POWER ENGINEERING TRAINING COURSE

ON

FAULT CURRENT CALCULATIONS, RELAY SETTING AND RELAY CO–ORDINATION

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FAULT CURRENT CALCULATION

1.0 PER UNIT(PU) AND PERCENTAGE QUANTITY(%) :

Per Unit quantity = Percentage quantity / 100

- **Quantity ⇒ Voltage, Current, MVA, Impedance**
- **e.g. Z = 23% ⇒ Z = 0.23 PU ; V = 102% ⇒ V = 1.02 PU**
- **Per Unit computation *slightly advantageous* over percentage computation.**

  - **Product of Two quantities expressed in PU**

    ⇒ Result also in PU 0.5 x 0.5 = 0.25
  - **Product of Two quantities expressed in %**

    ⇒ Result shall be divided by 100 to get %

    (50% x 50%) / 100 = 25%

- **Fault Level Calculations are generally performed using per unit only.**

1.1 **Per unit quantity**

Q(PU) = Q (ACTUAL) / Q(BASE)

e.g. V_ BASE = 6.6 kV; V_ACTUAL = 3.3 kV; ⇒ V = 0.5 PU

e.g. P_ BASE = 100 MVA; P_ACTUAL = 200 MW; ⇒ P = 2 PU

1.2 **Choosing base**

- **In general, MVA(3 ϕ) & Voltage (L to L) chosen as Base**

  Base current = Base MVA / (√3 Base Voltage)

  Base impedance = Base Voltage / (√3 Base Current)

$$= \frac{\text{Base Voltage}}{\sqrt{3}\ \dfrac{\text{Base MVA}}{\sqrt{3}\ \text{Base Voltage}}}$$

$$= (\text{Base Voltage})^2 / \text{Base MVA}$$

- **Base voltage changes on either side of transformer :**
  - **Choose Base Voltage as 11 kV and Base Power as 100 MVA**

- Transformer voltage ratio: 11 / 132 kV .
- On the HT Side of transformer, Base voltage is *automatically* 132 KV .
- You can not *Independently* choose another Base voltage on other side of transformer
- Base Power is 100 MVA on either side of Transformer.
- On low Voltage side

  Base Voltage = 11 kV

  Base MVA = 100

  Base Current = 100 / (√3 x 11) = 5.2486 kA

  Base Impedance = 11^2 / 100 = 1.21 Ω
- On High Voltage side :

  Base Voltage = 132 kV

  Base MVA = 100

  Base current = 100 / (√3 x 132)= 0.4374 kA

  Base impedance = 132^2 / 100 = 174.24 Ω

1.3 Advantages of calculations in per unit system

- Per Unit impedance of transformer is same whether referred to Primary or secondary
  - e.g. 11 / 33 kV, 50 MVA, Z = 10% (0.1 PU)
    - In PU, Z = 0.1 on either 11 kV or 33 kV Side
    - In Ohms,
      - On 11 kV side

        $Z_{BASE} = 11^2 / 50 = 2.42\ \Omega$

        $Z_{11} = Z_{BASE} * Z_{PU} = 2.42 * 0.1 = 0.242\ \Omega$
      - On 33 kV side :

        $Z_{BASE} = 33^2 / 50 = 21.78\ \Omega$

        $Z_{33} = Z_{BASE} * Z_{PU} = 21.78 * 0.1 = 2.178\ \Omega$
- Per unit impedance lies within a narrow band while ohmic values can be widely different.

- **Transformer 415 V to 400 kV and 500 KVA to 500 MVA,**

  Z lies between 5% (0.05 PU) to 15% (0.15 PU)

TRANSFORMER IMPEDANCE

KV	MVA	Z %	$Z_{BASE}\ \Omega$	$Z_{ACT}\ \Omega$
0.415	2	8	0.0861	0.0069
400	600	15	266.7	40.0

Z % Range = 15 / 8 = 1.9

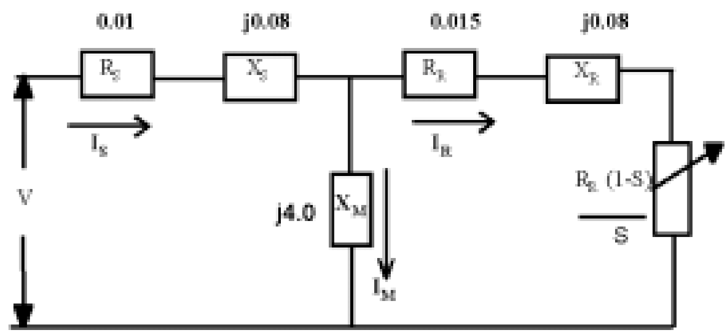
Z_{ACT} Range = 40 / 0.0069 = 5797

- **Generator 1 MVA to 500 MVA,**
  X'd lies between 15% (0.15 PU) to 35% (0.35 PU)

MVA	**18**	**48**	**106**	**160**	**230**	**353**	**495**	**600**	**645**	**775**
X'd	**0.35**	**0.25**	**0.19**	**0.25**	**0.32**	**0.33**	**0.24**	**0.25**	**0.31**	**0.24**

- **Induction Motor**

- EQUIVALENT CIRCUIT



- **Example : Motor Rating**

  6.6 kV ; 5 MW ; pf - 0.92 ; η- 0.95 ; 1485 RPM

  BASE MVA = 5 / (0.92 x 0.95) = 5.7208 MVA

  Z_{BASE} = BASE IMPEDANCE = 6.6^2 / 5.7208 = 7.6143 Ω

  Z_{ACTUAL} = Z_{BASE} x Z_{PU} Ω

  SLIP = (1500 – 1485) / 1500 = 0.01 (1%)

  FOR 2.5MW MOTOR, Z_{BASE} = 7.6143 x 2 = 15.2286 Ω

- **Example :**

		5MW **Z_{BASE} = 7.6143 Ω**	**2.5MW** **Z_{BASE} = 15.2286 Ω**
QUANTITY	**Z_{PU}**	**Z_{ACTUAL} Ω**	**Z_{ACTUAL} Ω**
R_S	**0.005**	**0.0381**	**0.0762**
R_R	**0.01**	**0.0761**	**0.1522**
X_S	**0.08**	**0.6091**	**1.2182**
X_R	**0.08**	**0.6091**	**1.2182**
X_M	**4.0**	**30.4572**	**60.9142**

- **Z_{ACTUAL} ⇒ Widely different for different motor ratings**

  Z_{PU} ⇒ Lies with in a close range for all sizes of motors

❖ **Per Unit : Only realistic way to solve big and practical problems.**

2.0 FAULT LEVEL CALCULATION PROCEDURE

- ❖ Step 1 : Draw SLD showing equipment rating and impedance.
- ❖ Step 2 : Choose Base MVA and Base Voltage.
- ❖ Step 3 : Convert all impedances in PU on common Base MVA and Base Voltage.
- ❖ Step 4: Draw impedance diagram showing impedances in PU.

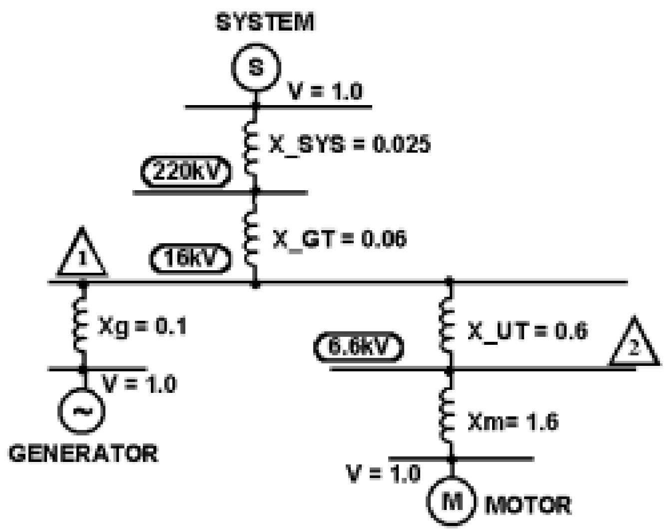
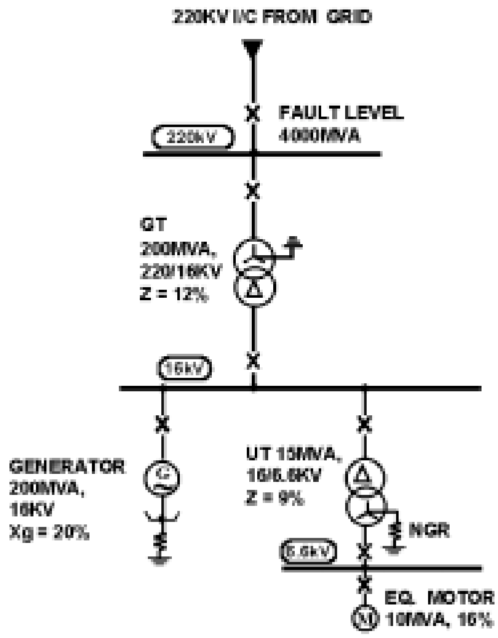


FIG._SC_15

- ❖ Step 5 : Do network reduction and find equivalent impedance at the point of fault , say, Z PU
- ❖ Step 6 : Evaluate fault current $I_{FAULT} = \frac{1}{Z}$ PU
- ❖ Step 7 : Convert fault current in PU to actual value in kA

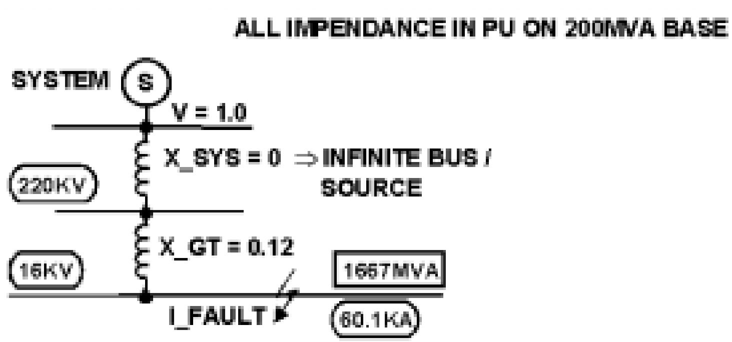
- System considered for simulation

  Typical auxiliary system of Power Plant



2.1 *EXAMPLE 1* :

- **Transformer Data : 16 kV / 220 kV, 200MVA, Z = 12%**
- **Ignore 220 kV Source Impedance**
- **Ignore rest of the network**
- **Consider fault on 16 kV Side of (Generator) Transformer**
- **Impedance diagram**



FIG_SC_12A

Base MVA = 200

Base Voltage = 16 kV

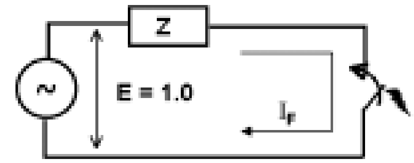
I_BASE = 200 / (√3 x 16) = 7.2171 kA

I_FAULT = 1/ Z_{PU} = 1 / (0.12 + 0) = 8.3333 PU

- Compared to I_{FAULT} (KiloAmps), I_{LOAD} is very less (Amps)
- Pre fault current assumed to be zero

$\therefore$ Pre fault voltage : 100% (1 PU)

$$\text{Current} = \frac{\text{Voltage}}{\text{Impedance}} = \frac{1.0}{Z}$$



Fault Current = I_FAULT x I_BASE
= 8.3333 x 7.2171 = 60.1422 kA

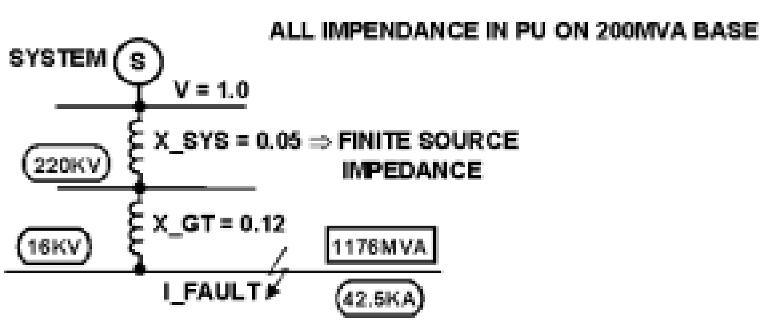
Fault MVA = $\sqrt{3}$ x 16 x 60.1422 = 1667 MVA

- If we have to analyze only One element, We need not have done all the above calculations, as Fault MVA is given by
  Fault MVA = 200 / 0.12 = 1667 MVA

- *But Realistic Problems :*
  - ❖ Large number of components
  - ❖ Different ratings
  - ❖ Different Impedances
  - ❖ Impedance Diagram & Analysis $\Rightarrow$ Only Practical Method
  - ❖ Method introduced
  - ❖ shall be well understood to make Fault Level Calculations.

2.2 EXAMPLE 2 :

- Same as Example 1 with Source Fault Level of 4000 MVA
- Impedance diagram



FIG_SC_12B

X_SYS = 200 / 4000 = 0.05 PU

I_FAULT = 1 / (0.12 + 0.05) = 5.8824 PU

I_BASE = 7.2171 kA { From Example 1}

Fault Current = I_FAULT x I_BASE

= 5.8824 x 7.2171 = 42.4539 kA

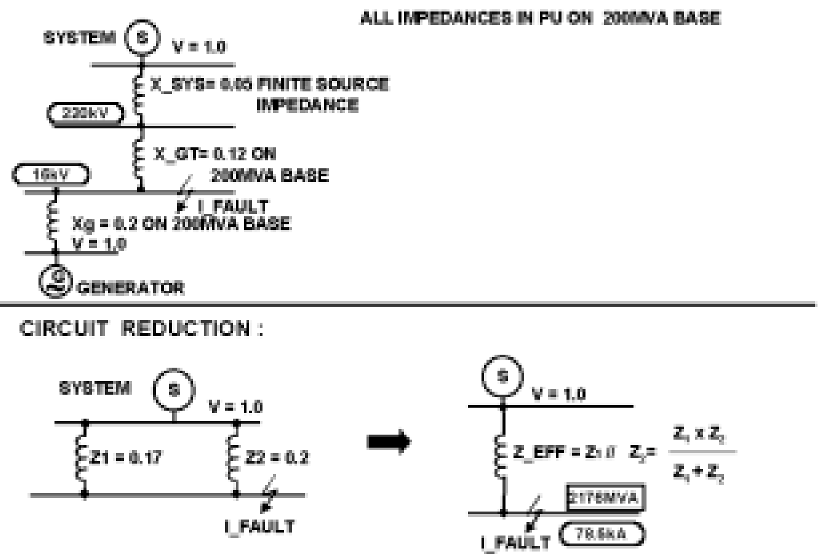
Fault MVA = √3 x 16 x 42.4539 = 1176 MVA

- **As in Example 1, fault level can be directly found as follows:**

  Fault Level = 200 / 0.17 = 1176 MVA

2.3 EXAMPLE 3 :

- **Same as Example 2 with 200 MVA Generator at 16 kV**
- **Generator data : 16 kV, 200MVA, Xg = 20%**
- **Impedance diagram**



FIG_SC_13

- **Impedance values on 200 MVA Base**

  Z1 = X_SYS + X_GT = 0.05 + 0.12 = 0.17

  Z2 = Xg = 0.2

  Z_EFF = Z1 || Z2 = 0.0919 PU

  I_FAULT = 1 / 0.0919 = 10.8814 PU

I_BASE = 7.2171 kA { From Example 1 }

Fault Current = I_FAULT x I_BASE

= 10.8814 x 7.2171 = 78.5322 kA

Fault MVA = $\sqrt{3}$ x 16 x 78.5322 = 2176 MVA

ANOTHER APPROACH

Contribution from System (Example 2) = 1176 MVA

Contribution from Generator = 200 / 0.2 = 1000 MVA

Fault Level = 2176 MVA

2.4 EXAMPLE 4 :

- Same as Example 3 with 15 MVA Unit Transformer (UT)
- Transformer data : 16 kV / 6.6 kV, 15 MVA, Z = 9%
- Problem : UT Rating (15 MVA) different from Generator or GT Ratings (200 MVA)
- To solve : Choose a common Base
- Choose Base MVA = 100
- To convert impedance from one Base to another Base

$Z_1 \Rightarrow$ (BASE MVA_1) $\Rightarrow$ (BASE kV_1)

$Z_2 \Rightarrow$ (BASE MVA_2) $\Rightarrow$ (BASE kV_2)

$$Z_2 = \frac{(\text{BASE } kV_1)^2}{(\text{BASE } kV_2)^2} \; \frac{(\text{BASE } MVA_2)}{(\text{BASE } MVA_1)} \; Z_1$$

❖ Usually (Base kV) is same or nearly same through out the system $\Rightarrow$ (BASE kV_1) = (BASE kV_2)

$$Z_2 = \frac{(\text{BASE } MVA_2)}{(\text{BASE } MVA_1)} \; Z_1$$

❖ e.g. Z = 10% (0.1 PU) on 150 MVA BASE

On 75 MVA BASE, Z = (75 / 150) x 0.1 = 0.05 PU

❖ Higher the Base $\Rightarrow$ Higher the impedance

Lower the Base $\Rightarrow$ Lower the impedance

- **Express impedance on Common Base MVA of 100**

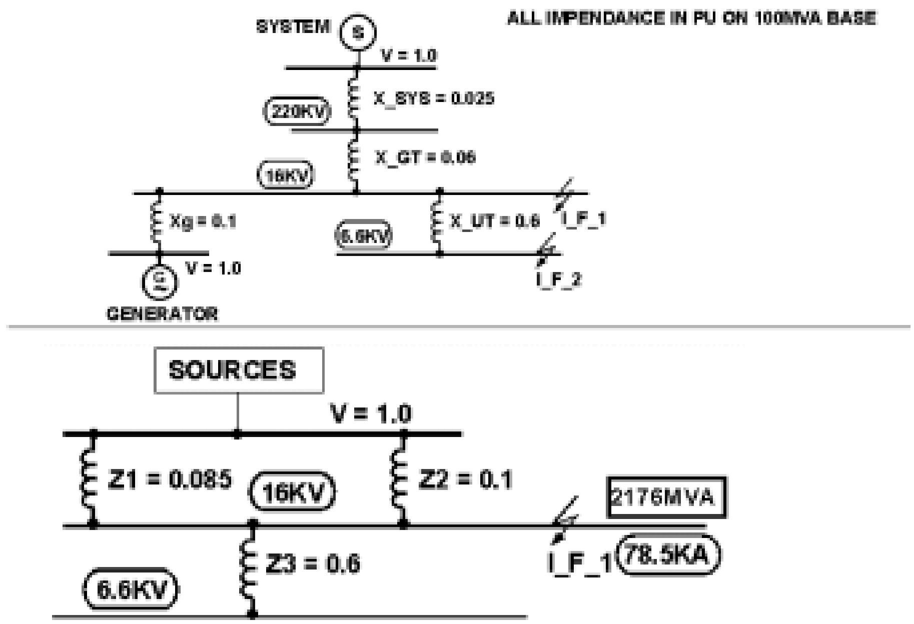
X_SYS = 100 / 4000 = 0.025 PU

X_GT = (100 / 200) x 0.12 = 0.06 PU

X_GEN = (100 / 200) x 0.2 = 0.1 PU

X_UT = (100 / 15) x 0.09 = 0.6 PU

- **Impedance diagram**



FIG_SC_14

- ***Fault On 16 kV Bus :***

SOURCES : From 220 System through GT
From 200 MVA Generator
{ No source connected on UT 6.6 kV side }

$$Z\_EFF = \frac{0.085 \times 0.1}{0.085 + 0.1} = 0.0459 \text{ PU}$$

I_F_1 = 1 / 0.0459 = 21.7647 PU

I_BASE = 100 / (√3 x 16) = 3.6084 kA

Fault current = I_FAULT x I_BASE

= 21.7647 x 3.6084 = 78.5357 kA

Fault MVA = √3 x 16 x 78.5357 = 2176 MVA

Same as obtained in Example 3, with 200 MVA Base

- ***Fault on 6.6 kV Bus :***

  I_F_2 = 1 / (0.0459 + 0.6) = 1.5482 PU

  I_BASE = 100 / (√3 x 6.6) = 8.7477 kA

  Fault current = 1.5482 x 8.7477 = 13.5432 kA

  Fault MVA = √3 x 6.6 x 13.5432 = 154.8 MVA

  ❖ **Ignoring source impedance for UT**

  Fault MVA = 15 / 0.09 = 166.7 MVA

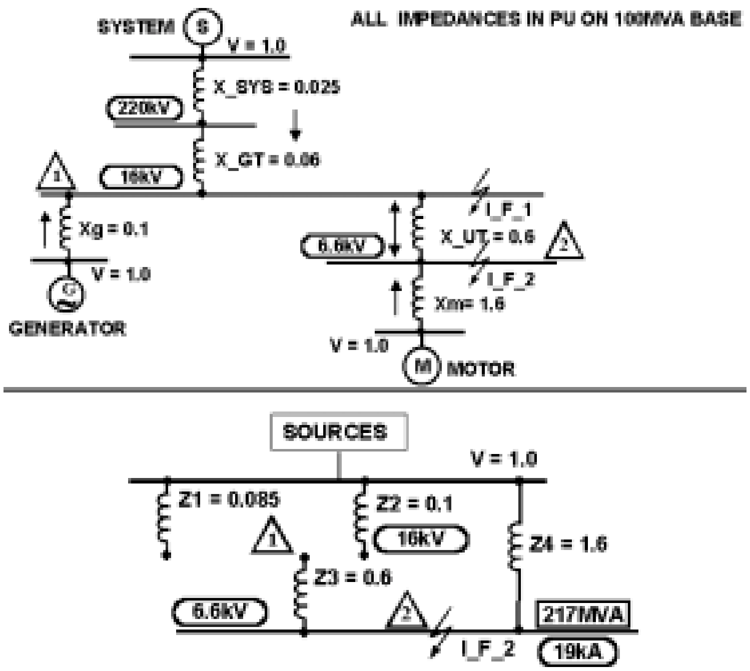
  Fault current = 166.7 / (√3 x 6.6) = 14.58 kA

2.5 EXAMPLE 5 :

- **Same as Example 4 with 10 MVA motor load on UT Bus**
- **Equivalent Motor : 10 MVA, Xm = 16% (0.16 PU)**
- **On Common Base of 100 MVA**

  Xm = (100/10) x 0.16 = 1.6 PU

- **Impedance diagram**



FIG_SC_15

❖ **Fault on 6.6 kV Bus**

SOURCES : From 220 kV System

From 200 MVA Generator

From 6.6 kV equivalent Motor

$$Z\_A = Z1 \parallel Z2 = \frac{Z1 \times Z2}{Z1 + Z2} = \frac{0.085 \times 0.1}{0.085 + 0.1} = 0.0459$$

Z_B = Z_A *in Series with* Z3 = 0.0459 + 0.6 = 0.6459

$$Z\_C = Z\_B \parallel Z4 = \frac{Z\_B \times Z4}{Z\_B + Z4} = \frac{0.6459 \times 1.6}{(0.6459 + 1.6)} = 0.4602 \text{ PU}$$

I_F_2 = 1 / 0.4602 = 2.1730 PU

I_BASE @ 6.6 kV = 8.7477 kA { FROM EXAMPLE 4}

Fault current = 2.1730 x 8.7477 = 19.0088 kA

Fault MVA = √3 x 6.6 x 19.0088 = 217.3 MVA

ANOTHER APPROACH :

Fault level without motor contribution (Example 4) = 154.8 MVA

Motor contribution = 10 / 0.16 = 62.5 MVA

Total Fault Level = 217.3 MVA

❖ ***Fault On 16 kV Bus :***

$$Z\_A = Z1 \parallel Z2 = \frac{Z1 \times Z2}{Z1 + Z2} = \frac{0.085 \times 0.1}{0.085 + 0.1} = 0.0459$$

Z_D = Z3 *in series with* Z4 = 0.6 + 1.6 = 2.2

$$Z\_E = Z\_A \parallel Z\_D = \frac{Z\_A \times Z\_D}{Z\_A + Z\_D} = \frac{0.0459 \times 2.2}{(0.0459 + 2.2)} = 0.045 \text{ PU}$$

I_F_1 = 1 / 0.045 = 22.2222 PU

I_BASE @ 16 kV = 3.6084 kA { FROM EXAMPLE 4}

Fault current = 22.2222 x 3.6084 = 80.1866 kA

Fault MVA $= \sqrt{3} \times 6.6 \times 80.1866 = 2222$ MVA

NOTE **:**

Fault current @ 16 kV without considering motor contribution

= 78.5357 kA [Example 4]

Difference due to Motor contribution = 80.1866 - 78.5357

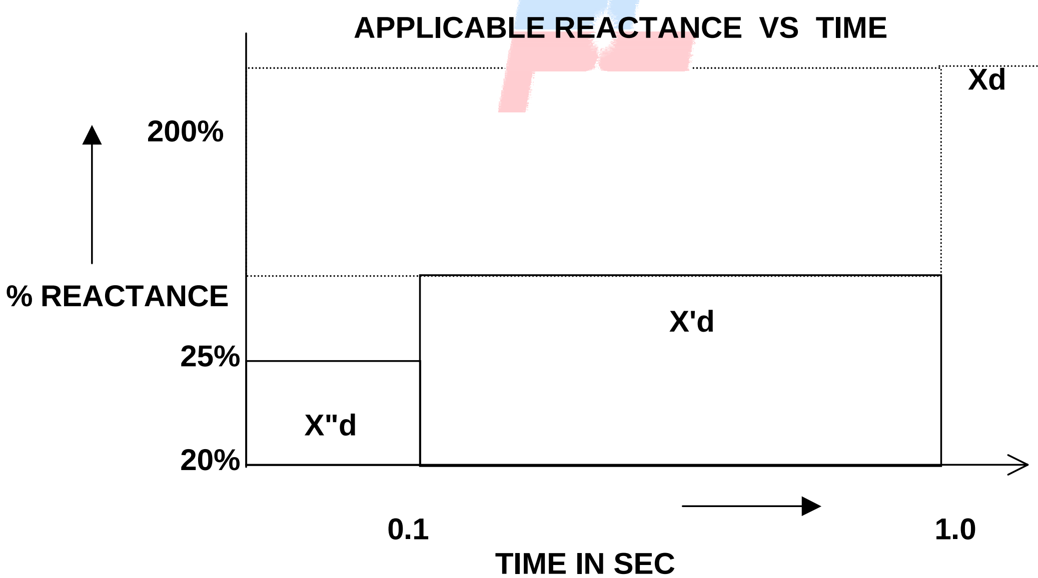
= 1.6509 kA ($\cong$ 2%)

< Insignificant >

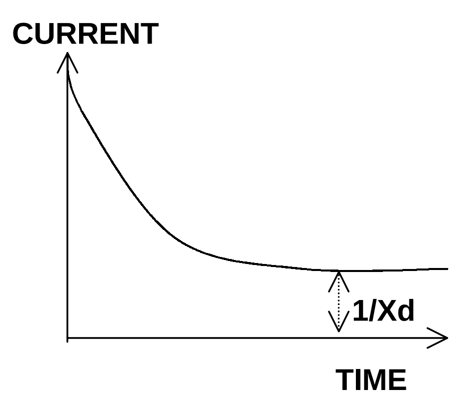
Generally the contribution from motors on a bus directly connected to the faulted bus is significant and the contribution from motors on buses connected to the faulted bus through transformers is insignificant.

3.0 SHORT CIRCUIT CONTRIBUTION OF EQUIPMENT :

- ***GENERATOR :***
  - ❖ **Subtransient reactance X"d → 20%**
    - ❖ **Used for breaker rating calculations**
    - ❖ **Valid for T < 100 milliseconds**
  - ❖ **Transient Reactance X'd → 25%**
    - ❖ **Used for relay coordination and motor starting studies**
    - ❖ **Valid for 0.1 < T < 1.0 Sec**
  - ❖ **Synchronous Reactance Xd → 200%**
    - ❖ **Valid for T >> 1 Sec**

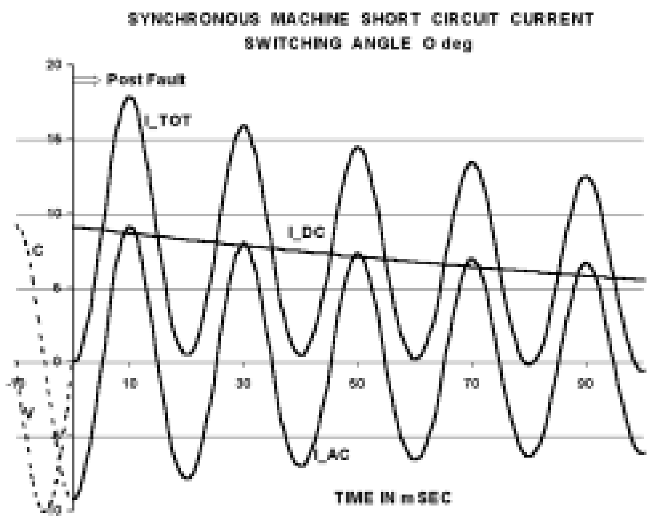


❖ **Fault current of synchronous generator does not fall to zero but reaches steady state value (→ 1.0 / Xd)**



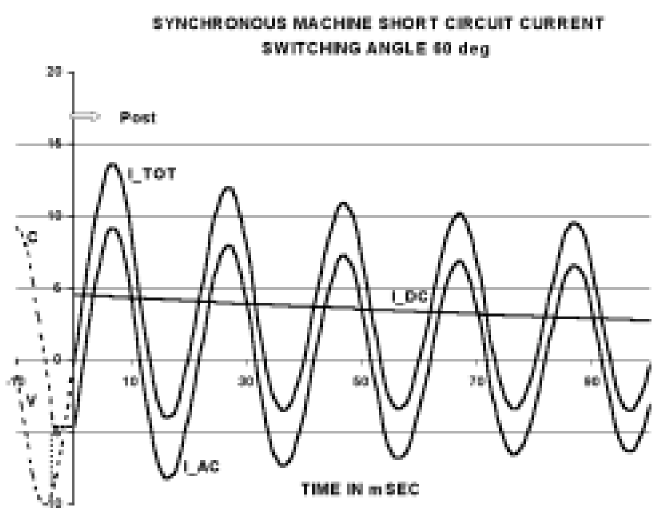
- **Short Circuit Current Vs Time Plot**

- **FIG_SC_16 : Short circuit @ switching angle 0°**
  Maximum DC (e.g. 9.2 PU)
  Maximum Peak Current at half cycle (e.g.17.9 PU)



FIG_SC_16

- **FIG_SC_17 : Short Circuit @ switching angle 60°**
  DC less (e.g. 4.6 PU)
  Peak Current Less (e.g.13.7 PU)



FIG_SC_17

❖ Short Circuit @ switching angle 90° .

i.e. Short Circuit @ Voltage maximum or minimum

DC is practically Zero; only decaying SYM RMS current flows

(1 / X"d) ⇒ (1 / X'd) ⇒ (1 / Xd)

- *INDUCTION MOTOR :*

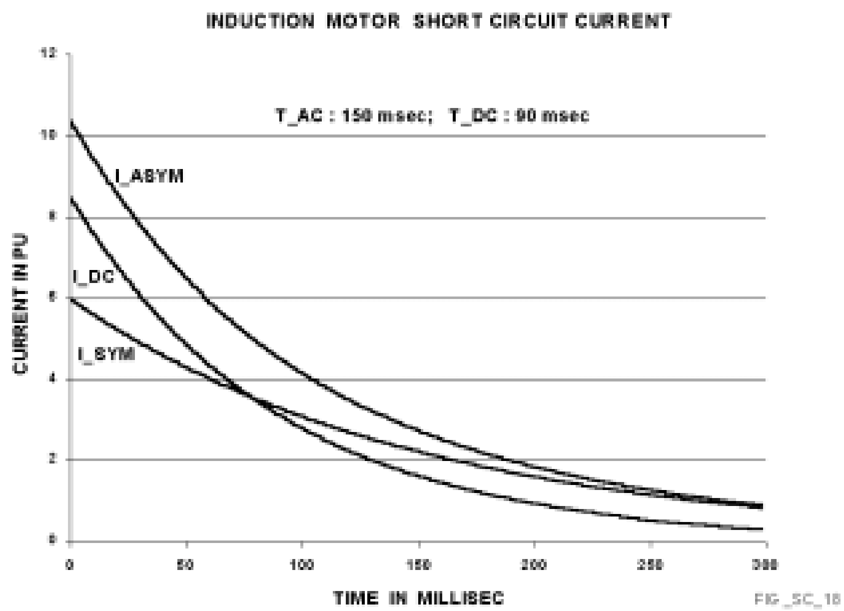
❖ Transient Reactance Xm = X'd

❖ IF I_{ST} is starting current (Say 5.0 PU)

$X'd = 1 / I_{ST} = 1 / 5 = 0.2$ PU

❖ Motor does not have external source of excitation fault current falls to nearly zero after 200 to 300 millisecond

❖ Typical short circuit current profile of induction motor



FIG_SC_18

- *Motor Contribution For Breaker Sizing Calculations :*

❖ Significant for Make duty (or Latch duty) :

Current that breaker has to carry after1/2 cycle

❖ Less significant for Break duty :

Current that breaker has to break at ~ 5 cycles

- ***Motor Contribution For Relay Coordination Studies :***
  - **Insignificant and can be ignored**

X.X.X

4.0 FAULT CURRENT CONSIDERATIONS IN RELAY COORDINATION STUDIES :

- **Do *not* base your calculations on breaker ratings**
- **Breaker rating can be 26 kA**

  But actual fault current magnitude can be 10 kA
- **Relay settings done with I_F = 26 kA may not hold good when fault current I_F = 10 kA**
- **Fault MVA and Fault Current**
  - **Fault MVA $\Rightarrow$ Out Moded Concept**
  - **Standards discourage their usage**
  - **40 kA breaker and not 500 MVA breaker**
  - **But for 'historical' reasons, power system engineers still use this term**

MVA = $\sqrt{3}$ x V x I_{FAULT}

MVA : Fault Level in MVA

V : Pre-fault voltage in kV

I_{FAULT} : Post-fault current in kA

I_PU = 1 / Z_PU

I_BASE = MVA_BASE / ($\sqrt{3}$ x V_BASE)

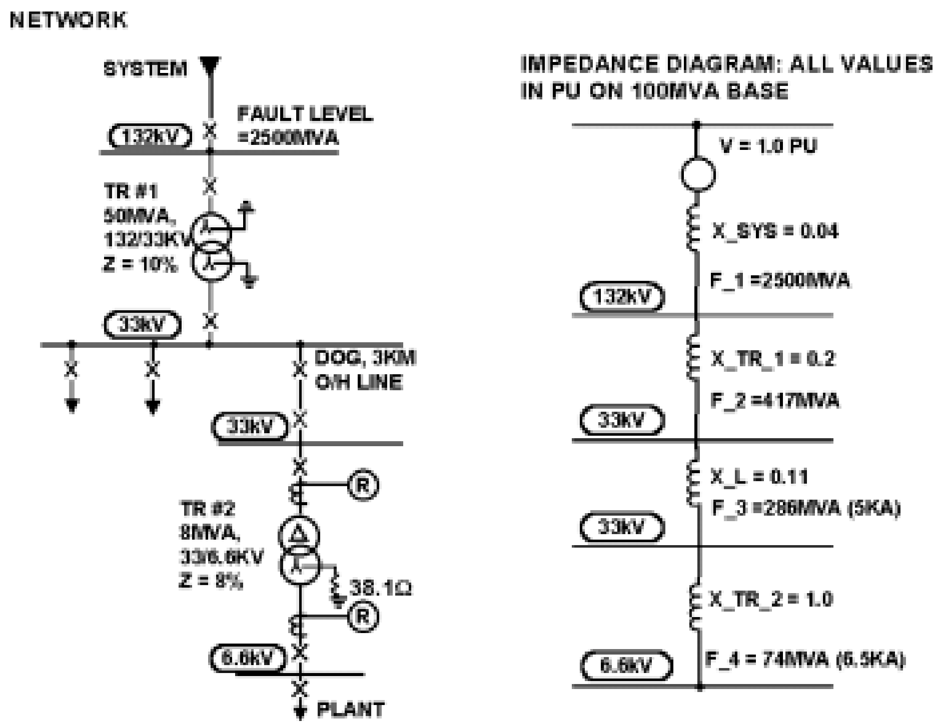
FAULT MVA = $\sqrt{3}$ x V_BASE x I_{FAULT}

= $\sqrt{3}$ x V_BASE) x I_PU x I_BASE

$$= \sqrt{3} \times V\_BASE \times \frac{1}{Z\_PU} \times \frac{MVA\_BASE}{\sqrt{3} \times V\_BASE}$$

= MVA(BASE) / Z_PU

- **Sample system for study :**



FIG_SC_19

- ***DATA :***

  ❖ **Fault level of 132 kV system : FL = 2500 MVA**

  ❖ **Transformer TR1 : 132 / 33 kV; 50MVA; X = 10%**

  ❖ **Over Head Line : 33 kV**

  Conductor – DOG; length – 3KM; X = 0.4 Ω / KM

  ❖ **Transformer TR2 : 33 / 6.6 kV; 8MVA; X = 8%**

- **Per Unit Impedance**

  ❖ **Choose Base MVA = 100**

  System impedance XSYS = 100/2500 = 0.04 PU

  Trans. TR1 impedance XTR1 = (0.1/50) x 100 = 0.2 PU

  O / H Line Impedance : X = 3KM x 0.4 Ω / KM = 1.2 Ω

  Base Impedance at 33 kV = X_B = 33^2 / 100 = 10.89 Ω

  O/H Line Impedance : XL = 1.2 / 10.89 = 0.11 PU

  Trans. TR_2 Impedance XTR2 = (0.08 /8) x 100 = 1.0 PU

- ***FAULT LEVEL CALCULATIONS (3φ to GROUND) :***

  - **Fault on HT Side of TR_1 (132 kV)**

    Fault Level F1 = 100 / 0.04 = 2500 MVA

  - **Fault on LT Side of TR_1 (33 kV)**

    Fault Level F2 = 100 / (0.04 + 0.2) = 417 MVA

    Fault current = 417 / (√3 x 33) = 7.3 kA

    Assuming Infinite Bus behind Transformer TR_1

    Fault Level F2 = 50 / 0.1 = 500 MVA

  - ***Fault on HT side of TR_2 (33 kV) :***

    Fault Level F3 = 100/ (0.04 + 0.2 +0.11) = 286 MVA

    Fault Level at sending end of the line : 417 MVA (100%)

    Fault Level at receiving end of the line : 286 MVA (69%)

    - **Depending on type of conductor and line length, receiving end fault level can be very different from sending end fault level**

  - ***Fault on LT Side of TR_2 (6.6 kV) :***

    Fault Level F_4 = 100 / (0.04 + 0.2 + 0.11 + 1.0) = 74 MVA

    Fault Current = 74 /(√3 x 6.6) = 6.5 kA

    Assuming infinite bus behind transformer TR_2

    Fault Level F4 = 8 / 0.08 = 100 MVA

    Fault current = 100 / (√3 x 6.6) = 8.7kA

    Actual fault current = 6.5 kA

❖ **Current for fault on 6.6 kV Side Of Transformer = 6.5 kA**

Reflected current flowing on 33 kV side of Transformer

= (6.6/33) x 6.5 = 1.3 kA

Fault level at 33 kV side of transformer = 286 MVA

Current for fault on 33 kV side of transformer

= 286 / (√3 x 33) = 5 kA

❖ **Relay located on 33 kV side of Transformer**

⇒ **Senses 1.3 kA for fault on 6.6 kV side**

⇒ **Senses 5 kA for fault on 33 kV side**

⇒ **This is the basis for discrimination by current in Relay Co-ordination**

⇒ **Discrimination by current obtained naturally because of transformer impedance**

- ***UNBALANCED FAULTS :***

❖ **Shunt Faults : Faults involving Phase to Phase or phase to ground**

- **Example : L to L, L to G, LL to G, LLL to G**

❖ **Series Faults : Faults on same phase not involving ground**

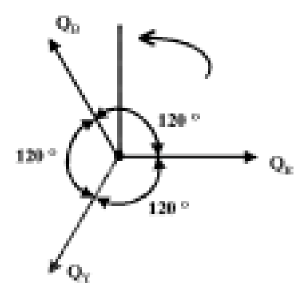
- **Example : Single Phasing, Open Conductor, One Pole Open, Two Poles Open**

- **Shunt Faults ⇒ Large fault current flow. Used for Relay Coordination**
- **(3φ to G) fault studies ⇒ Phase Over Current Relay Coordination**
- **Majority of faults (≅ 70%) ⇒ Line To Ground Fault**
- **(L to G) fault studies ⇒ Ground Over Current Relay Coordination**
- **Analysis of unbalance faults: symmetrical (sequence) components**
- **C L Fortescue ⇒ Introduced the concept in 1918**

- **Wagner & Evans fully developed applications in 1930s**
- **Three Balanced Vectors Q_R , Q_Y , Q_B**
- **Equal magnitude and 120° apart**

  $\angle Q_{RY} = \angle Q_{YB} = \angle Q_{BR} = 120°$

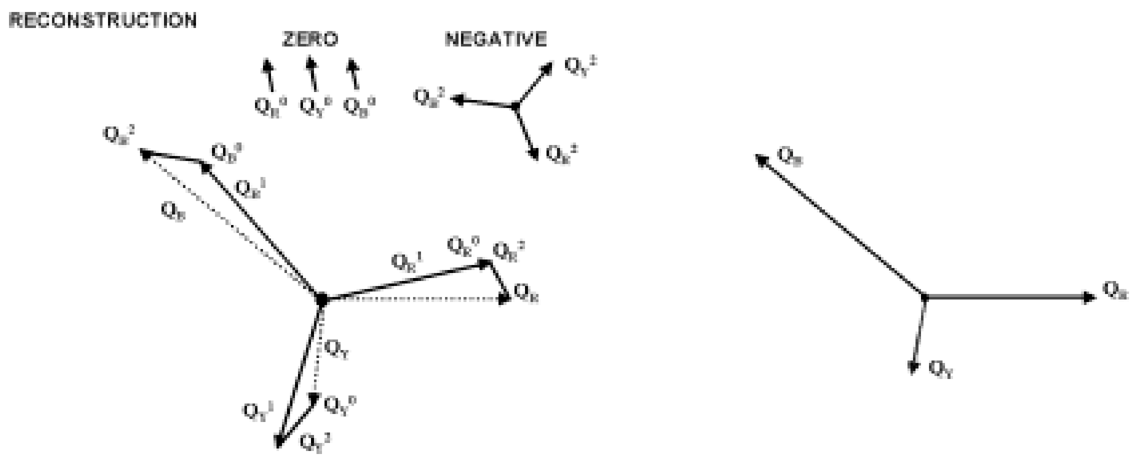
  $|Q_R| = |Q_Y| = |Q_B|$



- **Three Unbalanced Vectors**

  Q_R , Q_Y , Q_B

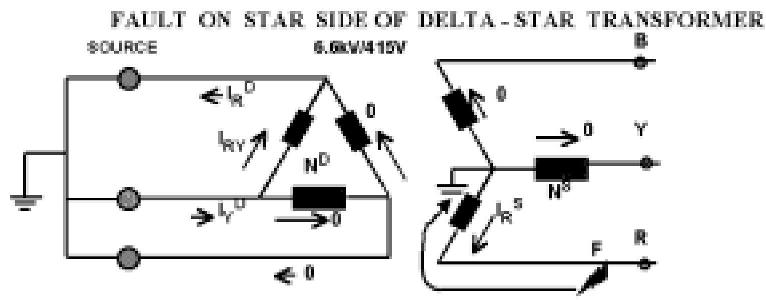
- **Magnitudes** $|Q_R| \neq |Q_Y| \neq |Q_B|$
- **Angles between vectors ≠ 120°**



- (+VE) Seq Current ⇒ Normal current in balanced system
  Phase rotation : Convention - Anti Clockwise.
- (-VE) Seq Current ⇒ Reversed Phase Rotation (Clockwise)
- (ZERO) Seq Current ⇒ Current flowing in Ground circuit
  Ground Relays respond to this current.

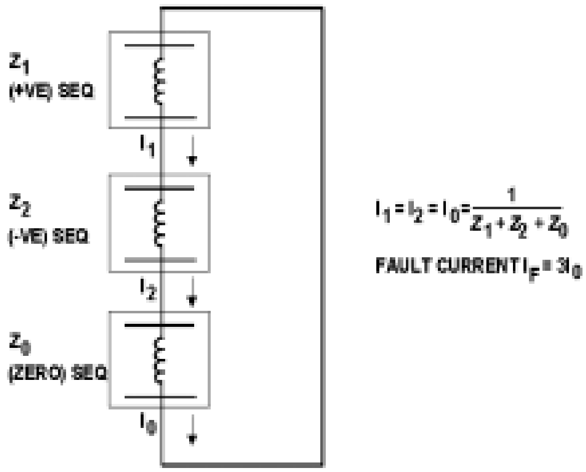
- ***Transformer vector group important***
  - **Example : L to G Fault On Star Side Of (Star-Delta) transformer appears as L to L fault on Delta side of transformer !**

  - **FIG_SC_24**



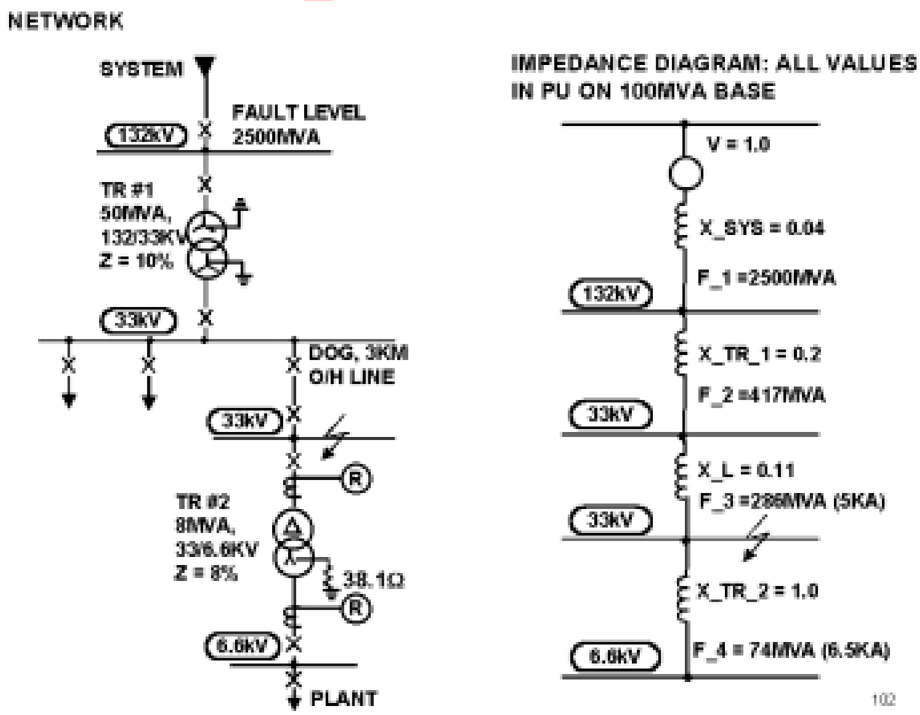
FIG_SC_24

- **Delta offers natural break for Zero Sequence (Ground Fault) currents**
- **For Line To Ground Fault, Sequence Interconnection**



FIG_SC_20

- **Line to Ground fault on 6.6 kV side of transformer of sample system**



FIG_SC_19

- **Assume, for the present 6.6kV side is solidly grounded**
  - **(+VE) Seq Impedance = Z_1 = 0.04 + 0.2 + 0.11 + 1.0 = 1.35 PU**
  - **(-VE) Seq Impedance = Z_2 = Z_1 = 1.35**

- (ZERO) Seq Impedance = Z_0 = 1.0PU
- 1 Phase fault current $I_F^{1\varphi} = \dfrac{3}{(1.35 + 1.35 + 1)} = 0.8108$ PU
- Base Current = 100 / (√3 x 6.6) = 8.7477 kA
- 1 Phase Fault Current $I_F^{1\varphi}$ = 0.8108 x 8.7477 = 7.1 kA
- At the same location,

  3 Phase fault current $I_F^{3\varphi}$ = 1 / 1.35 = 0.7407 PU
  3 Phase fault current $I_F^{3\varphi}$ = 0.7407 x 8.7477 = 6.5 kA
  [same as obtained previously]

$$I_F^{1\varphi} > I_F^{3\varphi}$$

- ***For Line to Ground fault on 6.6kV system*** **:**
  - Ground relay on 6.6 kV side of transformer senses 7.1 kA
  - Ground relay on 33 kV side of transformer does not sense at all !
  - Delta of transformer provides natural barrier for zero sequence (Ground fault) currents

- ***RESISTANCE GROUNDED SYSTEM :***
  - Neutral of generator stator / transformer grounded through external resistor
  - Current for Line to Ground fault limited by resistor
  - Fault current not much influenced by source impedance

$$I_F \cong V / (\sqrt{3} \times R)$$

R Ohms : Resistance connected in neutral circuit

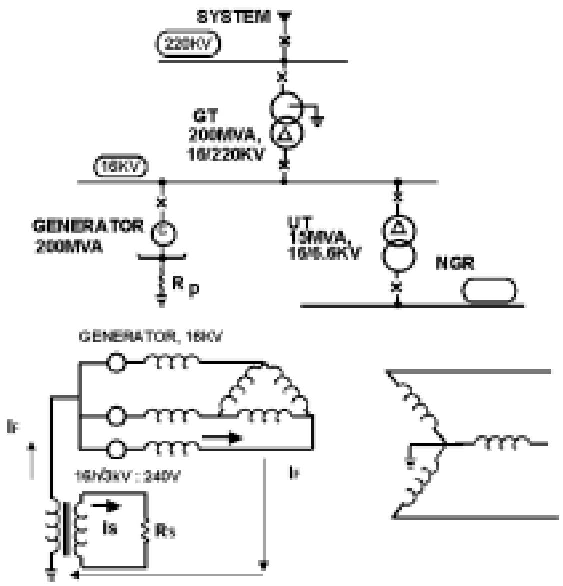
V Volts : Line to Line Voltage

- e.g. Star neutral of 6.6 kV side of 8 MVA transformer connected to ground through 38.1 Ω resistor

  FIG._SC_19

Current for L to G fault = 6600 / (√3 x 38.1) = 100 A

- ***NGR SIZING – SAMPLE CALCULATIONS :***
  - **Typical Power Plant System**



FIG_SC_22

- **Generator : 200 MVA, 16 kV**
- **Earth Fault Current I_F Restricted To 10A (Say) to minimize core Damage.**
- ***SIZING :***

  R_P : Resistance On Primary Side Neutral

  I_F : Earth Fault Current

  V_L : Generator Line Voltage

$$I_F = \frac{V_L}{\sqrt{3} \times R_P} \Rightarrow R_P = \frac{V_L}{\sqrt{3} \times I_F} \Rightarrow R_P = \frac{16{,}000}{\sqrt{3} \times 10} = 924\ \Omega$$

❖ **High Resistance (924 Ω) At High Voltage**

⇒ Results in uneconomical design

❖ **Solution : Connect NGR on the secondary side of a distribution transformer i.e. converted to low resistance at low voltage**

Distribution transformer Voltage Ratio : (16 kV/√3) / 240V

T_R = Turns Ratio = 16000/(√3 x 240) = 38.49

Equivalent resistance to be connected on secondary side:

$R_S = R_P / T\_R^2 \Rightarrow R_S = 924 / 38.49^2 = 0.624\ \Omega$

I_S : During fault, current through $R_S = I_F \times T\_R$

$= 10 \times 38.49 = 385$ A

Check power balance : $I_F^2 R_P = I_S^2 R_S$

$= 10^2 \times 924 = 385^2 \times 0.624$

= 93 KVA

TYPICAL SPECIFICATION :

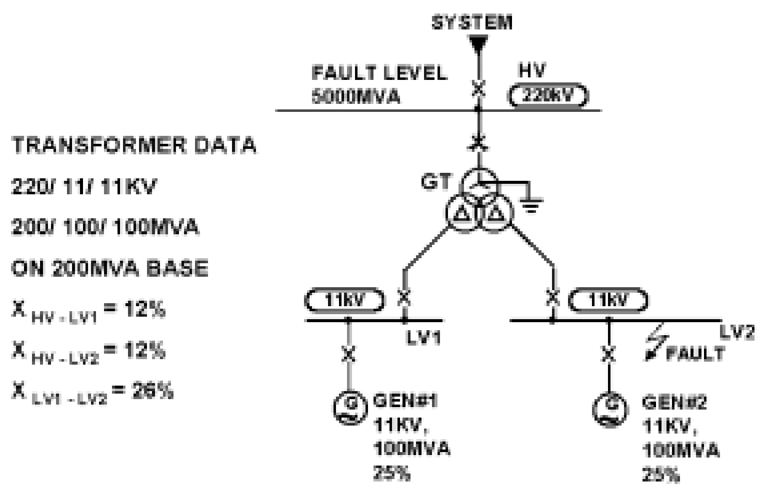
Distribution transformer : 1ϕ, (16 kV/√3) / 240V, 100 KVA

NGR : 0.63 Ω , 400 A, 240 V

Both transformer & NGR rated for 10 sec.

- *Fault Level Calculations With Three Winding Transformer :*

POWER SYSTEM WITH THREE WINDING TRANSFORMER

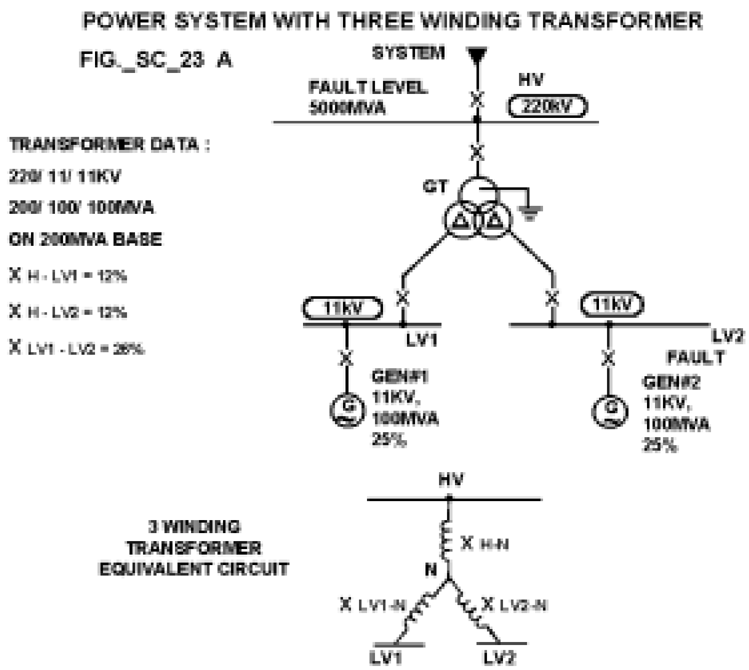


FIG_SC_23

- Three Windings : HV, LV1, LV2
- Manufacturers usually furnish impedance data as follows:
  - Impedance from HV to LV1, with LV1 shorted & LV2 open $\Rightarrow X_{HV-LV1}$
  - Impedance from HV to LV2, with LV2 shorted & LV1 open $\Rightarrow X_{HV-LV2}$

- **Impedance from LV1 to LV2, with LV2 shorted & HV open $\Rightarrow X_{LV1-LV2}$**
- **Impedances are given on Common Base MVA, usually HV winding rating**

- **STAR EQUIVALENT CIRCUIT**



FIG_SC_23A

$$X_{HV-N} = \{ X_{HV-LV1} + X_{HV-LV2} - X_{LV1-LV2} \} / 2$$
$$X_{LV1-N} = \{ X_{HV-LV1} + X_{LV1-LV2} - X_{HV-LV2} \} / 2$$
$$X_{LV2-N} = \{ X_{HV-LV2} + X_{LV1-LV2} - X_{HV-LV1} \} / 2$$

- ***CALCULATION PROCEDURE*** **:**
  - ❖ **Choose Base MVA : 200**
  - ❖ **System impedance : X_{SYS} = 200 / 5000 = 0.04 PU**
  - ❖ **Generator impedance : $Xg_1 = Xg_2 = \frac{0.25}{100} \times 200 = 0.5$ PU**
  - ❖ **Transformer impedance on 200 MVA Base**

    X_{HV-LV1} = 0.12(12%); X_{HV-LV2} = 0.12(12%); $X_{LV1-LV2}$ = 0.26(26 %)

$$X_{HV-N} = \frac{X_{HV-LV1} + X_{HV-LV2} - X_{LV1-LV2}}{2} = \frac{0.12+0.12-0.26}{2} = -0.01 \text{ PU}$$

$$X_{LV1-N} = \frac{X_{HV-LV1} + X_{LV1-LV2} - X_{HV-LV2}}{2} = \frac{0.12+0.26-0.12}{2} = 0.13 \text{ PU}$$

$$X_{LV2-N} = \frac{X_{HV-LV2} + X_{LV1-LV2} - X_{HV-LV1}}{2} = \frac{0.12+0.26-0.12}{2} = 0.13\text{PU}$$

NOTE : **Some times, one of the star branches in equivalent circuit can have negative values(e.g. x_{HV-N} in the above case). This is perfectly valid and in the end results are correct !**

From the impedance diagram:

$X1 = Xg_1 + X_{LV1-N} = 0.5 + 0.13 = 0.63$ PU

$X2 = X_{SYS} + X_{HV-N} = 0.04 - 0.01 = 0.03$ PU

$X3 = X1 \parallel X2 = 0.0286$

$X4 = X3 + X_{LV2-N} = 0.0286 + 0.13 = 0.1586$

$XEFF = X4 \parallel Xg_2 = 0.1204$ PU

Fault current $I_F = 1 / 0.1204 = 8.3056$ PU

Base current @ 11 kV $I_{BASE} = 200 / (\sqrt{3} \times 11) = 10.4973$ kA

Fault current $= I_F (PU) \times I_{BASE} = 8.3056 \times 10.4973 = 87.1864$ kA

Fault MVA $= \sqrt{3} \times 11 \times 87.1864 = 1661.1235$ MVA

Case with Generator#1 at LV1 on outage ; repeat above calculations for fault on bus LV2:

Fault current = 86.6 kA

Fault MVA = 1650 MVA

Remarks* : Contribution from Generator#1 at LV1 to fault at LV2 is *insignificant

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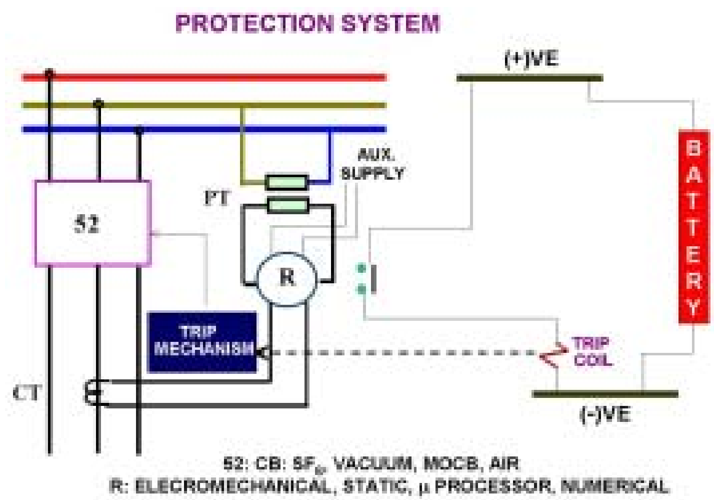
RELAY SETTING AND RELAY CO-ORDINATION

INTRODUCTION

Relay Co-ordination is essential to obtain continuous operation of system, to obtain maximum returns, to provide best service to the consumer and earn the most revenue. Absolute freedom from the failure of the plant cannot be guaranteed, even though the risk of failure of each item may be low. The risk factors of such items, if multiplied together go high**.** Larger the system, more will be the chances of the fault occurrence and disturbances due to the fault.

Stages in fault clearance are: (1) Occurrence of fault (2) Measurement by instrument transformer (CT / PT) (3) Analysis by protective relay for initiating selective tripping (4) Switchgear to clear the fault

Relay is only one part of protection chain in the protection system.



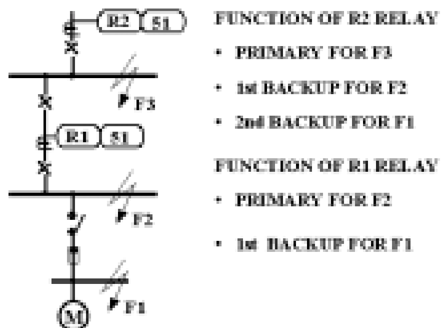
For successful clearing fault: (1) CT must not be saturated (2) CT and PT polarity must be correct (3) Integrity of wiring between instrument transformers to relay should be alright (4) Auxiliary supplies to the relay are available

(5) Relay characteristics are correct and set as per requirement (6) Compatibility between CT and relay (7) Correct CBCT installation (8) Trip coil and trip circuit healthy (9) CB tripping mechanism healthy (10) Earthing is correct?

Relays are installed not to prevent the faults, but only to isolate the fault and minimize the damage. Most of the relays act after damage has occurred. Sophisticated relays and correct relay setting and coordination are not a substitute for good maintenance practices.

PRIMARY & BACK UP PROTECTION

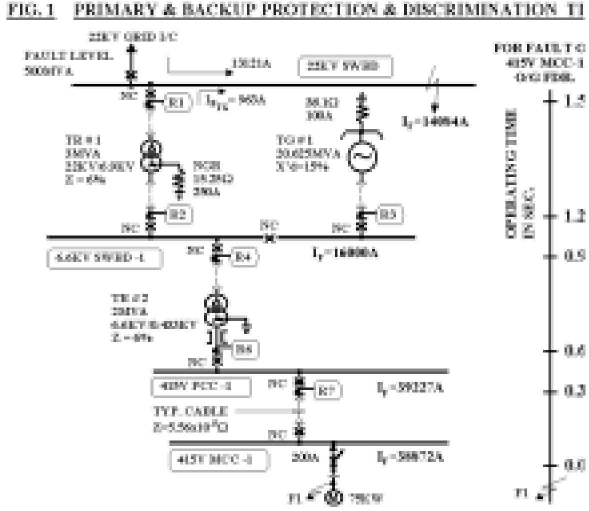
Device closest to the fault offers primary protection. Device next in the line offers back Up protection. If the primary protection fails to maintain the integrity of the system, back up protection should operate.



Failures of the Primary protection could be due to: (1) Mal-operation of the relay (2) Improper installation or deterioration in service (3) Incorrect system design (e.g. CT saturation) (4) Wrong selection of the relay type (5) Circuit Breaker failure (stuck breaker)

Consider the protection system shown in Fig. 1 below.

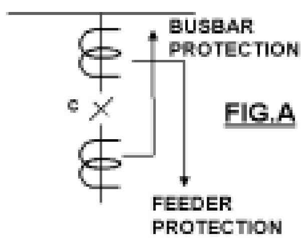
FIG. 1 PRIMARY & BACKUP PROTECTION & DISCRIMINATION TI

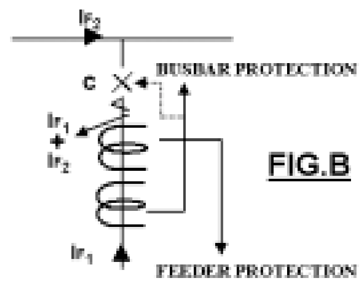


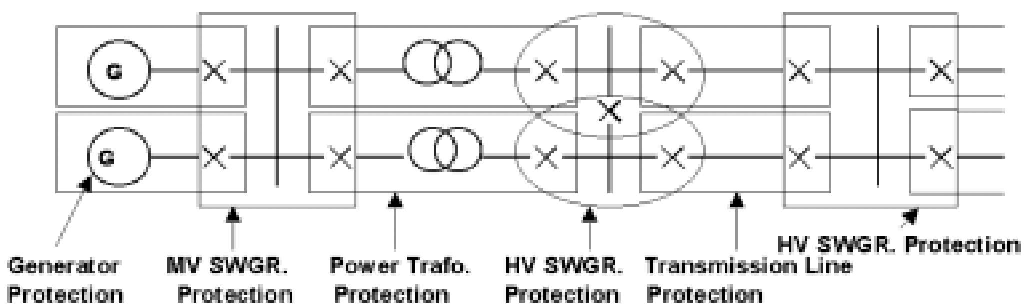
For fault on feeder of 415V PCC - 1 to MCC – 1, R_7 acts as primary protection, R6 acts as first back up for this fault and R_4 acts as second back up for this fault. For fault on 415 V PCC - 1 Bus, R_6 acts as primary protection, R_4 acts as first back up for this fault and R_2, R_3 acts as second back up for this fault. For fault on HT side of Transformer – T_2 , R_4 acts as primary protection and R_2 & R_3 as first backups. The same relay acts as some times primary protection for a particular fault & acts as back up protection for other faults.

ZONES OF PROTECTION:

Protection is arranged in zones, which would cover the power system completely leaving no part unprotected. Zone of protection should overlap across the circuit breaker being included in both zones (Fig A). Case A is not always achieved, accommodation of CT being in some cases only on one side (Fig B). For fault at 'F' bus bar protection would operate and trip C but fault continues to be fed through the feeder.







Power system protection is usually engineered through overlapping zones. The advantage is positive disconnection of faulty area / element. The disadvantage some times can be that more breakers will be tripped than the minimum necessary to disconnect the faulty element.

For fault at X,

CB_B trips due to Relaying equipment of zone B. CB_A trips due to relaying equipment of zone B, to interrupt the flow of short circuit current from zone A to the fault.

For fault at Y,

CB_B trips due to relaying equipment of zone B. CB_A trips unnecessarily due to relaying equipment of zone B. If there were no overlap, a failure in a region between zones would not lie in either zone and therefore no breaker will be tripped. The overlap is the lesser of the two evils.

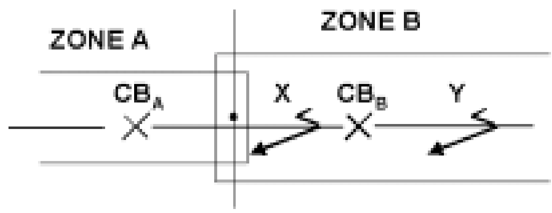


FIG. D

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NEED FOR CO-ORDINATION

- Improper Co-ordination:

  Refer Fig. 1. If proper co-ordination is not done, then MCC – 1 incomer trips for any fault on the outgoing feeder. Instead of tripping one load, an entire bus is lost.

- Proper Co-ordination

  Only relevant circuit breaker trips isolating the faulty equipment at the earliest. This minimizes the damage.

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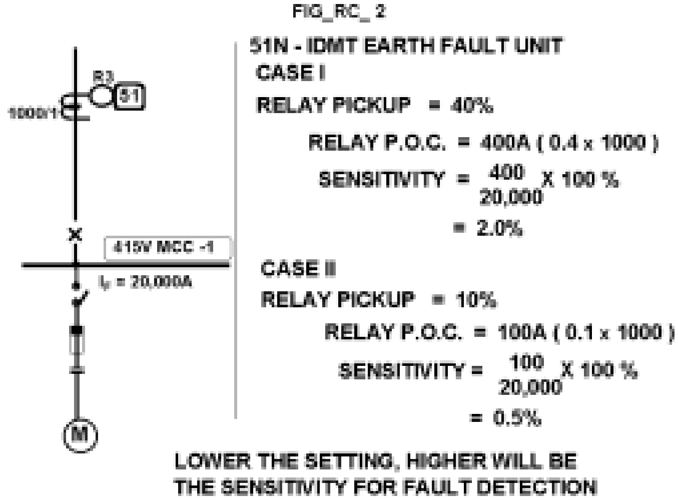
Properties of Protection schemes

Three essential characteristics of the protective relaying are *sensitivity*, *selectivity* and *speed*. These are not always the properties of the relays but properties of correct relay settings & protection scheme application

- *SENSITIVITY*

  Pick up refers to the minimum operating current of the relay. Lower the pick up of the relay, more will be the sensitivity. Higher the sensitivity, fault currents of small magnitudes can also be detected.

FIG_RC_ 2



- *Sensitivity Vs Thermal Capacity.*

  In case of static relays and numerical relays only thermal capability of relay imposes restriction on the choice of the lowest setting. For example, SPAJ 140C has thermal capability of 100 A for 1 second.

In case of electro-mechanical relay, lower the setting of the relay, more will be the burden on the CT resulting into more heating of the relay element and larger exciting current drawn by CT.

Consider a relay connected to 1000 / 1 CT. Let the fault current be 20 kA. Assume thermal capability of relay be 100 A for 1 second.

If relay is set for 10%, Relay Current = 20,000 / (1000 x 0.1) = 200 I_N

I^2t Criteria: $(200\ I_N)^2\ (t) = (100\ I_N)^2 \times 1$ sec

$$t = 0.25 \text{ sec}$$

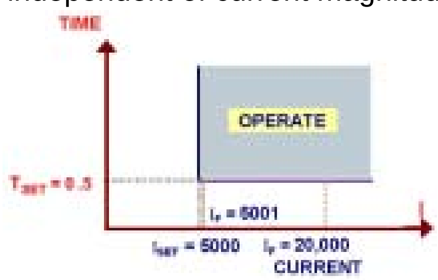
If operating time of the relay is less than 0.25 sec, the 10 % pick up is permissible, otherwise relay may be damaged.

- *SELECTIVITY*

  It refers to the selective tripping of the protective gears and also called as the discrimination. The three methods to achieve the discrimination are by Time, by Current and both Time & current.

- *DISCRIMINATION BY TIME*

  Definite Time Relays is a good example. If the current exceeds the set value, operating time is independent of current magnitude.



Assume the discrimination time between successive relays, in Fig. 1, is say 0.3 sec. Let the fault current above the pick up values for all the relays. For fault on MCC - 1 outgoing feeder, fuse operates in 10 millisec, Relay R_7 operates in 0.31 Sec and Relay R_6 operates in 0.61 Sec. All upstream relays are graded accordingly. The disadvantage of using DMT relays is that the operating time of the upstream relays will be very high. The fault closest to the source takes longest time to clear. The advantage of using DMT relays is that the operating time is well defined for variable source operating condition.

- *Discrimination By Current*

  Applicable only when substantial difference between the fault current magnitudes exists for the faults on the two ends of the equipment. The impedance of the equipment shall be substantial that will create the above difference like transformer or long cable. For illustration consider a fault on LT side of transformer TR_2 in Fig 1. The fault current is 39,227 A on 415 V side and the reflected current on 6.6 kV side is 2467 A. If the fault is on 6.6 kV side, the fault current is 16 kA. By setting the pick up current for relay R_4 above 2467 A , the relay R_4 will not pick up for fault on the LT side but will pick up for the fault on the HT Side. The disadvantage is that discrimination is obtained but no back up is ensured.

- *DISCRIMINATION BY BOTH TIME & CURRENT*

  IDMT(Inverse Definite Minimum Time) relays are used. The operating time of IDMT relay is inversely proportional to current magnitude. Even for highest current, time for operation is not Instantaneous but a minimum time. For the same fault current and specified pick up, relay operating time is varied by adjusting Time Dial.

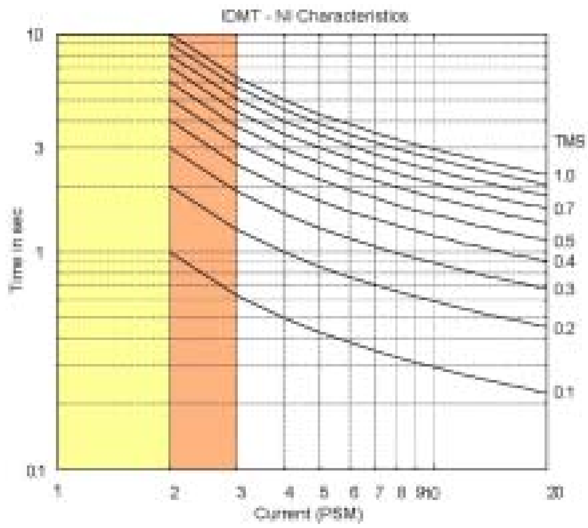
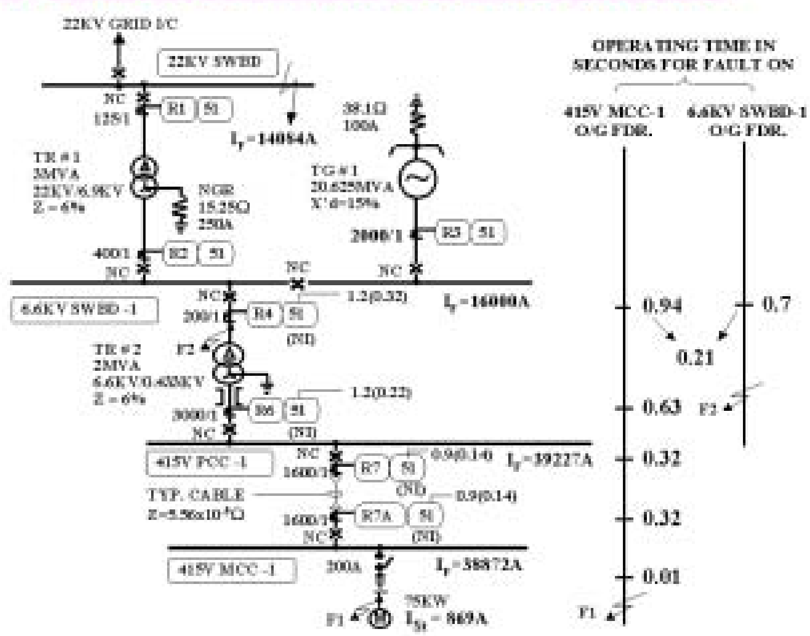


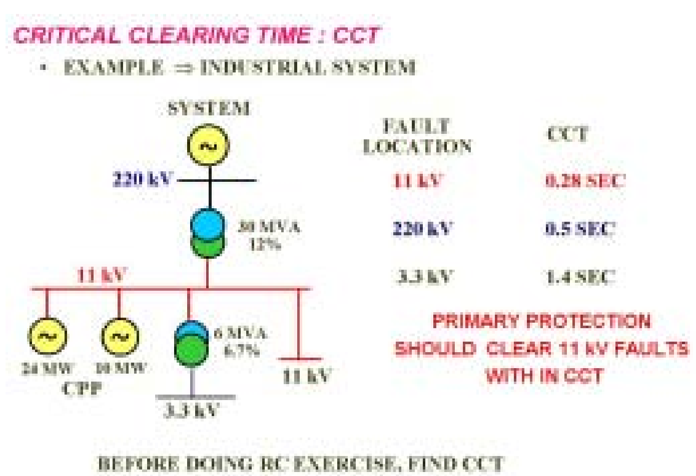
FIG. 3 INHERENT DISCRIMINATION OBTAINED BY IDMT RELAY

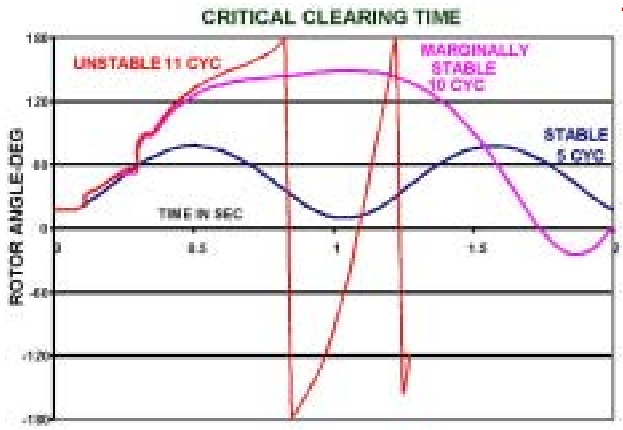


Assume the discrimination time between successive relays is say 0.3 sec. Let the fault current be above the pick up values for all the relays. For fault on FCC - 1 outgoing feeder, fuse operates in 10 msec, Relay R7 operates in 0.32 Sec and Relay R6 operates in 0.63 Sec and Relay R4 operates in 0.94 Sec. For the fault on HT side of Transformer TR2, the fault current is 16 kA and Relay R4 operates in 0.73 Sec. Reduced operating time of relay R4 for 6.6kV faults results in reduced operating time of upstream relays R2 & R3 for H.T. faults. The advantage gained by using IDMT relay is that with the same pick up and time dial settings, lower time of operation for near end faults and higher operating times for far end faults inherently achieved. In case of differences in fault current magnitude along the system , IDMT relays are superior to the DMT relays. In case of same fault current magnitude along the system, desired operating time can be achieved by adjusting Pick up & Time Dial.

- *SPEED*

  If the fault clearing time is less than 100 msec, it is termed as high speed tripping. High speed tripping minimizes the damage to the equipment, increases stability margin for synchronous machines and avoids unwarranted tripping of voltage sensitive loads. Critical Clearing Time(CCT) is the minimum time before which fault has to be cleared. Typically it varies between 200 msec to 1 second and depends upon location of fault.

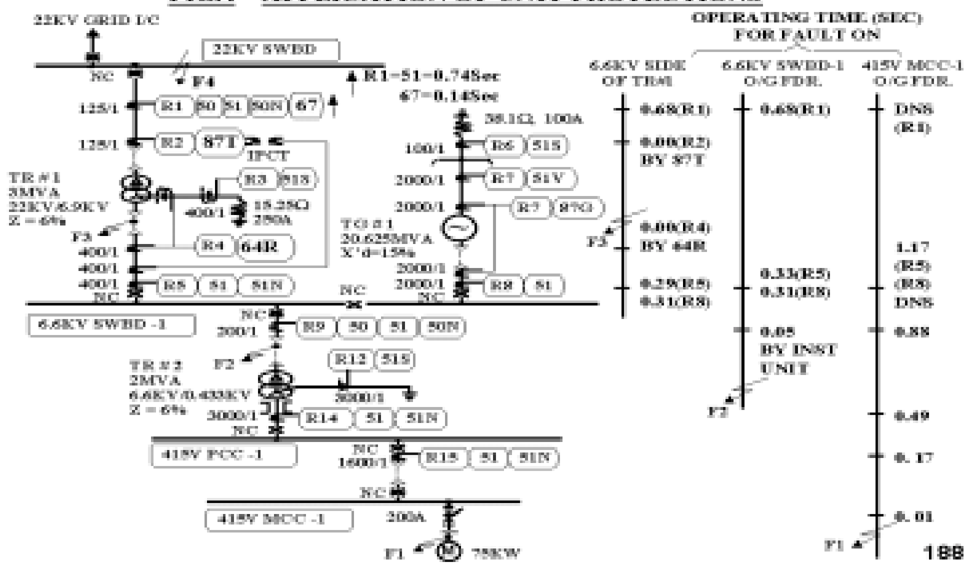




Speed without Selectivity leads to unsatisfactory co-ordination. Methods to achieve high speed tripping are:

- Unit protections: (Generator, Motor, Transformer, Bus, Feeder).
  Protection is provided to trip Instantaneously for faults only within the unit under protection. No co-ordination with external protections is required. Examples of unit protection are Bus differential protection, Feeder Pilot wire protection, Transformer or Motor Differential protection
- Directional protections for Multi Source / Non radial systems

FIG.4 APPLICATION OF UNIT PROTECTIONS



- **Example**

Speed must be weighed against economy. In LT distribution networks, loads are connected at radial end of system, fault clearance time is shorter and hence need of speedy clearance is not critical. Unit protections in LT are not generally employed. In Generating plants, M.V. & H.V. systems high speed tripping is essential to ensure system stability.

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DISCRIMINATION TIME (CO-ORDINATION INTERVAL)

This refers to the time interval between the operation of two adjacent breakers or breaker and fuse.

- *FACTORS AFFECTING DISCRIMINATION TIME*

R1, as on 0

FACTORS AFFECTING DICRIMINATION TIME

Co-ordination interval shall incorporate the following time periods :

- Interrupting time of Downstream Breaker(≅ 100msec)
- Relay Error Factor

  Refers to Negative or Positive Errors in operating time of the Downstream relays / fuse involved in grading.

  - For Co-ordination Time between Fuse & Breaker = 0.4t
  - For Co-ordination Time between Breaker & Breaker = 0.25t
  - t = operating Time of Downstream Fuse / Relay
- Overshoot Time of Upstream Relay
  - Operating time more than set value due to contact over travel etc. and about 50msec for electro-mechanical relays. This is not relevant for modern numerical relays.

- Safety Margin

  Refers to the extra allowance to ensure a satisfactory gap between operating time of two breakers or breaker and fuse. It can be about 100msec for electro-mechanical relays. If Numerical relays used for both upstream and downstream, this can be reduced, say, to even 50msec.

- *EMPIRICAL FORMULAS FOR CO-ORDINATION TIME*

For { Fuse - Breaker (Conventional Relays) } /
{ Fuse to IDMT or INST to IDMT relay)}

Discrimination time = 0.4t + 0.15, where

Fuse operating time = t

Relay error factor = 0.4t

Relay overshoot Time = 50 msec.

Safety Margin = 100 msec.

For Breaker - Breaker (IDMT to IDMT relays)

Discrimination time = 0.25t + 0.25, where

Downstream relay operating Time = t

Relay Error Factor = 0.25t

Downstream breaker interrupting Time = 100 msec.

Relay Overshoot Time = 50 msec.

Safety Margin = 100 msec.

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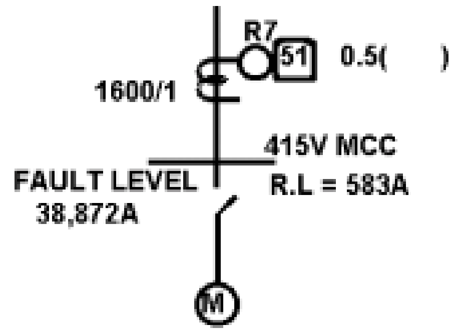
CRITERIAS FOR SETTING PICK UP & TIME DIAL

Introduction to Plug setting (PS) and plug setting multiplier (PSM) and Time Multiplier Setting (TMS)



PS = Desired pick up current / CT Ratio = 583 / 1600 = 0.364

Set PS = 0.5 A.

Primary Operating Current (P.O.C.)

= C.T.R. x P.S

= 1600 x 0.5 = 800 A

PSM = Fault Current / Actual POC

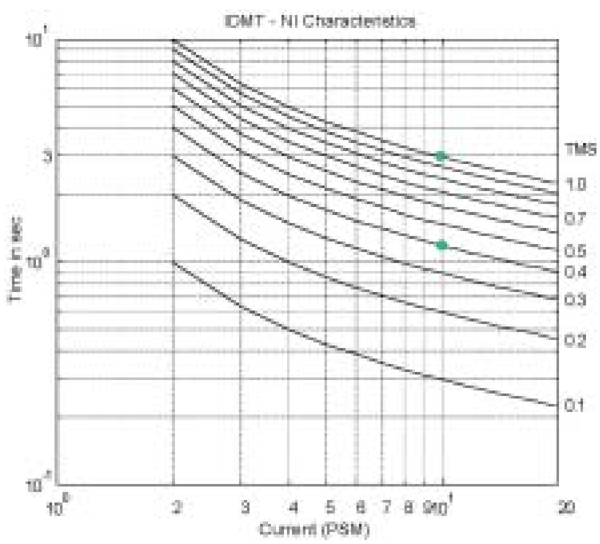
= 38872 / 800 = 48.59

Time Dial Vs Operating Time

For PSM = 10, TMS = 1. 0, OT1 = 3.0 sec

For TMS = 0.4,

Operating Time OT = 0.4 x (3 / 1) = 1. 2 sec



Prevalent practice for pick up setting : Case Study

Prevalent practice for pick up setting : Case Studies

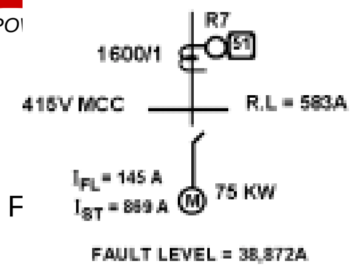
Data:

IDMT RELAY : Relay R7 : Location - Incomer of MCC

C.T.R = 1600/1

Pickup = (0.5 – 2.5) In, Step = 0.1 In

Time dial = 0.05 – 1.00, Step = 0.05



- Fault Current = 38872A (Obtained From Three Phase F
- Max. Running load current = 583A
- Highest Drive Full Load Current = 145A
- Highest Drive Starting Current = 869A (6 x IFL)

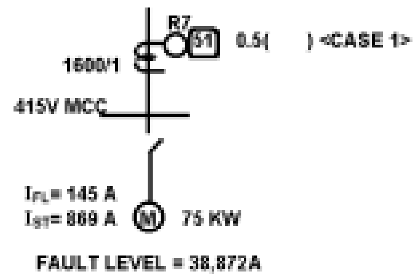
- <u>**THREE CASE STUDIES**</u> **:**
  - **CASE - 1**

    Pick up set only on basis of maximum connected load current & time dial set to obtain co-ordination with downstream fuse

    - **PS = Max. Running load current / CTR**

      = 583 / 1600 = 0.364

      Set PS AT 0.5A



- **Primary Operating Current (P.O.C.)**

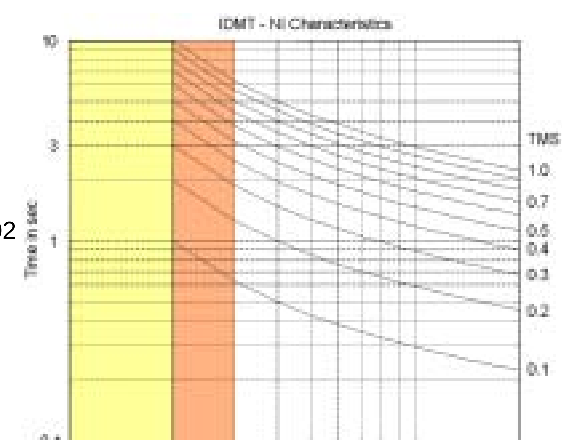
  = C.T.R. x P.S

  = 1600 x 0.5

  = 800A

- **PSM = Fault Current / Actual P.O.C = 38,872 / 800 = 48.59**

- **Choose normal inverse (NI) characteristic :**
- **Characteristic of IDMT unit flattens out for PSM > 20.**



IDMT relay equations

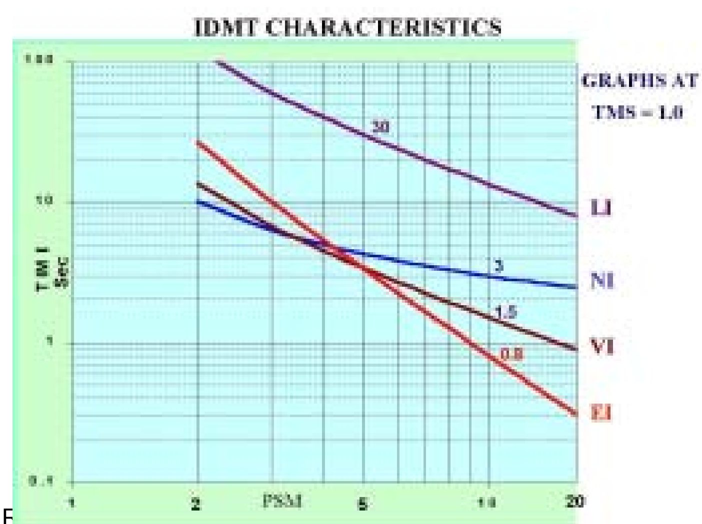
$OT = TMS * \beta / (PSM)^{\alpha} - 1.0$

OT: Operating Time in sec

TMS: Time Multiplier Setting

PSM: Plug Setting Multiplier

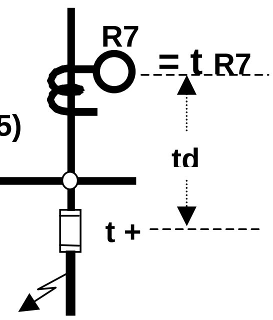
	β	α
Normal Inverse	0.14	0.02
Very Inverse	13.5	1.0
Extremely Inverse	80.0	2.0
Long Time Inverse	120.0	1.0



Operating time of R7 @ time dial 1.0 $= \dfrac{0.14}{(PSM)^{0.02} - 1}$

Operating time (with PSM OF 20) = 2.267 sec. @ time dial 1.0

- Time Dial Vs Operating Time
  - Desired Operating Time t R7:



Downstream fuse blow off time t = 0.01 SEC

Discrimination Time td = (0.4 t + 0.15)

= 0.154 SEC.

Desired Operating Time t R7 = t + td

= 0.01 + 0.154

= 0.164 SEC.

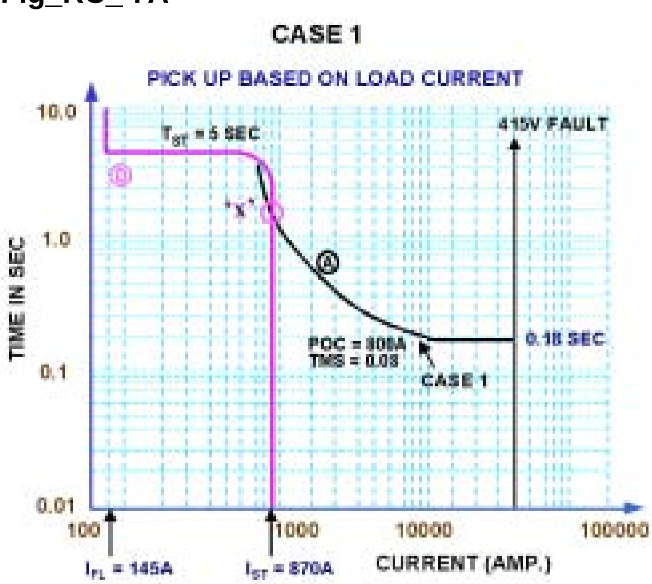
TMS = Desired operating time / Operating time at selected PSM and TMS 1.0

= 0.164 / 2.267 = 0.072

Set time dial = 0.08

Actual operating time = 2.267 x 0.08 = 0.18 sec

- Fig_RC_ 7A

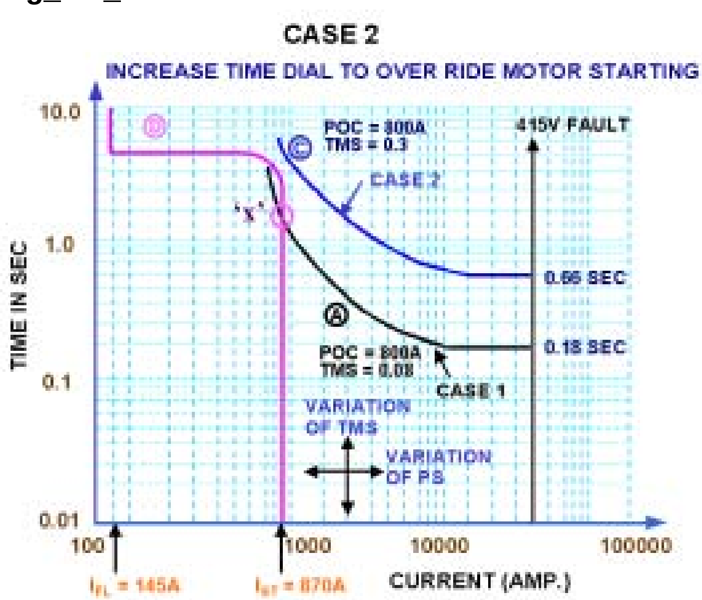


- **Curve 'A' shows the operating characteristic with the above settings.**
- **Curve 'D' shows the acceleration characteristic of the motor.**
- **Point 'X' is the intersection of curves 'A' & 'D'. i.e. (870A) @ 1.15 sec. Since motor starting time is more than 1.15 sec, relay will pick up & will trip MCC incomer breaker, which is not correct.**
- **This example illustrates that the choosing plug setting based only on load current is not correct. Using IDMT over current relays for overload protection leads to inadvertent tripping.**

- **CASE - 2**

  Pick up set only on basis of maximum connected load current & Time dial increased from Case-1 value to avoid relay operation during motor start up.

- **Fig_RC_7B**



- Time dial increased from 0.08 to say 0.3; Characteristic curve shift vertically upwards - from curve 'A' to curve 'C'; Curve 'C' & Curve 'D' do not intersect; Hence, relay does not operate for motor starting on full load.
- But, clearance time for faults = 2.267 x 0.3 = 0.66 sec
- Upstream relay clearance time will also increase.
- Hence, not acceptable.

- **Case - 3**

  Any Other Method

  Case -3 : Desired Settings

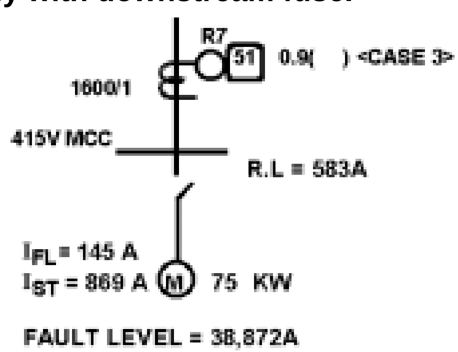
  - Previous two cases not acceptable
  - Case –1 : Relay operates during motor starting
  - Case– 2 : Operating time for faults very high.

- Now try the following criteria
  - Primary operating current > Max. running load current - Highest rating drive full load current + Highest rating drive starting current
  - Time dial to co-ordinate suitably with downstream fuse.
  - PS = $(I_{RL} - I_{FLM} + I_{STM})$ / CTR

    PS = (583 -145 + 869) / 1600

    = 0.816

    Let PS set at 0.9A



- Actual primary operating current (P.O.C.) = C.T.R. x P.S.

  = 1600 x 0.9

  = 1440A
- PSM = 38,872 / 1440 = 26.99

- **Choose normal inverse characteristic.**

Operating time	**=**	**Operating Time**
@ PSM>20 & time dial 1.0		**@ PSM = 20 & time dial 1.0**
Operating time of R7 @ time dial 1.0	**=**	$\dfrac{0.14}{(PSM)^{0.02} - 1}$ **For NI**

Operating Time = 2.267 sec for PSM = 20 & time dial = 1.0

- **Desired operating time t1 :**
  Downstream fuse blow off time t = 0.01 sec
  Discrimination time td = (0.4 t + 0.15)
  = 0.154 SEC.

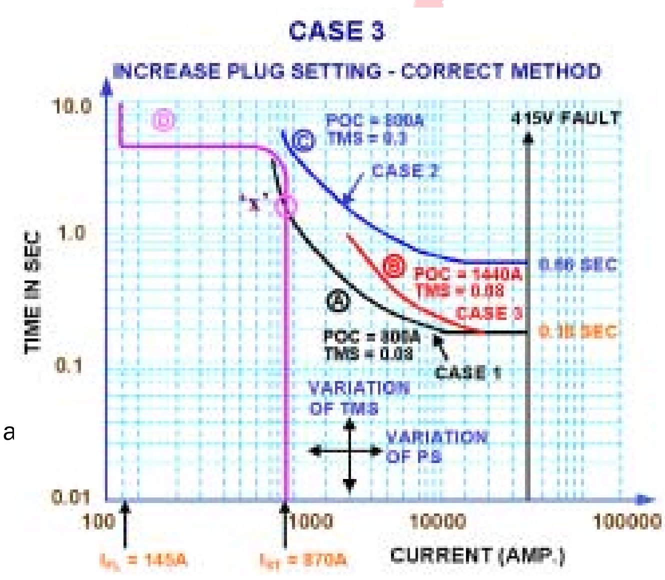
  Desired operating time t1 = t + td
  = 0.01 + 0.154
  = 0.164 SEC.

- **Desired Time Dial TMS:**

  TMS = 0.164 / 2.267 = 0.072

Next available set point = 0.08

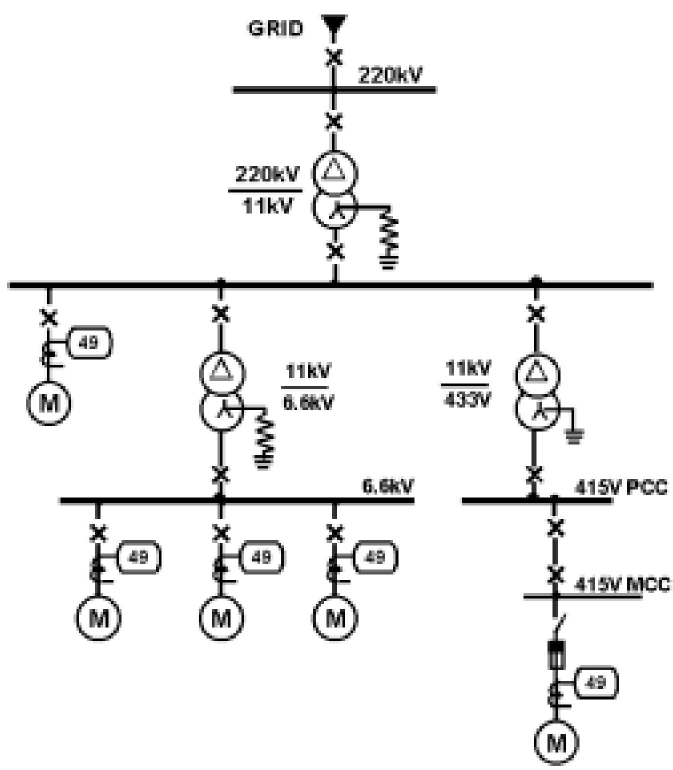
- **Operating time = 2.267 x 0.08**
  = 0.18 sec. for faults.



Curve ' B ' shows the operating characteristic with the above settings. Two goals are achieved. The relay does not pick up when highest rating motor is started with full load on the bus. Upstream operating times are also not increased.

- **<u>Over-load Vs Over-current</u>**
  - **Over load withstand capability of equipment in general – many seconds to minutes**

  - **For Example**



rotection

- **Generator overload capability**

Time (sec)	**10**	**30**	**60**	**120**
Stator current (%)	**226**	**154**	**130**	**116**

- **Transformer overload capability:**

Time (Minutes)	**2**	**10**	**20**	**45**	**80**
Current (%)	**300**	**200**	**175**	**160**	**145**

- **Over current is Short Circuit Current and in this case fault has to be removed with in 1 sec where as overload can be sustained in minutes. Hence, over current relay with any characteristics can not be used.**

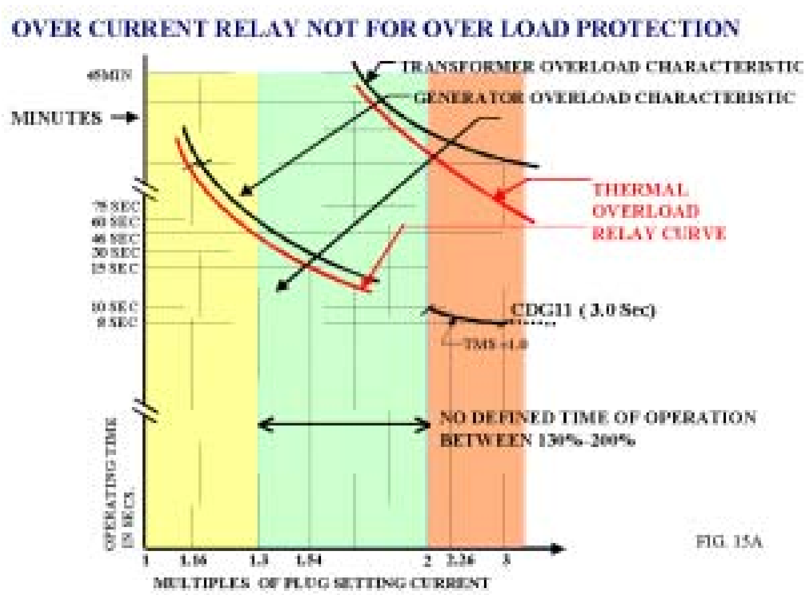
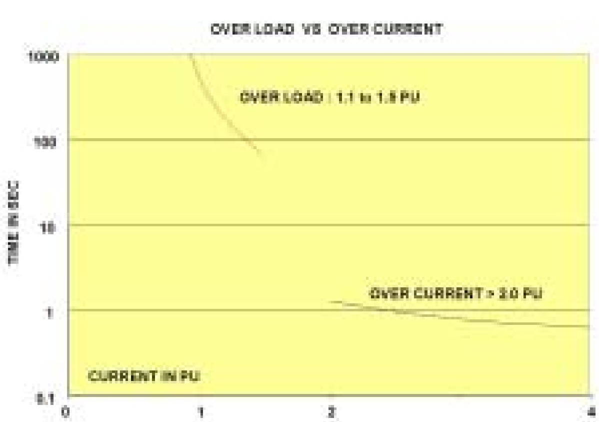
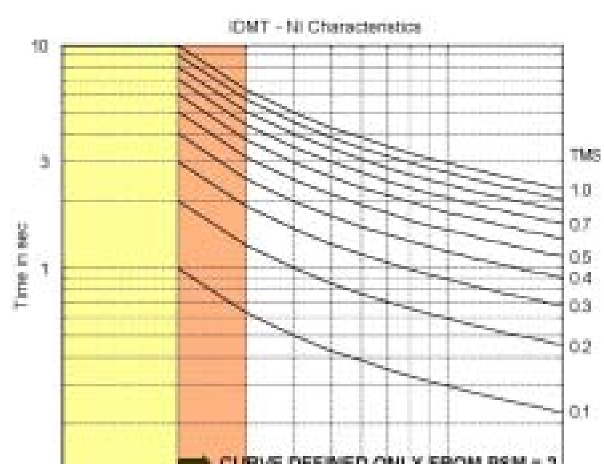


Fig. 15A





If over current persists for greater than 1 sec, it will result in loss of synchronism (angle instability) or motor stalling (voltage instability). Conceptually over current relays cannot be used for over load protection.

- **DMT Relays**
  - **Primary Operating Current**
    - Must lie above maximum running load current and largest drive starting current by safety margin.
    - Max. running load current includes motor full load current . Hence, it is subtracted.
    - Must lie below the lowest through fault current.
    - Relevant for generally used DOL starting.

♦ $I_F > \text{P.O.C.} > (I_{RL} + I_{STM} - I_{FLM})$

Where,

P.O.C. = **Desired Primary Operating Current of relay**

I_{RL} = **Max. Running Load Current**

I_{STM} = **Highest Rating Drive Starting Current**

I_{FLM} = **Highest Rating Drive Full Load Current**

I_F = **Minimum fault current relay to sense.**

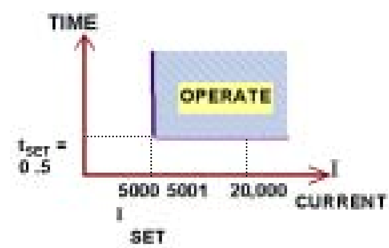
- **Remark: The first comparison IF > P.O.C is generally satisfied in most of the cases , since fault current magnitude is generally very** high. The only critical case in which this comparison is important is when source fault level is low.

- Desired Pick up
  - ♦ PICK UP $\geq$ $\dfrac{\text{Primary Operating Current (P.O.C.)}}{\text{C.T. Ratio}}$

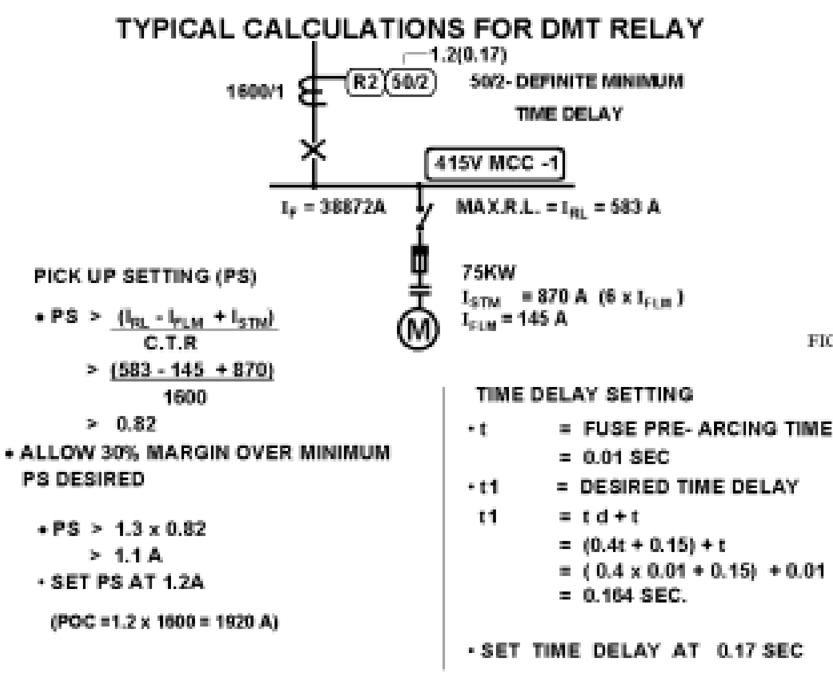
- DMT Relay - Independent of fault current, hence, plug setting multiplier applicable for IDMT relays not relevant.
  PSM > 1.1 for DMT Relays

$I > I_{SET}$

$I_{SET} = 5000A$
$I = 5001A$ or $I = 20000A$
Operating TIME $\Rightarrow$ SAME



TYPICAL CALCULATIONS



FIG_RC_6

- Relay R1 : Location : Incomer of MCC-1

- C.T.R = 1600/1
- Relay Type = SPAJ 140C (SPACOM Series ABB make)
- Though this relay has both DMT & IDMT Characteristics, for illustration, only DMT is used.
- Fault current = 38872A (Obtained from Three Phase Fault Calculations)

- **Desired Pick up PS :**
  - PS > (582.7 – 144.9 + 869.5) / 1600

    > 0.816

  - Allow 30% margin over minimum PS desired
    - 10 % Safety Margin
    - 20% Margin for variation in system impedance / voltage etc.
  - PS > 1.3 x 0.816

    > 1.1A

  Set PS at 1.2A

- **Desired Time Delay t1 :**

  t = Fuse Pre –arcing Time =0.01 Sec

  t1 = td +t

  t1 = (0.4t + 0.15) +t

  = (1.4 x 0.01 +0.15) + 0.01

  = 0.164 sec.

  Set Time Delay at 0.17 Sec.

  [Time Delay = 0.05 – 300 Sec., Step = 0.01 Sec.]

- **Desired relay operating Time**

  ♦ t1 = t + td

  where, t1 = Desired relay operating Time t = Downstream Breaker / Fuse operating Time

td = Discrimination Time

- Time Dial Set Point :

  Time Dial setting available in steps. Nearest Time Dial setting selected.

- Example of DMT Relays :

  Electromechanical relays: CTU , CAG + VTT

  All Numerical relays have in built DMT feature.

- **IDMT RELAYS :**

  - Primary Operating Current:

    Must lie above (Maximum running load current + Largest drive starting current)

    Max. running load current includes motor full load current of started motor. Hence, it is subtracted.

    Must lie below the lowest through fault current.

♦ P.O.C. = $I_{RL} + I_{STM} - I_{FLM}$

where, P.O.C. = Desired primary operating current

I_{RL} = Max. running load current

I_{STM} = Highest drive starting current

I_{FLM} = Highest drive full load current

- Desired Relay Pick up - PS (Plug Setting) :

  Ratio of Primary Opera35

  ting Current of Relay to C.T. Ratio (C.T.R.)

$$PS = \frac{P.O.C.}{C.T.R.}$$

$$= \frac{(I_{RL} - I_{FLM} + I_{STM})}{C.T.R}$$

- **Selected pick up setting :**

  Select the next higher available step.

- **Actual primary operating current (P.O.C.) :**

  Actual P.O.C. = Selected Pick Up x C.T.R.

- **Plug Setting Multiplier - PSM :**

  PSM = Fault Current / Actual P.O.C.

- **Desired relay operating time t1**

  t1 = t + td

  Where, t = Downstream Relay / Fuse Operating Time

  td = Discrimination Time.

- **Desired Time Dial Set Point - TMS (TIME MULTIPLIER SETTING)**

  <u>Desired Relay Operating Time t1</u> = Desired TMS setting Relay Operating Time @ Selected PSM and TMS =1.0

- **Selected Time Dial (TMS) setting :**

  Nearest Higher Time Dial Setting Selected

- **Electro Mechanical Relays**
- **Normal Inverse (NI) : CDG11- 3 SEC , CDG11- 1.3 SEC**
  - **Operating Time @ PSM = 10 & TMS = 1.0 ⇒ 3 sec / 1.3 sec**
  - **Slope of both 1.3 & 3 sec. characteristics same**
  - **Operating Time = TMS x 0.14 / [(PSM)$^{0.02}$ - 1.0]**

    2 < PSM < 20

- For a given change in time dial (Δ TMS)

  Δ operating time >> Δ operating time

  (3 Sec Relay) (1.3 Sec Relay)

- To achieve closer co-ordination 1.3 sec. relay more useful

- Application: time graded phase and earth fault protection e.g. transformer, feeder (incomer / outgoing)

- Very Inverse (VI): CDG13

  - Operating Time @ PSM = 10 & TMS = 1.0 ⇒ 1.5 SEC

  - Operating Time = TMS x 13.5 / [(PSM - 1.0]

    2 < PSM < 20

  - Used on H.T. side of transformer to co - ordinate with NI Characteristic relay on L.T. side.

FIG. 16A : TIME CURRENT CHARACTERISTIC OF 3SEC INVERSE TIME RELAY

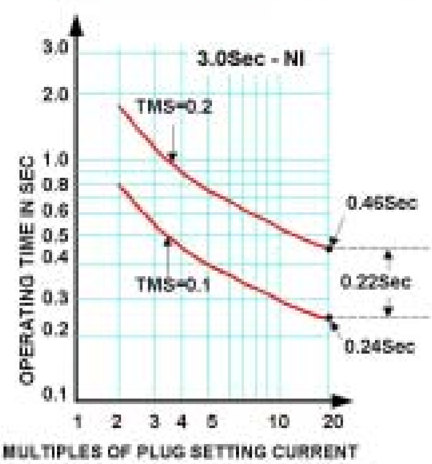
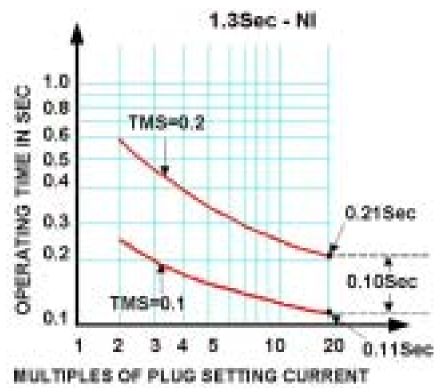


FIG. 16B : TIME CURRENT CHARACTERISTIC OF 1.3SEC INVERSE TIME RELAY



Very Inverse characteristics is useful where substantial reduction in fault current occurs due to large impedance of protected object, e.g. on upstream side of transformer. For L.T faults, operating time increases to coordinate with downstream faults and for HT faults, operating time is minimum to clear faults within CCT.

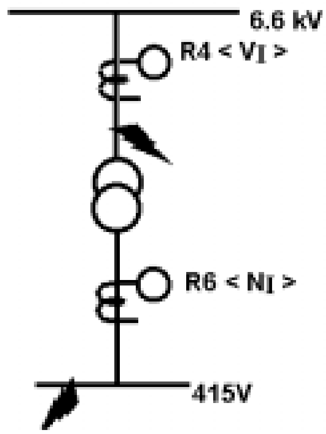


FIG. 17 SELECTION OF (VI) CHARATERISTICS

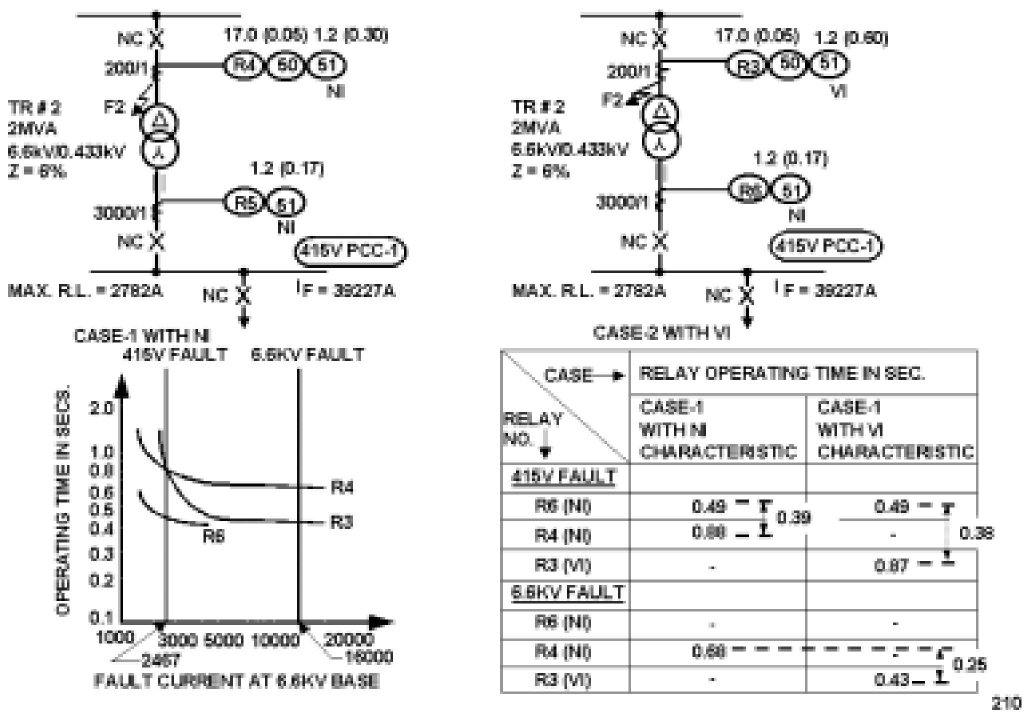
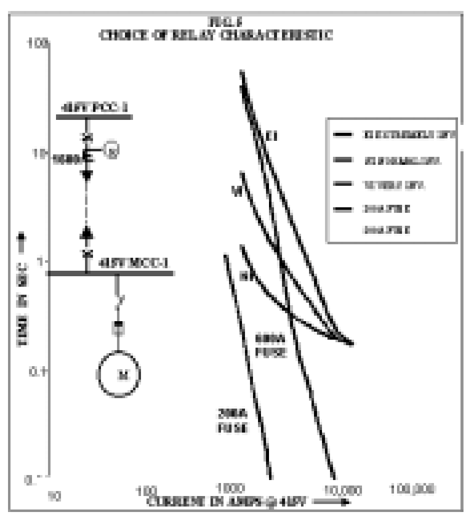


FIG 17

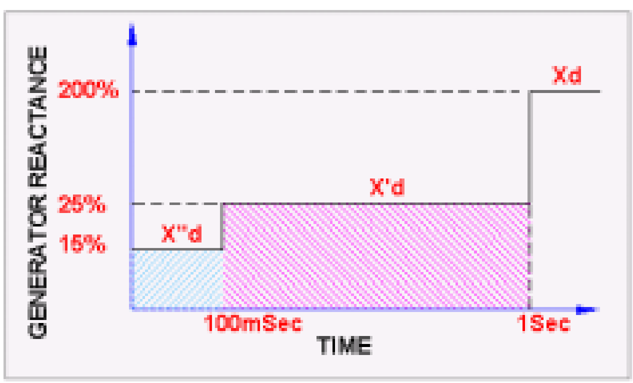
- Relays R6 : time for LT faults ≅ 0.49 sec
- Upstream Relay R4 (NI) 0.39
- Operating time for LT faults ≅ 0.88 sec
- Coordination for LT faults achieved between relays R6 & R4
- But operating time for HT faults ≅ 0.68 sec ⇒ Too High
- Operating time of relays above R4 will further increase
- Relays R6 : time for LT faults ≅ 0.49 sec
- Upstream Relay R3 (VI) 0.38
- Operating time for LT faults ≅ 0.87 sec
- Coordination for LT faults with downstream relays achieved as in case with (NI)
- Operating time for HT faults ≅ 0.43 sec
- Operating time of relays above R3 will further reduce

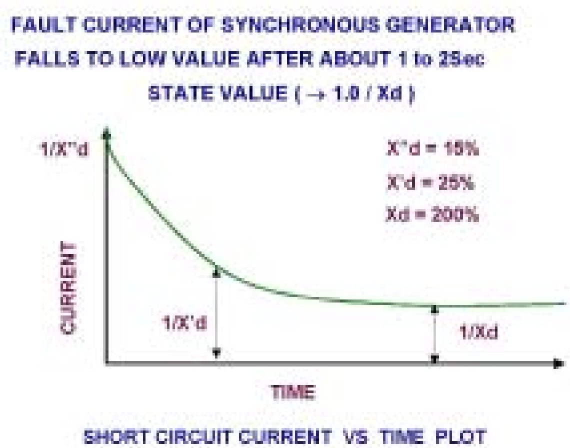
- Extremely Inverse (EI)
    - Generally used to back up fuse
- Very Inverse (VI) is preferred on upstream side of transformer
- Normal Inverse (NI): If in doubt use NI.
- Long Time Inverse (LI): To protect NGR



TOOLS AVAILABLE TO REDUCE FAULT CLEARANCE TIME

- **WHY FAST FAULT CLEARANCE:**
  - **Fault current reduces markedly after 1 sec. - because of high value of steady state reactance.**
  - **Sensing current itself may fall below relay pick up.**
  - **Equipment generally rated for 1 sec. short time duty.**
  - **Advisable to clear the faults, maximum within 1.0 sec.**
  - **Reduced damage at fault location.**





- **Tools Available**
  - **Instantaneous over-current (50)**
    - **Applicable only when substantial difference between the fault currents at two ends of the equipment exists.**

- Wrong application to use instantaneous over-current relay on an incomer, as any fault on outgoing feeder will trip the incomer, leading to complete loss of supply.

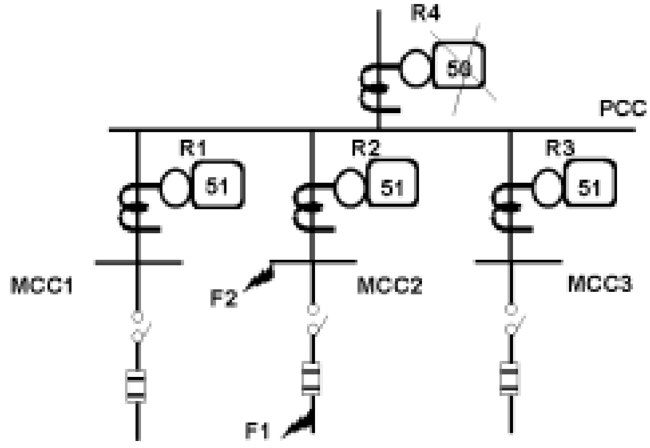
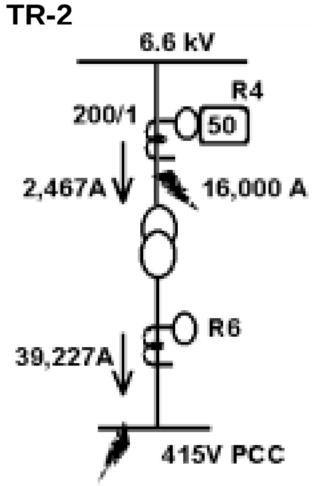


Fig 20

- **Example**
  - **Relay R4 : location - H.T. side of transformer TR-2**
  - **C.T.R = 200/1**



- **For PCC-1 bus fault,**

  Fault Current = 39227 A @ 415V

  = 2467 A @6.6 kV

- **For Transformer TR-2 H.T. fault,**

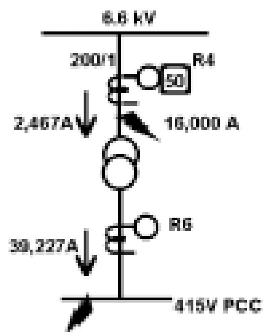
  Fault Current = 16000 A @ 6.6kV

- **By setting the pick up of instantaneous over current element above 2467A , the relay R4 will not pick up for fault on the L.T. side. but, will pick up instantaneously for the fault on the H.T. side.**

- **Not desirable to set instantaneous pick up at exactly L.T. reflected fault current.**
- **Margin above L.T. reflected fault current shall be not less than 30%.**

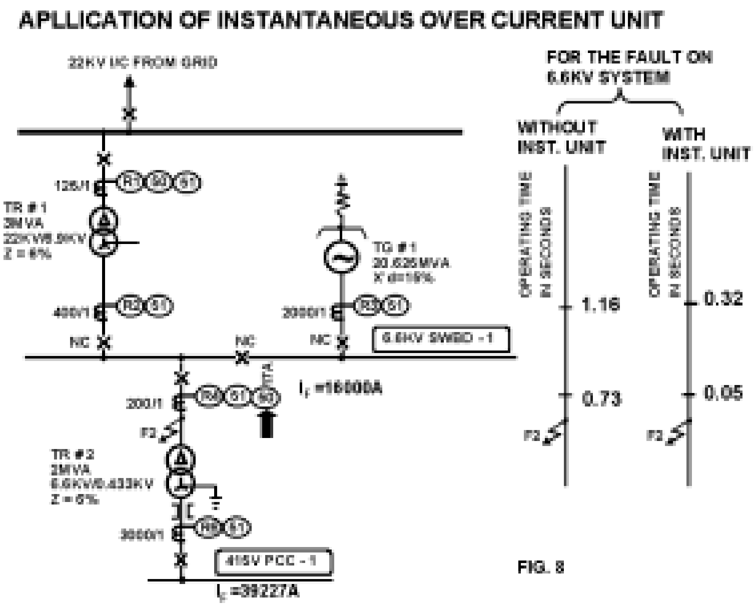
  20% for relay errors

  10% for variation in system impedance
  - **Transformer Impedance (± 10%)**
  - **Generator Impedance (± 15%)**
  - **Line, Cable Length ⇒ Approximate**
- **Primary operating current (P.O.C.) = 1.3 x 2467 = 3207A**
- **Pick Up PS** $= \dfrac{\text{P.O.C}}{\text{C.T.R}} = \dfrac{3207}{200} = 16.035\text{A}$



Set Pick Up AT 17A.

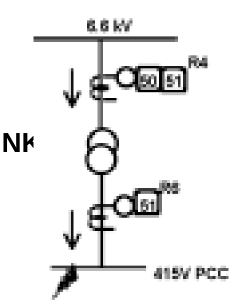
- **Advantage :-**



- **Fig. 8**
- **Instantaneous over current element (50) of relay R4 does not sense L.T. faults.**
- **But, operates instantaneously for the H.T. faults.**
- **Thus, upstream relays R2 & R3 time can be reduced.**
- **R2, R3 – need to be co-ordinated with relay R4 for 6.6 kV faults.**
- **R4 – Instantaneous**
- **R2, R3 – operating time reduces.**

- **Disadvantage: -**
  - **Instantaneous over current element (50) does not sense LT faults.**
  - **Thus, no back up protection to the L.T. faults.**

- **Hence, An Additional IDMT / DMT over-current**



(51 OR 50/2) relay is to be provided to give back up protection to the L.T. faults.

- **Example of instantaneous over-current relays:**
- **Electromechanical Relays: CAG17 .**
- **All numerical relays have in built instantaneous over- current feature.**

ABB make- SPACOM SERIES - SPAJ 140C

SIEMENS make - 7SJ 600

GE MULTILIN make - SR 750 (Feeder Management Relay)

• Case Study

Data

415 V side

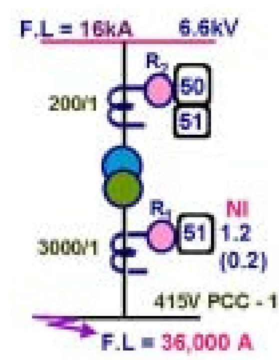
CT Ratio: 3000 / 1

R1 setting: PS = 1.2, TMS = 0.2

NI characteristics

Fault level 36000 A

6600 V side



CT ratio: 200 / 1

Desired discrimination time between R1 and R2 for 415 V fault = 0.3 sec.

To find: Operating time for R1 and R2 for 415 V fault

Characteristics of R2

Setting – (50) and (51) of R2

Solutiion:

415 V side

P.O.C. = 3000 * 1.2 =3600 A

PSM = 36000 / 3000 = 12

For Ni characteristics R1 → OT = 0.15 * 0.14 / ($(12)^{0.02}$ – 1.0)

= 0.41 sec

Desired discrimination time between R1 and R2 for 415 V fault = 0.3 sec

Desired operating time for R2 = 0.41 + 0.3 = 0.71 sec for 415 V fault.

Relay R2 characteristics → VI (HT side of transformer)

Fault level on 415 V side = 36000 A

Reflected fault current on 6.6 kV side = 415 / 6600 * 36000 = 2264 A

Pick up setting = 1.3 * 2264 = 2943 A

Plug setting = 2943 / 200 = 14.7 A

Set PS = 15 A

Actual Primary setting = 15 * 200 = 3000 A

Since, HT fault level is 15 kA, instantaneous of R2 will operate for HT faults but will not pick up for LT faults

P.O.C. of R1 = 3000 * 1.2 =3600 A

Reflected current on 6.6 kV side = 415 / 6600 * 3600 = 226 A

Plug Setting = 226 / 200 = 1.13 A

Set PS = 1.25 A

P.O.C. of R2 =200 * 1.25 = 250 A

Reflected fault current on 6.6 kV side = 415 / 6600 * 36000 = 2264 A

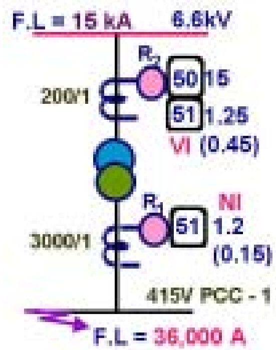
Plug Setting Multiplier PSM = 2264 / 250 = 9.1

PSM of R2 = 9.1

For VI characteristics

Operating time at TMS = 1.0

OT = 13.5 / (9.1 – 1.0) = 1.67 sec



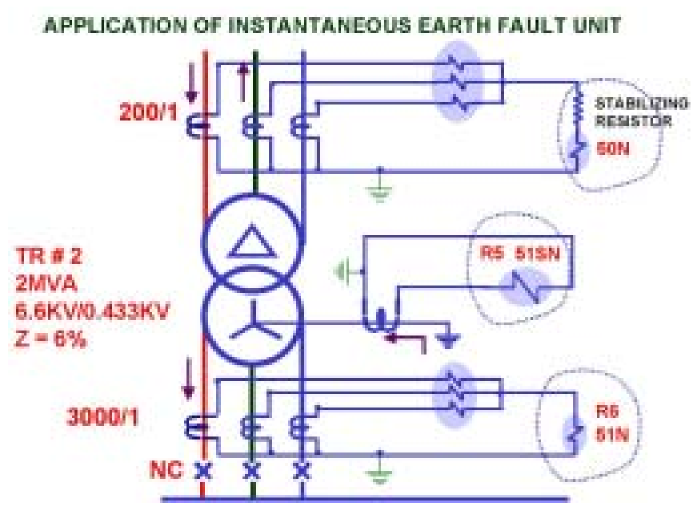
Desired operating time for 415 V fault = 0.71 sec

Time Multiplier Setting TMS = 0.71 / 1.67 = 0.425

Set TMS = 0.45

Actual operating time for 415 V fault = 1.67 * 0.45 =0.75 sec

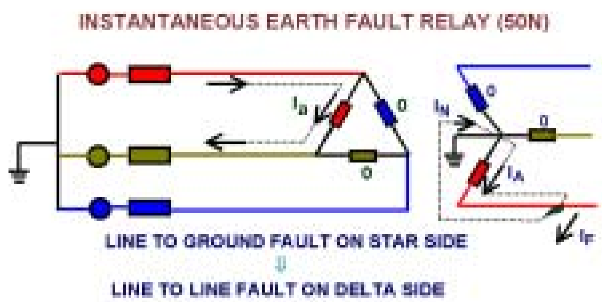
- **Instantaneous earth fault (50N)**



- **Applicable On Delta Side Of Star- Delta Transformer**
- **Earth fault on star side of transformer**
- **Return path for any earth faults at star side of star / delta**

transformers is via transformer neutral.

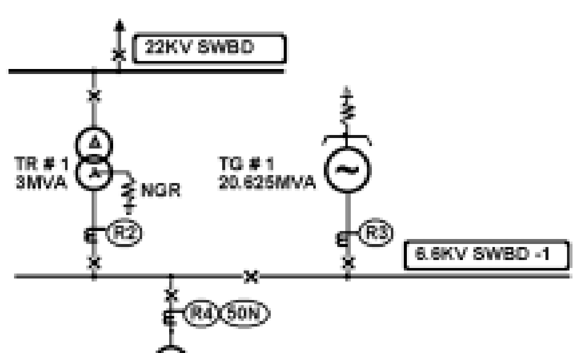
- Earth fault relay connected in residual circuit - measures only zero sequence current.
- No zero sequence current flows in line side of transformer delta.



- Thus, earth fault relay on delta side of transformer primary remains inoperative for star side earth faults.
- Delta provides natural isolation for zero sequence currents
- No co-ordination required for ground faults between star & delta side of transformer .
- Hence, possible to use instantaneous earth fault relay (50N) at transformer primary

- **Advantage**

APPLICATION OF INSTANTANEOUS EARTH FAULT UNIT



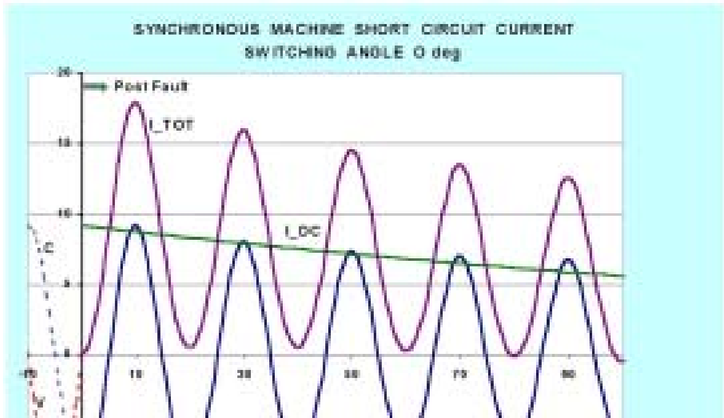
Fig_RC_9 B

- **Upstream relays R2 & R3 operating time for 6.6 kV faults will reduce drastically as R4 will be instantaneous.**
- **Example of instantaneous earth fault relays:**
- **Electromechanical relays:**

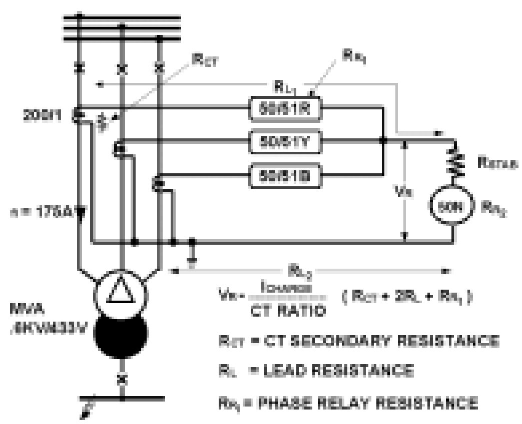
  CAG11, CAG12, CAG14

- **All numerical relays have in built instantaneous earth fault feature. e.g.**
  - **ABB make- SPACOM SERIES - SPAJ 140C**
  - **SIEMENS make - 7SJ 600**
  - **GE MULTILIN make - SR 750 (Feeder Management relay)**

- **Generally requires stabilising resistor to prevent spurious tripping during transients.**

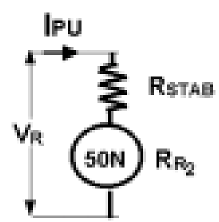


- **Example**



$$V_R / I_{PU\ (50N)} = R_{STAB} + R_{R2}$$

$$R_{STAB} = V_R / I_{PU} - R_{R2}$$



- **$R_{CT} = 4\ \Omega$**
- **Length = 100m, $R_L = 8\ \Omega$ /km**

  $R_{L1} = R_{L2} = 0.8\ \Omega$ FOR 100m

- **Burden : 50-51R = 1VA**
- **$I_{PU} = 1A$**
- $$R_{R1} = \frac{\text{Burden}}{(I_{PU})^2} = \frac{1VA}{(1)^2} = 1\ \Omega$$

- $R_{R2} = \dfrac{\text{Burden}}{(I_{PU})^2} = \dfrac{1VA}{(0.1)^2} = 100\ \Omega$

- $V_R = \dfrac{I_{CHARGE}}{CT_{\ RATIO}} (4 + 2 \times 0.8 + 1)$

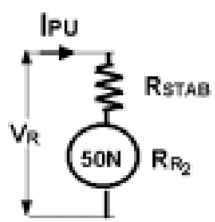
$$= \frac{8 \times 175}{200} (4 + 1.6 + 1)$$

$= 7\ (6.6)$

$= 46.20V$

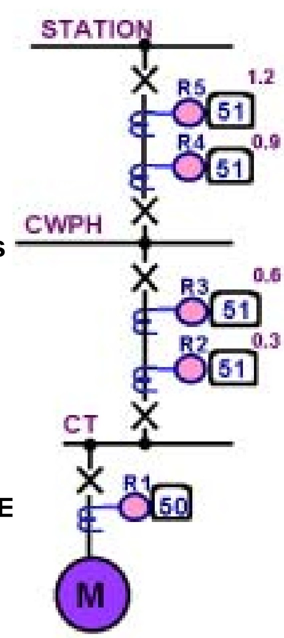
- $R_{STAB} = \dfrac{46.20}{0.1} - 100$

$= 462 - 100$



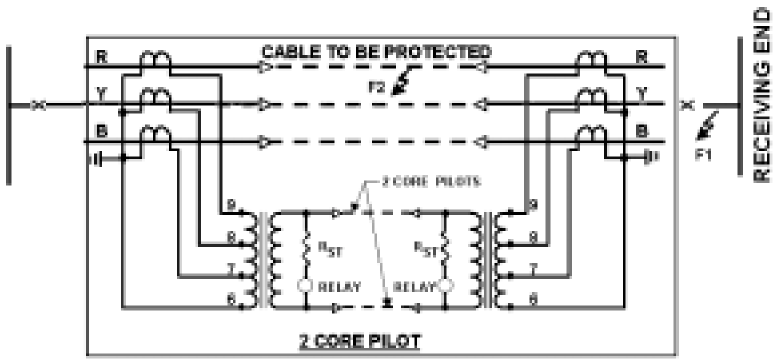
$= 362\ \Omega$

Fix R_{STAB} Above 362 Ω



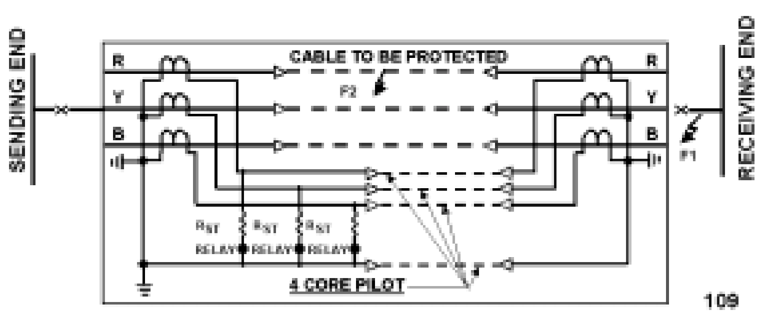
- **Pilot Wire protection**
  - **High speed tripping on cable faults**
    - **Pilot wire protection unit is used to clear cable faults instantaneously.**
  - **This reduces damage to the cables & increases stability of network.**
  - **Reduces fault clearance time of upstream relays.**

- In case of large interconnected networks with number of tie lines, the upstream relays - located on grid & generator feeders - operating time becomes too high.
- In order to reduce upstream relays operating time, pilot wire protection employed.
- Application
- Pilot wire protection relay - used for cable of length > 500 mtrs.
- Example of pilot wire protection relay:
- Static Relays : e. g. Horm- 4 – Alstom Make.



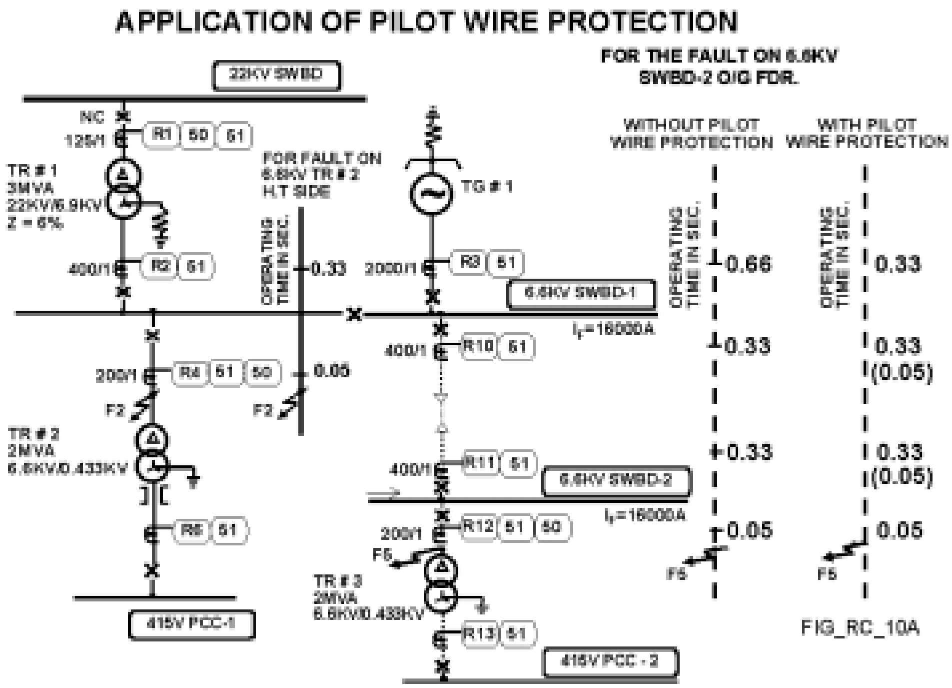
- Pseudo pilot wire protection relay (Feeder Differential Protection)
- High impedance differential relay.
- Example
  - CAG 34 - Electro Mechanical Type
  - MCAG34 - Static Relays
  - RADHA - ABB Combiflex

R1, as or



R

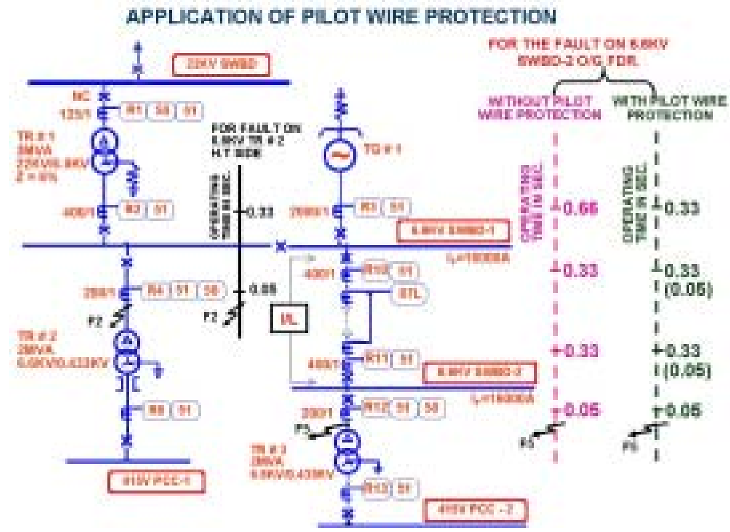
- **Example**



Fig_RC_10A

- **Location : 6.6 kV SWBD - 1.**
- **Consider another outgoing radial feeder to SWBD-2.**
- **Before provision of pilot wire protection : for fault on H.T. of transformer TR-3**
- **R12 - Primary protection operates instantaneously ≅ 50 msec.**
- **R11 Acts as first back up operates in 330 msec.**
- **R10 Acts as second back up operates in 330 msec.**
- **R2 ,R3 Acts as third back up with desired operating time - 660msec. (Co ordination interval between R10 & R2/R3 330 msec.)**
- **Thus, operating time of relay R2 & R3 increased to 660 msec. compared with 330 msec without this SWBD - 2 feeder.**

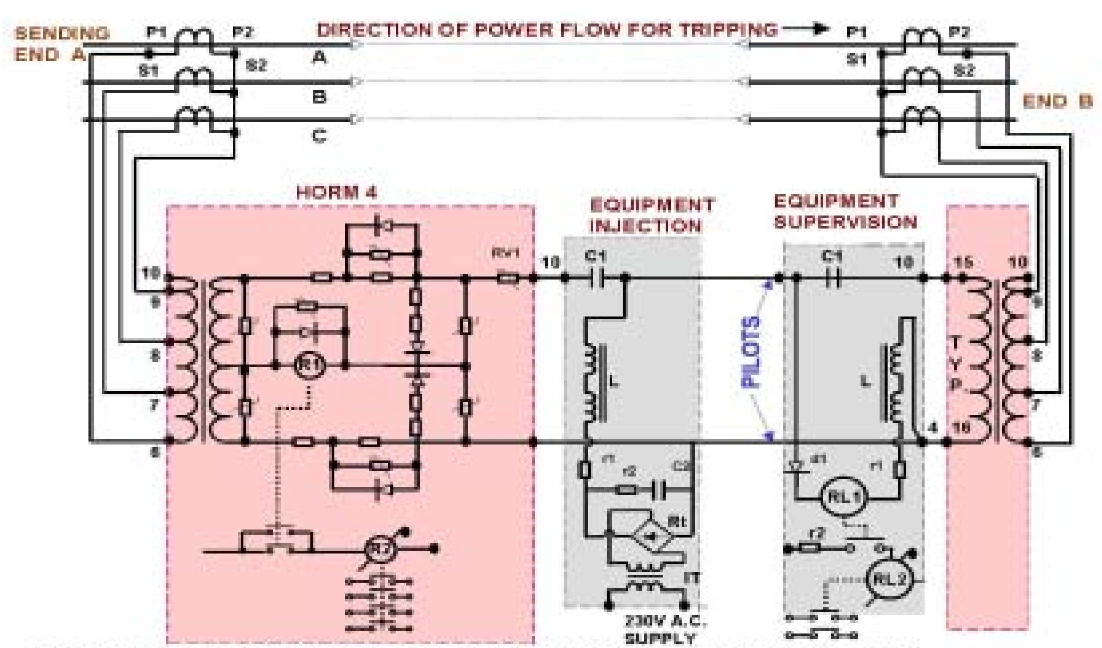
- **After provision of pilot wire protection relay to the 6.6 kV SWBD - 1 to SWBD - 2**



  - **Any cable fault, which are frequent will be cleared instantaneously by pilot wire protection.**
  - **Hence, operating time of relays R2 & R3 FOR 6.6 kV faults can be only 330 milliseconds**

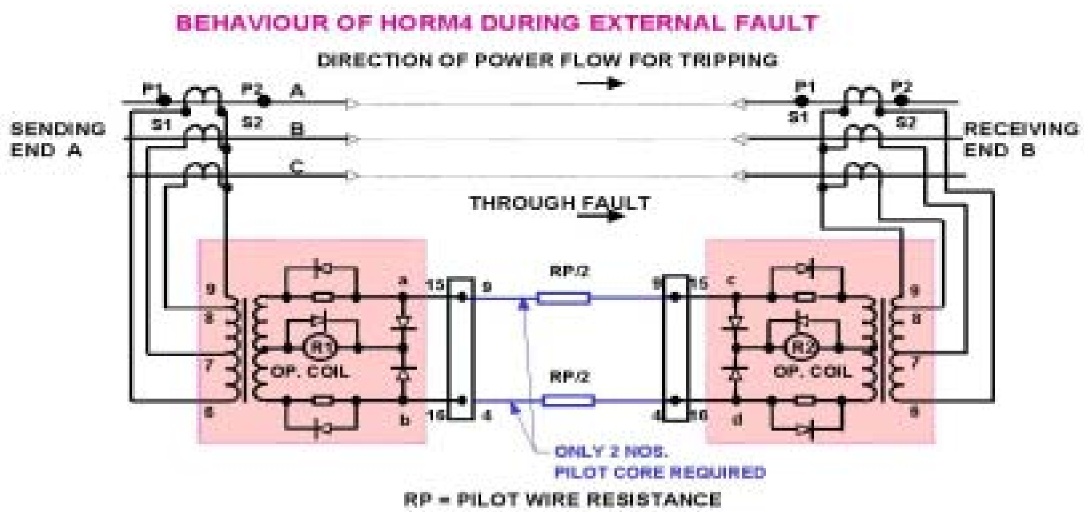
  - **This on assumption that bus faults are very rare.**
    - **HORM 4 - Schematic**

R1



TYPICAL SCHEMATIC DIAGRAM OF PILOT WRE PROTECTION RELAY, TYPE HORM 4, WITH PILOT SUPERVISION

- **Response of HORM 4 for external fault**



- **Bus bar protection**

  Though the bus faults are rare, the damages caused by bus faults are very severe. This may require clearing of bus faults instantaneously. In system with two bus sections, it will be desirable to isolate the faulty bus section at the earliest, to maintain continuity of the supply through the healthy bus section.

- **Differential protection**

- **Restricted E/F protection etc.**

Typical Relay Setting & Co-ordination Exercise

- **The initial discussions centered around individual protections. This was given for basic understanding of concepts involved. Using all these concepts, now we will attempt to do Relay Co-ordination for an entire system.**
- **Normally these are done separately for Phase fault and Ground fault.**
- **Since Ground faults are more frequent, these settings shall be scrutinized more thoroughly.**
- ***Phase Fault* :**
    - **Fig. 11.**

R1, as on 0

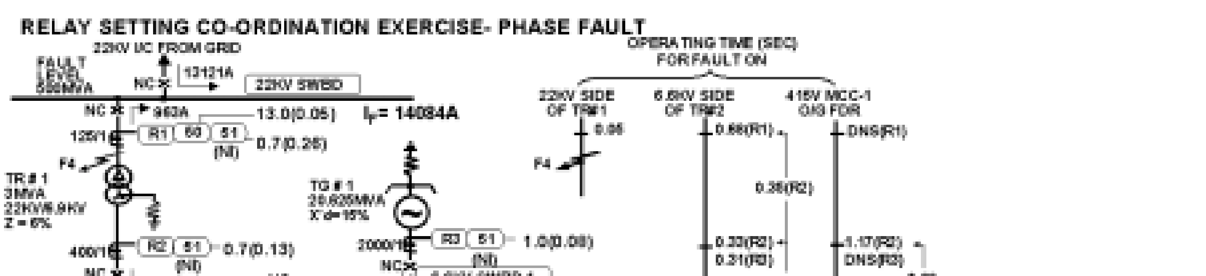


Fig. 11

- Relay R7 : Location : Incomer of MCC-1 (415 V)
  - C.T.R = 1600/1
  - Relay type = SPAJ140C (SPACOM series ABB make)
  - Over current IDMT unit (51) :

    Pick up = (0.5 - 2.5) x In, Step = 0.1 In

    Time Dial = 0.05 - 1.00, Step = 0.01
- Fault current = 38872A , (Obtained from Three Phase fault calculation)
- Max. Running Load current = 583A
- Highest Rating Drive Starting current = 869A
- Highest Rating Drive Full Load current = 145A

For R7?? : PS?, Actual P.O.C?, PSM.? Characteristics? OT @ 1 TMS? OT @1 TMS ?

- Pick up, PS $= \dfrac{I_{RL} + I_{STM} - I_{FLM}}{\text{C.T.R.}}$

  $= \dfrac{(583 + 869 - 145)}{1600}$

  $= 0.816$

  Set PS at 0.9A

- Actual Primary Operating Current (P.O.C.) = C.T.R. x P.S.
  = 1600 x 0.9
  = 1440A

- PSM $= \dfrac{\text{Fault Current}}{\text{Actual P.O.C.}}$

  $= \dfrac{38872}{1440}$

  $= 26.99$

- *Choose Extremely Inverse (EI) characteristic* :

  Relay R7 to be graded with fuse. EI characteristic is particularly suitable for grading with fuse due to it's long operating time for lower arcing faults.

- Operating Time of R7 @ Time Dial 1.0 $= \dfrac{80}{(PSM)^2 - 1}$ for EI

- Operating Time = 0.2 Sec for PSM = 20 & Time Dial = 1.0

- **Desired operating Time t1:**

Downstream fuse blow-off time t = 0.01 Sec

Co-ordination interval td = 0.4 t + 0.15

= 0.154 Sec.

Desired operating time t1 = t + td

= 0.01 + 0.154

= 0.164 Sec.

- **Desired Time Dial TMS :**
  for PSM = 10,
  TMS =1.0 ⇒ OT^1 = 3.0 sec

$$TMS = 0.4 \Rightarrow OT = 0.4 \times \frac{3}{1.0} = 1.2\ SEC$$

$$OT = TMS\ OT^1$$

Operating time at any = TMS x operating time AT

$$TMS = \text{Required Time Setting} = \frac{OT}{OT^1}$$

$$= \frac{\text{Desired Operating Time}}{\text{Operating Time @ TMS = 1.0}}$$

OT ⇒ From Coordination Requirement

OT^1 ⇒ From Equation Or Standard Graphs

$$TMS = \frac{\text{Desired operating time t1}}{\text{Operating Time @ TMS 1.0 \& PSM 20}}$$

$$= \frac{0.164}{0.20}$$

= 0.82

Set Time Dial at 0.85. [Time Dial = 0.05 - 1.00, Step = 0.01]

- Operating Time = 0.17 Sec. for faults. [0.2 x 0.85]
- With above settings, proper co-ordination with downstream fuse can be obtained as seen from Fig. 12.
- Relay R6 : Location : Incomer of PCC-1 (415V)
  - C.T.R = 3000/1
  - Relay type = SPAJ 140C (SPACOM series ABB make)
  - Over Current IDMT unit (51)

    Pick up = (0.5 - 2.5) x In, Step = 0.1 In

    Time Dial = 0.05 - 1.00, Step = 0.05

- Fault current through Relay R6 for fault at 415V MCC-1 = 38872A (Obtained from Three Phase fault calculation)
- Max. running load current = 2782A
- Highest drive starting current = 869A
- Highest drive full load current = 145A
- Pick up PS

$$= \frac{I_{RL} + I_{STM} - I_{FLM}}{C.T.R.}$$

$$= \frac{(2782 + 869 - 145)}{3000}$$

$$= 1.169$$

Set PS at 1.2A

- **Actual Primary Operating Current (P.O.C.) = C.T.R. x P.S.**

  = 3000 x 1.2

  = 3600A

- **PSM = $\dfrac{\text{Fault Current}}{\text{Actual P.O.C}}$**

  = $\dfrac{38872}{3600}$

  = 10.797

- ***Choose Normal Inverse (NI) Characteristic* :**

- **Operating Time of R7 @ PSM 10.797 & Time Dial 1.0 = $\dfrac{0.14}{(PSM)^{0.02} - 1}$ for NI**

- **Operating Time = 2.87 Sec for PSM = 10.797 & Time Dial = 1.0**

- **Desired operating Time t1:**

  Downstream relay R7 operating Time t = 0.17 Sec

  Co-ordination interval td = (0.25 t + 0.25)

  = 0.2925 Sec.

  Desired operating Time t1= t + td

  = 0.17 + 0.2925

  = 0.4625 Sec.

- **Desired Time Dial TMS:**

  TMS = $\dfrac{\text{Desired operating Time t1}}{\text{Operating Time @ TMS 1.0}}$

  = $\dfrac{0.4625}{2.87}$

= 0.1611

Set Time Dial at 0.17. [Time Dial = 0.05 - 1.00, Step = 0.01]

- Operating Time = 0.49 Sec. for faults. [2.87 x 0.17]
- With above settings, proper co-ordination with downstream relay R7 can be obtained as seen from Fig. 12.

- Relay R4: Location : 2 MVA Transformer Primary (6.6 kV)
  - C.T.R = 200/1
  - Relay type = SPAJ 140C (SPACOM series ABB make)
  - *IDMT Over Current IDMT unit (51)* :

    Pick up = (0.5 - 2.5) x In, Step = 0.1 In

    Time Dial = 0.05 - 1.00, Step = 0.01

  - *Instantaneous Over Current IDMT unit (50)* :

    Pick up = (0.5-40) x In, Step = 0.1 In

    Time delay = 0.04 - 300 Sec., Step = 0.01 Sec.

- For fault on the L.T. side of Transformer TR – 2 :

  Fault current = 39227A @ 415 V

  = 2467A @ 6.6 kV

- For the fault on the H.T. side of the same Transformer TR - 2,

  Fault Current = 16000A @ 6.6kV

- ***Instantaneous Over-Current element (50) setting*** **:**

  - **Provides Primary protection to the 6.6 kV H.T. faults.**
  - **This Instantaneous Over-Current element of relay should not Pick up for L.T. faults.**
  - **Desired Primary Operating current (P.O.C) = 1.3 x 415Vreflected fault current @ 6.6kV**

    = 1.3 x 2467

    = 3207A

  - **Pick up, PS = $\frac{\text{P.O.C.}}{\text{C.T.R.}}$**

    = $\frac{3207}{200}$

    = 16.035A

    Set Pick up at 17A

  - **Set Time Delay at 50 msec.**

    [Time Delay = 0.04 - 300 Sec., Step = 0.01 Sec]

    Time delay essential to prevent Instantaneous element Pick up during transformer charging,

- ***IDMT Over-Current element (51) setting*** **:**

  - **Provides back up to the 415V faults.**
  - **Desired P.O.C. of downstream relay R6 = 3600 A @ 415V**

    = 226A @ 6.6kV

  - **Pick up PS = $\frac{\text{Desired P.O.C.}}{\text{C.T.R.}}$**

$$= \frac{226}{200}$$

$$= 1.13$$

Set PS at 1.2A

If, C.T. ratios on H.T. & L.T. side $\cong$ Rated current Ratios on H.T. & L.T. side.

PS of 51 on L.T. & H.T. side almost the same.

- Actual Primary Operating Current (P.O.C.) = C.T.R. x P.S.
  = 200 x 1.2
  = 240A

- PSM = $\frac{\text{415V fault current reflected @ 6.6 kV}}{\text{Actual P.O.C}}$

  $= \frac{2467}{240}$

  $= 10.18$

- *Choose Normal Inverse (NI) Characteristic* :

  Operating time of R4 @ Time Dial 1.0 $= \dfrac{0.14}{(PSM)^{0.02} - 1}$ for NI

- for PSM = 10.18 & Time Dial = 1.0

  Operating Time = 2.947 sec

- Desired Operating Time t1:

  Downstream relay R6 operating time t = 0.49 Sec

  Co-ordination interval td = (0.25 t + 0.25)

  = 0.3725 Sec.

  Desired Operating Time t1 = t + td

= 0.49 + 0.3725

= 0.86 Sec.

- **Desired Time Dial TMS:**

TMS = $\dfrac{\text{Desired operating time t1}}{\text{Operating Time @ PSM 10.18 \& TMS 1.0}}$

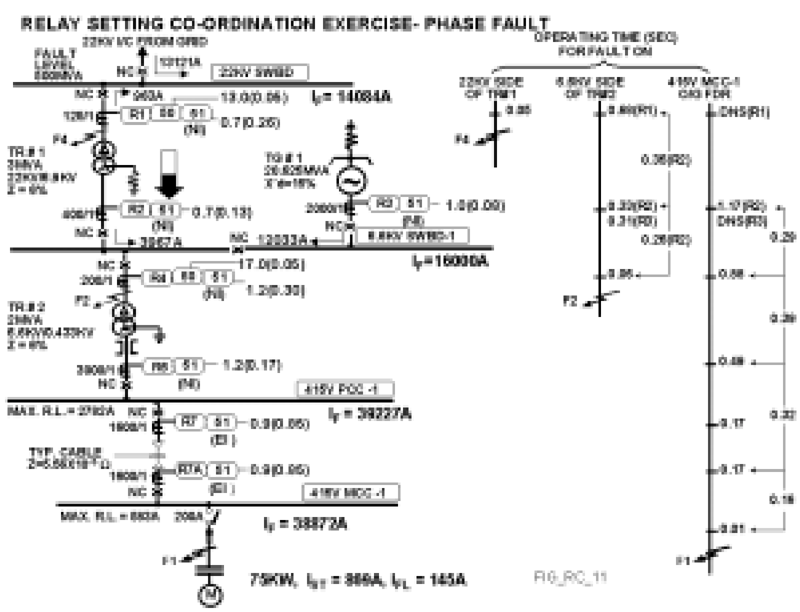
$= \dfrac{0.86}{2.947}$

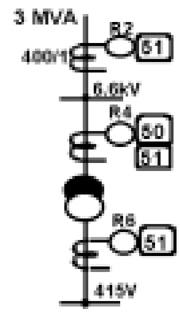
$= 0.2917$

Set Time Dial at 0.30. **[Time Dial = 0.05 - 1.00, Step = 0.01]**

- **Operating Time = 0.88 Sec. for faults.** **[2.947 x 0.30]**

- **Relay R2 : Location : Incomer from Grid Transformer TR-1 (6.6 kV)**
  - **FIG_RC_ 11**





- C.T.R = 400/1
- Relay type = SPAJ 140C (SPACOM series ABB make)
- Over Current IDMT unit (51)

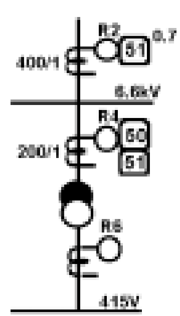
  Pick up = (0.5 - 2.5) x In, Step = 0.1 In

  Time Dial = 0.05 - 1.00, Step = 0.01

- Max. Running Load Current = 262A [Full Load current of TR-1]
- No H.T. motor considered in this example. If H.T. motor is present then the Plug Setting for relay R2 shall be raised to override the motor starting.
- <u>For fault on 6.6 kV bus</u> :
  - Total fault current = 16000A.
  - Contribution through TR-1 from Grid = 3967A
- <u>For fault on 415V bus</u> :
  - Total fault current = 2467A @ 6.6kV
  - Contribution through TR-1 from Grid = 607A @ 6.6 kV
- Pick up PS = $\dfrac{I_{RL} + I_{STM} - I_{FLM}}{\text{C.T.R.}}$

  $= \dfrac{262}{400}$

  $= 0.65$



Set PS at 0.7A

- Actual Primary Operating Current (P.O.C.) = C.T.R. x P.S.

  = 400 x 0.7

  = 280A

- PSM for 6.6 kV fault contribution from Grid $= \dfrac{\text{Fault current}}{\text{Actual P.O.C.}}$

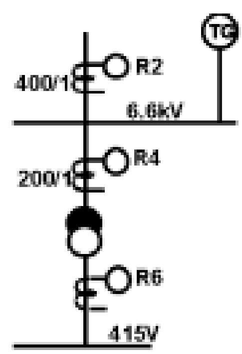
  $= \dfrac{3967}{280}$

  = 14.2

- PSM for 415V fault contribution from Grid $= \dfrac{\text{Fault current}}{\text{Actual P.O.C.}}$

  $= \dfrac{607}{280}$

  = 2.17



- For 415V faults :

  Co-ordination interval td = (0.25 t + 0.25)

  = 0.47 Sec. [t = 0.88 Sec]

  Desired Operating Time t1 = t + td

  = 0.88 + 0.47

  = 1.35 Sec.

- **For 6.6 kV faults :**

Co-ordination interval td = **(0.25 t + 0.25)**

= **0.26 Sec.** **[t = 0.05 Sec]**

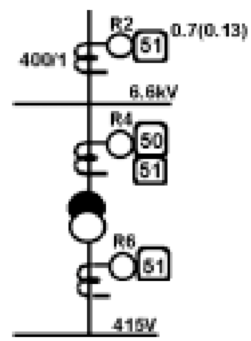
Desired operating Time t1 = **t + td**

= **0.05 + 0.26**

= **0.31 Sec.**

- **Desired Time Dial TMS:**

  - **For 6.6 kV faults:**



For PSM 14.2 & Time Dial 1.0 ,

$$\textbf{Operating Time} = \frac{0.14}{(14.2)^{0.02} - 1} \quad \textbf{for NI}$$

$$= 2.568 \text{ Sec.}$$

$$\textbf{TMS} = \frac{\text{Desired operating Time t1 HV}}{\text{Operating Time @ TMS 1.0}}$$

$$= \frac{0.31}{2.568}$$

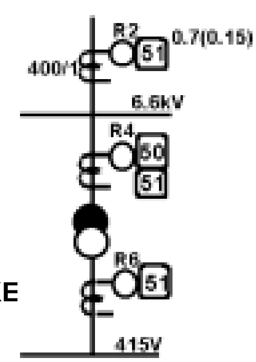
$$= 0.1207$$

  - **For 415V faults :**

For PSM = 2.17 & Time Dial = 1.0 ,

$$\textbf{Operating Time} = \frac{0.14}{(2.17)^{0.02} - 1} \quad \textbf{for NI}$$

$$= 8.98 \text{ Sec.}$$



TMS = $\dfrac{\text{Desired operating Time t1LV}}{\text{Operating Time @ TMS 1.0}}$

$$= \frac{1.35}{8.98}$$

$$= 0.150$$

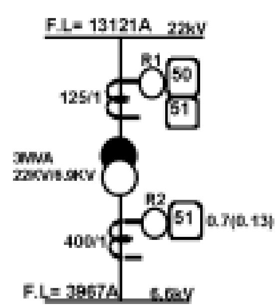
- Theoretically it may be desirable to select higher TMS (0.15 in this example) to achieve proper co-ordination for both faults. However, this increases operating time of upstream relays still further.
- Since R2 acts as Second back up for L.T. PCC bus faults, perfect Co-ordination with relay R4 not essential.
- Hence, select TMS = 0.13 [Time Dial = 0.05 - 1.00, Step = 0.01]
- Operating Time = 0.33 Sec for 6.6 kV faults. [2.568 x 0.13]
- With above settings, proper co-ordination with downstream relay R4 can be obtained for 6.6 kV faults, as seen from Fig. 12.

- **Relay R1 : Location : Grid transformer TR - 1 Primary (22kV)**
  - **C.T.R = 125/1**
  - **Relay type = SPAJ 140C (SPACOM series ABB make)**

  - **IDMT Over Current unit (51) :**

    Pick up = (0.5 – 2.5) x In, Step = 0.1 In

    Time Dial = 0.05 - 1.00, Step = 0.05



- Instantaneous Over Current unit (50) :
  - Pick up = (0.5 - 40)x In, Step = 0.1 In
  - Time Delay = 0.04 - 300 Sec., Step = 0.01 Sec.
- **<u>For fault on 6.6 kV bus</u>** :
  - Contribution through TR - 1 from Grid = 1190A @ 22kV
- **<u>For fault on transformer H.T. winding</u>** :

  Current through relay R1 = contribution from Grid @ 22kV

  = 13121A

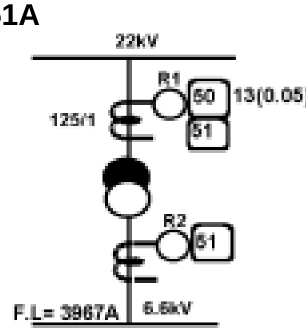
- Instantaneous Over-Current element (50) setting :
  - Provides Primary protection to the 22 kV H.T. faults.
  - This Instantaneous Over-Current element of relay should not Pick up for 6.6kV faults.
  - Primary Operating current (P.O.C) = 1.3 x current through relay R1 for 6.6 kV fault

    = 1.3 x 1190

    = 1551A
  - Pick up PS = $\frac{\text{P.O.C.}}{\text{C.T.R.}}$

    = $\frac{1551}{125}$

    = 12.41A



Set Pick up at 13A.

- Set Time delay at 50 msec.

- **IDMT Over-Current element (51) setting :**
  - **Provides back up to the 6.6 kV faults.**
  - **Primary Operating Current of downstream relay R2**

    = 280 A @ 6.6kV

    = 84A @ 22kV

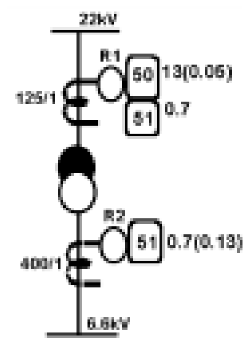
Desired Primary Operating Current of relay R1 = Primary Operating current of downstream relay R2

- **Pick up, PS =** $\dfrac{\text{Desired P.O.C.}}{\text{C.T.R}}$

  $= \dfrac{84}{125}$

  $= 0.672$

  Set PS at 0.7A



- **Actual Primary Operating Current (P.O.C.)** = C.T.R. x P.S.

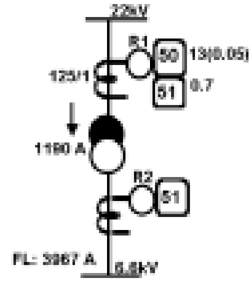
  = 125 x 0.7

  = 87.5A

- **PSM for current through Relay R1 for 6.6 kV fault** $= \dfrac{\textbf{Reflected fault current}}{\textbf{Actual P.O.C}}$

  $= \dfrac{1190}{87.5}$

  PSM = 13.6



- **Choose Normal Inverse (NI) Characteristic :**

  Operating Time of R1 @ selected PSM & Time Dial 1.0 $= \dfrac{0.14}{(PSM)^{0.02} - 1}$ **for NI**

- **Operating Time = 2.6125 Sec, for PSM = 13.6 & Time Dial = 1.0**

- **Desired operating Time t1 :**

  - **For 6.6kV faults, relay R1 shall discriminate with IDMT Over-Current unit (51) of relay R2.**

    Downstream relay R2 operating Time :

    IDMT element (51) : t = 0.33 Sec for 6.6 kV faults.

  - **For 6.6 kV faults :**

    Co-ordination interval td = (0.25 t + 0.25)

    = 0.3325 Sec. [t = 0. 33 Sec]

    Desired Operating Time t1 = t + td

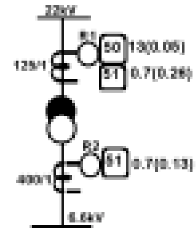
    = 0.33 + 0.3325

    = 0.6625 Sec.

- **Desired Time Dial TMS :**
  TMS for 6.6 kV faults = **Desired Operating Time t1 / Operating Time @ TMS 1.0**

  = **0.6625 / 2.6125**

  = **0.2535**



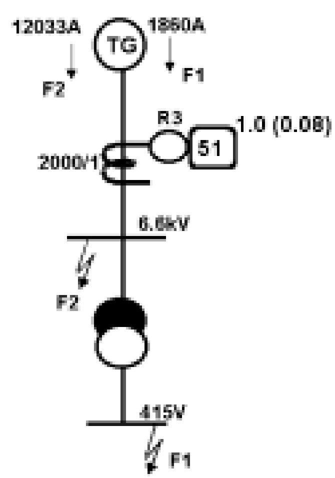
  Set TMS at 0.26 **[Time Dial = 0.05 - 1.00, step=0.01]**

- **Operating Time = 0.68 Sec. for 6.6 kV faults.** **[2.6125 x 0.26]**
- **With above settings, proper co-ordination with downstream relay R2 can be obtained for 6.6 kV faults, as seen from Fig. 12.**

- **Relay R3 : Location : Incomer from Generator TG - 1 (6.6kV)**
  - **C.T.R = 2000/1**
  - **Relay type = SPAJ 140C (SPACOM series ABB make)**
  - **Over Current IDMT unit (51) :**

    Pick up = (0.5 - 2.5) x In, Step = 0.1 In

    Time Dial = 0.05 - 1.00, Step = 0.05



- **For fault on 6.6 kV bus :**
  - **Total fault current = 16000A.**
  - **Contribution by TG – 1 = 12033A**

    { from the fault study output }

- **For fault on 415V PCC-1 :**
  - **Total fault current = 2467A @ 6.6kV**
  - **Contribution by TG-1= 1860A @6.6kV**
- **Max. running load current = 1804A [Full Load Current of TG-1]**
- **Pick up, PS** $= \dfrac{\text{Running Load Current}}{\text{C.T.R.}}$

$$= \frac{1804}{2000}$$

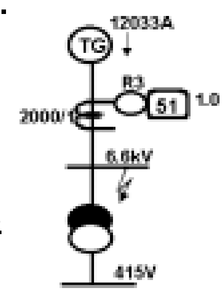
$$= 0.902$$

Set PS at 1.0A

- **Actual Primary Operating Current (P.O.C.) = C.T.R. x P.S.**

$$= 2000 \times 1.0$$

$$= 2000\text{A}$$



- **PSM for 6.6 kV fault current contribution of TG-1.** $= \dfrac{\text{Fault current through relay R3}}{\text{Actual P.O.C}}$

$$= \frac{12033}{2000}$$

$$= 6.02$$

- **PSM for 415V fault contribution of TG-1** $= \dfrac{\text{Fault Current}}{\text{Actual P.O.C.}}$

$$= \frac{1860}{2000}$$

$$= 0.93$$

Relay R3 does not sense the 415V faults as PSM < 1.0

- Choose Normal Inverse (NI) Characteristic :

  Operating Time of R3 @ selected PSM & Time Dial 1.0 $= \dfrac{0.14}{(PSM)^{0.02} - 1}$ for NI

- Operating Time for 6.6 kV faults = 3.833 Sec.

  for PSM = 6.02 & Time Dial = 1.0

- Desired operating Time t1:

  - Relay R3 does not sense 415Vfaults. Hence, no need of further calculation.
  - For 6.6kV faults, relay R3 shall discriminate with Instantaneous Over-Current unit (50) of relay R4
  - Downstream relay R4 operating Time

  Instantaneous element (50) : t = 0.05 Sec. for 6.6kV faults.

  - For 6.6 kV faults :

    Co-ordination interval td = (0.25 t + 0.25)

    = 0.26 Sec. [t = 0.05 Sec]

    Desired Time of Operation t1 = t + td

    = 0.05+ 0.26

    = 0.31 Sec.

- **Desired Time Dial TMS :**

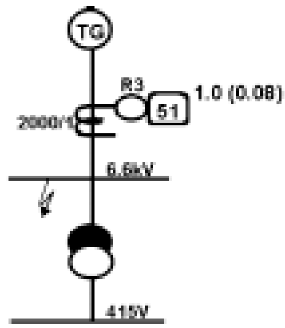
TMS for 6.6 kV faults = $\frac{\textbf{Desired operating Time t1}}{\textbf{Operating Time @ PSM 6.01\& TMS 1.0}}$

$= \frac{0.31}{3.833}$

$= 0.078$

Set TMS at 0.08 **[Time Dial = 0.05 - 1.00, Step = 0.01]**

- **Operating Time for 6.6 kV faults = 0.31 Sec.** **[3.833 x 0.08]**



- **Co-ordination between R3 & R4 obtained. Refer Fig.12.**

- ***Ground Fault*** **:**

  - **Solidly Grounded system :**

    Fault current is typically in kAmps.

  - **Medium Resistance Grounded system :**
    - **Fault current limited to transformer full load current or**
    - **Typically around 400 Amps.**

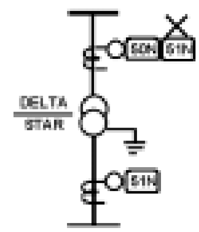
  - **High Resistance Grounded system :**

    Fault current limited to less than 15 Amps.

- Criterias for selecting Ground fault Pick up setting :
- For Solidly Grounded System :
  - Higher Pick up shall be selected to avoid excessive current through the relay.
  - By adopting higher Plug Setting, Sensitivity is not sacrificed as fault current is in kAmps.

- For High Resistance Grounded System :
  - Pick up shall be low enough to obtain desired Sensitivity. This is true as fault current is low. This current further reduces for arcing faults.

  - To increase Sensitivity, sometimes 5A C.T. connected to 1A relay.
- Ground relay senses only zero sequence currents.
  - Flow of zero sequence currents is very much influenced by Transformer Vector Group Connections.

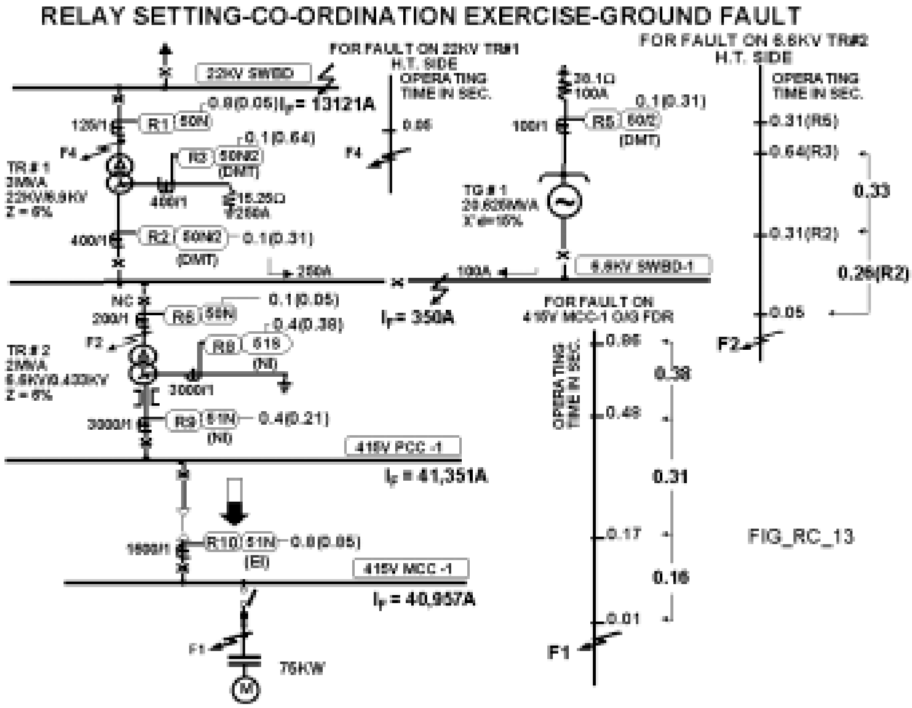


  - Example:
    - Fault on Star side of Delta - Star Grounded Transformer results in flow of Zero Sequence Current on Star side.
    - But, no Zero Sequence Current can flow on Delta side.
    - Hence, providing the back up Ground Over-Current relay (say 51N) on Delta side of Star-Delta Transformer is meaningless.

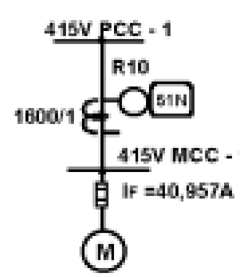
- Detection of faults on the Ungrounded systems can only be done using Voltage relays.

Zero Sequence Voltage obtained through the Open Delta P.T.

- In the Resistance Grounded Systems the fault currents magnitudes remains almost the same irrespective of fault location.
- Fig. 13.



- Relay R10 : Location : Incomer of MCC-1 (415V)
  - C.T.R = 1600/1 Relay type = SPAJ 140
  - C (SPACOM series ABB make)



- Ground fault IDMT unit (51N)

Pick up = (0.1 - 0.8) x In, Step = 0.1 In

Time Dial = 0.05 - 1.00, Step = 0.01

- **Fault current = 40957A (Obtained from Ground fault calculation)**
- **Selection of Plug Settings for Ground fault relays are not influenced by equipment rated current and motor starting current as system is assumed to be balanced. Under these conditions, zero sequence current minimum.**
- **Let PS be set at 0.8A.**

Primary Operating Current of relay (P.O.C.) = 0.8 x 1600

= 1280A.

Current flow through relay @ bolted earth fault $= \frac{40957}{1280}$

= 31.99

Current flow through relay @ arcing earth fault $= \frac{26622}{1280}$ **[40957 x 0.65]**

= 20.798

Thus, relay operating Time will be same for both arcing & bolted earth faults as for both cases PSM >20.

- **Choose Extremely Inverse (EI) Characteristic :**

Relay R10 to be graded with fuse. EI characteristic is particularly suitable for grading with fuse (slopes are almost matching) due to it's long operating time for lower arcing faults.

operating Time of R10 @ Time Dial 1.0 $= \dfrac{80}{(PSM)^2 - 1}$ **for EI**

- **Operating Time = 0.2 Sec for PSM = 20 & Time Dial = 1.0**
- **Desired operating Time t1:**

Downstream fuse blow off Time t = 0.01 Sec

Co-ordination interval $td = (0.4\,t + 0.15)$

$= 0.154$ **Sec.**

Desired operating Time $t1 = t + td$

$= 0.01 + 0.154$

$= 0.164$ **Sec.**

- **Desired Time Dial TMS :**

$$TMS = \frac{\text{Desired operating Time t1}}{\text{Operating Time @ TMS 1.0}}$$

$$= \frac{0.164}{0.20}$$

$$= 0.817$$

Next available set point = 0.85 [Time Dial = 0.05 - 1.00, Step = 0.05]

- **Operating Time = 0.17 Sec. for faul.s.** **[0.2 x 0.85]**

- With above settings, proper co-ordination with downstream fuse can be obtained as seen from Fig. 14A

- Relay R9 : Location : Incomer of PCC-1 (415V)

  - C.T.R = 3000/1
  - Relay type = SPAJ 140C (SPACOM series ABB make)
  - Earth fault IDMT unit (51N) :

    Pick up = (0.1 - 0.8) x In, Step = 0.1 In

    Time Dial = 0.05 - 1.00, Step = 0.05

- Fault current passing through relay for fault at MCC-1 = 40957A (Obtained from Ground fault calculation)

- Set PS at 0.4A.

- Primary Operating Current of relay (P.O.C.) = 0.4 x 3000

  = 1200A.

- Current flow through relay element @ bolted earth fault $= \frac{40957}{1200}$

  = 34.12

- Current flow through relay element @ arcing earth fault $= \frac{26622}{1200}$ [40957 x 0.65]

  = 22.18

Thus, relay operating Time will be same for both arcing & bolted Earth faults as PSM > 20.

- **Chosen characteristic is Normal Inverse (NI) :**

  Operating Time of R9 @ PSM 20 & Time Dial 1.0 $= \dfrac{0.14}{(PSM)^{0.02} - 1}$ **for NI**

  Operating Time = 2.267 Sec for PSM = 20.0 & Time Dial = 1.0

- **<u>Desired Operating Time t1</u> :**

  Downstream relay R10 operating Time t = 0.17 Sec

  Co-ordination interval td = (0.25 t + 0.25)

  = 0.2925 Sec.

  Desired Operating Time t1 = t + td

  = 0.17 + 0.2925

  = 0.4625 Sec.

- **<u>Desired Time Dial TMS</u> :**

  $$TMS = \frac{\text{Desired Operating Time t1}}{\text{Operating Time @ TMS 1.0}}$$

  $$= \frac{0.4625}{2.267}$$

  $$= 0.2040$$

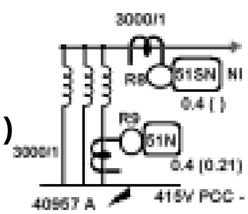
Set TMS at 0.21. **[Time Dial = 0.05 - 1.00, Step = 0.01]**

- **Operating Time = 0.48 Sec. for faults.** **[2.267 x 0.21]**

- **With above settings, proper co-ordination with downstream relay R10 in the desired fault current range can be obtained as seen from Fig. 14A.**

- **Relay R8 : Location : Standby Earth fault relay of TR-2 (415V)**
  - **For any fault between relay R9 & Star winding neutral, relay R9 will not Pick up. There is no back up Ground relay for this fault. Phase Over-Current relay on the Delta side may operate as a back up for Star side Ground faults. But, this will take long time and if system is resistance earthed , it may not operate.**
  - **Line to Ground fault on Star side will be reflected as line to line faults on the Delta side.**
  - **Hence, Relay R8 is provided on the Transformer neutral.**
  - **C.T.R = 3000/1**
  - **Relay type = SPAJ 115C (SPACOM series ABB make)**

    Earth fault IDMT unit (51N)



Pick up = (0.05 - 0.4) x In, Step = 0.1 In

Time Dial = 0.05 - 1.00, Step = 0.05

- **Fault current passing through relay for MCC-1 fault = 40957A (obtained from ground fault calculation)**
- **As discussed for relay R9, set PS at 0.4A.**

  PSM >20, for both bolted & arcing earth faults.

- Chosen characteristic is Normal Inverse (NI) :

  Operating Time = 2.267 Sec. for PSM = 20.0 & Time Dial = 1.0

- Desired Operating Time t1 :

  Downstream relay R9 operating Time t = 0.48 Sec.

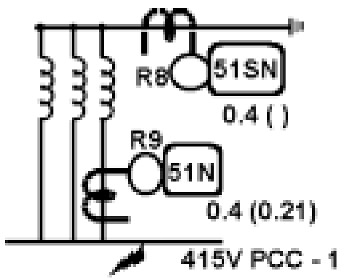
  Co-ordination Interval td = (0.25 t + 0.25)

  = 0.37 Sec.

  Desired Operating Time t1 = t + td

  = 0.48 + 0.37

  = 0.85 Sec.



- Desired Time Dial TMS :

  TMS = $\frac{\text{Desired Operating Time t1}}{\text{Operating Time @ TMS 1.0}}$

  = $\frac{0.85}{2.267}$

  = 0.3749

Set Time Dial at 0.38 [Time Dial = 0.05 - 1.00, Step = 0.05]

- Operating Time = 0.86 Sec. [2.267 x 0.38]
- With above settings, proper Co-ordination with downstream relay R9 can be obtained as seen from Fig. 14A.

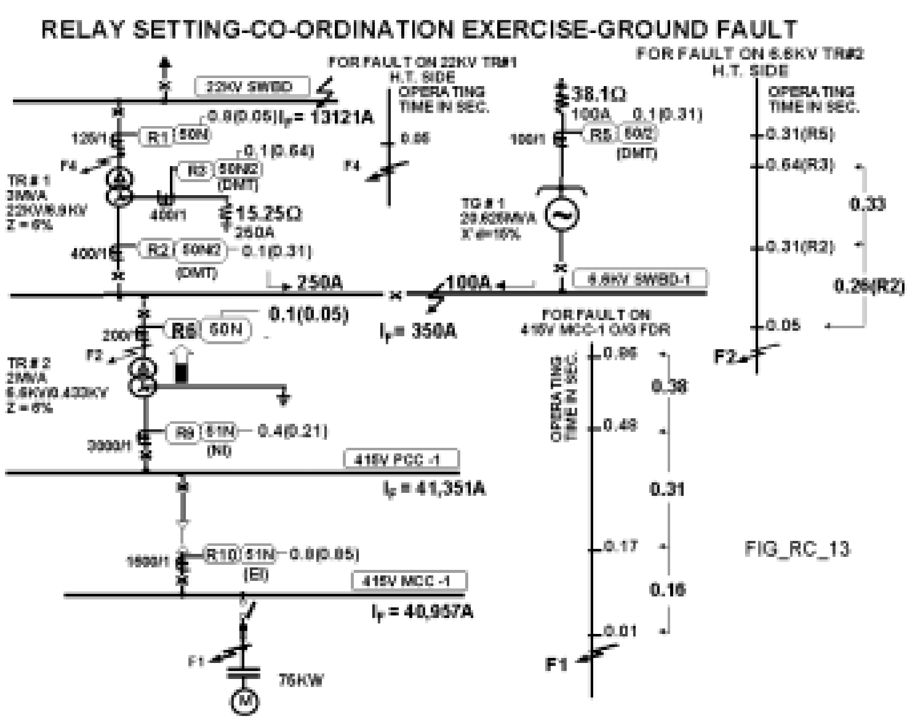
- **Note:**
    - **R9 => Trips L.T. side breaker**
    - **R8 => Trips both H.T. & L.T. side breakers.**
- **Relay R6 : Location : 2 MVA Transformer Delta Primary (6.6kV)**
    - **C.T.R = 200/1**
    - **Relay type = SPAJ 140C (SPACOM series ABB make)**
    - **Instantaneous Over Current unit (50N) :**

      Pick up = (0.1- 0.8) x In, Step = 0.1 In

      Time Delay = 0.04 - 300 Sec., Step = 0.01 Sec.
- **For the fault on the H.T. side of Transformer TR-2 :**

  Fault current = 350A

R1, as

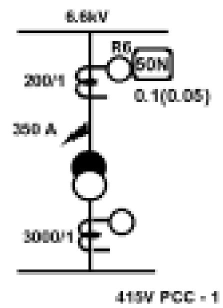


- Let PS be set at minimum 0.1A (Resistance Grounded system).
- Primary Operating Current of relay (P.O.C.) = 0.1 x 200

  = 20A

- Sensitivity of relay $= \frac{20}{350} \times 100$

  = 5.7 %



Thus, relay will Pick up for both arcing & bolted earth faults.

- Time delay is set at minimum i.e. @ 50 msec.
- Relay R2: Location : Incomer from Grid transformer TR-1(6.6 kV)
  - C.T.R = 400/1
  - Relay type = SPAJ 140C (SPACOM series ABB make)
  - Earth fault DMT unit (50N/2)

    Pick up = (0.1 - 0.8) x In, Step = 0.1 In

    Time Delay = 0.05 - 300 Sec., Step = 0.01 Sec

- For 6.6 kV Earth faults, fault current through relay R2 = 250A
- Let PS be set at 0.1A

  (Resistance Grounded System)

- Chosen Definite Minimum Time (DMT) Characteristic.

6.6kV system is Resistance Grounded System. Hence, fault current does not vary much with the location of the fault. No variation in the fault current. Hence IDMT not useful.

DMT relays used : Grading can be obtained using Discrimination by Time Principle.

- **Desired Operating Time t1 :**

Downstream relay R6 Operating Time t	**=**	**0.05 Sec**
Co-ordination interval td	**=**	**(0.25 t + 0.25)**
	=	**0.2625 Sec.**
Desired Operating Time t1	**=**	**t + td**
	=	**0.05+ 0.2625**
	=	**0.31 Sec.**

Set Time delay at 0.31 Sec.

[Time delay = 0.05 -300 Sec, Step = 0.01]

- **With above settings, proper co-ordination with downstream relay R6 can be obtained as seen from Fig. 14B.**
- **Relay R3 : Location : Stand by Earth fault relay of TR-1 (6.6 kV)**
  - **C.T.R.= 400/1**
  - **Relay type = SPAJ 115C (SPACOM series ABB make)**

Earth fault DMT unit (50N/2)

Pick up = (0.05 - 0.4) x In, Step = 0.1 In

Time Dial = 0.05 - 1.00, Step = 0.05

- Set PS at 0.1 A :   Same as relay R2 at the downstream.
- Desired Operating Time t1   :

Downstream relay R2 Operating Time t	=	0.31 Sec
Co-ordination interval td	=	(0.25 t + 0.25)
	=	0.3275 Sec.
Desired Operating Time t1	=	t + td
	=	0.31+ 0.3275
	=	0.6375 Sec.

Set Time delay at 0.64 Sec.

[Time delay = 0.05- 300 Sec, step = 0.01]

- Relay R5 :   Location : Incomer from Generator TG-1 (6.6kV) :
  - C.T.R = 100/1
  - Relay type = SPAJ 140C (SPACOM series ABB make)
  - Earth fault DMT unit (50N/2) :

    Pick up = (0.1 - 0.8) x In, Step = 0.1 In

    Time delay = 0.05 - 300 Sec., Step = 0.01 Sec

- **Set PS at 0.1A**
- **Desired operating Time t1 :**

Downstream relay R6 operating Time

Instantaneous element (50N) t	**=**	**0.05 Sec**
Co-ordination interval td	**=**	**(0.25 t + 0.25)**
	=	**0.26 Sec. [t = 0.05 Sec]**
Desired operating Time t1	**=**	**t + td**
	=	**0.05 + 0.26**
	=	**0.31 Sec.**

Set Time delay at 0.31 Sec.

[Time delay = 0.05 - 300 Sec, Step = 0.01]

- **With above settings , proper co-ordination with downstream relay R6 can be obtained as seen from Fig. 14B**
- **Though as per co-ordination the operating Time is obtained as 0.31 Sec., it can be set higher say 0.6 Sec. so that the Generator trips the last.**
- **Relay R1: Location : Grid Transformer TR-1 Primary (22kV)**
  - **C.T.R = 125/1**
  - **Relay type = SPAJ 140C (SPACOM series ABB make)**
  - **Earth fault Instantaneous unit (50N) :**

Pick up = (0.1 - 0.8) x In, Step = 0.1 In

Time delay = 0.05 - 300 Sec., Step = 0.01 Sec

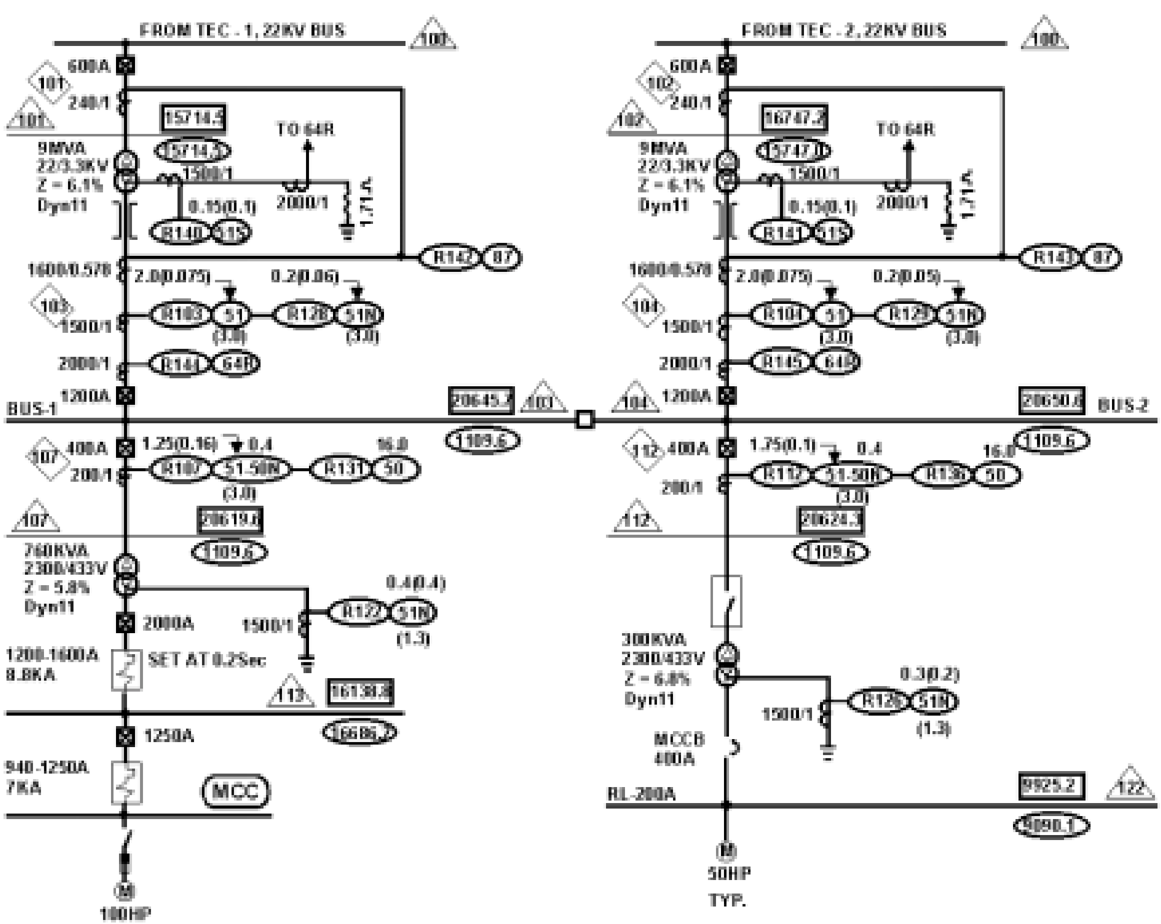
- **For the fault on the H.T. side of the same transformer TR-1 :**

  Fault current = 13121A

  - **Let PS be set 0.8A**
  - **Time delay is set at minimum i.e. @ 50mSec.**

x.x.x.

9.0 Typical Key Single Line Diagram



x.x.x

Glossary Of Terms

Terms	Description
IDMT	Inverse definite minimum Time
DMT	Definite minimum Time relay
NI	Normal inverse
VI	Very inverse
EI	Extremely inverse
H.T.	High Tension
L.T.	Low Tension
SWGR	Switch Gear

O/G	Outgoing
I/C	Incomer
FDR	Feeder

X.X.X

References

Title	Author	Publisher
Protective Relays Application Guide	Alstom Measurements	Alstom Measurements
Protective Relays Application & Selection Volume - 1, 2 of 2	Wan. C. Warrington	Chapman & Hall Ltd.
Art & Science of Protective Relaying	C. Russel. Masson.	John Wiley & Sons.
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