AN ADVANCE COURSE IN POWER SYSTEM PROTECTION

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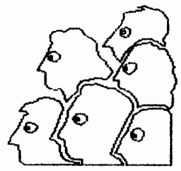
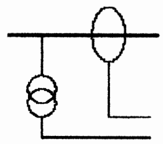
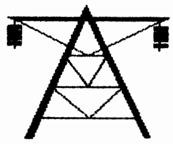
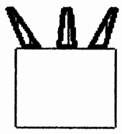
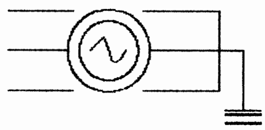










CHAPTER (LECTURE) ONE

GENERAL VIEW

"GENERAL VIEW"
LEC. #1

CONTENTS

INTRODUCTION

The objective of the power system is to generate, transmit, and distribute electric power. This should be done with maximum availability and minimum losses taking as well as taking into account the safety and environmental aspects.

The power system consists of high-voltage equipment which naturally have certain limits for their operation when it comes to voltage, current, and frequency.

In each moment the generation of electric power has to be equal to the consumption. Any difference will cause a change in the frequency of the system. The objective of the control system is to maintain this balance with an optimum load flow in order to minimize the losses.

Operating a power system therefore includes a large number of control functions necessary to provide a continuous and uninterrupted supply of power.

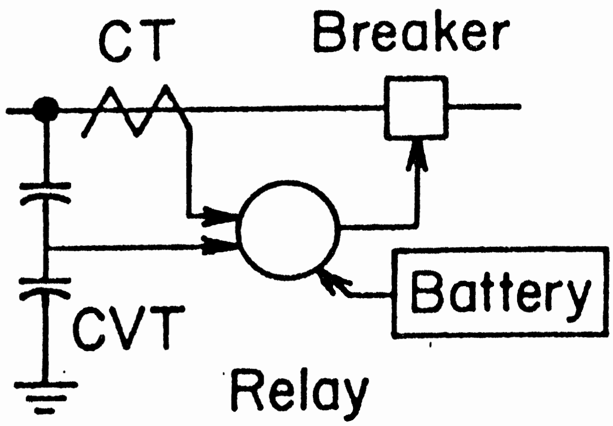
A disturbance in the system means that an element of the system power (i.e; frequency, current, or voltage) exceeds the specified limits.

The objective of the protection system is to supervise these limits and to minimize the disturbance thereby ensuring maximum safety for person and equipment.

THE PROTECTION SYSTEM

A protection system protects the power system from the bad effects of a maintained fault. A fault (meaning in most cases a short circuit, but more generally an abnormal system condition) occurs as a casual event.

Although a protection system is usually understood to mean relays, it consists of many other subsystems which contribute to the fault removal process (look the figure below).



A PROTECTION SYSTEM

* The circuit breaker actually isolates the faulted circuit by interrupting the current at or near current zero. A modern extra high voltage circuit breakers can interrupt fault currents of the order of 100 KA at system voltages of up to 800 KV. The breaker is operated by energizing its trip coil from the station battery, and the relay(s) do this job by closing contacts between the battery and the trip-coil. Very often other relays (reclosing relays) are used to reclose the circuit breakers after a suitable time interval.

* The transducers (current (C.T) and voltage (V.T) transformers) constitute another major component of the protection system. They are necessary because the high magnitude currents and voltages of the power system must be reduced to more manageable levels in order to derive low energy (and hence safe of the human access) devices such as relays. We shall consider the current and voltage transformers in some detail later. For the present, it is sufficient to note that certain features of the transducers have been standardized. C.T secondary rating has been standardized at 5 amperes or 1 ampere. This implies that maximum load current in the primary winding of the C.T would produce 5 amp.(1 amp.) or less in its secondary winding. This leads to a desired C.T winding turn ratio, which is then approximated by one of the standard C.T ratio available. The V.Ts have the secondary windings rated at 67 volts phase-to-neutral (110 v. line-line). Within certain limits, the current and voltage transformers reproduce the primary current and voltage waveforms faithfully on their secondaries. As those limits are exceeded, the C.Ts and V.Ts reproduce distorted waveforms on their secondaries.

* The most important component of a protection system is the relay. This device which responds to the condition of its inputs (voltage, current, or contact status) in such a manner that it provides proper output signals to trip circuit breakers when input conditions correspond to faults for which the relay is designed to operate. Relays are the logic elements in the entire protection system. The design of a relay must be such that all fault conditions for which it is responsible must produce a trip output, while no other conditions should.

In general the relay must be reliable. To a relay engineer, this has two characters : it is **dependable** (which means that the relay will always operate for conditions for which it is designed to operate), and it is **secure** (which means that the relay will not operate for any other power system disturbance). In general the security is more difficult to achieve, since any fault in the neighborhood of a relay will disturb its input voltages and currents. The relay should neglect those voltage and current conditions that are produced by faults which are not the responsibility of the relay.

TYPES OF RELAYS

Almost all the relays in use on power systems may be classified as follows:

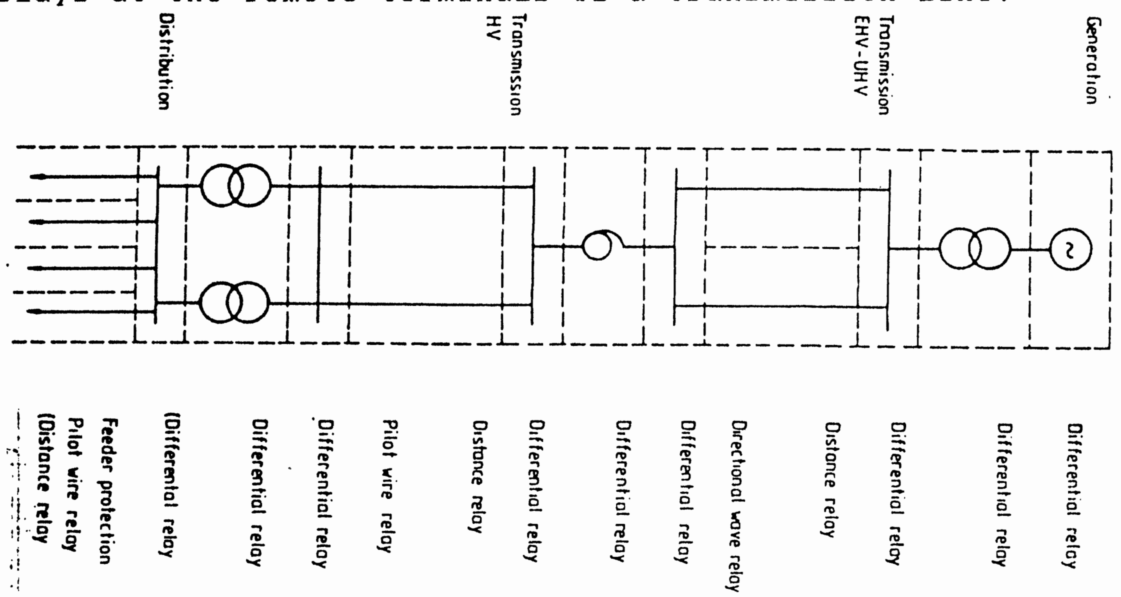
1) Magnitude Relays : These relays respond to the magnitude of the input quantity. An example is the overcurrent relay which responds to changes in the magnitude (either the peak value or the rms value) of the input current.

2) Directional Relays : These relays respond to the phase angle between two ac inputs. A commonly used directional relay may compare the phase angle of a current with a voltage. Or, the phase angle of one current may compare with that of another current.

3) Ratio relay : These relays respond to the ratio of two input signals expressed as phasors. Ratio of two phasors is a complex number, and ratio relay may be designed to respond to the magnitude of this complex number or to the complex number itself. The most common ratio relays are the several versions of the impedance or distance relays.

4) Differential Relays : These relays respond to the magnitude of the algebraic sum of two or more inputs. In their most common form, the relays respond to the algebraic sum of currents entering a zone of protection. This algebraic sum may be made to represent the current in any fault (if it exists) inside the zone of protection.

5) Pilot Relays : These relays utilize communicated information from remote locations as an input signal. This type of protection generally communicates the decision made by a local relay of one of the four types described above to relays at the remote terminals of a transmission line.



APPLICATION OF RELAYS TYPES IN A POWER SYSTEM

TYPES AND USES OF SYSTEM PROTECTION

1) Overfrequency Protection : is normally used only for generators by monitoring of the speed of the generator.

2) Overvoltage Protection : is used for generators and buses where high-voltage can occur due to capacitive current from long lines.

3) Overload Protection : is used for generators, transformers, motors and cables. It can be arranged as a plain temperature monitoring, a plain current monitoring or a combination of both.

4) Unbalanced Load Protection : the unbalanced load is dangerous for generators and motors. This condition can be detected by a negative sequence current protection.

5) Overexcitation Protection : overexcitation can be caused by both overvoltage and/or underfrequency. This results in temperature rise in the transformer which can damage the transformer. An overexcitation protection should be installed for transformers for which this operating condition can occur.

6) Underfrequency Protection : underfrequency means that the load exceeds the generation. Load shedding systems are based on underfrequency detection.

7) Undervoltage Protection : is used for larger motors to prevent loss of synchronism.

POWER SYSTEM PROTECTION REQUIREMENTS

From the power system point of view three major requirements are on protective relays;

* SPEED : short operation time for sever faults

  a) Short fault clearing will reduce damages and safety hazards. Furthermore mechanical and thermal stresses on windings and machine shafts will be reduced.

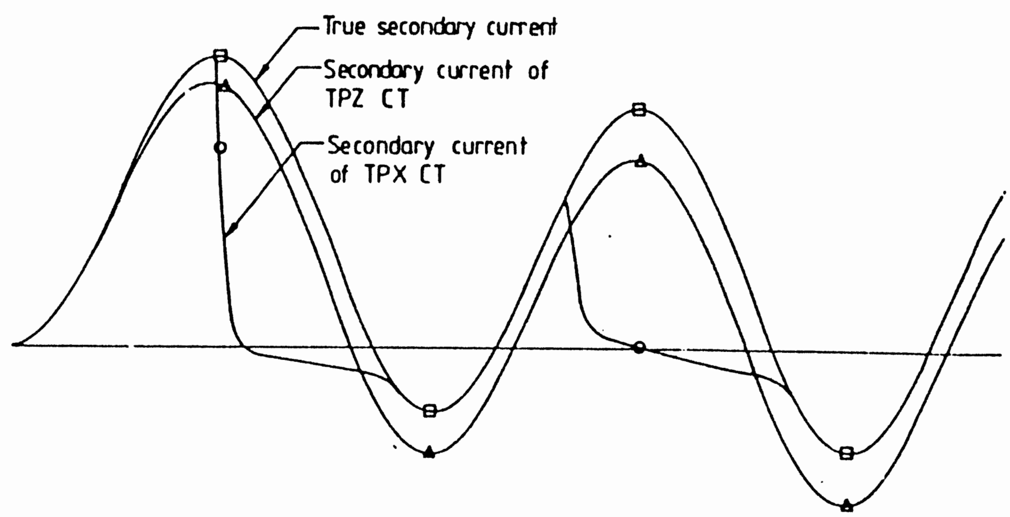
  b) Short fault clearing time will also reduce the ionization of the air and make support a successful autoreclosing.

  c) Short fault clearing time may increase the stability margin which intern will increase the power transfer.

  The following may effect the speed of operation;

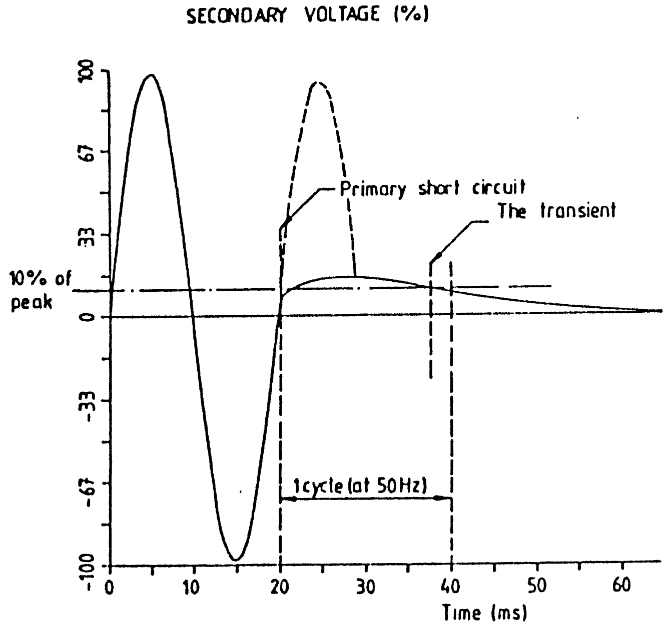
  1- high frequency transients; which could be overcome by filtering.

  2- C.T saturation; which could be overcome by; measuring before saturation, or by measuring at zero crossing.
  Below, the effect of CT saturation on the produced secondary waveforms, is illustrated.



CT SATURATION EFFECT

3- C.V.T transients; which could be overcome by, measuring change in voltage, or by, measuring on fundamental frequency.
Below the effect of C.V.T transients on the output voltages, is shown.



C.V.T TRANSIENTS

* **SENSITIVITY** : capability to detect all types of fault. It is important to detect all faults even if the fault current is smaller than the load current.

Two examples on the sensitivity, are considered, one in transmission lines and the other in power transformer protection schemes respectively.

IN TRANSMISSION LINES

A single-phase fault on a line results in fault currents flowing from both ends. The magnitude of these fault current (IF) is depending on the source impedance (Zs), the line impedance (ZL) and the fault resistance (RF).

IF = UF/ZF where;

Z = Zs + ZL + RF

Hence, higher Z will give lower IF values and may effect the sensitivity of the detection devices.

In general the following may effect the sensitivity;

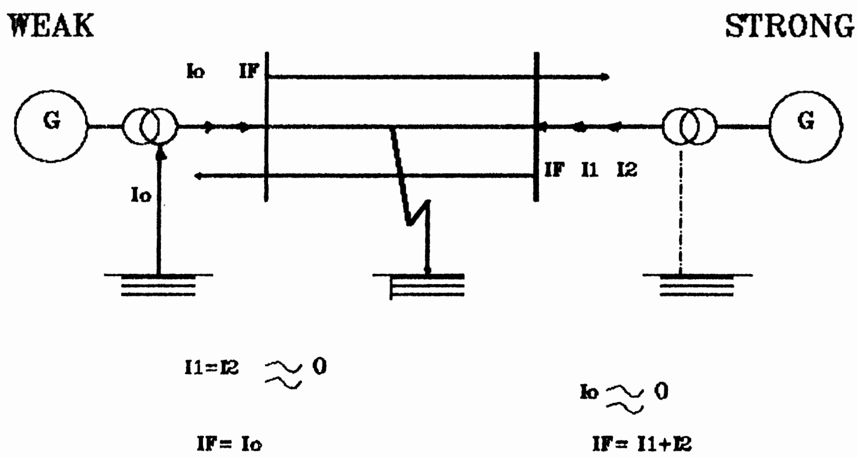
1- load: any protection device should distinguish between fault and normal load cases.
A fault detection method completely independent of load is to measure the change in phase current which is done in the directional way detector.

2- steady state errors: the currents produced by CTs steady state errors (current and phase errors), may also effect the sensitivity.

3- high fault resistance
4- long lines

It has been shown; how the increasing of any of fault resistance and line impedance, may lead to affect and minimize the fault current magnitude.

5- weak infeed:



A FAULT CURRENT REPRESENTED BY ITS SYMMETRICAL COMPONENTS

The fault current can be represented by its symmetrical components,

$$IF = I1 + I2 + Io$$

I1 and I2 are depending on the generating capacity connected to the system and Io is depending on the grounding of transformers neutrals in the system. This means that the relative magnitude of I1,I2, and Io is mainly depending on system conditions (ie, how many generators and transformers are connected to the system). The best solution for this problem is still to measure phase quantities to become less dependent on system conditions.

IN POWER TRANSFORMER

Magnetizing currents or inrush currents are mainly a problem for transformers. The differential protection have to be secure during these conditions and not give any false trip.

* **SELECTIVITY** : capability to determine the fault location and only disconnect the faulted object.

Talking about selectivity and what affects it, is a wide subject. It is better to talk about the selectivity within the protection of each part of the power system.

CHAPTER (LECTURE) TWO

INSTRUMENT TRANSFORMERS

"INSTRUMENT TRANSFORMERS"

LEC. #2

CONTENTS

INTRODUCTION

Both current transformer (C.T) and voltage transformer (V.T) are called instrument transformers. The main tasks of instrument transformers are;

1- to transform currents or voltages from a usually high value to a value easy to collect for relays and instruments.

2- to insulate the metering circuit from the primary high voltage system.

3- to provide possibilities of standardizing the instruments and relays to a few rated currents and voltages.

Instrument transformers are special forms of transformers in respect to measurement of currents and voltages. The theory for instrument transformers are the same as those vailed for transformers in general.

For C.Ts, the current transformation in proportion to the primary and secondary turns is,

$$\frac{I1}{I2} = \frac{N2}{N1}$$

For V.Ts, the voltage transformation in proportion to the primary and secondary turns is,

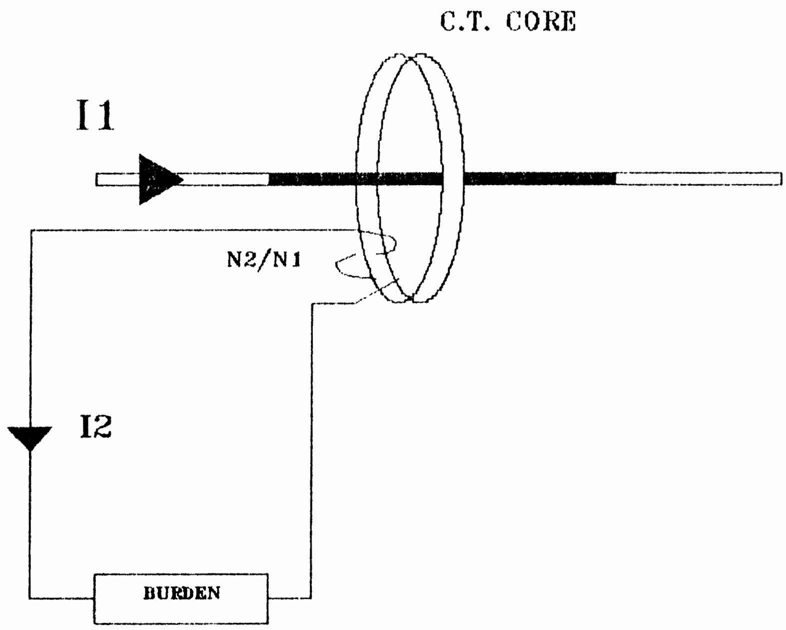
$$\frac{E1}{E2} = \frac{N1}{N2}$$

CURRENT TRANSFORMERS (C.Ts)

The primary of the C.T is connected in series with network as shown. That means,

a) the impedance of the primary winding is negligible compared with the network impedance.

b) the primary and secondary currents are not affected at all by the secondary burden.

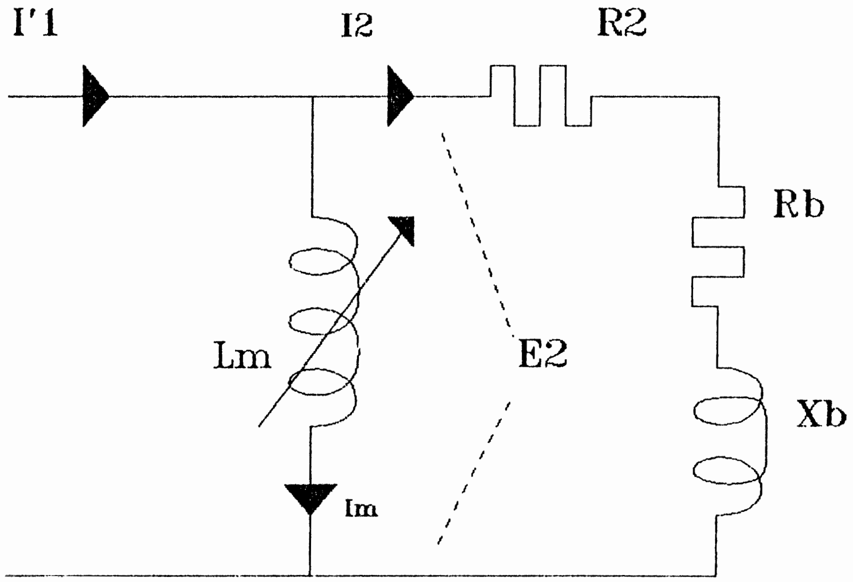


The secondary of the C.T is a continues ring core wound with uniformly distributed secondary windings. That means that the leakage reactance of the secondary winding can be neglected and only the winding resistance is taken into consideration.

MEASURING OF CURRENTS DURING STEADY STATE CONDITIONS

EQUIVALENT CIRCUIT AND MEASURING ERROR

A simplified equivalent circuit of the CT can be shown as,



From the circuit diagram I2=I`1 if Im=0 where,

I2 : is the CT secondary current

I`1: is the primary current reduced by the CT turn ratio

Lm : is the magnetizing branch inductance

$$I`1 = I1 \frac{N1}{N2}$$ where,

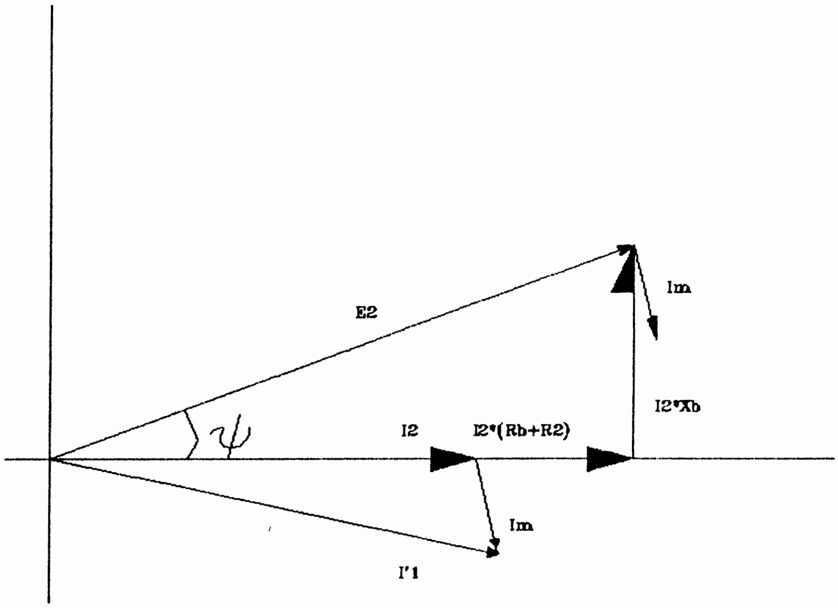
Im : is the magnetizing exciting current.

N1 & N2: are the CT primary and secondary turns numbers respectively.

However a part of I`1 is exhausted by the core as (Ie). The secondary current in actual is,

I2 = I`1 - Im (error)

with the secondary opened. All the primary current will pass through the magnetizing brunch which may cause total damage to the C.T.



ERROR

The error in the reproduction will appear both in amplitude and phase. The error in amplitude called <u>current or ratio error</u> and the error in phase is called <u>phase error or phase displacement.</u> The current error is positive if the secondary current is too high and the phase error is positive if the secondary current is leading the primary.

ERROR CALCULATION

The error calculation is performed in the following four steps;

1) the secondary induced voltage E2 can be calculated as;

$$E2 = I2 * Z2$$

Z2 : is the total secondary impedance
$Z2 = R2 + Zb$ (burden)

2) the core flux density (B) then is calculated using the following equation;

$$B = \frac{E2}{4.44 * f * A * N2} * 10^{8} \quad (Web/cm^{2})$$

f : is the frequency in Hz

A : is the core area in cm^{2}

3) the magnetizing current (Im) which produces the magnetic flux density (B) can then be calculated as;

$$Im = H * \frac{Lc}{N2}$$

H : is the magnetizing force in $\left[\frac{Amp.Turn}{cm}\right]$

it is obtained from B/H characteristics of the core given by the manufacturer.

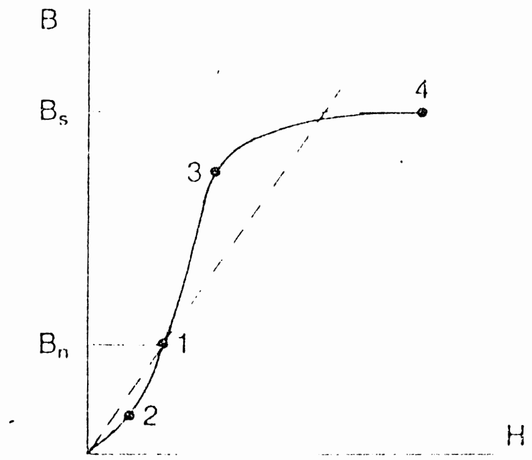
Lc : is the core length in cm.

4) from the vector diagram of the CT equivalent circuit, the angle between E2 and I2 can be calculated as;

$$\psi = \arctan \frac{Xb}{R2+Rb}$$

RATINGS

CT secondary rating has been standardized at 5 and 1 amp.

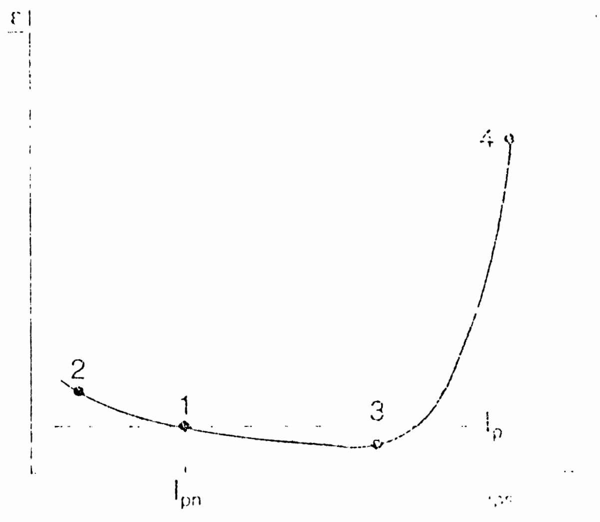


MAGNETIZING CURVE

ERROR vrs CURRENT

The error is a function of the current. This is because of the non-linear characteristics of the magnetizing curve.

The error vrs current is shown below. The error decreases as the current increases. This goes on until the current and the flux have reached a value (point 3)(look at the same point on the mag. curve also) where the core starts to saturate. A further increase in current will result in a rapid increase of error and at a certain current (Ips) the error reaches a limit stated in the current transformer standard.



SATURATION LIMIT FACTOR

For measuring C.Ts ;Ips is the instrument security current. The ratio of (Ips) to the rated primary current (In) is called the instrument security factor (Fs).

For protective C.Ts ;Ips is the accuracy limit current. The ratio of (Ips) to the rated primary current (In) is called the accuracy limit factor (ALF).

The both saturation factors are practically the same. The normalized values of those factors are 5,10,15,20,and 30.

MEASURING OF CURRENTS DURING TRANSIENT CONDITIONS

During transient conditions, the fault current consists of A.C short-circuit current and a D.C,

$$If= Io + I1 + I2 + \ldots\ldots + In \quad \text{where,}$$

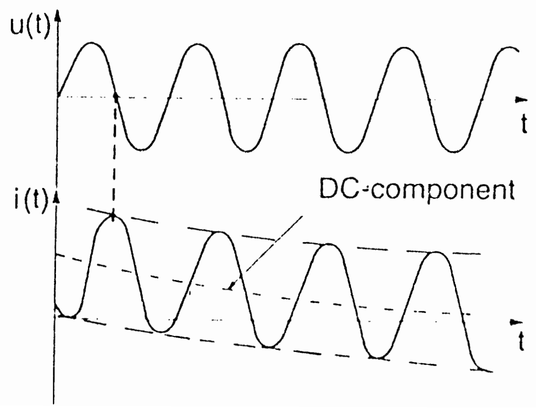
$$In= A_n * \sin (nwt+\theta) \quad \text{(nth harmonic component)}$$

The voltage and short-circuit current transient waveforms are shown below. The time before the D.C component runs out depends on the time constant (Tp) of the network;

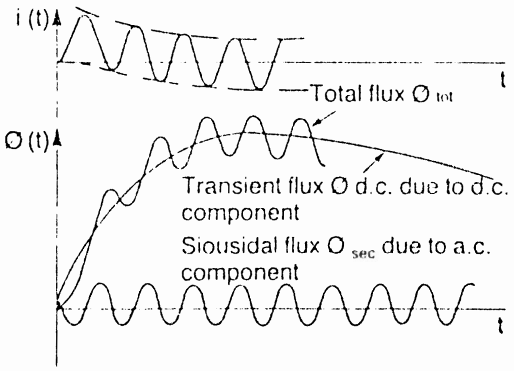
$$Tp = \frac{L}{R} \quad \text{where,}$$

L & R : are the network inductance and resistance respectively.

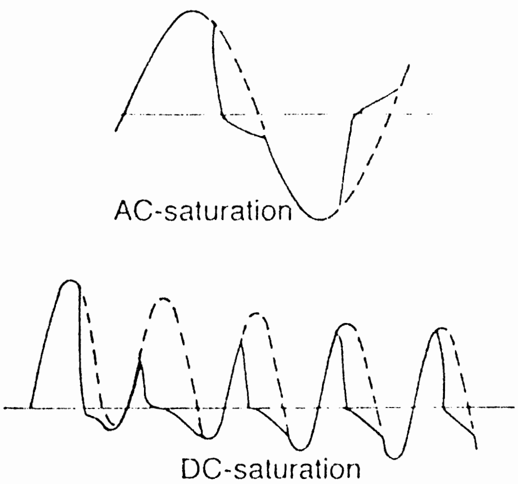
100-360 kV >>>>> Tp=up to 100 msec. (typically 50)
380-500 kV >>>>> Tp=up to 150 msec. (typically 80)



Both A.C and D.C components cause the C.T to saturate within (5) msec. Below, the flux development in the C.T core and the effect of the D.C component of the primary fault current on the produced flux is shown. Typical distorted secondary currents due to C.T A.C and D.C saturation are shown also.



Effect d.c. component of primary fault current on flux demands of CT core.



Distortion in secondary current due to saturation.

VOLTAGE TRANSFORMERS (VTs)

Voltage transformers can be split up in two groups, namely magnetic voltage transformers and capacitor voltage transformers (CVT).

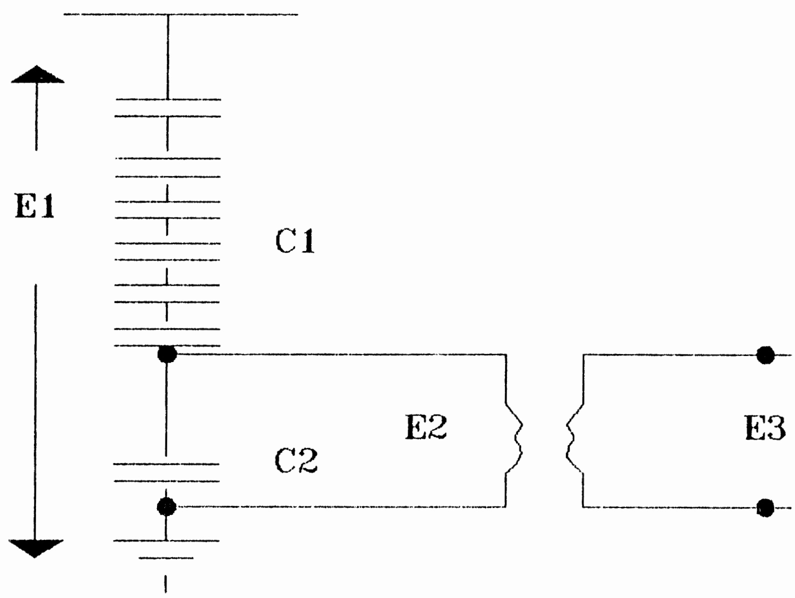
The former types are most economical up to a system voltage of approximately 145kV, while the later types are to above 145kV. The CVT has two functions, one for metering and one for power network communications (PLC).

The normal measuring range of a voltage transformer is for the metering winding, 80-120% of the rated voltage. The relay winding has a voltage range from 0.05 to 1.5 (for systems with solidly earthed neutral) or to 1.9 (for systems not being solidly earthed). The normalized secondary rated voltage is 110 v line-line.

VT CONSTRUCTION

The construction of the magnetic voltage transformer is similar to the power transformer construction. Its equivalent circuit will be illustrated in some details later.

However, the CVT consists of a capacitive voltage divider (CVD) and a magnetic intermediate transformer (IVT). The IVT voltage level is typically of 22/1.732 kV and the rated voltage of the complete CVT determines the ratio at the capactive voltage divider.



It is more convenient to make a magnetic voltage transformer (MVT) for lower voltage levels and let the CVD takes care of the high voltage levels.

The ratio of the capacitive divider is;

$$K1 = \frac{C1+C2}{C1} = \frac{E3}{E2}$$

the ratio of IVT (or MVT) is ;

$$K2 = \frac{E2}{E1}$$

the total ratio factor is therefore;

$$K = K1 \, . \, K2$$

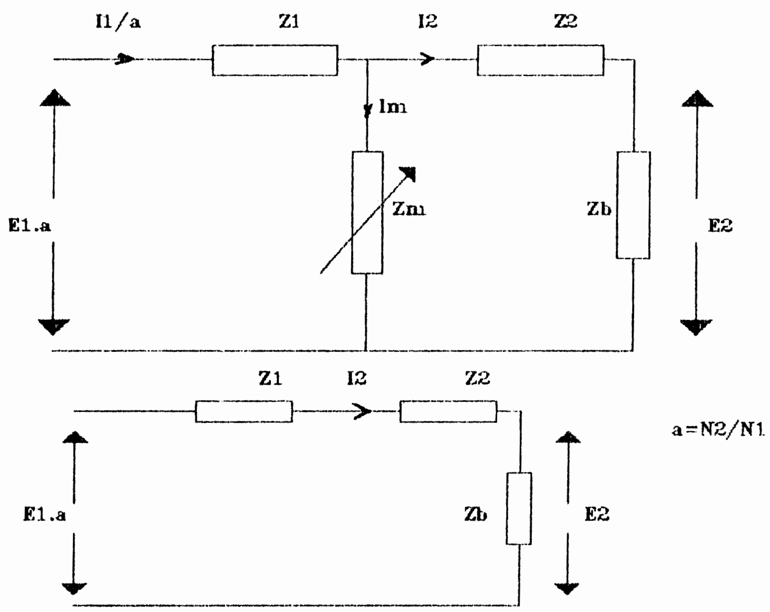
For different primary voltages only C1 differs and a standard IVT can be used for all primary voltages. The IVT also contains reactors for compensation of the capacitive voltage regulation.

MEASURING OF VOLTAGES DURING STEADY STATE CONDITIONS

The following short introduction to voltage transformers concerns magnetic voltage transformers. The contents apply, however, in general also to capacitor voltage transformers as regards accuracy and measuring errors.

EQUIVALENT CIRCUIT AND MEASURING ERROR

A simplified VT equivalent circuit referred to the secondary side is shown below. The impedance Z1 represents the primary resistance and reactance, while Z2 is of the secondary. On load conditions, the magnetizing branch iductance is too high and can be neglected and the equivalent circuit becomes as shown in the last figure.



If the voltage drops could be neglected the transformer should reproduce the primary voltage without errors and the following will be correct;

$$E2 = \frac{N2}{N1} E1$$

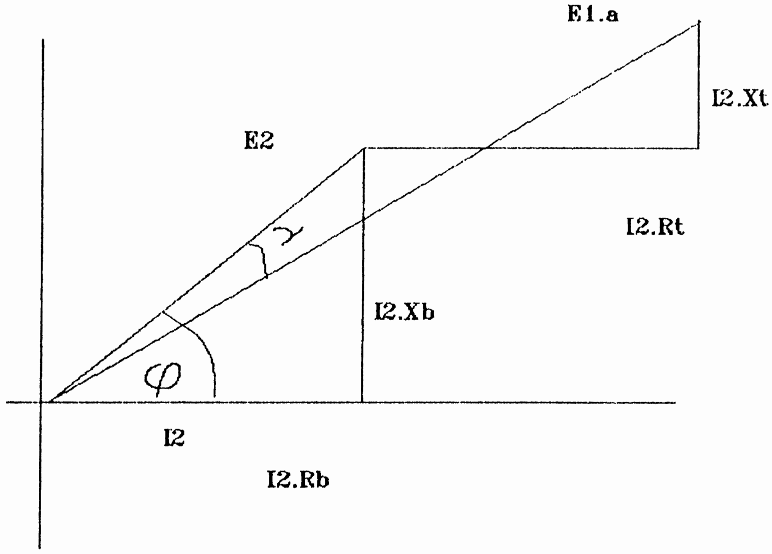
However, in reality, it is not possible to neglect voltage drops in the winding resistances and the leakage reactances. The primary voltage is therefore not exactly reproduced. The connection between voltages will be;

$$E2 = \frac{N2}{N1} E1 - U \qquad \text{where;}$$

E1 & E2 : are the primary and secondary voltages
U : is the voltage drop

ERROR

The error in the reproduction will appear both in amplitude and phase. The error in amplitude called <u>voltage or ratio error</u> and the error in phase is called <u>phase error or phase displacement.</u> The voltage error is positive if the secondary voltage is too high and the phase error is positive if the secondary voltage is leading the primary.



ERROR CALCULATION

The load-voltage drop (U) is calculated the last equivalent circuit as;

$$U = \frac{N2}{N1} \cdot E1 \cdot \frac{Zt}{Zb+Zt}$$

$$= \frac{Zt}{Zb} \cdot E2$$

The voltage drop expressed in percent of E2 as

$$U = \frac{Zt}{Zb} .100 \%$$

The resistive and reactive components of U are

$$Ur = \frac{Rt}{Zb} \cdot 100\ \%$$

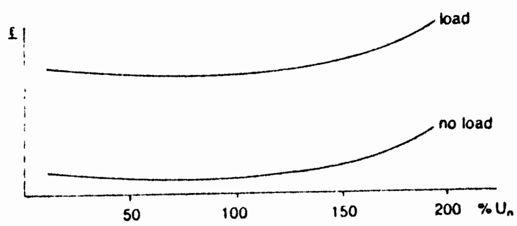
$$Ux = \frac{Xt}{Zb} \cdot 100\ \%$$

The phase angle between the I2 and E2 is;

$$\phi = \operatorname{arct}\left(\frac{Xb}{Rb}\right)$$

ERROR vrs VOLTAGE

The errors vary if the voltage change. This variation depends on the non-linear characteristics of the exciting curve. The variation of errors is small even if the voltage varies within wide limits.



MEASURING OF VOLTAGES DURING TRANSIENT CONDITIONS

TRANSIENT RESPONSE FOR CVTs

When a primary short-circuit occurs, the discharge of energy stored in the capacitve and inductive elements of the transformer will result in a transient voltage oscillation on the secondary side. This transient is normally a combination of one low frequency oscillation of 2-15 Hz and one high frequency oscillation that can lie between 900 to 4000 Hz. The high frequency part is damped out within 10 ms. whereas the low frequency part stays longer. The amplitudes of the transients are determined by the phase angle of the primary voltage at the moment of the short-circuit. Higher capacitance gives lower amplitude on the low frequency oscillation.

The secondary voltage must not be higher than a specified value at a certain time after the short-circuit. IEC specifies a secondary amplitude value not higher than 10% of the secondary voltage before the short-circuit within a time equivalent to one period of the rated frequency.

TRANSIENT RESPONSE FOR MVTs

In the magnetic voltage transformer only the fast high frequency oscillation laps occurs. The dominating low frequency laps in the CVT will be missing since there are no capacitors in the magnetic voltage transformers.

CHAPTER (LECTURE) THREE

TRANSMISSION LINE PROTECTION

"TRANSMISSION LINE PROTECTION"
LEC. #3

CONTENTS

TRANSMISSION LINE PROTECTION

Protection of transmission lines can be classified into two types according to the type of signals used;

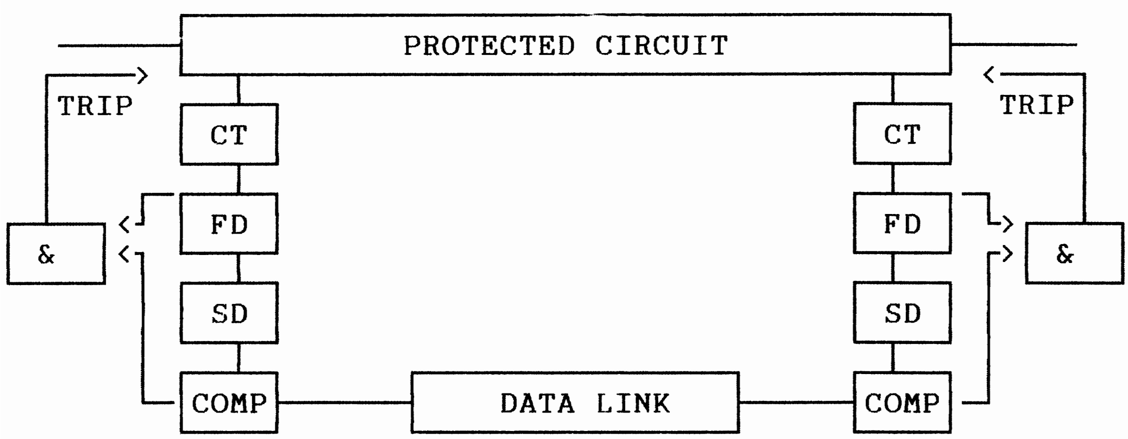
1) differential protection.
2) distance protection.

Differential protection

A differential protection scheme compares signals quantities derived from the input and output currents of the protected circuit. The basic of operation is that for all healthy system and through fault conditions these quantities balance and protection is quiescent, whist for internal fault conditions within the protected circuit the balance is disturbed and the protection initiates breaker tripping.

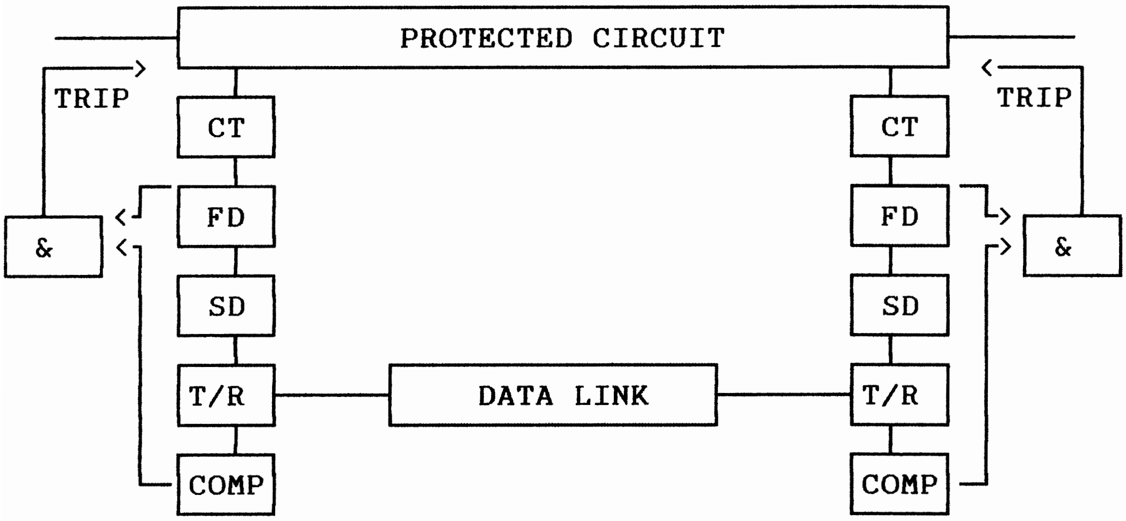
The basic types of differential protection schemes are;

1) pilot wire protection.



CT : CURRENT TRANSFORMER
FD : FAULT DETECTOR
SD : SUMMATION DEVICE
COMP : COMPARATOR

2) phase comparison carrier protection.



CT : CURRENT TRANSFORMER

FD : FAULT DETECTOR or starting relays are provided to detect the presence of system faults fulfil two basic functions;

a) provide a second line of defense ensuring that undesired tripping of the protected circuit cannot occur under normal circuit loading conditions when there is a communication channel failure.

b) they are required to control the comparison function in cases where continues comparison is not possible either because statutory regulations do not permit it, or because the communication link is normally used for some other function (e.g. telephony).

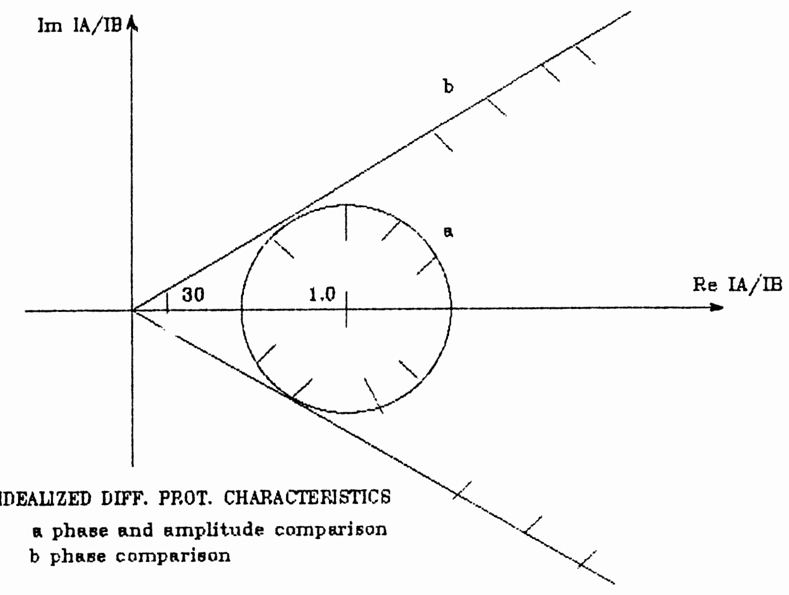
SD : SUMMATION DEVICE . The basic function is to provide a single phase relaying signal quantity at a suitable current level. It is also to provide isolation between current transformer and comparator circuit.

COMP : COMPARATOR

T/R : TRANSMITTER / RECEIVER

The idealised characteristics of such schemes are shown below. They illustrate the boundary of two types of characteristics plotted on the complex current plane in terms of the effective ratio of outputs from the summation devices at the two ends of the protected line.

Practical pilot wire protection systems may have either of these characteristics or frequently a composite characteristic depending upon the operating level of the protection. In practical carrier current systems and because the amplitude information is not conserved in the relaying signal quantities, they always posses the phase comparison characteristic.

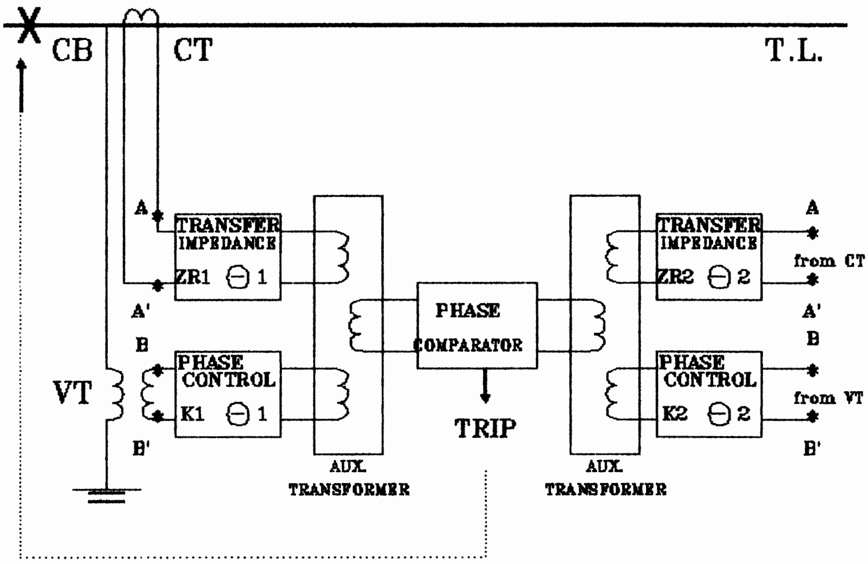


IDEALIZED DIFF. PROT. CHARACTERISTICS
a phase and amplitude comparison
b phase comparison

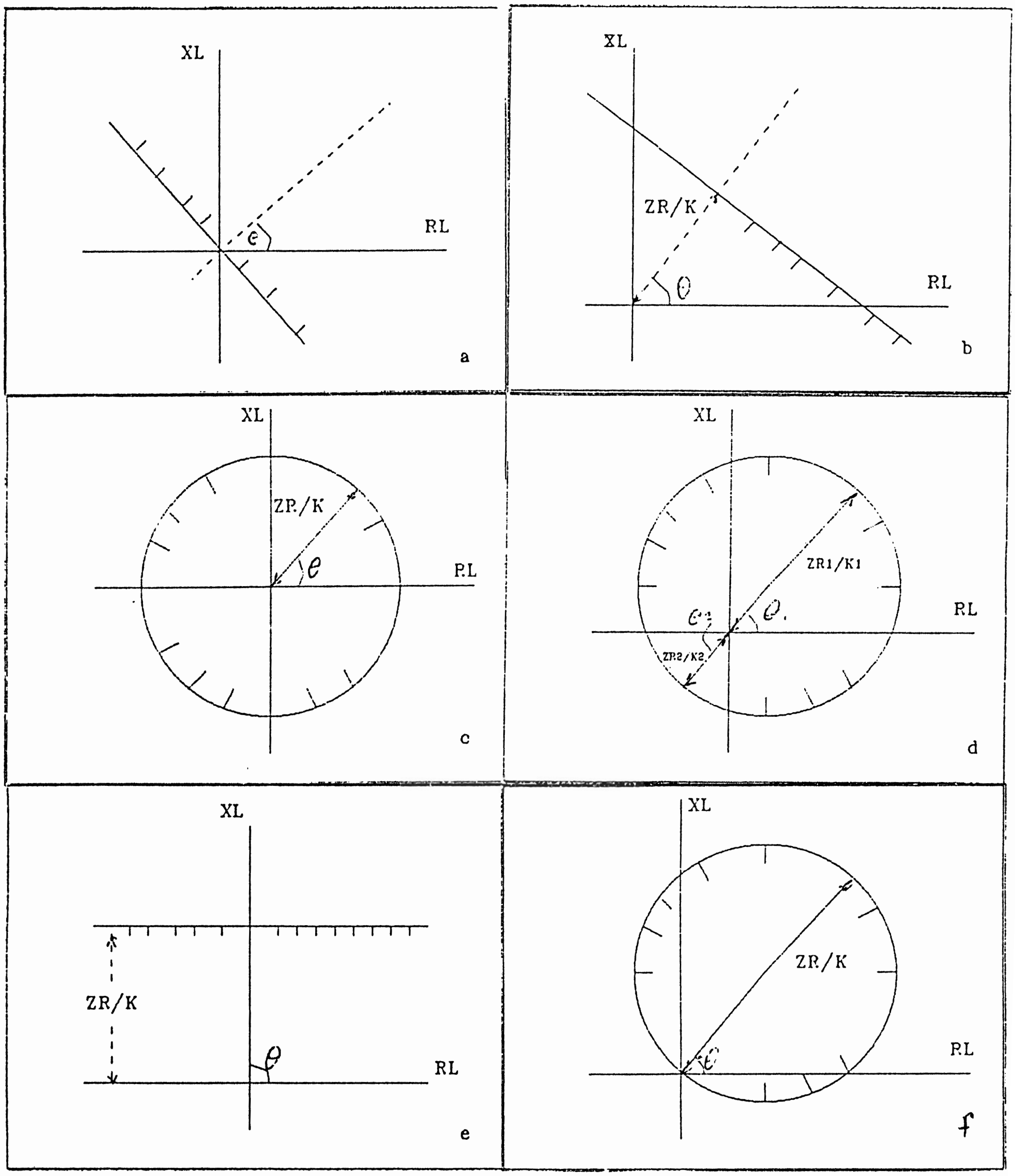
DISTANCE PROTECTION

BASIC OF OPERATION

The basic of distance relay operation is to measure the impedance to the fault location using the currents and voltages signals collected at relay location. The distance can be recognized then since it is proportional to the line impedance. Operation takes place if the measured distance is within the protected zone. In selecting suitable comparator characteristics to provide an overall distance protection scheme, consideration must be given to the requirements required upon the protection, by the power system, particularly with respect to the achievement of adequate discriminating margins between internal fault conditions on the one hand and external fault and healthy system conditions on the other. Below, the basic phase comparator schematic and the derivation of signal inputs to provide the different characteristics are shown.



BLOCK DIAGRAM OF 2-INPUT
PHASE COMPARATOR DISTANCE PROTECTION



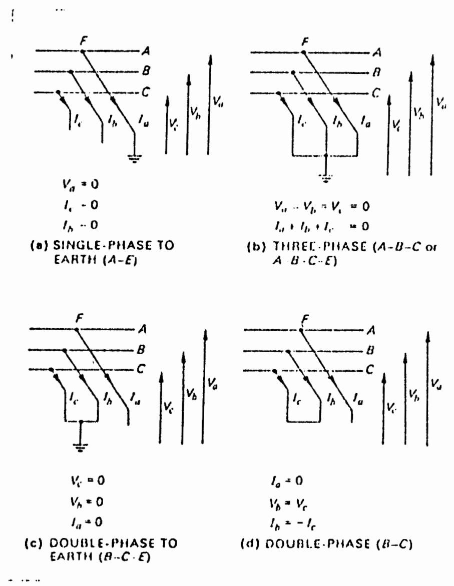
a) Directional	$S_1 = K V_L$		$\angle \theta - \phi$
	$S_2 =$	$Z_R I_L$	$\angle \theta - \phi$
b) Ohm	$S_1 = -K V_L +$	$Z_R I_L$	$\angle \theta - \phi$
	$S_2 =$	$Z_R I_L$	$\angle \theta - \phi$
c) Impedance	$S_1 = -K V_L +$	$Z_R I_L$	$\angle \theta - \phi$
	$S_2 = K V_L +$	$Z_R I_L$	$\angle \theta - \phi$
d) Offset Imped.	$S_1 = -K_1 V_L +$	$Z_R I_L$	$\angle \theta_1 - \phi$
	$S_2 = K_2 V_L +$	$Z_R I_L$	$\angle \theta_2 - \phi$
e) Reactance	$S_1 = -K V_L +$	$Z_R I_L$	$\angle \theta - \phi$
	$S_2 =$	$Z_R I_L$	$\angle \theta - \phi$
f) Mho	$S_1 = -K V_L +$	$Z_R I_L$	$\angle \theta - \phi$
	$S_2 = K V_L$		$\angle \theta - \phi$

SIGNALS SELECTION DUE TO FAULTS TYPES

In general there are four types of faults;

1) single phase to earth fault.
2) three phase fault.
3) double phase to earth fault.
4) double phase fault.

Anyhow, the can be classified into earth (single phase to earth) and phase (multi-phase) faults. They are illustrated below.



Current and voltage relations in fault branch for various shunt faults

For earth faults measurements, the voltages and currents at the relaying point are the phase quantities;

currents : Ir(i1) Is(i2) It(i3)

voltages : Vr(v1) Vs(v2) Vt(v3)

For phase faults measurements, the voltages and currents at the relaying point are line voltages and the difference between the phase currents;

currents : i1-i2 i2-i3 i3-i1

voltages : v12 v23 v31

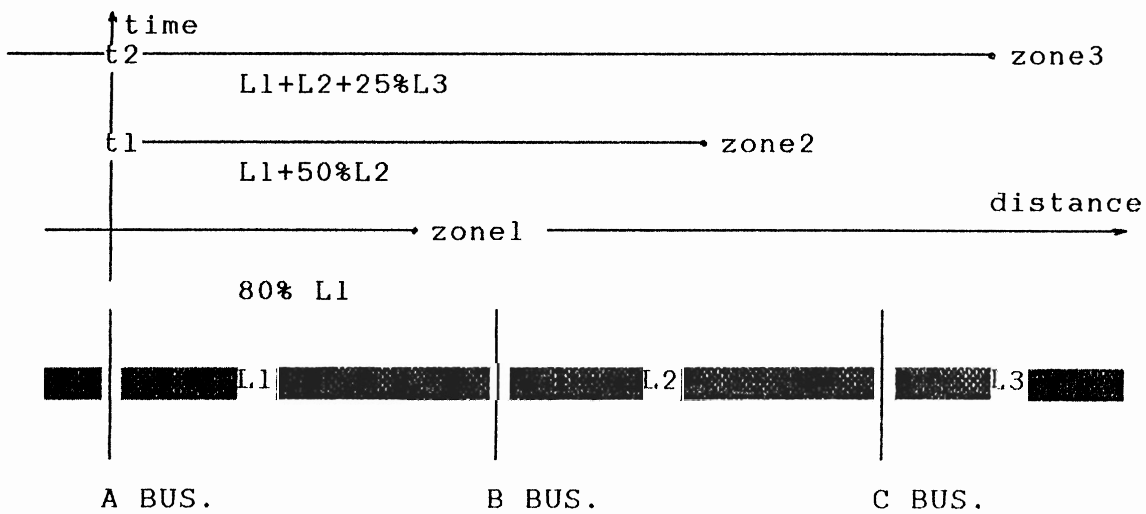
MULTI ZONES DISTANCE PROTECTION

The basic philosophy of multi zone distance protection requires the provision of high speed protection over the major portion of the protected circuit and delayed protection over the remaining part. In addition, it is normally required to provide time delayed back-up protection zones, covering the whole of the succeeding circuit and a part of the next circuit beyond.

It is common to choose a relay setting of about 80% of the protected line impedance for zone1 (instantaneous zone) of protection. This limitation is necessary to provide an adequate margin against possible error in distance measurement which might be caused by current transients, or current and voltage transformer errors, or variations in line impedance.

As this leaves 20% of the line unprotected, it is necessary to extend the reach of the measuring relay to cover all faults within the protected line, at the same time maintaining system discrimination. This is achieved by extending the reach of the relay from zone1 to zone2 so that it covers the whole of the protected line , plus 50% of the next shortest line. In order to discriminate between this and the zone1 unit of the second line, a time interval is added to the zone2 reach of the first line relay. Zone2 unit operates with a time delay (t1) after fault initiation.

It is usual in distance schemes to provide a zone3 reach which is set to cover about 25% of the longest third line. Zone3 is also provided with a controlled reverse reach feature. This may provide the remote back-up protection and reverse back-up protection. Zone3 unit operates with time (t2) after fault initiation, where t2 > t1.



ZONES ASPECTS

ZONE 1

1) high speed clearance of faults within the protected circuit, ideally from both terminations.

2) high stability against tripping for all faults behind the relay location, and for those beyond the remote termination in the forward direction.

3) the ability to discriminate against through-load and power-swing conditions and against healthy-phase impedance.

4) controlled reach in the fourth quadrant of the complex impedance plane to feel the close-in arcing faults.

ZONE 2

1) time graded tripping for faults within the protected circuit and those in a selected first part of adjacent circuits in the direction of the forward reach.

2) high discrimination for faults behind the relay location and beyond the remote termination of the immediately following circuits.

3) as for zone 1 .

4) as for zone 1 .

ZONE 3

1) time graded tripping for faults within the protected circuit and ideally behind, over the whole of the immediately following circuits, irrespective of faults in-feeds at the intermediate busbar.

2) directional discrimination may not be required and a controlled reverse-reach feature may be included to give slow speed back-up protection to plant immediately behind the relay location.

3) as for zones 1 and 2.

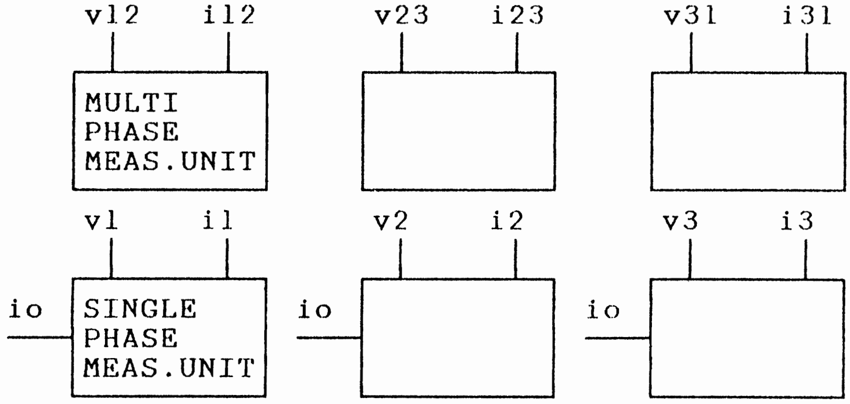
4) as for zones 1 and 2.

DISTANCE PROTECTION MEASURING SCHEMES

In a three phase transmission line, a wide range of faults can occur. Certain arrangements of relays are thus necessary to provide complete and reliable protection scheme. Those arrangements can be classified mainly into single and multi measuring schemes.

Multi Measuring Scheme

Using of six sets of relays to cover the three possible phase-phase faults and the three phase to earth faults. Other faults are covered by one or more sets of relays. Six measuring relays hence are applied for each zone so that the total measuring relays are (18). Anyhow, this number can be reduced to (12) since zone1 and zone2 relays are of the same type. The later scheme is referred to as zone switched scheme. This method involves the most equipments but it is more reliable and for that reason it generally adopted by nearly all manufacturers for all important applications.



Single Measuring Scheme

A more economical is to use one set of relays and can be switched to any one of the six measuring conditions. This phase selection is normally accomplished by overcurrent and residual current relays. The proper voltage and current are selected for each kind of faults by a complicated connection of the contacts of the fault selector. This selector also selects the zone timing too.

The economy of using the a single measuring unit has to be faced by the following disadvantages compared with the multi measuring one;

a) time delay necessary for the fault detectors to estimate the type of fault.

b) complete loss of protection if the selector contacts fail.

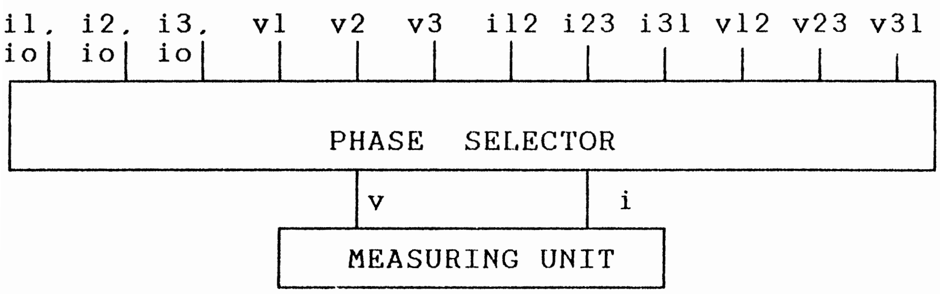
c) possible wrong tripping if the type of fault changes during operation of the relay (as it may happen due to the effect of wind on an arcing fault).

d) inaccuracy due to ununiform phases impedances (effect of unsymmetrical transposition of conductors)

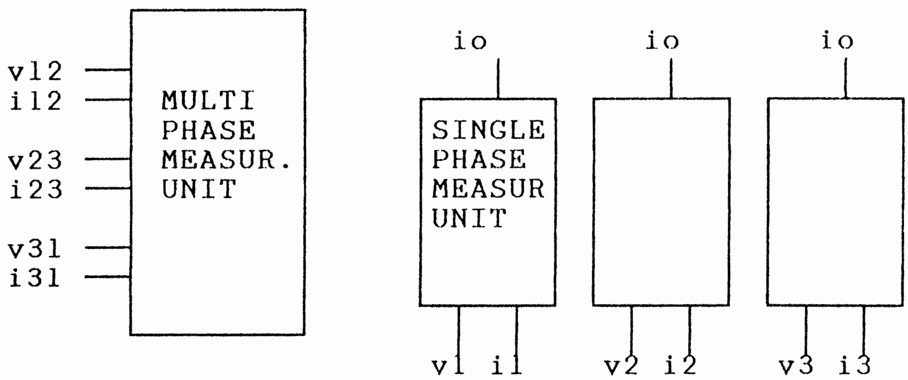
e) possible reduction in reliability due to dependance upon a number of contacts in series in the ac switching circuit.

f) there is a problem in case of double-phase to ground faults where the single measuring scheme has to select either phase-phase or phase-earth condition.

For all those reasons the single measuring systems are used for lower voltage and relatively unimportant lines.



Recently a scheme proposed and manufactured by (ABB) have been in use. It is to use a single measuring units for all multi phase faults and three single measuring unit for the phase faults. In this scheme there is no need to distinguish between single and multi phase faults.



Early, two schemes were proposed as measuring schemes. The first is to use three sets of relays which can be switched to measure either phase-phase or phase to earth quantities. The relays are normally connected for phase-phase faults and are switched to earth-fault measurement by a residual and overcurrent relays. This method is not in common use since it has the same disadvantages of the single measuring scheme and using the later then may be more economical.

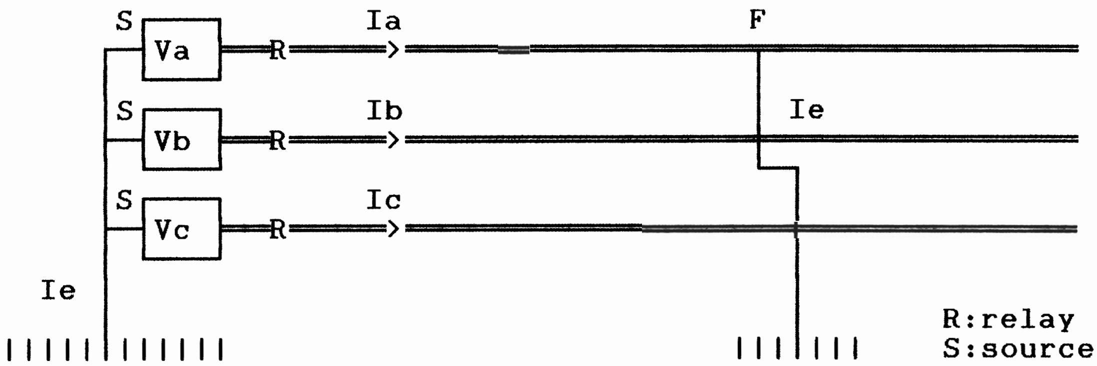
The second is to use only one voltage and current signal set, filtered as the phase sequence components of the terminal phase voltages and currents quantities, to measure the fault impedance. This method has many limitations. Its accuracy is effected by some system parameters (e.g: load currents, weak feeding problems, the phase angle between source and line impedance, and earthing of the system). This old analog solution had been not adopted for two-phases to earth faults. The idea of this method of using the symmetrical components theory in distance protection, has been modified recently using the digital techniques.

SOURCES OF ERROR IN DISTANCE PROTECTION

ERROR DUE TO ZERO SEQUENCE IMPEDANCE

When a single phase to earth fault takes place, as shown below the following is right,

$$Ib = Ic = 0$$



The voltage drop to the fault (F) is the sum of the sequence voltage drops between the relaying point (R) and the fault, that is:

$$Va = Ia1\ ZL1 + Ia2\ ZL2 + Iao\ ZLo$$ where;

ZL1, ZL2, and ZLo :are the positive, negative, and zero sequence components of the transmission line to the fault location.

The current in the fault loop is:

$$Ia = Ia1 + Ia2 + Iao$$ where,

Ia1, Ia2, and Iao : are the positive, negative, and zero sequence components of Ia.

$$Ia1 = \frac{1}{3} (Ia + a\ Ib + a^2\ Ic)$$

$$Ia2 = \frac{1}{3} (Ia + a^2\ Ib + a\ Ic)$$

$$Io = \frac{1}{3} (Ia + Ib + Ic)$$

and the earth current at the relaying point is:

$$Ie = Ia + Ib + Ic$$

and since Ib=Ic=0 then;

$$Ia1 = Ia2 = \frac{Ia}{3}$$

$$Iao = \frac{Ia}{3}$$

$$Ie = Ia = 3\ Iao$$

and as ZL1=ZL2, the last voltage drop equation can then be rewritten as,

$$Va = \frac{2Ia}{3} ZL1 + \frac{Ia}{3} ZLo$$

and the impedance of the line to the fault location is measured then as:

$$\frac{Va}{Ia} = ZL1\ (\ 1 + Ko\ )$$

$$\text{where } Ko = \frac{ZLo - ZL1}{3\ ZL1}$$

It is obvious from the last equation that if the phase current (Ia) is not compensated to the value of Ia(1+Ko), the actual measured impedance to the fault location is then of error equal to Ko.

The factor <u>Ko</u> is called <u>the residual current compensation factor</u> or <u>the earth compensation factor.</u>

In case of earth faults distance measurements the current signals and due to impedance zero sequence compensation are;

$$i1 = Ia\ (1+Ko)$$
$$i2 = Ib\ (1+Ko)$$
$$i3 = Ic\ (1+Ko)$$

where, i1, i2, and i3 are the relay currents.

ERROR DUE TO MUTUAL COUPLING IMPEDANCE

When two or more three phase transmision circuits are arranged on the same tower or follow on adjacent towers, the same right-of-way, these circuits are mutually coupled due to the magnetic induction. This phenomenon has to be considered for the fault calculations and the protection design.

MUTUAL COUPLING IMPEDANCE

The mutual impedance (Zm) of two conductors with common earth return can be calculated as;

$$Zm = \frac{\pi \, \mu o}{4} \, f + j \, \mu o \, f \, Ln \, \frac{\delta}{Dab} \qquad \text{ohm/km}$$

μo = $4 \, \pi \, 10^{-4}$ ohm.sec/km

δ = 658 SQR(Γ /f) : is the penetration depth of the earth current .

Γ = is the earth resistivity.

Dab = is the distance between the two lines.

The Zero sequence mutual impedance is defined and can be measured as;

$$Zom = 3 \, Zm$$

Example

With typical Γ =100 ohm and Dab = 20 m then;

$$Zm \approx 0.05 + j \, 0.24 \text{ ohm/km}$$

We can now estimate the induced voltage on parallel conductors Ub= Zm Ia . For 100 km and 2000 A, Ub becomes 50 kV.

This shows the high effect of the induced mutual coupling on distance measurement.

IMPACT ON DISTANCE PROTECTION

Distance relaying of phase-phase and three-phase faults is not affected so much by the mutual coupling impedance as the mutual coupling in the positive and negative sequence system is relatively weak and can be neglected for normal protection considerations. The mutual impedance is in this case usually below 5% of the related self-impedance for untransposed lines and lower than 3% for transposed lines. Anyhow, this impedance in the zero sequence system is comparatively high and may cause an error in earth faults distance relaying.

In principle this error appears due to the fact that the parallel-line earth current, [Iep = 3 Iop], induces a voltage, [Iep . Zm = Iep . Zom /3], into the fault loop. The calculated impedance by the relay is then:

$$Z = \frac{V_{ph-E}}{I_{ph} + K_o\, I_e} \qquad \text{where;}$$

$$V_{ph-E} = Z_L * [\, I_{ph} + K_o \cdot I_e + \frac{Z_{om}}{3\, Z_L} I_{ep} \,]$$

Ko : is the residual current compensation factor.
Iph: is the phase current of the line.
Ie : is the earth current of the line.
Iep: is the parallel line earth current.

If we apply a relay current and make it equal only to (Iph + Ko Ie) for residual current compensation as in the previous equation, then the measured impedance is;

$$Z = Z_L * [\, \frac{I_{ph} + K_o\, I_e + K_{om}\, I_{ep}}{I_{ph} + K_o\, I_e} \,] \qquad \text{then,}$$

$$Z = Z_L * [\, 1 + \frac{K_{om}\, I_{ep}}{I_{ph} + K_o\, I_e} \,]$$

The error in distance measurements due to mutual inductance is;

$$\text{Error} = \frac{K_{om}\, I_{ep}}{I_{ph} + k_o\, I_e}$$

From the last analysis we can conclude the flowing,

1) The error is proportional to the mutual coupling factor Kom.

2) The error increases with the parallel line earth current (Iep) in relation to the relay current (Iph + Ko Ie).

3) The relay underreaches when (Iep) is in phase with (Iph) and (Ie).

$$Zm = ZL\left[\,1 + \frac{Kom\ Iep}{Iph + Ko\ Ie}\,\right]$$

then $Zm > ZL$
where Zm is the impedance measured by the relay.

4) The relay overreaches when (Iep) and Iph/Ie have opposite signs.

$$Zm = ZL\left[\,1 - \frac{Kom\ Iep}{Iph + Ko\ Ie}\,\right]$$

then $Zm < ZL$

COMPENSATION OF MUTUAL COUPLING

In the conventional distance relays, the measuring current with earth current effect compensation is,

$I = Iph + Ko\ Ie$

The error due mutual coupling effect can be compensated by adding a relevant further term to the relay measuring current proportional to the earth current of the parallel line (Kom Iep). The measuring current becomes then,

$$\boxed{I = Iph + Ko\ Ie + Kom\ Iep}$$

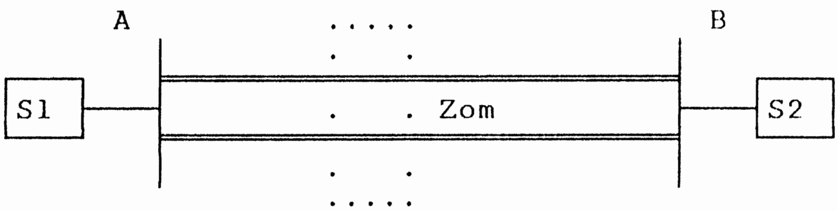
$$Ko = \frac{ZoL - ZL}{3\ ZL}$$

$$Kom = \frac{Zom}{3\ ZL}$$

TYPES OF PARALLEL OPERATION

1

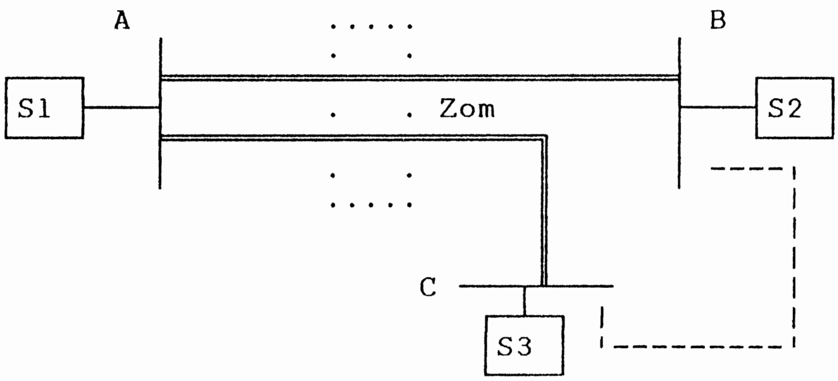
In the classical case, a double circuit or parallel line exist when two equal circuits are mounted at the same tower and connected the same substation;



From the protection point of view, the simplest case is given when both systems are connected to the same infeed sources (bus-bars) in each station. The proximity of the parallel line terminals makes it possible to apply compensation methods against mutual coupling, if necessary.

2

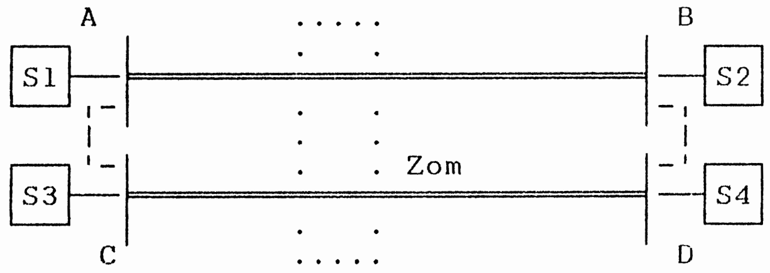
Often the case occurs when the lines are connected only partly and end at separate substations at the remote end;



This allows to apply compensation only in one substation.

3

The most unfavorable condition is given when lines run parallel but end at different substations at both line ends.



No compensation of the mutual coupling effects is possible in this case.

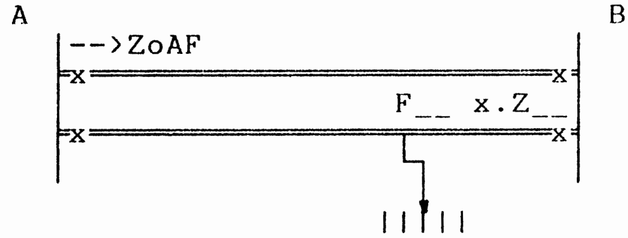
The picture becomes more complex when the parallel lines belong to different power systems and possibly also of different voltage level.

MUTUAL COUPLING COMPENSATION EFFECT ON HEALTHY CIRCUIT

With mutual coupling compensation is applied, the relays on the healthy parallel line measure incorrectly and tend to overreach. Three typical cases may be studied to illustrate that.

1

In general, double circuits are connected to a common bus-bar at both ends.

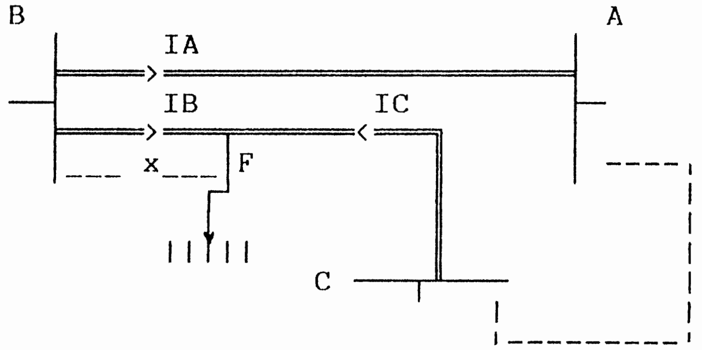


When single phase to earth fault takes place at F, the zero sequence impedance (ZoAF) measured by the relay on end A, varies from (1.54 Zo) when x=0, to (2 Zo) when x=1.

Relays of the healthy circuit always overreach in such cases.

2

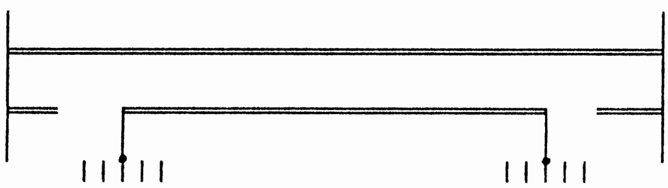
If double circuits are connected to a common bus-bar at one end only, overreaching may occur. This overeaching may be inhibited by an infeed of fault current at the common bus-bar :



In this case overreaching occurs if IoC < 2.35 IoA.

3

If one of the double circuit is taken out of service and earthed at both ends, the distance protection installed on the circuit remaining in service may overreach under external fault conditions. There are no conditions which will diminish this overreaching.



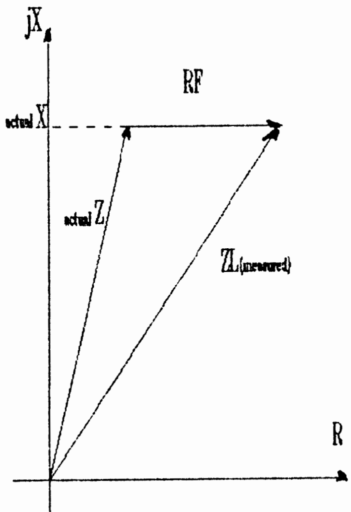
It is therefore necessary to block the distance relays or to switch-off the mutual compensation on the healthy parallel line.

One solution to detect the healthy line is to compare the earth currents of both lines (i.e; earth current scale); and to release the compensation only in the line with the higher earth current which is always the faulted lines.

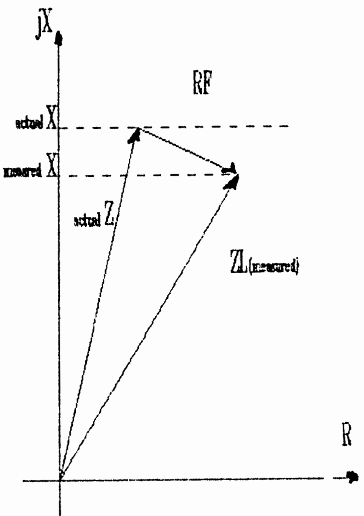
This compensation method requires a cross-connection of the earth current wires of parallel feeder bays in the substation and the additional current compensation equipment. This may be one reason why the mutual compensation is not very often applied for distance relaying. The other reason is that the problem can be normally overcome by proper zone settings or by application of command protection system.

ERROR DUE TO THE FAULT RESISTANCE

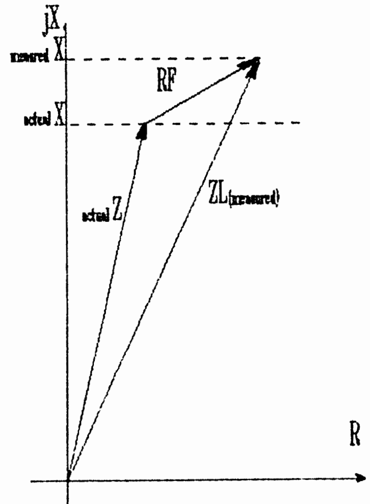
The effect of resistance at the point of fault is to introduce errors in the calculated resistance and reactance of the impedance. It introduces into the fault loop a resistance which both increase the loop impedance and causes under-reaching problem and may reduce the phase angle of the measured impedance. If the fault current is no longer in phase with the relay current. It is appearing that a limiting condition of application is encountered beyond which discriminative protection is impossible and that the critical limit vary according to the length of the protected circuit and prefault loading conditions. This is illustrated below.



(a) no error in X calculation



(b) actual X is more than the measured



(c) the actual X is less than the measured

no prefault current

(a) fault and relay currents are in phase

fault and relay currents are not in phase

due to prefault current,

(b) relay and prefault load currents are in phase

(c) relay and prefault currents are not in phase

TYPES OF THE RESISTIVE EARTH FAULT

We have in general to distinguish between two types of earth fault resistances, a fault comprises a flashover to the earth and earth fault involving direct contact with ground.

a) FLASHOVER TO EARTH FAULTS

in which the fault resistance determined by the air length using the well known formula,

$$R(arc) = \frac{8750\ L}{I^{1.4}} \qquad \text{where;}$$

L : is the arc road distance

I : is the fault current

However, if the flashover occurs to the steel tower, then the footing resistance also must be added.

The majority of earth faults are caused by the flashover of coordinate gaps. For all practical purpose, the resistance at the point of fault in those cases would not exceed 0.5 ohm and it is found that the maximum ratio of the arc resistance to the line impedance is not greater than 0.1 ohm. Anyhow, in case of adding the footing resistance, this resistance is increased to about 10 ohm.

In short transmission lines where the source/line impedance ratios are high, this will give rise to the arc fault resistance values so that the measured impedance may fall outside the protection characteristics. In long transmission lines the source/line impedance ratios are low and the arc fault resistance are of small values which does not make the measured impedance to fall outside the protection characteristics. It appears that the short transmission lines presents the more difficult case for resistive faults caused by arcing.

b) EARTH FAULTS INVOLVING DIRECT CONTACT

The second type is a fault to earth through a contact in which the fault resistance is determined by the contact resistance. Faults of such type, will have a random values of fault resistance which in most cases will have a far higher ohmic values than that encountered values for the arcing faults and in such cases the limiting conditions of application may often be exceeded. Experience has shown that values approaching 100 ohm or even higher value been encountered. It would appear that the use of a special protection characteristics shapes (e.g; inductance relays) can only provide a marginal improvement in the ability of the protection to accommodate higher faults resistance values and in consequence it is difficult to arrive at a confident assessment of the efficiency of such techniques in extending application limits. [look to the phase diagram above].

EARTH FAULT RESISTANCE CALCULATION

The only solution seems for the fault resistance problem seems to be the digital solution which takes into consideration the prefault load. In fact the fault locators can do that.

One of the digital solution proposed by the Japanese is to calculate the distance to the fault using the following equation;

$$D = D1 - B^2 \frac{D1^3}{3} \qquad \text{where,}$$

$$D1 = \frac{Im\ [\ Vs\ \ (Is")^* \ ]}{Im\ [\ Z\ Is\ (Is")^*\ ]}$$

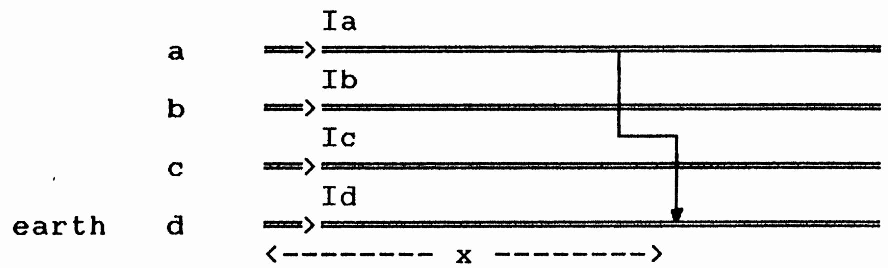
B : is Im(U).
U : is the propagation constant.
Vs: is the sending end voltage.
Is: is the sending end current.
Is": is the sending end current difference between prefault and after fault currents.
* : is for conjugate.
Z : is the line impedance ohm/km.

DISTANCE PROTECTION OF UNTRANSPOSED LINES

It is now quite common practice to leave high voltage transmission lines untransposed as the advantage gained by transposition are often considered to be too small to warrant its cost. Anyhow, the unsymmetrical untransposed transmission line cause circulating currents in a multi-circuit line configuration. Negative and zero phase sequence currents in order of 5% of line load current may appear also. This unsymmetry effect is amplified by series compensation of lines. In general it leads to certain error in fault impedance calculation.

IMPACT OF UNTRANSPOSITION ON DISTANCE PROTECTION

An overhead transmission line may leave one or more earth wires which will be bounded to the ground at frequent intervals. The voltage gradients along the ground and any earth wire will thus be the same, and they can be replaced by a single equivalent conductor having the necessary self and mutual impedances with the various phase conductors. A single circuit line can therefore be represented by the 4-conductors arrangement;



It is obvious that if a solid single phase to earth fault (earth fault) occurs on phase (a) at distance (x) along the line, the phase-earth voltage of conductor (a) at the sending end of the line is:

$$Va= X\ (Ia\ Zsa + Ib\ Zmb + Ic\ Zmc)$$

or;

$$X\ Zsa = \frac{Va}{Ia + \dfrac{(zmb\ Ib + Zmc\ Ic)}{Zsa}} \quad \ldots\ldots\ldots\ 1$$

where;

Zsa : Zaa - Zad
Zmb : Zab - Zad
Zmc : Zac - Zad

Zaa : is the self inductance (Zs) of a-line.
Zab : is the mutual inductance (Zm) of lines a-b.

Due to the unsymmetry caused by the untransposition;

a) The mutual inductances (Zm) among the wires become non-uniform so that circulating currents are generated in the various lines.

b) The zero sequence currents induced by the single phase to earth fault is no longer equal to (Ia+Ib+Ic)/3, this is because of the zero phase sequence circulating currents. It may happen that a zero phase sequence circulating current contained in the relay input current, may exceed the zero phase sequence current caused by a single phase to earth fault.

So it is not possible to rewrite the last equation so that the sound-phase currents (Ic,Ib), are replaced by the residual or zero sequence current, and therefore there will be error if schemes employing residual compensation are applied to untransposed line.

c) The zero phase sequence circulating currents may bring mal-operation when balance relaying is applied.

NORMAL PROTECTIVE COMPENSATION ARRANGEMENTS

(1) Sound-Phase Compensation

Using the sound-phase compensation equipment shown below, the zero phase sequence currents are measured as;

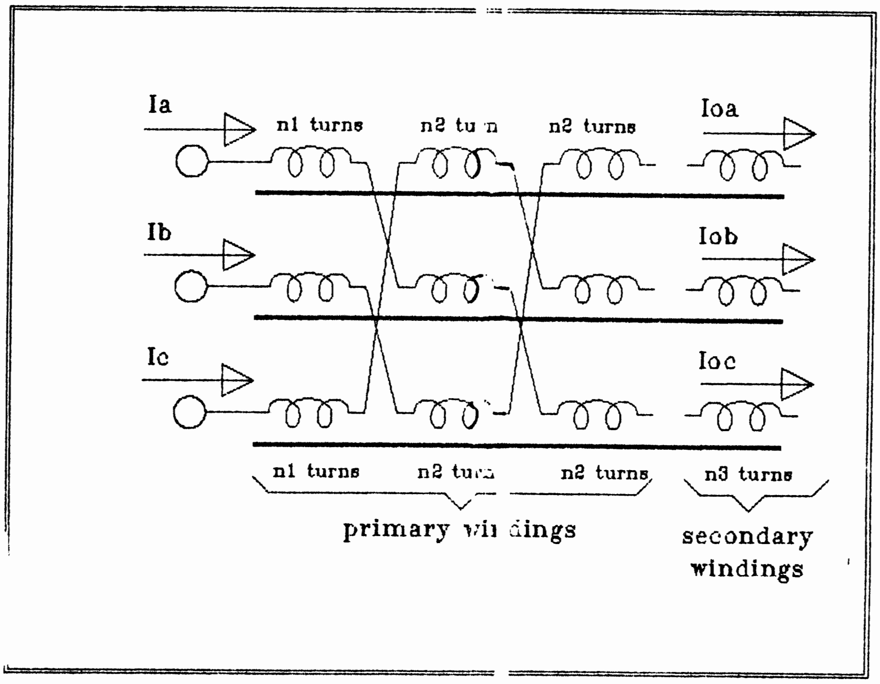
$$Iao = \frac{n1}{n3} \left[Ia + \frac{n2}{n1} (Ib + Ic) \right]$$

$$Ibo = \frac{n1}{n3} \left[Ib + \frac{n2}{n1} (Ia + Ic) \right]$$

$$Ico = \frac{n1}{n3} \left[Ic + \frac{n2}{n1} (Ia + Ib) \right]$$

$$\frac{n2}{n1} = ABS\ (Zm/Zs)$$

where Zs and Zm are the self and mutual impedances per Km of each phase respectively, <u>if the line was transposed.</u>



The distance protection measuring relays would normally be set for the transposed condition. The phase difference between Zs and Zm would almost be neglected to simplify the equipment.

(2) Residual Compensation

Using the residual compensation equipment shown below, the zero phase sequence currents are measured as;

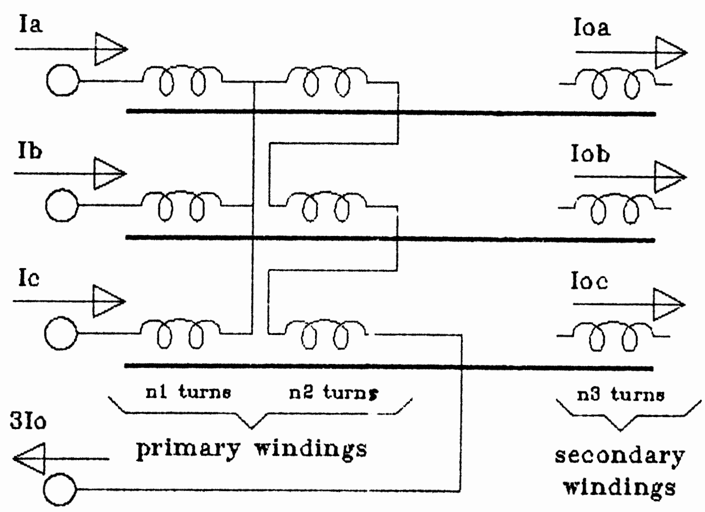
$$I_{ao} = \frac{n1}{n3} \left[I_a + \frac{3\ n2}{n1} I_o \right]$$

$$I_{bo} = \frac{n1}{n3} \left[I_b + \frac{3\ n2}{n1} I_o \right]$$

$$I_{co} = \frac{n1}{n3} \left[I_c + \frac{3\ n2}{n1} I_o \right]$$

$$\frac{n2}{n1} = \frac{Z_o - Z_1}{3\ Z_1}$$

where Zo and Z1 are the zero and positive phase sequence impedances per Km of each phase respectively.



The distance protection measuring relays would normally be set for the transposed condition. The phase difference between Zo and Z1 would almost be neglected to simplify the equipment.

While sound-phase compensation is inherently superior to residual compensation in this respect, it is the normal practice to set sound-phase compensation equipment to the values which would be required if the protected line is transposed (as it was seen above). Under these conditions , errors are also produced with this type of compensation. The actual errors are dependent on the line configuration and vary with the system operation conditions. Those errors are developed in appreciable overreaching by as much as 10% . Such an error could not be accepted with a scheme intended to operate instantaneously for faults in 95% of the protected line length.

To enable very high first zone settings to be used on untransposed lines, sound-phase compensation set to suit the individual phases should be used.

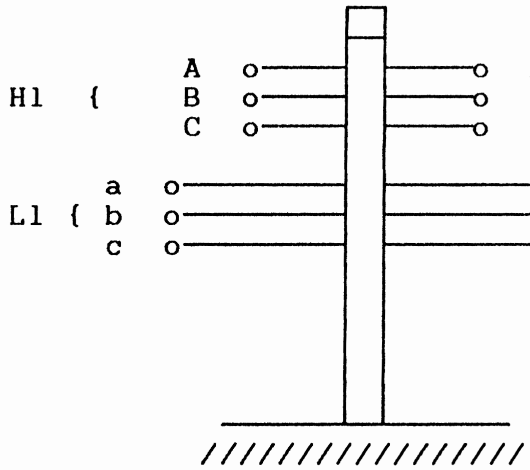
UNTRANSPOSITION OF MULTIPLE TRANSMISSION LINES ON A COMMON TOWER

Simple solution is by setting the normal sound phase compensation equipment to the values which would be required if the protected lines were transposed. Under those conditions error (due to overreaching), may be reduced but still the error in fault impedance measurement which in general depends upon the line configuration.

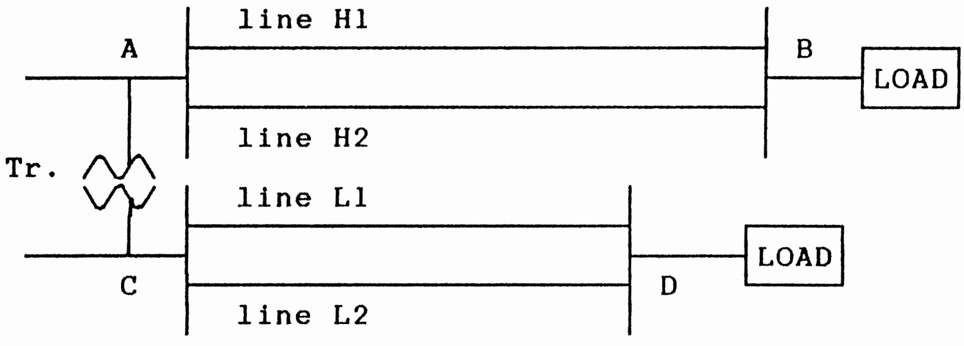
A new method which is specially suitable for the digital relay, has been proposed to prevent the relay from mal-operation due to the existence of the circulating current during single phase to earth faults.

In this method a new balance ground relaying with counter measure against zero phase sequence circulating current which is induced due to untransposition of the line, is proposed.

If we have more than two lines on a common tower in such a way;

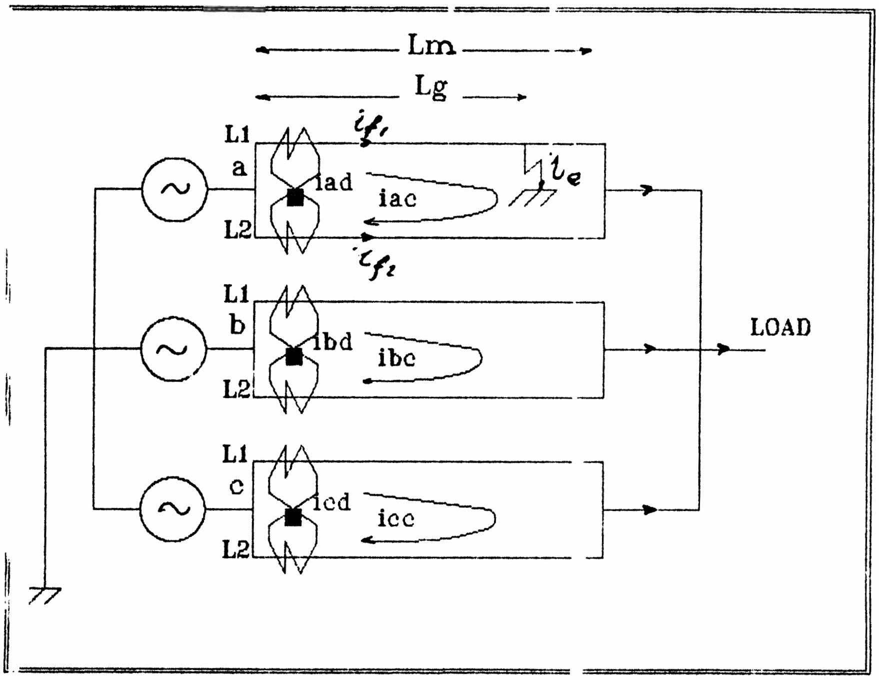


(WIRE ARRANGEMENT)



(CIRCUIT)

When H1, and/or H2, L1, and L2 are in operation, iac,ibc, and icc are circulating through Li and L2. When an a-phase to earth fault occurs on L1 under this condition, the distribution of the currents will be such as shown below.



Currents caused by the earth fault do not flow on the sound phases (b and c) wires. Differential currents between L1 and L2, iad, ibd, and icd, are measured by using CTs and as follows,

$$iad = if1 - if2 + 2\ iac \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad 2$$

$$ibd = 2\ ibc \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad 3$$

$$icd = 2\ icc \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad 4$$

Thus the zero phase sequence current of differential currents is represented as;

$$3\ iod = iad + ibd + icc \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad 5$$

$$= if1 - if2 + 2(iac + ibc + icc) \quad \ldots\ldots \quad 6$$

$$= if1 - if2 + 2{*}3ioc \quad \ldots\ldots\ldots\ldots\ldots \quad 7$$

ioc : is the zero phase sequence current caused by the load currents flowing on H1 and/or H2. Its phase and absolute value are determined by the load currents flowing on H1 and/or H2 and the wire arrangement.

From the figure above,

$$if1 = \frac{2 - n}{2}\, ie \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \quad 8$$

$$if2 = \frac{n}{2}\, ie \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \quad 9$$

where;

$$n = \frac{Lg}{Lm}$$

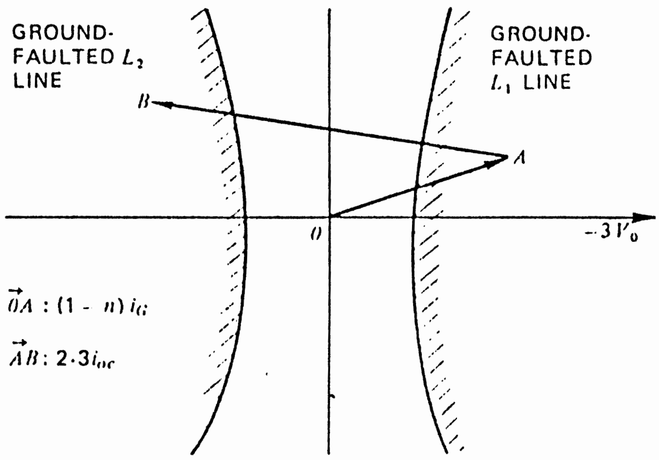
ie : is the current which flows into the earth fault point.

Substitutions 8 and 9 in 7 yields;

$$3iod = (1 - n)\, ie + 2*3ioc \quad \dots\dots\dots\dots\dots\dots \quad 10$$

In the last equation, the quantity [(1 - n) ie] is the zero phase sequence current caused by a ground fault, and the quantity (3ioc) is the zero phase sequence current caused by the load currents flowing on H1 and/or H2, and its phase and absolute values are determined by the load currents flowing on H1 and/or H2 and the wire arrangement.

The balance relaying has been adopted in most cases as a ground fault protection relaying for HV lines. The zero phase sequence current (3iod) of differential currents and zero phase sequence voltage (3Vo) are fed as inputs into a balance ground relay. For a balance ground relay, the selection of a ground faulted line is made according to the relay characteristics shown below.



Characteristics of balance ground relay

When (3ioc) component in equation 10 is zero, the operating point of the balance ground relay is at point A as shown above and the relay select L1 as the ground faulted line. Anyhow, the operating point may shift to point B due to 3ioc. Thus, the balance ground relay may sometimes select sound line L2 as a ground faulted line and generate the tripping signal to the sound line L2 by mistake.

Thus, we have to eliminate the effect of (3ioc) component in case o a single phase to earth fault. This can be done by estimating a value of (3ioc) using the sound phase circulating current with defined ratios.

In case of an a-phase to earth fault, sound circulating currents (ibc and icc) can be measured as in equations (3) and (4). We can estimate (3ioc) as follows;

$$2*3ioc' = Kb\ ibd = 2\ Kb\ ibc \quad \ldots\ldots\ldots\ldots 11$$

or

$$2*3ioc' = Kc\ icd = 2\ Kc\ icc \quad \ldots\ldots\ldots\ldots 12$$

where 3ioc` is the estimated value of 3ioc, and Kb and Kc are defined ratios.

Defining (2*3ioc`) we can compensate (2*3ioc) in equation (10) as follows,

$$3iod_{(compensated)} = 3iod - 2*3ioc' \ldots\ldots\ 13$$

In the same way, in case of a b-phase to earth fault, (3ioc) is estimated as:

$$2*3ioc' = Kc\ icd = 2\ Kc\ icc \quad \ldots\ldots\ldots\ldots 14$$

or

$$2*3ioc' = Ka\ Iad = 2\ Ka\ iac \quad \ldots\ldots\ldots\ldots 15$$

In case of a c-phase to earth fault,

$$2*3ioc' = Ka\ iad = 2\ Ka\ iac \quad \ldots\ldots\ldots\ldots 16$$

or

$$2*3ioc' = Kb\ ibd = 2\ Kb\ ibc \quad \ldots\ldots\ldots\ldots 17$$

The ratios Ka, Kb, and Kc are calculated using the measured values of the differential currents when all lines are healthy:

$$\left.\begin{aligned} iad &= 2iac \\ ibd &= 2ibc \\ icd &= 2icc \\ 3iod &= 2*3ioc \end{aligned}\right\} \text{equations 18}$$

Then by using measured values iad,ibd,icd and 3iod as in equations (18), the ratios Ka,Kb, and Kc are defined as:

$$Ka = 3iod/iad = 3ioc/iac$$
$$Kb = 3iod/ibd = 3ioc/ibc$$
$$Kc = 3iod/icd = 3ioc/icc$$

DISTANCE PROTECTION WITH TELECOMMUNICATION LINKS

One of the main objections to the use of distance protection is the fact that because of inaccuracies in the relay and in the determination of power system data, the high speed zone1 protection can only be applied to operate for faults within the first 80% of the feeder. This leaves a portion of the feeder at each end to witch can only be protected by zone2 of the remote end distance protection and unless additional equipment is used, final clearance of faults in those areas is delayed by zone2 time, the matter which is unwanted in the protection of UHV and very important transmission lines. The picture becomes more worse due to the effect of mutual inductances which causes underreaching in the protection system. This means that we would not protect only 20% of the remaining feeder but in fact up to 50%.

In general there are many ways to use the telecommunication links in distance protection which can be represented as;

DIRECT INTERTRIPPING

The simplest form of end to end signalling is to use a direct intertripping channel to signal to the other end that a fault has been detected in zone1 and therefore the other end should trip directly . The problem with this arrangement is that the interference at any time will directly trip the circuit breaker and therefore the signalling channel must be very secure and therefore slow.

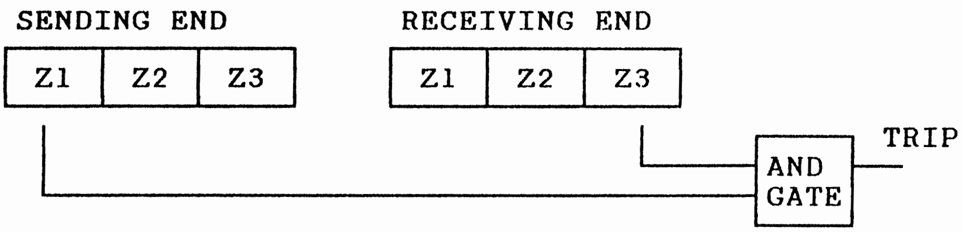
To improve the security of the end-end signalling system, it is gated with a local relay and this allows a faster signalling channel to be used because operation is dependent upon both the signalling channel and the local relay.

PERMISSIVE INTERTRIPPING

(a) UNDERREACHING INTERTRIPPING

The signal to the other end is sent by zone1 which is set to its conventional setting (80%). The received signal is permitted to trip if zone3 (or zone2 if it is available separately), has operated.

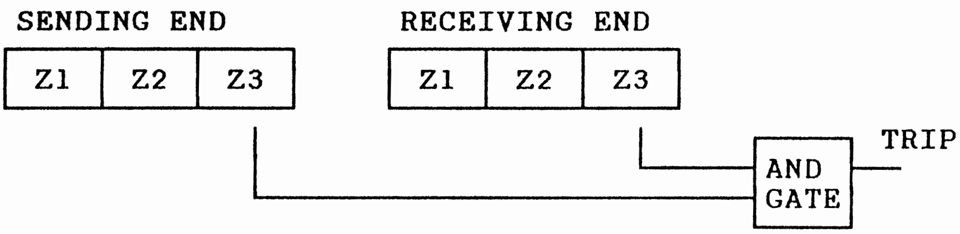
In general it is suitable for the cases when the relays overreachs for any reason (ie; some cases of the induced mutual inductance).



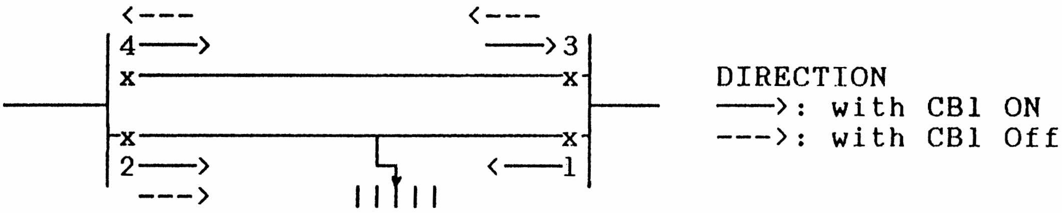
(b) OVERREACHING INTERTRIPPING

Very short lines require the use of overreaching schemes because the distance relay settings may not be low enough to match the line. Also with short lines the fault resistance, which is determined by line configuration, earthing and rated voltage, will be higher in relation to a conventional relay setting of 80% of line impedance so that an overreach scheme may be used to increase the effective fault resistance coverage.

the simplest form of an overreach intertripping scheme is when using zone3 to signal the remote end zone3 to trip.



A practical problem of overreach systems is the reversing fault problem which may arise in the parallel lines. It is when a healthy circuit in parallel with the faulted circuit, first detects the fault in one direction (relay 4) and on opening one of a circuit breaker in the faulted circuit (CB1), then detects the fault in the apposite direction (relay 3). AS a result, the healthy circuit may be tripped.



This problem may be solved by delaying the trip logic a short time to allow the establishment, or reset of the end to end signalling in relation to the operation and reset of the overreaching distance relays at the healthy line only until the faulted line is isolated.

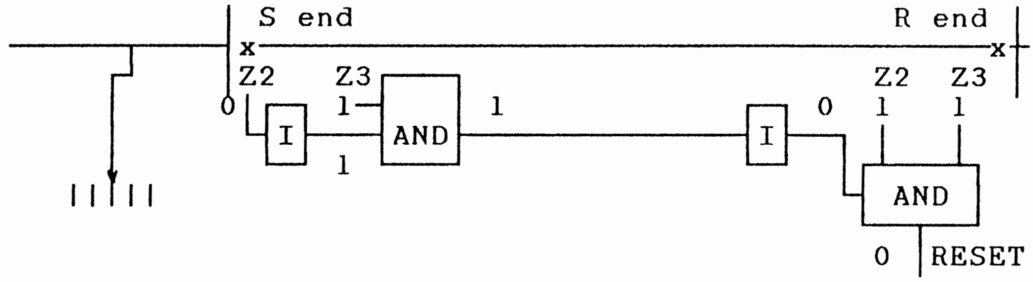
BLOCKING TRIPPING SCHEMES

It is obvious that to receive a permissive signal (whether it is an underreaching or an overreaching signal), the power line carrier equipment is required to transmit through a primary fault. Experience has shown that this is a practicable system, but doubt still remains in some minds and the alternative system of using the signal to stabilize the remote end is thus favored. These schemes are referred to as blocking schemes and generally require more complex relaying. A simple blocking scheme where the signal is sent to the other end if the local zone3 operates and zone2 does not operate, thus indicating that the fault is in the reverse looking portion of the zone3 characteristics and signalling that the overreaching zone2 at the other end is not operate.

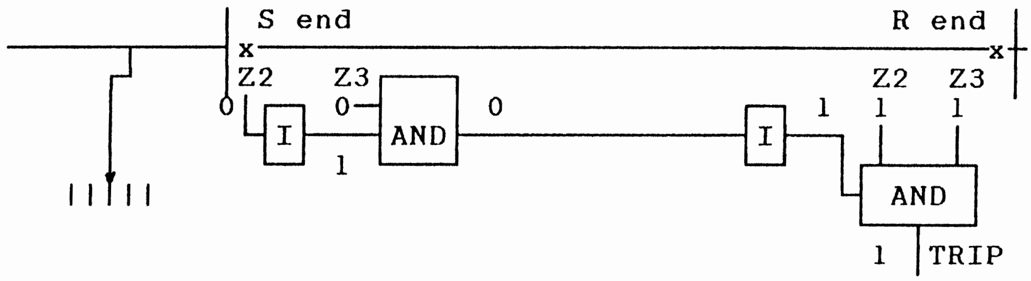
TRIP if:
at S : Z2=1 Z3=1
at R : Z2=1 Z3=1

I: inverse logic

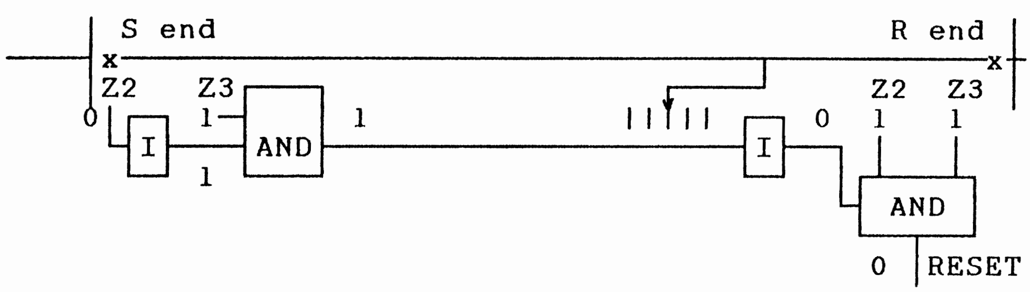
An external fault within the reach of the remote zone2 relay (as a receiving end) must be blocked by operation of the local zone3 relay (as a sending end) which will detect the fault within its reverse reach, as shown below.



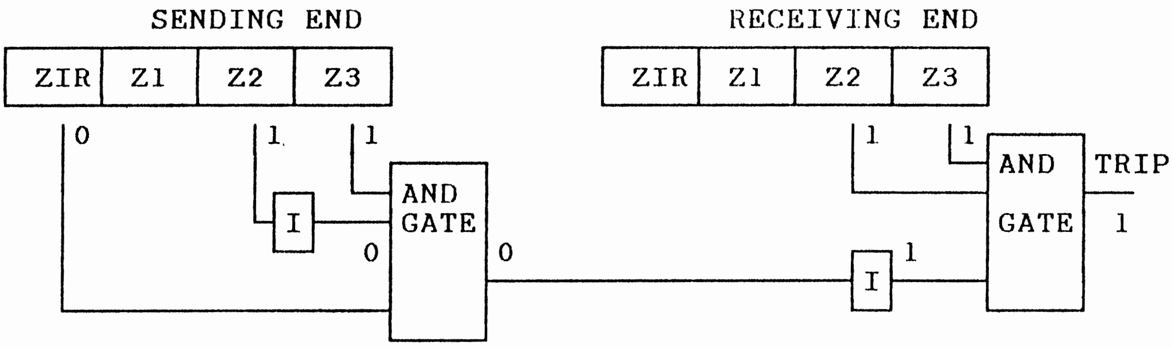
If the zone2 relay is intrinsically more sensitive than the zone3 relay, low level faults can operate the zone2 and the zone3 may not detect them within its reverse reach, thus giving mal-operation for low level external fault, as shown below.



To correct this the zone2 may be made less sensitive than the zone3 relay but this may cause blocking of an internal fault which could operate the zone3 relay and not the zone2 relay at low infeed end and thus giving a blocking signal and causing failure to trip, as illustrated below. This is the basic problem of simple blocking system.



The classical blocking scheme uses elements for blocking which can only operate for external faults, (e.g. directional elements looking into the reverse direction ZIR).



TRIP if:
at S : Z2=1 Z3=1 ZIR=0
at R : Z2=1 Z3=1 I: inverse logic

Tripping here is dependent on operation of both zone3 and zone2 which ensures that the blocking signal is more sensitive than tripping signal because the zone3 is not a sensitive element as the reverse measuring element (ZIR).

CONCLUSION

It is a basic task to select a protection equipment which fulfil the important power system requirement. Where those requirements emphasize high speed fault clearance, even at the expense of discrimination, it follows that those types of protection which provide high speed tripping over a wide range of conditions give the best performance.

It has been found that the use of overreaching conditional blocking principle provide the most acceptable form of distance protection with telecommunication links for general use.

A further advantage of using the overreaching blocking system lies in;

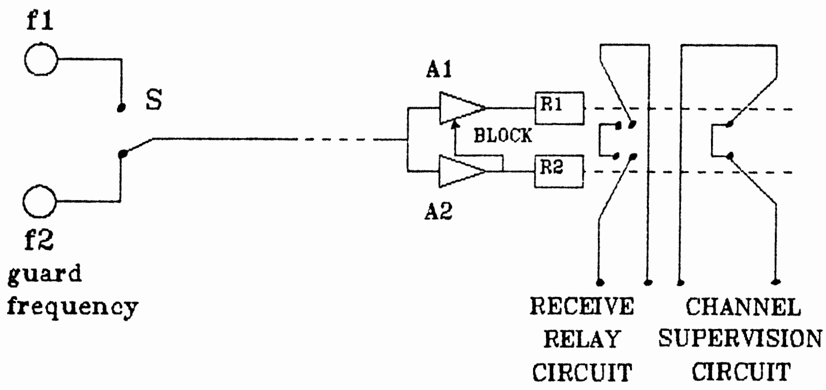
1) its ability to protect short feeders (possibly without zonel direct trip feature).

2) its ability to provide fast tripping over the whole feeder length of a circuit energized from one end only.

In this respect it provides many complimentary features to pilot protection system, which would normally be used for this application.

TELECOMMUNICATION LINKS CHECKING

There are many types of telecom. links schemes provided with checking schemes, to insure the wanted operation, under any condition. One of those schemes is the frequency-shift system. An example of a elaborate scheme is the frequency-shift signalling equipment with channel supervision.



R1 : is fast-operate fast-release
R2 : is fast-operate slow-release

With relay (S) unoperated, the guard frequency (f2) is continuously transmitted and relay (R2) is continuously energized. Contacts of this relay are closed in the receive circuit and opened in the supervision circuit. Output of (A2) amplifier blocks (A1) and thus prevents operation of (R1) by received noise. With (S) operate, (f2) is removed and replaced by (f1). The output of amplifier (A2) drops to zero, unblocks (A1) and thus permits operation of (R1). The rest of (R2) is slightly delayed thus permitting closure of the receive circuit. The supervision circuit remain effectively opened as the response of this circuit is need not be fast. Hence, unwanted operation caused by noise is only possible if the noise characteristics are such as to cancel the guard frequency (f2) and at the same time produce a frequency of (f1).

CHAPTER (LECTURE) FOUR

POWER TRANSFORMER PROTECTION

"POWER TRANSFORMER PROTECTION"
LEC. #4

CONTENTS

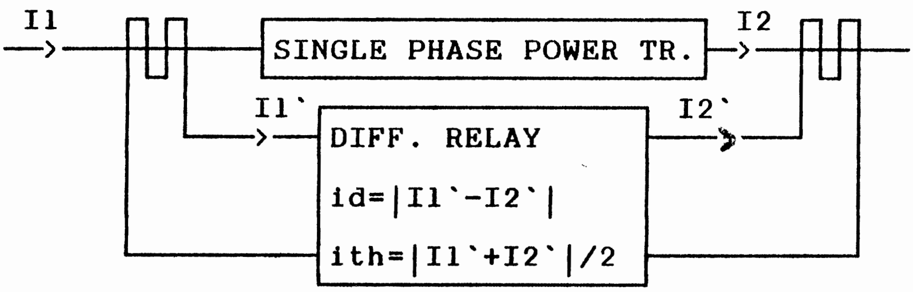
DIFFERENTIAL PROTECTION OF POWER TRANSFORMER

INTRODUCTION

The basic circuit of a single phase power transformer differential protection scheme is shown below. The basic of differential protection is that the tripping takes place due to internal fault, as the differential current (id) becomes greater than a fraction of the restraint through current (ith). Ideally, (id) is zero during the healthy operation of the transformer. Anyhow, in practice (id) may not appear only due to internal faults. There are many reasons which stand behind the appearance of power transformer differential currents. Those reasons are;

a) CT`s mismatching.
b) CT`s saturation during external faults.
c) inrush current and overexcitation phenomenon.
d) internal faults cases.

Any differential relay for power transformer protection has to be selective. That means to restraint in the former cases as well as in external fault cases, and to operate in the later case. Differential protection characteristics must be so designed to prevent the operation due to external faults and CTs saturation or mismatching. The problem of distinguishing between the magnetizing inrush and overexcitation currents and internal fault currents need special care and many solutions have been proposed to solve this problem.

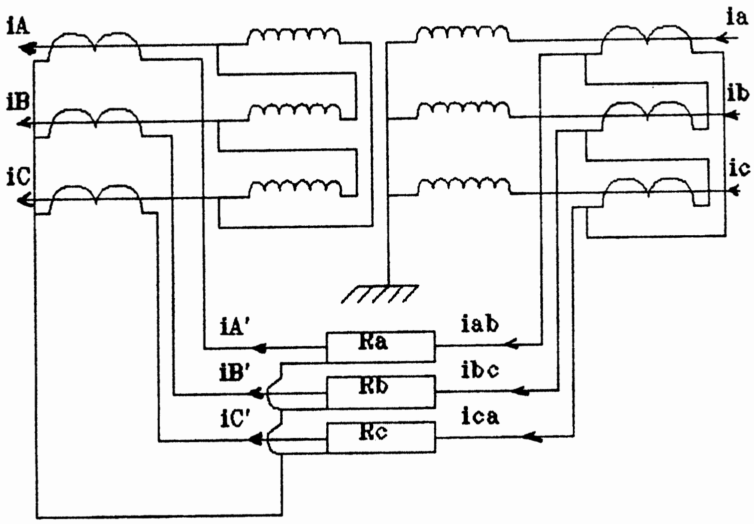


ideal healthy operation $id=0$, $ith > id$

ideal internal fault operation $id > K\ ith$

CTs SCHEME FOR DELTA-STAR CONNECTED POWER TRANSFORMER DIFFERENTIAL PROTECTION

For delta-star transformer banks, differential relays have traditionally been connected with delta connected CTs on the star side, and star connected CTs on delta side. This removes external zero sequence infeed to the star bank winding and it also introduce a (30) degree phase shift which compensates the complementary shift in the transformer currents themselves. this is illustrated below.

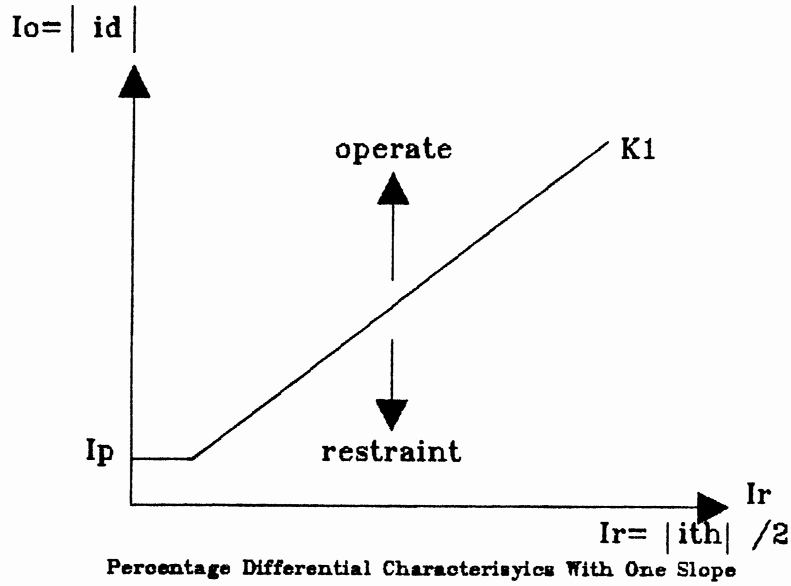


CTs Connection On The Delta-Star Power Transformer

PERCENTAGE DIFFERENTIAL PROTECTION CHARACTERISTICS

If the ratio of the transformer is not matched by the ratio of the CTs then and due to the tap changing of the transformer, differential current will appear. CTs saturation in the transformer differential system is more likely with very large external fault currents in transient and large dc components. This may cause high differential current specially if the CTs saturate on one side of the transformer only. This current is not limited by the transformer impedance. However, CTs saturation due to the ac component of the external fault in steady state is unlikely since the fault current is limited by the impedance of the transformer. Percentage differential protection characteristics must be then so designed that the relay operates only for internal faults cases.

The slope of the percentage differential protection used in most of differential relays, is the ratio of the rectified differential current to cause operation (Io), to the rectified through current to cause restraint (Ir). The percentage differential protection characteristics with one slope is shown below.



Percentage Differential Characterisyics With One Slope

The minimum pickup current (Ip) is adjustable with a range of 20% to 50% of the rated current (In). The slope (K1) is taken in the range of (20-50)% . The points to be considered in setting the relay characteristics are;

a) the slope of current required to operate under external fault conditions must be well above the slope of anticipated spill current.

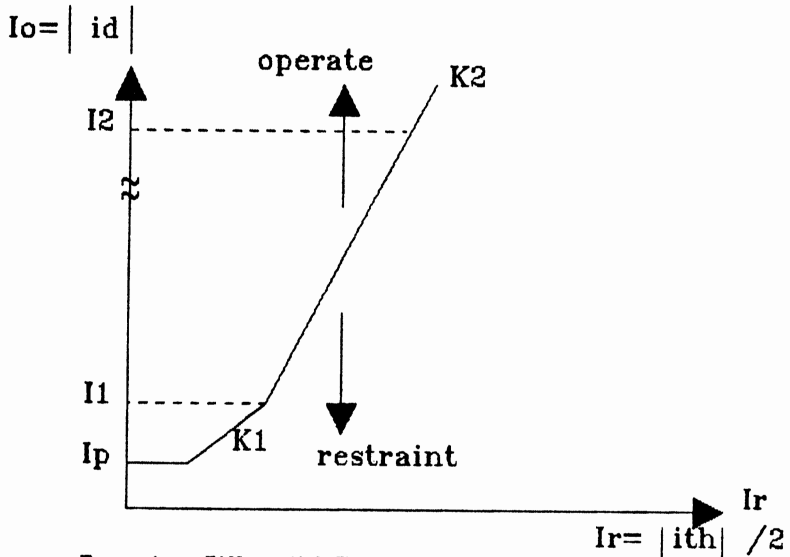
b) the slope of available operating current under internal fault conditions must be well above the slope of current required to operate.

With the wide abilities of digital techniques, the old characteristics are developed to be of two slops as shown in below. I1, is the maximum expected differential current which may appear due to the CTs error. The slope (K1) is related to the fixed minimum threshold current (Ip). Reducing (K1) and increasing (I1) will increase the sensitivity to the lower fault currents. The slope (K2) is taken to be higher than (K1) to make the relay to restrain for high external through currents. The relay will operate if the differential operating current (Io) satisfies one of the following conditions;

$$I_o \geqslant K_1 I_r \qquad \text{for } I_p \leqslant I_o < I_1$$

$$I_o \geqslant K_2 (I_r - I_1/K_1) + I_1 \qquad \text{for } I_1 \leqslant I_o < I_2$$

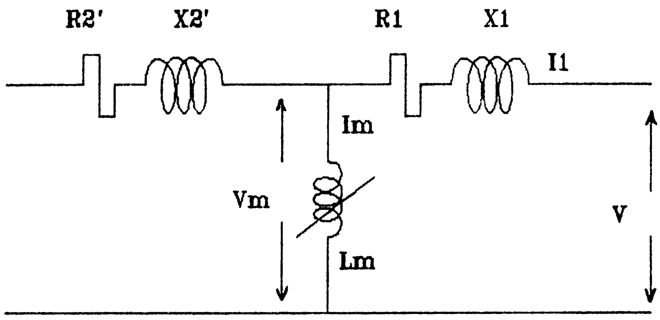
The characteristics are provided also with overcurrent protection. Instantaneous tripping takes place as (Io) exceeds a certain value (I2). I2 represents the maximum expected inrush current for that transformer multiplied by a factor of (1.2 - 1.3). In general (I2) is of (8-16) times of the rated current.



Percentage Differential Characteristics With Two Slopes

MAGNETIZING INRUSH CURRENT AND OVEREXCITATION PHENOMENON

To study the inrush current case an unloaded single phase transformer equivalent circuit (as shown below) is considered.



As the transformer is initially energized, then neglecting the winding impedance;

$$V = Vm = \frac{d\,\phi}{d\,t}$$

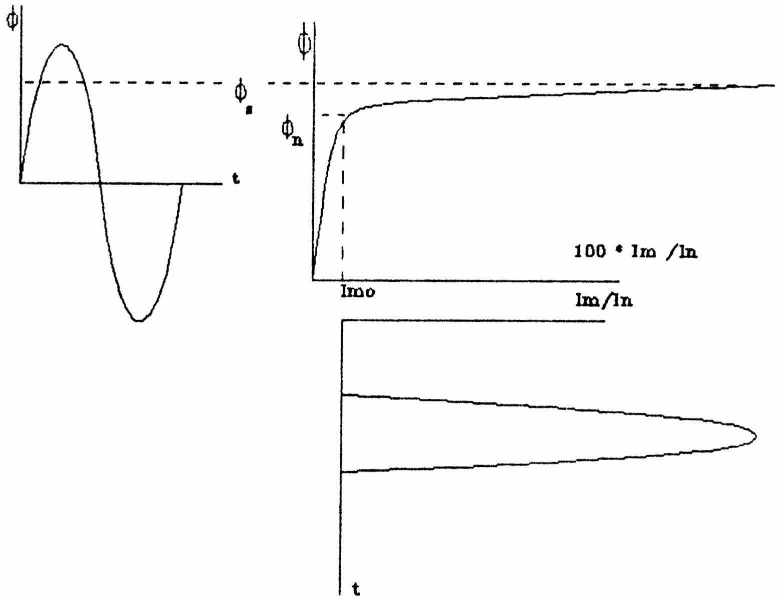
Lets consider that [V= V\` sin (wt+a)], where (a) is the switching-on angle, V\` is the peak value, and w is the system frequency. Then from the equation above;

$$\phi = \int V\,dt = \frac{V`}{w}\cos(wt+a) + \phi r$$

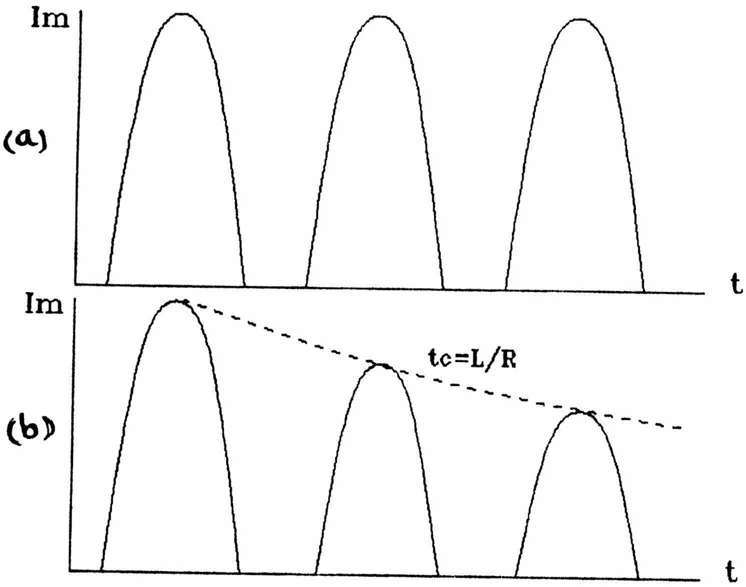
where ϕr is the residual flux and it is equal to (0.7 - -0.7) of the rated flux (ϕn). From the last equation we can deduce that maximum flux could be produced if,

a = 0 degree
ϕr= is maximum

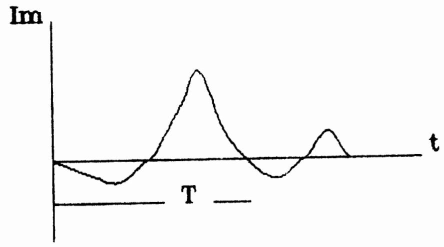
The effect of the produced flux in the core on producing the magnetizing current in the magnetizing brunch is shown below.



As the flux exceeds the rated value (ϕn), the produced magnetizing current tends to increase. It becomes of very high value compared to the no load magnetizing current (Imo). This is clear if the operation is within the saturation region of the magnetizing characteristics. The produced magnetizing inrush current waveform is shown below (a). In general, the effect of the source impedance cannot be neglected, and the effect of the dc component during the transient state on the inrush current waveform is shown below (b).



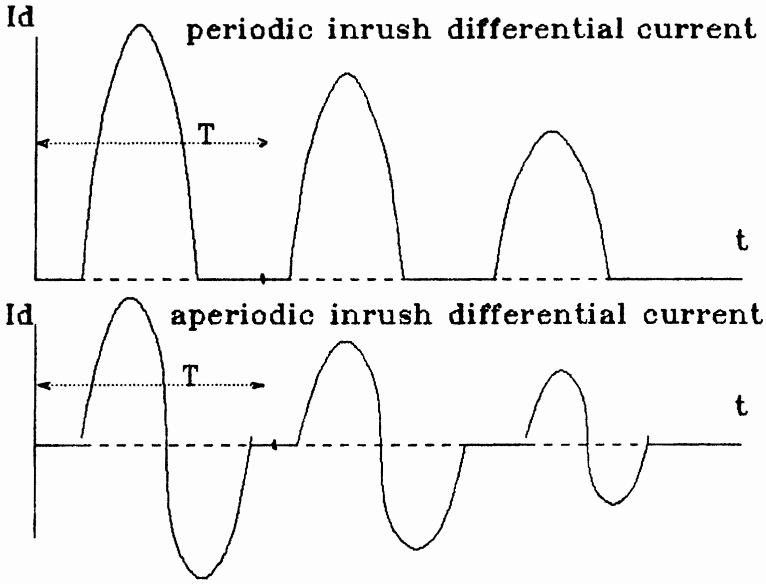
The overexcitation phenomenon is produced when the transformer terminal voltages are increased suddenly of at least 10% of the rated value, or the operating frequency is decreased suddenly. Below, typical wave forms of the magnetizing current during the overexcitation phenomenon are shown.



MAGNETIZING CURRENT DURING OVEREXCITATION

For the three-phase applications the same basic idea could be analyzed. And as the differential currents during healthy operation is proportional to the magnetizing currents in the various brunches, the differential currents may appear due to the inrush current or overexcitation phenomena and cause the differential protection to maloperate. Typical differential inrush current waveforms are shown below. In general the shape, magnitude and duration of the inrush current depend on the following factors;

1) The size of the power transformer.
2) The source impedance.
3) The magnetic properties of the core material.
4) The residual flux in the core.
5) The moment when the transformer is switched in.



DISTINGUISHING BETWEEN INTERNAL FAULT CURRENTS AND INRUSH AND OVEREXCITATION CURRENTS.

Any differential relay for power transformer protection must distinguish between internal fault and inrush and overexcitation currents, and to cause the protection to operate for the former and to restrain for the later. The fact that inrush currents are richer in harmonics than the fault currents, is the key to the design of the harmonic restrain function. The second harmonic component of the differential current is used to detect an inrush current case, while the fifth harmonic component of the differential current is used to detect an overexcitation case. All the conventional relays to protect power transformers use the harmonic restraint.

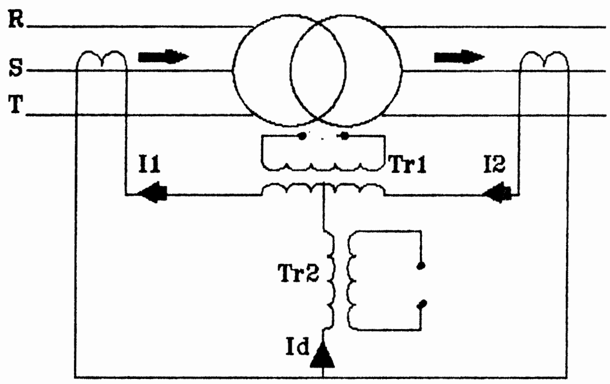
HARMONIC RESTRAINT RELAYING

The popular method of conventional harmonic relaying is to filter out the selected harmonics from the differential currents, rectify them and add them to the percentage differential restraint. Earlier relays used only the second harmonics to indicate the inrush currents. In the later relays, the fifth harmonic has been used to indicate an overexcitation case. Third harmonics restraint to indicate overexcitation cases has not been used because it is the predominant one in the output current of a saturated CT, and hence to use it for restraint is to hazard as a blocked relay during a severe fault. Second and fifth harmonic filters are used to get the harmonic component of the differential current. L-C circuits are used to filter the harmonics and semiconductors bridges are used to rectify them.

The harmonic restrained characteristics of the conventional relay have been designed so that either (15-20)% second harmonic or (30-35)% fifth harmonic of the fundamental will restrain the relay.

Conventional harmonic restraint relays are slow. They need (1.5-2) cycles to indicate a fault. This time may reach several hundred milliseconds effected by CTs saturation and high dc component of the fault current.

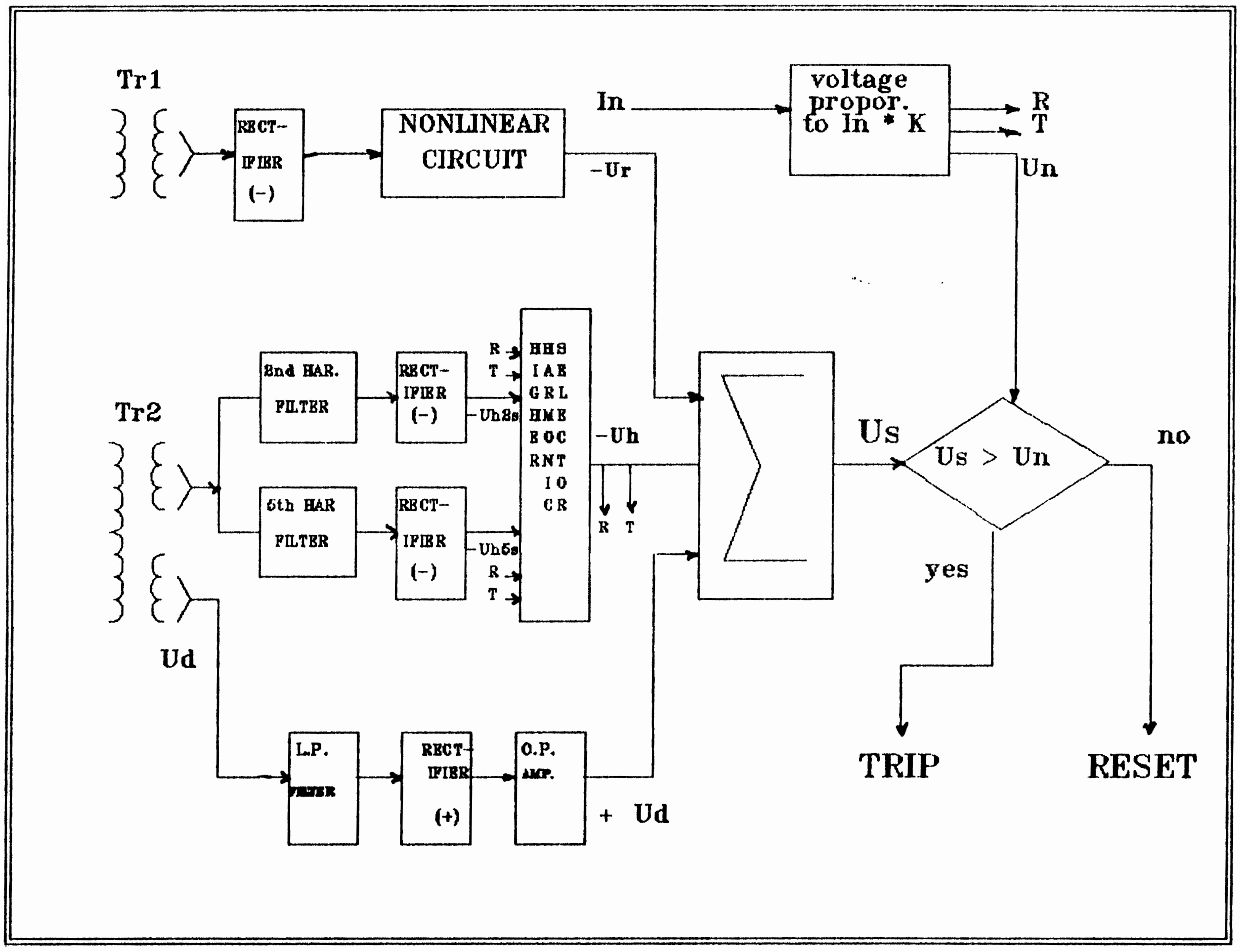
MODERN STRUCTURE OF A CONVENTIONAL HARMONIC RESTRAINT DIFFERENTIAL RELAY.



Above, a simplified circuit of the differential protection scheme for phase S of a power transformer. The input transformers of phase S, Tr1 and Tr2, are connected to the line current transformers, possibly via auxiliary CTs. The transformers Tr1 and Tr2, have secondary voltages, proportional to the currents Ir=(I1+I2)/2 and Id=I1-I2, respectively. It is obvious that I1 and I2 are the total input and output currents of phase S respectively.

Below, the block diagram of the relay is shown. The output voltage of Tr1 is rectified and via a nonlinear circuit, a negative voltage Ut is obtained. This voltage provides the differential relay with a variable through-fault restraint. The restraint is small at small through currents and large at large through currents where CTs saturation could cause large differential currents.

The differential current will run through the primary winding of Tr2. Tr2 has two secondary windings with suitably adapted load resistors. One of the windings provides the voltage that initiates operation at internal faults. This voltage passes through a low-pass filter which suppress the signals from differential currents of frequencies higher than the fundamental. The voltage is then rectified in a rectifier and composed by operational amplifiers and the positive voltage (Ud) is obtained.



The other winding of Tr2 provides voltages to two band-pass filters. Those filters are tuned for the second and fifth harmonics and provide after a rectifier a negative voltages Uh2s and Uh5s (corresponding to phase S), respectively. Uh is obtained from all three phases. The phase having the largest second or fifth harmonic current in a certain moment, will thus provide a restraint voltage to all three phases. The harmonic voltage Uh is opposite to the voltage Ud and prevents operation if the second or fifth harmonic current is more than 17 and 38 %, respectively, of the fundamental current.

The voltages Ut, Ud, and Uh are summed and supplied to a level detector. The resultant voltage Us which is a pulsating dc signal, is compared with a reference dc voltage Un. The voltage Un can be controlled with a switch on the measuring circuitry board providing settings of the restraint operate value KIn (K= 0.2-0.4 ,and In is the rated current). If the Us remains greater than Un for a time duration not shorter than 41% of the cycle (i.e, to insure the case), trip takes place due to internal fault, otherwise reset will take place.

HARMONIC RESTRAINT DIFFERENTIAL PROTECTION OF POWER TRANSFORMERS USING DIGITAL TECHNIQUES.

In the area of digital protection of power transformer, two different approaches have been proposed to estimate the harmonic components of the operating differential current to use them in the harmonic restraint task.

1) Using of digital filters for separating the harmonic components:
   in which one or a set of equations is proposed to calculate certain harmonic component.

2) Correlating the differential current waveform with a pair of orthogonal waveforms :
   in which sin, cos, odd and even square waves of one cycle duration or less, ...etc, are used as orthogonal waveforms. The differential currents waveforms are correlated with the orthogonal waves to calculate the Fourier coefficients in different ways.

THE EFFECT OF DIFFERENTIAL CURRENTS DISTORTION ON THE HARMONIC RESTRAINT RELAYING.

Harmonic restraint has been used for transformer protection. However, there are many limitations in the application of the harmonic restraint. Those limitations become of concern because they involve restrictions on through fault current magnitude, sensitivity to minor faults, speed of operation and CTs performances.

Sever fault currents cause the CTs to saturate deeply. CTs saturation cause a substantial distortion to the differential current. Those distorted currents contain higher second and fifth harmonic components. The higher second harmonic components may be of (60 %) of the fundamental harmonic component or even more during transient state saturation. This may cause in the operation of the relay up to several cycles. Anyhow, the higher fifth harmonic components which may appear during steady state saturation, may be of (40 %) of the fundamental. This high fifth harmonic components are of great risk since it may cause the relay to block because it is recognized as an overexcitation case.

Modern transformers are of small size cores to minimize the losses. This means that they are of high flux density which may be more than (1.8) Tesla. This in turn means that they are of high residual flux up to (80 %) of the saturation flux and hence very high inrush currents with very slow decaying may be expected. This in turn reduces the second harmonic components of those currents to be even less than (20 %) of the fundamental harmonic component which may lead to maloperation.

All the mentioned limitations call for new, faster, and more accurate techniques for power transformer protection. The wide door opened by using the digital techniques in power systems protection, gives the green light for that task. Recently, many approaches have been proposed using the transformer voltages as supplementary signals in transformer differential protection. Those techniques have been tested and found of higher security and of high speed of operation.

OVERCURRENT PROTECTION

Time-overcurrent relays are used on all feeding circuits to a power transformer. Their function is to back up the differential protection and the protective relays on the load side of the transformer. The overcurrent relays perform as a primary short circuit protection if no differential protection is used.

Time-overcurrent relays with an instantaneous element for high fault currents are normally used in each phase. The time-overcurrent relay is normally set for operation at about 150% of the transformer rated current. The time delay must be long enough to avoid tripping due to the magnetizing inrush current when the transformer is energized.

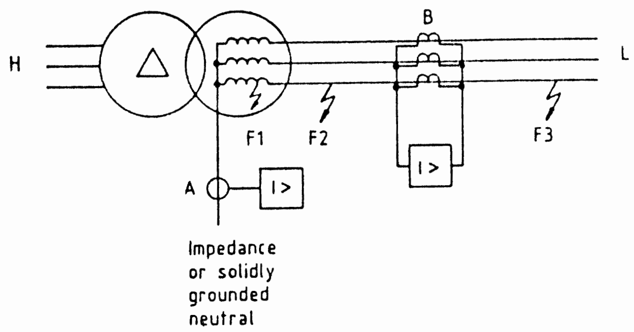
The instantaneous element has to be set about 25% above the maximum through fault current and above the maximum inrush current. With this setting, instantaneous tripping is only obtained for severe faults on the feeding side of the transformer. There can, for example, be faults on the transformer winding close to the bushing, faults in the bushing or on the circuits between the CTs and the transformer.

The relay operates late for faults on the remaining parts of the windings and for faults on the load side of the transformer if the fault current and the duration exceed the setting of the relay.

EARTH FAULT PROTECTION

Power transformers with impedance-grounded or solidly grounded neutral, can be equipped with different types of ground fault relays to protect the grounded winding.

Low-impedance residual overcurrent relays or harmonic restraint overcurrent relays can be connected according to A or B in the figure below, respectively.



Connection of ground fault overcurrent relays

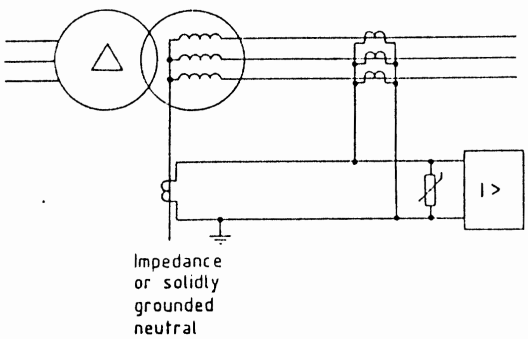
When the transformer neutral is solidly or effectively grounded and the transformer is fed from either side H or L, a fault at F1 or F2 is detected by a relay at point A. The relay at point B may also operate depending on the distribution of the zero sequence impedance in the network. A fault at F3 is detected by the relays at point A and B.

Consider the transformer fed from either side H or L and that the transformer neutral is impedance-grounded. With only one point in the network grounded, a fault at F1 and F2 is detected by a relay at point A. Fault F3 is detected by the relays at points A and B.

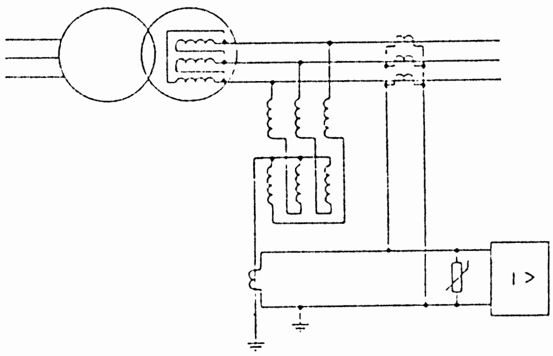
These types of overcurrent relays must therefore be delayed, or else they will operate for faults which should be taken care of by other ground fault relays in the network.

The relays also have a back up function regarding the ground fault protection of the line. They are also a slow back up for transformer differential relays in solidly grounded networks.

A restricted ground fault relay of the current differential type can only operate for faults inside the protective Zone, as shown below. The relay is sensitive and reliable and a high speed of operation is obtained.



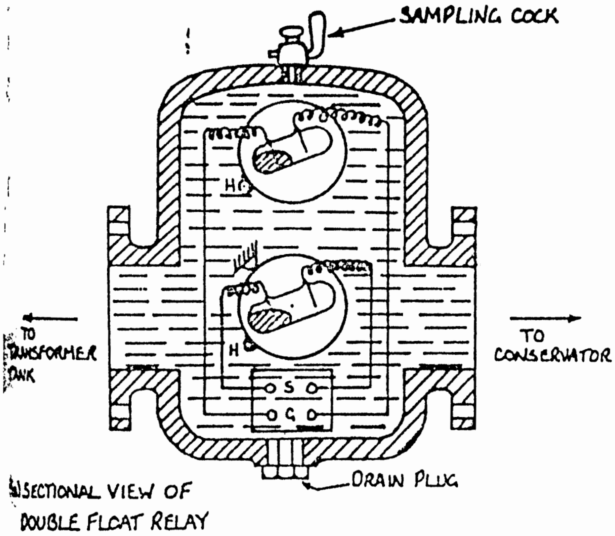
Connection of a restricted ground fault relay for a Y-connected winding.

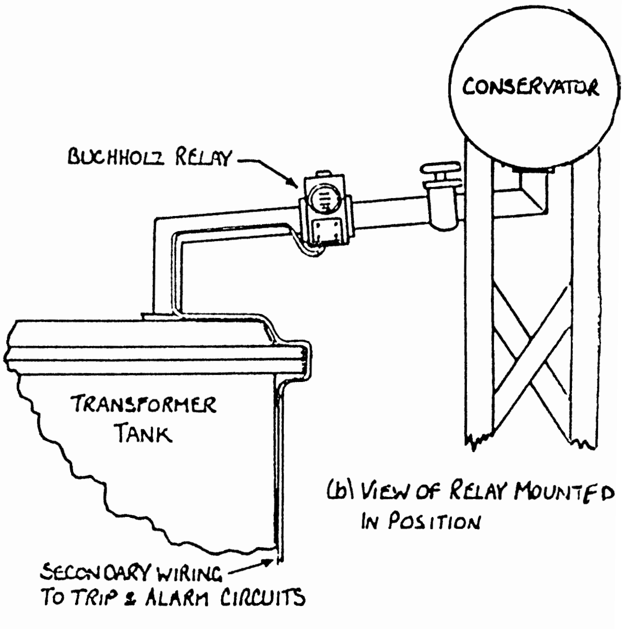


Connection of a restricted ground fault relay for a D-connected winding and a grounding transformer.

GAS DETECTOR RELAY (BUCHHOLZ RELAY)

The relay structure and its location on the transformer are shown below. Under normal conditions the Buchholz relay is full of oil, the floats are fully raised and the mercury switches are open.





This device relies upon the fact that an electrical fault inside the transformer tank will be attached by the generation of gas and, if the fault current is high enough, by a surge of oil from the tank to the conservator.

Gas bubbles due to a core fault will be generated slowly and collect in the top of the relay. As the collect, the oil level will drop in the relay and the upper float will turn on its pivot until the mercury switch closes. This is used to give an alarm.

Similarly, earliest winding insulation faults and interturn faults which produce gas by decomposition of insulation material and oil may be detected. Such faults are of very low current magnitude and the Buchholz relay is the only satisfactory method of detection.

Serious electrical faults, such as flashover between connections inside the main tank generate gas rapidly and produce a surge of oil. This causes the lower float to be forced over about its pivot, causing the lower mercury switch to close. This is arranged to trip both the H.V. and L.V. circuit-breakers.

In addition to the above, serious oil leakage will be detected initially by the upper float which will give an alarm and finally by the lower float which will disconnect the transformer before dangerous electrical faults results.

The Buchholz relay is thus a protective devise which is capable to deal with many tasks, and for certain types of faults it is the only protection available.

The operating time of the trip contact depends on the size of the transformer, the magnitude and location of the fault. The operating time can therefore vary between 0.1-0.3 sec. Thus, for severe electrical faults on large transformers, the Buchholz relay as a back-up to other faster forms of protection.

CHAPTER (LECTURE) FIVE

GENERATOR PROTECTION

"GENERATOR PROTECTION"

LEC. #5

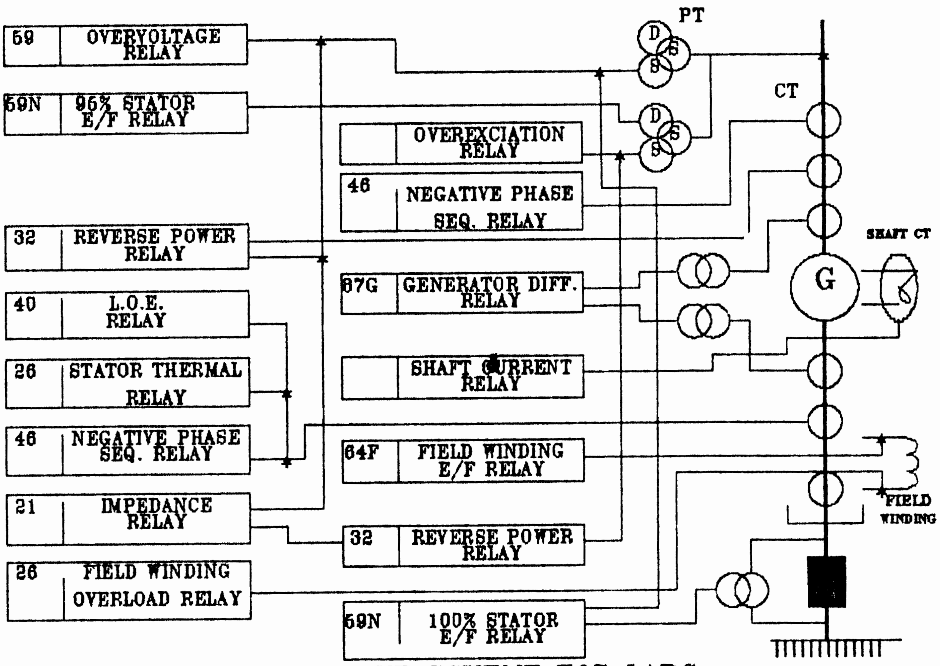
CONTENTS

INTRODUCTION

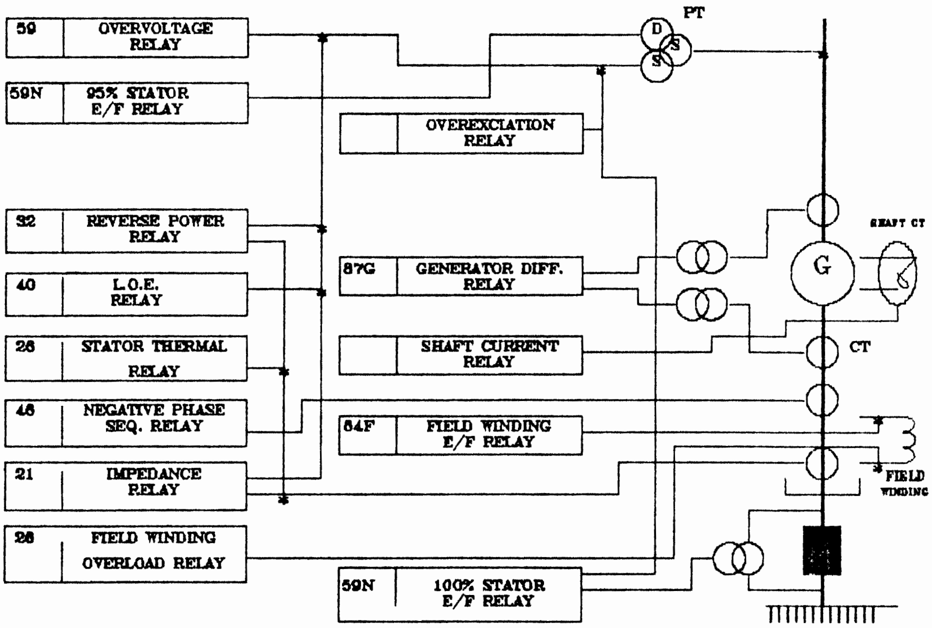
Generators are designed to run at a high load factor for a large number of years and permit certain incidents of abnormal working conditions. The machine and its auxiliaries are supervised by monitoring devices to keep the incidence of abnormal working conditions down to minimum. Despite the monitoring, electrical and mechanical faults may occur, and the generators must be provided with protective relays , which, in case of a fault, quickly initiate a disconnection of the machine from the system, and if necessary, initiate a complete shut down of the machine.

PROTECTIVE RELAY SCHEMES

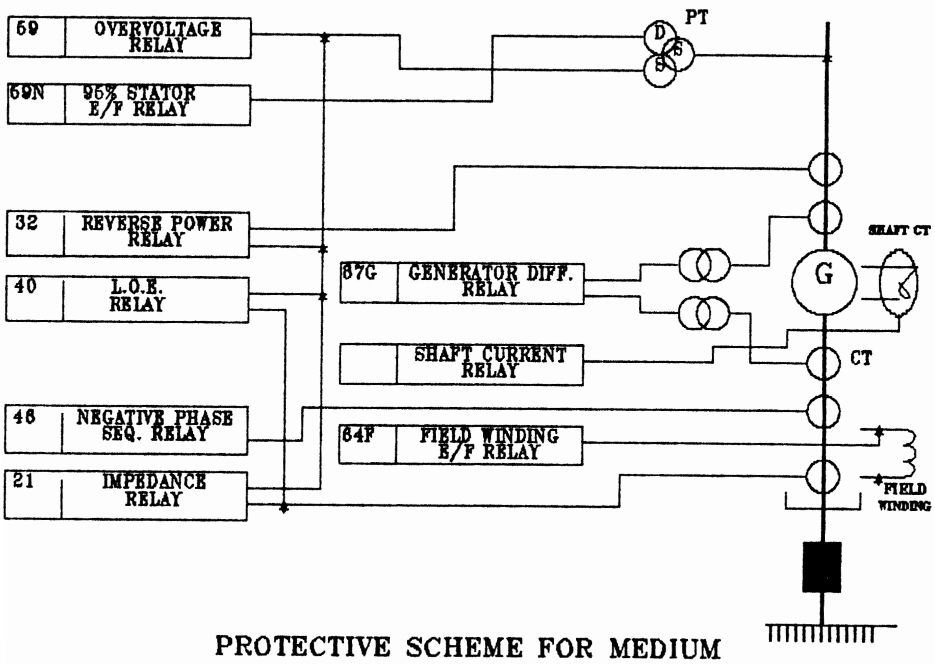
The number and types of relays to be included in a generator protective scheme depend on the size and also the system layout. As a general recommendation, the figures below show examples on connection of generator protective relay to current and voltage transformers. The numbers (59F,40, etc) used in the figures are in accordance with ANSI/IEEE C 37.2-1979.



PROTECTIVE SCHEME FOR LARG
TURBOGENERATORS > 250 MVA



PROTECTIVE SCHEME FOR LARG HYDROGENERATORS > 250 MVA



PROTECTIVE SCHEME FOR MEDIUM SIZE GENERATORS 20 - 100 MVA

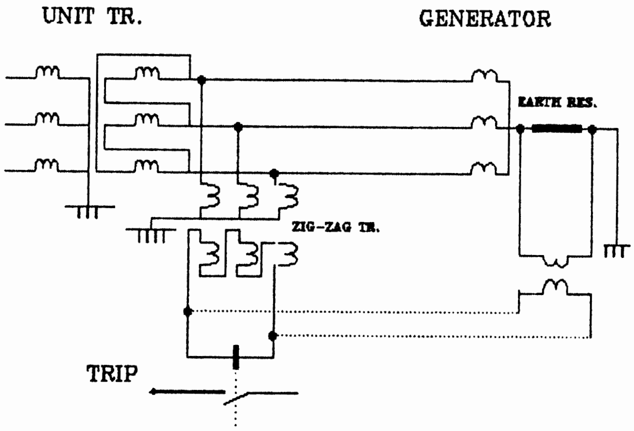
STATOR EARTH-FAULT PROTECTION

Common practice is to ground the generator neutral through a resistor, which limits the maximum earth-fault currents to 5-10 A. Using the tuned reactors those currents are reduced to less than 1 A. In both cases, the transient voltages in the stator system during periodic earth-faults are kept within acceptable limits, and earth-faults which are tripped within some few seconds will have negligible effect on the stator core laminations. The generator grounding-resistor normally limits the neutral voltage transmitted from the high voltage side of the unit transformer in case of a earth-fault on the H.V. side to max. 2-3% of rated generator phase voltage.

Short circuits between the stator winding in the slots and the stator core are the most common electrical fault in the generator. The fault is normally initiated by mechanical or thermal damage to the insulation material or the anti-corona paint on the stator coil. Interturn faults which are difficult to detect, will rapidly developed into an earth fault and will be tripped by the stator earth-fault protection.

95% STATOR EARTH-FAULT PROTECTION

For generators with unit transformer and with high impedance earthing of the neutral, a neutral voltage relay with harmonic restraint and independent time-delay is used. The relay may be fed either from a neutral voltage transformer or from the broken delta winding of three-phase voltage transformers on the generator as shown in the figure below.

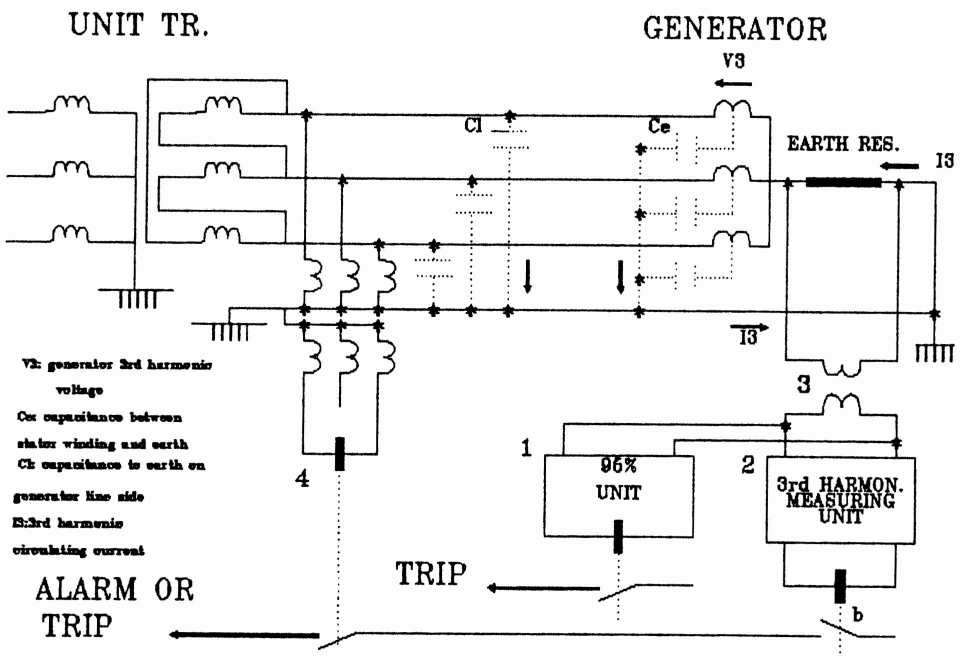


95% STATOR EARTH FAULT PROTECTION

The relay is normally set to operate at 5% of maximum neutral voltage with a time delay of 0.3-0.5 sec. With this voltage setting, it protects approximately 95% of the stator winding. It also covers the generator bus, the low voltage winding of the unit transformer and the high voltage winding of the unit auxiliary transformer.

100% STATOR EARTH-FAULT PROTECTION

Generator which produce more than 1% third harmonic voltage under all service conditions due to the flowing of the 3rd harmonic circulating current (I3), can have the entire stator winding up to and including the neutral point protected by the 100% earth-fault protection scheme. The basic idea is that the produced 3rd harmonic voltage becomes less than 1% of the fundamental when fault occurs near the neutral of the generator. A 95% protection scheme is used to protect the stator winding from 5% of the neutral. The 100% stator earth-fault scheme is shown in the figure below.



100% STATOR EARTH-FAULT PROTECTION

This scheme includes;

a) 95% unit (1) : which covers the stator winding from 5% of the neutral.

b) 3rd harmonic voltage measuring unit (2) : which protects the rest of the stator winding by sensing the 3rd harmonic voltage lower than 1% of the fundamental. This unit is connected to the generator neutral voltage transformer (3), and has standard scale range of 0.15 - 0.45 V, 150 Hz, and is provided with a filter which increases the basic frequency operating voltage by a factor of more than 25.

c) voltage checking unit (4) : which is included to prevent faulty operation of the relay at generator standstill or during the machine running-up or running down periods.

When the generator is running and there is no earth-fault current near the neutral, the 3rd harmonic voltage unit (2) and the voltage checking unit (4) are both activate, and the contact (b) is open and the 95% protection unit takes care. If an earth-fault occurs close to the generator neutral, the 3rd harmonic voltage unit will reset, contact (b) will close, and alarm or tripping is obtained.

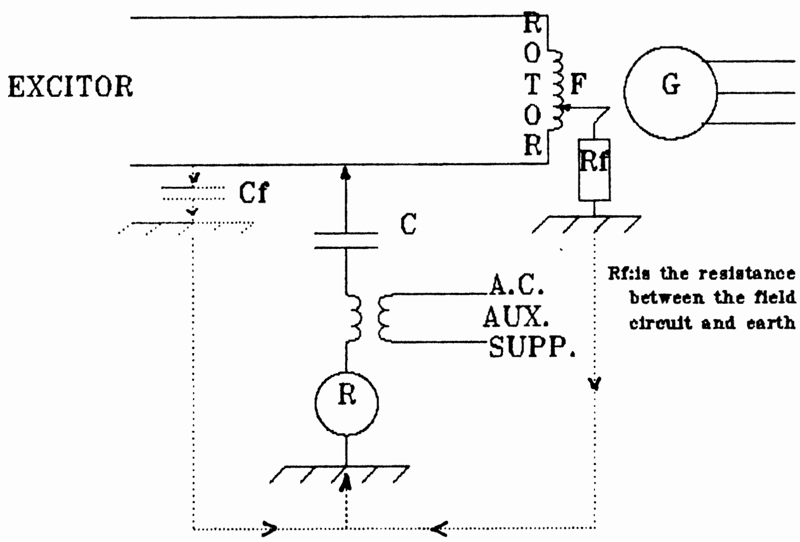
ROTOR EARTH-FAULT PROTECTION

In general, two methods are used to provide this type of protection;

A.C. INJECTION PROTECTION SCHEME

This scheme is shown below. It comprises an auxiliary supply transformer, the secondary of which is connected between earth and one side of the field circuit, through an interposed capacitor and a relay coil. The field circuit is subjected to an alternating potential at substantially the same level throughout, so that an earth fault anywhere in the field system will give rise to current which is detected by the relay. The capacitor (C) limits the magnitude of the current and blocks the normal field voltage, preventing the discharge of a large direct current through the transformer.

The main limitation of this method is that some current will flow to earth continuously through the capacitance of the field winding (Cf). This current may flow through the machine `, causing erosion of the bearing surface. Thus, it has to insulate the bearings and to provide an earthing brush for the shaft.

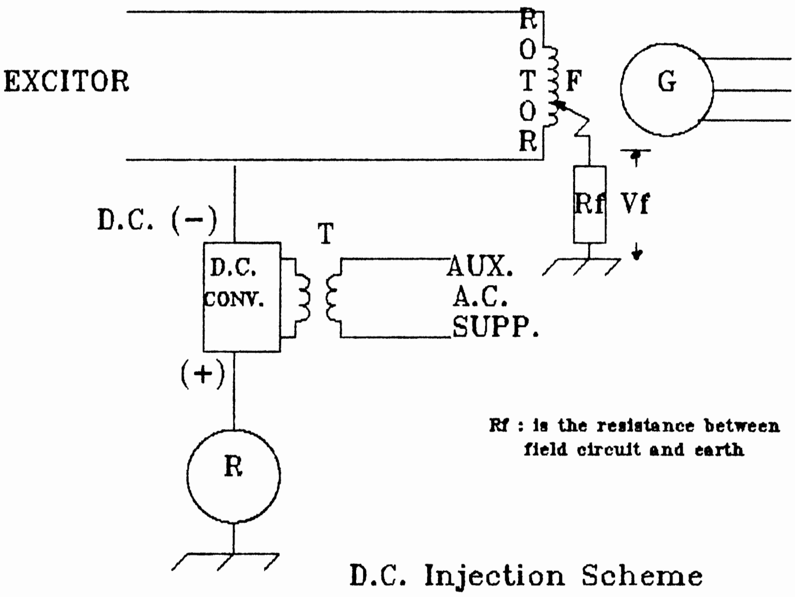


A.C. Injection Scheme

D.C. INJECTION PROTECTION SCHEME

The capacitance current objection to the A.C. injection scheme is overcome by rectifying the injection voltage as shown below. The D.C. output voltage of the transformer D.C. rectifier power unit (nearly 48 V) is arranged to bias the positive side of the field circuit to a negative voltage relative to earth. The negative side of the field system is at greater negative voltage to earth, so at normal operation no current will pass through the power unit. When an earth fault at any point in the field winding occurs, a certain contribution to the injection voltage is obtained depending on the field voltage and where in the rotor winding the fault occurs (in other word Vf). This will cause current to flow through the power unit.

The relay must have enough resistance to limit the fault current to a harmless value. In another hand, the relay must not be so sensitive as to operate with the normal insulation leakage current. A time delay (of about 11 sec.) is included before to prevent unwanted operation of the relay due to capacitive ground currents at the voltage increases which can arise on rapid regulation of the field voltage.



D.C. Injection Scheme

PHASE SHORT-CIRCUIT PROTECTION

In case of short-circuits between phases in the stator winding or between the generator terminals, the machine must quickly be disconnected from the network and brought to a complete shutdown in order to limit the damage. Phase short circuits on the generator bus, in the unit transformer, or in the high voltage winding of the unit transformer, must also be quickly disconnected from the network. The generator must be brought to a complete shutdown if there is no circuit-breakers between the machine and the transformer. The fast acting phase short-circuit protection for can only be obtained by means of differential protection. Back-up protection, should be provided too.

GENERATOR DIFFERENTIAL PROTECTION

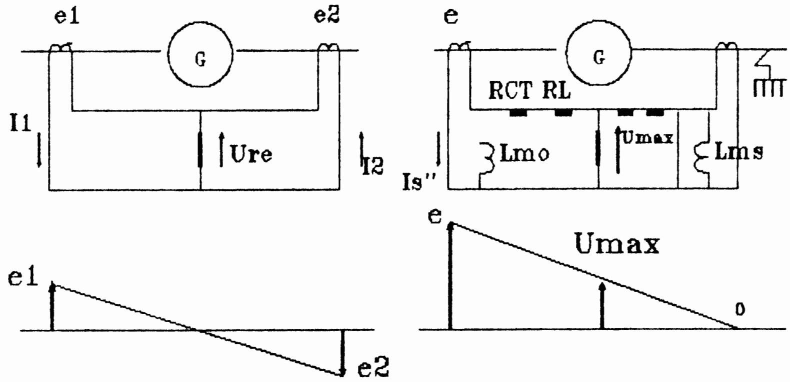
In any differential protection scheme, the CTs on both generator neutral and line sides shall have identical turns ratio and similar magnetizing characteristics. Anyhow, in modern generators , the time constant of the D.C. component in the short-circuit current is large (more the 200 msec.). CTs saturation hence is expected. Therefore, the generator differential protection scheme must keep stable even when CTs are heavily saturated during external faults.

High Impedance Differential Protection Scheme

This scheme is used for small and moderate size generators. Under normal operation conditions and external fault with unsaturated CTs, the principle of operation is shown in (a) below. The voltage (Ure) across the relay is negligible, and the relay is restrained. In case of an external short-circuit, one of the CTs may saturate more than the other. The worst case will ba if one is completely unsaturated. The principle of operation under this condition is shown in (b) below. The maximum voltage across the relay will be:

$U_{max} = I_s'' (R_{CT}+R_L)$ where;

- Is":secondary subtransient short-circuit current.
- RL :resistance of the pilot wire between the CT and The relay.
- RCT:resistance of the secondary winding of the saturated current transformer.



(a) NORMAL OPERATION
e: emf in CT secondary winding
Lmo: unsaturated CT magn. branch inductance
Lms: saturated CT mag. branch inductance

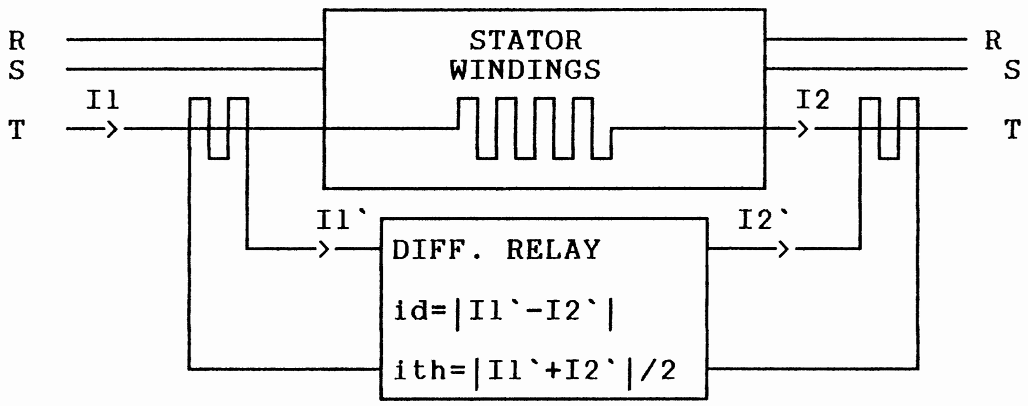
(b) EXTERNAL FAULT WITH FULLY SATURATED CT

HIGH IMPEDANCE RELAY OPERATION PRINCIPLE

The relay operating voltage is set higher than Umax. The minimum operating current depends mainly on the voltage setting of the relay, the magnetizing characteristics and the CTs current ratio, and it is normally 1-5% of the rated current. With internal faults, the fault current exceeds the relay minimum operating current, the voltage across the relay goes higher than Umax and operation takes place.

Percentage Differential Protection Scheme

This protection scheme is used for generators with ratings of higher than 250 MVA. The principle of operation of this scheme is shown below. This protection scheme is of percentage differential protection characteristics similar to that used in power transformer differential protection (as illustrated in lecture #4), with a slop K=20% to prevent maloperation due to CTs saturation during external faults. The minimum operating current can be set as low as 3% of the rated current.



GENERATOR AND UNIT TRANSFORMER DIFFERENTIAL PROTECTION

The differential relay used in that scheme has to be designed to be of twofold restraint;

1) Through fault restraint during external faults. The relay percentage differential protection characteristics must be so designed to keep the relay restrained even with deep CTs saturation during external faults

2) Magnetizing inrush and overexcitation current restraint.

During the time of the fault, the terminal voltage of the main transformer is practically zero and at the instance of fault clearance, (i.e. when the circuit breaker of the faulty feeder opens, the transformer terminal voltage quickly rises. This may cause sever magnetizing inrush currents (8-15 times the rated current). For generators-transformer units with separate generator breaker, the inrush restraint is also required when the unit transformer is energized from the H.V. bus.

Without the overexcitation restraint, there is an obvious risk that the differential relay may trip the generator due to the produced differential currents during overexcitation case. This case is obtained due to the overvoltage if a substantial part of the load is disconnected when clearing a fault. The voltage then rises immediately (up to 140% of the rated voltage) and remains high until the automatic voltage regulator (AVR) of the machine has brought it back to the normal value.

The harmonic restraint can be used to achieve that task. The second harmonic component of the differential current higher than (15-20%) of the fundamental, and the fifth harmonic component of the differential current higher than (30- 35%) of the fundamental, are used to indicate an inrush current and overexcitation current, respectively.

The relay must also be provided with instantaneous operation overcurrent protection function. The operation current of the overcurrent protection should be higher than the maximum inrush current of the transformer.

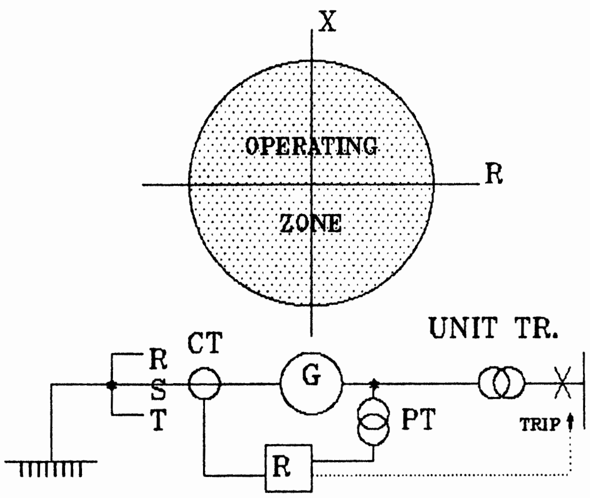
PHASE SHORT-CIRCUIT BACK-UP PROTECTION

It is considered necessary to have fast and reliable acting phase short-circuit protection. Thus, a back-up protection should be added to act in the case of differential protection scheme failure to protect large generators.

As a back-up short-circuit protection, an impedance relay (for generators with high ratings) or an undervoltage with overcurrent starting relay (for lower rating generators), are used. Anyhow, in the case of a static excitation system, which receives its power from the generator terminals, the magnitude of a sustained phase short-circuit current depends on the generator terminal voltage. In case of a nearby interphase fault, the generator terminal voltage drops and the fault current may fall below the setting of the overcurrent relay within a few seconds. However, for generators with excitation system not fed from the generator terminals, the short-circuit current may drop below rated current after 0.5-1 sec. if the AVR is out of service. For those reasons the impedance relay is generally recommended for back-up short-circuit protection.

Relay Impedance

The relay impedance has a circular operation characteristics and independent time delay. The relay is connected to CTs on the generator neutral side to provide back-up also when the generator is disconnected from the system. At rated generator voltage, the relay will work as a definite time overcurrent relay. At reduced voltages the current required for operation will be correspondingly reduced. At zero voltage, operation is obtained with a current of less than 20% of the relay rated current. Both, relay operating characteristic and connection are shown below.



IMPEDANCE RELAY USED AS BACK-UP
PHASE SHORT-CIRCUIT PROTECTION

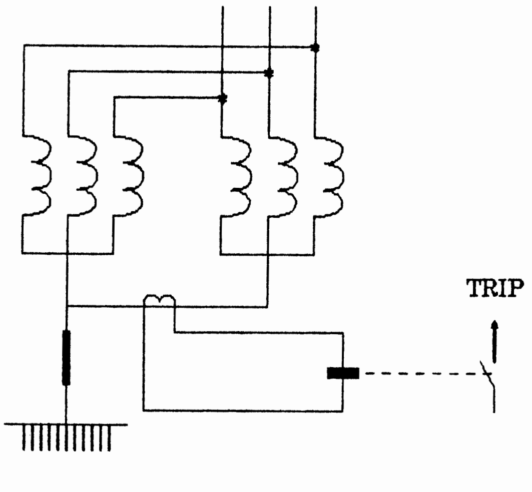
The relay is normally set to operate at 70% of the generator load impedance, corresponding to an operate current of 104 times the rated current at rated voltage. This setting secures back-up protection for the generator-transformer unit and the high voltage busbar. Selectivity against other relays in the network has to be secured by a proper time delay. For faults on the high voltage side of the DY-connected unit transformer, the impedance measured by the relay is influenced by the relay connection, the fault type and the generator and system impedance. For this reason the circular characteristics without offset is preferred.

PHASE INTERTURN SHORT-CIRCUIT PROTECTION

Modern medium size and large size generators turbo-generators have the stator winding designed with only one turn per phase per slot. For these machines, interturn faults can only occur in case of double earth-fault. Anyhow, multiturn windings are used in some cases for machines up to maximum 50 MVA.

It is generally difficult to obtain a reliable protection against short-circuiting of one turn if the stator winding has a large number of turns per phase.

For generators with split neutrals, the conventional inter-turn fault protective scheme comprises a time-delayed overcurrent relay which senses of the current flowing in the connection between the neutrals of the stator windings, as shown below. The fault current can be extensively large in case of interturn faults, hence, the time delay must be short (0.2-0.4 sec.), and overcurrent relay must be set higher than the maximum unbalanced current flowing between neutrals in case of external short-circuits. The maximum unbalanced current in case of external faults and the minimum unbalanced current for a single-turn have to be obtained from the manufacturer of the machine.



INTERTURN SHORT-CIRCUIT PROTECTION

Due to the difficulties in obtaining a reliable and secure interturn protection, it is in most cases omitted. It is assumed that the interturn fault, first of all, will be developed into a single phase earth-fault at the faulty spot, and the machine will then be tripped by the earth-fault relay within 0.3-0.4 sec.

NEGATIVE PHASE-SEQUENCE CURRENT PROTECTION

The currents in a three-phase machine are normally in balance, but if a fault occurs on the supplied system (or supplying system in case of a motor case), this balance can be influenced. Single-phase and two-phase faults, phase rupture or asymmetrical loading on the system can give rise to unbalanced currents, hence negative sequence current.

These currents generate a machine stator flux that has the same rotational speed as the rotor flux but rotates in the opposite direction. Relative to the rotor, the stator flux rotates at double the power system frequency and generates eddy currents in the rotor. The high frequency of these eddy currents causes the outer parts of the rotor, and the winding, to become heated. If the negative sequence current is of high magnitude, or if it persists for long periods of time, these rotor parts can be damaged due to overheating. It is normally assumed that a generator can sustain negative sequence currents which exceed a given minimum value for a period of time (t), which is determined from the following equation:

$$t = K \left(\frac{In}{Insc} \right)^2 \qquad \text{where;}$$

In : rated current of the machine
Insc : negative sequence current
t : time in seconds
K : a constant in seconds that is characteristic for the generator. This constant represents the length of time the machine can withstand a negative phase sequence current equal to rated current.

The validity of the last equation is based on the assumption that all the energy generated by the negative sequence current is transmitted in the form of heat to the rotor, without any losses to the surroundings.

In reality, part of this heat is dissipated to the surrounding cooling medium and to the stator. If the negative sequence current is of continues nature, a thermal balance will be obtained. The magnitude of this current which can be tolerated for an unlimited period of time, without risking thermal damage to the rotor , varies depending on the type of generator and the method of cooling used. Furthermore, in the case of salient pole generators, the eddy currents occur to a great extent in the damper windings. On hydro-generators, these windings are, in general, heavily dimensioned and generators of this type will therefore be able to withstand higher negative sequence current than non-hydrogenerators of similar ratings.

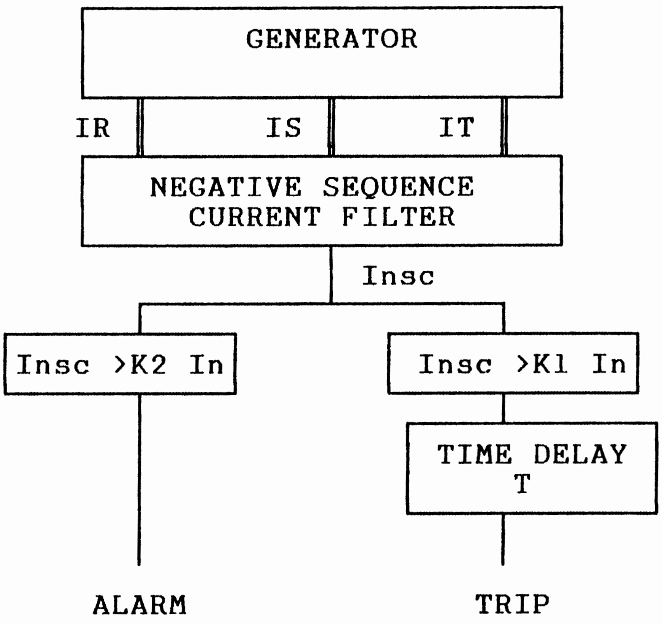
Modern, direct cooled turbo-generators and salient pole hydro-generators without damper windings, can be damaged and must therefore be tripped if negative phase sequence currents exceeding 5% of the rated current are allowed to last for long period of time.

The capability of the machine to withstand continuously unbalanced currents is expressed as Insc percent of rated stator current. Typical values for generators are given below,

TYPE OF GENERATOR	MAX. PERMITTED K (SECONDS)	MAX. PERMITTED CONTINUOUS Insc (%)
Cylindrical rotor;		
indirectly cooled	30	10
directly cooled	5-10	5-8
Salient pole;		
with damper winding	40	10
without damper winding	40	5

An open conductor may give rise to a considerable Insc, as a maximum of more than 50% of rated machine current. The combination of two or more of the above mentioned dissymetries can give rise to harmful Insc. It is therefore considered as good engineering practice to provide negative sequence current protection for all, but for small size generators.

Below, typical configuration of the negative sequence current protection scheme is shown.



where;

K1 : adjustable start tripping ratio = 4-10 %

K2 : adjustable start alarming ratio = 3-7 %

T : adjustable time delay = 0.1 - 300 sec.

LOSS-OF-EXCITATION PROTECTION

SOURCES AND EFFECT OF LOSS-OF-EXCITATION

Loss-of-excitation (LOE) problem may arise due to;

1) a fault within the automatic voltage regulator (AVR), and as a result the field current is reduced to zero.

2) an open circuit or short circuit of the main field winding.

3) an incidental opening of the field breaker.

When a generator with sufficient active load looses the field current, the it accelerates and runs asynchronously at a speed higher than the system. It is operating then as an induction generator absorbing reactive power (VAr) for excitation from the system.

With loss of excitation, the difference between direct axis (Xd) and quadrature axis (Xq) synchronous reactances, limits the maximum active power generated without loosing of synchronism. This difference in generators with salient poles, is sufficiently large to keep the generator running synchronously even with an active load of (15-25)% of the rated load. However, the picture becomes worse in turbo-generators since the direct and qudrature axis reactances are practically equal, which makes the generator to run asynchronously even with a very small active load.

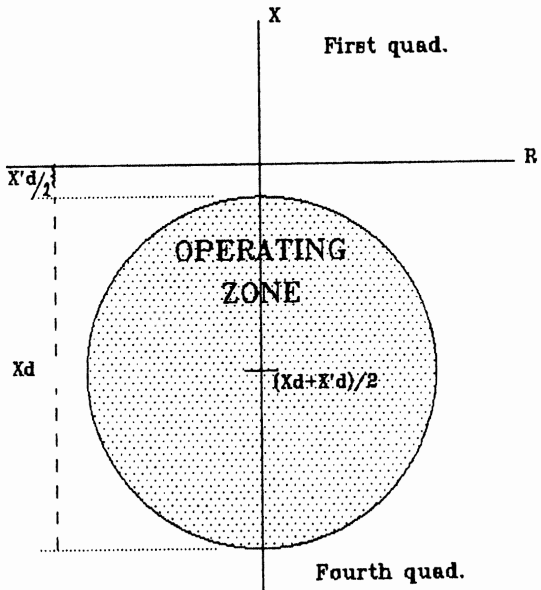
The following may arise if the loss-of-excitation protection does not operate or if it is not provided at all;

1) The end regions of the stator and parts of the rotor will be overheated if the generator runs for a long time at a speed higher than the slip speed. With salient pole generators with damper winding, the overheating will not be serious. Anyhow, with turbo-generators it is generally necessary to trip with some minutes (i.e; about 10 min.) to avoid serious damage. The maximum permitted hot spot temperature is obtained for most turbo-generators by running the machine continuously unexcited with an active load of (20-30)% of the rated.

2) The generator terminal voltage varies periodically due to the large variation in the relative current absorbed from the system. The low voltage intervals may lead to stall the generator auxiliary induction motors, the matter which would lead to a complete shutdown of a thermal power station.

USING OF IMPEDANCE RELAY FOR LOSS-OF-EXCITATION PROTECTION

An impedance relay with off-set mho characteristics (shown below), has been used for loss-of-excitation protection. The standard recommended settings of the relay is to make the diameter of the circle to be equals to the generator synchronous reactance (Xd) and is usually off-set by half of the transient reactance (X`d).



IMPEDANCE RELAY CHARACTERISTICS

With both active and reactive power out of the generator, the measured impedance points fall in the first quadrant on the plan. As the reactive power output decreases, the path of the impedance drifts down forward the fourth quadrant. When the reactive power output is negative, the impedance then is in the fourth quadrant. A loss-of-excitation case is indicated as the impedance trajectory insert the operating circle and stays inside for a specified time.

EFFECT OF TRANSIENT SYSTEM DISTURBANCES ON IMPEDANCE RELAY OPERATION

It has been found that system disturbances caused by nearby faults initiation and clearing, may bring the impedance relay to maloperate and to cause false tripping. Such transient system disturbances can be concluded by transient swings and low frequency disturbances;

1) Transient Swings Disturbances:

Transient swings which appear after clearing faults in the system, may cause the impedance loci for a generator to enter the operation zone of the impedance relay used for loss-of-excitation protection, and to stay inside a time not less than 0.3 seconds. The picture becomes worse with lower system impedance, leading power factor, and with voltage regulator is out.

As a solution, a time delay element may be added to delay the decision of the impedance relay a time enough for the transient swings to pass. A time delay of 1 to 5 seconds will be sufficient. It has to take care when fixing this time delay, taking in mind the generator withstanding during this time if a real loss-of-excitation occurs.

2) Low Frequency Disturbances:

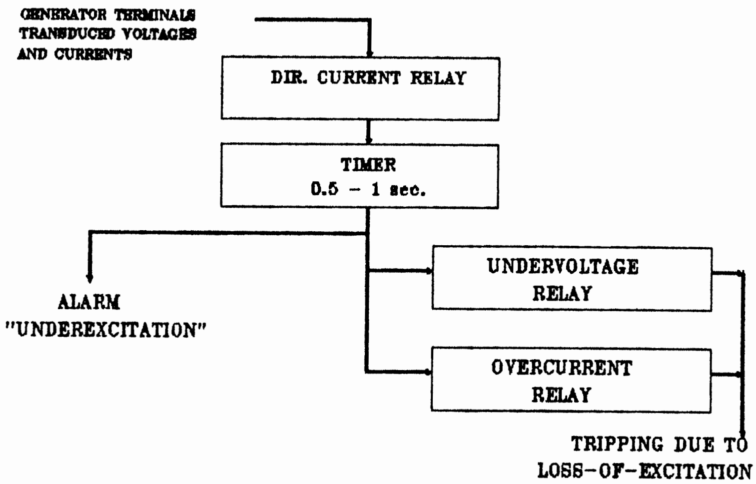
Low frequency disturbance may lead to loss of synchronism in those generators having exciters characteristics as a function of frequency (speed). This loss of synchronism may lead intern to full loss of excitation. It has been found that loss-of-excitation impedance relay cannot distinguish between loss of synchronism case and loss of excitation case. Thus. using the conventional loss-of-excitation impedance relay may lead to trip the generator during some loss of synchronism cases.

As a solution, additional relays have to be added to indicate a loss of synchronism cases and to insure the operation of the loss-of-excitation impedance relay. Overcurrent and undervoltage relays on the generator terminals currents and voltages, have been used to provide this solution.

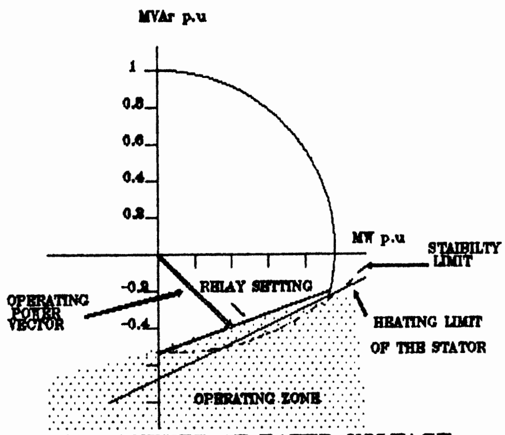
TYPICAL MODERN LOSS-OF-EXCITATION PROTECTION SCHEMES

Two typical schemes for loss-of-excitation protection may be considered. Their basics of operation can be taken as the general modern lines to provide that protection.

The first scheme shown below uses directional current relay instead of impedance relay. This relay is used to operate as the appearing power vector comes below the typical relay setting on the P-Q characteristics. This setting depends on the thermal capability curve of the generator and at the steady-state stability limits. Those limits are shown below.



A MODIFIED L.O.E. PROTECTION SCHEME USING DIRECTIONAL, UNDERVOLTAGE, AND OVERCURRENT RELAYS

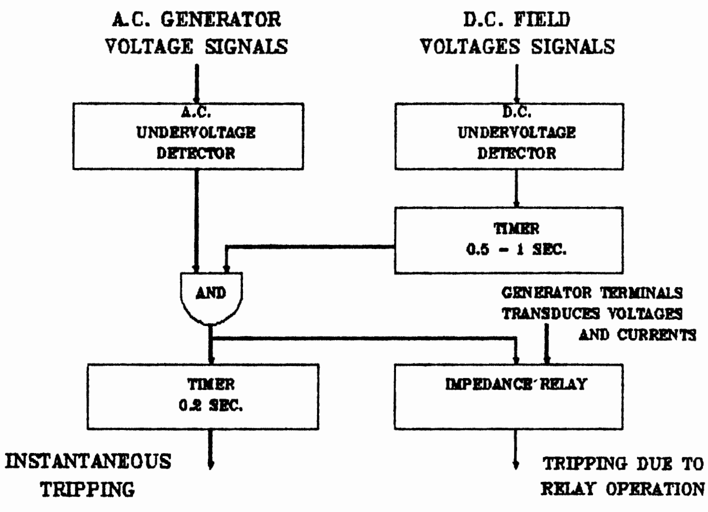


CAPABILITY CURVES AT RATED VOLTAGE
FOR A TYPICAL GENERATOR

When this relay operates, it initiates a timer (typically of time delay 0.5-1 sec.) which effectively prevents unnecessary operation during transient power swings due to the tripping of faults close to the generator. If the timer complete its cycle then an alarm for underexcitation case is initiated. If any of undervoltage (normally set to 90% of the rated voltage) or overcurrent relay (normally set to 110% of the rated current) operates, then, a loss-of-excitation condition is indicated and trip takes place.

The second scheme shown below, has two steps of checking. In the first step of checking, both the field and generator terminal voltages are checked. The flag of the terminal voltage is initiated to (1) if the terminal voltage becomes less than a specified value (typically 95% of the rated terminal voltage). The flag of the field voltage checking is set to (1) if the field voltage becomes less than a specified value (typically 5% of the rated field voltage), and a timer (typically set to 0.5-1 sec.) completes its cycle.

If the output of and gate, an impedance relay is called to operate. If this relay does not operate within 0.2 sec. then the final stage timer completes its cycle and trips the generator instantaneously.



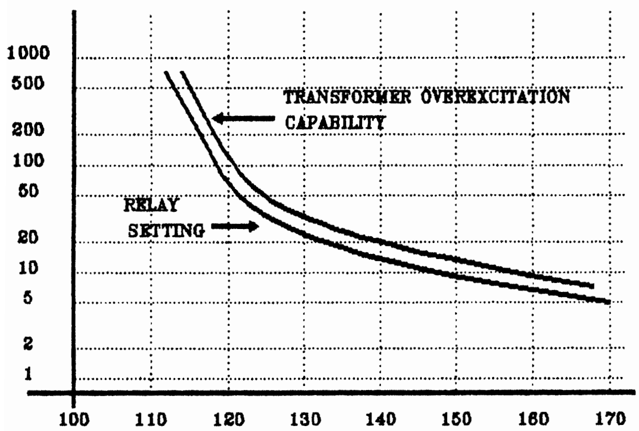
A MODIFIED L.O.E. PROTECTION SCHEME USING AN IMPEDANCE, AND UNDERVOLTAGE DETECTORS

OVEREXCITATION PROTECTION

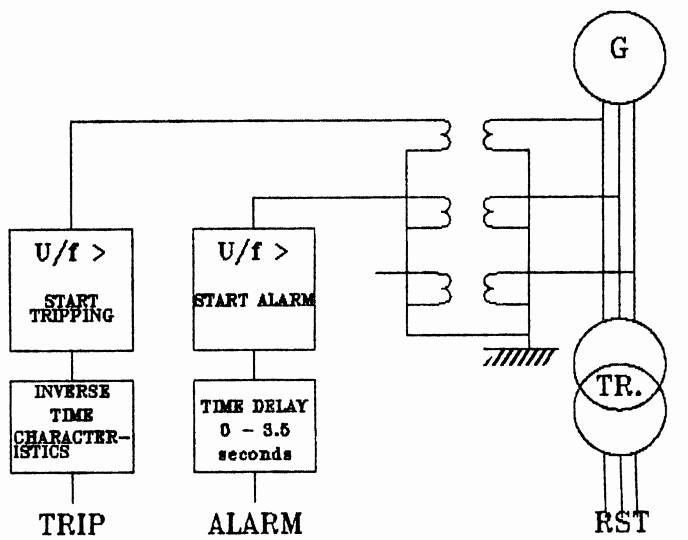
As long as the generator-transformer unit is connected to the network, the risk of overexcitation is relatively small. However, when the generator-transformer unit is disconnected from the network, there is an obvious risk for over-excitation, mainly during generator start-up and shut-down.

The risk of overexcitation is largest during periods when the frequency is below rated value. Hence, overvoltage relays cannot be used to protect the generator-transformer unit against overexcitation. The proper way of doing this is to use a relay which measures the ratio between voltage frequency (V/Hz relay). Below, the structure of such a relay is shown.

The relay measures the relationship between voltage and frequency within certain frequency range (typically fro 2 to 80 Hz). The relay is of an alarm and trip circuits. The level detector for the instantaneous or a time delayed (typically up to 3.5 sec.) alarm has a setting range from 1.5 to 3 V/Hz. The tripping function has an inverse time characteristics which provide optimum protection against overexcitation. The relay characteristics shown below have to be adjusted to match substantially any excitation capability curve.



INVERSE TIME CHARACTERISTICS OF AN OVEREXCITATION RELAY



TYPICAL OVEREXCITATION RELAY STRUCTURE

SHAFT CURRENT PROTECTION

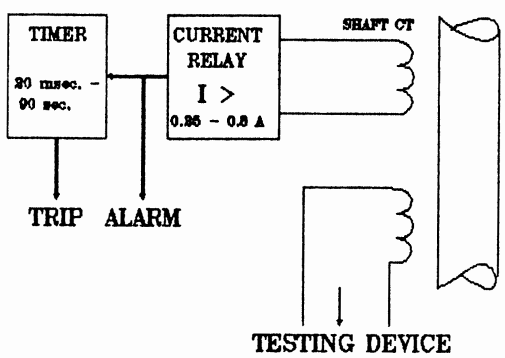
An induced emf is developed in the shaft of the generator due to the magnetic dissimilarities in the armature field. Normally, the induced emf is within the range 0.5-1 V for turbogenerators and 10-30 V for hydrogenerators. Both the emf wave shape and magnitude depend on the type and size of machine and the also varied with the load.

If the bearing pedestals at each side of the generator are grounded the induced emf will be impressed across the thin oil-films of the bearings. A breakdown of the oil-film insulation in the two bearings can give rise to heavy bearing currents due to the very small resistance of the shaft the and the external circuit will be developed. Therefore, the bearing pedestal remotest from the prime mover is usually insulated from ground and the insulation supervised by a suitable relay. To prevent the rotor and the shaft from being electrostatically charged, the shaft of turbogenerators are usually earthed via a slip ring on the prime mover side. For hydrogenerators, the water in the turbine provides the necessary connection to earth.

Anyhow, severe damage on the bearings is not expected to occur if the shaft current is less than 1 A.

Below, typical shaft current protection scheme is shown. The shaft current transformer surrounds the shaft which constitute the primary winding. The secondary winding is connected to a current relay which measures the fundamental a.c. component in the shaft current. The minimum primary operating current increases with the diameter of the shaft, typically from 0.25 A for a diameters of 0.2 meter to 0.8 A for a diameter of 2.8 meters. The current relay is connected to a timer of a time scale varies from 20 msec to 90 sec. Testing the shaft current is possible through an extra secondary winding of the shaft CT.

In some applications, a current relay which measures the third harmonic component in the shaft current is used instead of the current relay in this scheme.



SHAFT CURRENT PROTECTION SCHEME

REVERSE POWER PROTECTION

The purpose of the reverse power relay is basically to prevent damage on the prime mover (turbine or motor).

If the driving torque becomes less than the total losses in the generator and the prime mover, the generator starts work as a synchronous compensator, taking the necessary active power from the network. In case of steam turbines, a reduction of the steam flow reduces the cooling effect on the turbine blades and overheating may occur. Hydroturbines may also be damaged if the turbine blades surf on the water and set up an axial pressure on the bearing. Diesel engines may be damaged due to insufficient lubrication.

When the generator is working as a motor the small active current to the machine may be combined with a substantial reactive current delivered by the machine. Hence, the angular error of voltage and current transformers feeding low set reverse power relays should be small.

For the largest turbogenerators, where the reverse power may be substantially less than 1% of the rated value, reverse power protection is obtained by a minimum power relay, which normally is set to trip the machine when the active power output is less than 1% of the rated. A directional current relay with a timer with scale range of 6 to 60 sec. are the main segments of the reverse power protection scheme.

UNDERFREQUENCY PROTECTION

The underfrequency relay is basically a protection for various apparatuses in a network which, in case of a disturbance, may be separated from the rest of the system and supplied from one generator.

Operation at low frequency must be limited, also, in order to avoid damage on generators and turbines. In general, the necessity of underfrequency protection has to be evaluated from knowledge of the network and the characteristics of the turbine regulator.

The underfrequency relay for generators, shown below, contains one static frequency measuring unit with scale range of 44-50 Hz (for 50 Hz system), and one timer with a certain scale range (typically from 20 msec - 90 sec).

OVERVOLTAGE PROTECTION

If the generator circuit-breaker is tripped while the machine is running at full load and rated power factor, the subsequent increase in terminal voltage will normally be limited by a quick acting AVR. However, if the AVR is faulty, or, at this particular time switched for manual control of a voltage level, sever overvoltage will occur. This voltage rise will be further increased if simultaneous overspeeding should occur, owing to a slow acting turbine governor. In case of a hydrogenerator, a voltage rise of 50-100% is possible during the most unfavorable conditions.

Modern unit transformer with high magnetic qualities have a relatively sharp and well defined saturation level, with a knee point voltage between 1.2 and 1.25 times the rayed voltage. A suitable setting of overvoltage relay is, therefore between 1.15 and 1.2 times the rated voltage and with a definite time delay of 1-3 sec.

An instantaneous high set voltage relay can be included to trip the generator quickly in case of excessive overvoltage following a sudden loss of load and generator overspeeding.

The voltage relays are connected to the voltage between phases to prevent faulty operation in case of earth faults in the stator circuits.

THERMAL OVERLOAD PROTECTION

Overloads up to 1.4 time the rated current are not normally detected by the impedance or overcurrent protection. Maintained overloads within this range are usually supervised by temperature monitors (resistance elements) of several measuring segments buried at various points in the stator slots.

The temperature rise of the stator winding is also influenced by the coolant flow in addition to the magnitude of the current. Therefore, the current overload relay, cannot be expected to give an exact measurement of the winding temperature under all conditions.

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Wroclaw, November 5th, 2013

Dr Yesri Zaki Mahammad

I appreciate very much receiving from you the drafts of the books:

1. An Introduction to the Digital Protection of Power Systems, 162 pages
2. An Advance Course in Power System Protection, 5 lectures.

After careful studying of them I would like to say that those are very good materials which are suitable for use by our students studying at the M.Sc. specialisations: Control in Electrical Power Engineering and Renewable Energy Systems. The teachers in our Institute including myself will recommend this two drafts as the literature for the courses: Power System Protection, Digital Signal Processing for Power System Protection, Power System Faults and M.Sc. theses related to those subjects. Therefore those two drafts will be sent to our Faculty Library to be available for all interested students. Also I will appreciate receiving from you the pdf files of the books to include them on the web sites with materials for students.

Thank you very much for nice and fruitful cooperation.

Yours sincerely

DYREKTOR INSTYTUTU

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