth fault current are used for earth-fault relays
- Fault current calculated at normal power system operating state

Setting instantaneous units

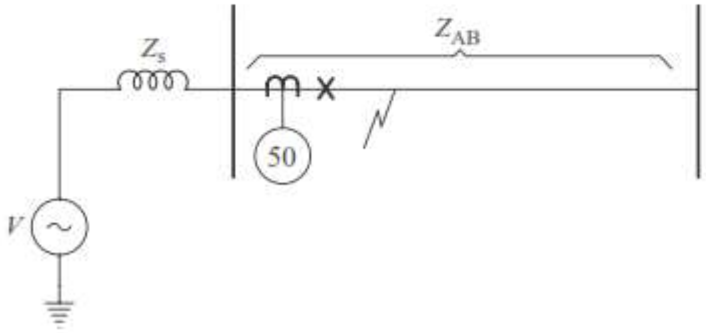
- For power system elements with high impedance, Instantaneous units are more effective
  - criteria for setting instantaneous units vary depending on the location and the type of system element being protected
- Advantages:
  - Reduce operating time of the relays for severe system faults.
  - avoid loss of selectivity in a protection system consisting of relays with different characteristics; this is obtained by setting the instantaneous units so that they operate before the relay characteristics cross

Setting instantaneous units

- Lines between substations
  - Take at least 125% of the symmetrical r.m.s. current for the maximum fault level at the next substation
  - If two relays at particular fault level fails to coordinate the relay furthest from the source shall operate at lower level of current, 25% margin avoids overlapping the downstream instantaneous unit if a considerable DC component is present
- Distribution lines: fifty percent of the maximum short-circuit current at the point of connection of the CT supplying the relay **OR** between six and ten times the maximum circuit rating.
- Instantaneous units of the overcurrent relays installed on the primary side of the transformers should be set at a value between 125% and 150% of the short-circuit current

Coverage of instantaneous units protecting lines between substations

- Percentage of coverage of an instantaneous unit that protects a line, X, can be illustrated by considering the system



$$K_i = \frac{I_{\text{pick-up}}}{I_{\text{end}}} \qquad K_s = \frac{Z_{\text{source}}}{Z_{\text{element}}}$$

From figure:

$$I_{\text{pick-up}} = \frac{V}{Z_s + XZ_{ab}}$$

where V = voltage at the relay CT point
Z_s = source impedance
Z_{ab} = impedance of the element being protected = Z_{element}
X = percentage of line protected
I_{end} = current at the end of the line
$I_{\text{pick-up}}$ = minimum current value for relay PU

$$K_i = \frac{Z_s + Z_{ab}}{Z_s + XZ_{ab}} \Rightarrow X = \frac{Z_s + Z_{ab} - Z_s K_i}{Z_{ab} K_i}$$

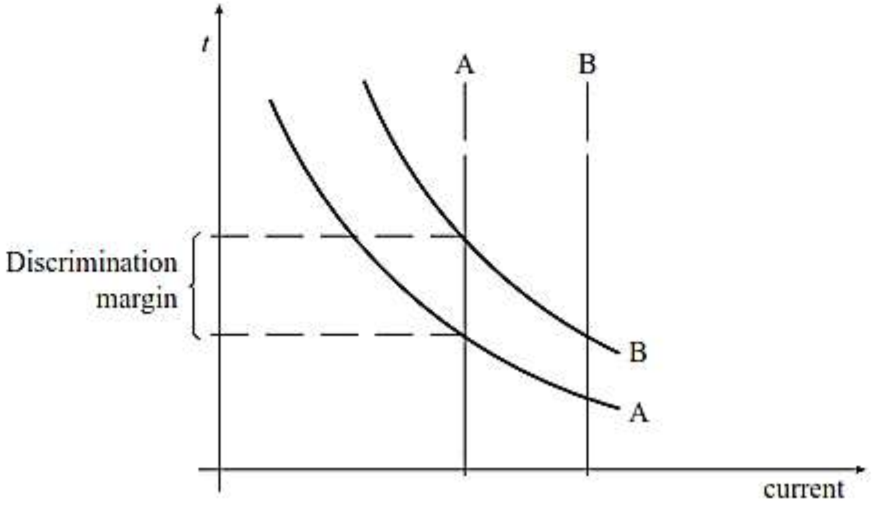
This gives

$$K_s = \frac{Z_s}{Z_{ab}} \Rightarrow X = \frac{K_s(1 - K_i) + 1}{K_i}$$

If Ki = 1.25 & Ks = 1, then X = 0.6
60% of the line is protected

Setting the parameters of time-delay overcurrent relays

- Operating time of an overcurrent relay has to be delayed to ensure that the relay does not trip before any other protection situated closer to the fault.
- Figure illustrate the difference in the operating time of two relays at the same fault levels in order to satisfy the discrimination margin requirements.
- Definite-time relays and inverse-time relays can be adjusted by selecting two parameters
  - time dial or time multiplier setting
  - Pick Up (PU) or Plug setting (tap setting).



The pick-up setting

- PU/plug setting, refer as plug setting multiplier (PSM), is used to define the PU current of the relay
  - ratio of the fault current in secondary amps to the relay PU or plug setting.
- For phase relays, the PU setting is determined by allowing a margin for overload above the nominal current, as in the following expression:

$$\text{Pick-up setting} = \frac{\text{OLF} \times I_{\text{nom}}}{\text{CTR}}$$

where

OLF = overload factor that depends on the element being protected

I_{nom} = nominal circuit current rating

CTR = CT ratio

The pick-up setting

- For earth-fault relays, the PU setting is determined taking account of the maximum unbalance that would exist in the system under normal operating conditions. A typical unbalance allowance is 20% so that the expression

$$\text{Pick-up setting} = \frac{0.2 \times I_{\text{nom}}}{\text{CTR}}$$

Time dial settings

- Adjusts time delay before the relay operates whenever the fault current reaches a value equal to, or greater than, the relay current setting.
- **<u>Electromechanical relays</u>**: time delay is usually achieved by adjusting the physical distance between the moving and fixed contacts
  - smaller time dial value results in shorter operating times.
- Time dial setting is also referred to as the time multiplier setting.

Time dial settings – criteria

1. Determine the required operating time of the relay furthest away from the source by using the lowest time dial setting and considering the fault level for which the instantaneous unit of this relay picks up.
2. Determine the operating time of the relay associated with the breaker in the next substation towards the source, $t_{2a} = t_1 + t_{margin}$,
   - t_{2a} is the operating time for back up relay and t_{margin} is the discrimination margin for the same fault as 1
3. With the same fault current as in 1 and 2 above, and knowing t_{2a} and the PU value for relay 2, calculate the time dial setting for relay 2.
   - Use the closest available relay time dial setting whose characteristic is above the calculated value.
4. Determine the operating time (t_{2b}) of relay 2, but now using the fault level just before the operation of its instantaneous unit.
5. Continue with the sequence, starting from the second stage

Time discrimination margin

- time discrimination margin between two successive time/current characteristics of the order of 0.25–0.4 s should be typically used for selectivity:
  - breaker opening time
  - relay overrun time after the fault has been cleared
  - variations in fault levels.
- Single-phase faults on the star side of a DY transformer are not seen on the delta side.
  - setting earth-fault relays, the lowest available time dial setting can be applied to the relays on the delta side, which makes it possible to considerably reduce the settings and thus the operating times of earth-fault relays nearer the source infeed.

Mathematical expression for relay

$$t = \frac{k\beta}{(I/I_s)^{\alpha} - 1} + L$$

where

t = relay operating time in seconds

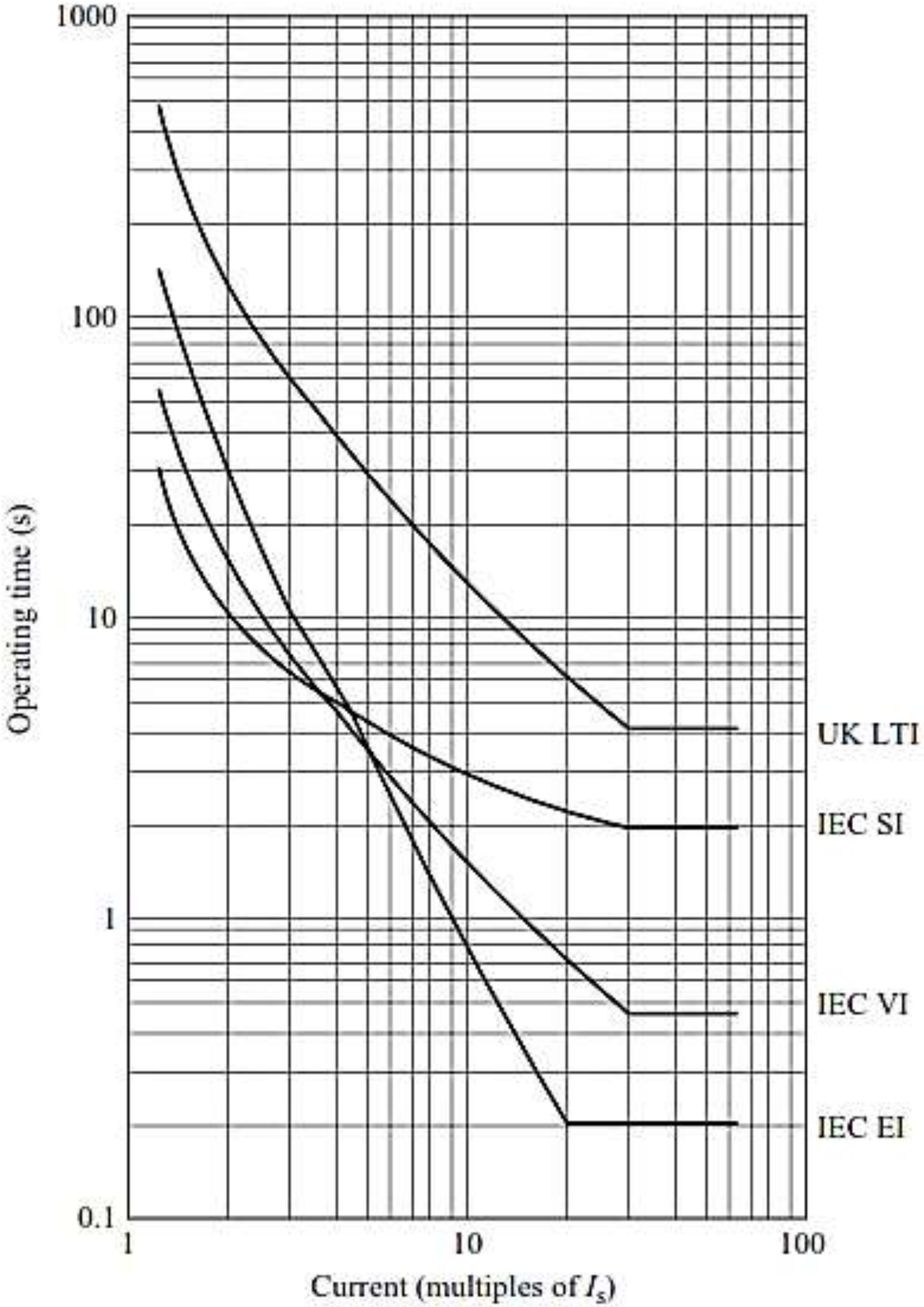
k = time dial, or time multiplier, setting

I = fault current level in secondary amps

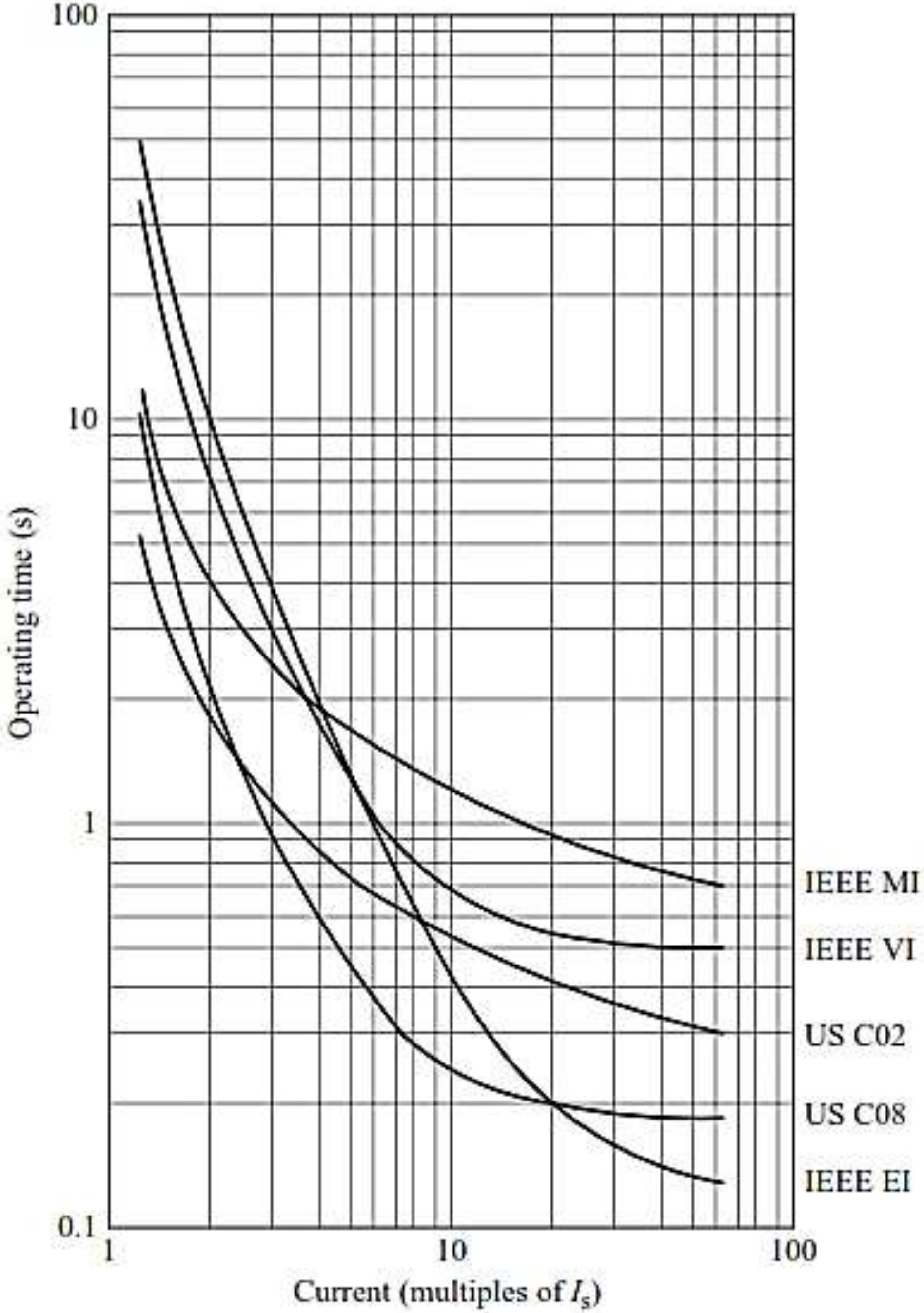
I_s = PU current selected

L = constant

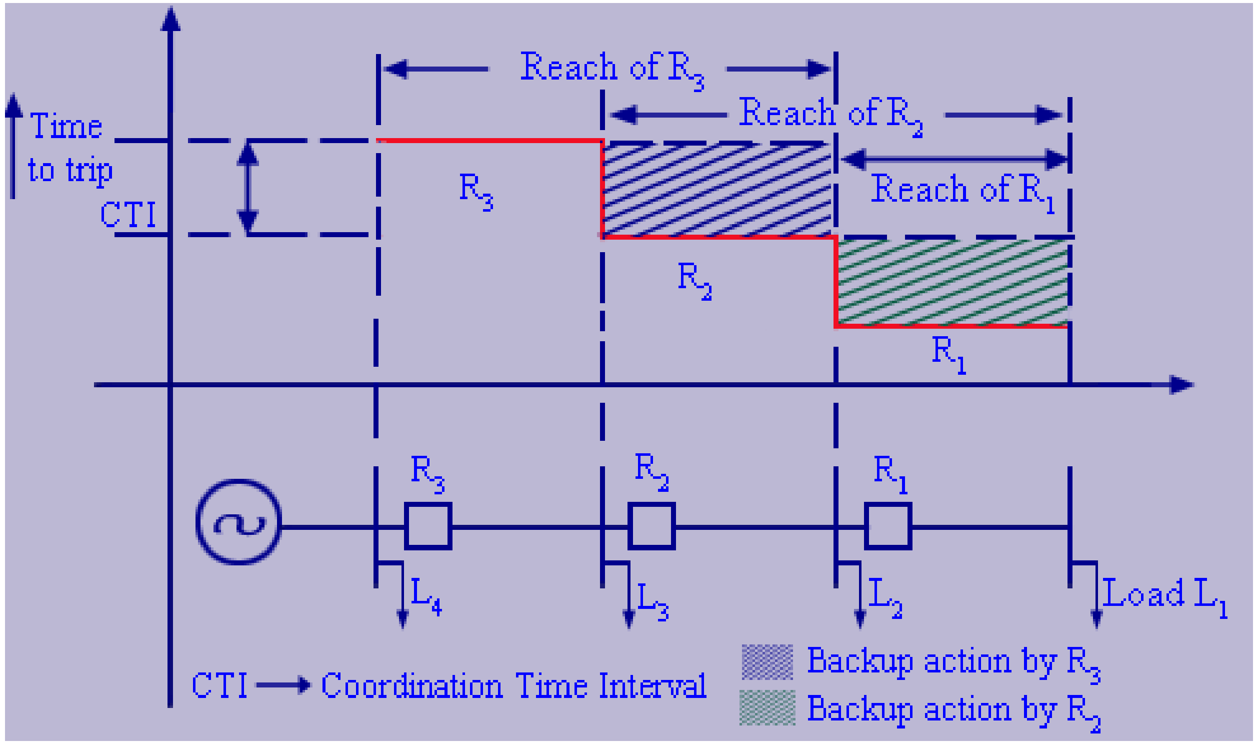
Curve description	**Standard**	α	β	L
Moderately inverse	IEEE	0.02	0.0515	0.114
Very inverse	IEEE	2.0	19.61	0.491
Extremely inverse	IEEE	2.0	28.2	0.1217
Inverse	CO8	2.0	5.95	0.18
Short-time inverse	CO2	0.02	0.0239	0.0169
Standard inverse	IEC	0.02	0.14	0
Very inverse	IEC	1.0	13.5	0
Extremely inverse	IEC	2.0	80.0	0
Long-time inverse	UK	1.0	120	0



1000
100
10
1
0.1
1
10
100
Operating time (s)
Current (multiples of I_s)
UK LTI
IEC SI
IEC VI
IEC EI



100
10
1
0.1
1
10
100
Operating time (s)
Current (multiples of I_s)
IEEE MI
IEEE VI
US C02
US C08
IEEE EI



Relay R1 does not have any coordination responsibility and hence it can trip without any intentional time delay. Relay R2 has to coordinate with relay R1 and hence its time of operation is delayed by time equal to Coordination Time Interval (CTI). Relay R3 has to back up R2. Hence its time of operation is delayed by another CTI. Thus, we see that as we move along towards source, the relaying action slows down.

Pick up current for phase fault protection

- **Guidelines**
  - Pickup current should be above maximum load current seen by the feeder. This ensures that relay does not trip on load. $I_{ref} > 1.25\ I_{Lmax}$
  - Pick up current should be below the minimum fault current i.e; $I_{ref} < I_{fmin}$. This ensure that protection system operates for low as well as high fault current.
    - During this condition, in the utility least number of generators are in service. Hence, this coordination occurs at light load condition and at the remote end of the feeder

Pick up current for phase fault protection

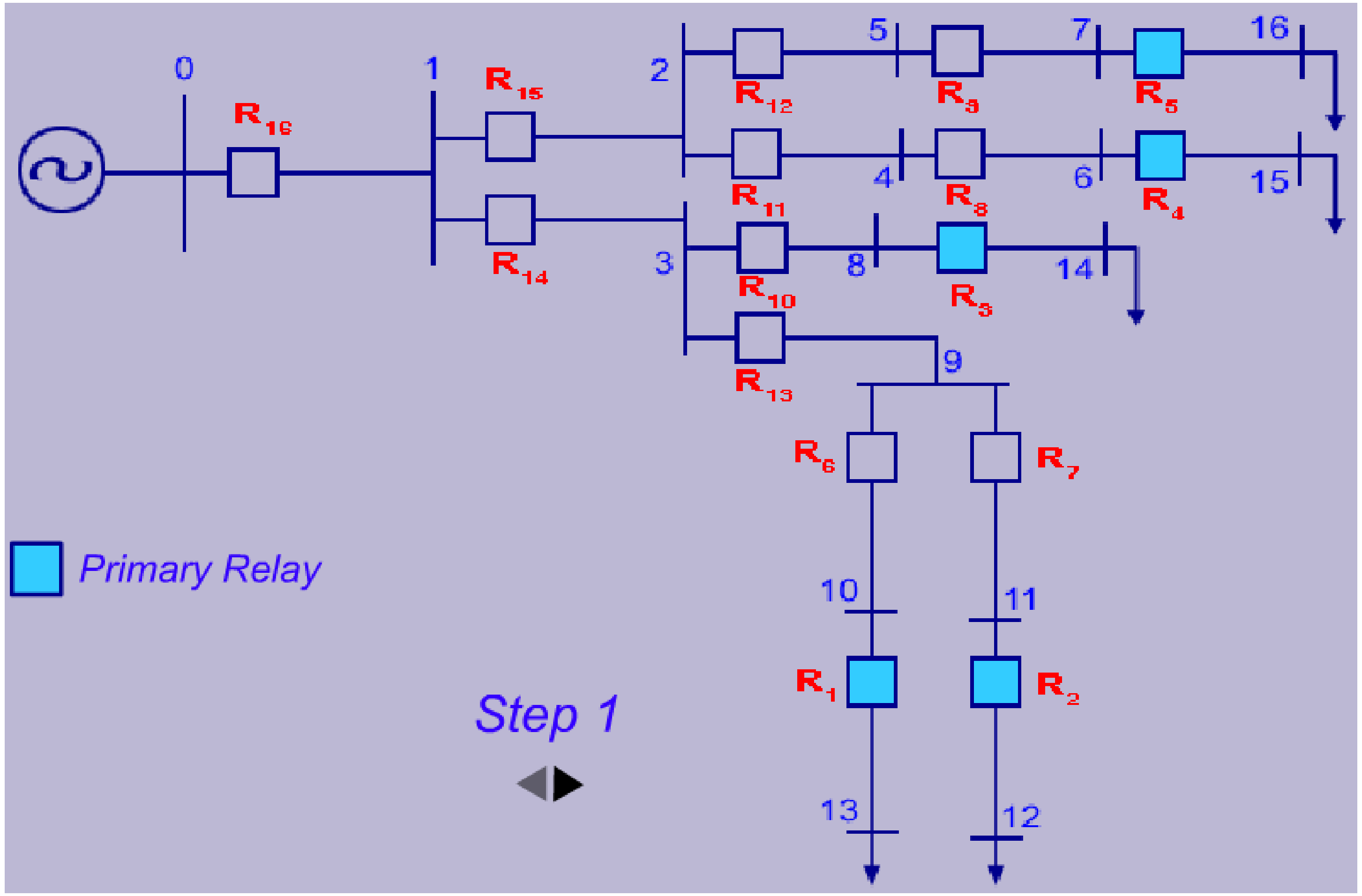
- **Guidelines**
  - Pick up current should also be below the minimum fault current of the feeder that it has to backup. Otherwise, a relay's backup protection responsibility will not be fulfilled.
  - For a fault on the feeder being backed up, the relay should provide sufficient time for the corresponding primary relay to act before it issues tripping command. This interval is called CTI (co-ordination time interval). Typically, CTI is about 0.3 sec. It consists of CB operating time+ Relay operating time + Factor of safety

If above measures can not be satisfied simultaneously, then overcurrent relays cannot be used for protection. Alternatives are distance or directional protection.

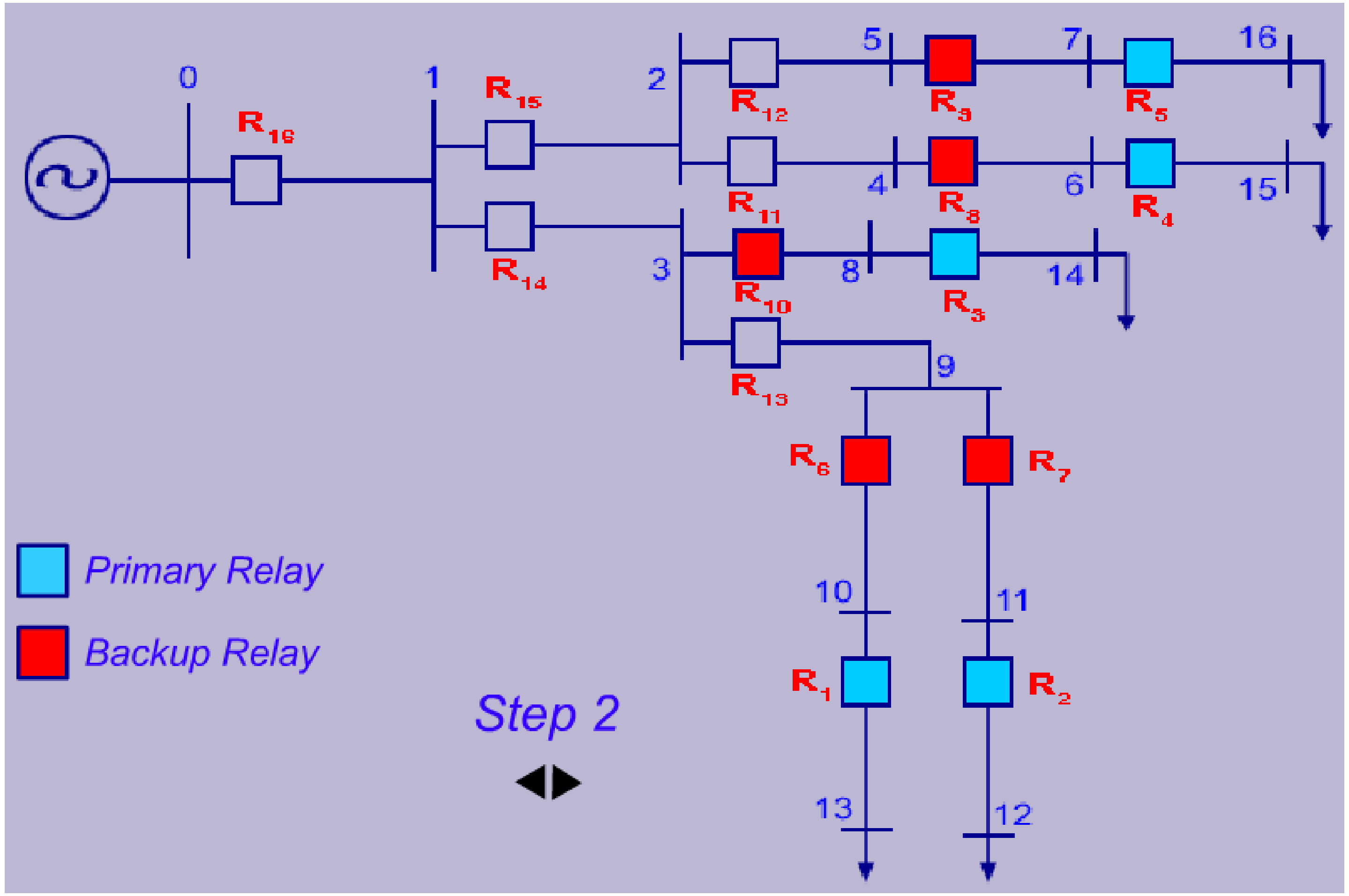
Back up protection by time discrimination

- Relay setting and coordination involves primarily following steps:
  - Identify all possible Primary-Back-up relay pairs.
  - Decide the correct sequence for coordination of relays.
  - Decide the pickup value and hence PSM for relays.
  - Compute the TMS/TDS to meet the coordination.
  - Validation of the results.

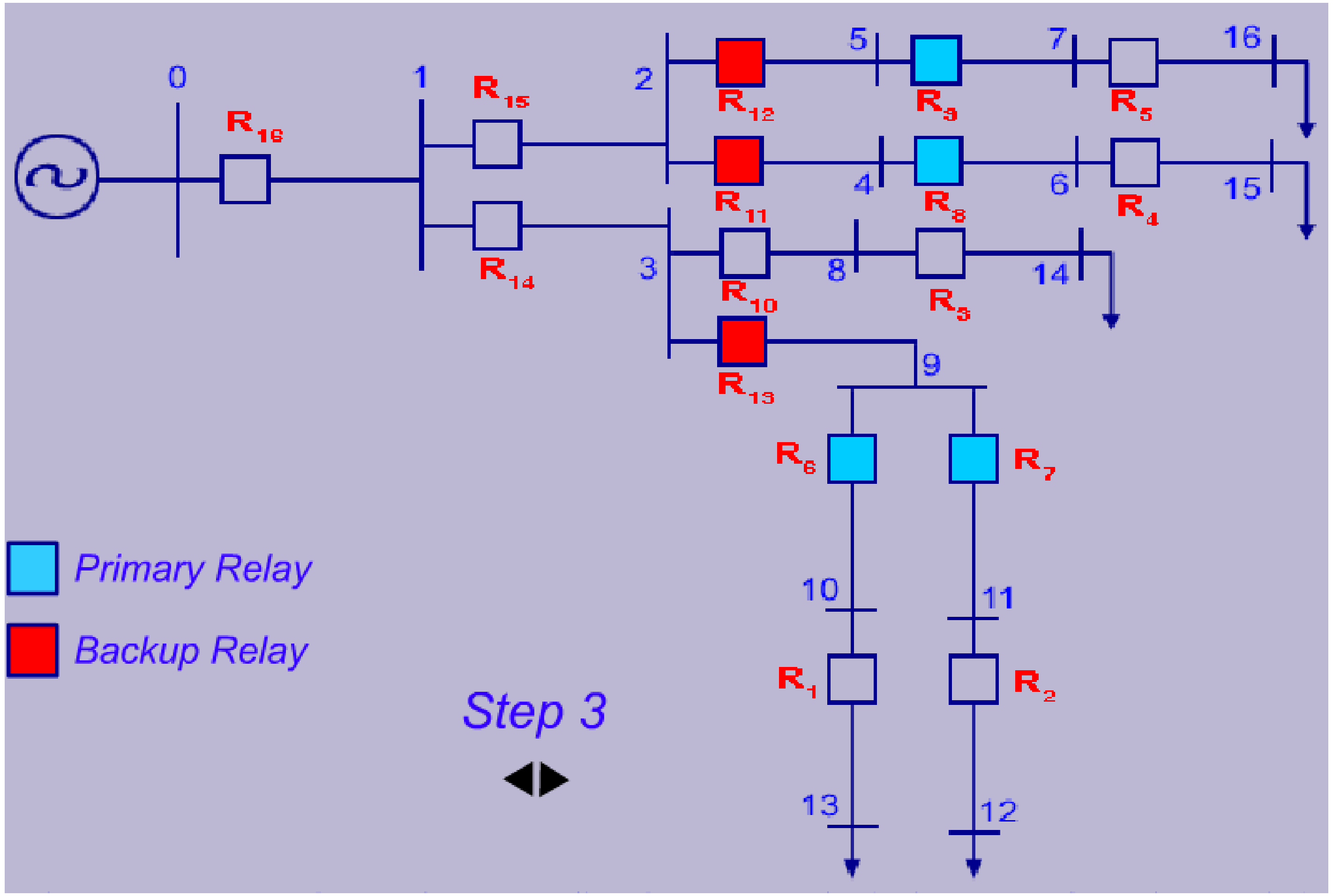
Identification of primary backup relay pairs



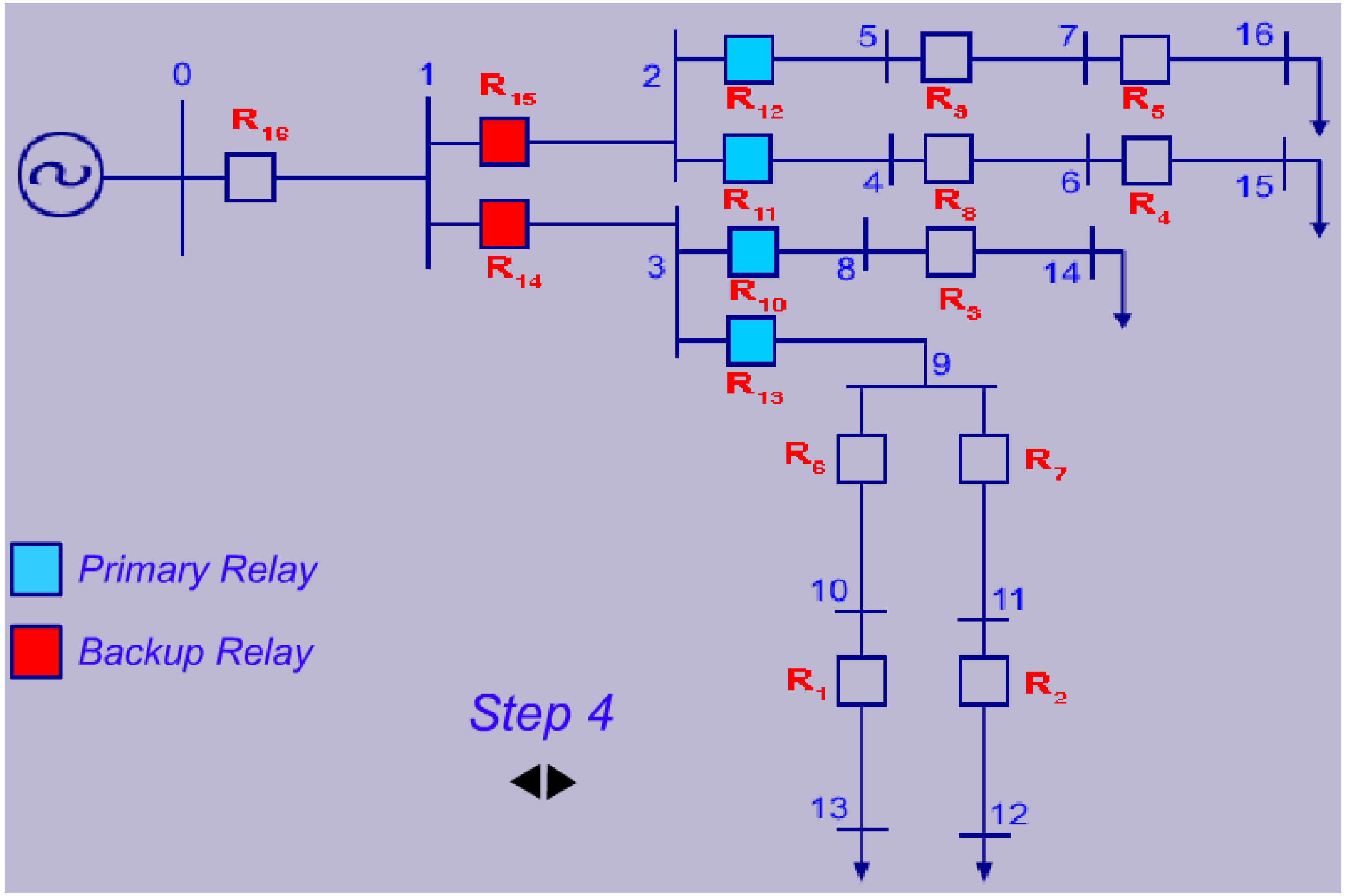
Identification of primary backup relay pairs



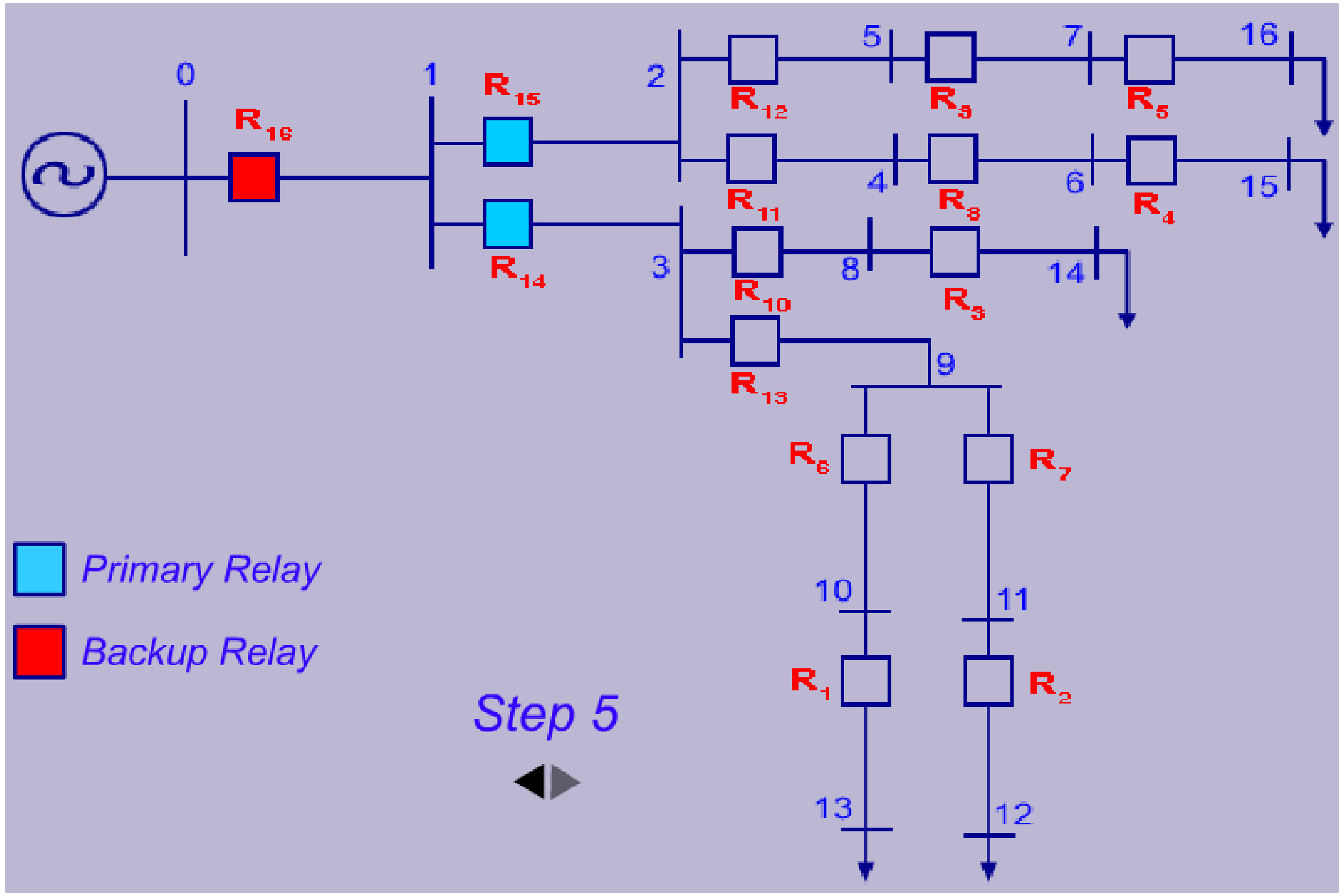
Identification of primary backup relay pairs



Identification of primary backup relay pairs



Identification of primary backup relay pairs



Setting and Coordination of Overcurrent Relays

- Relay settings and coordination activity has to be determined after identifying the primary and backup relay pairs
  - At leaf node, the relay is not providing the back up so the TSM/TDS is set to minimal level
  - The PSM is set for the primary and the back up relay
  - TMS of the back-up relays is computed so that they maintain at least a time delay equal to CTI with all primary relays
- Then, we delete the leaf nodes, update the coordination tree and this process is repeated until we hit the source node

Setting and Coordination of Overcurrent Relays

Step 1 Initialize the coordination tree.

Step 2 Are there any leaf nodes except the root? If yes, go to step - 3, else to step - 7.

Step 3 Identify the leaf nodes in coordination tree.

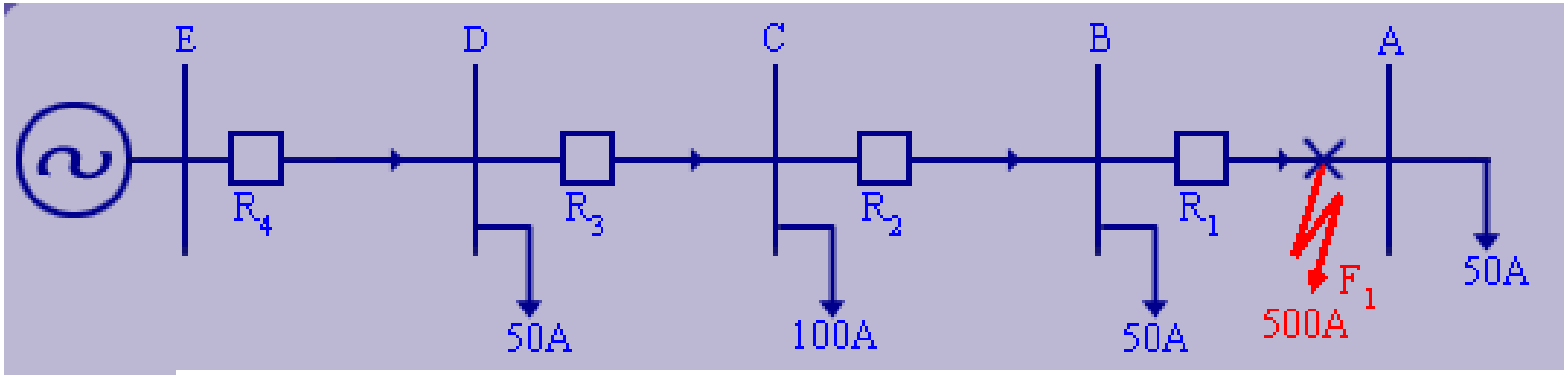
Step 4 If the PSM and/or TMS of these relays have not been set so far, set them.

Step 5 Identify the backup relay of leaf-nodes in step - 3. Compute their PSM and TMS for backup protection and co-ordination.

Step 6 Delete the leaf nodes. Update the co-ordination tree and go back to step - 2.

Step 7 The co-ordination activity is now complete.

Example



3 φ fault under consideration; Relays used have Normal Inverse, IEC standard characteristics. Coordination time interval CTI is 0.3sec.
Required primary protection should fulfill its responsibility within 1.0 sec

IEC Inverse Characteristic Equations		
IEC SI (Standard Inverse)	IEC VI (Very Inverse)	IEC EI (Extremely Inverse)
$t = TMS \times \frac{0.14}{(I/Is)^{0.02} - 1}$	$t = TMS \times \frac{13.5}{(I/Is) - 1}$	$t = TMS \times \frac{80}{(I/Is)^2 - 1}$

Example

- Pick up current settings for the relays should be above the feeder load currents and not the bus load currents
  - **Rule of thumb:** set the pick-up current at 1.25 times maximum load current or limit to 2/3rd of the minimum fault current

Data for Phase Relay Setting and Coordination			
Bus	Maximum Load	Minimum Fault Current	Maximum Fault Current
bus A	50	250	500
bus B	50	650	1200
bus C	100	1100	2000
bus D	50	1600	3500

Example

- Pick-up current of relay R2, not adequate to just look at the minimum fault current of section CB.
  - Because, relay R2 has to back up the relay R1. Hence, minimum fault current to be protected by relay R2 is also 250 A.
  - However, if we use same TMS/TDS setting for R2 as R1 then it leads to a serious conflict of interest between relays R1 and R2 with both of them competing to clear the fault.
  - If R1 clears the fault F1 first, then there is absolutely no problem. But if R2 clears the fault first then, there is an unwanted loss of service to load at node B.

Example

- Step 1
  - Choose for relay R1
    TMS = 0.025. No intentional time delay is provided because R1 does not have backup responsibility.
    Relay 1 (R1), pickup current = 160A.
    For fault on section AB (I_{fmax} = 500 A):
    PSM = Fault Current / Actual Pick up = 500/160 = 3.125
    Operating time using IEC SI TCC

$$t = 0.025 \frac{(0.14)}{\{(3.125)^{0.02} - 1\}} = 0.15\text{sec}$$

a_1	a_2	$a_3 = 1.25 \times a_2$	a_4	a_5	a_6		
Relay	Max Feeder segment load current (A)	Min limit on Pickup current (A)	Min Fault current at remote bus	Max limit on Pickup current	Max Fault current at remote bus	PSM (A)	TMS
R_1	50 $\xrightarrow{x\ 1.25}$	62.5	250	$\frac{2}{3} \times 250 = 167$	500 (1)	160	0.025

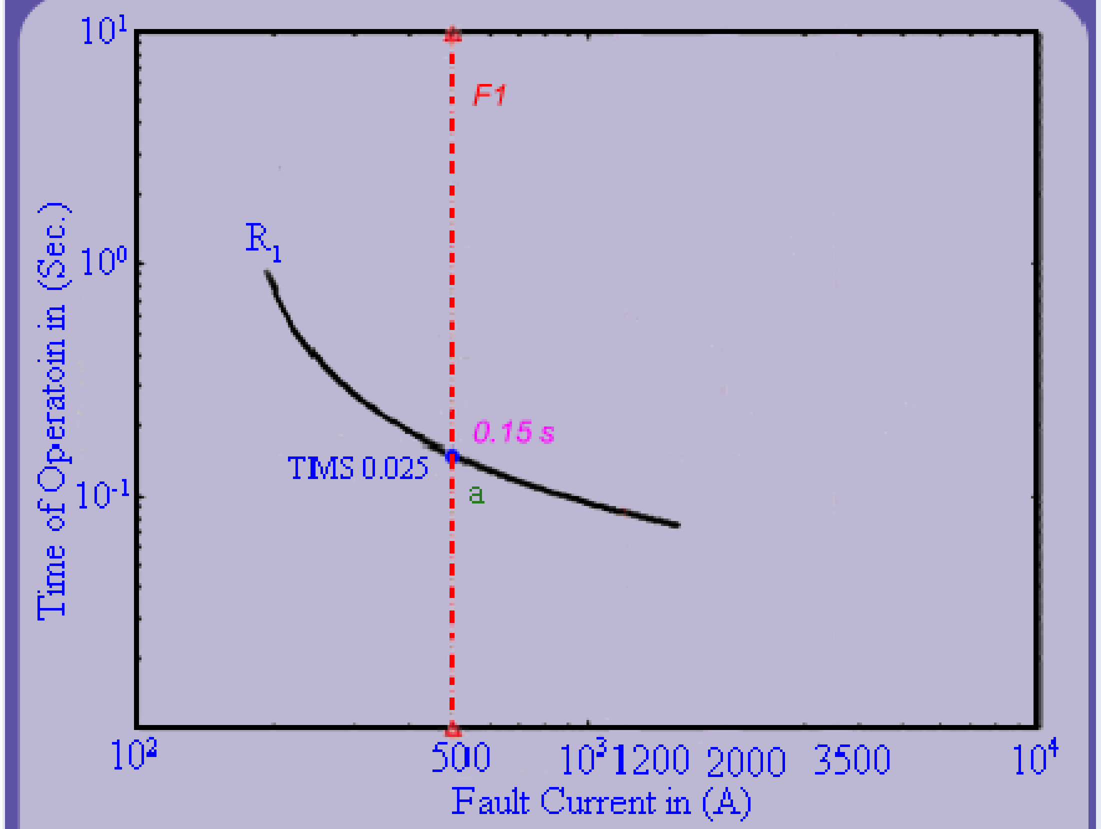
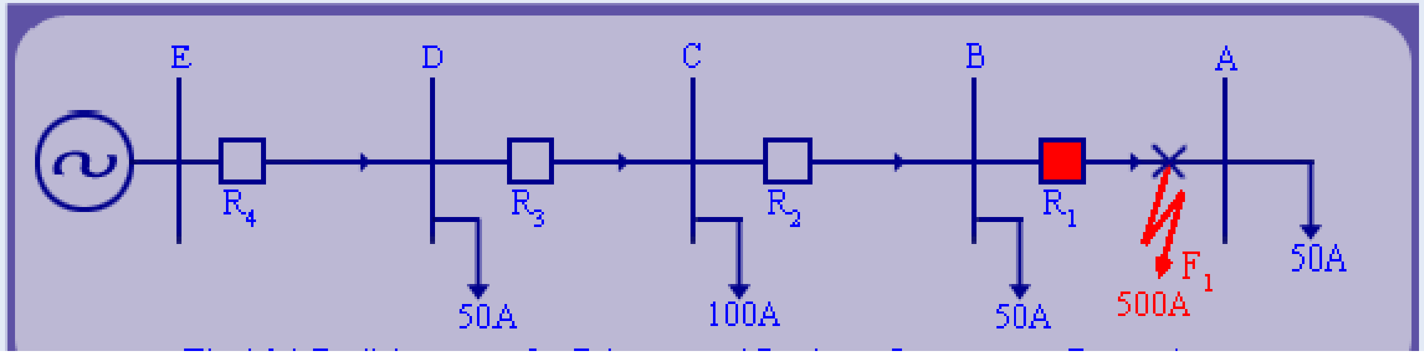


Fig 16.2 Relay Co-ordination for Phase fault

Step 1:

- *R_1 is at leaf node*
- *Set Pick up at 167 A (See Table 1)*
- *Set TMS to min. i.e. (0.025) (See Table 1)*
- *Tripping time of R_1 for F_1 (Point 'a')*



Example

- Step 2
  Relay 2 (R2)
  Let, Actual Pick up = 167 A. R2 co-ordinate with R1 for close in fault for relay R1 leading to large PSM. If relays co-ordinate at large PSM, then co-ordination at lower values is automatically ascertained.
  PSM = Max Fault Current / Actual Pick up = 500/167 = 2.99
  Expected operating time for relay 2 = Operating time of relay 1+ CTI = 0.15 + 0.3 = 0.45sec.

$$0.45 = TMS \frac{(0.14)}{\{(2.99)^{0.02} - 1\}}$$

TMS = 0.07

a_1	a_2	$a_3=1.25 \times a_2$	a_4	a_5	a_6		
Relay	Max Feeder segment load current (A)	Min limit on Pickup current (A)	Min Fault current at remote bus	Max limit on Pickup current	Max Fault current at remote bus	PSM (A)	TMS
R_1	50 $\xrightarrow{\times 1.25}$	62.5	250 $\xrightarrow{2/3^{rd}}$	$\frac{2}{3} \times 250 = 167$	500 (1)	160	0.025
R_2	100 $\xrightarrow{\times 1.25}$	125	650	167	1200 (2)	167	0.07

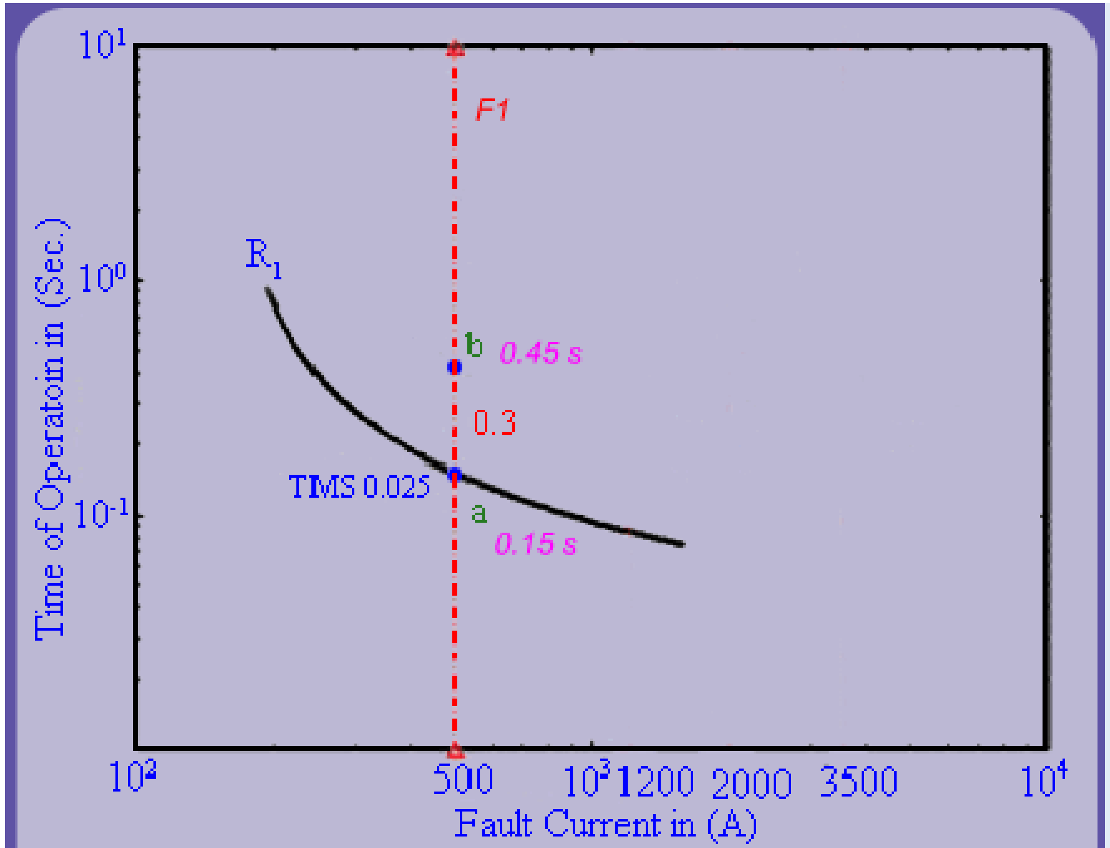
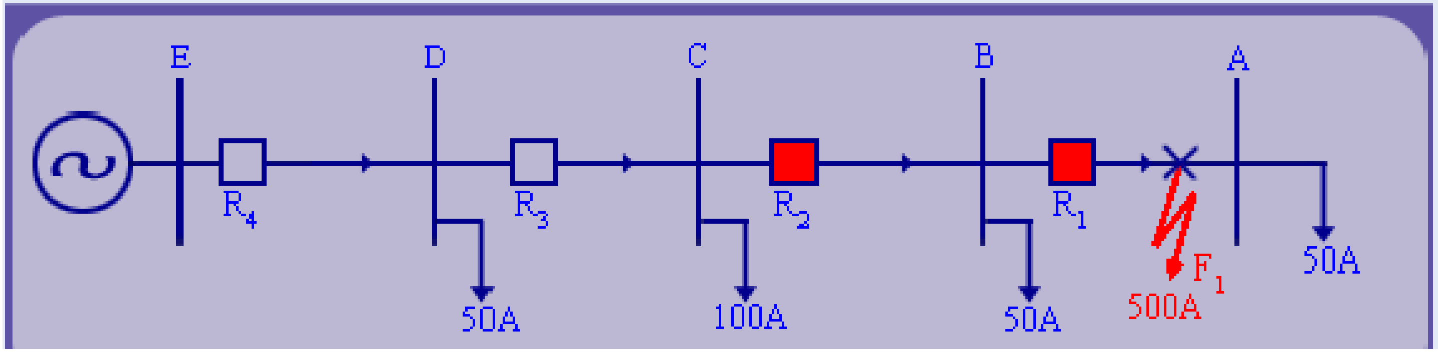


Fig 16.2 Relay Co-ordination for Phase fault

Step 2:

- # *R_2 is second relay to be set*
- # *Acts as back-up to R_1 for F_1*
- # *Relay picks up at 167 A. (See Table 1)*
- # *Should trip after CTI (0.3 sec.)*
- # *Locate point 'b' (0.15+0.3=0.45 sec)*



Example

- Now for maximum fault current on section BC (1200A)
  PSM = Fault Current / Actual Pick up = 1200/167 = 7.185 with TMS = 0.07 operating time of relay 2

$$t = 0.07 \frac{(0.14)}{\{(7.185)^{0.02} - 1\}}$$

- Operating time of relay 2 = 0.24sec.
  In the similar way all relays can be coordinated.

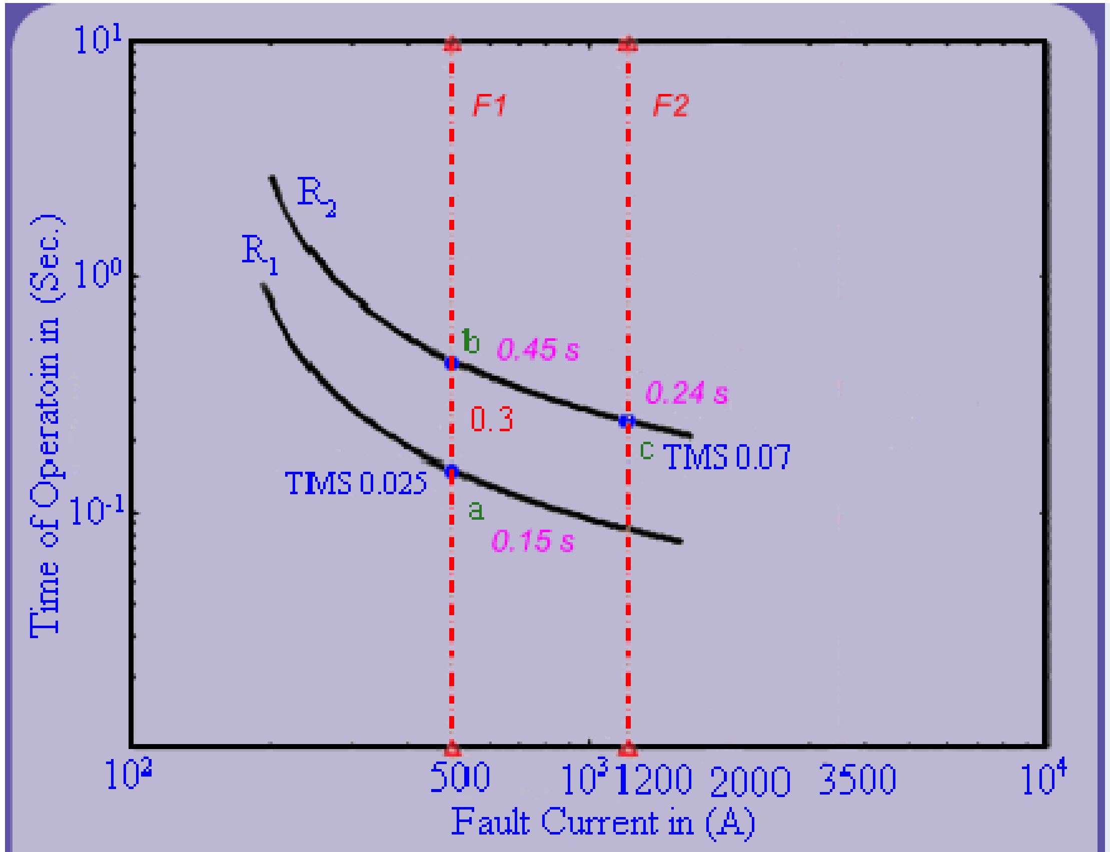
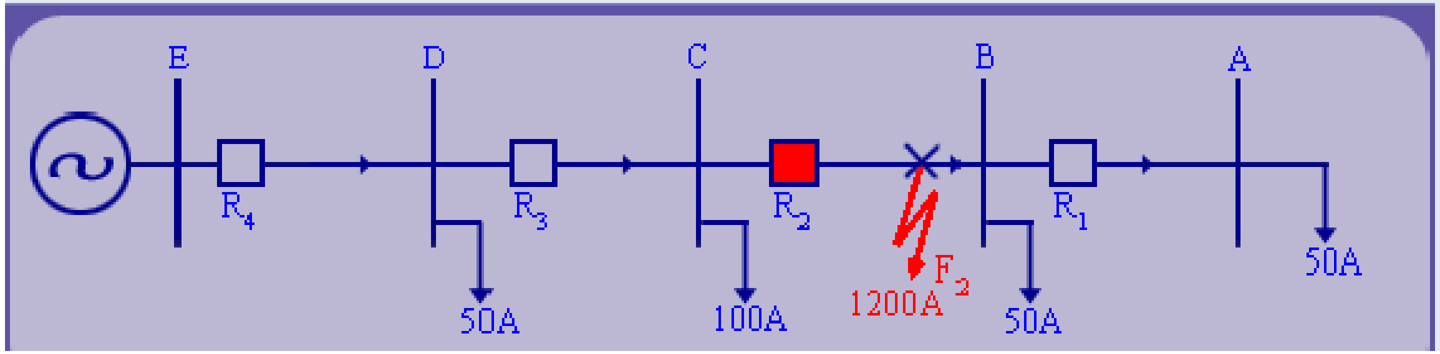


Fig 16.2 Relay Co-ordination for Phase fault

Step 3:

- # Relay to be set : R_3
- # Find operating time of R_2 for F_2 (Point 'c')



a_1	a_2	$a_3 = 1.25 \times a_2$	a_4	a_5	a_6		
Relay	Max Feeder segment load current (A)	Min limit on Pickup current (A)	Min Fault current at remote bus	Max limit on Pickup current	Max Fault current at remote bus	PSM (A)	TMS
R_1	50 $\xrightarrow{\times 1.25}$	62.5	250 $\xrightarrow{2/3^{rd}}$	$\frac{2}{3} \times 250 = 167$	500 (1)	160	0.025
R_2	100 $\xrightarrow{\times 1.25}$	125	650 $\xrightarrow{2/3^{rd}}$	167	1200 (2)	167	0.07
R_3	200 $\xrightarrow{\times 1.25}$	250	1100	433	2000 (3)	400	0.086

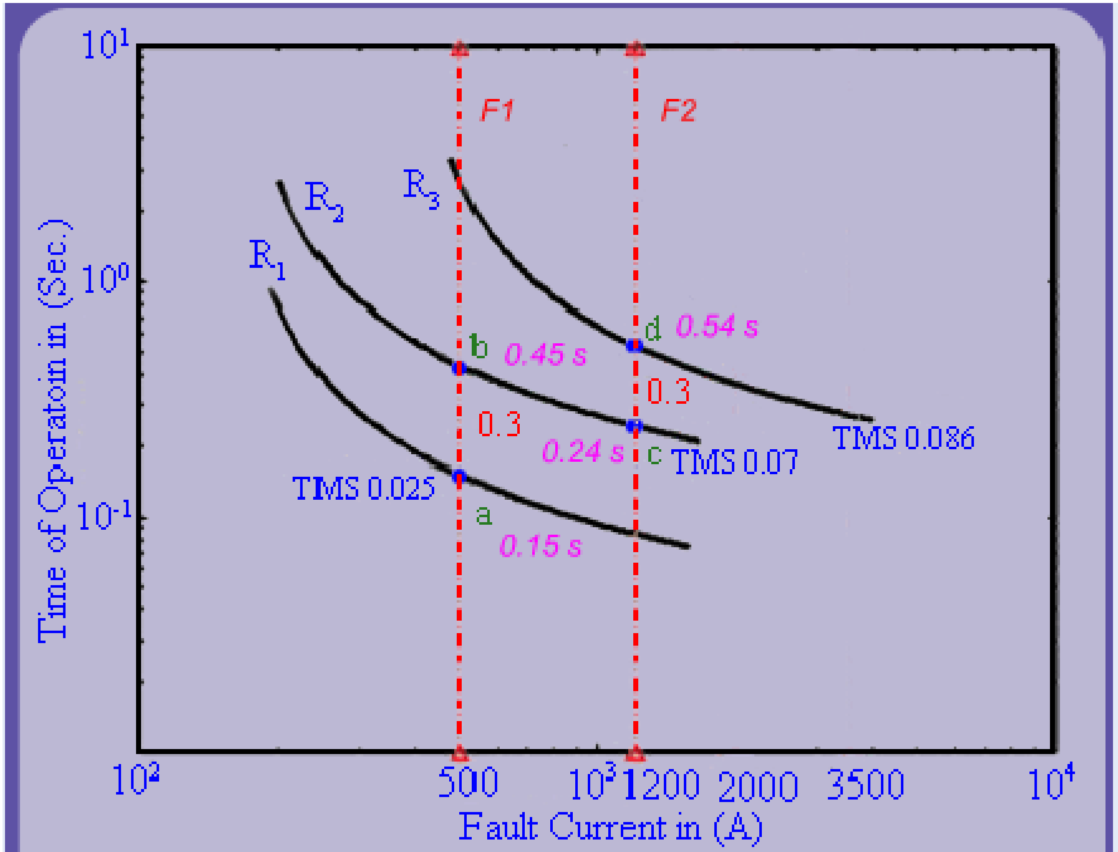
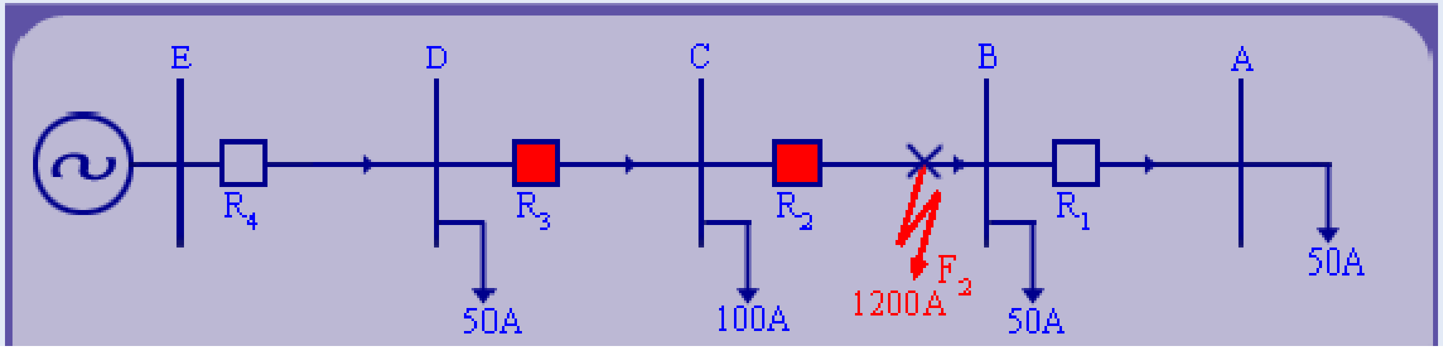


Fig 16.2 Relay Co-ordination for Phase fault

Step 3:

- # Relay R_3 must pickup for F_2
- # Pick up set at 400 A
- # R_3 should trip at [Time at point 'c'+CTI] (Locate point 'd' on TCC)
- # Find TMS (0.086) so that relay TCC passes through point 'd'



a_1	a_2	$a_3=1.25 \times a_2$	a_4	a_5	a_6		
Relay	Max Feeder segment load current (A)	Min limit on Pickup current (A)	Min Fault current at remote bus	Max limit on Pickup current	Max Fault current at remote bus	PSM (A)	TMS
R_1	50 x 1.25	62.5	250 2/3rd	$\frac{2}{3}\times 250 = 167$	500 (1)	160	0.025
R_2	100 x 1.25	125	650 2/3rd	167	1200 (2)	167	0.07
R_3	200 x 1.25	250	1100 2/3rd	433	2000 (3)	400	0.086
R_4	250 x 1.25	312.5	1600	733	3500	700	0.097

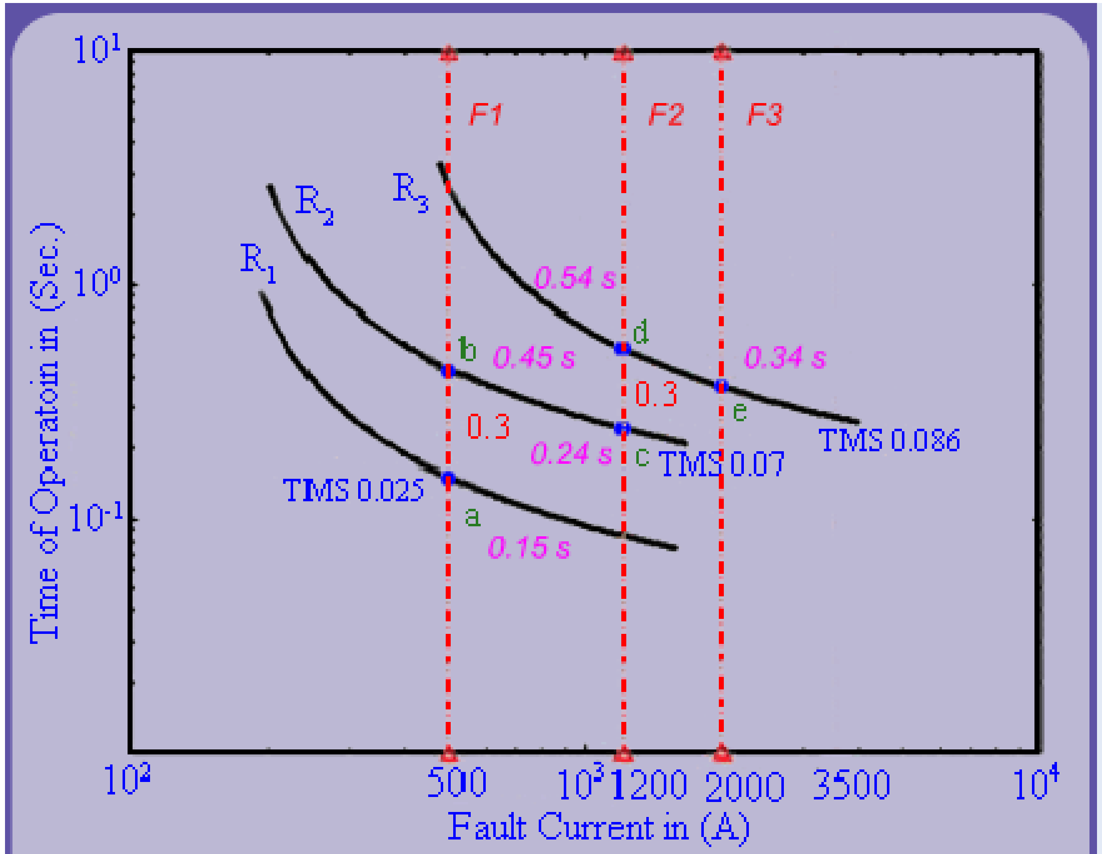
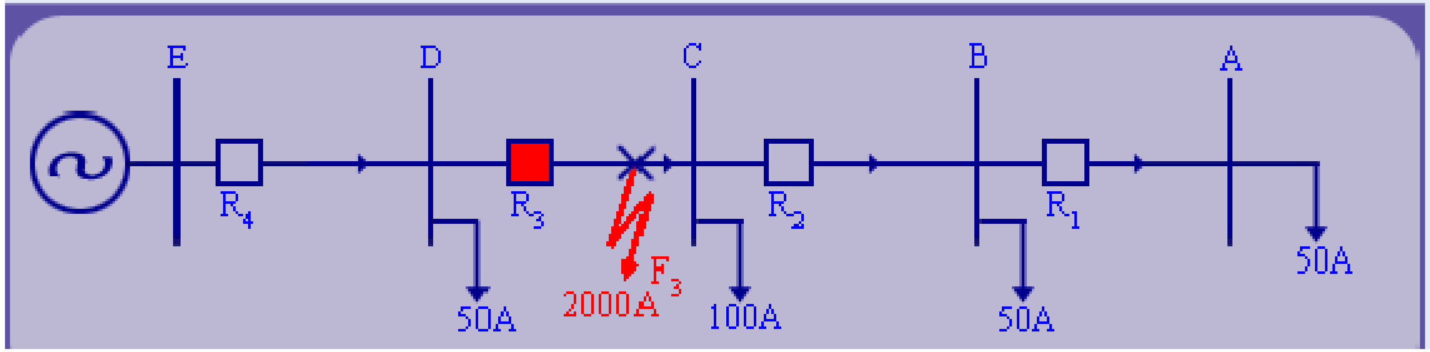


Fig 16.2 Relay Co-ordination for Phase fault

Step 4:

Relay to be set R_4
Find operating time of R_3 for F_3 (Point 'e')



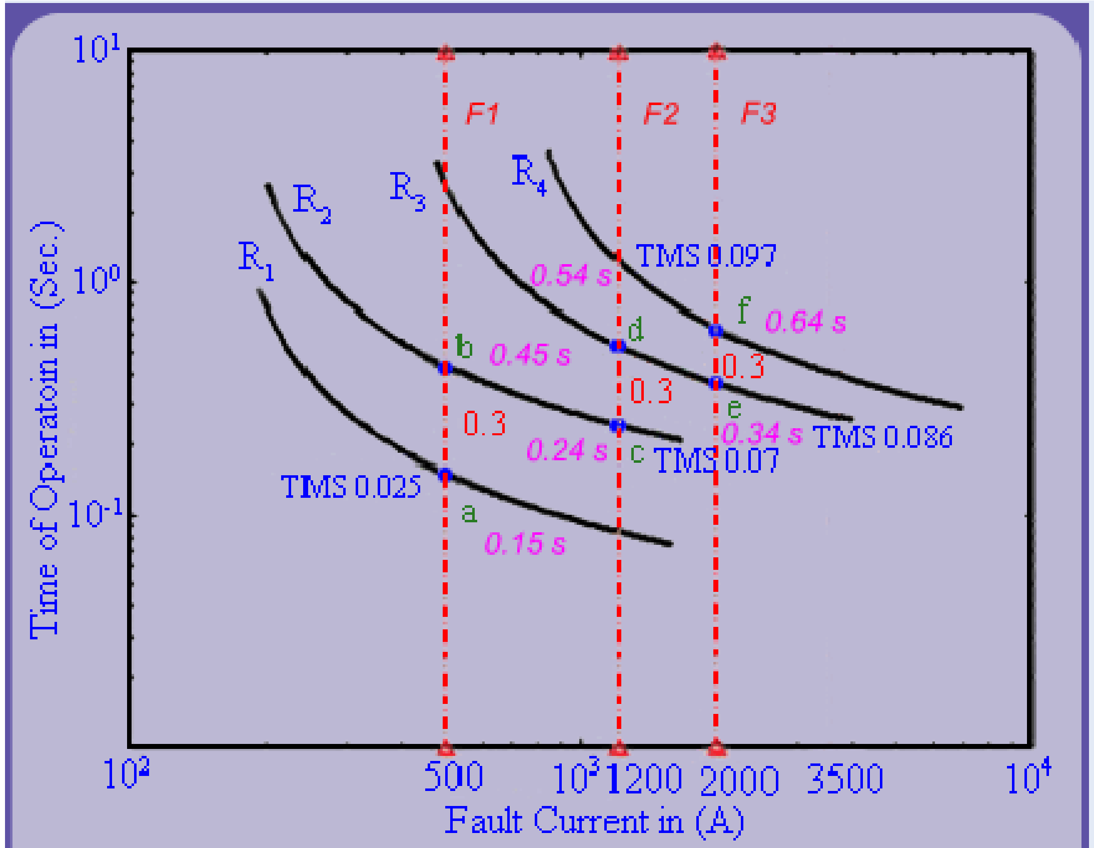
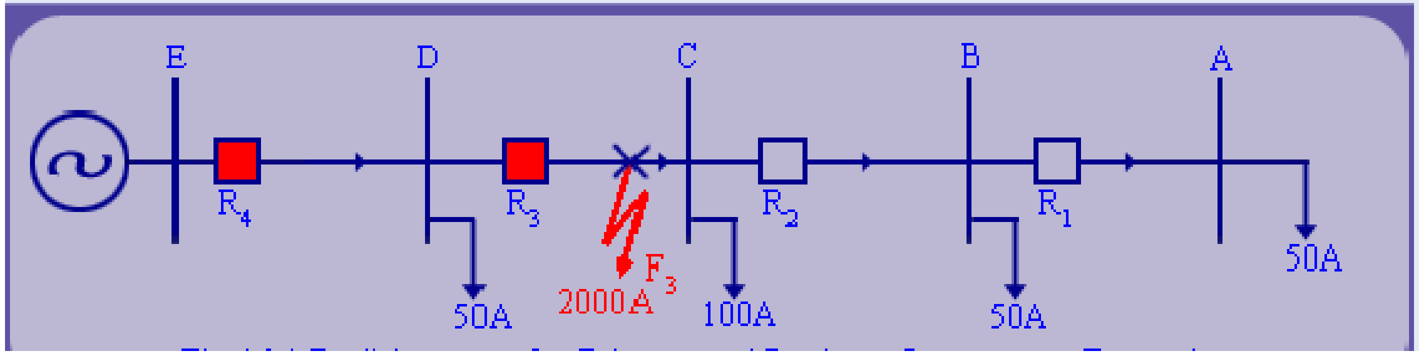


Fig 16.2 Relay Co-ordination for Phase fault

Step 4:

- # Relay R_4 must pick up for F_3
- # Pick up set at 700 A
- # R_4 should trip at [Time at point 'e'+CTI] (Point 'f' on TCC)
- # Find TMS (0.097) so that relay TCC passes through point 'f'



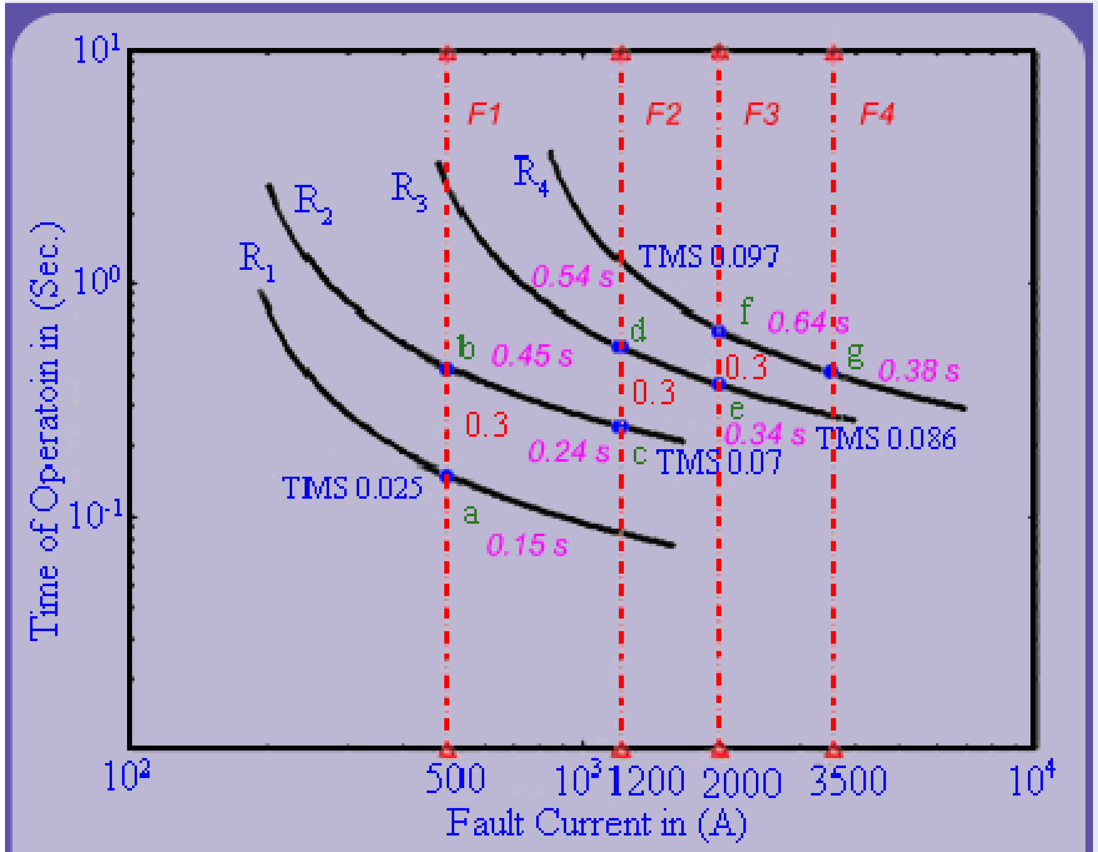
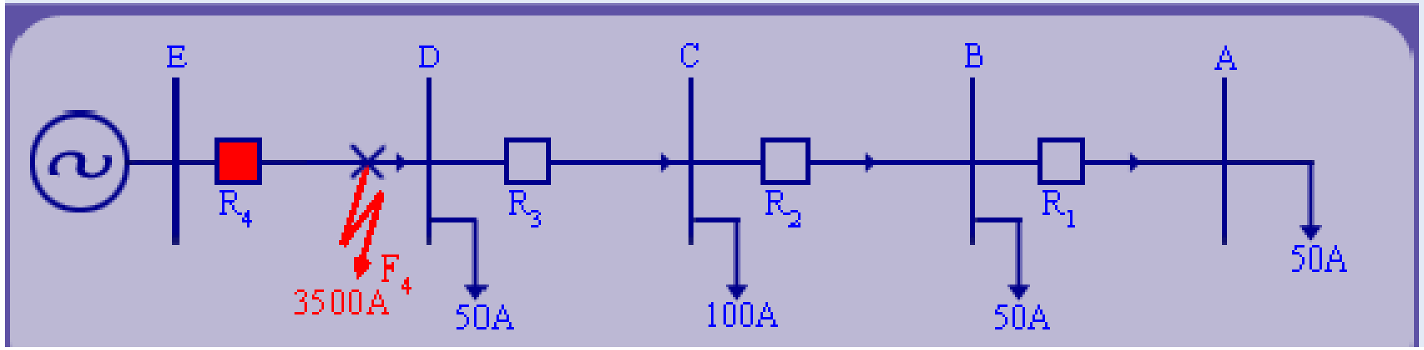


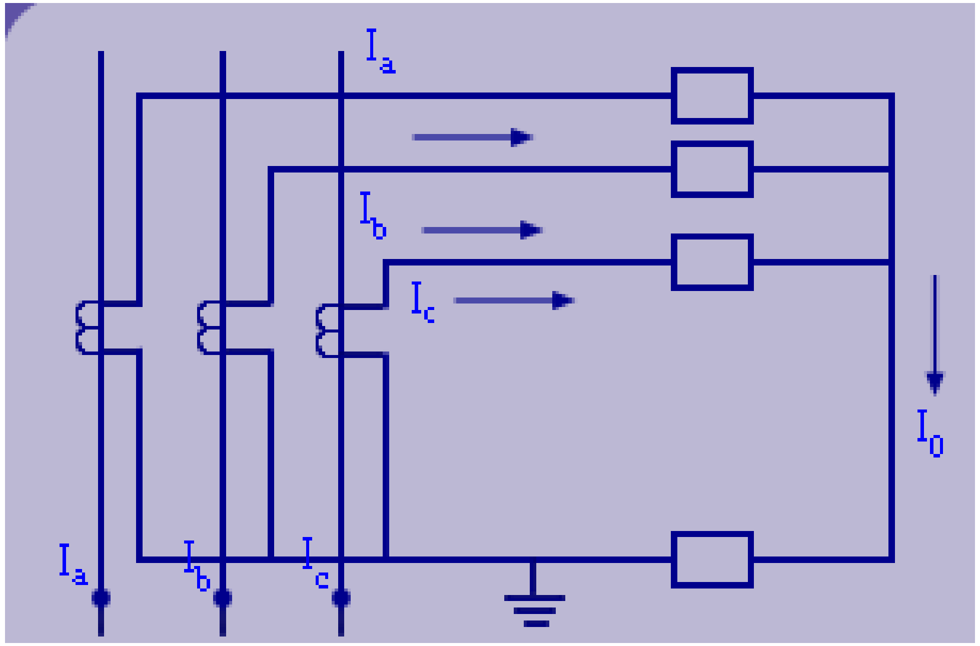
Fig 16.2 Relay Co-ordination for Phase fault

Step 4:

- # *Find operating time of R_4 for F_4 (Point 'g')*
- # *Relay coordination completes.*



Fault Type and CT burden



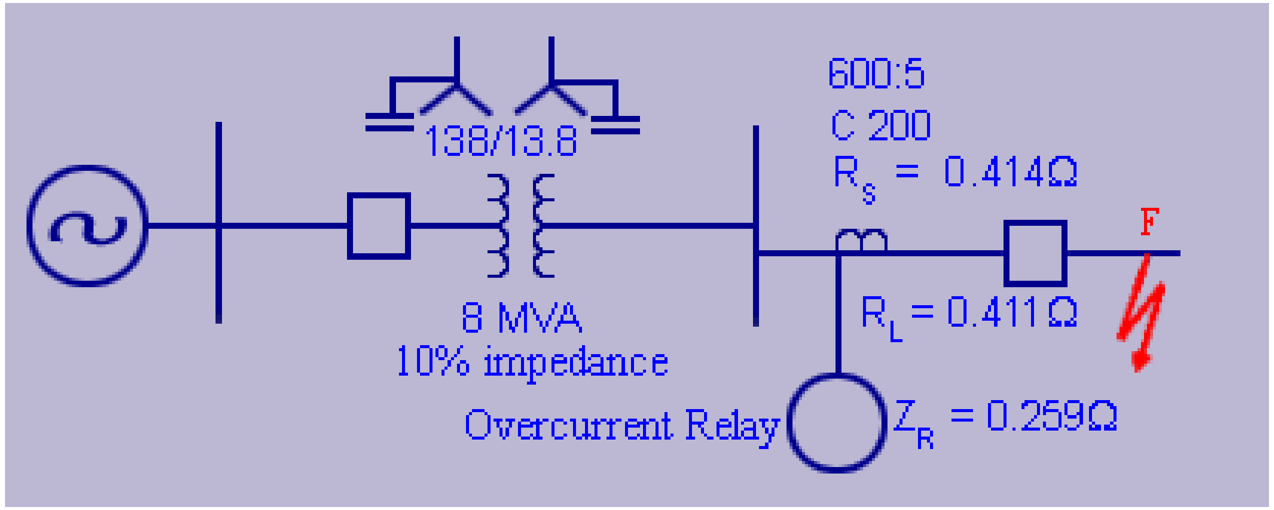
Consider a **three phase fault in WYE connected CT**. The current does not require an explicit return path. Therefore, only single lead wire resistance RL is taken into account. Then effective impedance seen by CT, Z = RS + RL + ZR.

phase to ground fault: fault current requires an explicit return path and hence the lead wire resistance RL has to be doubled. Effective impedance: Z = RS + 2RL + ZR

Fault Type and CT burden

Fault Type and Its Effects on CT burden		
Type of fault		
Connection	**3 - Phase or Phase to Phase**	**Phase to Ground**
Wye (connected at CT)	$Z = R_S + R_L + Z_R$	$Z = R_S + 2R_L + Z_R$
Delta (connected at CT)	$Z = R_S + 3R_L + 3Z_R$	$Z = R_S + 2R_L + 2Z_R$
Z	is the effective impedance seen by the CT	
R_S	is the CT secondary winding resistance and CT lead resistance; also includes any relay impedance that is inside the delta connection (ohms)	
R_L	is the circuit one-way lead resistance (ohms)	
Z_R	is the relay impedance in the CT secondary current path (ohms)	

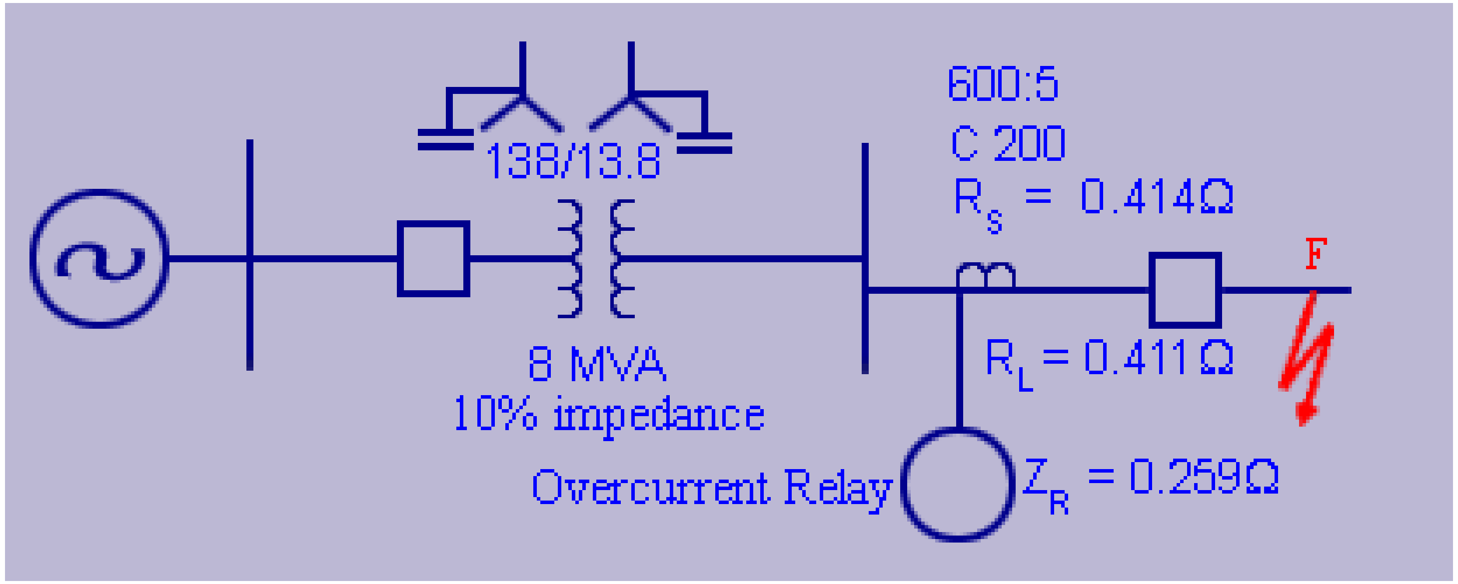
Example 2



1. A 8 MVA, 138/13.8 KV transformer is connected to an infinite bus. If a bolted three phase fault occurs at F, find out the fault current. The impedance of the transformer is 10% and location of the fault is close to the bus
2. If the distribution feeder has 600/5 C 200 CT with a knee point 100 Volt, calculate the voltage developed across CT and comment on its performance. CT secondary resistance is 0.414 Ω.

   Assume that (1) CTs are star connected (2) Lead wire resistance is 0.411Ω and relay impedance is 0.259 Ω .

Example 2



3. If the existing 8 MVA transformer is replaced with a new 28 MVA transformer with 10% leakage impedance, find out the new fault current. Will this new fault current lead to CT saturation?
4. In case CT saturates, comment on the performance of
   (a) Primary relay (b) back up relay (c) co-ordination between primary and back up relay pair.

Earth Fault Relays

Overcurrent Protection

Earth-fault Relays

- Used to protect feeder against faults involving ground.
  - Typically, earth faults are single line to ground and double line to ground faults.
  - For the purpose of setting and coordination, only single line to ground faults are considered.
- Maximum fault current line to ground is given by:

$$I_F = \frac{3E}{Z_{s1} + Z_{s2} + Z_{s0}}$$

- For identical sequence impedance:

$$I_F = \frac{E}{Z_{s1}}$$

Earth-fault Relays

- The I_F is identical to the bolted three phase fault current.
  - If however, $Z_{S0} < Z_{S1}$ then the bolted single line to ground fault current can be higher than the three phase fault current.
  - As we move away from the source, for a bolted fault, fault current reduces due to larger impedance. Since, for a feeder, zero sequence impedance can be much higher than the positive or negative sequence impedance, it is apparent that fault current for bolted fault reduces significantly as we go away from source.
  - If single line to ground fault has an impedance Z_F, then the fault current can fall even below the bolted line to ground fault value.

$$I_F = \frac{3E}{Z_{1,eq} + Z_{2,eq} + Z_{0,eq} + 3Z_F}$$

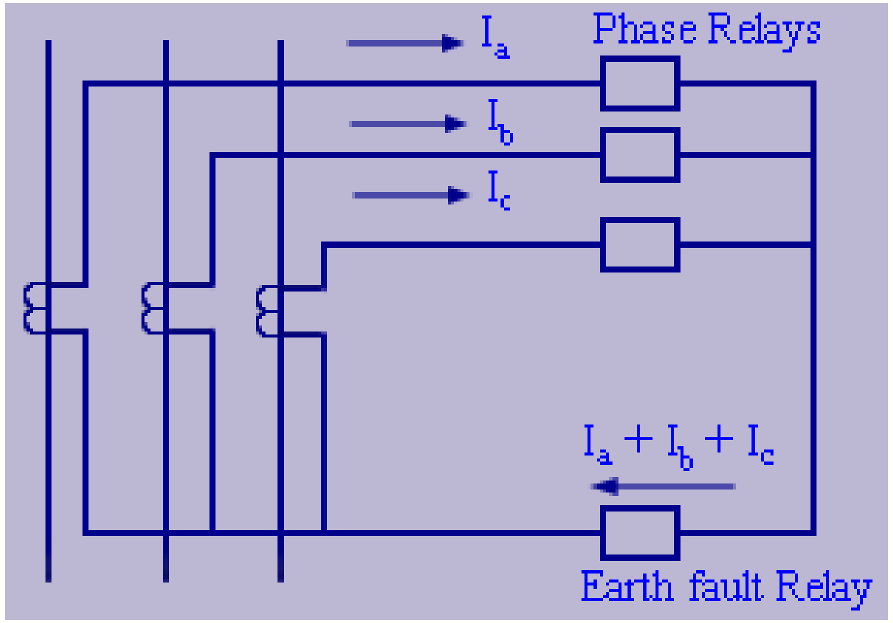
In contrast, for a balanced system, three phase fault current is independent of the value of Z_F.

Earth fault relays

- **<u>Important</u>**
  - Significant variation in earth fault current values and can be even below the load current due to large impedance to ground.
  - To provide sensitive protection, earth fault relays use zero sequence current rather than phase current for fault detection.
    - Note that the zero sequence component is absent in normal load current or phase faults. Hence, pickup with zero sequence current can be much below the load current value, thereby providing sensitive earth fault protection.

Earth fault relays

- Distribution systems are inherently unbalanced and therefore load current would also have a small percentage of zero sequence.
  - mandatory to keep the pick up current above the maximum unbalance expected under normal conditions.
  - Rule of thumb assume maximum unbalance factor to be between 5 to 10%.
- Earth fault relays will not respond to the three phase or line to line faults.
  - One earth fault relay is adequate to provide protection for all types of earth fault
  - Three phase relays are required to provide protection against phase faults
  - Thus with four relays complete overcurrent protection can be provided



Adaptive Relaying

- Protection scheme in which settings can adapt to the system conditions automatically, so that relaying is tuned to the prevailing power system conditions.
  - Traditionally, in overcurrent fault protection, one would like to choose pick-up current to be above the maximum possible load current and below minimum possible fault current. Sometimes, it may be quite difficult to obtain such 'comfort zones'. for relay settings.
- Load currents vary significantly from 'light loads' to 'peak load' conditions, one can increase 'sensitivity' of a overcurrent relay under light load conditions by safely reducing corresponding overcurrent pick up value. Such, adjustments makes relaying' adaptive'.

Adaptive Relaying

- In the present era, generation is being added to the distributed system directly. This also changes the fault level in the system directly.
- Presence or absence of grid and/or distributed generator will alter fault current levels drastically, and it would be impossible to achieve a single acceptable setting for distributed generators.
- However, if overcurrent relay could be made aware through communication that grid and/or DG is connected, it could choose the settings from a set of a present values and 'adaptive' to new load condition.
- Adaptive protection has not yet realized its full potential, and hence provides new opportunities for bright and innovative research in relaying.

Automatic Reclosing

- Faults (80-90%) in the overhead distribution system like flash over of insulators, temporary tree contacts , etc are temporary in nature taking a feeder or line permanent outage
  - lead to unnecessary long loss of service to customers.
- Many utilities use fast automatic re-closers for an overhead radial feeder without synchronous machines or with minimum induction motor load.
  - Presence of synchronous machines will require additional problem of synchro-check to be addressed.
  - The almost universal practice is to use three and occasionally four attempts to restore service before lock out

Automatic Reclosing

- The initial re-closure can be high speed (0.2 - 0.5 sec) or delayed for 3 - 5 seconds - allowing for de-ionization time for fault arc.
- If the temporary fault is cleared, then the service is restored. Otherwise, the relay again trips the feeder.
  - Then one or two additional time delayed re-closures are programmed on the reclosing relay.
  - Re-closers use three phase and single phase oil or vacuum circuit breakers for overhead distribution lines.
- With underground network, faults tend to be more often permanent and re-closers are not recommended.

Automatic Reclosing