POWER SYSTEM PROTECTION
EE 567

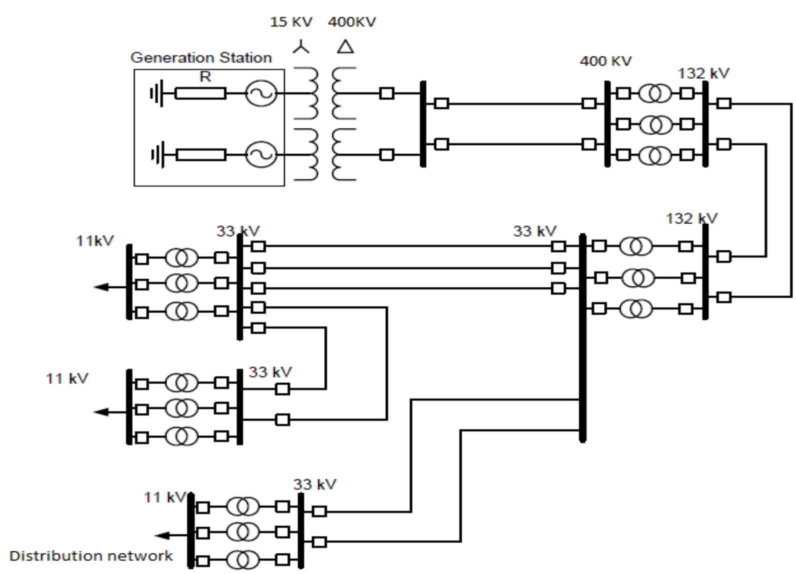
Dr. Feras Alasali

Introduction

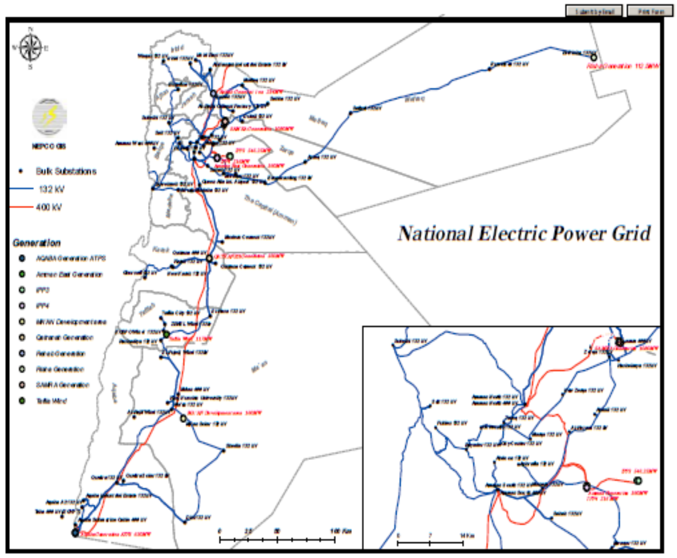
- Why do we need power system protection? Objectives?
- The purpose of power system protection is to continuously monitor the system to detects the faults and abnormal operation and to ensure maximum continuity of electrical supply with minimum damage to life, equipment and property.
- Protection is the branch of electric power engineering concerned with the principles of design of (Protection Schemes) and **operation of equipment (called 'relays')** that detects abnormal power system conditions, and initiates corrective action as quickly as possible in order to return the power system to its normal state. The quickness of response is an essential element of protective relaying systems – response times of the order of a few milliseconds are often required.

Electrical Network Structures

- **Overview of Electrical Power Grid.**



- Electrical power grid (Jordan - NEPCO)



Electricity Sector in Jordan

Generation

شركة توليد الكهرباء المركزية
شركة السمرا لتوليد الكهرباء
شركة توليد شرق عمان
شركة توليد القطرانة
شركة عمان آسيا للطاقة/ طاقة متجددة
AES LEVANT HOLING/
شرق عمان
محطة العطارات (صخر الزيتي)

Transmission

شركة الكهرباء
الوطنية

Distribution

شركة الكهرباء الاردنية
شركة كهرباء إربد
شركة توزيع كهرباء

Voltage levels in the power grid

- *High voltage (HV):* for a V_{P-P} between 35 and 440 KV, the standard ratings are: 45, 66, 110, 132,150, 220, 300, 400 KV.

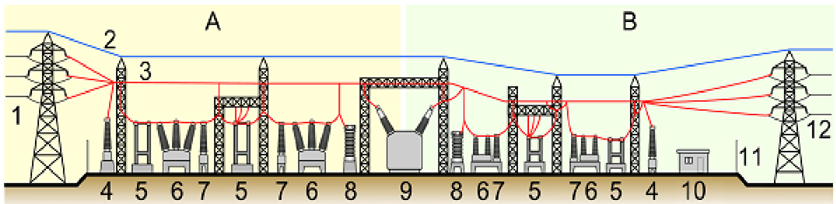
- *Medium voltage (MV):* for a V_{P-P} between 1 and 35 KV, the standard ratings are: 3.3, 6.6, 11, 22, 33 KV.

- *Low voltage (LV):* for a V_{P-P} of between 100 V and 1 KV, the standard ratings are: 400 V - 690 V - 1,000 V (at 50 Hz).

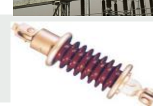
Power Substations

- SUBSTATION - A station in the power transmission system at which electric power is transformed to a conveniently used form. The Substation can be LV, MV or HV. The voltage rating of the supply source depends on the consumer supply power. The greater the power required, the higher the voltage must be.
- The main function is to receive energy transmitted at high voltage from the generating station, by either step-up or step-down the voltage to a value appropriate for local use and provide facilities for switching. Substations have some additional functions. Its provide points where safety devices may be installed to disconnect circuits or equipment in the event of trouble.
- The station may consist of transformers, switches, circuit breakers and other auxilliary equipment.

Elements of a Substation



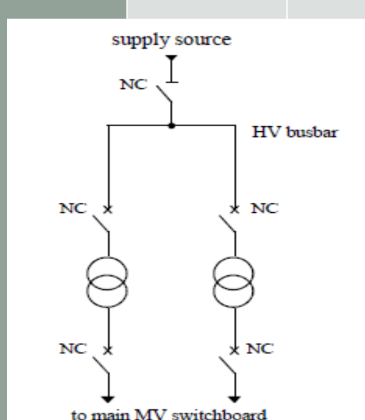
Elements of a substation A: Primary power lines’ side B: Secondary power lines’ side.	
1- Primary power lines 2- Ground wire 3- Overhead lines 4- Transformer for measurement of electric voltage 5- Disconnect switch 6- Circuit breaker	7- Current transformer 8- Lightning arrester 9- Main transformer 10- Control building 11- Security fence 12- Secondary power lines

Power Transformer	
The instrument transformer (CT&VT) is a static device utilised for reduction of higher currents and voltages for safe and practical usage which are measurable with traditional instruments such as digital multi-meter etc. The value range is from 1A to 5A and voltages such as 110V etc.	 
The busbar is a conductor which carries current to a point having numerous connections with it. The busbar is a kind of electrical junction which has outgoing and incoming current paths.	
The insulators are the materials which do not permit flow of electrons through it. Insulators are used in substations for avoiding contact with humans or short circuit.	
The isolators in substations are mechanical switches which are deployed for isolation and these switches have no specific current breaking value neither these have current making value. These are mechanically operated switches.	
The Lightning Arresters are devices used to provide the necessary path to ground for such surges, yet prevent any power current from following the surge.	

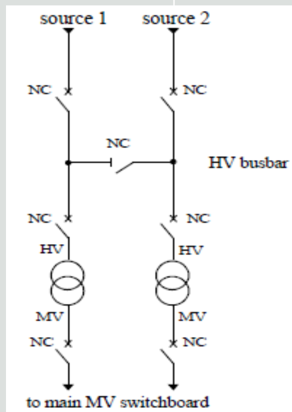
The circuit breakers are such type of switches utilized for closing or opening circuits at the time when a fault occurs within the system.	
Metering and Indication Instruments (Realys): are a dedicated component of electrical substation equipment for the protection of system against abnormal situations.	
The capacitor bank is aimed to correct power factor as well as protection of circuitry of the substation. These are acting like the source of reactive power and are thus reducing phase difference amid current and voltage.	
Batteries bank is important part of substation such as emergency lighting, relay system, and automated control circuitry are operated through batteries.	
The switchyards, switches, circuit breakers, and transformers for the connection and disconnection of transformers and circuit breakers. These are also having lighting arrestors to protect the substation or power station from strokes of natural lighting.	

HV Network Structures (power supply + busbar)

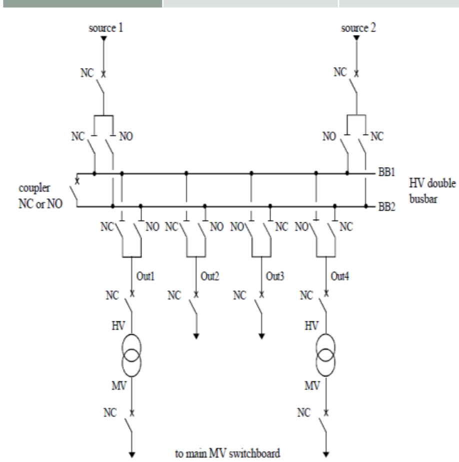
Structure	Advantage:	Disadvantage:	Operating mode
Single power supply	Reduced cost. Simplicity .	low reliability	<u>normal:</u> - One incoming circuit-breaker are closed, as well as the coupler isolator. - The transformers are thus simultaneously fed by one source. <u>Disturbed:</u> - If the supply source is lost, the total network off.



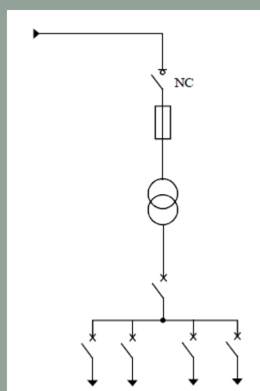
	Advantage:	Disadvantage:	Operating mode
Dual power supply	– Very reliable in that each source has a total network capacity. – Maintenance of the busbar possible while it is still partially operating.	– More costly solution. – Only allows partial operation of the busbar if maintenance is being carried out on it.	**Normal:** - Both incoming circuit-breakers are closed, as well as the coupler isolator. - The transformers are thus simultaneously fed by two sources. **Disturbed:** - If one source is lost, the other provides the total power supply.



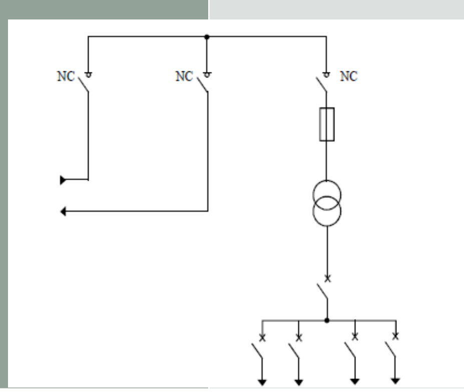
	Advantage:	Disadvantage:	Operating mode
Dual fed double bus system	– Highly flexible and Reliable power supply. – Busbar transfer possible without interruption.	More costly in relation to the single busbar system.	**Normal:** - Source 1 feeds busbar BB1 and feeders Out1 and Out2. - Source 2 feeds busbar BB2 and feeders Out3 and Out4. - The bus coupler circuit-breaker can be kept closed or open. **Disturbed:** - If one source is lost, the other provides the total power supply. - If a fault occurs on a busbar (or maintenance is carried out on it), the bus coupler circuit-breaker is tripped and the other busbar feeds all the outgoing lines.

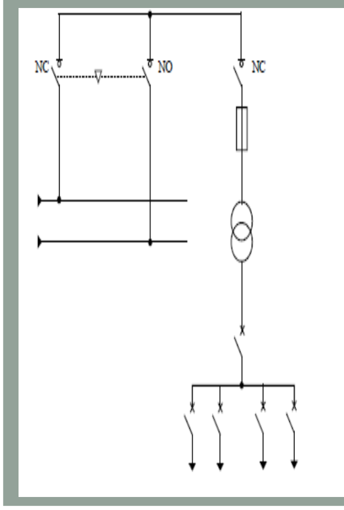


MV Network Structures (***MV power supply***)

MV connection Structure	Operating mode
Single line service 	The substation is fed by a <u>single circuit tee-off from an MV distribution (cable or line)</u>. This type of MV service is very common <u>in rural areas</u>. It has one supply source via the utility .

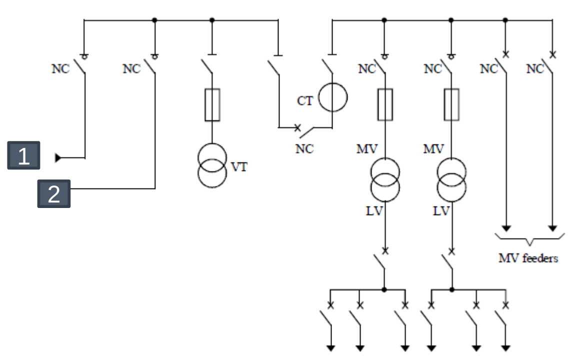
MV connection Structure	Operating mode
Ring main units (RMU)	• This arrangement provides the user with <u>a two-source supply</u>, thereby considerably reducing any interruption of service due to system faults or operational maneuvers by <u>the supply authority.</u> • The main application for RMUs <u>is in utility MV underground cable networks in urban areas</u>.



MV connection Structure	Operating mode
Parallel feeder 	• The main operational difference between this arrangement and that of an RMU is that the two incoming *switches are mutually interlocked*, in such a way that only one incoming switch can be closed at a time, i.e. its closure prevents that of the other. • On loss of power supply, the closed incoming switch must be opened and the (formerly open) switch can then be closed. • The sequence may be carried out manually or automatically. • This type of switchboard is used particularly in networks of high load density and in rapidly expanding urban areas supplied by MV underground cable systems.

MV substation

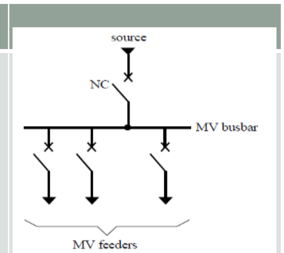
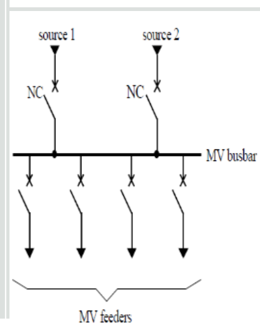
- **The MV consumer substation** may comprise several MV transformers and outgoing feeders. The power supply may be a single line service, ring main principle or parallel feeder.
- The below figure shows the arrangement of an MV consumer substation using a ring main supply with MV transformers and outgoing feeders.



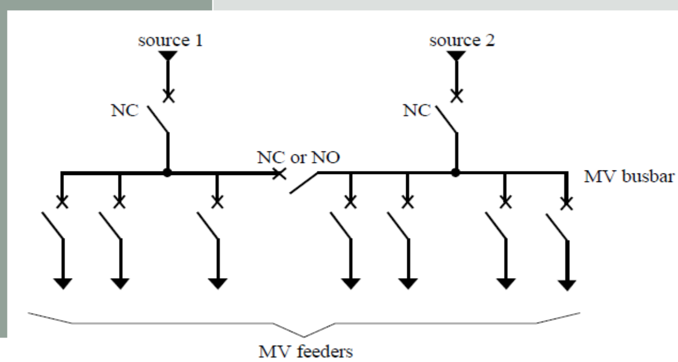
MV networks inside the site

- A) MV main switchboard power supply modes.
- B) MV network structures used to feed secondary switchboards and MV/LV transformers.

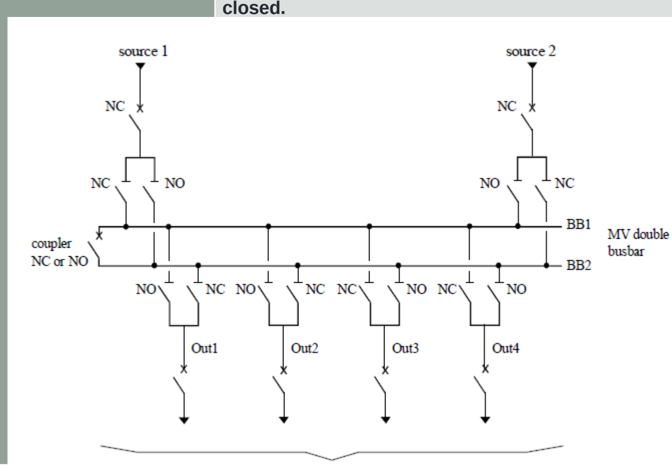
A) MV switchboard power supply modes

MV connection Structure	Operating mode	
1 busbar, 1 supply source	if the supply source is lost, the busbar is put out of service until the fault is repaired.	
1 busbar with no coupler, 2 or supply sources	one source feeds the busbar, the other provides a back-up supply. If a fault occurs on the busbar (or maintenance is carried out on it), the outgoing feeders are no longer fed.	

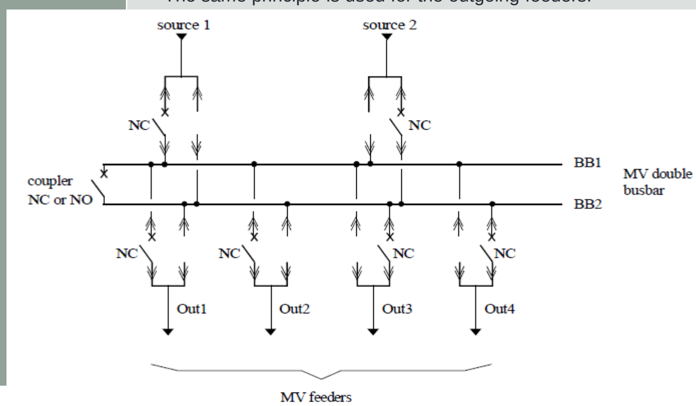
MV connection Structure	Operating mode
2 bus sections with coupler, 2 supply sources. 3 bus sections with couplers, 3 supply sources	• <u>Each source feeds one bus section</u>. • The bus coupler circuit-breaker can be kept closed or open. If one source is lost, the coupler circuit-breaker is closed and the other source feeds both bus sections. • If a fault occurs in a bus section (or maintenance is carried out on it), <u>only one part of the outgoing feeders is no longer fed.</u>



MV connection Structure	Operating mode
2 busbars, 2 connections per outgoing feeder, 2 supply sources	each outgoing feeder can be fed by one or other of the busbars, depending on the state of the isolators which are associated with it, and only one isolator per outgoing feeder must be closed.

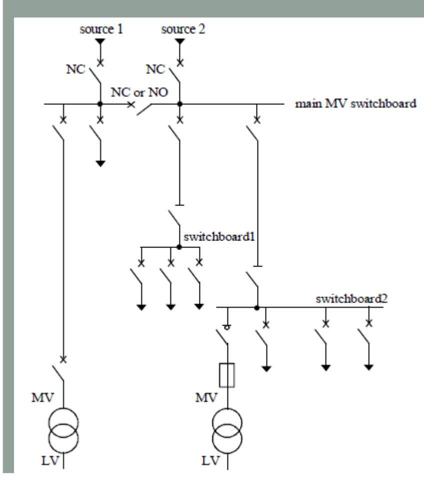


MV connection Structure	Operating mode
"**Duplex" distribution system**	• each source can feed one or other of the busbars via its two drawout circuit-breaker cubicles. For ***economic reasons***, there is only one circuit-breaker for the two drawout cubicles, which are installed alongside one another. It is thus easy to move the circuit-breaker from one cubicle to the other. Thus, if source 1 is to feed busbar BB2, the circuit-breaker is moved into the other cubicle associated with source 1. • The same principle is used for the outgoing feeders.



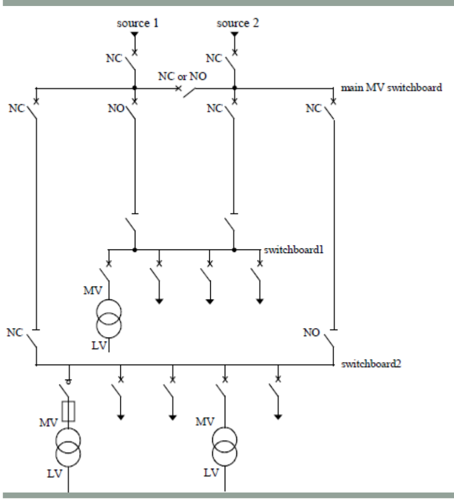
B) MV network structures used to feed secondary switchboards and MV/LV transformers.

MV connection Structure	Operating mode
Single fed radial network	• The main switchboard is fed by 2 sources with coupler. • Switchboards 1 and 2 are fed by a single source, and there is no emergency back-up supply. • This structure should be used when service continuity is not a vital requirement and it is often adopted for cement works networks. • Lower cost.



<table>
<tr><th>MV connection Structure</th><th>Operating mode</th></tr>
<tr><td>

Dual fed radial network with no coupler



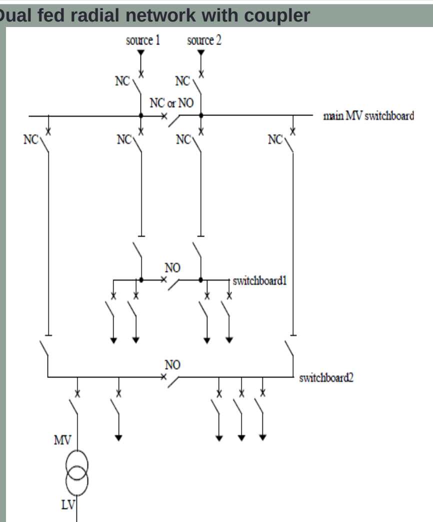
</td><td>

- The main switchboard is fed by two sources with coupler.
- Switchboards 1 and 2 are fed by two sources with no coupler, the one backing up the other.
- Service continuity is good; the fact that there is no source coupler for switchboards 1 and 2 means that the network is less flexible to use.

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

<table>
<tr><th>MV connection Structure</th><th>Operating mode</th></tr>
<tr><td>

Dual fed radial network with coupler



</td><td>

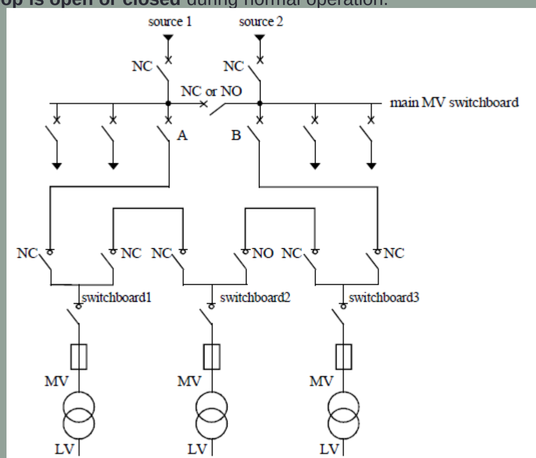
- The main switchboard is fed by two sources with coupler and Switchboards 1 and 2 are fed by 2 sources with coupler.
- During normal operation, the bus coupler circuit-breakers are open.
- Each bus section can be backed up and fed by one or other of the sources. This structure should be used when good service continuity is required and it is often adopted in the iron and steel and petrochemical industries.

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

MV connection Structure

Open Loop

Loop system
This system should be used for widespread networks with large future extensions. There are two types depending on whether the **loop is open or closed** during normal operation.

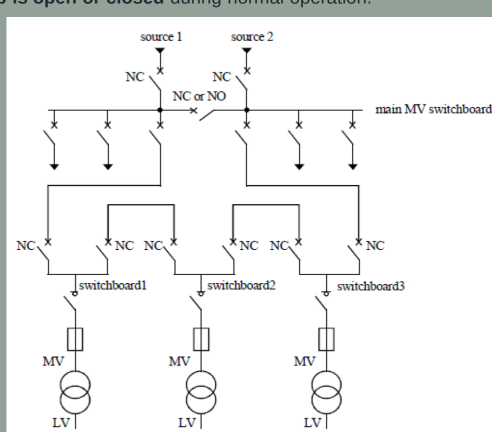


- **The main switchboard is fed by two sources with coupler.**
- **The loop heads in A and B are fitted with circuit-breakers.**
- **Switchboards 1, 2 and 3 are fitted with switches.**
- **The switchboards can be fed by one or other of the sources.**
- **Reconfiguration of the loop enables the supply to be restored upon occurrence of a fault or loss of a source.**
- **This reconfiguration causes a power cut of several seconds if an automatic loop reconfiguration control has been installed.**
- **The cut lasts for at least several minutes or dozens of minutes if the loop reconfiguration is carried out manually by operators.**

MV connection Structure

Close Loop

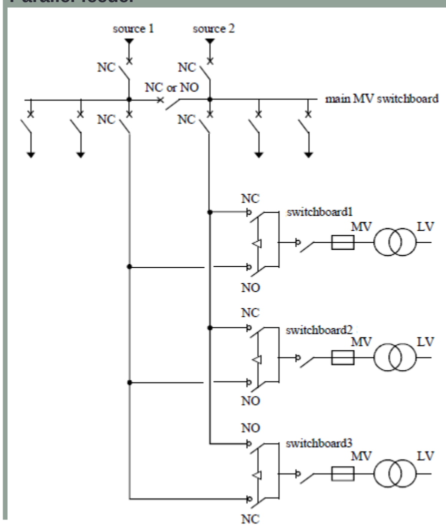
Loop system
This system should be used for widespread networks with large future extensions. There are two types depending on whether the **loop is open or closed** during normal operation.



- **All the loop switching devices are circuit-breakers.**
- **During normal operation, the loop is closed.**
- **The protection system ensures against power cuts caused by a fault. This system is more efficient than the *open loop system* because it avoids power cuts.**
- **However, it is more costly since it requires circuit-breakers in each switchboard and a complex protection system.**

<table>
<tr><th>MV connection Structure</th><th>Operating mode</th></tr>
<tr><td>

Parallel feeder



</td><td>

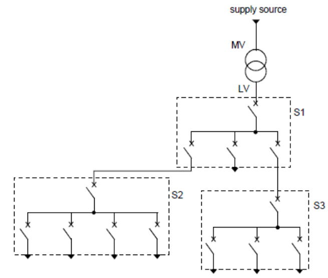
- Switchboards 1, 2 and 3 can be backed up and fed by one or other of the sources independently.
- The main switchboard is fed by two sources with coupler.
- This structure should be used for widespread networks with limited future extensions and that require good supply continuity.

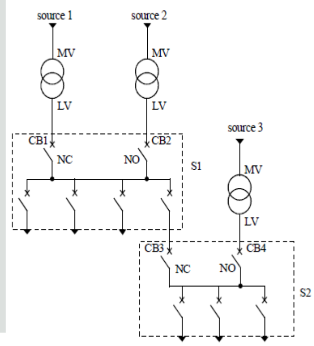
</td></tr>
</table>

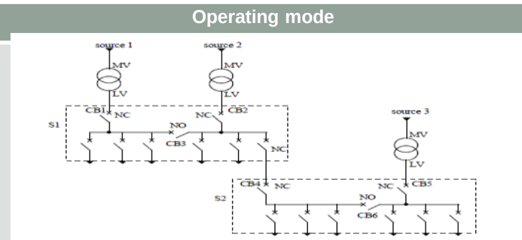
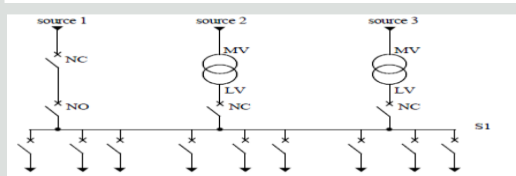
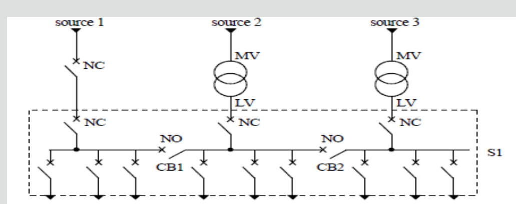
LV networks inside the site

- LV switchboard supply modes.
- LV switchboards backed up by generators / an UPS

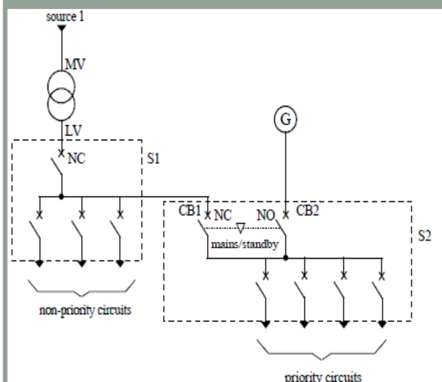
LV connection Structure	Operating mode
Single fed LV switchboards	**Switchboards S1, S2 and S3 have only <u>one supply source</u>. The network is said to be of the arborescent <u>radial type</u>. If a switchboard supply source is <u>lost, the switchboard is put out of service until the supply is restored.</u>**
Dual fed LV switchboards <u>with no coupler</u>	**Switchboard S1 has a <u>dual power supply</u> with no coupler via two MV/LV transformers. Operation of the S1 power supply: <u>one source feeds switchboard S1 and the second provides a back-up supply;</u>** **Switchboard S2 has a <u>dual power supply</u> with no coupler via an MV/LV transformer and outgoing feeder coming from another LV switchboard.** **Operation of the S2 power supply:** **– one source feeds switchboard S2 and the second provides a back-up supply;** **– during normal operation only one circuit-breaker is closed (CB3 or CB4).**





LV connection Structure	Operating mode
Dual fed LV switchboards with coupler	
Triple fed LV switchboards with no coupler .	
Triple fed switchboards with coupler	

LV switchboards backed up by generators.

<table>
<tr><th>LV connection Structure</th><th>Operating mode</th></tr>
<tr><td>Example : 1 transformer and 1 generator

</td>
<td>During normal operation CB1 is closed and CB2 is open. Switchboard S2 is fed by the transformer. If the main source is lost, <u>the following steps are carried out:</u>

1. The mains/standby changeover switch is operated and CB1 is tripped.
2. Load shedding, if necessary, of part of the loads on the priority circuit in order to facilitate start-up of the generator.
3. Start-up of the generator.
4. CB2 is <u>closed when the frequency and voltage of the generator are within the required ranges.</u>
5. Reloading of loads which may have been shed during step 2.
6. Once the main source has been restored, the generator is stopped and the mains/standby changeover device switches the S2 supply to the mains.</td></tr>
</table>

LV switchboards backed up an uninterruptible power supply (UPS)

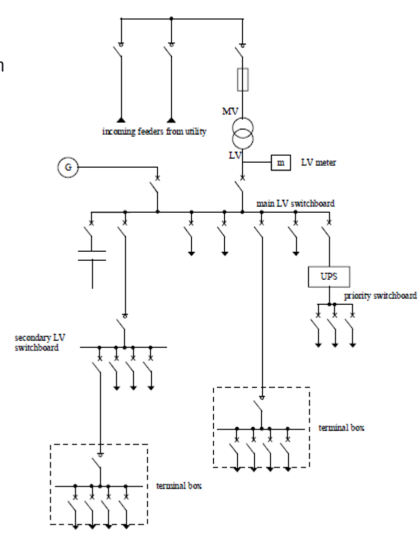
- Example (1) :

– MV consumer substation in a ring main system with two incoming feeders;

– main low voltage switchboard backed up by a generator;

– a priority switchboard fed by a UPS;

– the low voltage network is of the arborescent radial type, and the secondary switchboard and terminal boxes are fed by a single source.



- Check and study all examples in Chapter 1: “Protection of Electrical Networks”.

Quiz

- Why we need protection system for the power network grid?

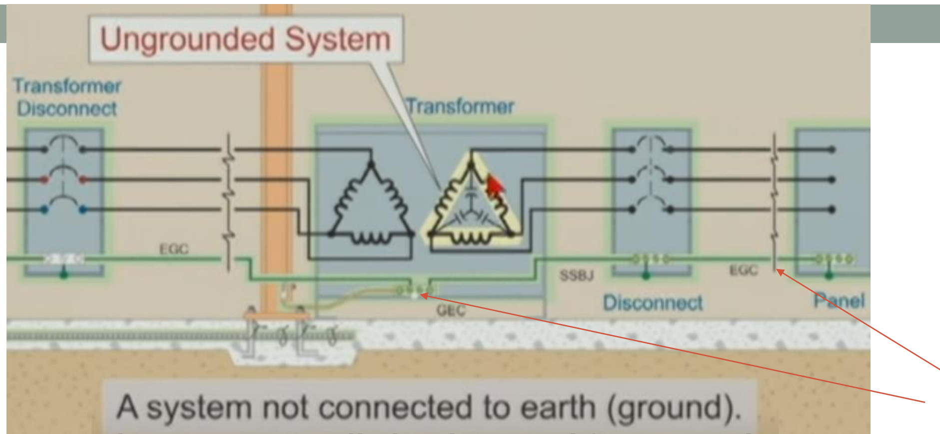
Earthing Systems

Introduction

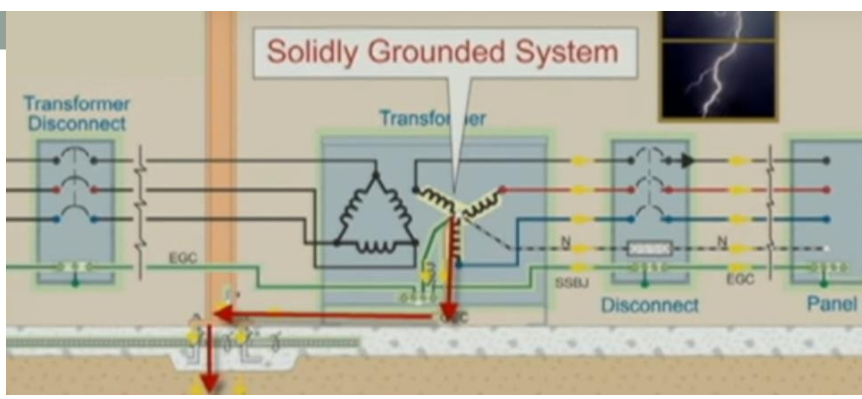
- What is grounding?
- The term grounding is commonly used in the electrical industry and power system to mean both "*equipment grounding*" and "*system grounding*".
- **Equipment grounding** means the connection of earth ground to non-current carrying conductive materials such as conduit, cable trays, junction boxes, enclosures, and motor frames.
- **System grounding** means the connection of earth ground to the neutral points of current carrying conductors such as the neutral point of a circuit, a *transformer, rotating machinery, or a system*.

- What is a grounded system?
- It is a system in which at least one conductor or point (usually the middle wire or neutral point of transformer or generator windings) is intentionally grounded, either solidly or through an impedance (IEEE Standard 142-2007 1.2).

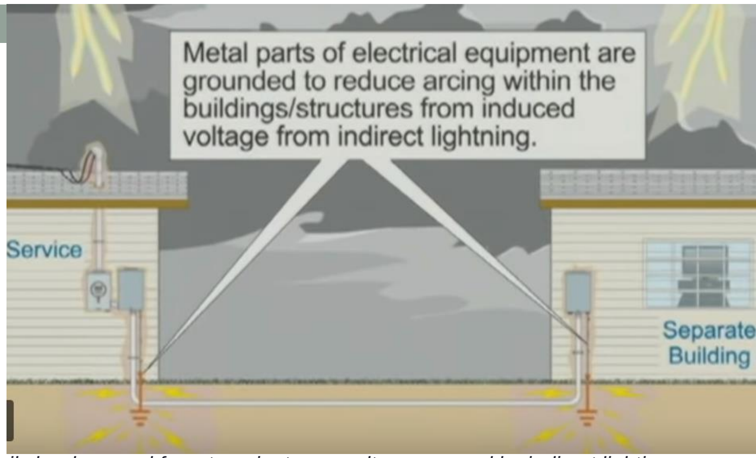
- What Is the Purpose of System Grounding?
- System grounding, is for the **purpose of controlling the voltage to earth, or ground**, within predictable limits. It also provides for a flow of current that will allow detection of an unwanted connection between system conductors and ground [a ground fault].



- ***Equipment can easily be damaged from transient over voltage caused by indirect lighting or ground fault.***
- ***Over voltage cause damage in the insulation.***
- ***So what we need? We need a grounded system***

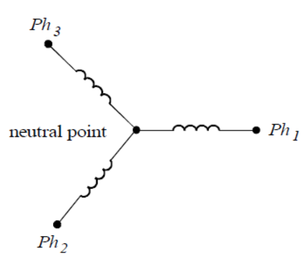


- ***System grounding help to reduce voltage stress or on electrical insulation.***
- **Wire should not longer than necessary (shorter is better) and non necessary bends**



- *Equipment can easily be damaged from transient over voltage caused by indirect lighting or ground fault.*
- *Cause fire in the building*
- *Wire should not longer than necessary (shorter is better) and non necessary bends*
- ***You can not clear fault using grounded but make it safe (PE: protective earth conductor)***
- **Earth cable : Green and yellow wire**

- In any **medium or low voltage** three-phase system there are three single voltages measured between each phase and a common point called the "neutral point".
- the neutral is **not distributed at medium voltage**. However, the neutral is very **often distributed at low voltage**.
- In a medium or low voltage installation, **the neutral may or may not be earthed.**



How neutral connected to earth?

- Directly connected to earth (called *directly earthed*)
- Connected through a resistor or (Called *impedance-earthed*).
- When a connection has not been made between the neutral point and earth, we say that the neutral is *unearthed.*

The choice of earthing system in both low voltage and medium voltage networks depends on:

1- the type of installation

2- the type of network.

3-the type of loads and service continuity required.

- In a network, the earthing system plays a very important role. When an insulation fault occurs.

- **A directly earthed neutral strongly** limits over voltages but it causes very high fault currents, **whereas an unearthed** neutral limits fault currents to very low values but encourages the occurrence of high over voltages.

- An unearthed neutral permits service continuity during an insulation fault. Contrary to this, a directly **earthed neutral**, or low impedance-earthed neutral, **causes tripping as soon as the first insulation fault occurs.**

- The extent of the **damage to some eq**uipment, such as motors and generators presenting an internal insulation fault, also **depends on the earthing system**.

Earthing systems at low voltage

- There are three types of LV earthing systems:

  IT, TT and TN.

- The first letter defines **the neutral point in relation to earth**:
  - T: directly earthed neutral
  - I: unearthed or high impedance-earthed neutral (e.g. 2,000 Ω)

- The second letter defines the exposed **conductive parts (loads) of the electrical installation in relation to earth**:
  - T: directly earthed exposed conductive parts
  - N: exposed conductive parts directly connected to the neutral conductor

POWER SYSTEM PROTECTION
EE 567

Dr. Feras Alasali

Earthing Systems

Earthing systems at low voltage

- There are three types of LV earthing systems:

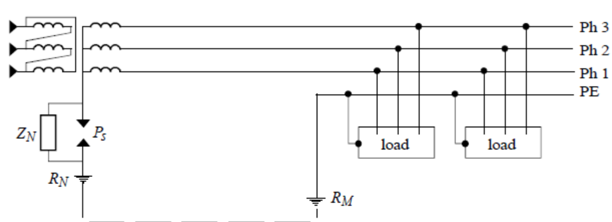
  IT, TT and TN.

- The first letter defines **the neutral point in relation to earth**:
  - T: directly earthed neutral
  - I: unearthed or high impedance-earthed neutral (e.g. 2,000 Ω)

- The second letter defines the exposed **conductive parts (loads) of the electrical installation in relation to earth**:
  - T: directly earthed exposed conductive parts
  - N: exposed conductive parts directly connected to the neutral conductor

IT system

- *Letter I :* The neutral is unearthed or connected to earth by a high impedance (an impedance of 1,700 Ω is often used).
- *Letter T:* The exposed conductive parts of the loads are interconnected and earthed. A group of loads can be individually earthed if it is situated far away from the other loads.



Z_N: *neutral earthing impedance*
P_s: *overvoltage limiter*

IT system characteristics:

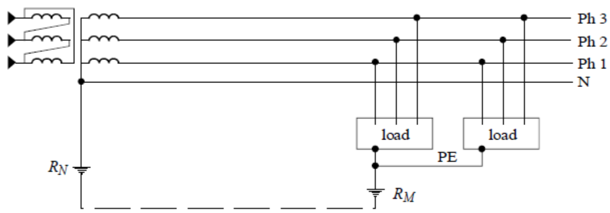
- A group of individually earthed loads must be protected by an RCD (Residual current device).
- It is not advisable to distribute the neutral.
- It is compulsory to install an overvoltage limiter (Ps) between the MV/LV transformer neutral point and earth. If the neutral is not accessible, the overvoltage limiter is installed between a phase and earth.

➢ If the short-circuit current is not large enough to activate protection against phase-to-phase faults, notably if the loads are far away, protection should be ensured by residual current devices (RCDs).

IT system	
Advantages	**Disadvantages**
– System providing the best service continuity during use. **– When an insulation fault occurs, the short-circuit current is very low.**	– Requires maintenance personnel to monitor the system during use. – Requires a good level of network insulation. – Overvoltage limiters must be installed. –RCDs is required.

TT system

- *First letter T:* The neutral is directly earthed.
- *Second letter T:* The exposed conductive parts of the loads are interconnected either altogether or by a group of loads. Each interconnected group is earthed. One exposed conductive part can be individually earthed if it is far away from the others.



- **TT characteristics:**
  - The installation of RCDs is compulsory.
  - All exposed conductive parts protected by the same protective device should be connected to the same earth.

TT system	
Advantages	**Disadvantages**
– The simplest system to design, implement, monitor and use. –	– Use of an RCD on each outgoing feeder to obtain total selectivity.

TN system

- *Letter T:* The neutral is directly earthed.
- *Letter N:* The exposed conductive parts of the loads are connected to the neutral conductor.

There are two types of systems, possibly depending on whether the neutral conductor and protective conductor (PE) are combined or not:

➢*Case 1*: The neutral and protective earth conductors are combined in a single conductor called PEN. The system is identified by a third letter C and is called **TNC**.

❑ Earthing connections must be evenly placed along the length of the PEN conductor to avoid potential rises in the exposed conductive parts if a fault occurs.

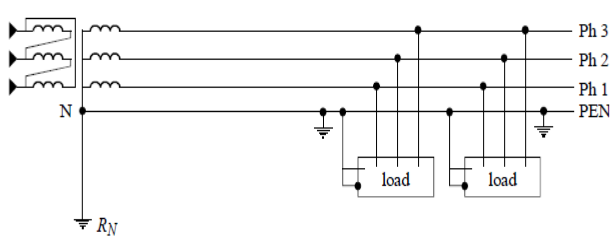


Figure 2-4: *TNC system*

- *Case 2*: The neutral conductor and protective conductor ***are separate***. The system is identified by a third letter S and is called TNS.
- Earthing connections must be evenly placed along the length of the protection conductor PE to avoid potential rises in the exposed conductive parts if a fault occurs.

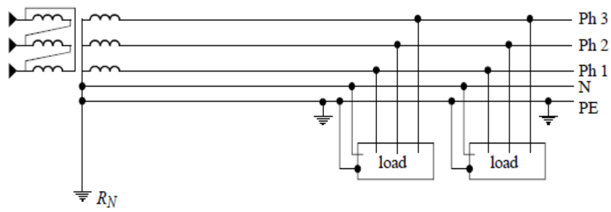


Figure 2-5: *TNS system*

- ***Specific characteristics of TNS and TNC systems:***

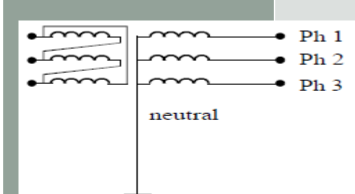
- Note: both TNS and TNC systems can be used in the same installation.
- The TNC system (4 wires), however, must never be downstream of the TNS system (5 wires). since any accidental interruption in the neutral on the upstream part would lead to an interruption in the protective conductor in the downstream part and therefore a danger.

TNC – TNS systems	
Advantages:	Disadvantages:
– The TNC system may be less costly upon installation. **– Use of overcurrent protective devices .**	– Requires earthing connections to be evenly placed in the installation so that the protective conductor remains at the same potential as the earth. – Third and multiples of third harmonics circulate in the protective conductor (TNC system). – Upon occurrence of an insulation fault, the short-circuit current is high and may cause damage to equipment or electromagnetic disturbance.

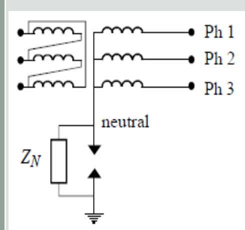
Medium voltage earthing systems

1- ***Directly earthed neutral*** : An electrical connection is made - between the neutral point and earth.

Operating technique	Advantages	Disadvantages
–Compulsory switching on occurrence of the first insulation fault.	– Reduces the risk of over voltages occurring.	– Very high fault currents leading to maximum damage and disturbance. – The risk for personnel is high while the fault lasts; the touch voltages which develop being high. – ***Requires the use of differential protection devices so that the fault clearance time is not long. These systems are costly.***

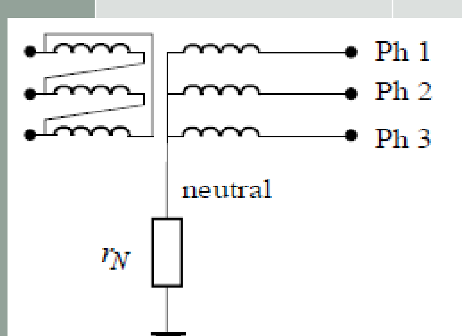


- ***Unearthed neutral:*** There is no electrical connection between the neutral point and earth, ***except for measuring or protective devices***.
High impedance earthing. A high impedance is inserted between the neutral point and earth.

Operating technique	Advantages	Disadvantages
– No switching on occurrence of the first insulation fault – it is thus compulsory: to carry out permanent insulation monitoring; to indicate the first insulation fault; to locate and clear the first insulation fault; to switch upon occurrence of the second insulation fault (double fault).	– Provides continuity of service by only tripping upon occurrence of the second fault.  	The unearthed neutral involves: - the risk of high internal over voltages making it advisable to reinforce the equipment insulation. - the compulsory insulation monitoring, with visual and audible indication of the first fault if tripping is not triggered until the second fault occurs.

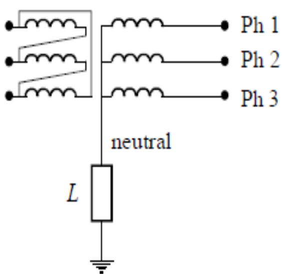
- ***Resistance earthing:*** A resistor is inserted between the neutral point and earth.

Operating technique	Advantages	Disadvantages
Operating technique: – Switching upon occurrence of the first fault.	– Limits fault currents (reduced damage and disturbance).	. – Tripping on the first fault.

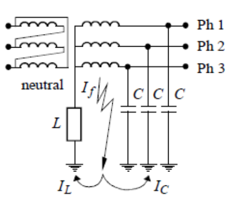


- ***Reactance earthing:*** A reactor is inserted between the neutral point and earth..

Operating technique	Advantages	Disadvantages
– Switching upon occurrence of the first insulation fault.	– Limits the fault currents (reduced damage and disturbance). – The coil, being of low resistance, does not have to dissipate a high heat load.	– May cause high over voltages during earth fault clearance. – Compulsory tripping upon occurrence of the first fault.



- ***Petersen coil earthing:***. L is used for limiting the capacitance earth fault current which is flowing when the line ground fault occurs in the line.
- The coil is provided with the tapping so that it can be adjusted with the capacitance of the system.
- The reactance is selected so that the current through the reactor is equal to the small line charging current which would flow into the line-to-ground fault
- If I_C is equal to I_L there will be no current through the ground, and there will be no tendency of the arcing grounds to occur. With the help of Peterson coil neutral grounding, arc resistance is reduced to such a small value that it is usually self-extinguishing



$$\bar{I}_f = \bar{I}_L + \bar{I}_C$$

I_f *: fault current*

I_L *: current in the neutral earthing reactor*

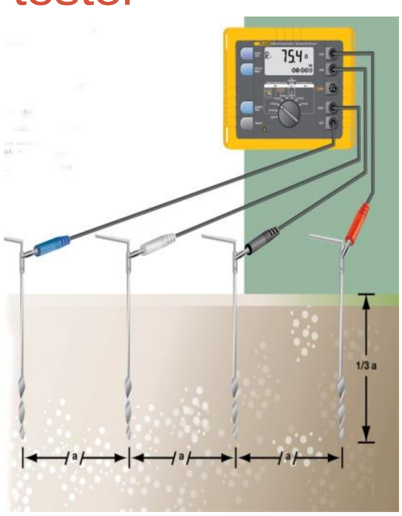
I_C *: current in the phase-earth capacitances*

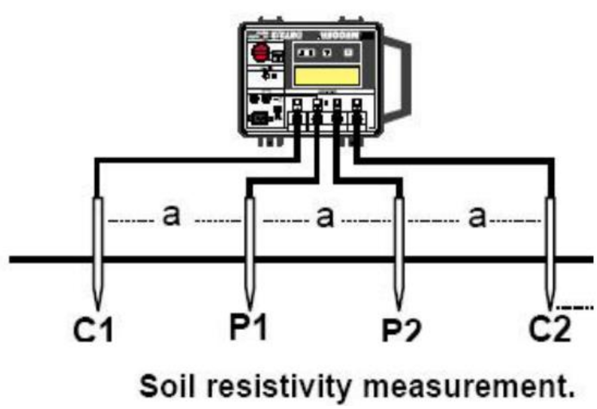
Operating technique	Advantages	Disadvantages
– No switching upon occurrence of the first fault.	- tripping necessarily occurring on the second fault; - **the first fault is indicated by the detection of the current flowing through the coil.**	– The risk of over voltages occurring is high. – Requires the presence of monitoring personnel.

Earth Tester

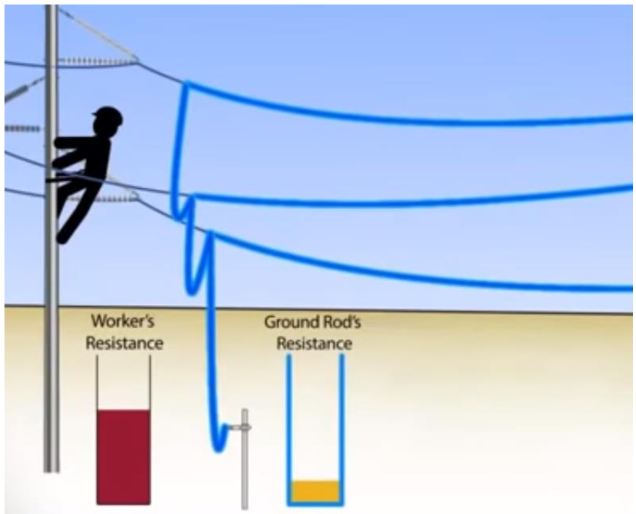
- **Why Ground, Why Test?**
- Poor grounding contributes to unnecessary downtime, but a lack of good grounding is dangerous and increases the risk of equipment failure.
- Without an effective grounding system, you could be exposed to the risk of electric shock, not to mention instrumentation errors, harmonic distortion issues, power factor problems.
- Definition of Earth tester : The instrument used for measuring the resistance of the earth is known as earth tester.
- All the equipment of the power system is connected to the earth through the earth electrode. The earth protects the equipment and personnel from the fault current. The resistance of the earth is very low. The fault current through the earth electrode passes to the earth. Thus, protects the system from damage
- **What is a good ground resistance value?**
- There is a good deal of confusion as to what constitutes a good ground and what the ground resistance value needs to be. Ideally a ground should be of zero ohms resistance.
- There is not one standard ground resistance threshold that is recognized by all. However, the IEEE have recommended a ground resistance value of 5.0 ohms or less.

Earth tester



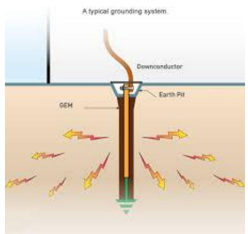


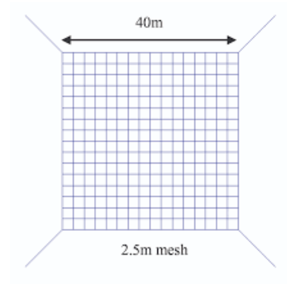
Why we need low resistance for ground ?
What relation between the given electrode deep and ground resistance?

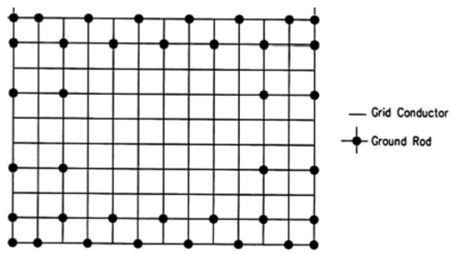


How to achieve an acceptable ground

- Treatment of the Soil: to lower earth resistivity is to treat the soil with a salt, such as copper sulfate, magnesium sulfate, or sodium chloride.
- Effect of Rod Size
- Use of Multiple Rods







MESH SYSTEM AS EARTHING OR GROUNDING ELECTRODE

Earthing systems (shapes):
1 – rod 2- mesh 3- combination

POWER SYSTEM PROTECTION
EE 567

Dr. Feras Alasali

Power system protection

Protections :

- The purpose of power system protection is to continuously monitor the system to detects the faults and abnormal operation and **to ensure maximum continuity of electrical supply with minimum damage to life**, equipment and property.

Types of Faults and Abnormalities

The main types of faults in a power system are:

- Short-circuit faults (3Φ, 2 Φ, Φ g, 2 Φ g)
- Open-circuit faults (open conductor)

- **Abnormalities**:
- Overload and excessive operating temperature
- Over voltage or under voltage
- Under excitation of synchronous machines
- Over fluxing of power transformers
- Over frequency

- **Typical Short-Circuit Type Distribution**
- Single-Phase-Ground: 70 – 80 %
- Phase-Phase-Ground: 17 – 10 %
- Phase-Phase: 10 – 8 %
- Three-Phase: 3 – 2 %

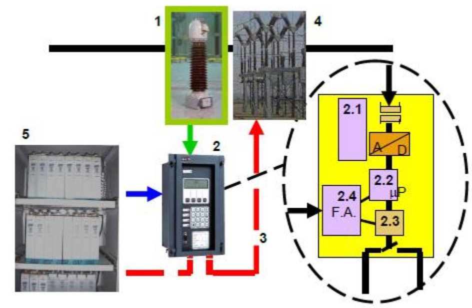
- **Causes of Short-Circuit Faults**
- Insulation breakdown due to inherent weakness Lightning
- Birds and animals bridging insulators
- Dig-ups for underground cables
- Poles collapsing
- Conductors breaking
- Vehicle impact
- Wind
- Incorrect operation by personnel

Effects of **Short- Circuit** Type Faults

- Large or very large currents can flow through parts of the network - thousands or tens of thousands of Amps can be involved
- These large currents can only be allowed to flow for a very short time otherwise equipment and generators would be damaged, most likely terminally - allowable short-circuit current flow duration could range from as short as 10 milliseconds up to say 3 seconds.
- Arcs, sparking and the heating effect of short-circuit currents can start fires involving non-electrical assets / property.

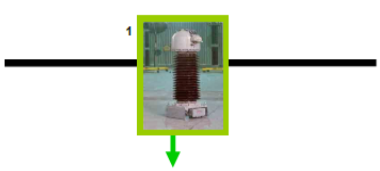
Main components of the protection system

- 1- Relays
- 2- Circuit breaker
- 3- Voltage and Current Transformer.
- 4- batteries system.



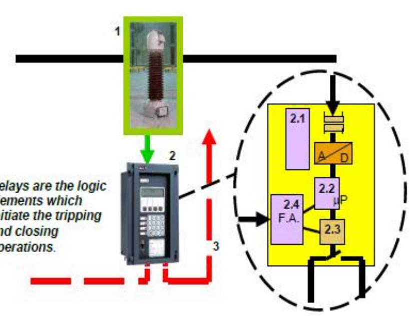
1 – CT or VT , 2- Relay 3- TC 4- CB 5- DC supply

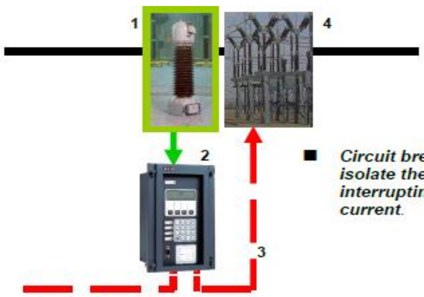
F.A. = Fault Alarm



- *The function of transducers (usually CT and VT) is to provide current and voltage signals to the relays, to detect deviations of the parameters watched over.*

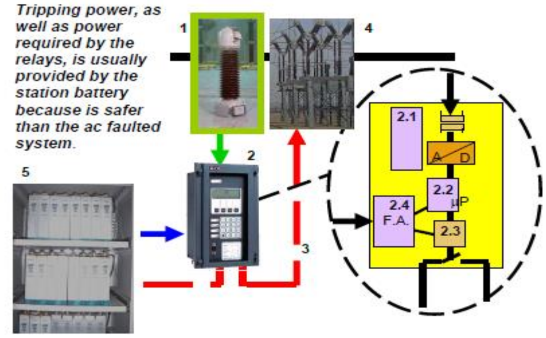
- ***Relays are the logic elements which initiate the tripping and closing operations.***





- *Circuit breakers isolate the fault by interrupting the current.*

- *Tripping power, as well as power required by the relays, is usually provided by the station battery because is safer than the ac faulted system.*



Protection and Fault sequence of events

- 1- Faults occurs somewhere on the system, changing the system currents and voltages parameters.
- 2- CT and VT sensors measure and detect the change in current and voltage.
- 3- Relays use sensor input to determine whether a fault has occurred.
- 4- If fault occurs relays open circuit breakers to be isolated the fault.

What is a Relay?

- Device which receives a signal from the power system and determines whether conditions are "normal" or "abnormal" (measuring function)-
- If an abnormal condition is present, relay signals circuit breaker to disconnect equipment that could be damaged (Switching or signaling function)
- "Relays" signal from system to circuit breaker.

What is the Purpose of the Relay?

- ***The purpose of the protective relaying systems is to <u>isolate only the faulty component of power system.</u>***

- Relaying equipments are <u>classified into two groups based on purpose of operation</u>:
- 1. Primary relaying equipment.
- 2. Back-up relaying equipment.
- Primary relaying is the first line of defense for protecting the equipments.
- Back-up protection relaying works only when the primary relaying equipment fails (they are slow in action).

* **Performance requirement** of protection system.
* Protection system **design criteria.**

*Relay Characteristics

The main six (element) design criteria, for all well designed and efficient protractive system are:

- 1- **Reliability.**

➢ Perform correctly when it needed (dependability). This criteria can be checked by (a) laboratory (b) during installation.

➢ Avoid unnecessary operation (security). This criteria more difficult to test or check and it evaluated during real operation.

➢ Have no "blind spots" i.e. unprotected zones.

2- **Speed**

The protective system need to have (a) minimum fault time (b) minimum damage to power system component

➢ This criteria applied to relay, where the relay operation time is in ms.

➢ The instantaneous term in relays indicates that no time delay is purposely introduced in real operation time.

- **3- Selectivity**

➢ coordinate with other protection systems

➢ Maximum service continuity.

➢ With minimum power systems components disconnected.

4- **Economics.**

➢ maximum protection with minimum cost

- **5- Simplicity**
- ➢Minimum protection system equipment. Major saving are possible by using complex protection system that use minimum number of CB
- ➢Minimum circuitry (wires, cables).
- ➢Simplicity of design improves systems reliability; because there are fewer elements that can used as multifunction.
- 6- **Discriminate** between load (normal) and fault (abnormal) conditions
- ➢Not be confused by non-damaging transient conditions.

CLASSIFICATION OF RELAYS

- Relays may be classified in several different ways, such as by function, input, performance characteristics, or operating principles.

- Classification **by function** is most common. There are five basic functional types: (1) protective; (2) regulating; (3) reclosing, synchronism check, and synchronizing and (4) monitoring.

Protective Relays

- They are applied to all parts of the power system: generators, buses, transformers, transmission lines, distribution lines and feeders, motors and utilization loads, capacitor banks, and reactors.

- In general, distribution equipment below 480 V is protected by fuses or protection devices that are integral with the equipment.

Regulating Relays

- Regulating relays are associated with tap changers on transformers and on governors of generating equipment to control the voltage levels with varying loads.

- Regulating relays are used during normal system operation and do not respond to system faults unless the faults are left on the system far too long.

Reclosing, Synchronism Check, and Synchronizing Relays

- Relays of this type are used in energizing or restoring lines to service after an outage and in interconnecting preenergized parts of systems

monitoring Relays

- Monitoring relays are used to verify operation conditions in the power system by using alarm units.

auxiliary Relays

- Generally, there are two categories: multiplication contact where more than one contact is needed and circuit isolation. Auxiliary relays do not perform protective functions themselves but add additional logical functions to protection systems when combined with protection and measurement relays.

Relays may be also classified based on:

Incoming signal:

- Current.
- Voltage.
- Frequency.
- Temperature.
- Pressure.
- Velocity.
- **Type of protection**
- Over current.
- Directional over current.
- Distance.
- Over voltage.
- Differential.

- ***Construction:***
- ***Electromagnetic***: These relays were the earliest forms of relay used for the protection of power systems, and they date back nearly 100 years. They work on the principle of a mechanical force causing operation of a relay contact in response to a stimulus.
- ***Solid state***: is a solid state electronic component that provides a similar function to an electromechanical relay but does not have any moving components, increasing long-term reliability. Introduction of static relays began in the early 1960's.
- ***Computerized***. Is also digital protective relay is a microcomputer controlled relay The data acquisition system collects the transducers information and converts it to the proper form for use by the microcomputer.
- ***Nonelectric:*** (thermal, pressure ......etc.).

POWER SYSTEM PROTECTION
EE 567

Dr. Feras Alasali

Instrument Transformers

What is an Instrument Transformer ?

- It is a ***transformer*** that is used in conjunction with any measuring **instrument** (i.e., Ammeter, Voltmeter, Wattmeter, Watt-hour-meter, …etc.)or protective equipment (i.e., Relays).
- It utilizes the ***current-transformation and voltage transformation*** properties to measure **high** ac current and voltage.

current Transformer

What is current Transformer (CT)?:

- A current transformer is a transformer, which produces in its secondary winding low current, which is proportional to the high current flowing in its primary winding.
- The design of CT **depends on which type of instrument** is connected to its secondary winding.

Measuring instrument OR Protective instrument.

-**Measuring instrument CT** is expected to give accurate results up to a maximum of 125% of its normal full-load rated current.

-**Protective instrument CT** is expected to be accurate for up to 20 times of its normal full-load rated current.

Types of Current Transformers

Window-type

Bar-type

Function of CT:

- The principal function of a CT is to produce a proportional current at a level of magnitude, which is suitable for the operation of low-range measuring or protective devices such as indicating or recording instruments and relays.
- The primary and secondary currents are expressed as a ratio such as 100/5 or 1000/5 .
- With a 100/5 ratio CT, 100A flowing in the primary winding will result in 5A flowing in the secondary winding.

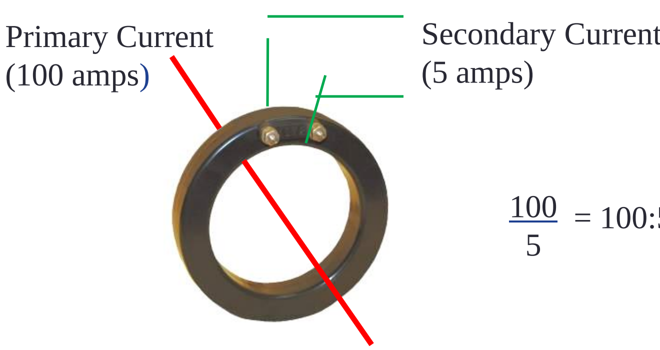
Working (Measurement):

- If a current transformer has primary to secondary current ratio of 100:5 then it step down the current ***1/20*** times of its actual value.

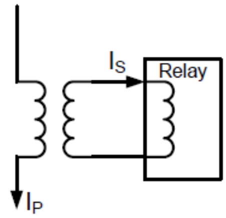
Primary Current = CT ratio × ammeter reading

CT Turns-ratio (TR)

$$\text{Transformer Ratio} = \frac{\text{Primary Current}}{\text{Secondary Current}}$$



$$\frac{100}{5} = 100{:}5 \text{ or } 20{:}1$$



$$I_P = I_S \times \frac{N_S}{N_P} = I_S \times N$$

Turns Ratio $= \mathrm{N}$

"Class" of a CT:

- The extent to which the actual secondary current magnitude differs from the calculated value, expected by the virtue of the CT ratio, **is defined as the accuracy "Class" of the CT**.

- The greater the number used to define the class, the greater "**current error**" [the deviation in the actual secondary current from the calculated value.

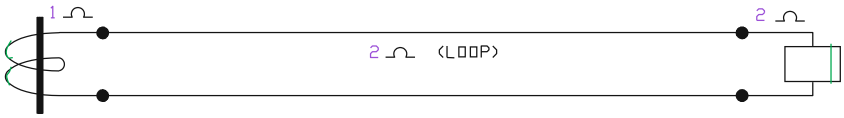
IEEE CT **Metering Accuracy**

Accuracy (error)	Application
0.15	High Accuracy Metering
0.3	Metering
0.6	Indicating Instruments
1.2	Indicating Instruments

Burden

- Load connected to CT secondary
- Includes devices & connecting leads
- Expressed in ohms

CT accurate Burden Calculation



$$Z_T = R_{CT} + R_L + Z_B$$

Z_T = Total burden in ohms
R_{CT} = CT secondary resistance in ohms @75 deg C
R_L = Resistance of leads in ohms (Total loop distance)
Z_B = Device impedance in ohms

PHASE CURRENT INPUT

Source CT:	1 to 50000 A primary / 1 or 5 A secondary
Relay input:	1 A or 5 A (specified when ordering)
Burden:	Less than 0.2 VA at 1 or 5 A

VA = VI. -------------V= IR,

VA = I^2 R = 0.2

R = VA/ I^2

R=0.2/25 = .008 ohms

CT Actual Connections

Typical window CT

CT CLASSIFICATION for Metering

A current transformer for metering purposes may typically have an accuracy of 0.3%. The C.T. must maintain this **accuracy for normal load currents**, **provided the rated burden on the C.T. is not exceeded**. The accuracy for a typical metering C.T. is specified as:

0.3 M 0.9

0.3% METERING 0.9 OHMS BURDEN

This metering C.T. has an accuracy of 0.3% ***when the connected burden does not exceed 0.9 OHMS***.

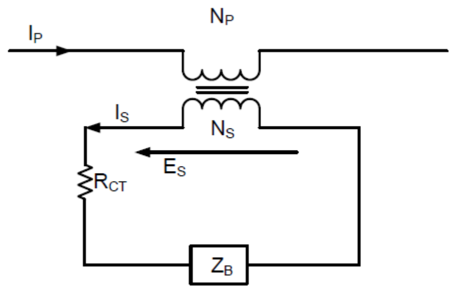
IEC standard accuracy classes: PROTECTION

- **15 VA Class 10 P 20**

- **15 VA: continuous VA**
- **10: Accuracy class**
- **P: for protection**
- **20: Accuracy Limit current Factor (saturation factor ALF) .** This value presented the maximum primary current that can be handled by CT without effect the accuracy at secondary side.
- For example if we have 200/1 CT and ALF = 20, Then the **maximum primary current** is 4000 A

Class	%error	Application
0.1	0.1	Metering
0.2	0.2	
0.5	0.5	
1.0	1	
5P	1	Protection
10P	3	

CT calculation



$$V_{o/p} = I_S Z_B = E_S - I_S R_{CT}$$

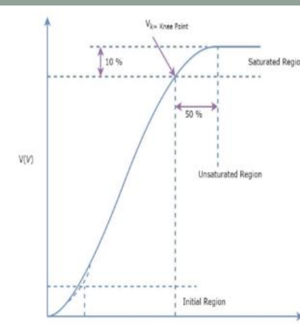
$V_{O/P}$ is the voltage on the relay or meter

$$E_S \quad \alpha \quad \frac{d\phi}{dt}$$

$$\phi = B \times A$$

$$\mathrm{B} = \mathrm{Tesla} = \mathrm{wb/m^2}$$

$$E_K = 4.44 * N * \ F * A * B_{Max}$$



Knee-point Voltage Is the maximum voltage on **the secondary side.** **Ek (maximum of Es)**

F is frequency

This value is used to determine the maximum resistance can connected to CT

Example

Calculate the maximum resistance (Relay or meter) can connect to this CT?

CT Ratio 2000/5

$R_{CT+L} = 0.31\ \Omega$

$I_{Pri\text{-}max} = 40$ kA

$B_{max} = 1.6$ Tesla

Core CSA = 20 cm^2

$$E_K = 4.44 * N * F * A * B_{Max}$$

$$N = 2000/5 = 400$$

$$E_K = 4.44 * 400 * 50 * 20 * 10^{-4} * 1.6 = 284 \text{ Volts}$$

$$I_{sec\text{-}max} = 40{,}000/400 = 100\text{A}$$

$$R_{max} = 284 / 100 = 2.84\ \Omega$$

$$Z_B = 2.84 - 0.31 = 2.53\ \Omega$$

POWER SYSTEM PROTECTION
EE 567

Dr. Feras Alasali

$$E_S \quad \alpha \quad \frac{d\phi}{dt}$$

$$\phi = B \times A$$

$$\mathrm{B} = \mathrm{Tesla} = \mathrm{wb/m^2}$$

$$E_K = 4.44 * N * \ F * A * B_{Max}$$

Knee-point Voltage — Is the maximum voltage on **the secondary side.** **Ek (maximum of Es)**

This value is used to determine the maximum resistance can connected to CT

Another Equation:

$$E_k = \frac{rated \quad VA}{I_s} \times ALF + I_s \times R_{CT} \times ALF$$

ALF: Accuracy Limit current Factor (saturation factor)

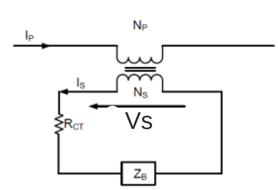
How to choose your CT based on the name plate information?

- If you have OC relay with (0.02 ohm) and expected current fault equal to 7226 A, determine whether the following ***CT is suitable or not*** ?

CTR = 1000/5 , 7.5VA, 10P20

$R_{CT} = 0.26 \ \Omega$

$R_L = 0.15 \ \Omega$



$$E_k = \frac{rated \quad VA}{I_s} \times ALF + I_s \times R_{CT} \times ALF$$

$$= 7.5/5 * 20 + 5 * 0.26 * 20 = 56 \text{ Volts}$$

$$V_S = I_{f\text{-}Sec} \, (R_{CT} + R_L + R_r)$$

$$= 7226 * 5/1000 * (0.26 + 0.02 + 0.15) = 15.54 \text{ Volts}$$

$Vs < E_k$

Then it’s ok

Example : 2000/5 CT with A= 0.25 m^2 and Rct = 0.31 ohm and total resistance for the wire and instrument is 2 ohm? Did this CT can work with Relay system when fault current is 35000 A, F= 50 Hz? Note the maximum B_{max} is 0.01 tesla.

$$E_K = 4.44 * N* \; F * A * B_{Max}$$

$$B_{max} = \frac{E_S}{4.44\, F \times A \times N}$$

$$I_s = 35000 * \frac{5}{2000} = 87.5A$$

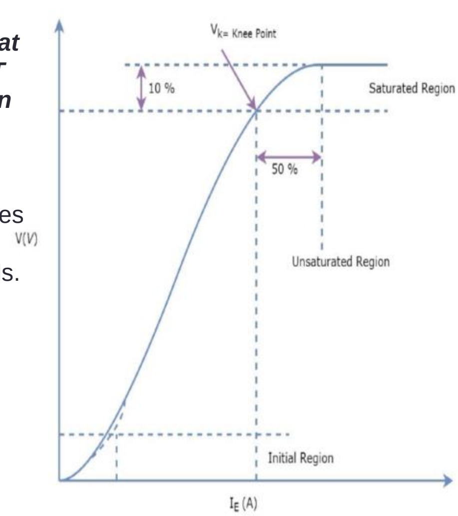
B max = 0.0091 so no problem

$$E = I_L\,(Z_B + Z_L) = 87.5\,(0.31 + 2) = 202.1\ \text{V}$$

CT excitation curve

knee Point Voltage of a Current Transformer is defined as the voltage at which a 10 % increase in voltage of CT secondary results in a 50 % increase in secondary current.

For voltages greater than the **knee point voltage**, the magnetizing current increases considerably even for small increments in **voltage** across the secondary terminals.



CT ratio calculation for **Power Transformer**

- Power transformer 33 / 11 KV, 12 MVA and its connected to tap changer (+5% to – 5%) consists of 3 single phase unit?
- Select the CT ratio for the transformer? Determine the CT mismatch and show how we can minimise it?

- Firstly, we calculate the primary and secondary current in normal conditions.

- Ip=12MVA/33KV=363A
  Is =12MVA/11 KV=1090 A
- Her it show the problem for relay/meter that we have different current (also under the normal condition).

- We choose a CTR for each side close to the normal current and give the 5 A secondary
- For CT (p) = **400/5**
- For CT (s) = 1100/5 but may not available1200/5

- The relay will see the currents based on the CT as following
- Ip = 363 * 5/400 = 4.5375 A
- Is = 1090 * 5/1100= 4.9545 A

- ***Still the current not the same*** , this problem called **CT Mismatch**

- Therefore , **we need to use Input TAPs at Relay to adjust the currents value.**

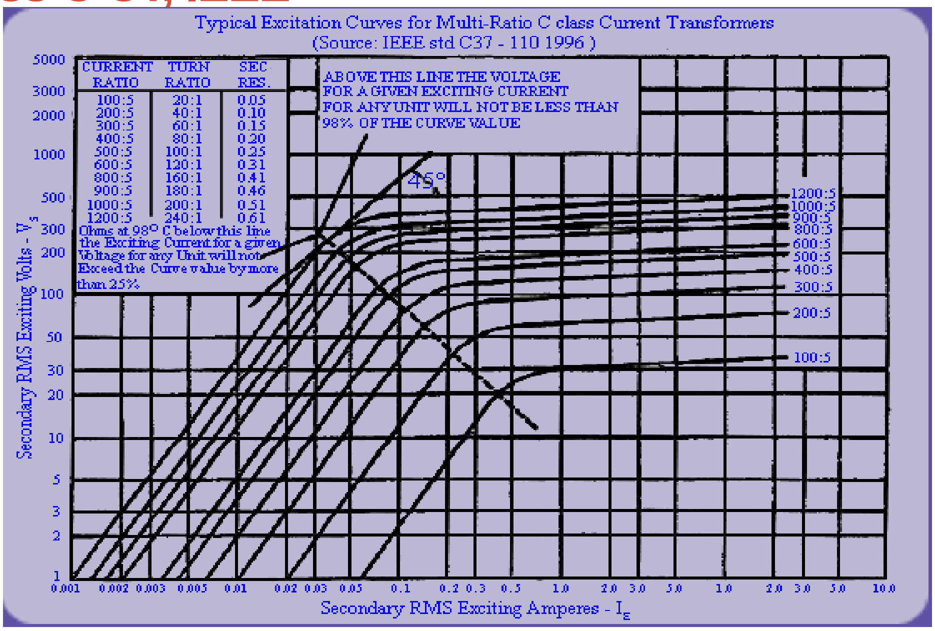
- For primary
  I Primary (Relay)=4.54/4.5 = 1.0088pu = 5.044A
- For secondary side
  I sec (Relay)=4.95/4.9=1.010pu=5.051A

- This reduce the difference between the two CT to
- 0.0065 A only

Class ***C CT***, IEEE

- Letter designation 'C' indicates that the **leakeage flux is negligible**.
- In such CTs, the leakage flux from the core is kept very small.
- For such CTs, ***the performance can be evaluated from the standard exciting curves***. Also, the ratio error is maintained within ± 10% for standard operating conditions.

Class C CT, IEEE



- For such CTs, voltage rating on the secondary is specified up to which linear response is guaranteed (unsaturated area).
- For example, a class C CT specification could be as follows: 300:5 C 100.
- The CT ratio is 300:5
- The maximum rated voltage is 100 V.
- The CT can provide response up to 20 times rated current (5A) = 100 A ***maximum current***.
- The max burden = 100/5*20 = 1 ohm

Example

A 1200/5, C400 CT with excitation curves shown is connected to a 2.0 Ω burden. Based on the accuracy classification, what is the maximum symmetrical fault current that may be applied to this CT without exceeding a 10% ratio error?

CT ratio = 1200/5 Relay burden = 2 Ω

For 20 times rated secondary current, i.e., 100A

From the curve

Secondary voltage = 100 x (2 + 0.61) = 261

Volts which is less than max voltage of the CT. Since this voltage is less than 400V, from electrical perspective, linearity will not be lost at even higher currents.

$$I_{max} = \frac{400}{2.61} = 153A.$$

$$\text{fault current} = 153 \times \frac{1200}{5} = 36720A.$$

Example

Assume that secondary burden of a 300:5 class C CT is 5 Ω. The relay setting is 2A and the CT ratio is 300/5. calculate the primary current required to operate the relay?

Secondary burden = 5 Ω

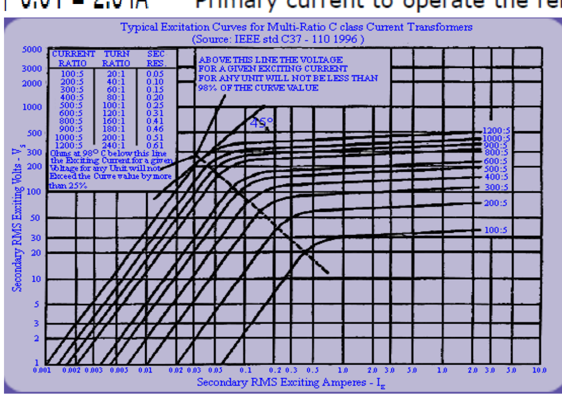
Secondary resistance for 300/5 CT = 0.15

From the curve

Relay setting, $I_s = 2A$ V_s = 2 x (5 + 0.15) = 10.3V Corresponding exciting current = 0.04A **From the curve**

Total secondary current = 2 + 0.04 = 2.04A

$$\text{Primary current to operate the relay} = \frac{300}{5} \times 2.04 = 122A$$



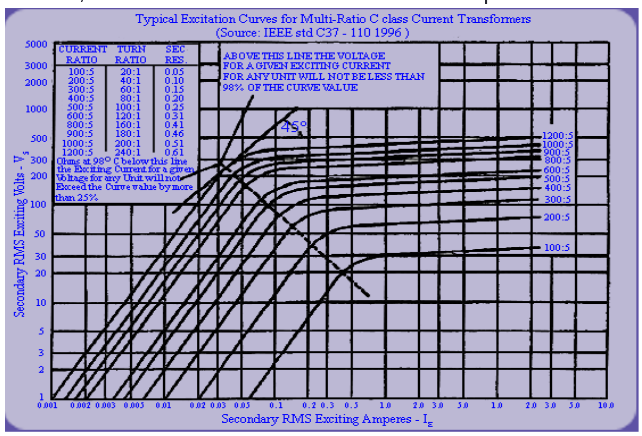
Example

A relay is expected to operate for 7000A primary current. The class C CT ratio is 600/5. Secondary burden is 3.5 Ω. Will the CT saturate at this burden? Also, comment on the ratio error.

Secondary current $I_S = \dfrac{7000}{600} \times 5 = 58.33A$

V_S = 58.33 (3.5 + 0.31) = 222.25V.

From the excitation curve of 600/5 CT, we can see that the CT will be in deep saturation and % ratio error will exceed the limits.



Example

What will be the approximate % error if a 500:5 class C CT is connected to a secondary burden of 2.5 Ω and the secondary current is 68A.

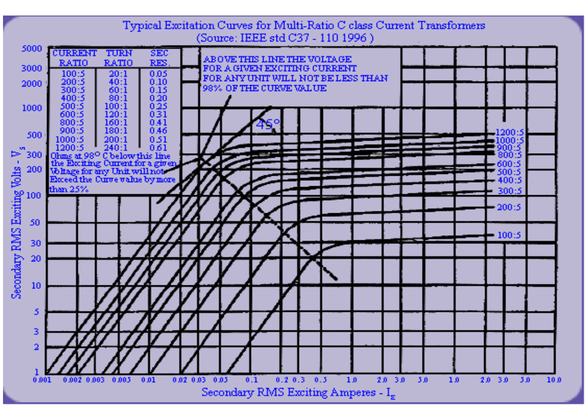
For a 500/5 CT, secondary resistance R_S = 0.25 Ω

Secondary burden R_B = 2.5 Ω

$$V_S = I_S(R_B + R_S)$$

$$V_S = 68(2.5 + 0.25) = 187V$$

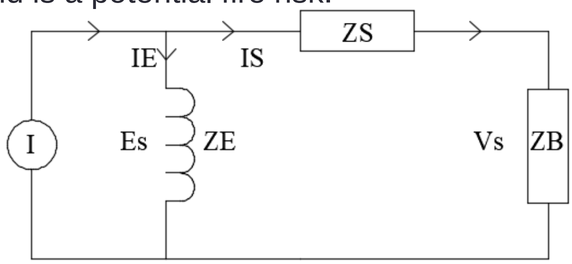
Corresponding exciting current I_E = 6A (approximate) From the curve



% ratio error = $\dfrac{I_E}{I_S} \times 100 = \dfrac{6}{68} \times 100$
= 8.82%

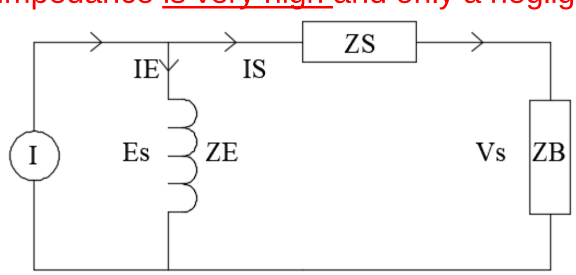
OPEN CIRCUIT CURRENT TRANSFORMER CHARACTERISTICS

- Open circuit condition in a current transformer (CT) can result in dangerous over voltage condition at the secondary terminals of the CT.
- This voltage is usually sufficient to sustain steady state arcing between CT shorting blocks and is a potential fire risk.



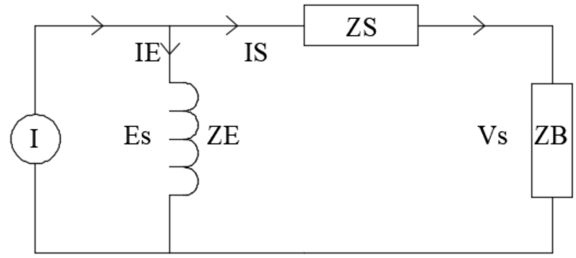
Current Transformer (CT) Equivalent Circuit

- To understand why an open circuited CT creates dangerously high voltage we need to understand the CT equivalent circuit.
- A CT can be represented using the previous figure. In this figure Z_E is <u>magnetizing impedance</u>, Z_S is the lead impedance and Z_B is burden (load) impedance.
- The ***secondary ratio current*** flows through the interconnect wiring impedance Z_S and the connected load (burden) Z_B. ***<u>A small portion of the current</u>*** also flows through the CT <u>magnetizing impedance Z_E</u>. Under normal circumstances, this magnetizing impedance <u>is very high</u> and only a negligible current flow in this circuit.



Current Transformer (CT) Equivalent Circuit

- When a CT which is carrying primary current becomes ***open circuited on the secondary*** **side**, the ratio current has no where to flow but through the high impedance of the magnetizing reactance Z_E.
- This creates a large voltage drop E_S across the impedance Z_E in the figure which drives CT in to saturation.
- This means that under open circuit conditions, the CT core will be operating under saturation.
- Under saturation, the rate of change of flux in the CT core is almost zero (it is already carrying the maximum flux).



Current Transformer (CT) Equivalent Circuit

- However, in the short interval in each half cycle current passes through zero and magnetizing flux is rapidly changed from saturation in one direction to saturation in another direction.
- exciting current ***is switched rapidly from positive to negative direction***.
- **It is this rapid change of flux during the short interval that is responsible for high open circuit crest voltage. The voltage appears as similarly shaped brief, but extremely high (peak) voltage spikes.**

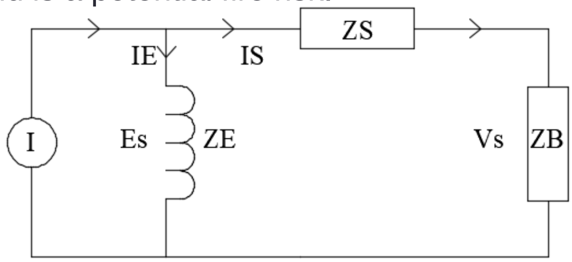
https://www.youtube.com/watch?v=j6v0ybdhGk0

POWER SYSTEM PROTECTION
EE 567

Dr. Feras Alasali

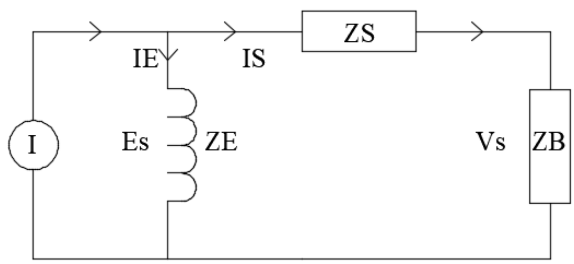
OPEN CIRCUIT CURRENT TRANSFORMER CHARACTERISTICS

- Open circuit condition in a current transformer (CT) can result in dangerous over voltage condition at the secondary terminals of the CT.
- This voltage is usually sufficient to sustain steady state arcing between CT shorting blocks and is a potential fire risk.



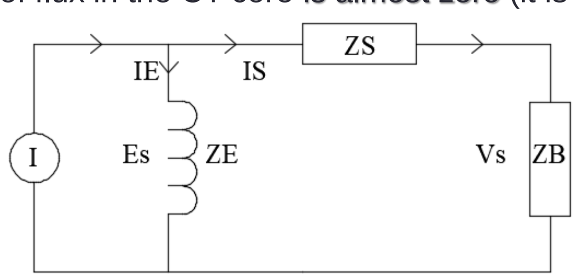
Current Transformer (CT) Equivalent Circuit

- To understand why an open circuited CT creates dangerously high voltage we need to understand the CT equivalent circuit.
- A CT can be represented using the previous figure. In this figure Z_E is magnetizing impedance, Z_S is the lead impedance and Z_B is burden (load) impedance.
- The ***secondary ratio current*** flows through the interconnect wiring impedance Z_S and the connected load (burden) Z_B. ***A small portion of the current*** also flows through the CT magnetizing impedance Z_E. Under normal circumstances, this magnetizing impedance is very high and only a negligible current flow in this circuit.



Current Transformer (CT) Equivalent Circuit

- When a CT which is carrying primary current becomes ***open circuited on the secondary*** **side**, the ratio current has no where to flow but through the high impedance of the magnetizing reactance Z_E.
- This creates a large voltage drop E_S across the impedance Z_E in the figure which drives CT in to saturation.
- This means that under open circuit conditions, the CT core will be operating under saturation.
- Under saturation, the rate of change of flux in the CT core is almost zero (it is already carrying the maximum flux).



Current Transformer (CT) Equivalent Circuit

- However, in the short interval in each half cycle current passes through zero and magnetizing flux is rapidly changed from saturation in one direction to saturation in another direction.
- exciting current ***is switched rapidly from positive to negative direction***.
- **It is this rapid change of flux during the short interval that is responsible for high open circuit crest voltage. The voltage appears as similarly shaped brief, but extremely high (peak) voltage spikes.**

https://www.youtube.com/watch?v=j6v0ybdhGk0

VT or potential transformers (PT)

- VT is mainly used to reduce voltage to acceptable level (100, 110 V) to feed meeting system (Kwh, Kw, Kvarh, Kv) and protection systems (Over/under voltage, E/F , directional OC) and controlling system (load shedding interlock).

- Therefore, is mainly required to have

V secondary =V primary with tacking into count turns ratio.

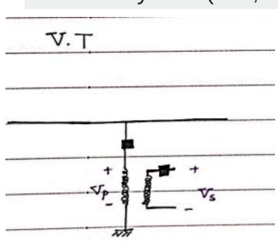
- This is mean the voltage drop at VT should be very low value.
- $\frac{Vp}{Vs} = \frac{Np}{Ns}$ = N

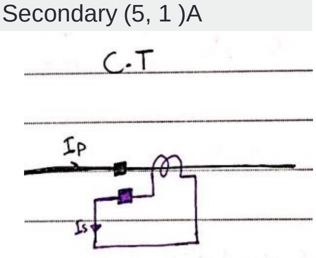
VT vs Power transformer:

VT	Power transformer
small	large
Low power	High power
no cooling system	Cooling system is required.

VT vs CT

VT	CT
Primary is connected in parallel with HV conductor.	Primary is connected in series with HV conductor.
Is with open circuit at secondary side	Is with short circuit at secondary side
Zero voltage regulation	Zero excitation current
Secondary side (110, 100)V	Secondary (5, 1)A



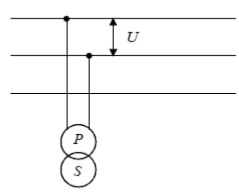


Indoor substation

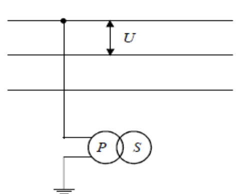
Outdoor substation

VT

- Rated voltage (*Rated primary voltage (Up))*: is the primary voltage (33KV,11KV.): depending on their design, voltage transformers
- will be connected either:
- – between phase and earth

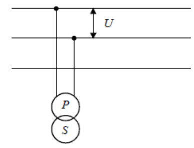


- – between phases .



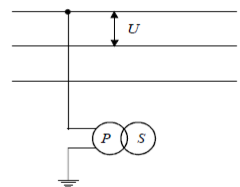
Level voltage (*Rated secondary voltage)* : is the secondary voltage and it is equal to 100 or 110 V for phase/phase VTs.

$$3{,}000\,/\,100 \qquad U_p = U$$



For single-phase transformers designed to be connected between a phase and earth, the rated secondary voltage is divided by $\sqrt{3}$. U = $\sqrt{3}$ Up
For example: 100/ $\sqrt{3}$

$$\frac{3{,}000}{\sqrt{3}}\,/\,\frac{100}{\sqrt{3}} \qquad U_p = \frac{U}{\sqrt{3}}$$



- Breakdown-pulse voltage: is the maximum voltage (over short period of time) that can be handle by the VT handle. Usually it during faults period.

- Turns ratio: the Vp/Vs ratio (N)
- Accuracy class: is describe the error at VT between
- (Vs, Vp).

$$Error = \frac{K_n V_s - V_p}{V_p} \times 100$$

VT ⇨ metering system

Accuracy Class	Error %	Phase (Error) (minutes)
0.1	-/+ 0.1	-/+ 5
0.2	-/+ 0.2	-/+ 10
0.5	-/+ 0.5	-/+ 20
1.0	-/+ 1.0	-/+ 40
3.0	-/+ 3.0	

VT ⇨ protection system

Accuracy Class	Error %	Phase (Error) (minutes)
3P	-/+ 3.0	-/+ 120
6P	-/+ 6.0	-/+ 240

Application	Accuracy class
not used in industry	0.1
precision metering	0.2
usual metering	0.5
statistical metering and/or measurement	1
measurement not requiring high accuracy	3

- In **a metering VT**, the VT is required to be within the specified errors **from 80% to 120%** of the rated voltage.

- In a **protection** VT, the VT is required **to be accurate** between ***5% the*** **primary voltage and the maximum value of this voltage,** which is the product of the primary voltage and the rated voltage factor

$$(kT \times U_n)$$

- ***Accuracy power****:* this is expressed in **VA** and it is the apparent power that the voltage transformer can supply to the secondary when it is connected under its rated primary voltage.
- It must not introduce an error in excess of the values guaranteed by the accuracy class (25%-100%).
- The standardized values are:
- 10 - 15 - 25 - 30 - 50 - 75 - 100 - 150 - 200 - 300 - 400 - 500 - VA.

Example of a protective voltage transformer

$$\frac{20,000}{\sqrt{3}} / \frac{110}{\sqrt{3}} \quad 100\ VA\ \ cl3P$$

$$kT = 1.9$$
$$\text{rated duration} = 8 \text{ hours}$$

The maximum voltage that the VT can withstand is: $1.9 \times \dfrac{20,000}{\sqrt{3}} = 21.9\ kV$ for 8 hours

The maximum voltage error will be 3% and the maximum phase displacement will last 120 minutes for a load between 25% - 100% = 25 VA and 100 VA.

Example of a measuring voltage transformer

$$\frac{20,000}{\sqrt{3}} / \frac{110}{\sqrt{3}} \quad 100\ VA\ cl1$$

Primary voltage = 20,000 V/$\sqrt{3}$
Secondary voltage = 110 V/$\sqrt{3}$
Accuracy power = 100 VA
Accuracy class = 1

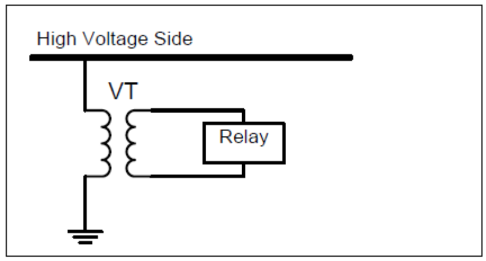
This means that for a load between 100/4 = 25 VA and 100 VA, and a primary voltage between:

$$20,000 \times \frac{80}{100} = 16,000\ V \quad \text{and} \quad 20,000 \times \frac{120}{100} = 24,000\ V \qquad \sqrt{3}$$

The voltage error will be more or less 1% and the phase displacement error will not exceed 40 minute.

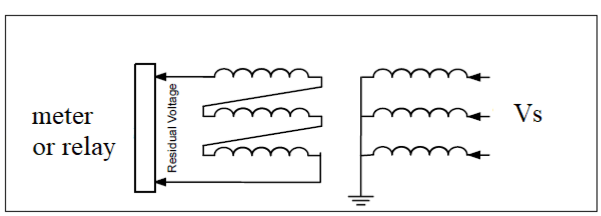
VT connections

- In general, VT connection separately in each phase (Phase to Neutral). Then the meter/relay can see Ia, Ib, Ic.



VT connected with single line

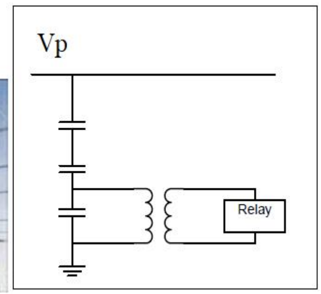
- In some cases, the VT is used to measure the total phases voltage (not PN) and this connection is called **Residual connection**.
- This connection is used to discover the unsymmetrical faults. Where in normal operation the total voltage equal ***zero***.
- This connection does not work with symmetrical faults.
- This connection is also called Broken delta



Residual Connection

CVT (Capacitor Voltage transformer)

- In case of H.V and Extra H.V is VT system is very expensive due to it require a high level of isolation.
- The main idea of this type is used capacitor voltage divider. As the voltage is divided over the capacitors and then the VT is connected over the last capacitor (closest to the ground).
  - Now, the primary voltage is smaller percentage of to the original voltage and it equal the capacitance percentage of last capacitor to total of all capacitors .



Choosing a VT

1- Calculate the PT ratio

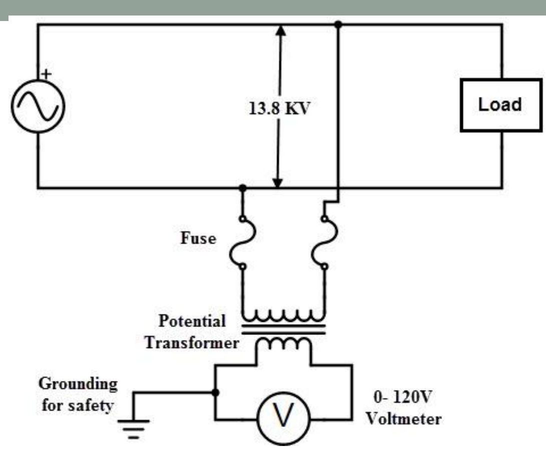
- We know the phase-to-phase voltage (for primary) for example (4.16 KV). Most meters are self contained and come with scales ranging from 150V to 750V.
- When you need to measure higher voltages, the PT reduces the measured voltage to that suitable for the voltmeter.
- The scale is then proportioned to read the actual higher voltage being measured. **For exampl, we have a voltmeter having a 150V full-scale indication**.
- You can determine the PT ratio by dividing the phase-to-phase voltage, **which is 4,160V, by the voltmeter full-scale range, which is 150V**.
- This simple calculation results in a value of **27.7, which you would interpret as an approximate 28:1 ratio**. The next higher standard PT ratio is ***40:1, and you would choose this ratio PT.***

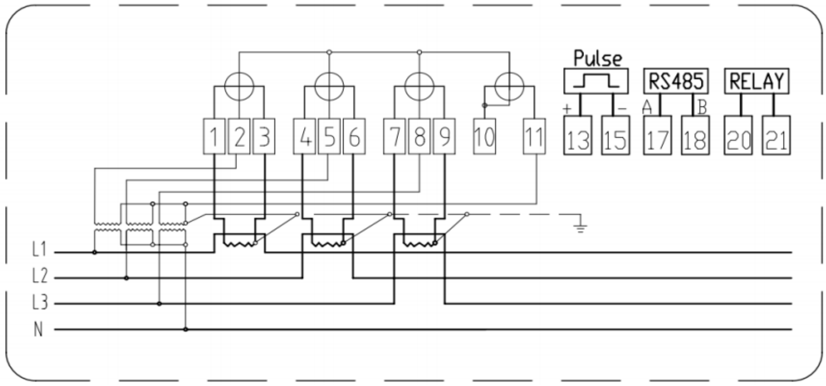
2- Verify the selection

- To make sure you've chosen the PT with the correct ratio, you should calculate **its secondary voltage**. This is done by dividing the phase-to-phase voltage by the ratio (4,160V ÷ 40), which yields **104V**. This is well within the **limits of the chosen voltmeter.**

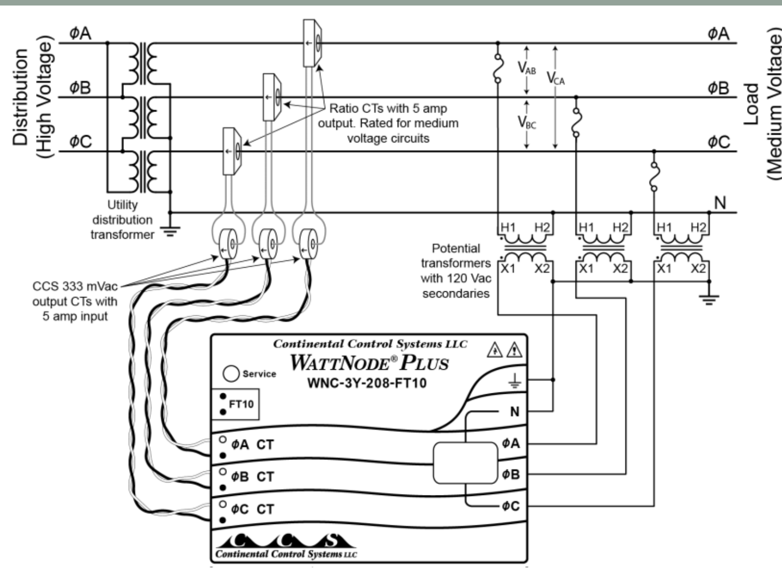
3- Connect the PT and voltmeter

- To connect the PT and **voltmeter**, you would normally connect the Pts in open delta. Where line-to-neutral loading is expected, you would more often connect them wye-wye, particularly **where metering is required**.





CT/PT connection



- *examples*
- Calculate the output voltage on a VT, if we have a 200 turns on the primary coil with 12 V AC and 100 turns at the secondary side?

$$\frac{12}{Vs} = \frac{200}{100}$$

- Vs = 6 V
- A voltage transformer with 600/200 turns ratio. If the primary and secondary voltage are 10 KV and 3 KV respectively, calculate the percentage error on the V.T?

$$Error = \frac{K_n V_s - V_p}{V_p} \times 100$$

Error = 10%

VT and short circuit

If Z is the secondary load impedance of the VT (voltage transformer), then:

$$P = \frac{U_s^2}{Z} \text{ and } I_s = \frac{U_s}{Z}$$

Never short-circuit a VT.

P : power flowing to the secondary
I_s : secondary current
U_s : secondary voltage (imposed by the primary circuit)

If Z increases, then P and I_s decrease.

At the terminals of a VT, it is thus possible to install an impedance with a value ranging between the VTs nominal impedance and infinity without any risk.

A VT can thus be left in an open circuit arrangement without any risk.

On the other hand, if Z is reduced, the current supplied is too high and the VT will deteriorate.

Test Blocks

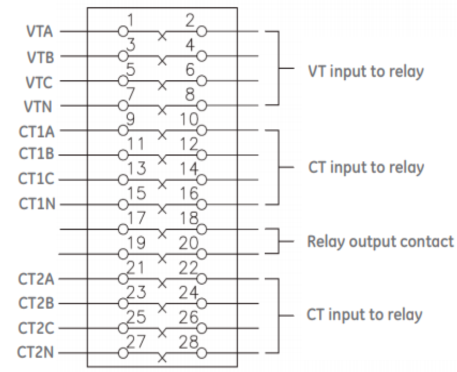


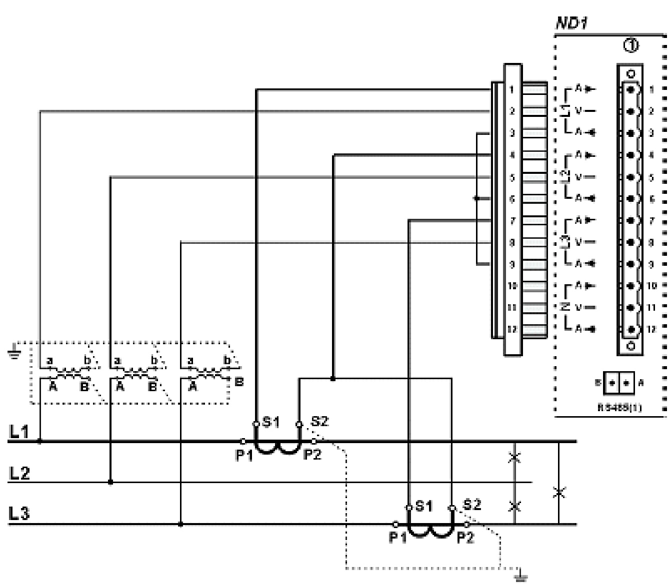
Test Blocks

1- Applications

- Isolate protection relays and inject current / voltage into the protective devices to quickly and safely verify system protection performance.
- • Automatically short CT secondaries with use of available test plug configurations.
- • Calibrate meters and control devices

- Key Benefits
- Enables the testing of protection relays and meters with no interruption of the power circuit
- Savings in man-hours for testing and trouble shooting
- No need to disturb existing connections or relay settings for testing purposes.





POWER SYSTEM PROTECTION
EE 567

Dr. Feras Alasali

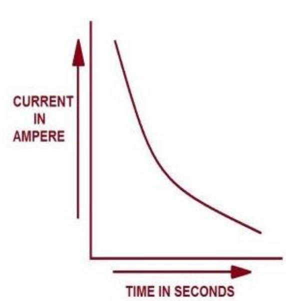
Overcurrent Protection

Fuses & Circuit Breakers

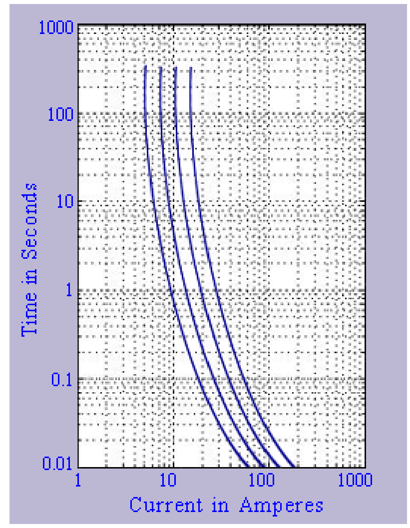
- ***Fuses***
- A 'fuse' refers to a device that opens a circuit with fusible (element) part, which is heated and severed by current flowing through it, to protect the circuits and equipments against **overload and short circuits**.
- When current flows in a fuse, **heat** is generated and the element temperature rises. If **the current is within (less or equal to)** its continuous rated value, then the steady state temperature is such that the fuse does not melt. However, if the current has large enough magnitude, it will lead to the fuse element to melt.
- After melting, an arc may be struck. The fault current will be finally interrupted when the arc is de-ionized.
- They are used for overcurrent protection of transformers, capacitors and in distribution systems

Fuse Characteristics

- Fuse element materials having **low melting point, high conductivity.**
- Its rating can start from few mA to several kA.
- Many forms and shapes depending on its application.
- Fuse has inverse time current characteristics.



- <u>**Thermal Characteristics**</u>
- As the magnitude of the current increases, melting time reduces. The larger magnitude currents will lead to higher power dissipation (I^2R) in the fuse and hence faster rise in temperature of the element.
- The relationship between the magnitude of the current that causes melting and the time needed for it to melt is given by the fuse's melting <u>**time current characteristics (TCC**</u>).
- The fuse element is a primary consequence <u>**of thermal effect**</u>. It <u>***does not depend upon mechanical forces, inertia etc. Thus there is no limit on how short the melting time can be.***</u>



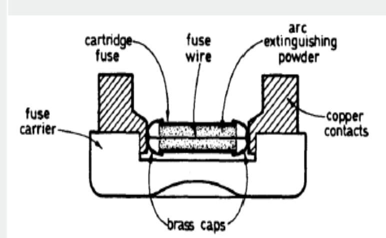
- <u>***Interrupting Characteristics***</u>
- There is always some <u>**period of arcing**</u> before the current is interrupted.
- Addition of melting time and this arcing overhead gives <u>***the total clearing time***</u>. <u>**Total clearing TCC curve**</u> describes this information.
- The total clearing time (both) are required to <u>coordinate back up fuse</u> or <u>overcurrent relay or any other protective devices</u>. Back up device should provide sufficient 'opportunity window' (time) to primary fuse to clear the fault.

- **Voltage Rating**
- Even a fuse has a maximum rated voltage. It is the highest voltage at which fuse is designed to operate.
-

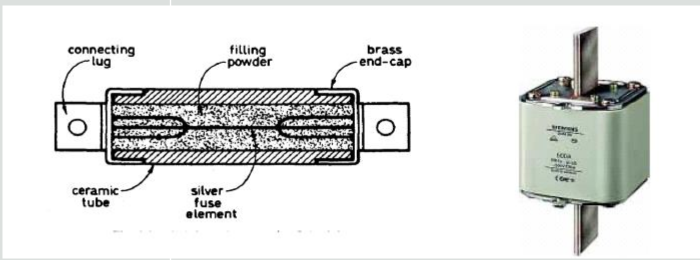
Low Voltage Fuses





Type of LV fuse	Advantage	disadvantages
Rewirable Fuse 	-Low cost -Wire may be easy available	wrong size of wire of to be fitted in fuse cause wrong operation at high current circuit which may be dangerous for the circuit protected and not adequate for electrical arc extinguish .
Cartridge Fuse. 	-The wire is enclosed in a cartridge-type container. - The wrong size of fuse cannot be fitted since it with different size for different current -The fuse wire does not deteriorate and is more reliable in operation	

Type of LV fuse	Characteristics and advantages
High Rupturing Capacity (H.R.C) or or High Breaking Capacity (H.B.C)	- For **large currents and where the energy level is high**, the high-breaking- capacity (h.b.c.) fuse is used. - This is a cartridge-type fuse in which a silver fuse element is connected between two end-contacts of a ceramic tube filled **with a special quartz powder**. When the fuse blows there is a fusion of the silver vapor produced with the filling powder, so that globules of high-resistance material are formed in the path of the arc**,**. - This type of fuse is very reliable in performance ***causing it to be extinguished*** and and has a high speed of operation



- **The disadvantage of all types of fuses, of course is the fact that when they have operated they have to be replaced.**

- ***Notes***
- The type of fuse chosen to protect a factory circuit will depend upon **the type of load and the circuit conditions**.
- It is important to realize the difference between ***the current rating of a fuse and its fusing current.***
- The current rating of a fuse is the current the fuse will carry continuously without blowing or deteriorating.
- The rated minimum fusing current is the minimum current at which the fuse will blow in a specified time. This may vary between **1.25 and 2.5 times the current rating**.

- The relationship between the rated minimum fusing current and the current rating ***is called the fusing factor***:

- **Fusing factor = rated minimum fusing current / current rating**

Fusing factor

- Fusing factor is the smallest current that will cause the fuse element to melt .

$$Fusing\ factor = \frac{Rated\ minimum\ fusing\ current}{Current\ rating}$$

$$Rated\ minimum\ fusing\ current = Fusing\ factor * Current\ rating$$

There are four classes, depending on fusing factors

1- Class P :- Having a **fusing factor of 1.25 or less**
This class is to protect circuits with small overloads

2- Class Q fuses:- Used for circuits with higher values of overload and its divided into two:

- **Class Q1—fusing factor between 1.25 and 1.5**
- **Class Q2—fusing factor between 1.5 and 1.75**

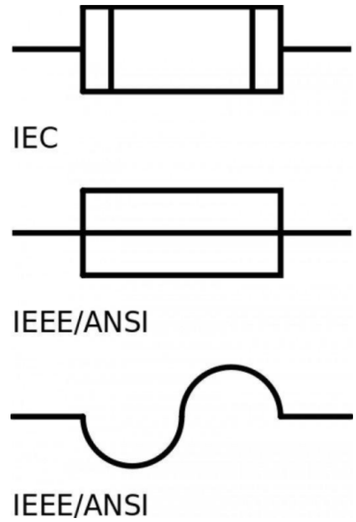
3- Class R fuses : Used to protected a circuit against large over- currents only. (Mainly is back-up protection)

- **Class R- Fusing factor between 1.75 and 2.5**

- ***Example*** : What is the minimum fusing current of the 20A Q2 fuse that will be operated?

$$Rated\ minimum\ fusing\ current = Fusing\ factor * Current\ rating$$
$$= 20\text{A} \times 1.5 = 30\text{A}\ \ or\ = 20\text{A} \times 1.75 = 35\text{A}$$
$$minimum\ fusing\ current\ rated\ to\ operat\ is\ between\ \ 30\ and\ 35 Amps$$

Fuse symbols

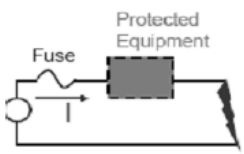


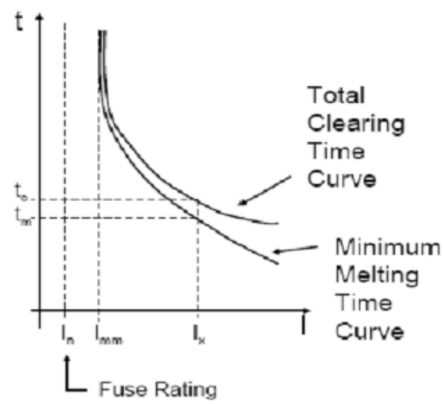
- According to IEC standard, three classes of LV cartridge fuse are widely used :

- 1.For *domestic (for lighting circuit*) and smaller installation ,type gG is used.
- 2.For *industrial* installations (*for motor protection*) gM type is used.
- 3.For *industrial* installations (*for short-circuit currents*) aM type is used.

Current Melting Fuse Element and Clearing Time

- A curve to represent the **<u>total clearing time</u>** as a function of the current with main characteristics of a fuse:
- 1.The minimum melting time curve
- 2.The total clearing time curve
- 3.The fuse minimum melting current
- 4.The fuse rating (nominal current)





The I^2t factor of the fuse

- *<u>The operation time of the</u>* fuse at **high** <u>levels of current is inversely proportional</u> <u>to the square of the current</u> during the **<u>pre-arcing stage (operation).</u>**
- It expresses the <u>amount of energy required to melt the element before it begins to arc</u>.
- For any conductor, its temperature rise depends on the current and duration **<u>I^2.t factor</u>**. This factor can be calculated by:

-For copper conductors

$$I^2\,t = 11.5\ x\ 10^4 A^2\ log_{10}\frac{273+\theta_m}{273+\theta_o}$$

-For Aluminum conductors

$$I^2\,t = 5.2\ x\ 10^4 A^2\ log_{10}\frac{273+\theta_m}{273+\theta_o}$$

Where:

I = Short circuit current (A)
t = Duration of the short circuit (s)
A = cross - sectional area of the conductor $(mm)^2$
θ_o = Initial temperature of the conductor (C^o)
θ_m =Final temperature of the conductor (C^o).

- **Example :** In case of using a 0.0503$\underline{\mathbf{mm^2}}$ copper wire as a fuse element for Rewirable type. If its initial temperature is 50 Cº, taking in consideration that the copper melt at1083 Cº. calculate the following:
- (a) TheI^2t needed to melt the wire.
- (b) The time needed to melt the wire if the short circuit current is 30A.

$$I^2 t = 11.5 \times 10^4 \times 0.0503^2 \times \log_{10}\left(\frac{273+1083}{273+50}\right) =$$

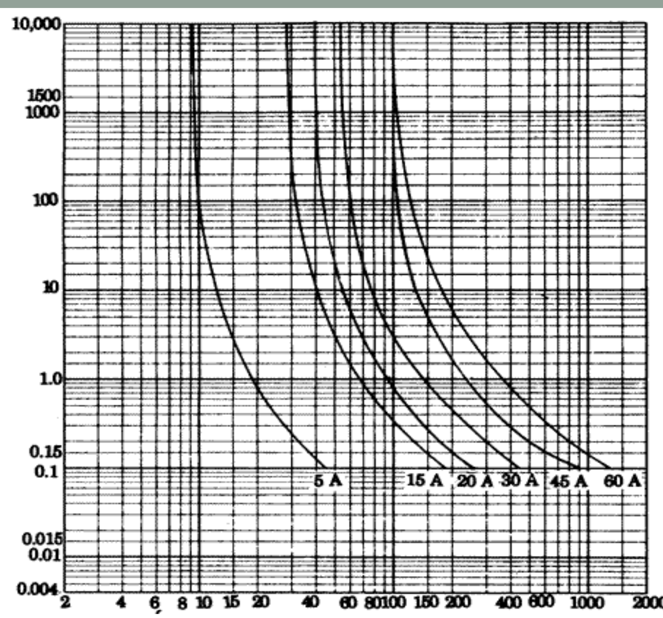
$$= 181.3 A^2 s \quad then;$$

$$t = \frac{181.3}{I^2} = \frac{181.3}{30^2} = 0.2s$$

$$I^2\, t = 11.5\ x\ 10^4 A^2\ log_{10}\ \frac{273 +\ \theta_m}{273 +\ \theta_o}$$

The melt of the fuse is after 0.2 second

Time/current characteristics of semi-enclosed fuses



High Voltage Fuses

- Same characteristics and operation as LV fuse but differing in size and shape

Circuit Breakers

Low Voltage Circuit breaker

- **A circuit breaker (CB) is an automatically switchable device to protect an electrical circuit from overload or short circuit.**
- Unlike a fuse, which operates once and then has to be replaced, a circuit breaker ***can be reset (either manually or automatically)*** to resume normal operation
- Circuit breakers are made in **varying sizes,** from small devices that protect an individual household appliance up to large switchgear designed to protect high voltage circuits feeding an entire city.

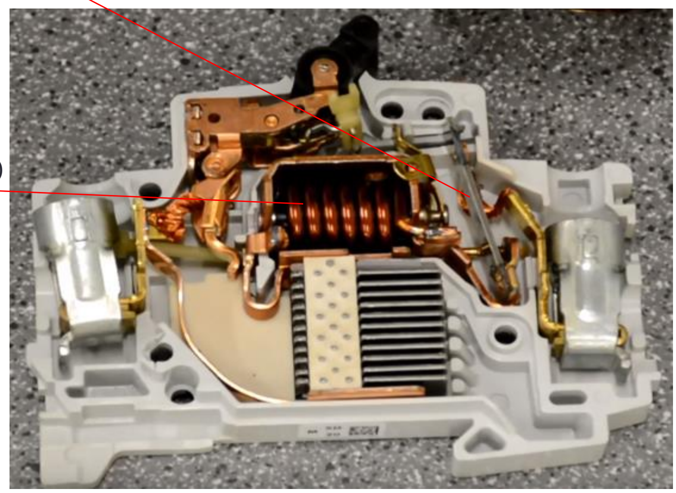
- **Circuit Breaker Operation:**

1-Magnetic circuit breakers :

- The contacts are held closed , in case of short current in the solenoid **increases beyond the rating of the CB**, the solenoid's pull and releases the latch. This allows the contacts to open by spring action.
- So, it based on a solenoid (**electromagnet**) with pulling force that increased with the current.

- **Thermo-magnetic circuit breakers**
- Thermal breakers use a bimetallic strip, which heats and bends with increased current, and release the latch. This type is commonly used with motor control circuits

solenoid(**electromagnet**)



Types of circuit breaker

- For applications at low voltage (less than 1000 V) the types are:-
- **a) Miniature Circuit Breaker (MCB) :**
- MCB rated current not more than 100 A.
- MCB is used for1-phase and 3-phase applications.
- Rated current : International Standard IEC (at ambient air temperature of 30 °C) are: (6,10,13,16,20,25,32,40,50,63,80 and 100) Amperes.
- Note :-The circuit breaker is labeled with the rated current in ampere, but without the unit symbol "A".

- Instead, the ampere figure is preceded by a letter **"B", "C" , "D“ "K" or "Z"** that indicates the instantaneous tripping current (the minimum value of current that causes the circuit-breaker to trip) without intentional time delay (i.e., in less than 100 ms):

Type	Instantaneous tripping current
B	above 3*In* up to and including 5*In*
C	above 5*In* up to and including 10*In*
D	above 10*In* up to and including 20*In*
K	above 8*In* up to and including 12*In* For the protection of loads that cause frequent short duration (approximately 400ms to 2s) current peaks in normal operation.
Z	above 2*In* up to and including 3*In* for periods in the order of tens of seconds. For the protection of loads such as semiconductor devices or measuring circuits using current transformers.

Note : *In*=Nominal current

- **b) Molded Case Circuit Breakers (MCCB)**
- Thermal or thermal-magnetic operation.
- Tripping current may be adjustable.
- Mainly is used for 3-phase circuits and for currents larger than 100A and up to 1600A.
- Mainly is used in industrial applications to protect cables and equipment.

c) Air Circuit Breaker(ACB)

- Tripping current is adjustable
- This type of circuit breaker is **used for very large current applications** up to 6000A.
- These are usually used in low voltage applications below 450V. We can find these systems in Distribution Panels (below 450V).
- Air circuit breaker is circuit operation breaker that operates **in the air as an arc extinguishing medium**, at a given atmospheric pressure.

d) Other types of circuit breakers.

✓ *Residual Current Device (RCD) or Residual Current Circuit Breaker(RCCB)* .

Disconnects a circuit when detects the electric current is not balanced between the phase conductor and the neutral conductor. Does NOT provide over-current protection.

✓ *Residual Current Breaker with Over-current protection* (RCBO): -combines the functions of an RCD and an MCB in one package.

✓ *Earth leakage circuit breaker (ELCB)* . This detects earth current directly rather than detecting imbalance.

High Voltage Circuit breakers

- The most important types are :

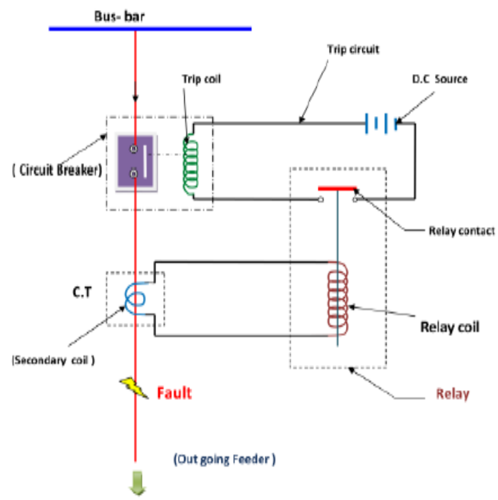
a) Oil circuit breakers (OCBs)

b) Air-blast circuit breakers

c) SF6 circuit breakers

d) Vacuum circuit break

- The action that causes a circuit breaker to open is usually produced by means of an <u>**overload relay**</u>. **The relay detect abnormal line conditions.**

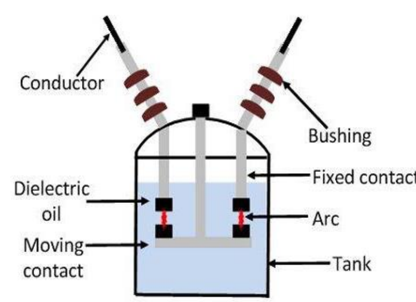


a) Oil Circuit Breakers:

- There are two types of oil circuit breakers:

1) Bulk oil circuit breakers

- Composed of a steel tank filled with insulating oil (for electric arc).
- For three phase there are three movable contacts<u>, actuated simultaneously</u> by an insulated rod, open and close the circuit.
- When the circuit breaker is closed, the line current for each phase, flows through the fixed contact
- <u>*If high current is detected the tripping coil releases a powerful spring that pulls on the insulated rod , causing the contacts to open.*</u>

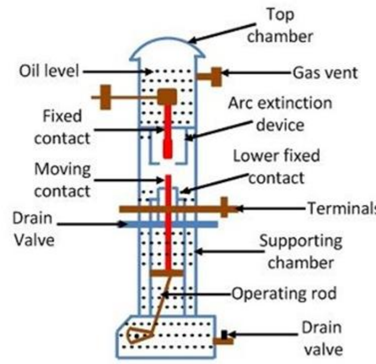


Oil Circuit Breaker

2) Minimum Oil Circuit breaker:

These circuit breakers contain minimum quantity of oil. Minimum oil circuit breaker requires less space as compared to bulk oil circuit breaker which is an important feature in large installations. The three phases are separated into three chambers as shown in Figure

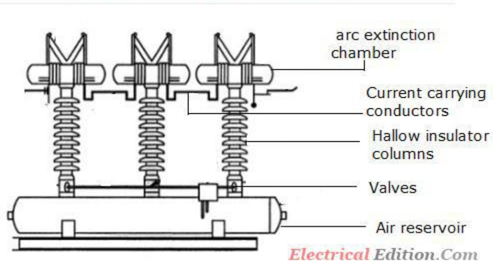
- **Advantages of OCB**:
- Oil has good dielectric strength.
- Low cost.
- Oil is easily available.
- It has wide range of breaking capability.
- **Disadvantages:**
- Slower operation
- It is highly risk of fire.
- High maintenance cost.



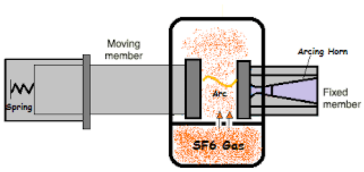
Minimum Oil Circuit Breaker

- **b) Air-Blast Circuit Breakers:**
- These circuit breakers interrupt the circuit by blowing compressed air (about 435 psi) at speed across the opening contacts.
- The most powerful circuit breakers can typically open short-circuit currents of 40 kA at a line voltage of 750 kV.
- The noise air blast breaker is **so loud then** must considered when to be installed near residential areas.

Air Blast Circuit Breaker



- **c) SF6 Circuit Breakers:** These totally enclosed circuit-breakers, insulated with SF6 (Sulfur hexafluoride) gas.
- Several characteristics of SF6 circuit breakers :-
- ➢ Simply of the interrupting ,does not need an auxiliary breaking chamber.
- ➢ Higher performance, up to 63 kA, with a reduced number of interrupting chambers.
- ➢ Possible compact solutions when used for GIS (gas insulation switchgear) or hybrid switchgear.
- ➢ Used in synchronized operations to reduce switching over-voltages.



SF6 C.B

Advantages

- Very short arcing period.
- Much larger currents as compared to other breakers.
- No risk of fire.
- Low maintenance, less size.
- No over voltage problem.
- Reliability and availability.
- Low noise levels.

Disadvantages

- Costly due to high cost of SF6.
- SF6 gas has to be reconditioned after every operation of the breaking.
- Additional equipment is required for this purpose.

- **d)Vacuum Circuit Breakers.** This is a kind of circuit breaker where the arc quenching takes place in vacuum medium.
- There is no gas to ionize when the contacts open.
- They are silent and never become polluted
- Several circuit breakers are connected in series. Their interrupting capacity is limited to about 30 kV for higher voltages and is often used in under ground distribution

- **Advantages:**
- Free from arc and fire hazards.
- Low cost for maintenance & simpler mechanism.
- Low arcing time & high contact life.
- Silent and less vibration operation.
- Due to vacuum contacts remain free from corrosion.

- **Disadvantages:**
- High initial cost due to creation of vacuum.
- High cost & size required for high voltage breakers.

POWER SYSTEM PROTECTION

EE 567

Dr. Feras Alasali

Circuit Breakers

c) Air Circuit Breaker(ACB)

- Tripping current is adjustable
- This type of circuit breaker is **used for very large current applications** up to 6000A.
- These are usually used in low voltage applications below 450V. We can find these systems in Distribution Panels (below 450V).
- Air circuit breaker is circuit operation breaker that operates **in the air as an arc extinguishing medium**, at a given atmospheric pressure.

d) Other types of circuit breakers.

✓*Residual Current Device (RCD) or Residual Current Circuit Breaker(RCCB)* .

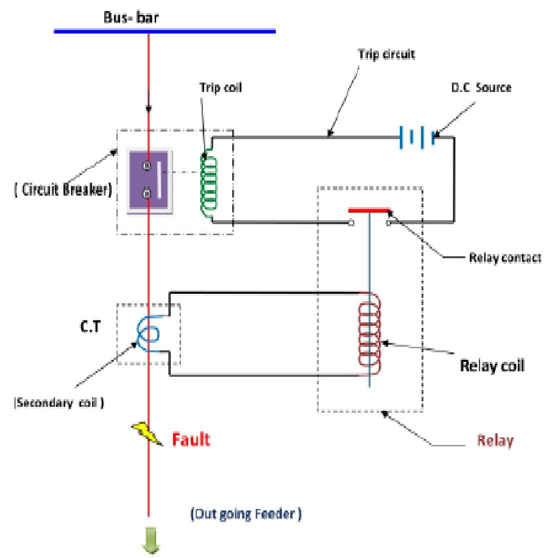
Disconnects a circuit when detects the electric current is not balanced between the phase conductor and the neutral conductor. Does NOT provide over-current protection.

✓*Residual Current Breaker with Over-current protection* (RCBO): -combines the functions of an RCD and an MCB in one package.

✓*Earth leakage circuit breaker (ELCB)* . This detects earth current directly rather than detecting imbalance.

High Voltage Circuit breakers

- The most important types are :
- a) Oil circuit breakers (OCBs)
- b) Air-blast circuit breakers
- c) SF6 circuit breakers
- d) Vacuum circuit break
- The action that causes a circuit breaker to open is usually produced by means of an <u>**overload relay**</u>. **The relay detect abnormal line conditions.**

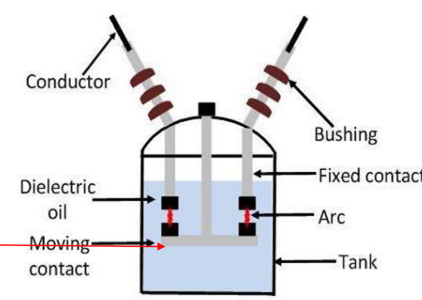


a) Oil Circuit Breakers:

- There are two types of oil circuit breakers:

1) Bulk oil circuit breakers

- Composed of a steel tank filled with insulating oil (for electric arc).
- For three phase there are three movable contacts, <u>actuated simultaneously</u> by an insulated rod, ~~open~~ and close the circuit.
- When the circuit breaker is closed, the line current for each phase, flows through the fixed contact
- <u>*If high current is detected the tripping coil releases a powerful spring that pulls on the insulated rod , causing the contacts to open.*</u>

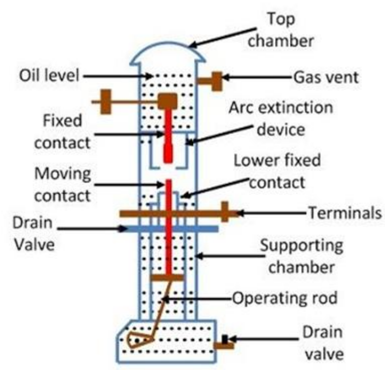


Oil Circuit Breaker

2) Minimum Oil Circuit breaker:

These circuit breakers contain minimum quantity of oil. Minimum oil circuit breaker requires less space as compared to bulk oil circuit breaker which is an important feature in large installations. The three phases are separated into three chambers as shown in Figure

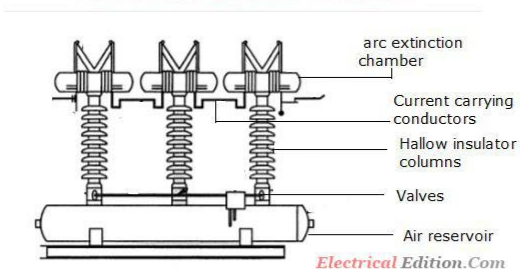
- **Advantages of OCB**:
- Oil has good dielectric strength.
- Low cost.
- Oil is easily available.
- It has wide range of breaking capability.
- **Disadvantages:**
- Slower operation
- It is highly risk of fire.
- High maintenance cost.



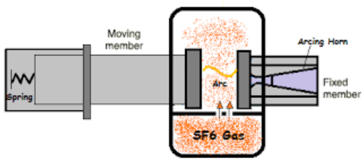
Minimum Oil Circuit Breaker

- **b) Air-Blast Circuit Breakers:**
- These circuit breakers interrupt the circuit by blowing compressed air (about 435 psi) at speed across the opening contacts.
- The most powerful circuit breakers can typically open short-circuit currents of 40 kA at a line voltage of 750 kV.
- The noise air blast breaker is **so loud then** must considered when to be installed near residential areas.

Air Blast Circuit Breaker



- **c) SF6 Circuit Breakers:** These totally enclosed circuit-breakers, insulated with SF6 (Sulfur hexafluoride) gas.
- Several characteristics of SF6 circuit breakers :-
  - Simply of the interrupting ,does not need an auxiliary breaking chamber.
  - Higher performance, up to 63 kA, with a reduced number of interrupting chambers.
  - Possible compact solutions when used for GIS (gas insulation switchgear) or hybrid switchgear.
  - Used in synchronized operations to reduce switching over-voltages.



SF6 C.B

Advantages

- Very short arcing period.
- Much larger currents as compared to other breakers.
- No risk of fire.
- Low maintenance, less size.
- No over voltage problem.
- Reliability and availability.
- Low noise levels.

Disadvantages

- Costly due to high cost of SF6.
- SF6 gas has to be reconditioned after every operation of the breaking.
- Additional equipment is required for this purpose.

- **d)Vacuum Circuit Breakers.** This is a kind of circuit breaker where the arc quenching takes place in vacuum medium.
- There is no gas to ionize when the contacts open.
- They are silent and never become polluted
- Several circuit breakers are connected in series. Their interrupting capacity is limited to about 30 kV for higher voltages and is often used in under ground distribution

- **Advantages:**
- Free from arc and fire hazards.
- Low cost for maintenance & simpler mechanism.
- Low arcing time & high contact life.
- Silent and less vibration operation.
- Due to vacuum contacts remain free from corrosion.

- **Disadvantages:**
- High initial cost due to creation of vacuum.
- High cost & size required for high voltage breakers.

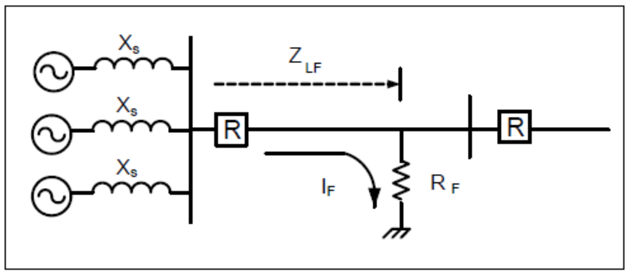
Overcurrent Relay

Overcurrent Relay

- Is the simplest and cheaper type of protection used for lines, transformers, generators and motor.
- Is the most famous and earliest protection system has been used to protect the electrical network.
- A high percentage of faults at network cause an overcurrent problems.
- The faults current is depend on :
- 1- fault location.
- 2- fault resistance.
- 3- Power source.

- 1- Fault location
- As the fault is far from the relay ,it mean higher resistance that can see by relay which also mean lower fault current.
- This explain why is difficult to find faults that far from the power source.

- 2- Fault resistance (R_F)



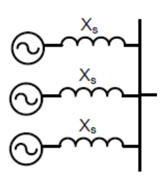
$$I_F = \frac{V_S}{Z_{LF} + R_F}$$

- 3- Power source :
- The type of feeding is radial or ring.
- The power source can be divided into two types during fault condition:

A) strong source: this is have low source impedance which mean high fault current.

- For example TWO power source connected in parallel (X/2).

B) weak source: for example we have one power source then the total impedance is equal to X not X/2. Higher impedance and less fault current

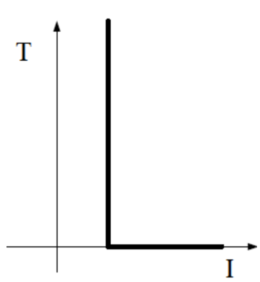


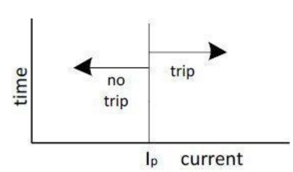
Overcurrent relays Types:-

- Based on operating time characteristics, normally **defined by the time vs. current curve** (or T-I curve), there are three main types:

- **Instantaneous**
- **Time-dependent** (**Definite time or Inverse time)**
- **Mixed (Definite time + Inverse time)**

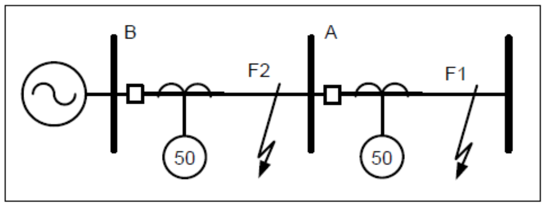
- **Instantaneous**
- These relays **operate without time delay**, so they are called instantaneous units (operating time= 0.1 second).
- The relay will open the circuit if the current exceed the setting current (instantaneously).
- This type is suitable for high currant faults, as you need to open the circuit directly.





. Characteristic of instantaneous overcurrent relays

- Generally, For this type of protection will face difficulties in coordinate the relays with short distance.
- For Relay (B), F1 and F2 is almost the same



Time-dependent Overcurrent Relays

- Operate with a time delay.
- Time delay is adjustable.
- Pick up current is also adjustable.
- There are two main different groups of time over-current relays (depends on their time-current characteristic curves) :-

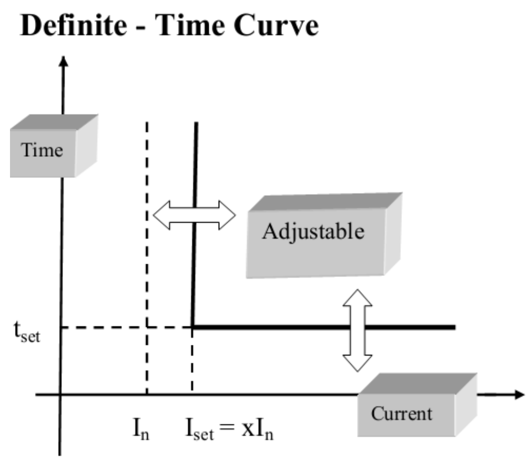
1-Definite time (DT).

2-Inverse-time :-

- Moderately inverse
- Inverse (Normal)
- Very inverse
- Extremely inverse

1- Definite-Time Overcurrent Relays (DT).

The definite-time relay operates with *some delay this delay is adjustable as well as the current threshold*.

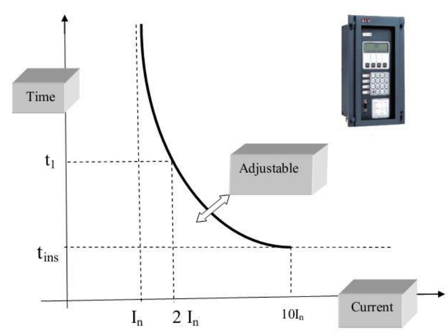


- The definite time protection is suitable for a fault current less danger compared to Instantaneous case , as no problem to have time delay before open the circuit.
- This type of protection is suitable for avoiding transient fault and it work only with permanent faults.
-
- Generally, For this type of protection will face difficulties in coordinate the relays with short distance.

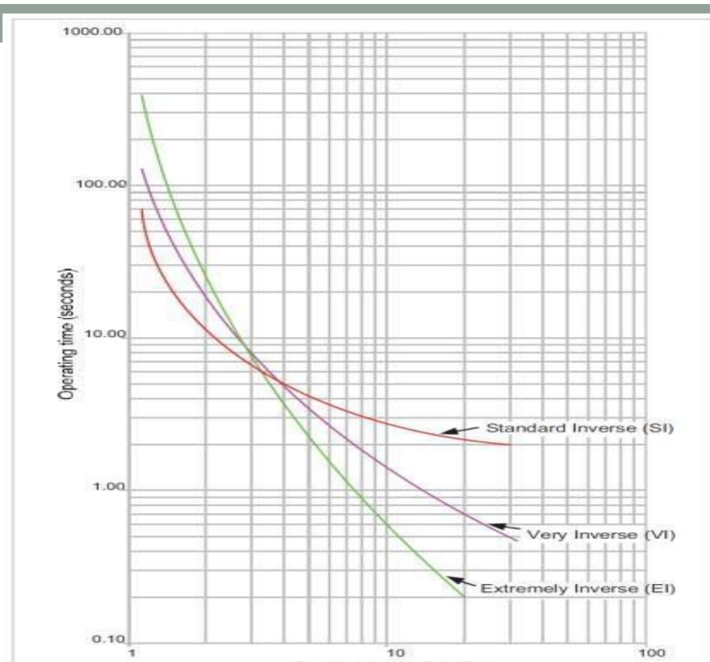
2- Inverses-Time

- This type of relay have an *operating time depending on the value of the current*, generally with an inverse characteristic, (increasing time decreasing current or voice versa)
- The **operation time** of the relay **is smaller as the current gets larger** (small value of time compared with current value).
- Also have two settings:
- 1- pick-up current
- 2- curve level.

Inverse - Time Curve (51)



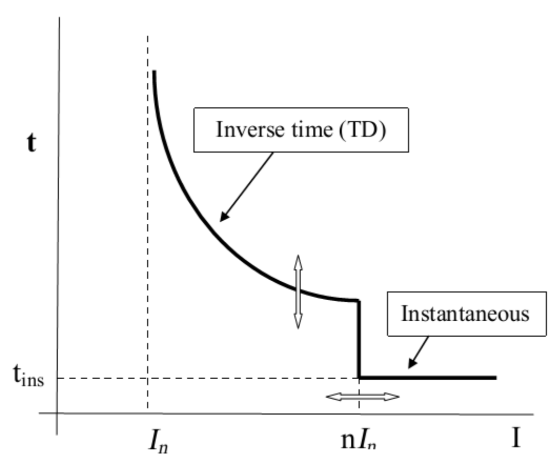
Inverse time curve (51)



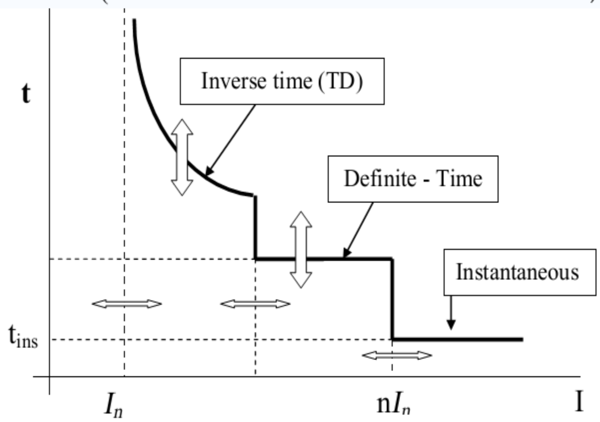
IEC 60255 IDMT relay characteristics; TMS=1.0

- **Mixed Curves Over-Current Relays**
- Mixed curves have all the advantages of the different types of over-current relays.
- As the over current elements are built as separate units, we may implement the over-current protection principles using:
- a) a combination of instantaneous and definite-time elements .
- b) a combination of instantaneous and inverse-time elements.
- c) a combination of instantaneous, definite-time and inverse-time elements.
- d)a combination of definite-time and inverse-time elements(IDMT).

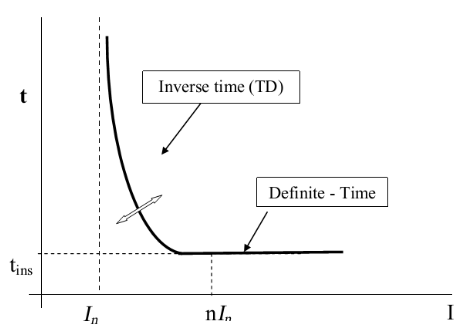
Mixed Curves (Inverse-Time + Instantaneous)



Mixed Curves (Inverse-Time +Definite -Time + Instantaneous)



- **Mixed Curves (Inverse-Time +Definite -Time) IDMT –Characteristics**
- The most commonly used *type of relay is the inverse definite with minimum time lag relay (IDMT)* in which inverse characteristic plus definite time characteristic are used.
- The **operating time** is approximately inversely proportional to the fault current near pickup value and become substantially constant slightly above the pick up value of the relay.
- The characteristic is shown in Fig.



POWER SYSTEM PROTECTION
EE 567

Dr. Feras Alasali

Overcurrent Relay

OC Relay setting

- There are three main steps for OC relay setting :
- 1- select the CT.
- 2- select the pickup current
- 3- Time setting

- Will work mainly on Inverse and instantaneous relays.

1- select CTR

- There is mainly two main parameters select the CTR (X: 5 or 1) :
- Full load current.
- Short circuit current which will cause CT saturation.

- For example: if we have a 4600 A short circuit and load current 130 A and if we assume the CT will be saturation when the secondary current equal to 100 A. What is the CTR?

$$X \geq 130 \qquad \begin{array}{ccc} X & \longrightarrow & 5 \\ I_{SC} & \longrightarrow & <100 \end{array} \qquad \begin{array}{ccc} X & \longrightarrow & 5 \\ 4600 & \longrightarrow & <100 \end{array} \qquad X \geq \frac{4600 * 5}{100} \geq 230$$

Then will choose the best next available ratio 300/5

- Secondary current at normal full load

$$\frac{130\times5}{300}=2.1A$$

- Secondary current at fault case :

$$I_{SC}=\frac{4600\times5}{300}=75A$$

- The current 75 A did not reach the saturation current (100 A) so the CT is suitable for this case

2- Pickup current

- For inverse relays, the pickup current is equal a multiple a value called (TAP) which determine the minimum current that allow relay to operate.
- In induction disc relay this value called PSM (Plug setting multiple).
- The fault current it also determine as

Pickup value	$I_{>}$	Multiple of TAP

- In general, the TAP determines as percentage of the CT secondary.

(1 TAP = 1 OR 5 A) or a spesfic pickup current at secondary OR full load current.

- The TAP can be adjusted between 50% to 200% and it also called the I setting (Is).
- Generally , it will be 100% but it can be less for some cases such as EF.
- For example, calculate fault current for OC relay adjusted at 75% and used with CTR 200/1. If a short current equal to 300 A on the primary side?
- Relay adjusted at 75% mean $TAP = 0.75 * 1A = 0.75A$
- Fault at secondary side = 300 * (1/200) = 1.5 A
- Fault current (measured by TAP) is = 1.5 /0.75 = 2 TAP

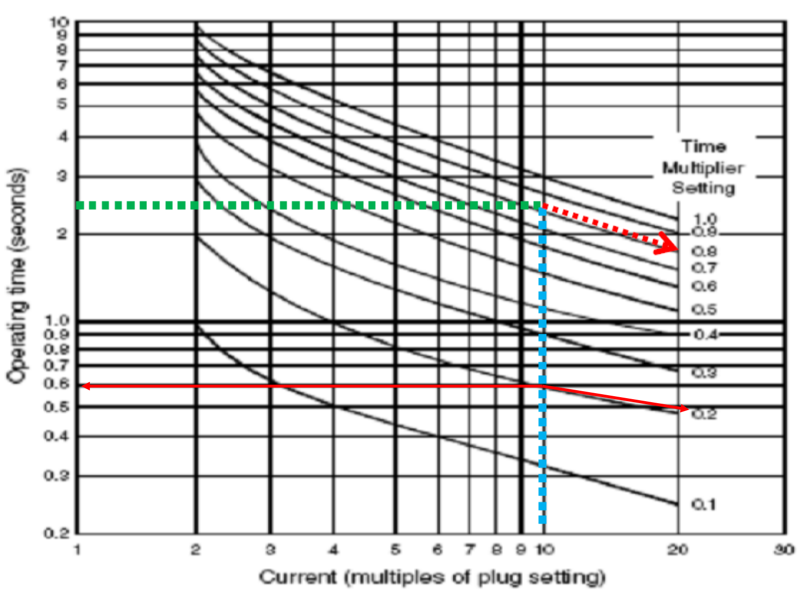
Relay pick up current= %current setting * CT ratio

$$PSM = \frac{Fault\ Current}{Relay\ Pick\ up\ current} \qquad PSM = \frac{Fault\ Current}{\%current\ setting * CT\ ratio}$$

- Example: If the plug position (current setting) 5 means the relay operates when the fault current is 5 times of the CT ratio (Relay pick up current).
- i.e The supply CT is rated 400:5A and the fault current is 3200A means, the plug positon is 5 then the relay operates, because of the relay gets MORE the Relay pick up current =5*5=25 A (2000 A=1PSM),
- At the fault current = (PSM = 3200/2000 = 1.6)

3- Time dial setting

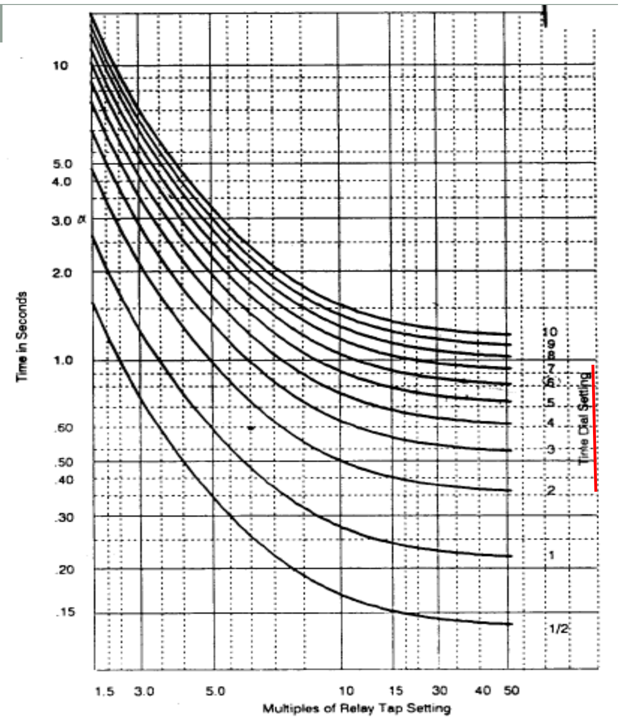
- It called also Time Multiplier Setting (TMS)
- **Operating Time of Relay** <u>for Inverse Curve</u>
- After determine the fault as TAP, we need to select the time for open the circuit by using a relay operation curve.



Example
Calculate the time operation for relay when a fault occurred and caused 12 A in the Relay. The pickup current for relay is 4 A and the curve # 2 is used for this relay?

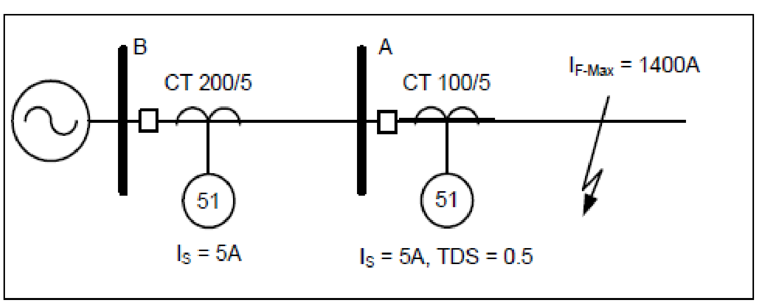
$$I_F(\text{as a multiple of } TAP) = \frac{12A}{4A} = 3\,TAP$$

Time is . 2.0 Sec



Example:

Calculate the operation time for Relay A and B?



- Firstly, it clear from the figure is TAP = Is = 5 A.
- At

Relay –A

$$I_F = \frac{1400}{100/5} \div 5A = 14\,TAP$$

- From the curve at TDS =0.5, The time will be 0.15 s.
- At

Relay-B

$$I_F = \frac{1400}{200/5} \div 5A = 7\,TAP$$

- From the same curve (TDS= 0.5) the time will be 0.25 S

- The difference between the two relays is 0.1 S. This is not suitable s coordinate time which should be equal 0.4 s to 0.3 s.

Therefore, we change the curve of the Relay B, we choose the next suitable curve TMS 1, the time will be 0.5 s which is ok .

The coordinate time is Time Gap between relays.

$$\Delta t \geq t_{CB} + t_{Reset} + t_{Inacc} + t_{M\arg}.$$

t_{CB} = Operating time for the circuit breaker = 40 : 100 msec.

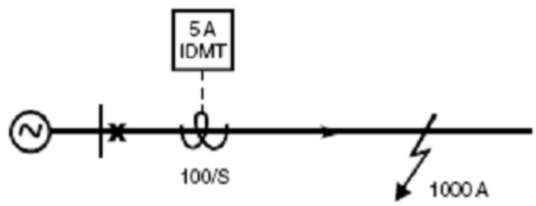
t_{reset} = Reaset time for the relay = 40 : 70 msec.

t_{inacc} = The sum of inaccuracy in time measurement = 50 : 100 msec.

t_{marg} = Saftey margin

Example :

- Calculate the plug setting and **time multiplier setting** for an relay on the following network so that it will trip in 2.4 s The relay characteristic is shown in Figure 2.The C.T. setting is 100/5 A and the fault current is 1000 A.



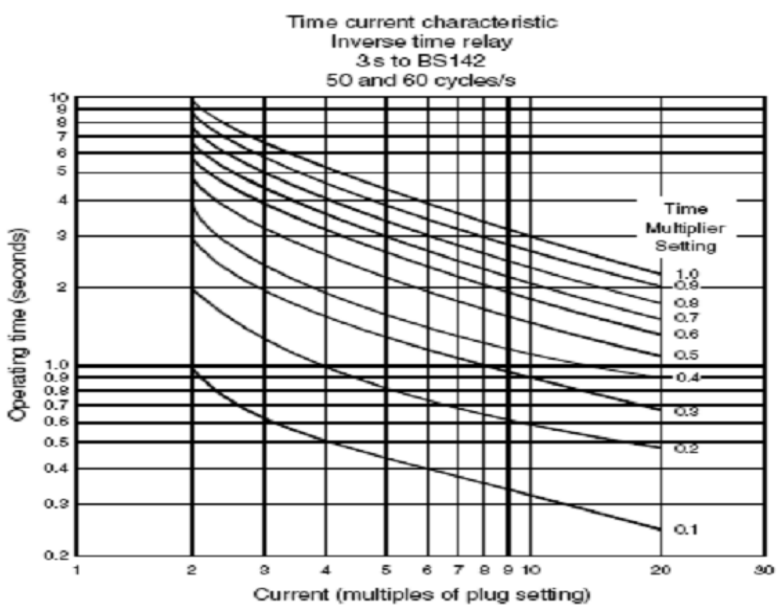


Figure 2 (Figure – 1A)

Answer:
Fault current = 1000 A
CT ratio = 100/5 A
The current into relay **under fault conditions**,

$$I_{op(relay)} = \frac{I_F}{CTR} = 1000 \times \left(\frac{5}{100}\right) = 50\text{A}$$

Choose plug setting100% this is 5 A Therefore, current into relay as a multiple of **plug setting during fault is 50 / 5 = 10** **Like TAP**

➢We require the relay to operate after 2.4 s as soon as this much current starts flowing in the circuit. Referring to characteristic curves below, read time multiplier setting where 10 times plug setting current and 2.4 s cross, which is about 0.8. Accordingly,

The relay settings is: PS=5 A (100%) and TMS=0.8.

Example:

- Determine the time of operation of a relay of rating 5A,

and having a relay setting of 125%, TMS=0.6. It is connected to a supply circuit through a C.T 400/5 ratio. The fault current is 4000A.

The operating current of the relay: 5×1.25=6.25A

$I_p = I_F = 4000$ A

$$I_s = 4000 \times \frac{5}{400} = 50\,A$$

$$PMS = \longrightarrow = \frac{50}{6.25} = 8$$

If we select TMS=0.6 then the operation time is 1.92 s

Example

- If the rated current (**pick up current**) of a relay is 3A, and the time dial setting(TDS) is 1. (a) How long(time) does it take the relay to trip if the supply C.T is rated at 400:5 A and the fault current is 480A?

(a) $I_p = 480\,A$

$$I_s = 480 \times \frac{5}{400} = 6\,A$$

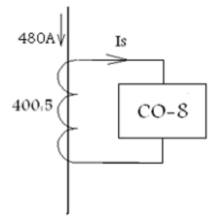
Tap value of current=3A

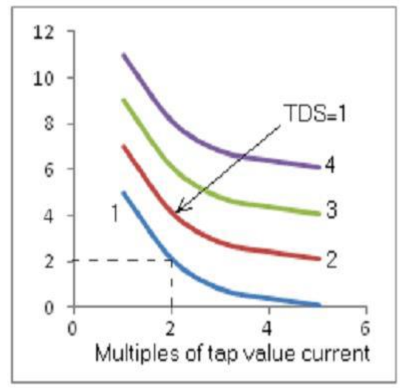
∴ Multiple of tap value current

$$= \frac{I_s}{I_{tap}} = \frac{6}{3} = 2$$

From the CO-8 characteristic curves:

Operating time=2.1 sec





- The type of the *OC relay is CO-8*.

Solve using the standard curve equation and compare the results?.

- **Curve Equation**
- The typical time curves for **CO-8** American over-current relay(normal inverse) characteristics can be approximated by the following equation.

Note: TDS(time dial setting)=TD(time delay)

$$t_{relay} = TD\left[\frac{5.95}{M^2-1} + 0.18\right]$$

Where TD = Time delay

$$M = \frac{I}{I_{pickup}}$$

$t_{relay=operating\ time\ of\ the\ relay}$

I_{pickup} = *Relay pick up current*

(b) Using the curve equation:

$$t_{relay} = TD\left[\frac{5.95}{M^2-1} + 0.18\right]$$

$$TD = 1 \Rightarrow TDS$$

$$M = \frac{I_s}{I_{pickup}} = \frac{I_s}{I_{tap}} = \frac{6}{3} = 2$$

$$\therefore \quad t_{relay} = 1 \times \left[\frac{5.95}{(2)^2-1} + 0.18\right]$$

$$= 2.16\text{sec}$$

(Same result)

- **The typical time curves for IEC standard overcurrent relay(normal inverse) characteristics can be approximated by the following equation.**

$$t_{relay} = \frac{0.14 \times TMS}{\left(\dfrac{I_F}{CTR \times PS}\right)^{0.02} - 1}$$

Where :

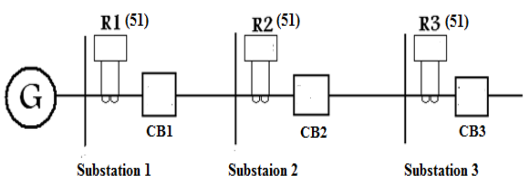
TMS = Time multiplier setting
CTR = Current transformer ratio
PS = Plug setting
I_F = Fault primary current

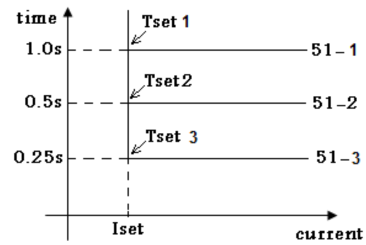
Instantenous Relays

- These relays **operate without time delay**, so they are called instantaneous units (operating time= 0.1 second).
- The relay will open the circuit if the current exceed the setting current (instantaneously).
- This type is suitable for high currant faults, as you need to open the circuit directly.

- I pickup = $I_{>>}$ > 1.2 fault current

- The relay operations must be **coordinated with respect to each other** in order to provide the desired selectivity. This is called "**relay coordination**".
- Among the various possible methods used to achieve correct relay coordination are those using either **time or current, or a combination of both**.



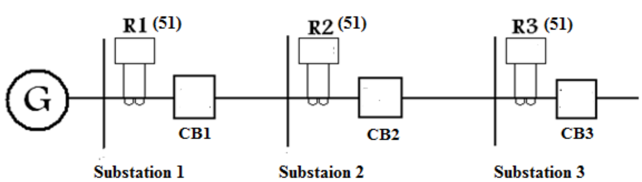


definite time characteristic are used

POWER SYSTEM PROTECTION
EE 567

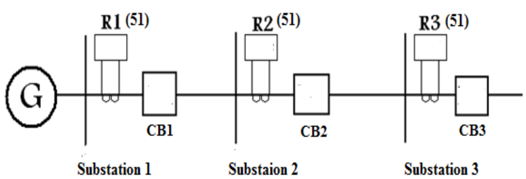
Dr. Feras Alasali

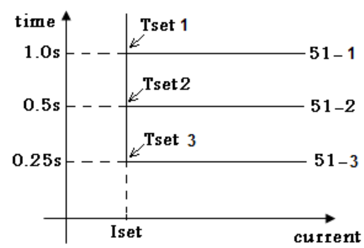
Overcurrent protection of transmission and distribution lines (Relay coordination principle)



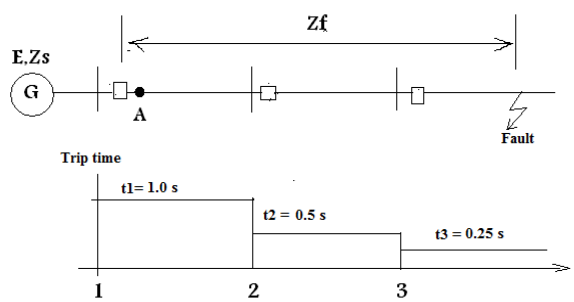
The protection scheme must satisfy the following requirements:
a) Under normal conditions the breakers are not tripped.
b) Under fault conditions only the breakers closest to the fault on the source side are tripped.
c) If the closest breaker fails to operate, the next breaker closer to the source should trip.

- The relay operations must be **coordinated with respect to each other** in order to provide the desired selectivity. This is called "**relay coordination**".
- Among the various possible methods used to achieve correct relay coordination are those using either **time or current, or a combination of both**.

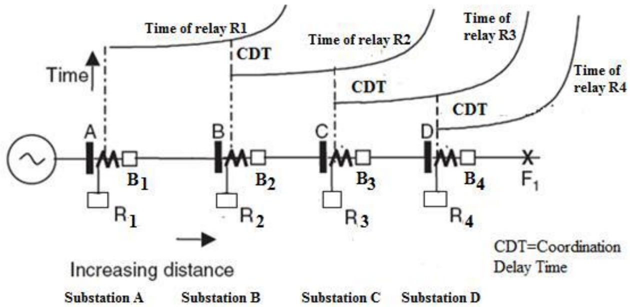




definite time characteristic are used



Advantage:	simple device, only current transformers are necessary
Disadvantage:	near infeed higher tripping time



The coordination between the relays for fault at F1 is necessary. The relay R4 tripping breaker B4 operates quickly at time T1, followed by the relays controlling B3, B2 and B1 so that B4 operates before B3, B3 before B2 and B2 before B1.

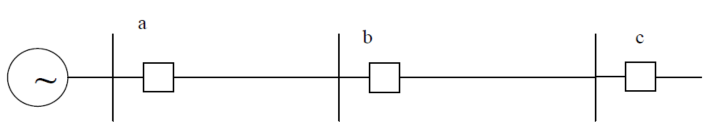
Therefore the operating time T2 of relay R3 can be expressed as

$$T2 = T1 + CDT$$

where CDT is called the coordination delay time (CDT=03-0.4s), which is the minimum interval that permits a relay and its circuit breaker to clear a fault in its operating zone

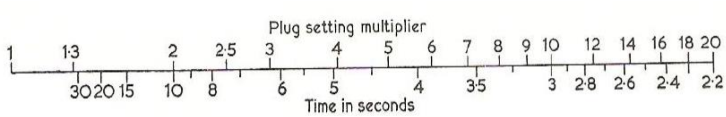
Example

It is required to provide time-current grading for the following system:



Relay point	*Plug setting(PS)*	*CT ratio*	*Fault current*
a	125%	400/5	6000A
b	125%	200/5	5000A
c	100%	200/5	4000A

Use time multiplier setting (TMS) = 1 according to British Standard given in the following figure :



Solution :

- At relay point C, the relay current on fault:

$$I_{RC} = 4000 * \frac{5}{200} = 100\ A$$

For PS=100%

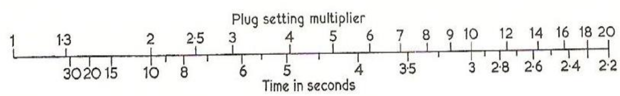
$$PSM = \frac{100}{5 * 1} = 20$$

For TMS=1 curve, the operating time corresponding to PSM=20 is 2.2s
If we select R_c to operate with fastest time, hence TMS=0.1, thus the operating time for R_c will be:

$$t_{op\ R_C} = \frac{0.1 * 2.2}{1.0} = 0.22\ sec$$

Hence for relay C:
TMS = 0.1
$t_{op\ R_C} = 0.22\ sec$

Use time multiplier setting (TMS) = 1 according to British Standard given in the following figure :



- For relay at B:
  This relay should respond to fault at C (backup) and respond to fault near B:
  - Fault at C
    For discrimination between R_c & R_B, let the time margin = 0.5 sec
    Hence

$$t_{op\ R_B} = 0.22 + 0.5 = 0.72\ sec$$

For fault at C:

$$I_{RB} = \frac{4000}{\frac{200}{5}} = 100\ Amps$$

The PS of relay B = 125%
hence the operating current $= 5 * 1.25 = 6.25\ Amps$

$$PSM = \frac{100}{6.25} = 16$$

From the curve, the operating time is 2.5 sec

The operating time of R_C is 0.72 sec
hence $TMS = \frac{0.72}{2.5} = 0.29$

TMS	t_{op}
1	2.5
x	0.72

- For fault near B:

$$I_{R_B} = 5000 * \frac{5}{200} = \frac{5000}{40}$$
$$PSM = \frac{5000}{6.25 * 40} = 20$$

The operating time correspond to the PSM is 2.2 sec

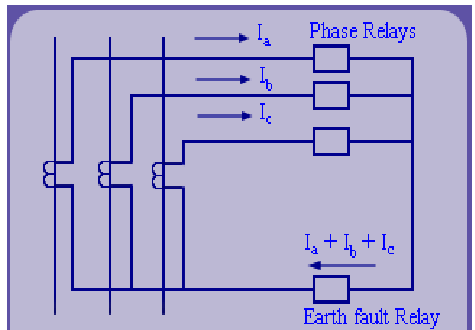
Actual operating time of R_B is:

$$t_{op\,R_A} = 2.2 * \frac{TMS = 0.29}{TMS = 1.0} = 0.638\ sec$$

Earth-fault Relays

- Earth fault relay is originally an overcurrent relay.
- Overcurrent takes number 50 (inst) or 51 (inverse) but Earth fault relay takes number 64.
- Earth-fault relay is used to protect feeder a**against faults involving ground**. Typically, earth faults are single line to ground and double line to ground faults. For the purpose of setting and coordination, only single line to ground faults are considered.

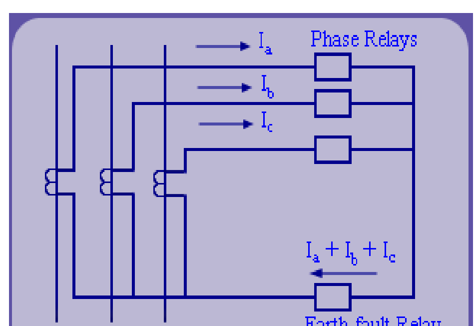
- The earth fault current values can be even below the load current due to large impedance to ground.
- Hence, to provide sensitive protection, earth fault relays use zero sequence current rather than phase current for fault detection. (The unbalanced **current** flows in the circuit during the earth fault is known as the **zero sequence current**)
- Note that the zero sequence component is absent in normal load current.
- Hence, pickup with zero sequence current can be much below the load current value, thereby providing sensitive earth fault protection.



Phase and Earth Fault Relay Configuration

- In practice, **distribution systems** are inherently **unbalanced**. Thus, load current would also have a small percentage of zero sequence due to unbalance. Hence, it is mandatory to keep the pick up current above the maximum unbalance expected under normal conditions.
- A rule of thumb is to assume maximum unbalance factor to be between 5 to 10%.

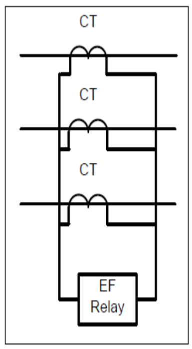
- It should be also observed that earth fault relays will not respond to the three phase or line to line faults.
- One earth fault relay is adequate to provide protection for all types of earth fault (a-g, b-g, c-g, a-b-g etc).
- Three phase relays are required to provide protection against phase faults (three phase, a-b, b-c, c-a). **Thus with four relays as shown in this figure to complete overcurrent protection can be provided.**



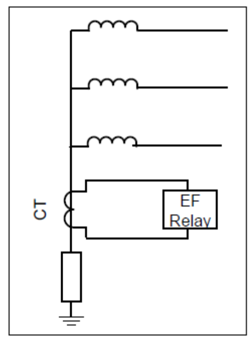
Phase and Earth Fault Relay Configuration

E/F relays protection types:

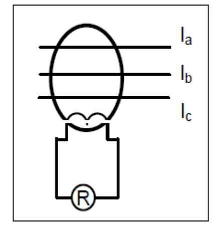
Residual Connected Earth Fault Relay



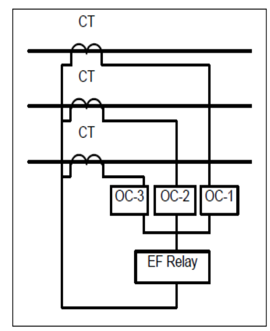
EF In Neutral Connection



Core Balance EF Protecection



Combined EF and Phase Fault Protection



5- Residual voltage relay: the total voltage Va+Vb+Vc = 0. During earth voltage 3Vo.

E/F relay setting

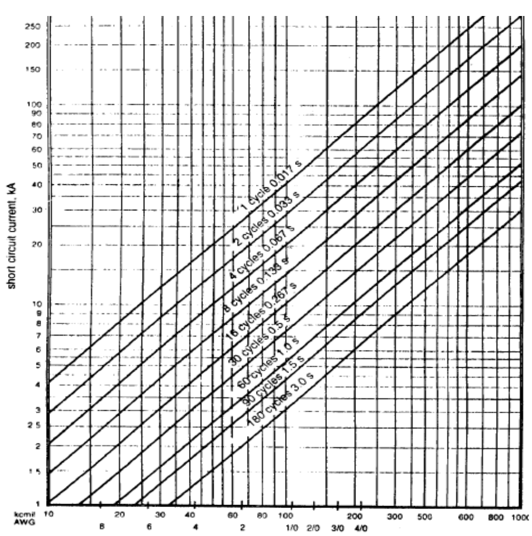
- EF relay setting is similar to overcurrent relay.
- Example: find the fault current at E/F relay adjusted by 20%, if the CTR = 100/ 1 A and primary fault is 60 A?
- Relay adjusted at 20% , then 1 TAP = 0.2 A.
- I (fault) = 60 *1/100 = 0.6 A ---- = 3 TAP.
- Note setting is 20% or less at E/F compared to 150% for O/C relays. As the E/R should be sensitive and value of current is lower than O/C

Automatic Reclosing

- Many faults (80-90%) in the overhead distribution system like flash over of insulators, crow faults, temporary tree contacts , etc are temporary in nature.
- Thus, taking a feeder or line permanent outage may lead to unnecessary long loss of service to customers. Hence, many utilities use fast automatic reclosers for an overhead radial feeder

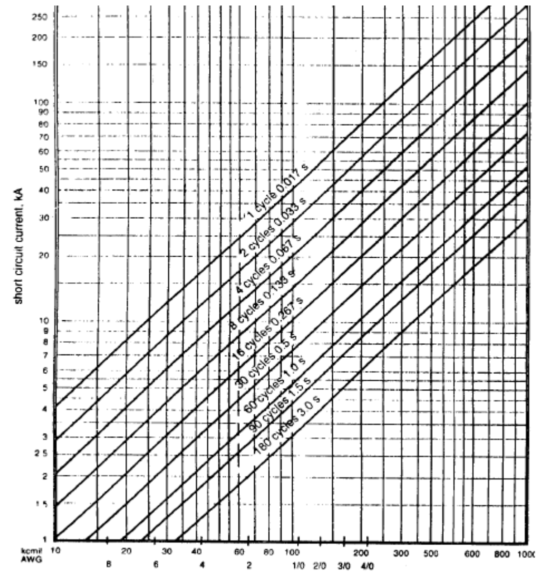
Thermal limitation for

- The time setting for relays will also make sure that C.B will open within the thermal limitation for equipment's.



Example

- If we have (1/0 AWG) cable and short circuit equal to 10 KA, what the disconnect time?
- From the table is should be less than 0.267 s.

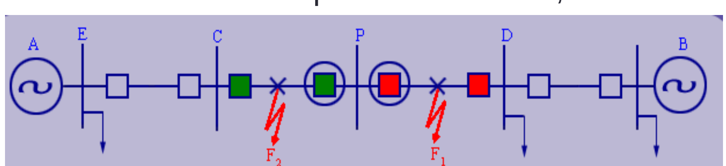


POWER SYSTEM PROTECTION
EE 567

Dr. Feras Alasali

Directional Overcurrent protection

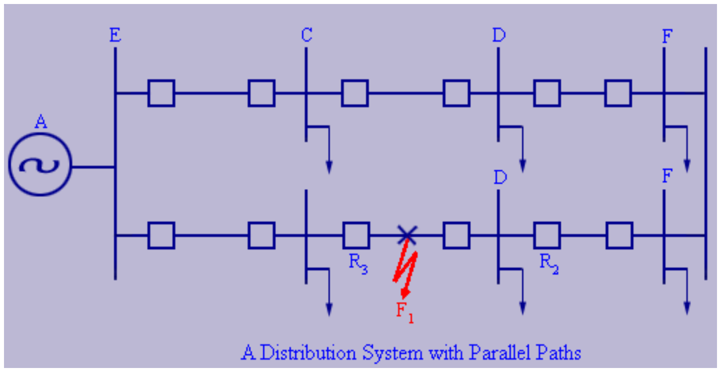
- In the overcurrent protection scheme considered in previous lectures, we had implicitly assumed that,
- 1. System is radial.
- 2. There is a single source.



A Radial Distribution System with Two Sources

- **If relays for protection are installed only at one end of transmission line say towards source A end, it is obvious that after opening of relay in red, the fault will continue to be fed from source B**

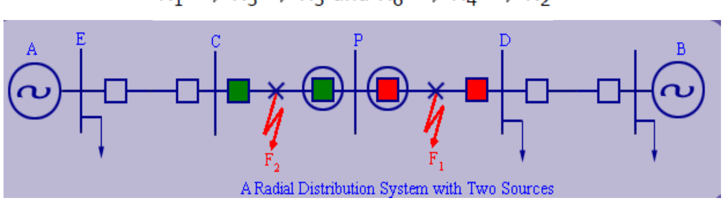
- Similar situation will exist even for a single source system if parallel paths exist



A Distribution System with Parallel Paths

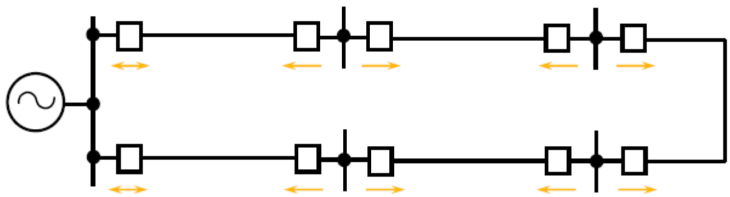
- To overcome this limitation, <u>the relay element has to be provided with additional</u> discrimination feature to distinguish <u>between faults that it should respond to, and others that it should not respond to</u>.
- Further, this '<u>**selectivity**</u>' will <u>not be sufficient</u> if it is based upon <u>magnitude of pick up</u> current (or fault currents).
- In the previous lectures, we had <u>**used time discrimination to provide selectivity**</u>. it is apparent that such discrimination will hold between relay sequences

$R_1 \rightarrow R_3 \rightarrow R_5$ and $R_6 \rightarrow R_4 \rightarrow R_2$



A Radial Distribution System with Two Sources

Directional Overcurrent Protection



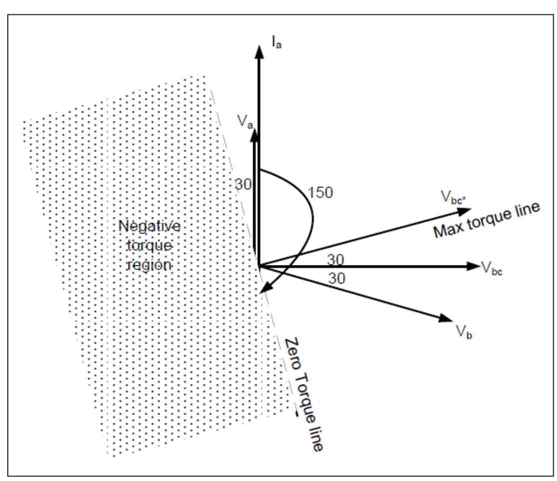
The arrows shown in the figure are used to represent the protection direction.

the relays are into two independent groups: the relays “looking” to the right and those “looking” to the left. .
All the relays are directional except the relays near the generation .

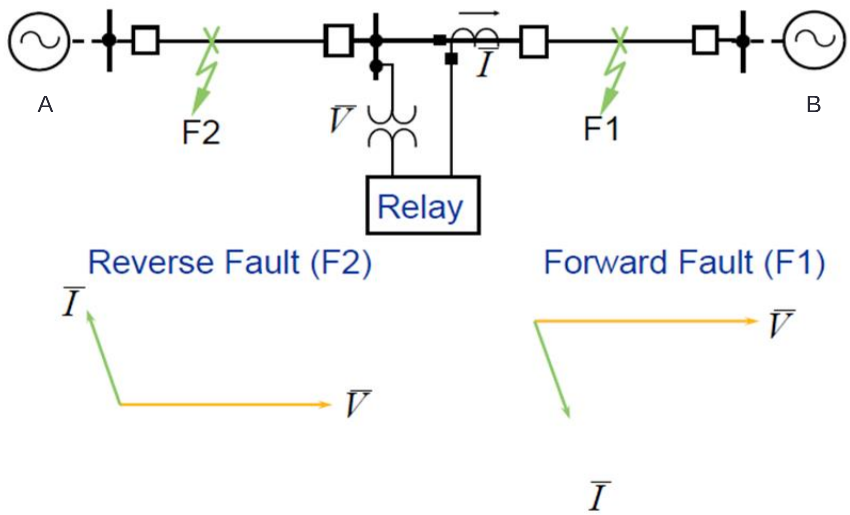
- Overcurrent Relay----- Current values (CT)
- Directional overcurrent --- will take CT and VT values

Torque,T $T = KVI \cos(\theta)$

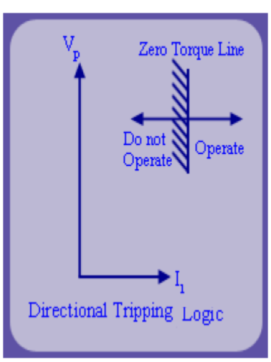
(θ) is **Maximum Torque Angle (MTA)**



- Directional relays are usually of wattmetric induction type(need VT and CT).
- Used in complex power system such as ring systems



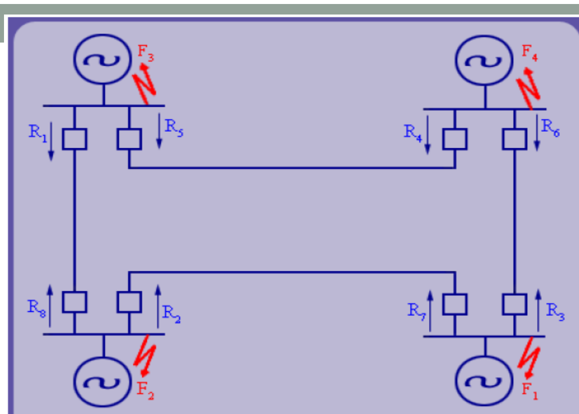
Fundamental Principle



Thus, if we measure the bus voltage phasor V_p and compute the phase angle of relay current with respect to bus voltage, then we can use the following logic to provide selectivity. If the relay 'detects fault' and current lags V_R (= V_p), then permit relay tripping. If the relay 'detects fault' and current leads V_R (= V_p), then inhibit the relay tripping. The 'discrimination principle' based on phase angle comparison between a set of phasors, one of which is used as reference is called 'directional discrimination principle'. Relays with this principle are called directional relays.

If the polarity of the current is appropriate, then directional unit picks up. If the current magnitude is above pickup, then the overcurrent unit also picks up and when both units pickup, the trip coil is energized and CB tripping is ensured. In a numerical relay, this can be programmed by a simple 'AND' logic

Example



Relay Coordination in a Loop System

In this case clockwise loop is given by $R_5 \rightarrow R_6 \rightarrow R_7 \rightarrow R_8 \rightarrow R_5$ and anti clockwise loop is given by $R_1 \rightarrow R_2 \rightarrow R_3 \rightarrow R_4 \rightarrow R_1$ where arrow '$\rightarrow$' should be read as 'backs up'.

Now, let us consider the anticlockwise loop for setting. We can start setting from any one of the four relays, i.e. R_1, R_2, R_3 and R_4. Let us start from R_2, i.e. setting in relay R_2 is assumed appropriately.

R_1 will be set to coordinate with R_2, since R_1 has to back up R_2.

Now R_4 has to coordinate with R_1, R_3 with R_4 and R_2 with R_3.

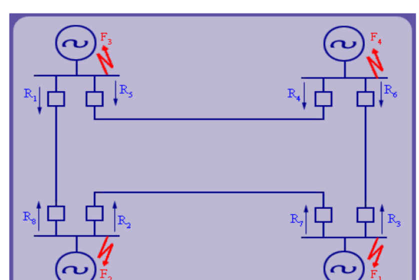
Thus we can see that the setting of R_2 has changed from what it was initially to coordinate with R_3.

After first iteration, we update the setting of R_2 to the corresponding new setting, to coordinate with R_3, thus closing the loop. If the setting of the R_2 has changed significantly, then we repeat the above process by fine tuning the settings of all the relays in the loop again.

As every iteration improvises the relay settings (TMS), we expect the settings to converge in a few iterations.

We have to repeat the same process with the clockwise loop also.

Then all the relays will be set and relay coordination activity is complete.



Relay Coordination in a Loop System

Example

the remote bus fault currents seen by each primary and back up relay pairs are tabulated below (Table 1). **for IEC standard Relays?**

Table 1 : Fault Current seen by Primary - Back up Relay Pairs				
	Anti clockwise loop		Clockwise loop	
Remote Bus Fault at	Current seen by primary relay	Current seen by back up relay	Current seen by primary relay	Current seen by back up relay
F_1	R_2 (639A)	R_1 (152A)	R_6 (1365A)	R_5 (272A)
F_2	R_1 (1652A)	R_4 (391A)	R_7(868A)	R_6 (240A)
F_3	R_4 (1097A)	R_3 (140A)	R_8 (1764A)	R_7 (287A)
F_4	R_3 (937A)	R_2 (142A)	R_5 (553A)	R_8 (197A)

For the relays in table 1, if the pick up values are as tabulated in table 2, find out the TMS.

Table 2 : Pick up Values of Relays								
Relay	R_1	R_2	R_3	R_4	R_5	R_6	R_7	R_8
Pick up setting (A)	60	80	60	160	80	160	128	100

- **The typical time curves for IEC standard overcurrent relay(normal inverse) characteristics can be approximated by the following equation.**

$$t_{relay} = \frac{0.14 \times TMS}{\left(\frac{I_F}{CTR \times PS}\right)^{0.02} - 1}$$

Where :

TMS = Time multiplier setting
CTR = Current transformer ratio
PS = Plug setting
I_F = Fault primary current

We can assume relay setting for any one of the four relays. Let us start setting from relay R_2.

Iteration 1

For relay R_2, assume a TMS of 0.05 (Normal range is 0.025 to 1.2). The reason to initialize TMS to 0.05 and not the minimum value i.e. 0.025 is that further iterations may reduce TMS. If to begin with 0.025 then the problem becomes infeasible.
For fault at F_1 where R_2 acts as primary,

Time of operation of standard inverse relay, $t_{R_2} = \dfrac{TMS_{R_2} \times 0.14}{\left(I/Is\right)^{0.02} - 1}$ (where Is = 80A, I = 639A)

$$= \frac{0.05 \times 0.14}{\left(639/80\right)^{0.02} - 1} = 0.165\text{sec}$$

For fault at F_1, R_1 will back up R_2.
Hence time of operation $R_1 = t_{R_2}$ + CTI (where CTI is the coordination time interval and CTI = 0.3sec.)
= 0.165 + 0.3 = 0.465sec

i.e. $0.465 = \dfrac{TMS_{R_1} \times 0.14}{\left(I/Is\right)^{0.02} - 1}$ (where I = 152A, Is = 60A)

$$= \frac{TMS_{R_1} \times 0.14}{\left(152/60\right)^{0.02} - 1}$$

$TMS_{R_1} = 0.0623$

For fault at F_2, where R_1 acts as primary,

$t_{R_1} = \dfrac{0.0623 \times 0.14}{\left(I/Is\right)^{0.02} - 1}$ (where I = 1652A, Is = 60A)

= 0.127sec

Relay R_4 will back up R_1 for fault at F_2. Hence, time of operation of $R_4 = t_{R_1}$ + CTI = 0.127 + 0.3 = 0.427sec

i.e., $0.427 = \dfrac{TMS_{R_4} \times 0.14}{\left(I/Is\right)^{0.02} - 1}$ (where I = 391A, Is = 160A)

Then, $TMS_{R_4} = 0.055$

For fault at F_3, where R_4 acts as primary relay, we have

$t_{R_4} = \dfrac{TMS_{R_4} \times 0.14}{\left(I/Is\right)^{0.02} - 1}$ (where I = 1097A, Is = 160A)

= 0.196sec

Since relay R_3 has to back up R_4, time of operation of relay R_3 = t_{R_4} + CTI = 0.496sec

For a fault at F_3

i.e., $0.496 = \dfrac{TMS_{R_3} \times 0.14}{\left(I/_{Is}\right)^{0.02} - 1}$ (where I = 140A, Is = 60A)

TMS_{R_3} = 0.0605

Now for fault at F_4, where R_3 acts as primary,

$t_{R_3} = \dfrac{TMS_{R_3} \times 0.14}{\left(I/_{Is}\right)^{0.02} - 1}$ (where I = 937A, Is = 60A)

= 0.15sec

For fault F_4, R_2 has to back up R_3

i.e., Time of operation of R_2 = t_{R_3} + CTI = 0.45sec

$0.45 = \dfrac{TMS_{R_2} \times 0.14}{\left(I/_{Is}\right)^{0.02} - 1}$ (where I = 142A, Is = 80A)

TMS_{R_2} = 0.037

We had assumed a value of 0.05 for TMS_{R_2}, but now the value has changed to 0.037. Therefore, let us update the TMS of R_2 to 0.037.

Iteration 2

Repeating the same process as above,

For fault at F_1, time of operation $t_{R_2} = \dfrac{0.037 \times 0.14}{\left(639/_{80}\right)^{0.02} - 1}$

= 0.122sec

Time of operation of R_1 = t_{R_2} + CTI

= 0.3 + 0.122 = 0.422sec

i.e., $0.422 = \dfrac{TMS_{R_1} \times 0.14}{\left(152/_{60}\right)^{0.02} - 1}$ or TMS_{R_1} = 0.0565

For fault at F_2, where R_1 acts as primary,

$t_{R_1} = \dfrac{0.0565 \times 0.14}{\left(1652/_{60}\right)^{0.02} - 1}$ = 0.1154

R_4 backs up R_1 for fault at F_2

Time of operation of R_4 = t_{R_1} + CTI = 0.1154 + 0.3

= 0.4154

i.e. $0.4154 = \dfrac{TMS_{R_4} \times 0.14}{\left(391/160\right)^{0.02} - 1}$

TMS_{R_4} = 0.0535

Now, for fault at F_3, where R_4 acts as primary,

$t_{R_4} = \dfrac{0.0535 \times 0.14}{\left(1097/160\right)^{0.02} - 1}$ = 0.191sec

Since, relay R_3 backs up R_4, time of operation of relay R_3 = t_{R_4} + CTI = 0.191 + 0.3 = 0.491

i.e. $0.491 = \dfrac{TMS_{R_3} \times 0.14}{\left(140/60\right)^{0.02} - 1}$

TMS_{R_3} = 0.0599

For fault at F_4, where R_3 acts as primary,

Time of operation $t_{R_3} = \dfrac{0.0599 \times 0.14}{\left(937/60\right)^{0.02} - 1}$ = 0.1484sec

R_2 backs up R_3; Therefore,

Time of operation of R_2 = t_{R_3} + CTI = 0.3 + 0.1484

= 0.4484sec

i.e. $0.4484 = \dfrac{TMS_{R_2} \times 0.14}{\left(142/80\right)^{0.02} - 1}$

TMS_{R_2} = 0.0369

Now, let us update the TMS of R_2 to this new value, i.e., 0.0369 and repeat iteration.

Iteration 3

For fault at F_1, $t_{R_2} = \dfrac{0.0369 \times 0.14}{\left(639/80\right)^{0.02} - 1}$

= 0.1217sec

For relay R_1, which has to back up R_2

Time of operation = 0.3 + 0.1217 = 0.4217sec

i.e. $0.4217 = \dfrac{TMS_{R_1} \times 0.14}{\left(152/60\right)^{0.02} - 1}$

TMS_{R_1} = 0.0565

Then for fault at F_2, $t_{R_1} = \dfrac{0.0565 \times 0.14}{\left(1652/60\right)^{0.02} - 1}$ = 0.1154sec

Since R_4 backs up R_1, time of operation of R_4
= 0.1154 + 0.3 = 0.4154sec

i.e. $0.4154 = \dfrac{TMS_{R_4} \times 0.14}{\left(391/160\right)^{0.02} - 1}$

TMS_{R_4} = 0.0535

For fault at F_3, where R_4 acts as primary, we have

$t_{R_4} = \dfrac{0.0535 \times 0.14}{\left(1097/160\right)^{0.02} - 1}$ = 0.191sec

R_3 backs up R_4
Time of operation of R_3 = 0.3 + 0.191 = 0.491sec

i.e. $0.491 = \dfrac{TMS_{R_3} \times 0.14}{\left(140/60\right)^{0.02} - 1}$

TMS_{R_3} = 0.0599

For fault at F_4, $t_{R_3} = \dfrac{0.0599 \times 0.14}{\left(937/60\right)^{0.02} - 1}$

= 0.1484sec
Now R_2 backs up R_3

i.e. time of operation of R_2 = 0.3 + 0.1484 = 0.4484 = $\dfrac{TMS_{R_2} \times 0.14}{\left(142/80\right)^{0.02} - 1}$

TMS_{R_2} = 0.0369 which is same as the result of iteration 2.

Therefore no more iteration is required. Hence, setting and coordination of all the four anticlockwise relays are complete.

Coordination of all primary and back up relay pairs R_2 - R_1, R_1 - R_4, R_4 - R_3 and R_3 - R_2 for faults at F_1, F_2, F_3 and F_4 respectively

Setting and Coordination of Clockwise Relays

Iteration 1

Now let us start setting all the clockwise relays. Let us start from relay R_5 for fault at F_4.

Assume a TMS of 0.05 for relay R_5. Then, time of operation of relay R_5, $t_{R_5} = \dfrac{0.05 \times 0.14}{\left(553/80\right)^{0.02} - 1} = 0.1775$

i.e. Time of operation of back up relay R_8 = t_{R_5} + CTI

= 0.1775 + 0.3
= 0.4775sec

Now, $0.4775 = \dfrac{TMS_{R_8} \times 0.14}{\left(197/100\right)^{0.02} - 1}$

= 0.04656

For a fault at F_3, where R_8 acts as primary,

$$t_{R_8} = \frac{0.0465 \times 0.14}{\left(1764/100\right)^{0.02} - 1} = 0.11\text{sec}$$

Now relay R_7 will back up R_8. Then time of operation of R_7 = 0.11 + 0.3 = 0.41sec

i.e., $0.41 = \dfrac{TMS_{R_7} \times 0.14}{\left(287/128\right)^{0.02} - 1}$

TMS_{R_7} = 0.0477

R_7 acts as primary relay for fault at F_2.

$$t_{R_7} = \frac{0.0477 \times 0.14}{\left(868/128\right)^{0.02} - 1} = 0.1711\text{sec}$$

R_6 backs up R_7,
i.e. Time of operation for R_6
= 0.1711 + 0.3 = 0.4711

i.e. $0.4711 = \dfrac{TMS_{R_6} \times 0.14}{\left(240/160\right)^{0.02} - 1}$

TMS_{R_6} = 0.0274

For fault at F_1, R_6 acts as primary,

i.e., $t_{R_6} = \dfrac{0.0274 \times 0.14}{\left(1365/160\right)^{0.02} - 1}$ = 0.0875sec

R_5 backs up R_6

i.e. Time of operation of R_5 = 0.0875 + 0.3 = 0.3875

i.e., $0.3875 = \dfrac{TMS_{R_5} \times 0.14}{\left(272/80\right)^{0.02} - 1}$

TMS_{R_5} = 0.0686

i.e. after 1st iteration TMS of R_5 has been changed from 0.05 to 0.0686. Let us update TMS of R_5 to 0.0686 and begin iteration 2.

Iteration 2

TMS_{R_5} = 0.0686

For fault F_4, $t_{R_5} = \dfrac{0.0686 \times 0.14}{\left(553/80\right)^{0.02} - 1}$ = 0.2436

For fault at F_4, R_8 backs up R_5

i.e. Time of operation of R_5 = t_{R_5} + CTI = 0.2436 + 0.3

= 0.5436sec

i.e. $0.5436 = \dfrac{TMS_{R_8} \times 0.14}{\left(197/100\right)^{0.02} - 1}$

TMS_{R_8} = 0.053

For fault F_3, where R_8 acts as primary,

$t_{R_8} = \dfrac{0.053 \times 0.14}{\left(1764/100\right)^{0.02} - 1}$ = 0.1256sec

Relay R_7 backs up R_8

Time of operation of R7 = 0.1256 + 0.3 = 0.4256sec

i.e. $0.4256 = \dfrac{TMS_{R_7} \times 0.14}{\left(287/128\right)^{0.02} - 1}$

TMS_{R_7} = 0.0495

For fault at F_2, R_7 acts as primary,

i.e. $t_{R_7} = \dfrac{0.0477 \times 0.14}{\left(868/128\right)^{0.02} - 1}$ = 0.1776sec

R_6 backs up R_7,

i.e. Time of operation for R_6 = 0.1776 + 0.3 = 0.4776sec

i.e. $0.4776 = \dfrac{TMS_{R_6} \times 0.14}{\left(240/160\right)^{0.02} - 1}$

TMS_{R_6} = 0.0278

For fault at F_1, R_6 acts as primary,

i.e. $t_{R_6} = \dfrac{0.0278 \times 0.14}{\left(1365/160\right)^{0.02} - 1}$ = 0.0888sec

R_5 backs up R_6,

i.e. Time of operation of R_5 = 0.0888 + 0.3
= 0.3888sec

i.e. $0.3888 = \dfrac{TMS_{R_5} \times 0.14}{\left(272/80\right)^{0.02} - 1}$

TMS_{R_5} = 0.0688

Now let us set TMS of R_5 to 0.0688 and repeat iteration.

TMS_{R_5} = 0.0688

For fault at F_4 $t_{R_5} = \dfrac{0.0688 \times 0.14}{\left(553/80\right)^{0.02} - 1}$ = 0.2443

R_8 backs up R_5,

i.e. Time of operation of R_8 = t_{R_5} + CTI = 0.2443 + 0.3

= 0.5443sec

$0.5443 = \dfrac{TMS_{R_8} \times 0.14}{\left(197/100\right)^{0.02} - 1}$

i.e. TMS_{R_8} = 0.0531

For fault at F_3, R_8 acts as primary,

Then $t_{R_8} = \dfrac{0.0531 \times 0.14}{\left(1764/100\right)^{0.02} - 1}$ = 0.1258sec

Relay R_7 backs up R_8
i.e. Time of operation of R_7 = 0.3 + 0.1258 = 0.4258sec

$$0.4258 = \frac{TMS_{R_7} \times 0.14}{\left(287/128\right)^{0.02} - 1}$$

TMS_{R_7} = 0.0495

For fault at F_2, R_7 acts as primary,

i.e. $t_{R_7} = \dfrac{0.0495 \times 0.14}{\left(868/128\right)^{0.02} - 1}$ = 0.1776sec

R_6 backs up R_7, Time of operation of R_6,
= 0.3 + 0.1776 = 0.4776sec

i.e. $0.4776 = \dfrac{TMS_{R_6} \times 0.14}{\left(240/160\right)^{0.02} - 1}$

TMS_{R_6} = 0.0278

For fault at F_1, R_6 acts as primary,

$t_{R_6} = \dfrac{0.0278 \times 0.14}{\left(1365/160\right)^{0.02} - 1}$ = 0.0888sec

Since R_5 backs up R_6 for fault at F_1, time of operation of R_5 = 0.3 + 0.0888sec = 0.3888sec

i.e., $0.3888 = \dfrac{TMS_{R_5} \times 0.14}{\left(272/80\right)^{0.02} - 1}$

TMS_{R_5} = 0.0688.

Since, the result of iterations 2 and 3 are the same, the iteration is complete. Thus, all the clockwise relays are set. The settings are tabulated in table 3. Coordination of all clockwise relay pairs R_6 - R_5, R_7 - R_6, R_8 - R_7 and R_5 - R_8 for faults at F_1, F_2, F_3 and F_4 are visualized in fig 19.3.

Table 3 TMS Setting for Relay			
Relay	1st Iteration	2nd Iteration	3rd Iteration
R_1	0.623	0.0565	0.0565
R_2	0.05	0.0369	0.0369
R_3	0.0605	0.0599	0.0599
R_4	0.055	0.0535	0.0535
R_5	0.05	0.0686	0.0688
R_6	0.0274	0.0278	0.0278
R_7	0.0477	0.0495	0.0495
R_8	0.04656	0.053	0.0531

POWER SYSTEM PROTECTION
EE 567

Dr. Feras Alasali

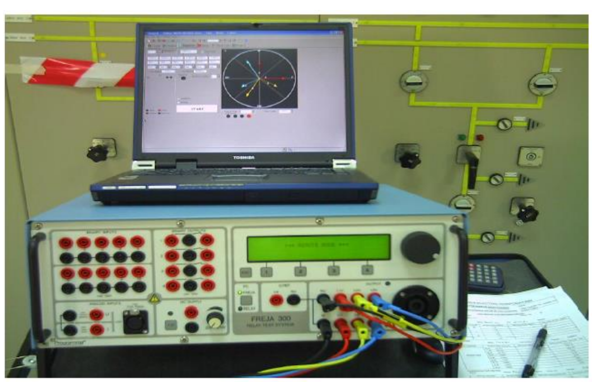
Overcurrent Relay Testing

Generally , there is a number of tests that need to be done on O/C Relay before operation and substation energization.

- Protective **function test**: the most important test and is related of the main function and purpose of using the relay.
- Accuracy test.
- Maximum and minimum rating such as frequency, current and voltage.
- Power supply test: is to check if the relay can work when the voltage change for example from 110 V to 220 V
- Inrush current
- Event recording.

Test requirements

- 1- Tester device 2- wires 3- Relay.
- Tester device can inject fault current , angle and time and receive signal from the relay.



Test Procedure

- 1- Before starting the test , we need to
- - Determine the normal current (1 or 5 A)
- - Determine the pickup current
- - Determine the operation time.
- CT and VT

- These values should be programmed on the relay and the tester device.
- 2- we start inject the relay with currents (the value of current should gradually increase from low current until the relay send open circuit signal).

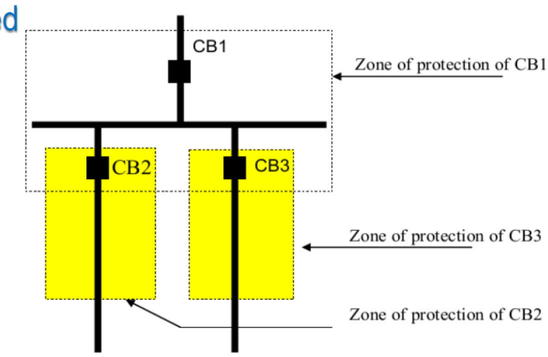
Phase	Low Setting					
	Setting		Test Results			
	Pickup Current	Op-Time	I_{pickup}	Trip Time	Pickup Current Error	Op-Time Error
R	0.25	0.5	0.244	0.51	-2.2%	2%
S	0.25	0.5	0.244	0.51	-2.2%	2%
T	0.25	0.5	0.244	0.51	-2.2%	2%

Low setting for EF and High setting for OC and short circuit.

Zones of Protection

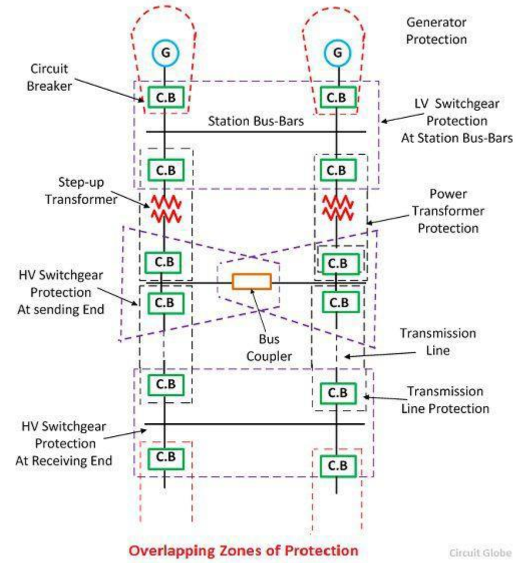
Zones of protection

Is the place or the distance that the relay can protect easily.Fig.1 shows an example of three protection zones for three circuit breakers. It is to be noted that the protection zones are overlapped

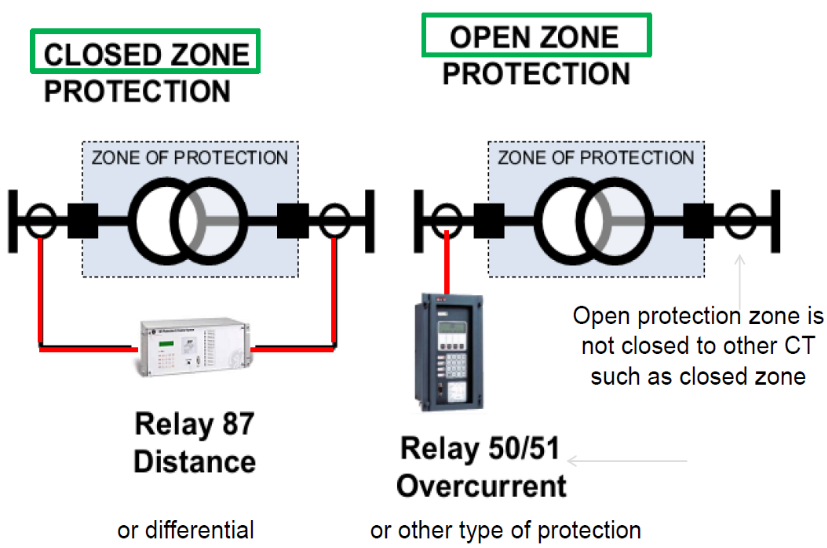


Note:-In power systems, all power system elements must be covered by at least one zone

- The important elements must be included two zones or more.
- Zones must overlap to prevent any element from unprotected.
- The overlap must be finite or limited, but small to minimize the probability of outcome fault from inside of this region.
- **A zone boundary is usually defined by a CT and a CB.**
- **The CT provides the ability to detect a fault inside the zone**
- The CBs provide the ability to isolate the fault.

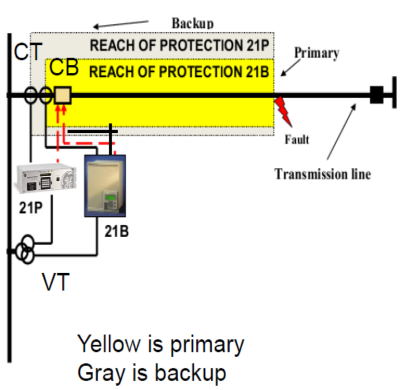


The protection zone may be open or close zone.

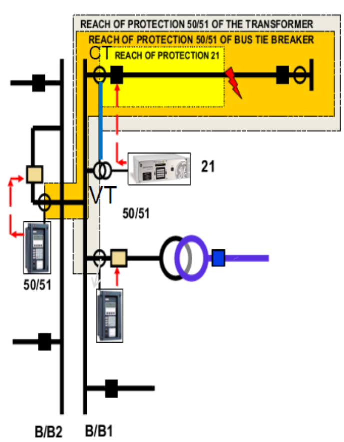


- **Backup protection**
- It is an alternative protection that work when primary protection fails to operate.
- Primary and backup protection are independent (relay, breaker , CT,PT) .
- Backup is slower time than primary.
- Sometimes backup protection opens more circuit breakers (that net necessary) to clear the fault.
- backup protection become primary protection when usual primary equipment **out of service**.
- Back up relaying may *be installed locally, in the same substation (local),* or remote in other substations(Clears fault on station away from where the failure has occurred).

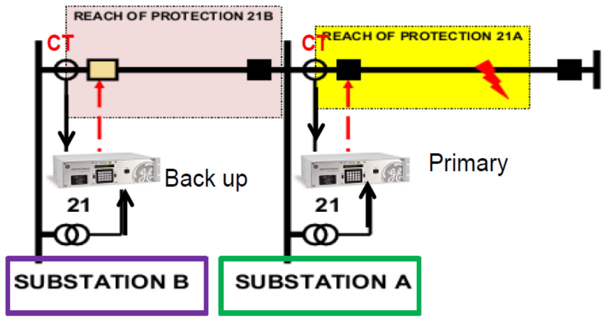
Primary and Back up protection at the same location (Local Backup)



Local backup protection at different locations



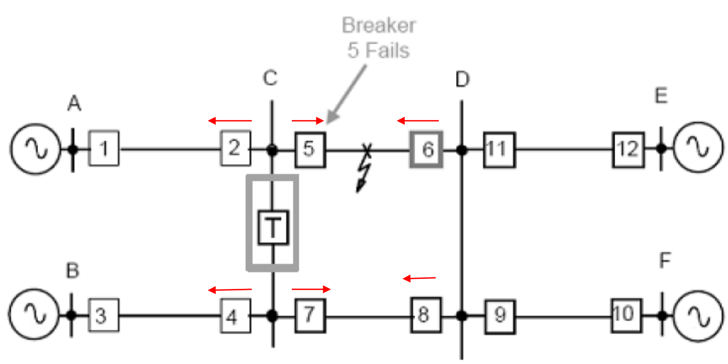
Remote back up protection



Selectivity and zones of protection

- Selectivity is defined in terms of regions of a power system (zones of protection) for which a given relay is responsible.
- The relay will be considered **secure** if it responds only to faults within its zone of protection.

Example

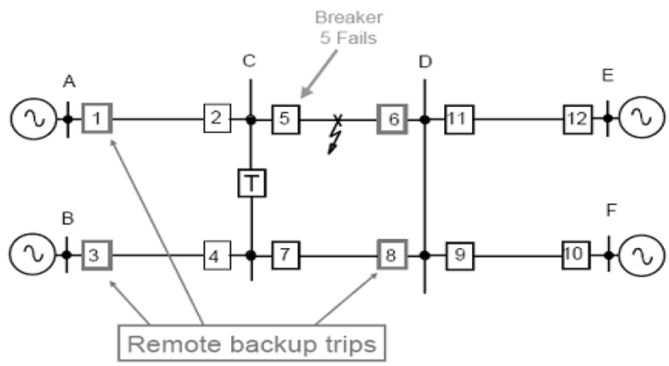


- The tie circuit breaker (T) is assumed to work normally closed.
- For a fault at CD, Line Breakers 5 and 6 should operate as the primary protection.
- If Protection 5 fails to operate, with existing technology, we have two possibilities for cutting the fault current contribution from A, B, and F: open Breakers 1, 3 and 8; or open Breakers 1 and T.
- In any case, backup protection needs time delay. The primary protection needs to be given an opportunity to operate before using the decision of a backup operation.

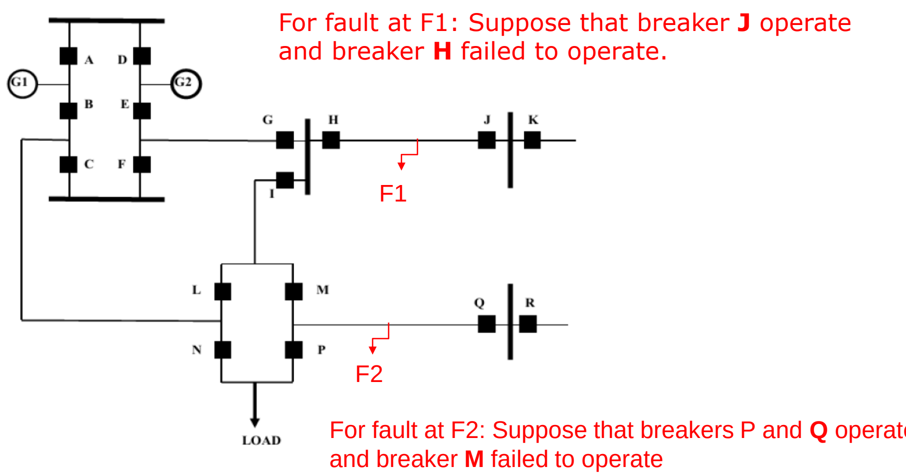
- **Local Backup(in same substation)**

- In case, Breakers 2 and **T** represent local backup protection, which is located in the same substation as the primary protection.
- Local backup protection is more expensive than remote backup because additional equipment is needed.
- Advantages of local backup over remote backup are *greater sensitivity, greater selectivity, and faster operation speed .*

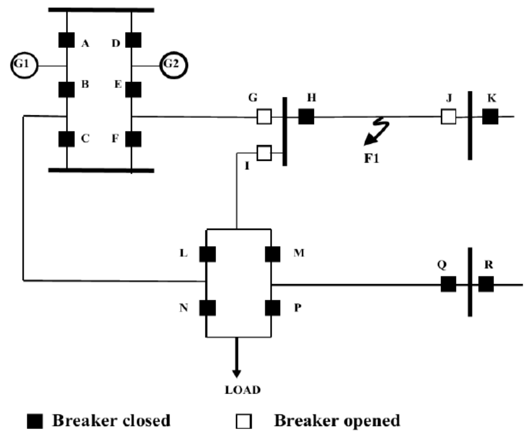
- **Remote Backup (in same substation)**
- Breakers 1, 3 and 8 are located in a remote substation. This is the remote backup protection. *An advantage of remote backup protection is low cost*: the remote backup protection comes from protection equipment that is needed for primary protection functions of adjacent system elements. Therefore, there is no need for additional investment.



- Example 2: Consider the following simple power system and Discuss the local and remote backup protection for two fault locations as follows:

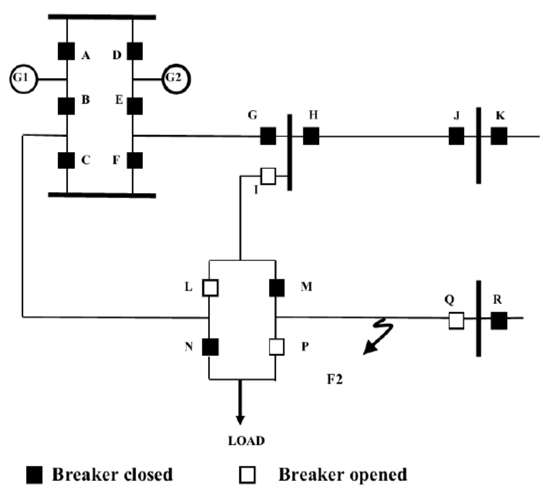


Case 1: Local Backup



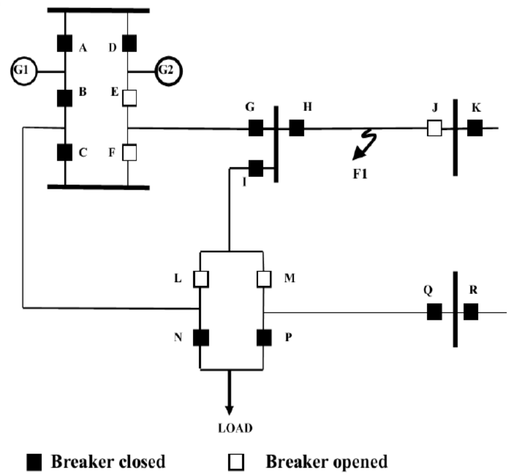
For fault at F1: Suppose that breaker **J** operate and breaker **H** failed to operate. Therefore:
G and **I** must operate as **local backup** protection

Case 2: Local Backup



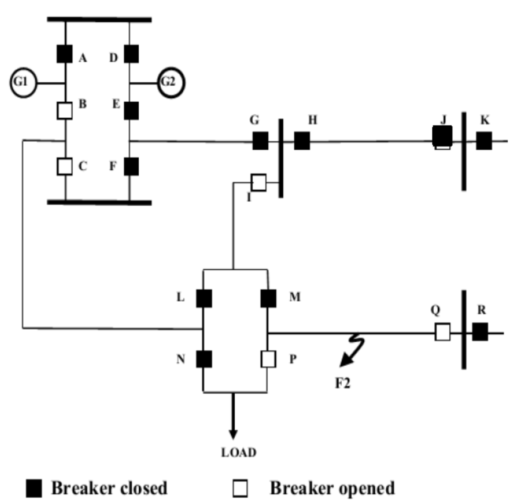
For fault at F2: Suppose that breakers P and **Q** operate and breaker **M** failed to operate. Therefore: **L and I** must operate as **local backup** protection

Case 3: Remote Backup



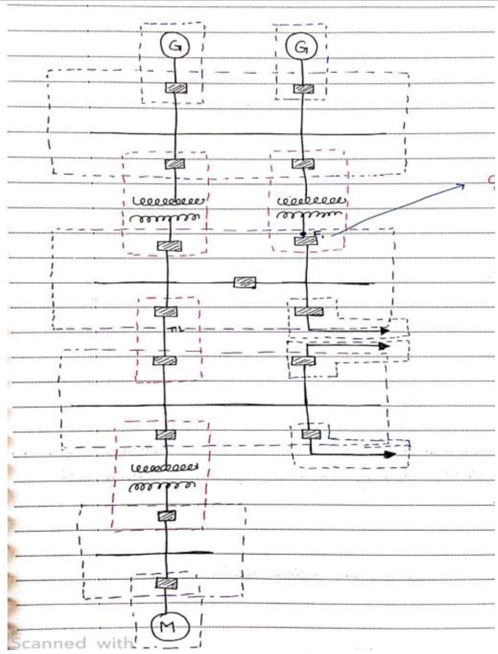
For fault at F1: Suppose that breaker **J** operate and breaker **H** failed to operate. Therefore: **E, F, L** and **M** must operate as **Remot backup** protection

Case 4: Remote Backup



For fault at F1: Suppose that breakers **P & Q** operate and breaker **M** failed to operate. Therefore: **I, B,** and **C** must operate as **Remot backup** protection

Example



POWER SYSTEM PROTECTION
EE 567

Dr. Feras Alasali

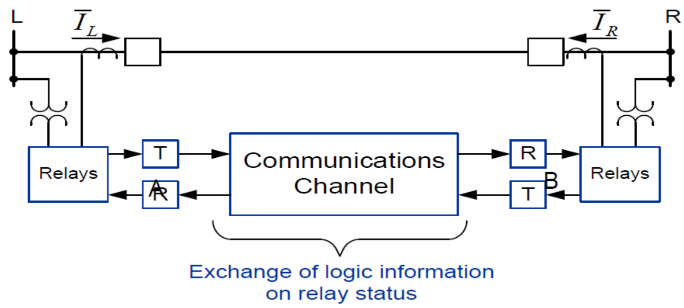
Pilot wire differential relays

- **Pilot wire differential relays (Device 87L)**
- The pilot wire differential relay is a high-speed relay (designed for protection of transmission and distribution lines).
- They are generally applied on ***short lines, normally less than 40 km long***.
- The scheme requires communication channel (link) to carry system voltage and current **information to the control location**.

- Four basic communication channels are used:
- 1. Separate telephone circuit (telephone wire or cable) this is called pilot wire carrier.
- 2. Microwave system.
- 3. Fibre optic cable.
- 4. Power line carrier.

- (a) **Operating principles of a current pilot wire relay**

1- Pilot wire differential relaying **are connected together** with a two-conductor pilot wire.



T:transmmit data
R:recived data

2- If the fault current flows through circuit breaker (A) **only**, the relay passes sufficient current through the pilot wire to operate the relay at circuit breaker B.

- Transformers are used ***to convert current signal to voltage signal***. For faults outside since, **VA = VB** , relay will not operate and if the fault inside **the line VA ≠ VB** , relay will operate.

- **(b) Power Line Carrier (PLC)**
- In power line carrier protection scheme, a high frequency signal in the band of 80-500 kHz and of low power lever is transmitted via the power line conductors from each end of the transmission to the other.
- Signal is received to give tripping the circuit breaker. The system is shown in Fig.2.
- The high frequency is injected to the power line by a coupling capacitor.
- The signals are limited to the line by an LC blocking filter at each end. This is called a line trap.

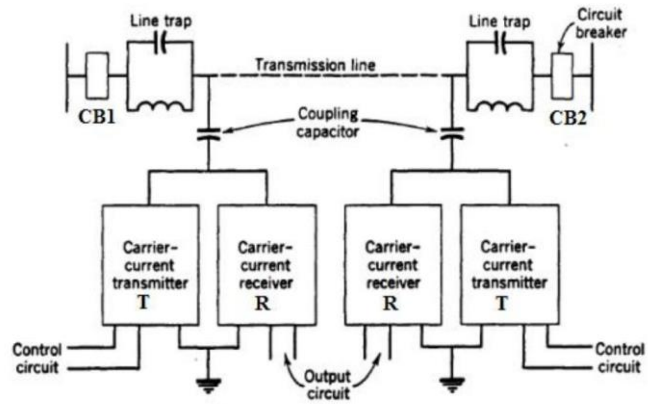


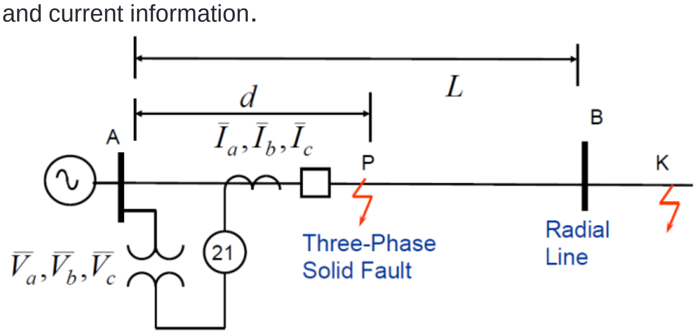
Fig.2 Power line carrier system.

Distance Relay

Distance Relay

- Since protection by pilot wires (pilot relaying) is limited to 30 to 40 km in rout length of TL then for longer distance of transmission lines and distribution feeders, distance protection is used
- ***Principle of Distance Protection:-***
- Every power line has a resistance and reactance per kilometer related to its design and construction so its total impedance will be a function of its length or distance.
- A distance relay therefore looks at current and voltage and compares these two quantities on the basis of Ohm's law .

- Consider the simple radial line with distance protection system installed at the end A (**the local end**) while end B is called **the remote end**.
- These relays sense local voltage and current and calculate the effective impedance at that point. This means that the relay requires voltage and current information.



When the protected line becomes faulted, the **effective impedance becomes** the **impedance from that point to the fault**.
Assume balanced three-phase fault at distance (d):

- For internal fault at point (p) : $Z_p = \frac{V_p}{I} < Z_L$ Relay will operate

For external fault at point k :

$$Z_p = \frac{V_k}{I} > Z_L \qquad \text{Relay will not operate}$$

In general the relay will trip when $Z_f = \frac{V}{I} < Z_L$ here Zf is the impedance at the fault point which is line length. For example at point p: $Z_{fp} = \frac{d}{L} Z_L$

$$Z_R = \frac{V_R}{I_R} = \frac{V_{FP} \times \frac{V_2}{V_1}}{I_{FP} \times \frac{I_2}{I_1}} = Z_P \times \frac{CT\ ratio}{VT\ ratio}$$

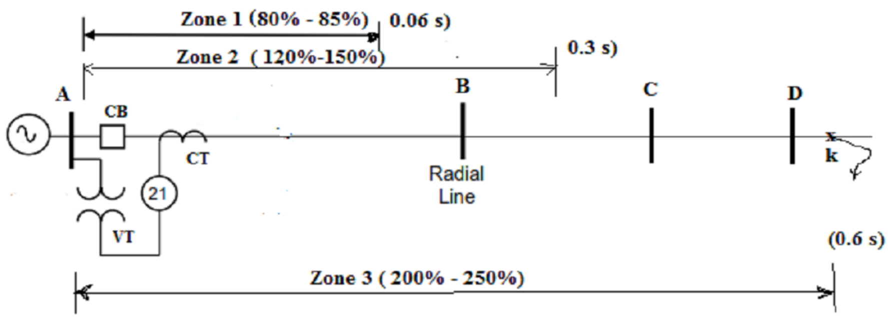
Advantage of distance relay:

1. Provide backup protection easily.
2. Eliminates the pilot channel.

Features

1- Distance protection is available for both phase and ground faults.
2- Step distance protection combines instantaneous and time delay tripping.

- **Relay Reach, under reach and over reach**
- The reach of the distance relay is that distance from the relaying point to the point of fault.
- The reach is usually refers as the relay setting and can be **as a distance (m),** or as a primary or secondary impedance.
- **Zones of protection**
- Due to the tolerance in the circuit components, the measuring accuracy cannot be perfect so it is usual to set **the relay at the local point A at 80-85% of the impedance of AB**. This is referred as zone 1 or stage A1 setting (see figure 3).
- The **remaining 20%** of AB is protected by changing the setting of the relay to reach 50% into zone BC (zone 2 or stage A2). Stage A2 is usually set at 0.3 s time



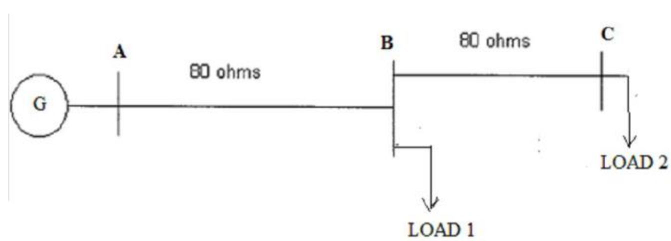
- For system reliability (failure of relay A will cause failure of stage A1 and stage A2),another distance relay is added for backup protection .
- This ***separate relay should*** have a reach of 20% into CD and called zone 3 or stage A3 which has a time delay of 0.6 s.

Notes:

- Zone 1 is an under reaching element, any fault within Zone 1 is known to be on the protected line. When Zone 1 operates, the line is tripped instantaneously.
- Zone 2, however, will operate for some external faults.

Example

- Figure shows a simple two radial lines. We will consider the settings for line AB at bus A. The line length is 80 km.



The **distance relay** at **bus A** is fed by current transformers rated at 2000/5A and voltage transformers rated at 200 kV/69 V.

Find the settings of zone 1 and zone 2 of the relays.?

Set Zone 1 for 85 %:

Zone 1 setting _=0.85 x 80 = 68 ohm, primary ohm setting (Z_{fp})

CT ratio = 2000/5 = 400

VT ratio _=200,000/69 =2900

Relay setting for zone 1 = Z_{fp} . CT ratio/VT ratio

=68 (400)/(2900)

= 9.38 relay ohms

Zone 2 setting : 120 % -150% Choose 140% ;

Zone 2 setting _=1.40 x 80 = 112 ohm, primary ohm setting (Z_{fp})

Relay setting for zone 2 = Z_{fp} . CT ratio/VT ratio

=112 (400)/(2900)

= 15.44 relay ohms

Impedance Diagram

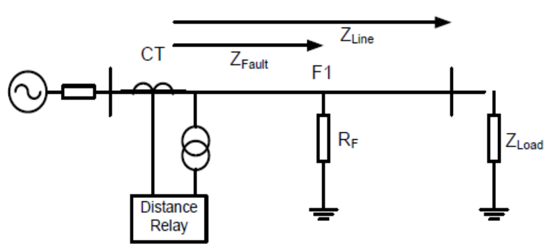
1- During normal operation Relay will see Z on Z load line.
2- in case of fault will move to Z fault. It can move because Rf (which can equal 0 to hundreds of ohms).

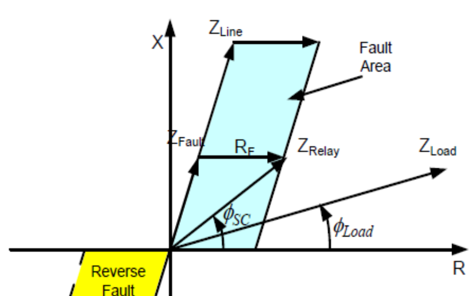
3- Rf is not constant.

4- if Rf is zero , Z line and Z fault will have the same angle.

5- Generally, angle of Z fault > Z load (because during fault R line < X line)

$$\phi = \tan^{-1}\frac{X_{Line}}{R_{Line}}$$

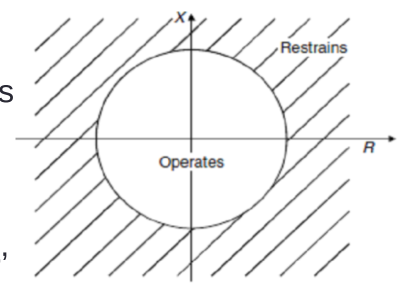




Impedance Diagram .

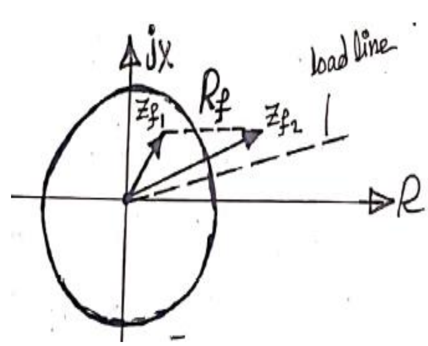
- **Tripping characteristics of distance relay**
- If the relay's operating boundary is plotted, on an R/X diagram, its impedance characteristic is a circle with its center at the origin of the coordinates and its radius will be the setting (reach) in ohms.

- The relay will operate for all values less than its setting i.e. is for all points within the circle.
- This is known as a plain impedance relay and it will be noted that it **<u>is non-directional</u>**, in that it can operate for faults behind the relaying point. It takes no account of the phase angle between voltage and current.

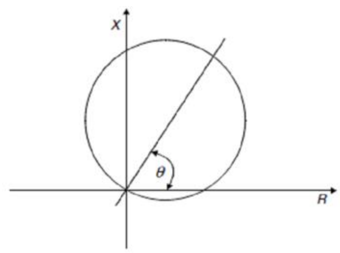


Plain impedance characteristic

This type of relays will be affected by the RF value

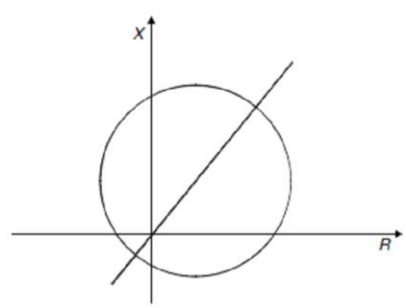


- **This limitation can be overcome** by a technique known as self-polarization.
- Additional voltages are fed into the comparator in order to compare the relative phase angles of voltage and current, so providing a directional feature. Angle θ is known as the relay's characteristic angle.
- This is known as the **MHO** relay, so called as it appears as a straight line on an admittance diagram.



(a) Mho characteristics

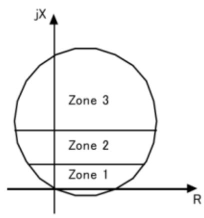
- By the use of a further technique of feeding in voltages from the healthy phases into the comparator (known as cross polarization) a reverse movement or offset of the characteristic can be obtained. This is called **the offset MHO characteristic**.



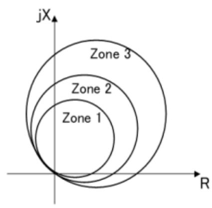
(b) offset mho characteristic

Types of Distance Relay

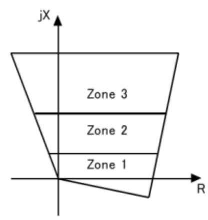
- Distance relays are classified according to their characteristics in the R-X diagram.
- The relays are set according to the positive and zero-sequence impedance of the transmission line.
- The below figure shows the R-X diagrams of some types of distance relays.



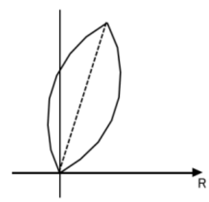
Mho and Reactance Characteristic



Mho Characteristic



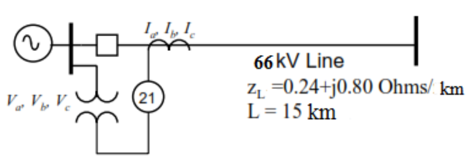
Quadrilateral Characteristic



Lenticular Characteristic

Example 1

- For the 66kV radial feeder shown, Calculate zone 1 setting for the distance relay in primary ohms?



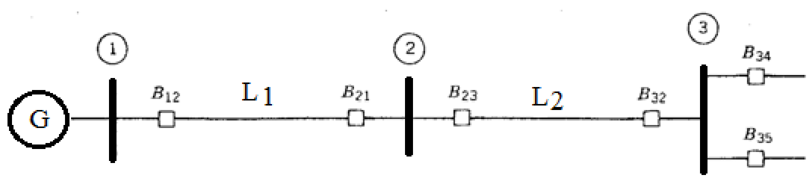
$$\overline{Z}_{L} = (0.24 + j0.8) \cdot 15 =$$
$$= 3.6 + j12 \text{ Ohms (primary)}$$

Zone 1

Relay setting: $Zr1 = (0.8)\,|3.6 + j12| = 10.02 \text{ Ohms}$

Example 2

- Consider the 230-kV transmission system shown in the below figure. Assume that the positive-sequence impedances of the lines L1 and L2 are 2 + j 20 Ω and 2.5 + j 25 Ω, respectively. If the maximum peak load supplied by the line L1 is 100 MVA with a lagging power factor of 0.9, **design a three-zone distance-relaying system for the R12 impedance relay by determining the following**:
- (a) Maximum load current
- b) CT ratio and VT ratio
- (c) Impedances measured by relay
- d) Zone 1 setting of relay R12
- e) Zone 2 setting of relay R12
- (f) Zone 3 setting of relay R12
- (g) Draw the zones of protection for R12 and suggest time settings for the three zones.



(a) Max.load current = $\frac{S}{V\sqrt{3}} = \frac{100x10^6}{230\ x\ 10^3\ \sqrt{3}} = 251.02$ A

(b) Choose: CT ratio $= 250 / 5$

VT ratio $= \frac{230\ x\ 10^3}{120} = \frac{1916.7}{1}$

(c) Impedances measured by relay is

$$Z_{sec} = Z_{prim}\ x\ \frac{CT\ ratio}{VT\ ratio} = \frac{250/5}{1916.7/1} Z_{prim} = 0.026\ Z_{line}$$

Impedance of line L1and line L2 as seen by the relay (Line impedances based on secondary ohms) are:

$Z_{sec\ -\ L1}$ = 0.026 (2+j20) = 0.52 + j 0.5196 Ω

$Z_{sec\ -\ L2}$ = 0.026 (2.5+j25) = 0.65 + j 0.6495 Ω

(d) Zone 1 setting of relay R 12 is

$$Z1 = 0.8\ (0.52 + j\ 0.5196\ ) = 0.0416 + j\ 0.4157 \text{ sec. } \Omega$$

(e) Zone 2 setting of relay R 12 is

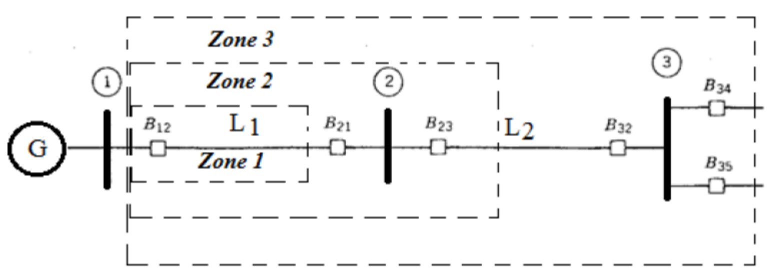
Z2 setting is = 120% - 150% , Choose 140%

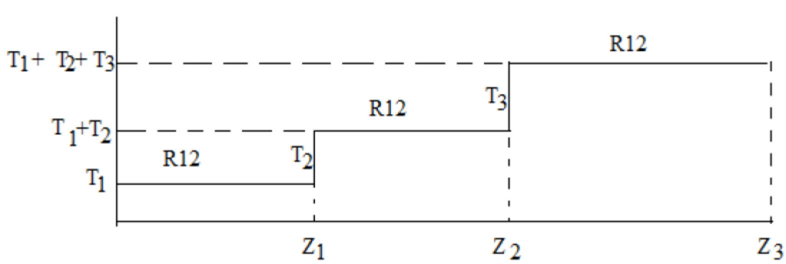
$$Z2 = 1.4\ (0.52 + j\ 0.5196\ ) = 0.0728 + j\ 0.727 \text{ sec. } \Omega$$

(f) Zone 3 setting of relay R12 : Since the zone 3 setting must reach beyond the longest line connected to bus 2 ,thus

$$Z3 = 120\%\ (Z_{sec-L1} + Z_{sec-L2}) = 1.20\ (0.52 + j\ 0.5196 + 0.65 + j\ 0.6495) = 0.1400 + j\ 1.402 \text{ sec. } \Omega$$

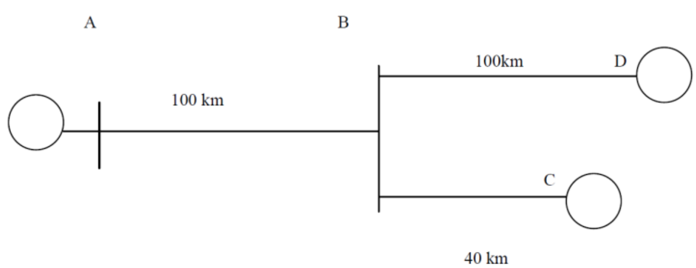
(g) Draw the zones of protection for R12 and suggest time settings for the three zones.





Example

- The below figure shows a simple radial transmission line system. Lines AB , BC and BD have an impedances of 0.8 Ω / km , 1.0 Ω / km and 0.8 Ω / km respectively. The distance relay at bus A is fed by current transformers rated at 2000/5 A and a voltage transformers rated at 354 kV/ 120V. Find zone 1 and zone 2 setting of the relay



Example

- A distance Relay is used as protection device for transmission line, the transmission line impedance is 6+j20 ohm.

1- Draw the relay characteristic of directional relay (impedance diagram).

1- Draw the relay characteristic of relay with offset by 15% of tine impedance?

sol:

$Z_L = 6+j20\ \Omega$ ∴ $Z_1 = .8(6+j20) = 4.8+j16$

(80%) ← $Z_1 = 16.7\angle 73.3$

$Z_2 = 130\% = 1.3(6+j20) = 7.8+j26 = 27.2\angle 73.3$

$Z_3 = 200\% = 2(6+j20) = 12+j40 = 41.76\angle 73.3^\circ$

Take $\tau \Rightarrow$ angle of max Torque line, angle of (Z_L)

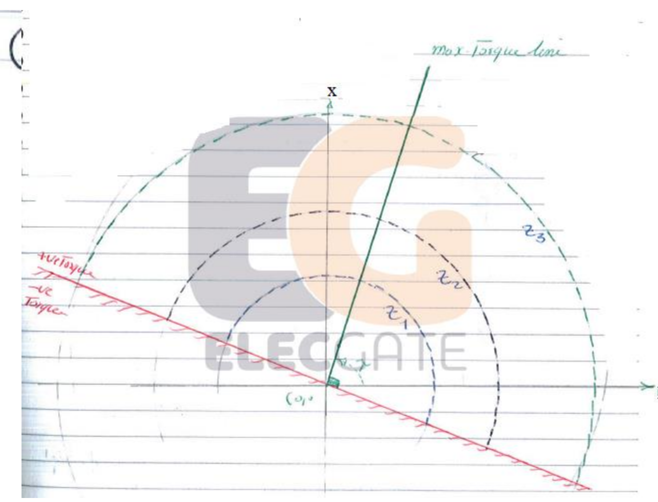
∴ $\tau = 73.3^\circ$

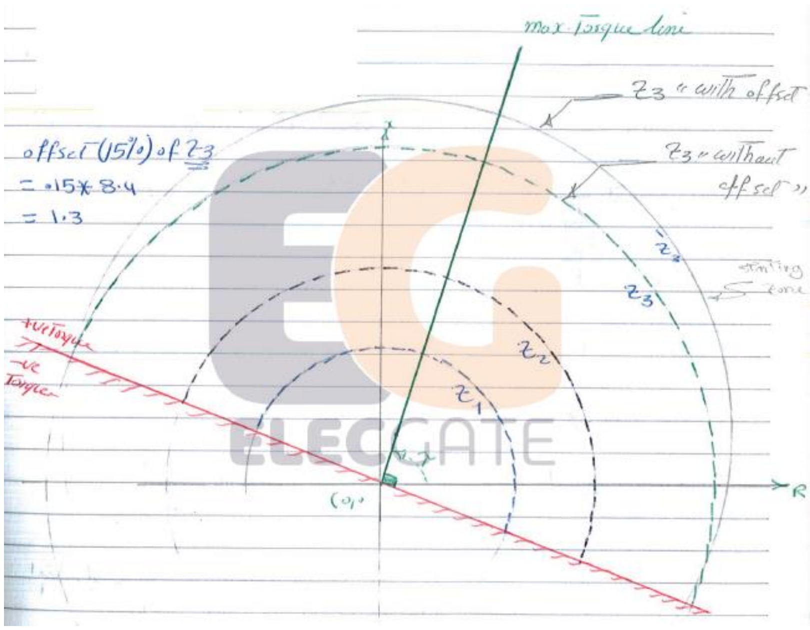
∴ Take scale (

$Z_1 = \frac{16.7}{5} = 3.4$ Cm

$Z_2 = \frac{27.2}{5} = 5.4$ Cm

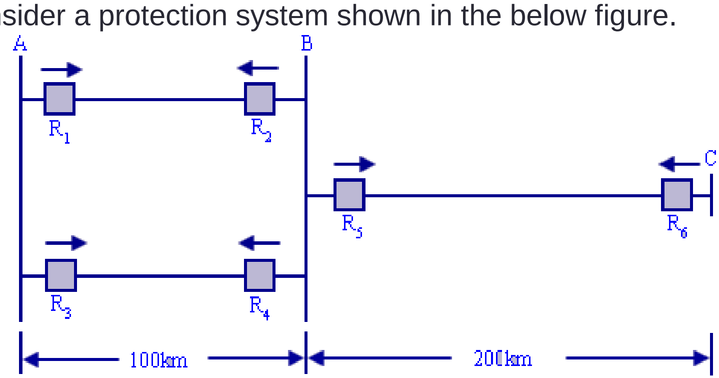
$Z_3 = \frac{41.76}{5} = 8.4$ Cm





Example

- Consider a protection system shown in the below figure.



1- Identify the primary relays for back up relay R1.

2- Assuming that pu impedance of all transmission lines in above Figure is α pu /km, determine the setting of zone 1, zone 2 and zone 3 of R1.

- 1- Relay R1 not only backup's line BC but also parallel line AB. Therefore, for relay R1 acting as back up, the primary relays are R5 and R4.

- 2-

$$Z_1(R_1) = 0.8\alpha \times 100\, pu\Omega = 80\alpha pu\Omega$$

$$Z_2(R_1) = 100\alpha + 50\alpha = 150\alpha pu\Omega$$

$$Z_3(R_1) = 100\alpha + 200\alpha = 300\alpha pu\Omega$$

POWER SYSTEM PROTECTION
EE 567

Dr. Feras Alasali

Distance Relay

Impedance Diagram

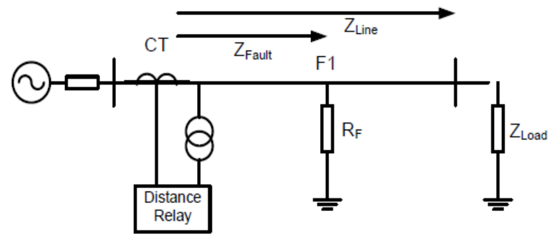
1- During normal operation Relay will see Z on Z load line.
2- in case of fault will move to Z fault. It can move because Rf (which can equal 0 to hundreds of ohms).

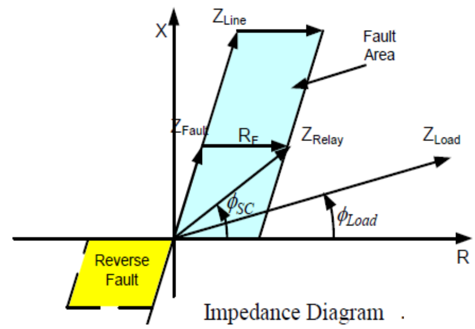
3- Rf is not constant.

4- if Rf is zero , Z line and Z fault will have the same angle.

5- Generally, angle of Z fault > Z load (because during fault R line < X line)

$$\phi = \tan^{-1} \frac{X_{Line}}{R_{Line}}$$

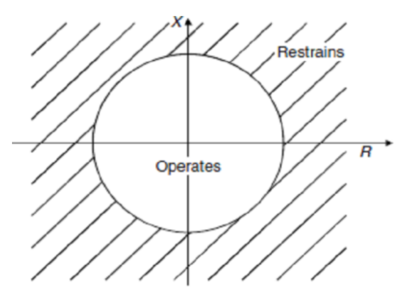




Impedance Diagram

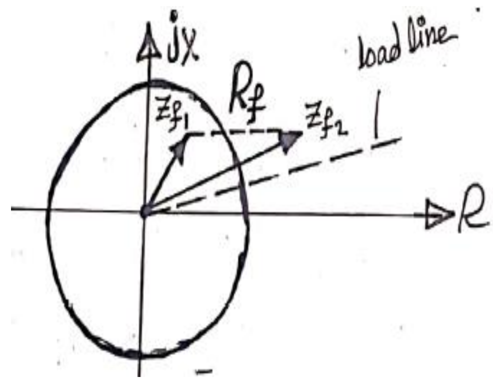
- **Tripping characteristics of distance relay**
- If the relay's operating boundary is plotted, on an R/X diagram, its impedance characteristic is a circle with its center at the origin of the coordinates and its radius will be the setting (reach) in ohms.

- The relay will operate for all values less than its setting i.e. is for all points within the circle.
- This is known as a plain impedance relay and it will be noted that it **is non-directional**, in that it can operate for faults behind the relaying point. It takes no account of the phase angle between voltage and current.

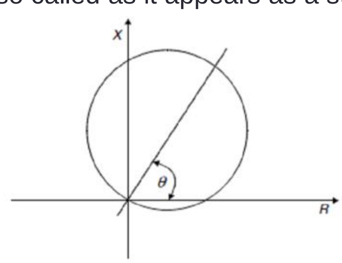


Plain impedance characteristic

This type of relays will be affected by the RF value

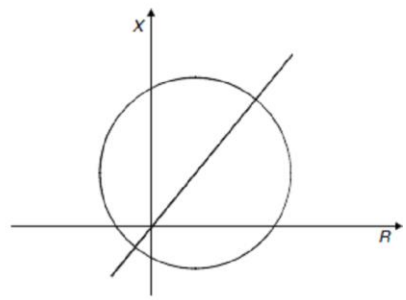


- **<u>This limitation can be overcome</u>** by a technique known as <u>self-polarization</u>.
- <u>Additional voltages are fed into the comparator</u> in order to compare <u>the relative phase angles of voltage and current</u>, so providing a <u>directional feature</u>. Angle θ is known as the relay's characteristic angle.
- This is known as the **MHO** relay, so called as it appears as a straight line on an admittance diagram.



(a) Mho characteristics

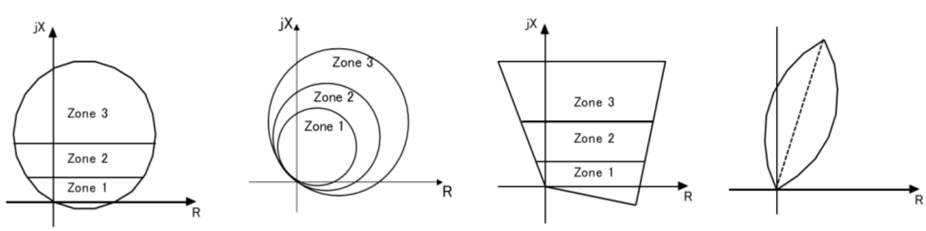
- By the use of a further technique of feeding in voltages from the healthy phases into the comparator (known as cross polarization) a reverse movement or offset of the characteristic can be obtained. This is called **the offset MHO characteristic**.



(b) offset mho characteristic

Types of Distance Relay

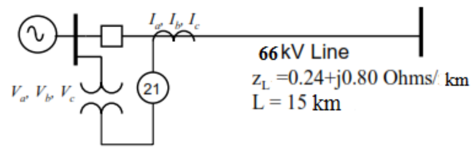
- Distance relays are classified according to their characteristics in the R-X diagram.
- The relays are set according to the positive and zero-sequence impedance of the transmission line.
- The below figure shows the R-X diagrams of some types of distance relays.



Mho and Reactance Characteristic **Mho Characteristic** **Quadrilateral Characteristic** **Lenticular Characteristic**

Example 1

- For the 66kV radial feeder shown, Calculate zone 1 setting for the distance relay in primary ohms?



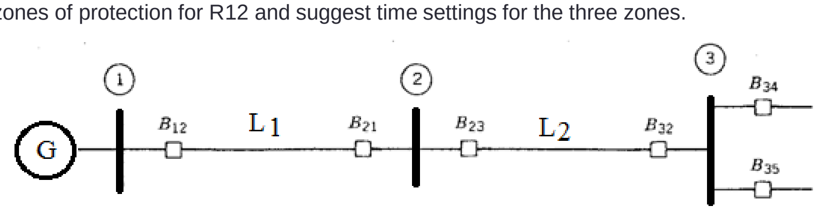
$$\overline{Z}_L = (0.24 + j0.8)\cdot 15 =$$
$$= 3.6 + j12 \text{ Ohms (primary)}$$

Zone 1

Relay setting: $Zr1 = (0.8)\,|3.6 + j12| = 10.02 \text{ Ohms}$

Example 2

- Consider the 230-kV transmission system shown in the below figure. Assume that the positive-sequence impedances of the lines L1 and L2 are 2 + j 20 Ω and 2.5 + j 25 Ω, respectively. If the maximum peak load supplied by the line L1 is 100 MVA with a lagging power factor of 0.9, **design a three-zone distance-relaying system for the R12 impedance relay by determining the following**:
- (a) Maximum load current
- b) CT ratio and VT ratio
- (c) Impedances measured by relay
- d) Zone 1 setting of relay R12
- e) Zone 2 setting of relay R12
- (f) Zone 3 setting of relay R12
- (g) Draw the zones of protection for R12 and suggest time settings for the three zones.



(a) Max.load current = $\frac{S}{V\sqrt{3}} = \frac{100x10^6}{230\ x\ 10^3\ \sqrt{3}}$ = 251.02 A

(b) Choose: CT ratio = 250 / 5

VT ratio $= \frac{230\ x\ 10^3}{120} = \frac{1916.7}{1}$

(c) Impedances measured by relay is

$$Z_{sec} = Z_{prim}\ x\ \frac{CT\ ratio}{VT\ ratio} = \frac{250/5}{1916.7/1}\ Z_{prim} = 0.026\ Z_{line}$$

Impedance of line L1and line L2 as seen by the relay (Line impedances based on secondary ohms) are:

$Z_{sec - L1}$ = 0.026 (2+j20) = 0.52 + j 0.5196 Ω

$Z_{sec - L2}$ = 0.026 (2.5+j25) = 0.65 + j 0.6495 Ω

(d) Zone 1 setting of relay R 12 is

Z1 = 0.8 (0.52 + j 0.5196)= 0.0416 + j 0.4157 sec. Ω

(e) Zone 2 setting of relay R 12 is

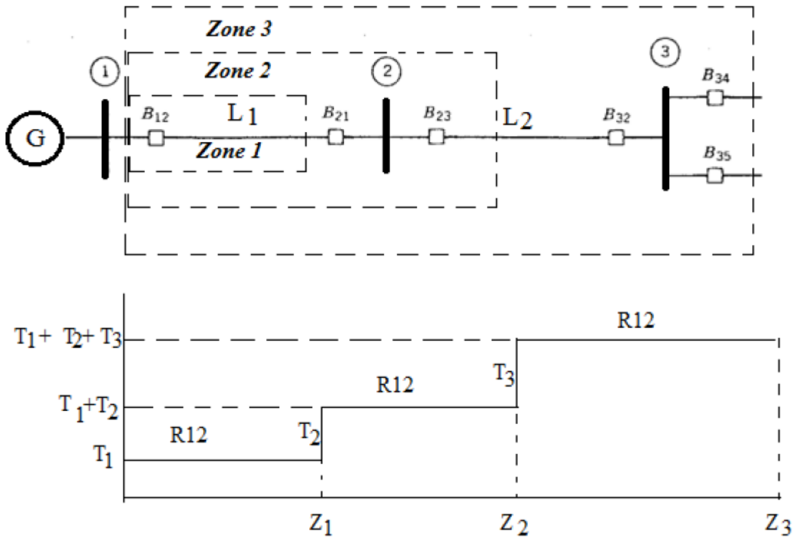
Z2 setting is = 120% - 150% , Choose 140%

Z2 = 1.4 (0.52 + j 0.5196)= 0.0728 + j 0.727 sec. Ω

(f) Zone 3 setting of relay R12 : Since the zone 3 setting must reach beyond the longest line connected to bus 2 ,thus

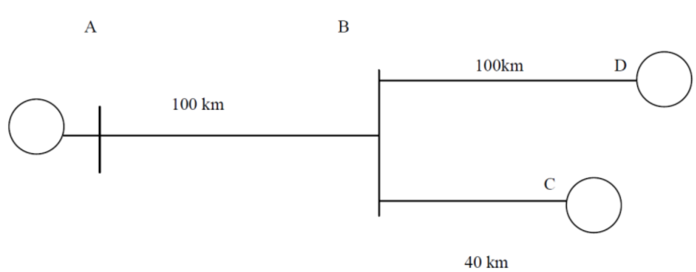
Z3 = 120% ($Z_{sec - L1}$ + $Z_{sec - L2}$) = 1.20 (0.52 + j 0.5196 + 0.65 + j 0.6495) = 0.1400 +j 1.402 sec. Ω

(g) Draw the zones of protection for R12 and suggest time settings for the three zones.



Example

- The below figure shows a simple radial transmission line system. Lines AB , BC and BD have an impedances of 0.8 Ω / km , 1.0 Ω / km and 0.8 Ω / km respectively. The distance relay at bus A is fed by current transformers rated at 2000/5 A and a voltage transformers rated at 354 kV/ 120V. Find zone 1 and zone 2 setting of the relay



Example

- A distance Relay is used as protection device for transmission line, the transmission line impedance is 6+j20 ohm.

1- Draw the relay characteristic of directional relay (impedance diagram).

1- Draw the relay characteristic of relay with offset by 15% of tine impedance?

$Z_L = 6 + j20\ \Omega \quad \therefore Z_1 = .8(6 + j20) = 4.8 + j16$

$(80\% Z_L) \leftarrow Z_1 = 16.7 \angle 73.3^\circ$

$Z_2 = 130\% Z_L = 1.3(6 + j20) = 7.8 + j26 = 27.2 \angle 73.3$

$Z_3 = 200\% Z_L = 2(6 + j20) = 12 + j40 = 41.76 \angle 73.3^\circ$

Take $\tau \Rightarrow$ angle of max Torque line, angle of (Z_L)

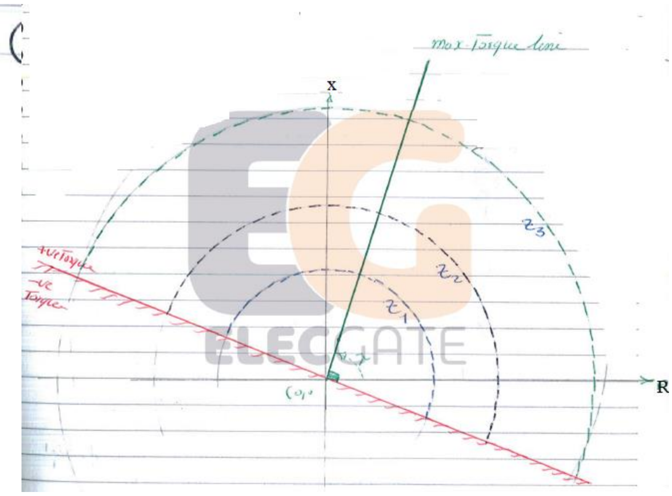
$\therefore \tau = 73.3^\circ$

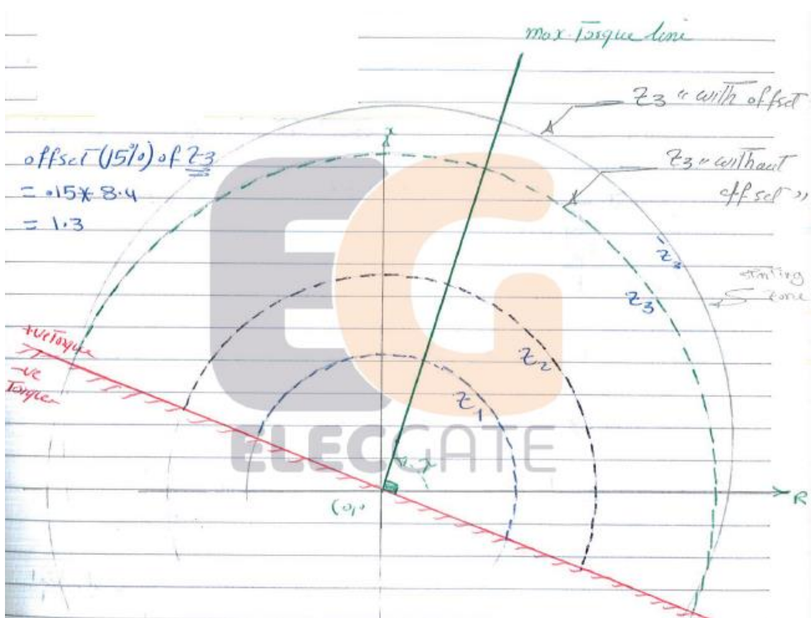
∴ Take scale (

$$Z_1 = \frac{16.7}{5} = 3.4\ \text{cm}$$

$$Z_2 = \frac{27.2}{5} = 5.4\ \text{cm}$$

$$Z_3 = \frac{41.76}{5} = 8.4\ \text{cm}$$



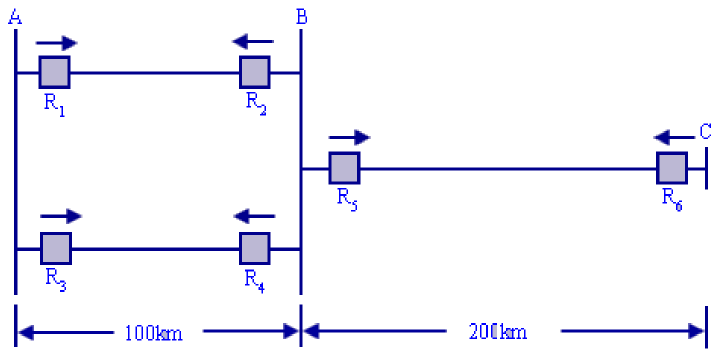


Example

- Consider a protection system shown in the below figure.

1- Identify the primary relays for back up relay R1.

2- Assuming that pu impedance of all transmission lines in above Figure is α pu /km, determine the setting of zone 1, zone 2 and zone 3 of R1.



- 1- Relay R1 not only backup's line BC but also parallel line AB. Therefore, for relay R1 acting as back up, the primary relays are R5 and R4.

- 2-

$$Z_1(R_1) = 0.8\alpha \times 100\, pu\Omega = 80\alpha pu\Omega$$

$$Z_2(R_1) = 100\alpha + 50\alpha = 150\alpha pu\Omega$$

$$Z_3(R_1) = 100\alpha + 200\alpha = 300\alpha pu\Omega$$

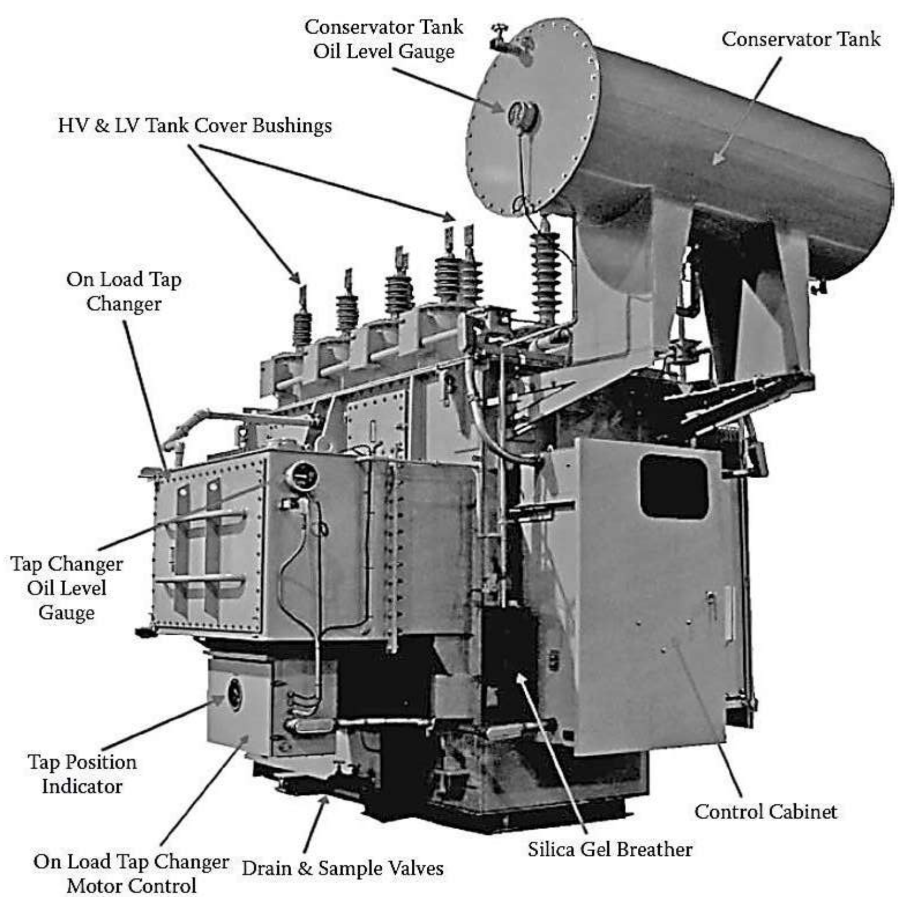
POWER SYSTEM PROTECTION
EE 567

Dr. Feras Alasali

Differential
&
Transformer Protection

- Generally, the main and most important components in the grid will have different protection systems.
- Generator will have around 20 types of protections.
- Power transformer will have around 5 types of protections.
- the higher power rated transformer will have more protection system compared to small size of transformer that can be protected by fusing system only.

- Key Components



Conservator design 15/20 MVA 72kV–25kV

oil

SF6

FAILURE

Why Do Transformers Fail?

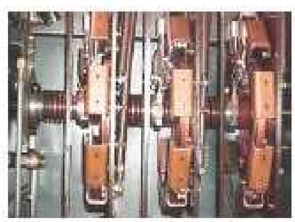
- The electrical windings and the magnetic core in a transformer are subject to a number of different forces during operation:

- • Expansion and contraction due to thermal cycling
- • Vibration
- • Local heating due to magnetic flux
- • Impact forces due to through-fault current
- • Excessive heating due to overloading.

What Fails in Transformers?

- **Windings**
  - Insulation deterioration from:
    - Moisture
    - Overheating
    - Vibration
    - Voltage surges
    - Mechanical Stress from through-faults

- **LTCs**
  - Malfunction of mechanical switching mechanism
  - High resistance contacts
  - Overheating
  - Contamination of insulating oil



What Fails in Transformers?

- **Bushings**
  - General aging
  - Contamination
  - Cracking
  - Internal moisture

- **Core Problems**
  - Core insulation failure
  - Open ground strap
  - Shorted laminations
  - Core overheating

IEEE Devices used in Transformer Protection

- **24:** Overexcitation (V/Hz)
- **26:** Thermal Device
- **46:** Negative Sequence Overcurrent
- **49:** Thermal Overload
- **50:** Instantaneous Phase Overcurrent
- **50G:** Instantaneous Ground Overcurrent
- **50N:** Instantaneous Residual Overcurrent
- **50BF:** Breaker Failure
- **51G:** Ground Inverse Time Overcurrent
- **51N:** Residual Inverse Time Overcurrent
- **63:** Sudden Pressure Relay (Buccholtz Relay)
- **64G:** Transformer Tank Ground Overcurrent
- **81U:** Underfrequency
- **87H:** Unrestrained Phase Differential
- **87T:** Transformer Phase Differential with Restraints
- **87GD:** Ground Differential (also known as “restricted earth fault”)

Types of Protection

Mechanical

- **Accumulated Gases**
  - Arcing by-products (Buchholz Relay)
- **Pressure Relays**
  - Arcing causing pressure waves in oil or gas space (Sudden Pressure Relay)
- **Thermal**
  - Caused by overload, overexcitation, harmonics and Geo-magnetically induced currents (GIC)
    - Hot spot temperature
    - Top Oil
    - LTC Overheating

Mechanical Protection This type is mechanical protection rather then electrical protection .When Insulation deterioration of the transformer or the iron core this may cause vaporization of insulation fluid. The basic mechanical protection used is **Buchholtz Relay**

Buchholtz Relay

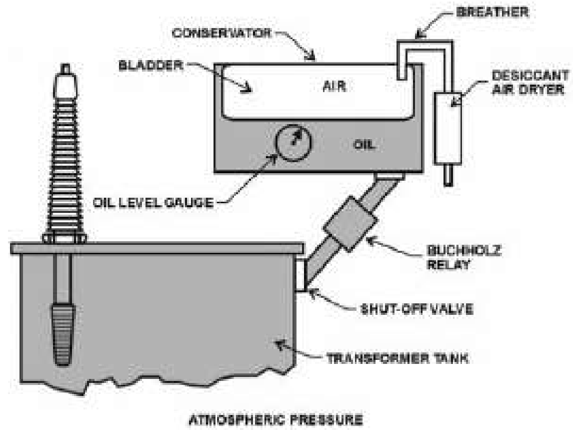
A Buchholz relay is a gas and oil operated device installed in the pipe between the top of the transformer main tank and the conservator.

- The function of the relay is to detect an abnormal condition within the tank and send an alarm or trip signal.
- Under normal conditions the relay is completely full of oil. when floats are displaced by an accumulation of gas, or a flap is moved by a surge of oil the relay will operate.

Buchholz relay Front View

Buchholz Relay

- Gas accumulator relay
- Applicable to conservator tanks equipped
- Operates for small faults by accumulating the gas over a period of time
  - Typically used for alarming only
- Operates or for large faults that force the oil through the relay at a high velocity
  - Used to trip
  - Able to detect a small volume of gas and accordingly can detect arcs of low energy
- Detects
  - High-resistance joints
  - High eddy currents between laminations
  - Low- and high-energy arcing
  - Accelerated aging caused by overloading



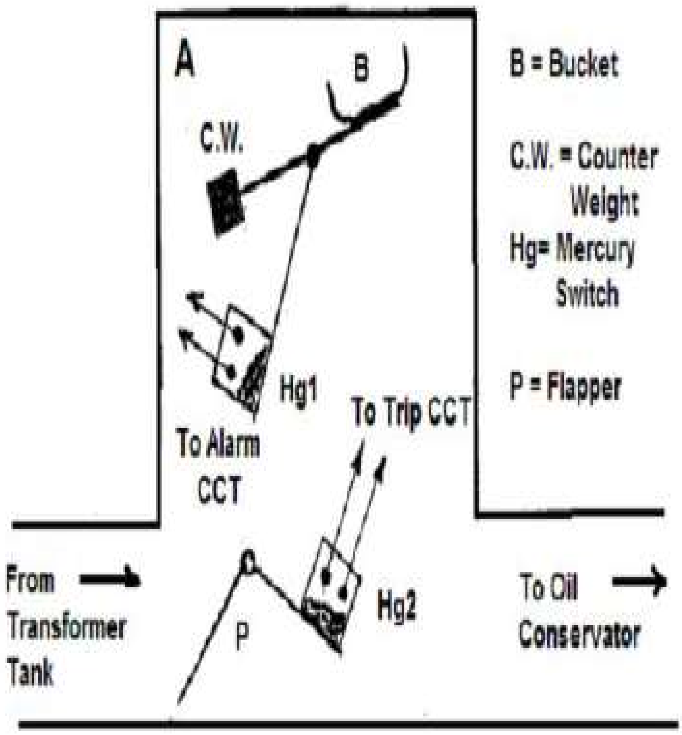
Principle of operation:

A Buchholz relay will detect:

- Gas produced within the transformer
- **An oil surge from the tank to the conservator**
- A complete loss of oil from the conservator (very low oil level)

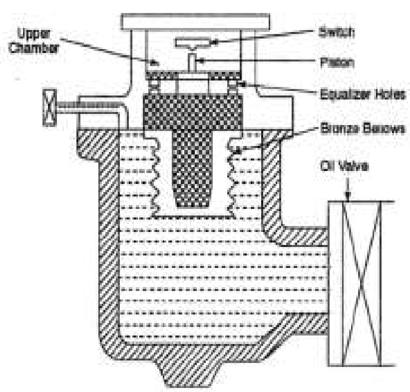
Fault conditions(internal fault) within a transformer produce gases such as carbon monoxide, hydrogen and a range of hydrocarbons.

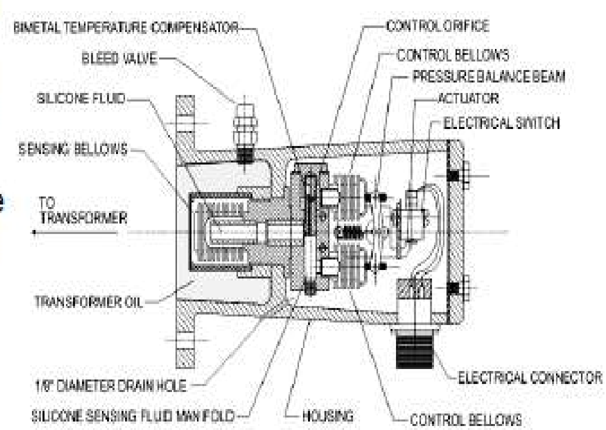
- A small fault produces a small volume of gas that trapped chamber (A) built into the relay. The oil level will be lowered and the oil in the bucket (B) will tilt the counter weight C.W., thus switch Hg1 operates alarm circuit to send an alarm .
- A large fault produces a large volume of gas which drives a surge of oil towards the conservator. This surge moves a flap (P) in the relay to operate switch Hg2 and send a trip signal to open the main circuit breaker.
- The device will also respond to a severe reduction in the oil level due to oil leakage from the tank.



Sudden Pressure Relay

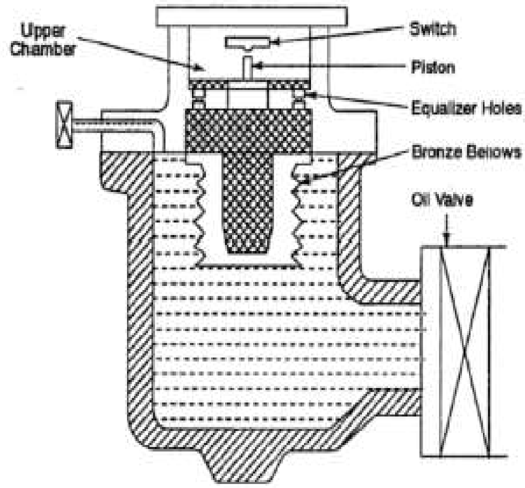
- When high current passes through a shorted turn, a great deal of heat is generated
  - Detect large and small faults
- This heat, along with the accompanying arcing, breaks down the oil into combustible gases
- Gas generation increases pressure within the tank
- A sudden increase in gas pressure can be detected by a sudden-pressure relay located either in the gas space or under the oil
- The sudden-pressure can operate before relays sensing electrical quantities, thus limiting damage to the transformer





Sudden Pressure Relay

- Drawback of using sudden-pressure relays is tendency to operate on high-current through-faults
  - The sudden high current experienced from a close-in through-fault causes windings of the transformer to move.
  - This movement causes a pressure wave that is transmitted through the oil
- Countermeasures:
  - Overcurrent relay supervision
    - Any high-current condition detected by the instantaneous overcurrent relay blocks the sudden-pressure relay
    - This method limits the sudden-pressure relay to low-current incipient fault detection.



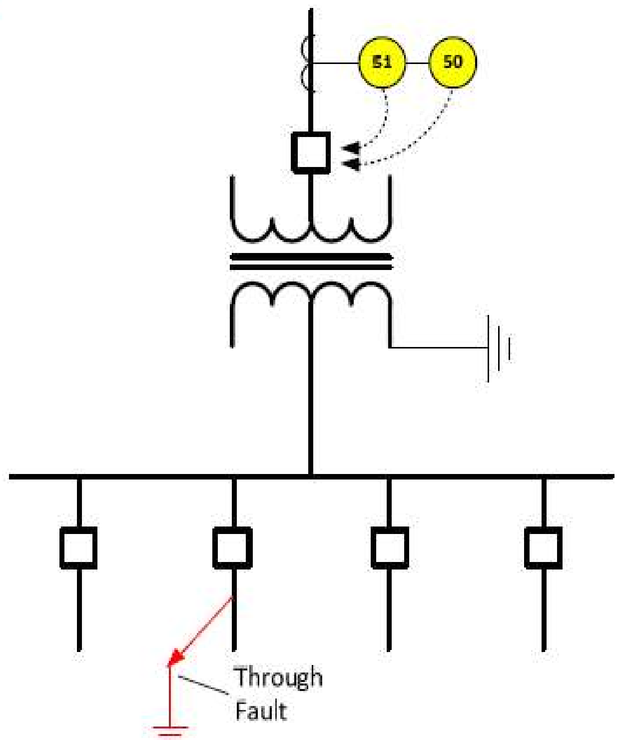
Types of Protection

Electrical

- **Fuses**
  - Small transformers (typ. <10 MVA)
  - Short circuit protection only
- **Overcurrent protection**
  - High side
    - Through fault protection
    - Differential back-up protection for high side faults
  - Low side
    - System back up protection
    - Unbalanced load protection

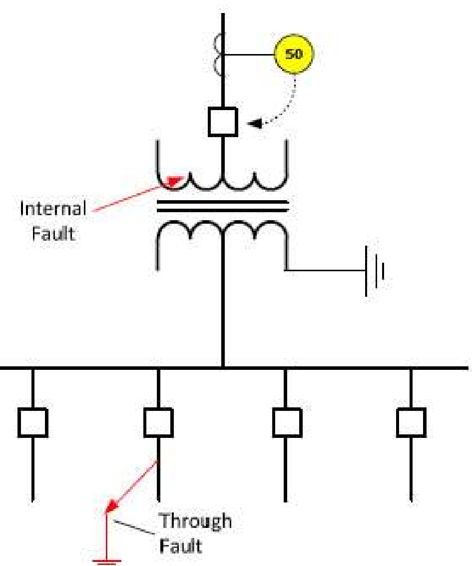
High Side Overcurrent

- Back up to differential, sudden pressure
- Coordinated with line protection off the bus
  - Do not want to trip for low-side external faults



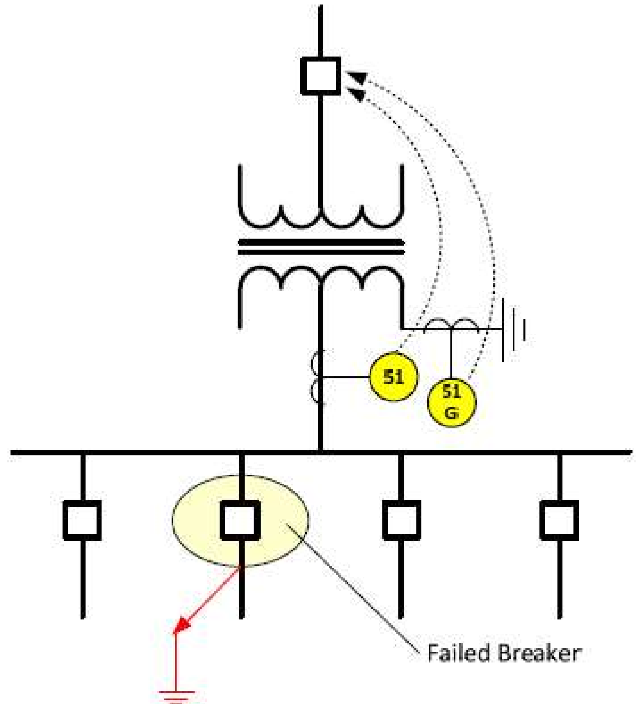
High Side Overcurrent for Internal Fault

- Set to pick up at a value higher than the maximum asymmetrical through-fault current.
  - This is usually the fault current through the transformer for a low-side three-phase short circuit.
- Instantaneous units that are subject to transient overreach are set for pickup in the range of 125% to 200



Low Side Overcurrent

- Provides protection against uncleared faults downstream of the transformer
- May consist of phase and ground elements
- Coordinated with downline protection off the bus

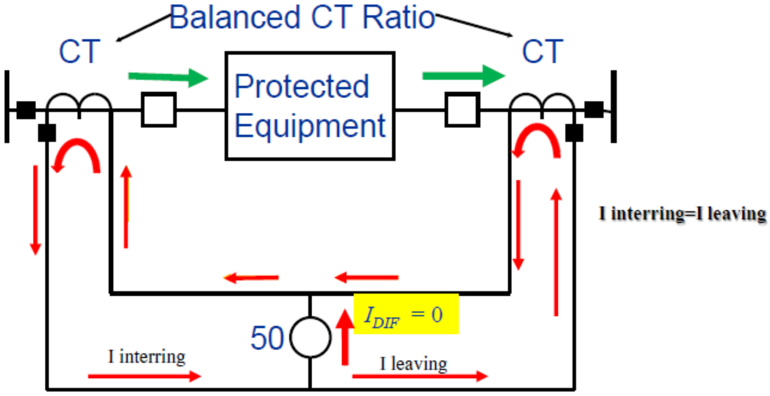


POWER SYSTEM PROTECTION
EE 567

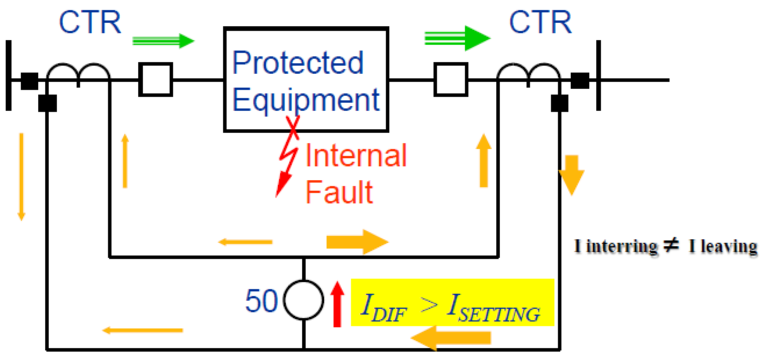
Dr. Feras Alasali

Differential Protection:

In this type of protection the technique is based on **electrical quantities entering and leaving the protected zone** (area covered C.T.s). If the net difference equal zero, it means no fault exist.



No Relay Operation , if CTs Are Considered Ideal



Relay Operates

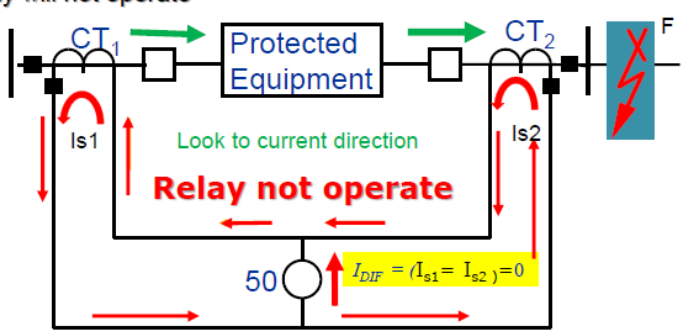
- Differential protection is applicable to all parts of the power system: such as :Generator , Transformers , Motors , Buses, Lines and feeders , Reactors and capacitors.
- **There are two basic types of differential protection:**
  - Current Balance Differential protection
  - Voltage Balanced Differential Protection

1-Current Balanced Differential Protection

Basic Current Differential Protection

a) External Fault of protection zone:

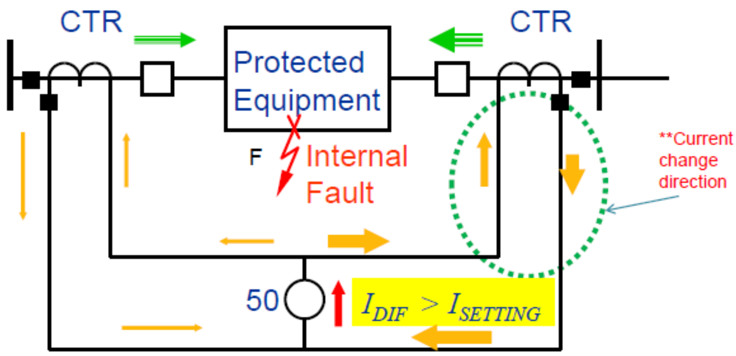
In this case the current deference between the protection zone CT1 and CT2 is same since the fault is out of the zone ,(I_{DIF} =0) and the the relay will not operate



$I_{s1} = I_{s2}$ then $\Delta I = 0$ **relay does not operate.**

b) Internal Fault within protection zone

If fault occurs at point F within the protected zone (internal fault) and the fault is fed from both sides, then current through CT_2 will be reversed. Therefore $\Delta I = |I_{s1}+I_{s2}|>|I_{relay}|$. This will cause the relay to trip the CB due to pick up current of relay.

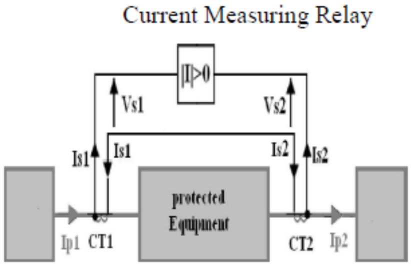


Consider ideal current transformer performance.
$I_{s1} \neq I_{s2}$ then $\Delta I \neq 0$ and the magnitude of $I > 0$ this case **the relay to operate**.

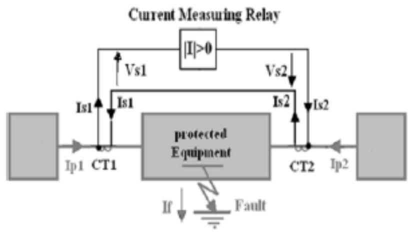
2-Voltage Balanced Differential Protection

- In this arrangement, the two similar current transformersCT_1&CT_2secondary windings are connected in opposition, so that there is no current flow in the relay operating coil (V_{s1}-V_{s2} =0) **relay not operate.**
- During internal fault Vs_1-$Vs_2 \neq 0$, The CTs used in such protections should based on induce voltages and since the magnitude of the fault current is very large, so that the voltage should be a linear function of such large currents, **the CTs should operate**

Balanced Voltage Differential Protection :



External Fault



Internal Fault

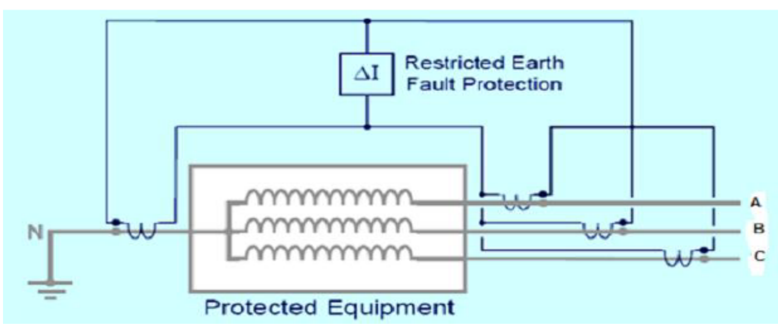
- $I_{p1} = I_{p2}$.
- $V_{s1} = V_{s2}$ and $I_{s1} = I_{s2} = 0$.
- Therefore magnitude of $I = 0$
- Current measuring relay does not operate.

- $I_{p1} \neq I_{p2}$
- Vs1 ≠ Vs2.
- Therefore magnitude of I ≠ 0
- Current measuring relay operates.

2-Restricted Earth Fault Protection

When the phase current differential protection is difficult to detect faults to earth near transformer neutral points. In this case **zero sequence current differential protection** comparing the neutral current with the residual current of three phases, which is often called restricted earth fault protection (REF).

This function can be combined with phase current differential protection in a single unit as shown in Fig..



Typical Application with REF.

Overall,

The characteristics of differential protection can be summarized as follows simple concept:

- Measure current entering and exiting the zone of protection
- If currents are not equal, a fault is present
- Provides:
  - High sensitivity
  - High selectivity Result
  - Relatively high speed

Percentage Differential Current Relay

This relay has an operating winding(op) and two restraining winding (Nr) connected as shown in Fig.

The function of the restraining windings is to prevent undesired relay operation should a current flow in the operating winding due to CT during external fault.

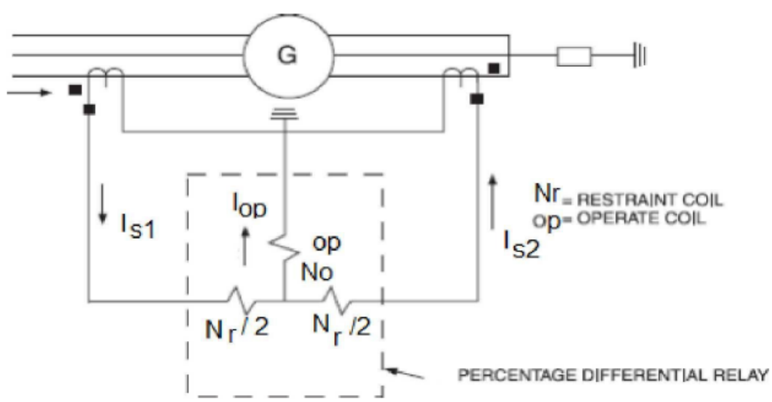


Figure show the basic relay connections (one phase) for fixed percentage restraint differential relay.

- 1- The operating current in the Diff relay is $(I_1 - I_2)$
- 2- This current will go through the operating coil.
- 3- The torque from this current will have a restraining torque equal to
- $$\left(\frac{I_1 + I_2}{2}\right)N$$
- If the $(I_1 - I_2)$ bigger than $\left(\frac{I_1 + I_2}{2}\right)N$ relay will operate.
- Otherwise the relay will not operate

Example

- In Diff relay the input current =5A and output current = 4.5A. This relay will operate or not?

$$I_{op} = (5 - 4.5) = 0.5A$$

$$I_{Res} = \frac{5 + 4.5}{2} = 4.7A$$

- Relay will not operate .

Example

- In Diff relay the input current =20A and output current = 1A. This relay will operate or not?

$$I_{op} = 20 - 1 = 19 \text{ A}$$

$$I_{Res} = \frac{20+1}{2} = 10.5A$$

- Relay will operate .

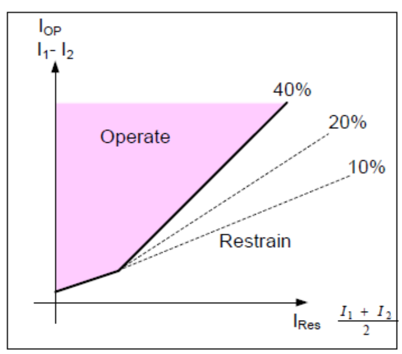
Percentage operating zone in Diff relay

In this type of protection, operating current need to exceed a fixed percentage of restraining current .

The percentage is almost equal the line slop

Here, the operating current need to exceed (k=10%) restraining current to operate the relay.

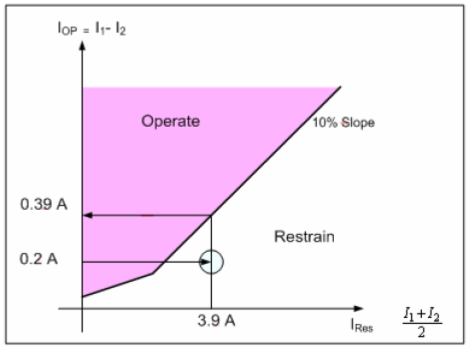
When K is small , the relay will be more sensitive.



Example

- Diff relay with slop equal to 10%, the input current 320 A and output current 304 A. If the CTR for both sides is 400:5, determine if this relay will operate or not?

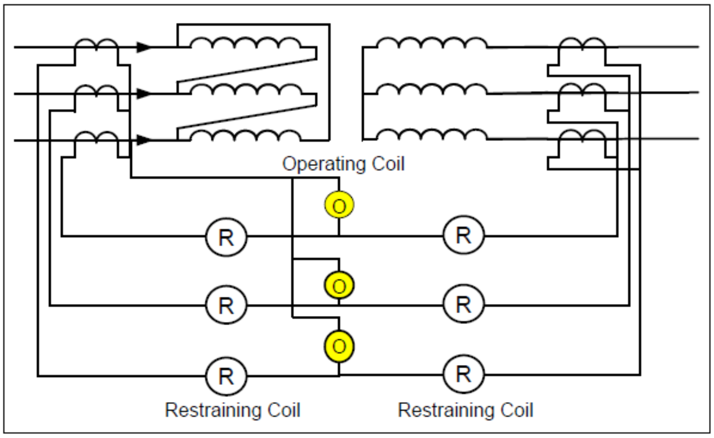
$$I_1 = \frac{320 \times 5}{400} = 4A$$
$$I_2 = \frac{304 \times 5}{400} = 3.8A$$
$$I_{op} = I_1 - I_2 = 0.2A$$
$$I_{reset} = \frac{I_1 + I_2}{2} = 3.9A$$



- K =0.2/3.9 = 0.05=5% which is less than 10% relay will not operate.

- When we use Diff relay to protect Tr. We will face number of problems:
- 1- Normal diff between input and output current related to CTR.
- 2- Tap changer
- 3- Transformer connection Y-Y , Delta-Y and which create phase shift. This can be solved by having CT with the opposite connection.

- Delta connection will help to remove the zero sequence current at it and will not move to the other side. The relay will not see this current as fault.



Examples

- Tr. Rated 20 MVA.=, 69/110 KV, it designed as single phase Tr. The Tr. Includes Tap changer under load (+5%,-5%). Design Diff relay protection for this Tr.?
- We need to do that find the following

CTR, Slope (percentage) , Determine minimum current will operate the relay.

$$I_p = \frac{20\,MVA}{69\,KV} = 289.8\,A \qquad CTR_p = \frac{300}{5}$$

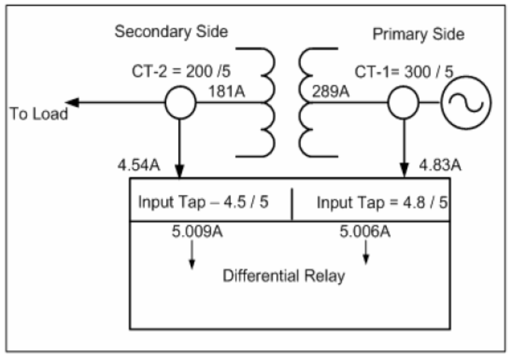
$$I_S = \frac{20\,MVA}{110\,KV} = 181.8\,A \qquad CTR_S = \frac{200}{2}$$

$$I'_P = 289.8 * \frac{5}{300} = 4.83A$$

$$I'_S = 181.8 * \frac{5}{200} = 4.54A$$

$$I'_P(\text{modified}) = \frac{4.83}{4.8} \times 5 = 5.006A$$

$$I'_S(\text{modified}) = \frac{4.54}{4.5} \times 5 = 5.009A$$



- Slop
- We take in account Tap-changer 5%
- CT error around 10%
- Our calculated error 0.3%
- Safe area 5%
- The total is 20.3%, the best slop is 20%

- Pickup current
- Normally pickup current will be the minimum operation current available for the relay which is 0.20 of the primary side when secondary is 0

- 0.20 * (4.8/5) * (300/5) = 11.52 A.

- This mean any current less than 11.52 A at primary side when secondary side is 0 will not operate relay.

- In Case we have 3 phase Tr. Delta-Y, the only change that we connect CT as Y-delta

- Here, line current at Delta will increase by $\sqrt{3}$ compared to Y side.

- This need to be take in account when select CT.

Example

Assume that a three-phase delta–wye-connected, 30-MVA, 69/34.5-kV power transformer is protected by the use of percentage differential relays,

If the CTs located on the delta and wye sides are of 300/5 and 1200/5 A, respectively, determine the following:

(a) Output currents of both CTs at full load.
(b) Relay current at full load.
(c) Minimum relay current setting to permit 25 percent overload.

Solution

(a) The high-voltage side line current is

$$I_{HV} = \frac{30 \times 10^6}{\sqrt{3}(69 \times 10^3)} = 251.02 \text{ A}$$

The low-voltage side line current is

$$I_{LV} = \frac{30 \times 10^6}{\sqrt{3}(34.5 \times 10^3)} = 502.04 \text{ A}$$

Therefore, the output current of the CT located on the high-voltage side is

$$251.02\left(\frac{5}{300}\right) = 4.1837 \text{ A}$$

and the output current of the CT located on the low-voltage side is

$$502.04\left(\frac{5}{1200}\right)\sqrt{3} = 3.6232 \text{ A}$$

Note that the winding current of the delta-connected CT is multiplied by $\sqrt{3}$ to obtain its line current.

(b) The relay current at full load is

$$4.1837 - 3.6232 = 0.5605 \text{ A}$$

(c) Thus, the minimum relay current setting to permit 25 percent overload is

$$(1.25)(0.5605) = 0.7007 \text{ A}$$

Example

- 3 phase Tr. Rated 30 MVA (11.5/69 KV) connected as
- Delta –Y. Determine the CT ratio?

- Tr. (Y, 69KV) current = 30 MVA/($\sqrt{3}$ 69KV) = 251 A
- Tr. (Delta, 11.5KV) current = 30 MVA/($\sqrt{3}$ 69KV) = 1506 A

- We will connect the CT as Y-Delta
- For the primary side of power Transformer (Delta) CT1 is 1500/5 or 1600/5)

- For the secondary side of power Transformer (Y) : CT2

we need to know that the secondary current for both CTs (1 and 2) should be equal

(1506* 5/1500) = (251 * 5/x) $\sqrt{3}$

X = 433 A and CT will be 500/5

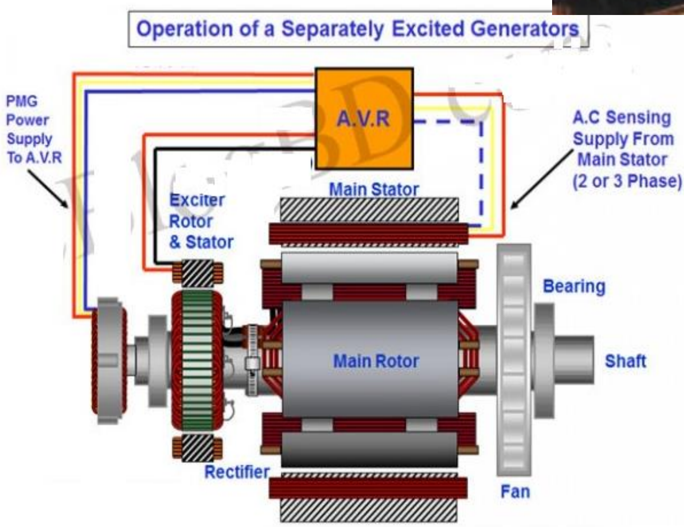
$\sqrt{3}$ is added because CT with Delta connection will have more current equal to $\sqrt{3}$

POWER SYSTEM PROTECTION
EE 567

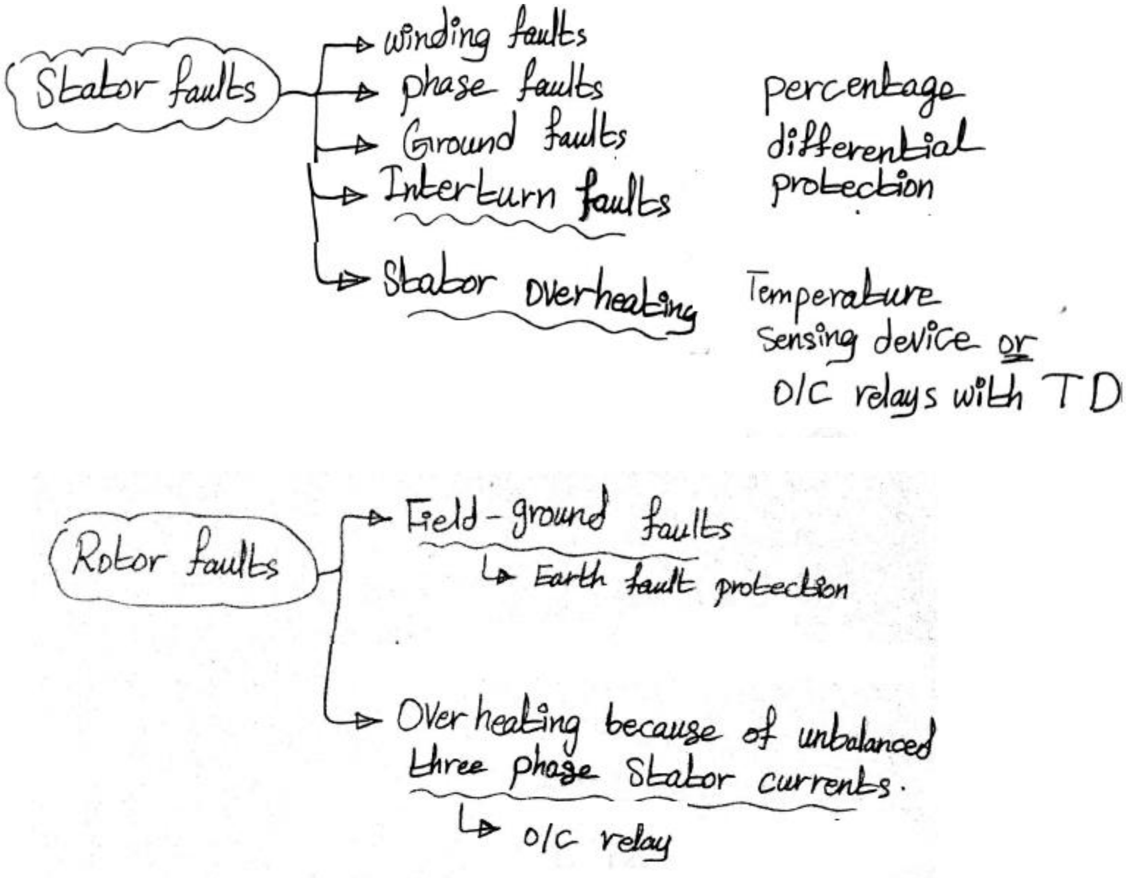
Dr. Feras Alasali

GENERATOR PROTECTION

GENERATOR



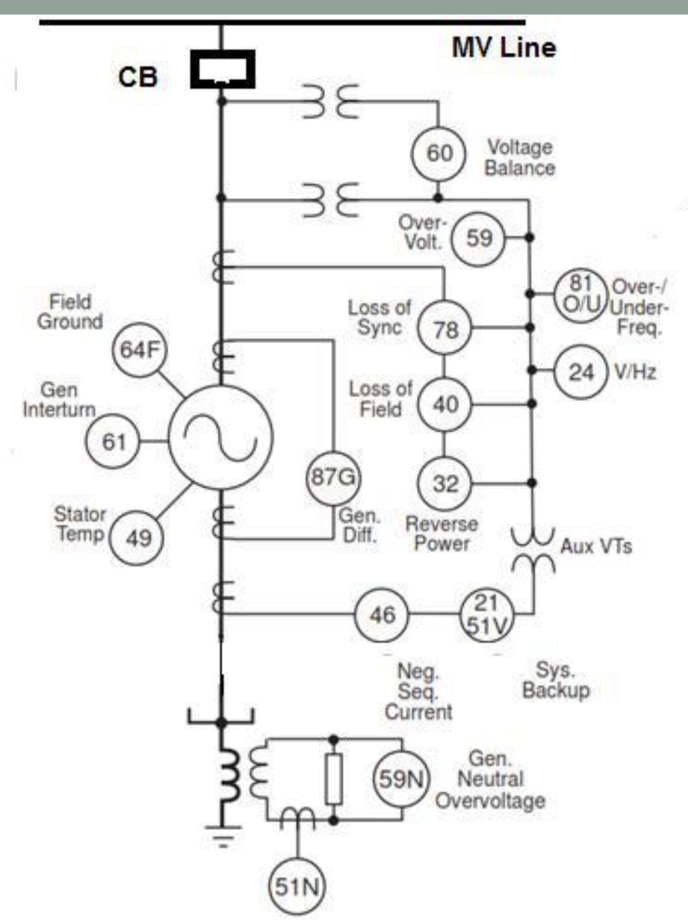
- The generator protection system design should take into account the **<u>types of faults and abnormal operating conditions</u>** that could be present at the generating plant and provide means for detecting and acting upon these conditions.
- The protection system design **<u>will depend on the size of the generating unit</u>**.
- These fault types and disturbance conditions are classified as:
- Overload protection, and Overcurrent (short-circuit) problems
- Stator electrical faults
- Rotor electrical faults
- Failure of prime mover (mechanical problems)
- Failure of the field circuit



- Hence we must protect the generator against the effect of these **faults and abnormalities** using the following protection schemes:
- Overvoltage and under voltage protection
- Over excitation
- Loss of synchronism
- Abnormal Frequencies
- Over speeding
- Excessive vibration

- <u>OVEREXCITATION PROTECTION</u>
- When the ratio of the **<u>voltage to frequency (volts/Hz)</u>** <u>exceeds 1.05 pu for a generator</u>, severe **overheating can occur due** to **<u>saturation of the magnetic core of the</u>** generator and the components not designed to carry flux.
- **<u>Such over excitation</u>** most often occurs during start-up or shutdown while the unit is operating at reduced frequencies.

- <u>OVERVOLTAGE PROTECTION</u>
- Generator overvoltage may occur during a **<u>load rejection</u>** or <u>excitation control failure</u>.
- upon load rejection the generator may speed up and the voltage can reach high levels. The overvoltage relay(59) is used to protect the generator from this condition.

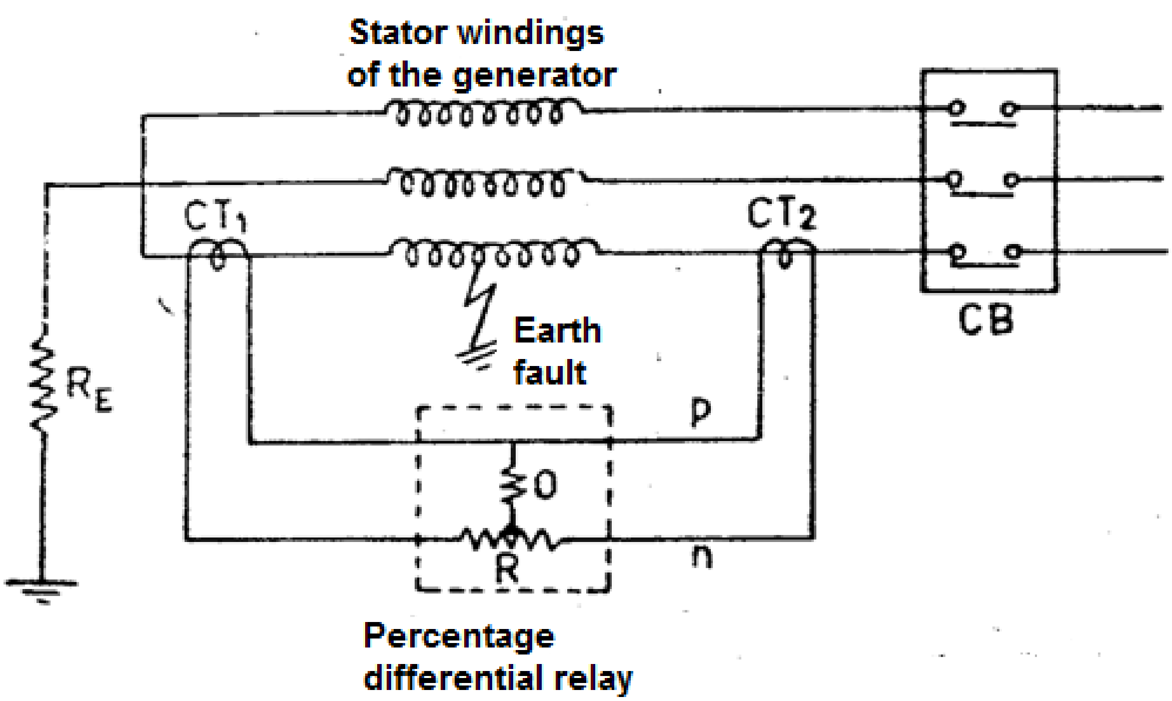


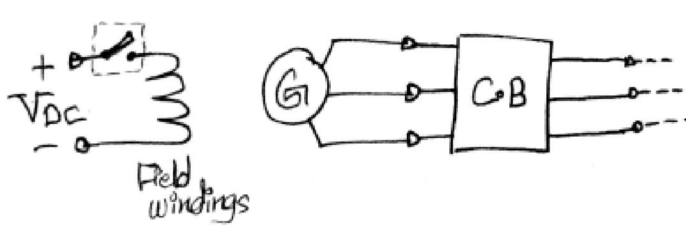
1. Generator protection using differential protection schemes

- To protect the generator against the failure of winding insulation and the failure of the field circuit as well as the primemover failures, differential protection is used with biased circulating current scheme.

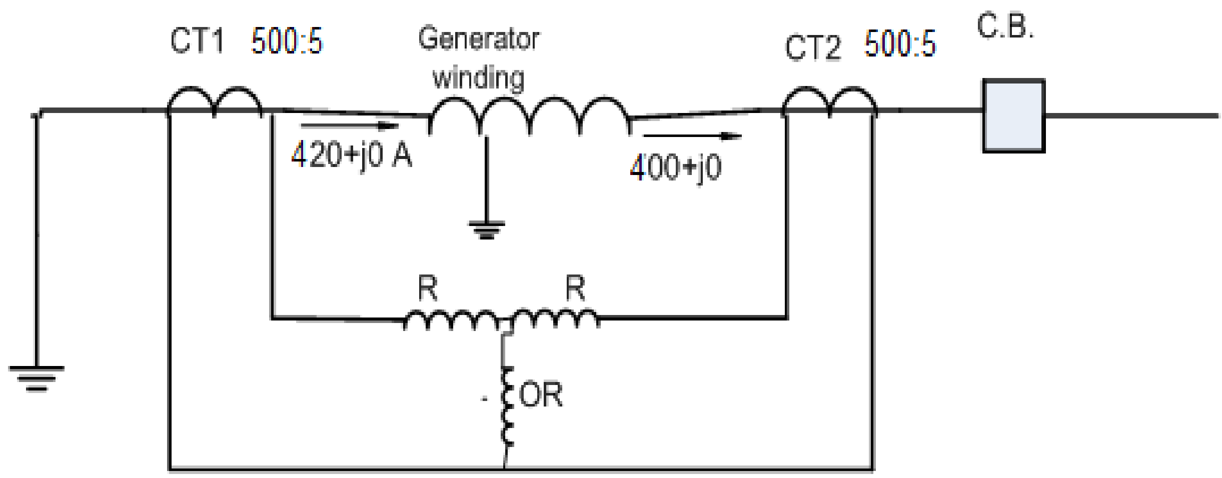
- The theory of circulating current differential protection is discussed fully in Transformer protection section.

- Normally differential protection is used for generators larger than or equal to 20MW.





- Example 1
- Figure shows a biased percentage differential relay applied for the protection of synchronous generator windings. The relay has 0.1A minimum pick up current and a 10 %.



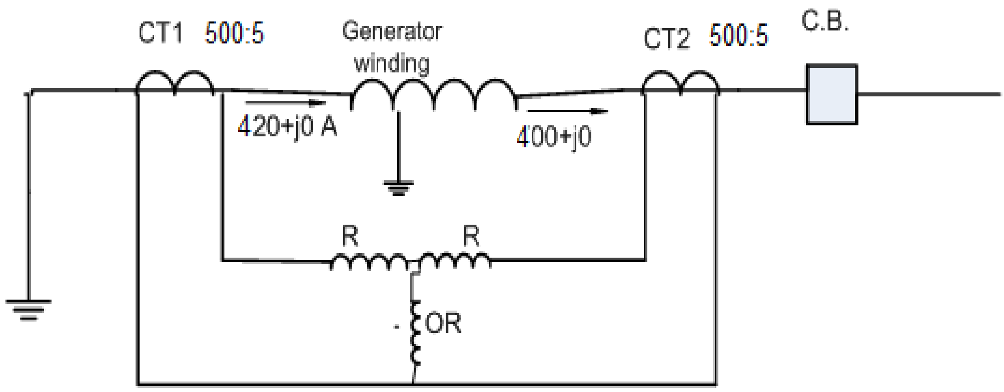
- (a) Fault has occurred <u>near the grounded neutral</u> end of the generator when the <u>generator is carrying load</u>. As a result, the currents flowing at each end are as shown in the figure. Would the relay operate or not?

- Is1 = 420* (5/500) = 4.2 A
- Is2 = 400* (5/500) = 4 A
- Operation current = Is1 – Is2 = 0.2 A
- Irest = (Is1+Is2)/2 = 4.1 A

Where we have 10% slop for Iop/Irest, we calculated K

K= Iop/Irest = 0.2/4.1= 4.7% which is less than 10% and relay will not operate.

- (b) would the relay operate at the given value of fault current in (a) is equal to 20 A and the generator was **carrying no load** ?
- As we have no load current Is2 = 0
- As the fault current = 20 A, Is1 = 20 A * (5/500) = 0.2 A
- Operation current = 0.2-0=0.2 A
- I rest = 0.2+0/2=0.1------ K (slope) = 0.2/0.1 = 200%
- Then the relay will operate.



- (c) On the same diagram , show the relay operating characteristics and the points that represent the operating and restraining currents in the relay for the two conditions

POWER SYSTEM PROTECTION EE 567

Dr. Feras Alasali

MOTOR PROTECTION

General

- Fuses , thermal overload relay and contactors has proved itself an effective and economical solution for small to medium-sized motors up to about 150 hp.

- Two basic protections are used for these motor:
- ■ Thermal overload protection
- ■ Short-circuit (overcurrent) protection

- On larger, more expensive motors or when maximum motor utilization is required under varying operational conditions more sophisticated flexible and accurate *microprocessor protection relays* should be considered. These relays typically include:
- ■ Thermal overload protection,
- ■ Short-circuit protection
- ■ Start-up and running stall protection
- ■ Phase unbalanced protection
- ■ Single-phasing protection
- ■ Earth fault protection
- ■ Undercurrent protection

Typical protective settings for motors

- *(a) Long- time pick-up*
- **(1.15) times** motor full load current (FLA) times motor service factor for applications, encountering 90% voltage dip on motor starting.
- **(1.25) times** motor FLA times motor service factor for applications encountering 80% voltage dip on motor starting.

(b) Instantaneous pick-up

- Not less than 1.7 times motor long-time pick up rated ampere (LRA) for medium-voltage motors
- Not less than 2.0 times motor LRA for low-voltage motors.

Motor protective device

- Molded Case Circuit Breakers (**MCCB**) are used for *low voltage motors of high ratings* .
- For **high voltage motor**: H.V. *circuit breaker and differential protection*

Example

- A 100 hp motor, 480 V, 0.85 P.F with Efficiency equal to 85%. This motor has starting up current = 5.9 rated current with voltage dip of 80% during the starting.
- Select a protection system for this motor?

- Efficiency = output power/ Input power --- Pin = Pout/Effi
- Pin = (100*746) / 0.85 = 87.764 KW
- I rated = Pin/($\sqrt{3}\,V\ P.F$) = 124 A

We choose MCCB with booth

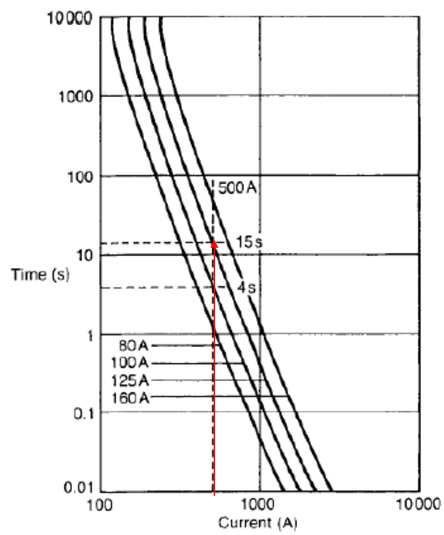
Thermal pickup setting (125%) I rated = 1.25*124 = 155A

instantaneous (LV) setting = 2 *124 = 248 A

Motors protection by fuses

- In several industrial applications, fuses are used for **protecting small and medium size motors**. To determine the fuse size for a motor, one should refer to below figure which shows typical fuse time/current characteristics.

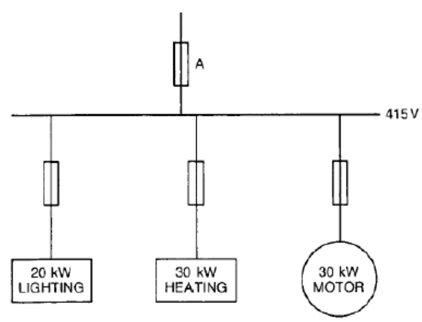
If the starting current of the motor is say 500 A and the run-up ***time 10s***, then a 125 A fuse would be required



- Examination of the fuse time/current characteristic shows that at 500 A the 125 A fuse would operate in 15 s.

- The fuse one size lower, 100 A, would operate in 4 s at 500 A and is, therefore, not suitable
- **To summarize**
- 1 .The fuse must be adequately <u>rated to supply normal current to the circuit.</u>
- 2. The rating must take into account any normal healthy <u>overload conditions e.g. the starting of motors.</u>
- 3. An allowance must be made <u>if an overload occurs frequently</u>.
- 4. There must be an adequate <u>margin if discrimination between fuses is required.</u> of the power system, e.g. contactors, cables, switches, etc.

Determine the fuse rating in the below figure



Motor with eff 92%, P.F= 0.83, starting current = 7 I rated.

a) Lighting load
$I = 20k/\sqrt{3}\,415 = 27.8$ A
We choose Fuse 32A

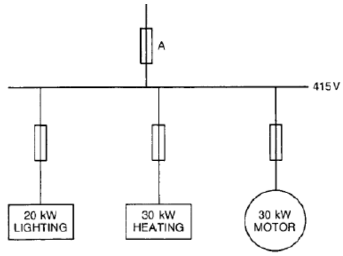
b) Heating load
$I = 30k/\sqrt{3}\,415 = 41.7$ A
We choose Fuse 50A

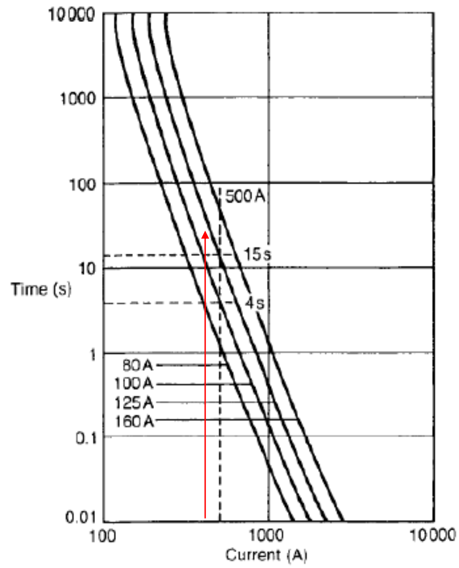
C) Motor
Pin =30/0.92= 32.6 kw
$I = 32.6k/\sqrt{3}\,415 * 0.85 = 54.7$ A
I starting = 7 I rated = 7*54.7= 383A

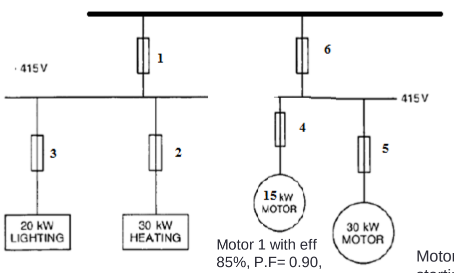
From the figure , we need 100 A fuse to operate 10s and more for the motor.

d) For fuse A
It will carry normal current = 27.8+41.7+54.7 = 124.2 A
It also will carry starting current = 383+41.7+27.8 = 452.5 A

From the figure the fuse rated is 160 A.







Motor 1 with eff 85%, P.F= 0.90, starting current = 6 I rated.

Motor 2 with eff 90%, P.F= 0.80, starting current = 6 I rated.