

ROLPHTON
NUCLEAR TRAINING CENTRE
COURSE 135

This course was originally developed for the use of Ontario Hydro employees. Reproduced on the CANTEACH web site with permission

FOR ONTARIO HYDRO USE ONLY

NUCLEAR TRAINING COURSE

COURSE 135

- 1 - Level
- 3 - Equipment & System Principles
- 5 - ELECTRICAL SYSTEMS

Index

135.00-0	Course Objectives
135.01-1	Introduction to Symmetrical Components & Unbalanced Current
135.02-1	Unbalanced Currents: Their Effects
135.03-1	Further Examples of Electrical Protective Relays
135.04-1	Composite Electrical Protective Schemes: Part I
135.05-1	Composite Electrical Protective Schemes: Part II

Electrical Systems - Course 135

COURSE OBJECTIVES

NOTE: Checkout Questions are based on Objectives and Assignment Questions.

135.01-1 Introduction to Symmetrical Components and Unbalanced Currents

On completion of the Lesson the student will be able to:

1. State the relationships between positive, negative and zero phase sequence currents when the following faults occur.
 - (a) 3 phase (L-L-L)
 - (b) line-to-ground (L-G)
 - (c) line to line (L-L)
2. State the condition(s) which give:
 - (a) only positive sequence currents
 - (b) zero sequence currents
 - (c) negative sequence currents.

135.02-1 Unbalanced Currents: Their Effects

On completion of the Lesson, the students will be able to:

1. Explain the effects produced by unbalanced currents in:
 - (a) generators
 - (b) induction motors
 - (c) transformers
2. Explain how negative phase sequence currents can damage:
 - (a) generators
 - (b) motors

given the relevant data, be able to calculate the time that a generator rotor can withstand:

- (a) a line to ground fault
- (b) a line to line fault

4. Explain how star/delta transformers affect the relationships between positive and negative phase sequence currents.

135.03-1 Further Examples of Protective Relays

On completion of the Lesson the student will be able to:

1. Explain the principle of:
 - (a) simple differential protection
 - (b) 'T' circuit differential protection
 - (c) differential protection with load restraint features
 - (d) differential protection with harmonic restraint features
 - (e) transformer gas relays
 - (f) transformer winding temperature detectors
 - (g) temperature measurement using change in resistance

135.04-1 Composite Electrical Protective Schemes, Part I

On completion of the Lesson the student will:

1. Be able to state the four essential features for any electrical protective scheme.
2. Given the relevant diagram(s) be able to explain the ac and dc tripping and alarm circuits associated with
 - (a) busbars
 - (b) transformers

135.05-1 Composite Electrical protective Schemes, Part II

On completion of the Lesson the student will:

- 1 Given the relevant diagram(s), be able to explain the ac and dc tripping and alarm circuits associated with a turbine-generator.

J.R.C. Cowling

Electrical Systems - Course 135

INTRODUCTION TO SYMMETRICAL COMPONENTS & UNBALANCED CURRENTS

1.0 INTRODUCTION

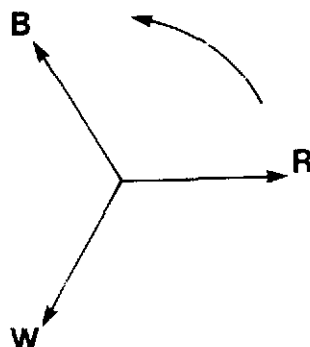
This lesson explains how unbalanced current problems can be solved using symmetrical components. This is done by:

- (a) explaining how the **symmetrical** components are derived for a three-phase system.
- (b) showing how **symmetrical** components are used to explain the components of currents in a line to ground (L-G) fault and in a line to line (L-L) fault.
- (c) explaining how and where they occur in a 3 phase system.

2.0 SYMMETRICAL COMPONENTS IN A THREE-PHASE SYSTEM

2.1 Balanced Three-Phase Conditions

In three-phase systems, during normal balanced three-phase loading or during a balanced three-phase fault, equal currents flow in each of the three lines. This can be represented by the vectors shown in Figure 1 where rotation is R-W-B anti-clockwise.



The current I in each line is found by

$$I = \frac{V_p}{Z_p}$$

where V_p is the phase voltage and Z_p is the phase impedance.

Figure 1: Balanced Three-Phase Currents.

2.2 Unbalanced Faults

When a line - ground (L-G) fault occurs or when a three-phase generator or supply has a single-phase load applied to it, the currents can be represented by Figure 2 where I_R is the current in the faulted red phase. The current in the healthy white and blue phases are zero, ie, $I_W = I_B = 0$.

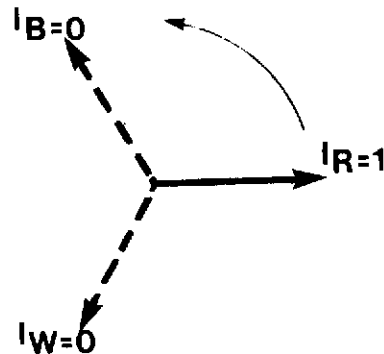


Figure 2: Vectors of Currents When a L-G Fault Occurs on Red Phase.

In this case, the current I_R cannot be found by

$$\frac{V_p}{Z_p}$$

because of the interaction of the other two phase in the generator. The problem was first investigated by Fortescue in the USA who noticed that the rotors of three-phase generators became excessively hot when they were supplying single-phase or unbalanced loads. This led to the investigation into the nature of unbalanced currents in three-phase circuits. A general theorem was produced which showed that, in the case of an unbalanced three-phase system, the current or currents could be resolved into three sets of components or vectors. Each set of vectors being equal in magnitude and displaced from each other by an equal angle. Because each set of the vectors is symmetrical in magnitude and angle they are called "symmetrical components". The theorem also states that the angle of displacement for the first set is 120° , the second set 240° and 360° for the third set. The three sets of vectors are shown in Figures 3(a), 3(b), and 3(c). (Reference 1.)

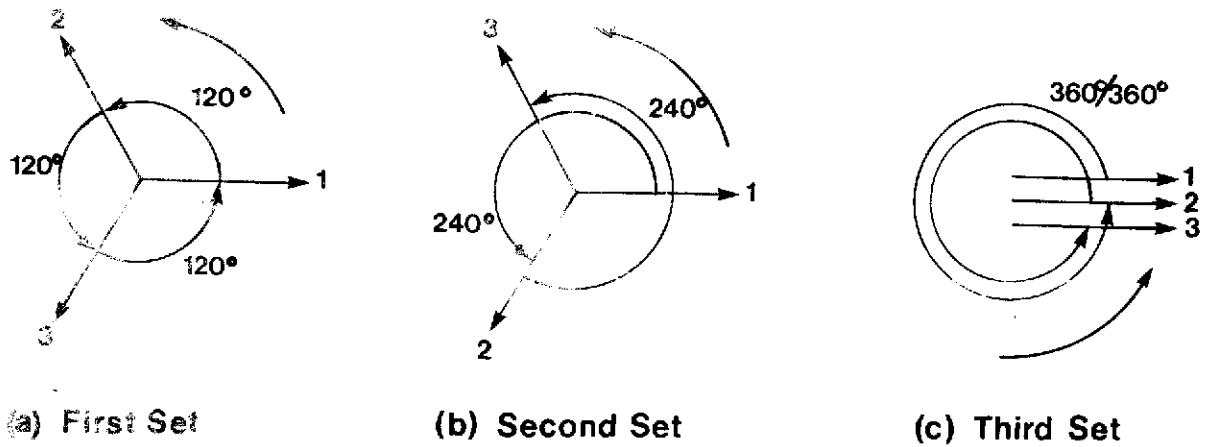


Figure 3: Symmetrical Component "Sets" for a Three-Phase System.

Applying the standard phase notation to the three symmetrical components sets gives:

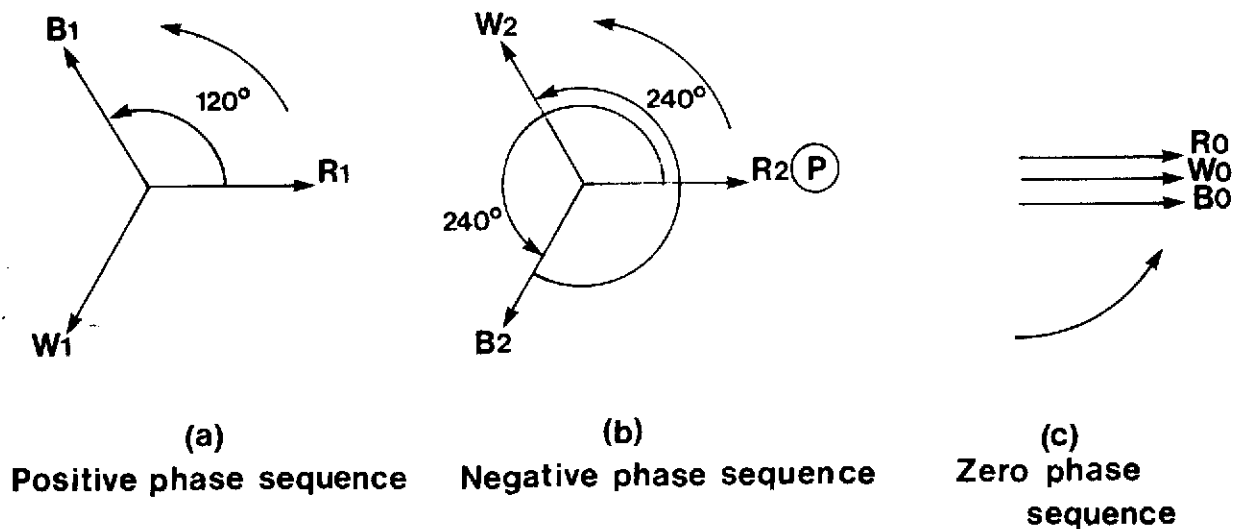


Figure 4: Symmetrical Components Sets and Their Standard Notations and for a Three-Phase System.

2.2.1 Positive, Negative and Zero Phase Sequences

- (a) Positive Sequence. Figure 4(a) shows the standard RWB vectors rotating in the standard anti-clockwise rotation and is called **positive phase sequence**. Positive phase sequence components currents are given the subscript 1, ie, R_1 , W_1 , B_1 .

- (b) Negative Sequence. Figure 4(b) shows the vectors, when rotated in the anti-clockwise direction have the order RBW, ie, the vectors pass point (P) in the order RBW.

Another way of looking at Figure 4(b) is to interchange the W and B vectors and rotate them in a clockwise or negative direction. Figure 5 shows that when this is done, the vectors have the same RWB configuration as in Figure 4(a) but the direction is **reversed**. The vectors now pass point (P) in the order RBW. Because this direction is opposite to the positive sequence direction, the vectors are called **negative phase sequence** vectors. Negative sequence components of currents are given the subscript 2, ie, R_2 , W_2 , B_2 .

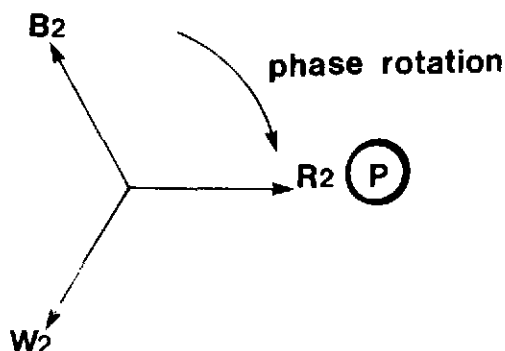


Figure 5: Negative Phase Sequence Vectors, RWB Clockwise.

- (c) Zero Phase Sequence. In the case of Figure 4(c), the vectors are all in phase and have 360° or effectively zero phase angle displacement between them and are, therefore, called **zero phase sequence** vectors. Zero phase sequence components of currents are given the subscript 0, ie, R_0 , W_0 , B_0 .

2.3 To Summarize

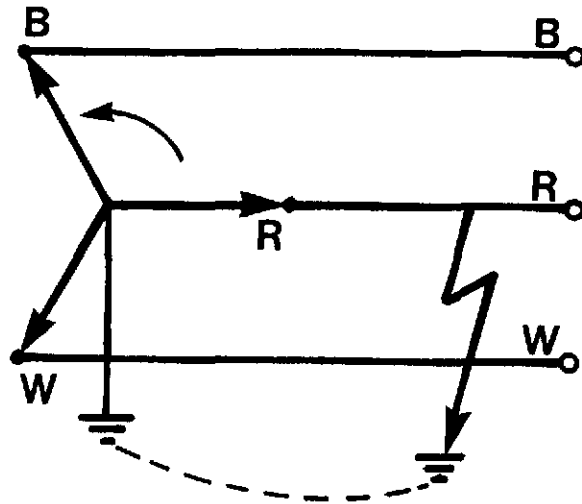
The unbalanced currents in a three-phase generator or supply can be resolved into three sets of symmetrical components of current, each set having the same magnitude. These symmetrical components of current are called "positive sequence", "negative sequence" and "zero sequence" symmetrical components of current.

3.0 ANALYSIS OF VARIOUS TYPES OF FAULTS

3.1 Line to Ground Fault

Figure 6(a) shows a red line to ground fault. Figure 6(b) shows the current vector for this fault. It is assumed there is little or no load current. Current flows in R line and no current flows in W or B lines. Figure 6(c) shows the standard positive, negative and zero components of current. Figure 6(d) shows how R-N line current I_R is made up from **equal quantities** of positive, negative and zero phase sequence components of current. The white and blue line currents resolve to zero.

(a) Red Line to Ground Fault.



(b) Current Vectors for the Above.

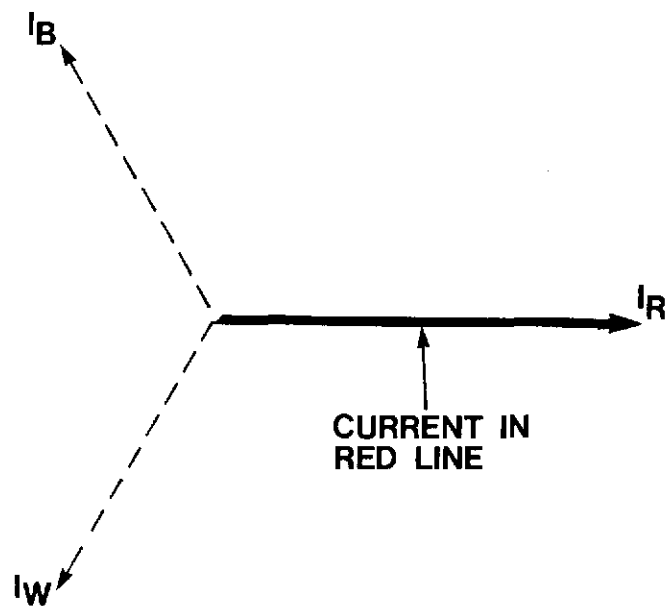


Figure 6

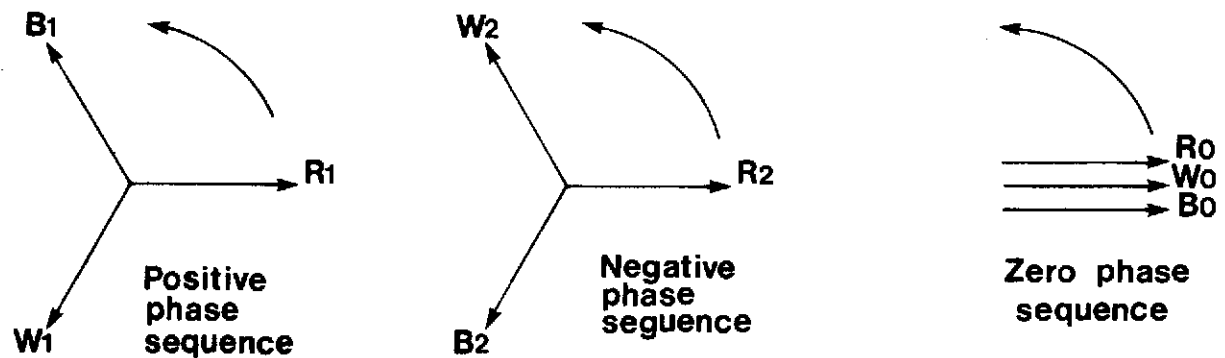


Figure 6(c): Positive, Negative and Zero Components of current.

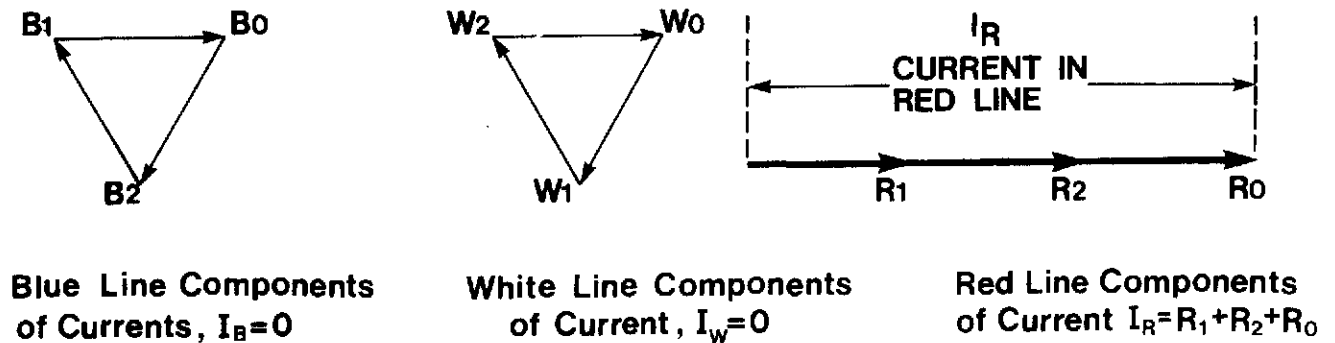


Figure 6(d): Vectors showing how the current in red line is made up from equal quantities of red positive, red negative and red zero phase sequence components of current. White and Blue line currents resolve to zero.

3.2 Line to Line Fault

Figure 7(a) shows a white to blue line to line fault. Figure 7(b) shows the current vectors for this fault. It is assumed there is little or no load current.

Note that because the current flows out from the white terminal and into the blue terminal, there is a 180° displacement between the currents in the white and blue lines.

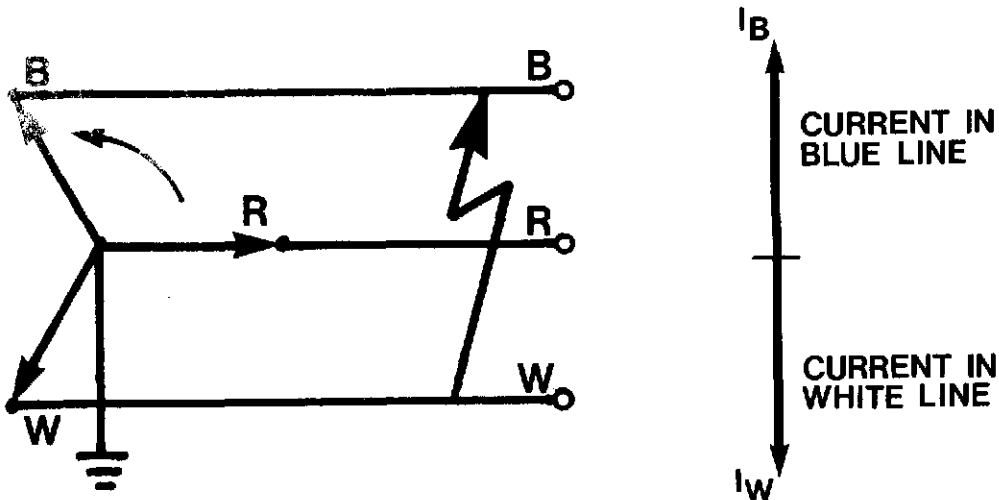


Figure 7(a): W-B Line Fault.

Figure 7(b): Currents Associated with a W-B Line to Line Fault.

Once again, symmetrical components can be applied to analyze the currents. Positive and negative sequence components will occur as before, but for zero sequence currents to flow, there must be a return path for the currents, ie, they must have a neutral in which to flow. Because there is no neutral connection when a L-L fault occurs, there can be no zero phase sequence component of current. In fact, zero sequence currents only occur when ground fault current flows.

Figure 8 shows how the W-B fault current in a L-L fault is made up from the components of equal quantities of positive and negative sequence currents. The components of red phase currents resolve to zero. The vectors of R_1 and R_2 current are 180° to each other. This fact is explain in symmetrical component theory. (Reference 2.)

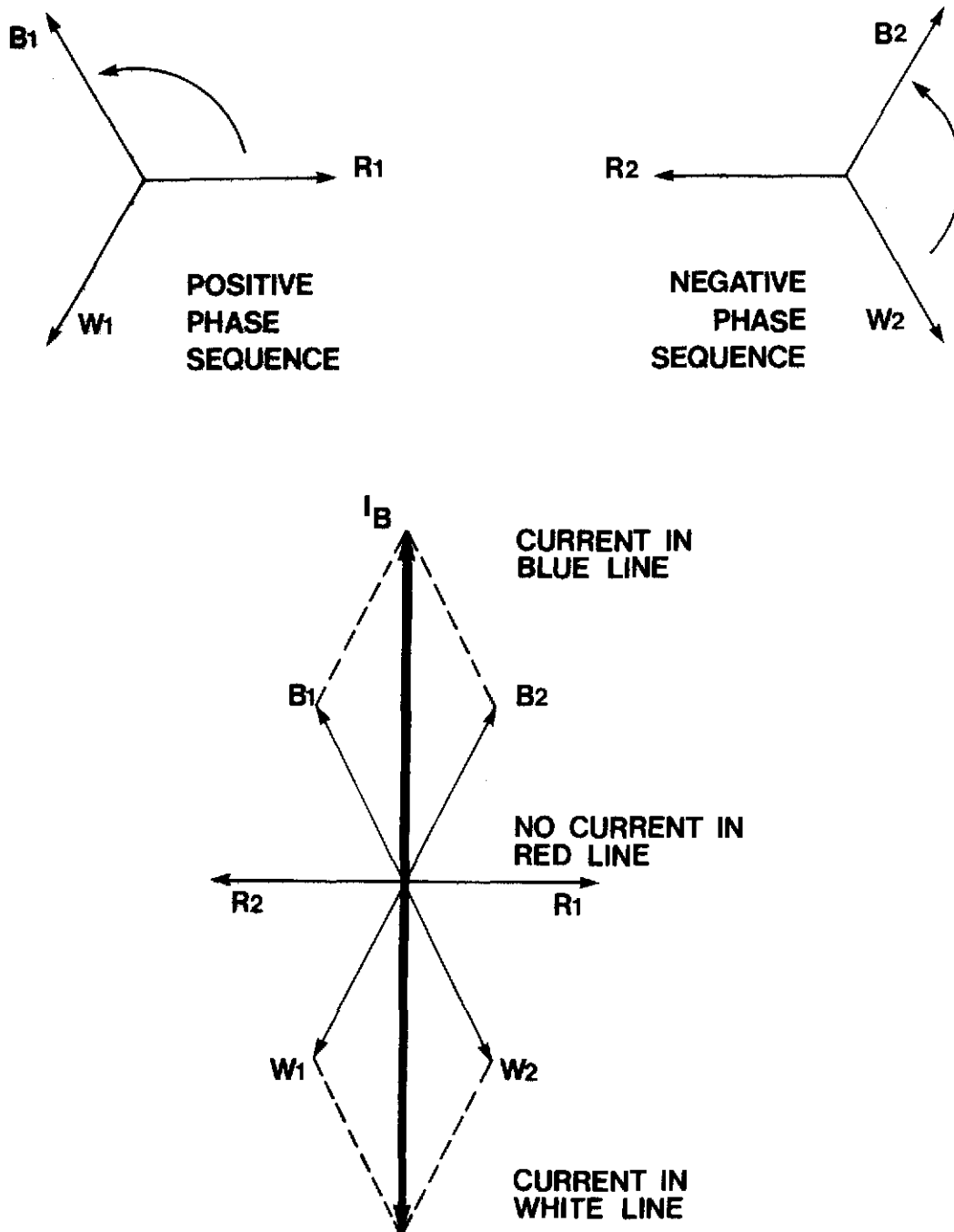


Figure 8: Diagram showing how the currents in a W-B, L-L fault are made up from the components of positive and negative sequence currents. The components of red phase current resolve to zero.

5.0 SYMMETRICAL COMPONENTS APPLIED TO OTHER TYPES OF FAULT

When faults or unbalances occur which are not of the simple L-G or L-L types, the nature of the currents can still be resolved by the use of symmetrical components. The subject is covered in detail in textbooks. (Reference 2.) It should be appreciated that with three phase systems:

- (a) when balanced conditions occur, only positive sequence currents flow.
- (b) zero sequence currents only occur when there is a ground fault, ie, L-G or L-L-G.
- (c) positive and negative sequence currents occur with all unbalanced conditions.

6.0 REFERENCES

Reference 1: J.R. Mortlock and Humphrey Davis, "Power System Analysis" Page 53. Chapman and Hall.

Reference 2: J.R. Mortlock and Humphrey Davies "Power System Analysis" Page 68. Chapman and Hall.

ASSIGNMENT

1. State the relationships between positive, negative and zero phase sequence currents when the following faults occur:
 - (a) Line-to-line-to-line (L-L-L)
 - (b) Line-to-ground (L-G)
 - (c) Line-to-line (L-L)
2. Explain how, when a line-to-ground (L-G) fault occurs, equal quantities of positive, negative and zero sequence currents are produced.
3. Explain how, when a line-to-line (L-L) fault occurs, equal quantities of positive and negative sequence currents are produced. Also, explain why no zero sequence currents occur with this type of fault.

J.R.C. Cowling

Electrical Systems - Course 135

UNBALANCED CURRENTS: THEIR EFFECTS

1.0 INTRODUCTION

The previous lesson, 135.01-1 explained that unbalanced currents, caused by faults in three phase systems, produce positive, negative and zero sequence components of current. This lesson explains how these components of current affect rotating and other electrical plant.

2.0 GENERATORS

2.1 Generators: Effects Produced by Positive and Negative Phase Sequence Currents

When a generator is subjected to balanced three-phase loading there will only be positive sequence currents flowing in the generator windings. However, when the generator is subjected to unbalanced loading, positive and negative sequence currents will flow. If a ground fault is present, zero phase sequence currents will also flow. The positive and zero sequence components of current create no problems but any continuous quantity of negative phase sequence current above about 0.08 - 0.15 per unit (depending on the generator in question) will cause severe damage to the rotor in a very short time.

Lesson 135.01-1 showed that a negative sequence current has an RWB phase rotation in the clockwise or negative direction. If a generator is subjected to unbalanced currents, there will be negative sequence (I_2) currents flowing in the stator windings. **These currents will produce negative phase sequence, or reverse rotation, flux in the generator.** The rotor, as it rotates in a positive direction will cut this flux which is rotating in the negative direction. See Figure 1. **Consequently, currents at a frequency of 120 Hz, (in the case of a 60 Hz machine) will be induced into the rotor body.** Due to skin effects, these currents flow on the surface of the rotor body and produce a great amount of heat which can irreparably damage a rotor in a very short time.

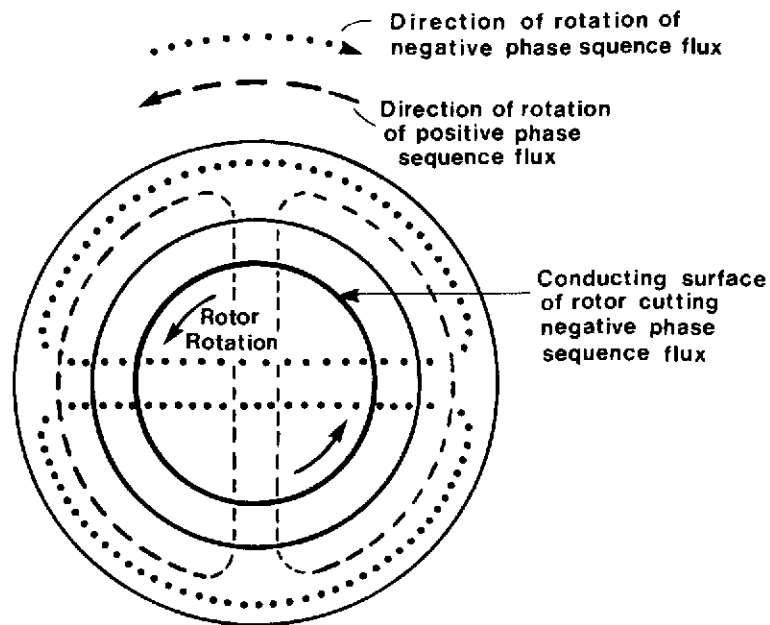


Figure 1: End view of generator rotor and stator showing rotor cutting negative phase sequence fluxes.

It has already been said that a generator can only withstand a 0.08 - 0.15 per unit value of negative phase sequence current **continuously**. When larger values of negative phase sequence currents occur, these currents produce rapid heating by $I_2^2 R$, where I_2 is the per unit value of negative sequence current (compared with full load current). The resistance R is the resistance of the iron in the rotor body and is assumed to be constant. As heat build up is time dependent, then the heating a rotor receives will depend on $I_2^2 R.t$. As R is constant, heating is proportional to $I_2^2 t$. Makers state that their generator rotors will have a certain $I_2^2 t$ rating. For example, Parsons Generators at BNGS 'A' have an $I_2^2 t$ rating of 3.0. If a negative phase sequence current of 0.5 per unit flows in the stator windings, the rotor will be damaged in 12 seconds. The calculation for this time is:

$$\text{Given: } I_2^2 t = 3.0.$$

Substituting 0.5 for I_2 gives

$$(0.5 \times 0.5)t = 3.0$$

$$t = \frac{3}{.25} = 12 \text{ seconds}$$

If the magnitude of I_2 was 2.0 per unit of full load current, the generator would be damaged after 0.75 seconds.

Larger generators have $I_2^2 t$ values of 2.5 - 10 and smaller generators have values up to 30.

Negative phase sequence current heating occurs when a generator is subjected to large magnitudes of negative sequence currents which persist for a long time. This can happen when:

- (a) Line and other faults are not cleared quickly.
- (b) A conductor burns through or breaks leaving only two lines in service giving, for example, only W-B current flowing in the generator. This W-B current is made up of equal quantities of positive and negative sequence components of current.
- (c) Incorrect test procedures where unbalanced currents in the generator are allowed to persist for long periods of time.

It should now be appreciated that generators should be protected against damaging quantities of negative sequence current and this is achieved by using relays and networks which operate when excessive values of $I_2^2 t$ occur. An alarm is provided which operates when the continuous I_2 rating of the generator is exceeded (usually 0.08 to 0.15 pu of full load current for large generators) and a trip occurs when the $I_2^2 t$ rating is exceeded.

2.2

Detection and measurement of negative sequence currents. Figure 2 shows three CT's installed at the neutral of a generator. The output of the CT's is fed into a negative sequence current detection network. The network has two outputs:

- (a) a "low set point" output which feeds a relay which is set to give an alarm when the **continuous** I_2 rating of the generator is exceeded.
- (b) a "high set point" output which is fed into either a disc type or a thermal type relay. The output from this relay is arranged to trip the generator after the $I_2^2 t$ setting has been exceeded.

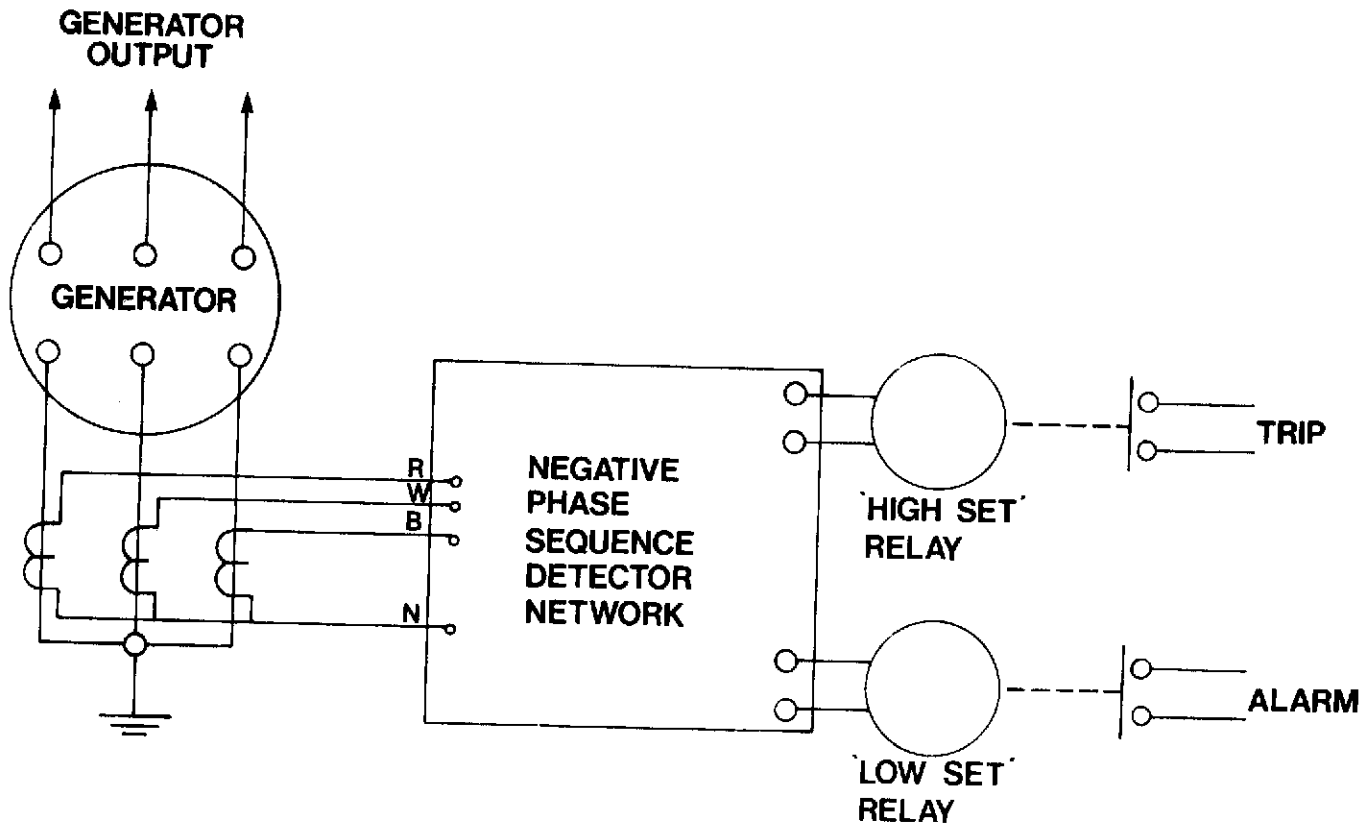


Figure 2: Diagram showing how a negative phase sequence trip and alarm is achieved.

- 2.3 Effects produced by zero sequence currents.
- The previous lesson has already explained that zero sequence currents only occur when a generator is subjected to ground fault current. The fluxes produced in a generator by zero sequence currents will not take the usual loop paths as shown in Figure 1. Because the currents are all in phase (not displaced by 120°) the fluxes produced by each winding will also be in phase and produce fluxes which flow toward the centre of the generator rotor. Figure 3(a) shows the flux produced by each phase flowing radially inwards. Figure 3(b) shows that the fluxes must form complete loops. Note that these loops pass inwards towards the centre of the rotor and then longitudinally before returning via bearings, hydrogen seals and the iron frame to the source. Because a ground fault is usually cleared within a few cycles, these fluxes usually cause little or no damage - with one exception. This exception is that the shaft can become magnetized **longitudinally** and the residual value of magnetism can be quite large. During subsequent running, eddy currents can be induced by this residual magnetism onto bearings and hydrogen seals. These currents can wreck the delicate surfaces of the bearings and hydrogen seals. The only way of demagnetizing the rotor is to apply a reverse mmf which will provide the necessary demagnetizing force.

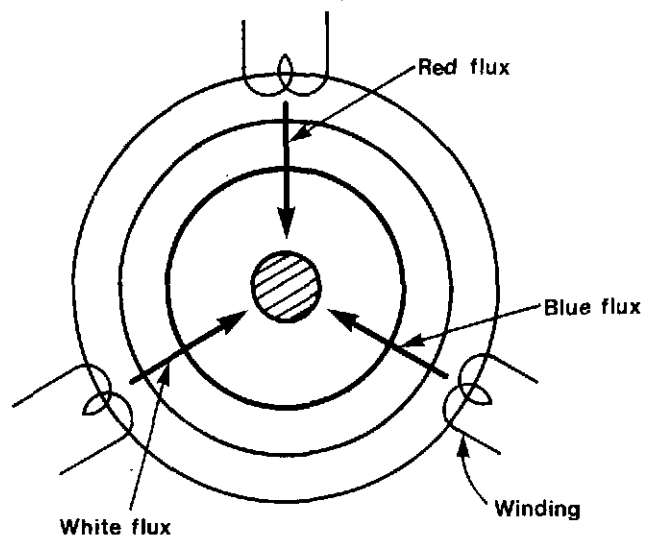


Figure 3(a): Endview of generator showing fluxes produced by zero sequence currents.

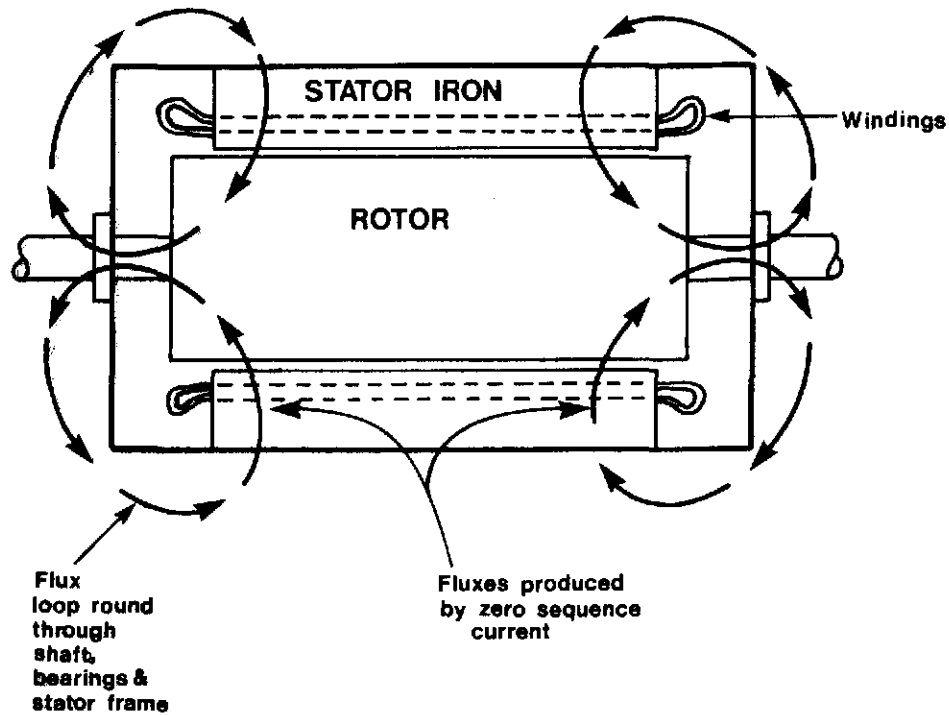


Figure 3(b): Fluxes produced by zero sequence currents.

Smaller generators, combustion turbines etc, are usually directly connected to the system so ground faults on the generator or on the system will cause zero (and positive and negative) sequence currents to flow in the generator. All large generators are connected to the system using step-up transformers having a delta primary (LV) and a star secondary (HV). Ground faults occurring on the secondary side of the transformer, ie, the HV transmission system, will appear as a line-to-line (L-L) fault at the generator. Figure 4 shows how this occurs.

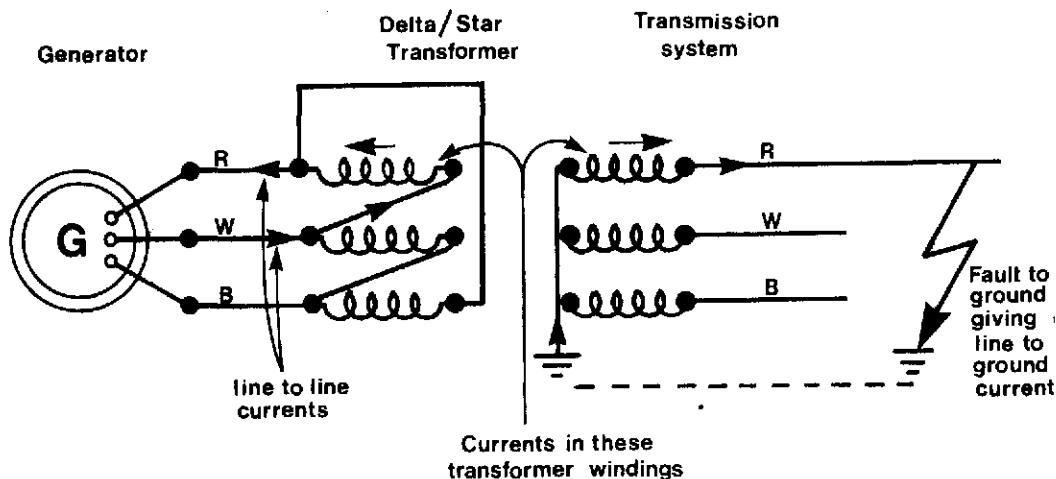


Figure 4: Transmission L-G fault producing L-L currents in generator.

It follows that when a transmission L-G fault occurs, no ground or zero sequence currents flow in the generator. However, it should be appreciated that when a L-G fault occurs on the generator windings, main connections or the transformer primary, ground and zero sequence currents will flow in the generator.

3.0 INDUCTION MOTORS

3.1 Effects produced by positive and negative sequence currents. When a normal 3 phase balanced supply is switched onto an induction motor, a rotating magnetic field is created which causes the motor to start and run. However, unbalances can occur in the supply current due to unbalanced windings or unbalanced supply voltages (for example, different impedances in the supply lines or blown supply fuses).

If the currents to the motor are unbalanced, then due to the negative phase sequence component of current flowing in the stator windings, the motor will be subjected to a rotating magnetic field rotating in the positive or normal direction **and** a negative rotating field which is rotating in the **reverse** direction. The reverse rotating magnetic field will:

- (a) apply a reverse torque to the rotor.
- (b) tend to reduce the output torque.
- (c) cause the motor to draw more current from the supply. The reverse RMF will produce a reverse torque. Consequently the motor has to take more current to drive the load.
- (d) induce 120 Hz currents in the rotor (in the case of a 60 Hz motor). These current will cause extra heating in the rotor and can lead to severe damage.

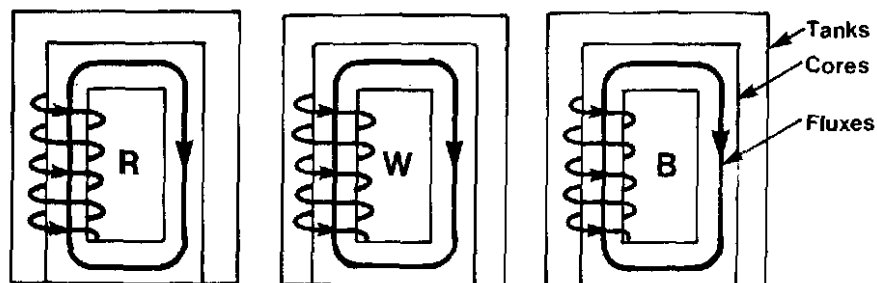
To guard against motor damage, negative phase sequence protection can be applied to induction motors. Because this type of protection is very expensive, the normal phase unbalance protection is usually adequate. P&B Golds relays have a phase unbalance detecting mechanism which is set to trip if the magnitude of the current unbalance is 12% or 20% depending on the built in setting on the relay. The setting is determined by the spacing of the phase unbalance contacts.

3.2 Effects Produced by Zero Sequence Currents

Zero sequence currents, because they are quickly cleared from the system, do not produce any damage or problems in induction motors. If the fault producing zero sequence currents was slow to clear it would have a braking effect on the motor as all the rotor conductors would be cutting this flux.

4.0 TRANSFORMERS

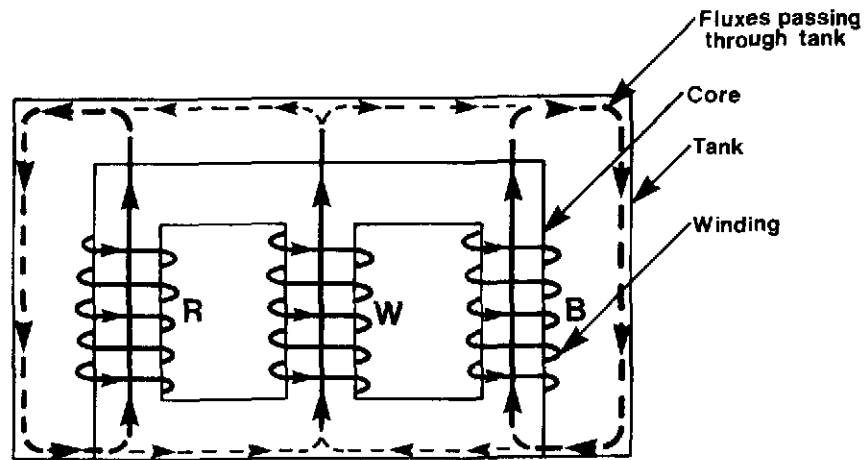
- 4.1 Because three-phase transformers do not have rotary components, they will operate equally well when supplying positive, negative or a combination of positive and negative sequence currents. If the three-phase transformer consists of three single phase units, the transformer can supply zero sequence currents. The fluxes produced by these currents circulate in the cores producing no problems. See Figure 5.



NOTE: Fluxes are all in phase

Figure 5: Fluxes produced in three single phase transformers, by zero sequence currents.

However, if the transformer is a three phase unit, see Figure 6, the fluxes produced by the zero sequence currents all flow in the same direction in the core and consequently there is no return path via the core. The fluxes have to return via the tank walls, clamps etc. Again, because ground faults are cleared quickly, the problems caused in transformers by zero sequence currents, cause no damage. If the fault was allowed to persist, considerable eddy current heating of the tank would occur.



NOTE: fluxes are all in phase

Figure 6: Fluxes produced in a three phase transformer by zero sequence currents.

ASSIGNMENT

1.
 - (a) Explain how 120 Hz currents can be produced in the rotor of a 60 Hz generator.
 - (b) Explain how these currents can damage a generator rotor.

2. A generator has the following characteristics stated by the manufacturer:
 - (i) I_2 continuous withstand = .12 pu
 - (ii) $I_2^2 t = 4.0$
 - (a) Explain what these figures signify.
 - (b) If a generator having an $I_2^2 t = 15$ was subjected to a L-G fault at its terminals and the negative phase sequence current was .75 pu, how long could the generator continue to operate before its rotor became damaged?

3. Line to ground faults on the transmission system for large generators produce positive and negative phase sequence currents at the generator terminals. Line to ground faults on the transmission system for small generators produce positive, negative and zero phase sequence currents at the generator terminals. Explain, using a labelled diagram, why this difference occurs.

4. Explain the effects negative and zero phase sequence currents have on:
 - (a) An induction motor.
 - (b) A transformer.

J.R.C. Cowling

Electrical Systems - Course 135

FURTHER EXAMPLES OF ELECTRICAL PROTECTIVE RELAYS

1.0 INTRODUCTION

Lesson 235.02-1 examined electrical protective relays used for motor protection and lesson 235.02-2 covered the basics of protective relays and schemes used to protect busbars, transformers, generators and power lines. This lesson examines, in greater detail, the principles of relays used to protect generators, transformers etc. The next two lessons will examine how these relays are connected to form composite ac and dc protective schemes for transformers, generators and other items of electrical equipment in a generating station or heavy water plant.

2.0 DIFFERENTIAL RELAYS

2.1 Principle of Operation

Figure 1(a) shows the principle of differential protection applied to a healthy busbar circuit. Current transformers (CT's) of equal ratio are installed on the external side of the breakers which protect a section of busbar B₁. A current operated relay is connected between two wires interconnecting the CT's. During healthy conditions, equal currents will flow in and out of the circuit and because the CT's have equal ratios, each CT will give an equal output. The CT outputs I_{S1} and I_{S2} will circulate around the interconnecting circuit. Note, that the currents in the relay, flow in opposite directions and therefore cancel.

Figure 1(a) shows the instantaneous directions of current flow and Figure 1(b) the dc equivalent of the ac secondary circuit. This circuit illustrates the current behaviour in the secondary circuit.

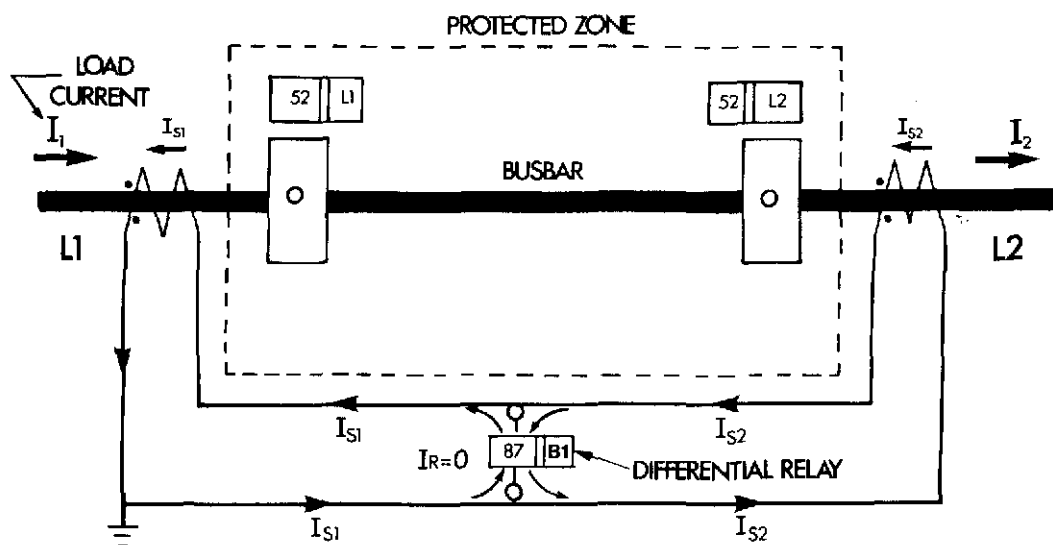


Figure 1(a): Healthy busbar - currents in relay balance; relay 87-B1 does not operate.

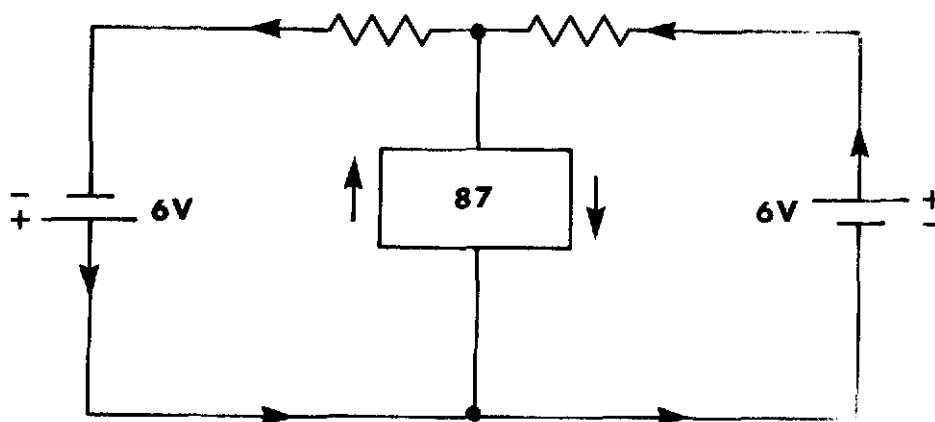


Figure 1(b): DC equivalent of the ac secondary circuit.

In Figure 2(a) the primary currents I_1 and I_2 are not equal and consequently the secondary currents are not equal. There will be a resultant current in the relay causing it to operate and trip the two breakers 52-L1 and 52-L2, de-energizing the busbar. Figure 2(b) shows the dc equivalent of the ac secondary circuit.

Because the differential relay (87-B1) will not operate with load current or "through faults" ie, faults outside the protected zone, it can be set to operate at a low value of current thereby giving rapid operation when a fault occurs. A typical setting for relay 87-B1 is 20% of full load current. There is no need to time delay the operation of relay 87-B1 and therefore a fast acting attracted armature type of relay is used.

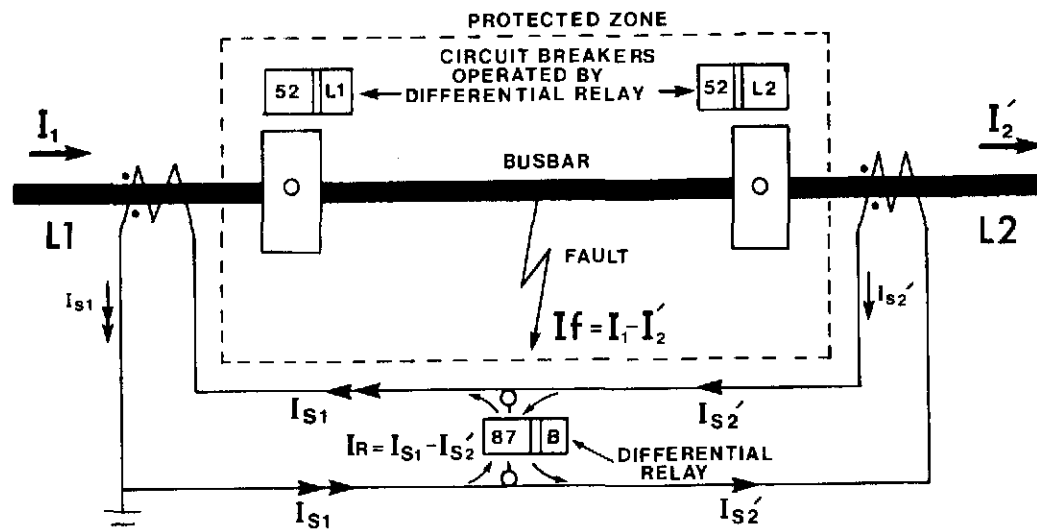


Figure 2(a): Unhealthy or faulted busbar - relay operates with current $I_{s1} - I_{s2}$

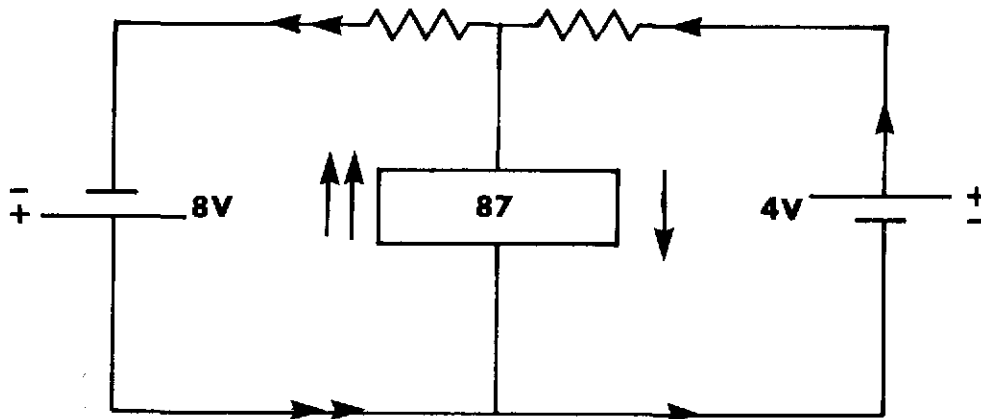


Figure 2(b): DC equivalent of the ac secondary circuit.

Protection of "T" circuits. Figure 3 shows a "T" circuit protected by differential protection. For simplicity, the current is shown to enter via line 1 and leave in equal amounts via lines 2 and 3. Note:

- (a) the protected zone.
- (b) the flow of currents in the CT's and secondary circuits.
- (c) there is no current flowing in the relay.

If a fault now occurs inside the zone, the currents entering and leaving the zone will not balance. Current will flow in the relay which will be connected to trip all the three breakers. This type of protection is normally used where "T" connections are employed on busbars and generator circuits.

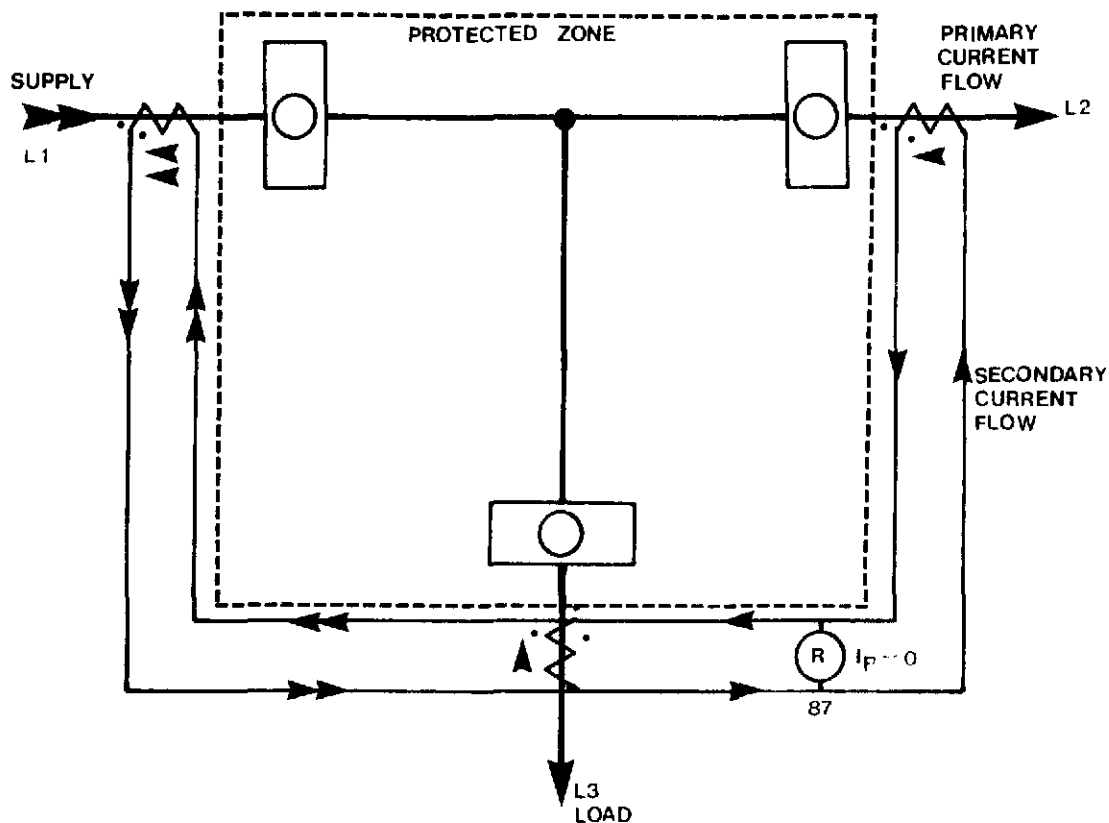


Figure 3: Differential protection applied to a "T" feeder. Note primary and secondary current flow.

2.2 Types of Differential Relay

2.2.1 Simple differential relays. The differential relays shown in Figures 1(a), 2(a) and 3 are simple current operated attracted-armature relays. Although this basic type of relay can be used for protecting generators and transformers, they are rarely used because:

- (a) The CT's feeding the relays, when an out-of-zone fault occurs, may not give exactly balanced outputs. Any unbalance in the output from the CT's may cause the relay to malfunction. The example given in Figure 4 shows the situation which can occur when two CT's each of 500/5 ratio, and each having a 1% error, are subjected to a through or out of zone fault current of 10 kA. The relay, set at 20% of 5A or 1A, will have a current of 2A flowing in it and it will mal-operate causing the breakers to trip incorrectly for the out of zone fault.

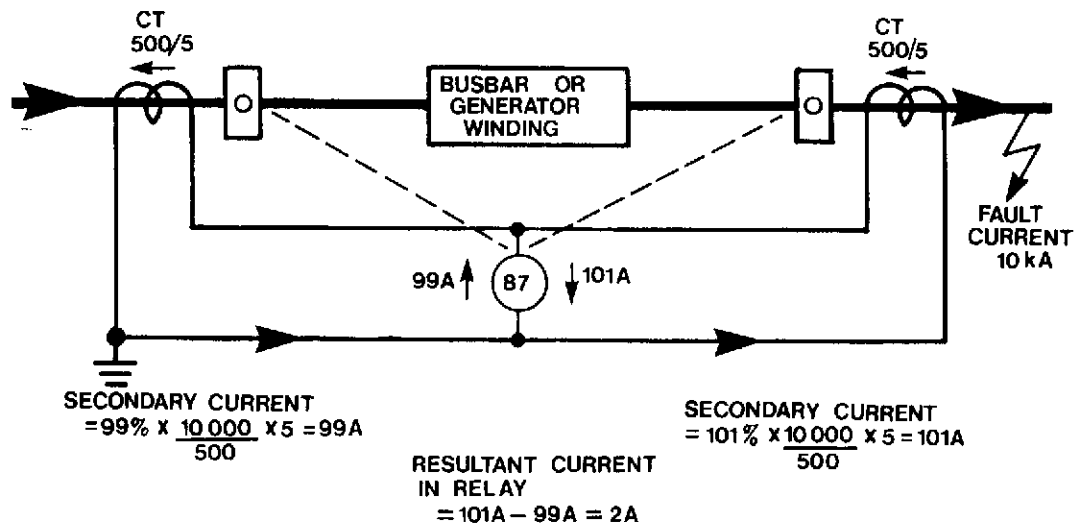


Figure 4: Current transformer errors causing differential relay to mal-operate on an out of zone fault.

- (b) In the primary circuit, there may be transformers with tap changers. Tap changers cause the transformer to produce a different voltage and current ratio. Unless the CT's also have taps, (which is very rarely the case), when the transformer is on a tap other than the one giving the nominal ratio there will be an unbalance in the CT output currents.

2.2.2 Percentage Differential Relays. To overcome these problems detailed in 2.2.1 (a) and (b), relays are made with restraint coils as well as operating coils. These restraint coils prevent tripping during through a "out-of-zone" fault conditions, but should an "in-zone" fault occur, tripping will take place.

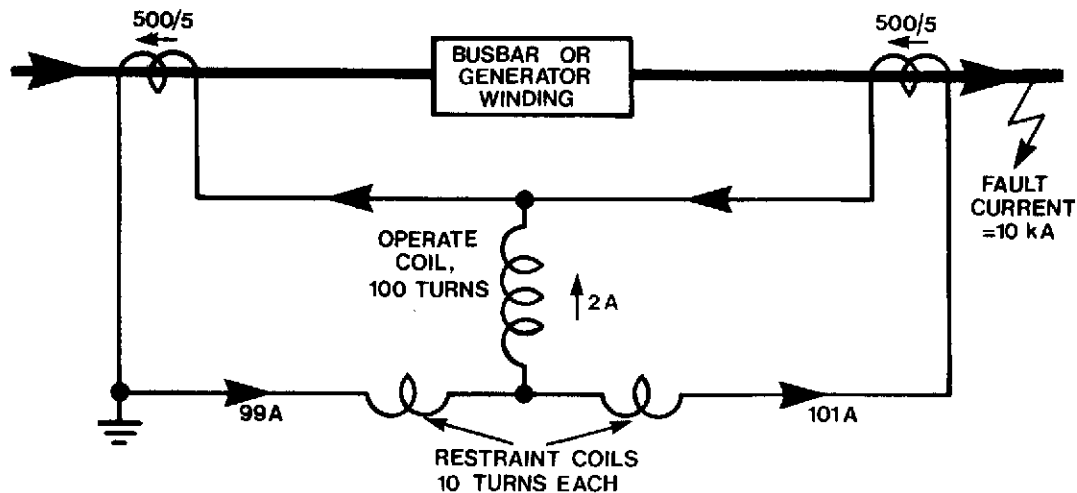


Figure 5(a): Differential relay with restraint coils. Relay does not mal-function when an out of zone fault occurs.

Figure 5(a) shows how the restraint and operating coils are connected. A typical relay is considered, which has 100 turns on its operate coil and 10 turns on each of its restraint coils. Under the same fault conditions as shown in Figure 4, the restraint coils produce $(99 \times 10) + (101 \times 10) = 2000$ ampere-turns. The operate coil produces $2 \times 100 = 200$ ampere-turns. Clearly, the restraint coils produce a greater magnetic force and the relay does not operate. For the relay to operate, the ampere-turns of the operating coil must exceed the ampere-turns of the restraining coil.

Figure 5(b) shows how a balanced beam type of differential relay is used. Under healthy or out of zone fault conditions, the restraint coils have a greater pull and prevent tripping. When an inzone fault occurs, the operate coil has a greater pull and the relay operates tripping the appropriate breakers. The breakers are not shown in Figure 5(b).

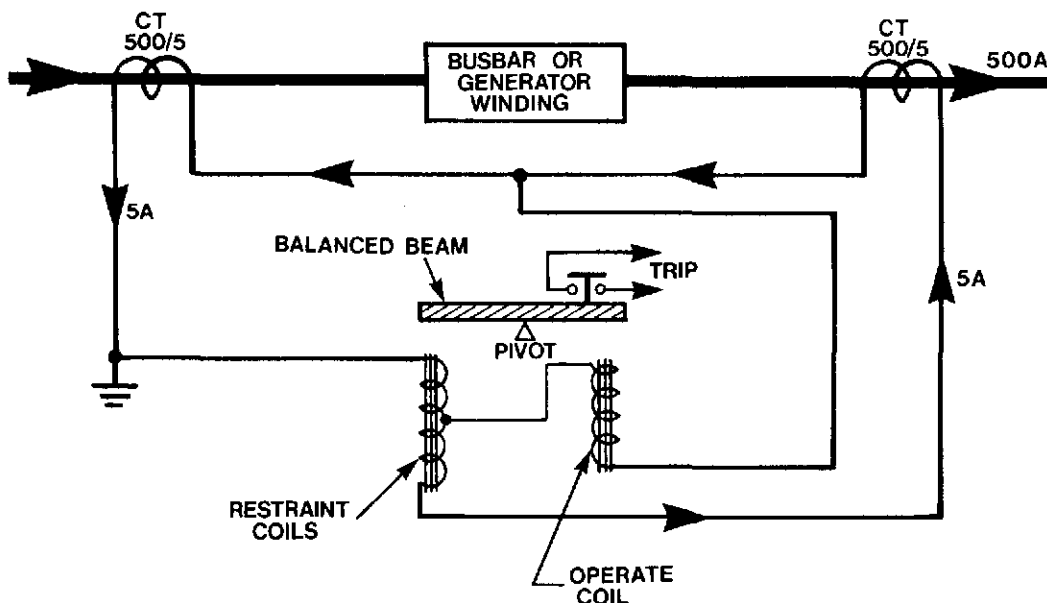


Figure 5(b): Balanced beam type differential relay.

Most manufacturers provide tapplings on the restraint coils. This enables the amount or percentage of the restraint to be altered to allow for:

- (a) CT ratio errors.
- (b) the unbalance in CT outputs produced by tap changers on transformers. See section 2.2.1(b).

To overcome these problems, sufficient (but not too much) restraint has to be provided and this is done by selecting the correct tap. Figure 6 shows, for various percentage tap settings of the restraint coils, curves of through or out of zone fault current versus levels of current to operate the relay.

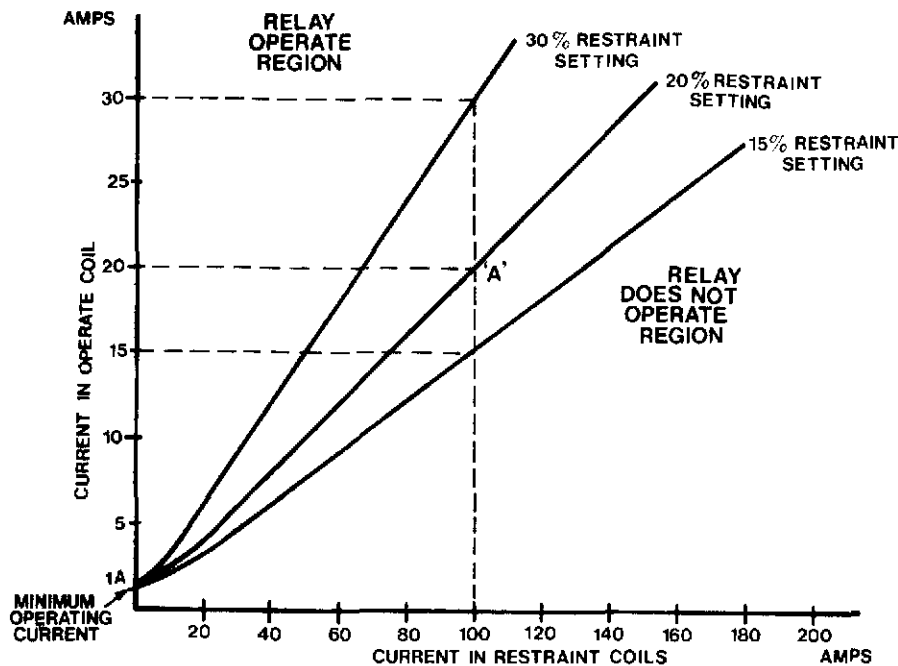


Figure 6: Typical operating characteristics of a percentage differential relay.

Taking the example shown in Figure 4, if the relay is set at 20%, see Figure 6, and 100 A flows in each of the restraint coils each having 10 turns, $100 \times 10 \times 2 = 2000$ ampere turns of **restraint force** are produced.

Before the relay can operate, a current greater than 20 A must flow through the 100 turn operating coil producing more than $20 \times 100 = 2000$ ampere turns of **operating force**. See point A in Figure 6 on 20% restraint setting, (also called 20% slope).

- 2.2.3 Harmonic Restraint Differential Relays. When transformers are switched onto their supply, there is a surge or inrush of current taken from the supply. Consequently, only the CT's on the supply side give an output which will cause a simple or a percentage differential relay to operate. It is worth noting that the surge only lasts for 10 - 20 cycles.

To overcome this problem, relays are produced which have a time delay which prevents tripping for approximately 0.5 sec. Unfortunately, the longer the tripping is delayed, the greater the damage that can be produced in the transformer. Analysis of the surge or inrush current shows that the current consists of appreciable quantities of second and third harmonics of 60 Hz, ie, 120 and 180 Hz. Filters are therefore provided which ensure that:

- (a) only 60 Hz currents flow through the operate coil.
- (b) the 120 and 180 Hz currents are used to produce additional restraint for the relay.

Figure 7 shows how a balanced beam relay can be used to provide the operate, restraint and harmonic restraint features that are required. During normal operation, the restraint coils prevent relay operation. During a healthy "switch in", when the supply side CT's are only giving an output, restraint is provided by the harmonic restraint coil. At any time,

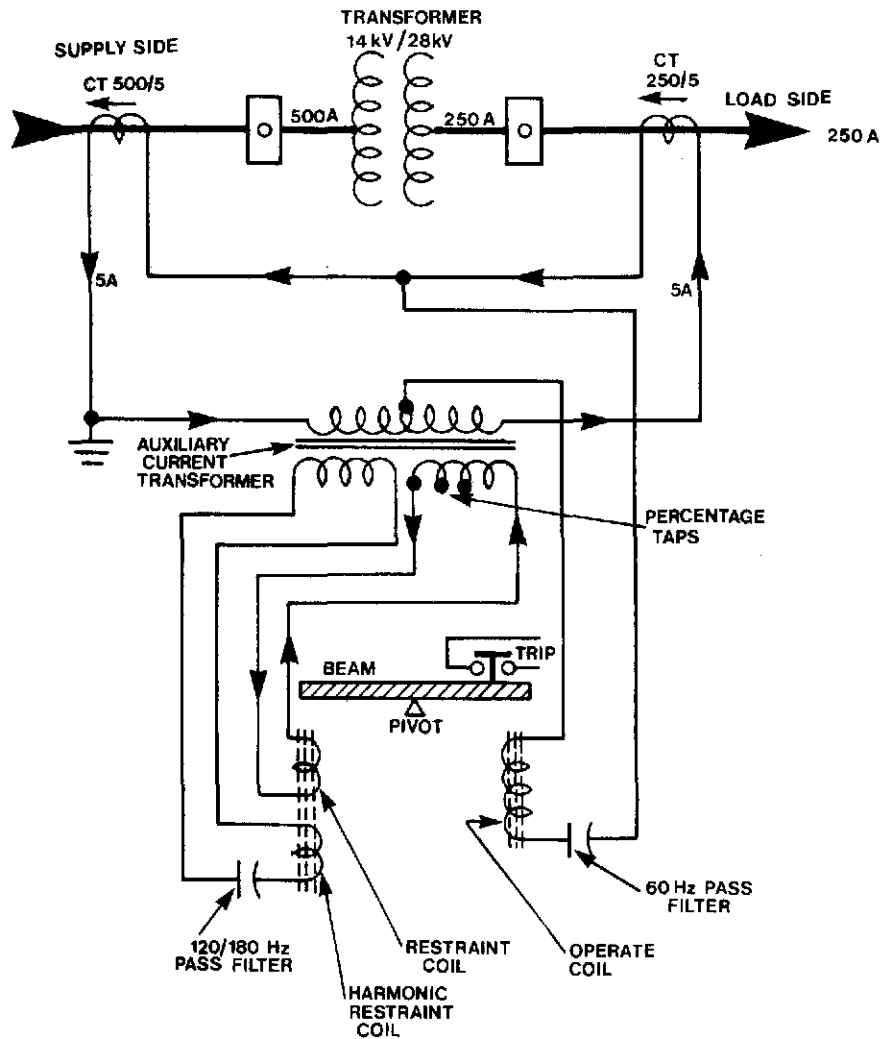


Figure 7: Percentage differential relay with harmonic restraint. Current flow are shown for a healthy condition.

should an in zone fault occur, the operate coil will provide sufficient operating force to tip the beam and send the necessary trip signals. Note, no time delay is required in this relay scheme.

The type of relay shown in Figure 7 shows the essential features for percentage differential protection with harmonic restraint. Some manufacturers, in place of the beam, use a disc, and others an attracted armature relay.

In Figure 7 note that both current transformers have the same secondary current of 5.0 A. This ensures that under healthy conditions no current will flow in the differential relay. This subject is covered in more detail in the next lesson.

3.0 OTHER TYPES OF TRANSFORMER PROTECTIVE DEVICE

3.1 Gas and Oil Relays

While the differential relay is the main means of protection for most transformers in the large sizes and at higher voltages, other measures may be used either alone or in addition to the differential relay. One such scheme which is particularly applicable to the oil filled transformer is the gas relay illustrated in Figure 8.

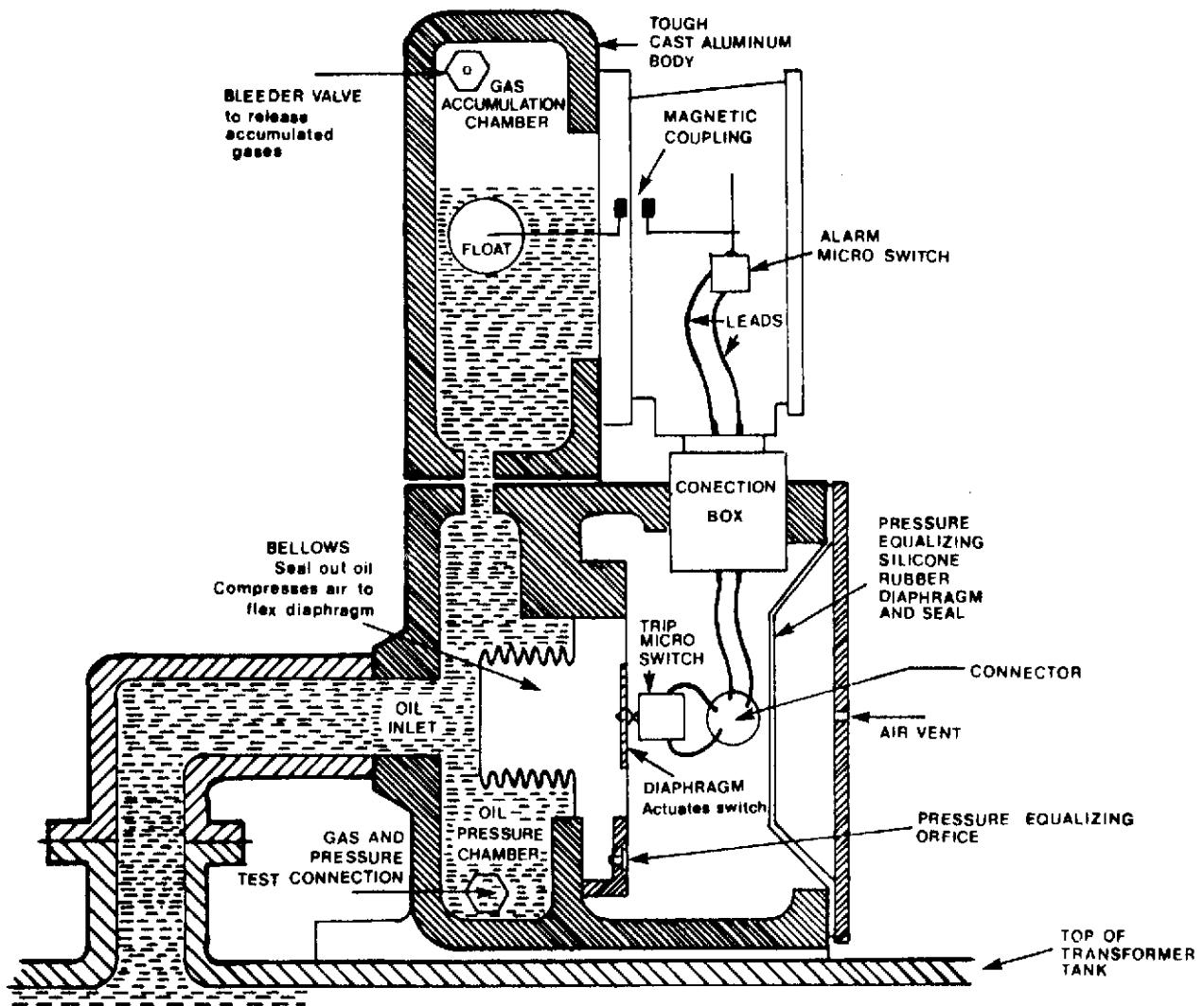


Figure 8: Sectional view of gas and oil relay.

This relay consists of 2 separate elements,

- (a) An upper element which detects the slow accumulation of gas produced by a fault developing in the transformer. For example, a loose connection will produce arcing in the oil. The oil will break down producing quantities of methane, hydrogen, acetylene and other gases. The relay will collect these gases and when the predetermined level has been reached, the float will fall and initiate an alarm. The big advantage of this type of relay is that it detects a fault **inside** the transformer **before** large fault currents flow causing severe damage.
- (b) A lower element operates when a more violent type of fault occurs in the transformer tank. This type of fault produces a pressure surge in the oil which compresses the bellows in the relay. The pressure in the space between the bellows and the diaphragm also rises. This makes the diaphragm flex and push the microswitch which initiates a trip of the transformer.

A gas and oil relay must be mounted at the top of a transformer tank. This will ensure that it will collect all the gases that are produced.

4.0 THERMAL SENSING AND MEASURING DEVICES

4.1 Direct Measurement

In many instances, it is possible to measure the temperature of electrical equipment directly. An example of this, is the method used for measuring the temperature of the core laminations in a generator or motor. A direct measurement is possible because the core is grounded. Another example is where the temperature of water cooled windings in a large turbo-generator are measured by measuring the temperature of the cooling water leaving the windings.

4.2 Indirect Measurement

Measuring the temperature of live conductors is much more difficult and involves the use of insulated sensors or **thermal image** devices.

Insulated sensors are occasionally used to measure the winding temperature of small domestic motors. Because of possible safety implications, they are not used for winding temperature measurement of 3 phase motors in generating stations.

An indication - but not an accurate measurement of the winding temperature in a motor can be achieved by measuring the cooling air temperature. A factor is then added on to allow for the temperature difference between the conductor and the cooling air.

Temperature measurement on motors using thermal relays producing thermal images is explained in lesson see 235.02-1. This method is satisfactory for use in motors but with oil filled transformers, a more accurate method is used.

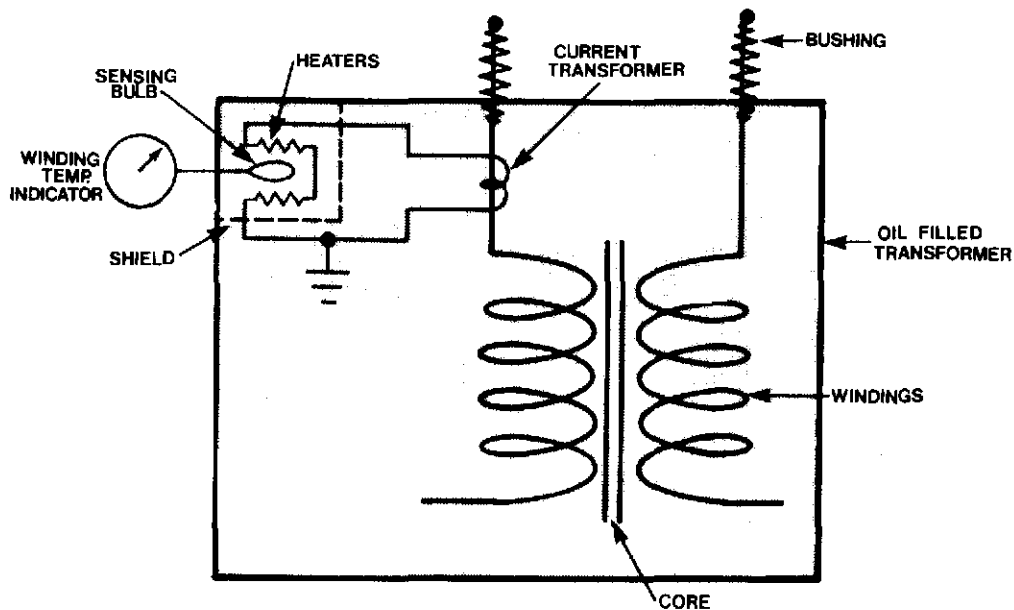


Figure 9: Principle of transformer winding temperature measuring device.

Figure 9 shows the principle of transformer winding temperature measuring device. Under load, the windings and core in a transformer will produce heat which is transferred to the oil. Due to convection, the hottest part of the oil is at the top of the tank. A temperature sensing device situated at the top of the transformer would record the top oil temperature but not the winding temperature. Obviously, the windings will operate at a temperature greater than the top oil temperature. To make the temperature indicator sense a temperature which is the same as the winding temperature, a small heater surrounds the sensing bulb which is placed in the hot oil at the top of the tank. This heater is connected to a current transformer which supplies the heater with a fraction of the main winding current. It would now be appreciated that:

- (a) The winding I^2R and iron losses will heat the oil and due to convection, the hottest oil will be at the top of the tank. Because the winding is a source of heat, the hottest part of the winding - usually called the **winding hot spot** will be hotter than the top oil. The winding hot spot temperature will therefore be the top oil temperature **plus** an increase due to the I^2R produced in the winding.
- (b) The winding temperature indicator will indicate the hot spot temperature, ie, the top oil temperature **plus** an increase due to I^2R produced by the heater.
- (c) The winding temperature indicator, after being correctly set up by the manufacturer, will give a true **thermal image** of winding hot spot temperature under all operating conditions.

4.3 Temperature Measurement Using Change in Resistance

Because of reactance being present, resistance in ac circuits cannot be measured by applying ac voltage and current. However, on dc circuits, temperature is frequently measured by observing the change in resistance of a coil or a winding and converting this change in resistance into a temperature reading. This type of measurement is used to measure the temperature of the dc rotor windings in an ac generator.

Figure 10 shows how the resistance of copper varies linearly with temperature. If the temperature of a winding is reduced, then at some temperature $-T$, the value of resistance will become zero, i.e., material becomes superconducting. Figure 10 illustrates this.

The cold conditions are represented by the solid triangle and the hot conditions are represented by the dotted triangle. As the triangles are similar, then the magnitudes of their sides are in direct ratio.

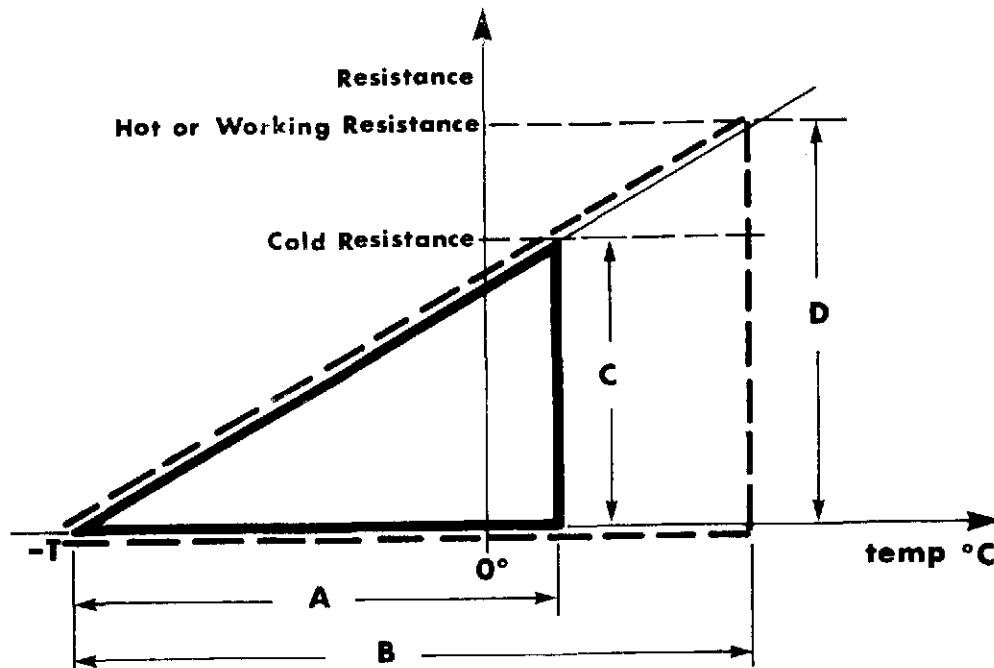


Figure 10: Resistance as a function of temperature.

Therefore, by comparing lengths of the sides of the triangles,

$$\frac{A}{B} = \frac{C}{D}$$

Note:

Length A is $-T$ plus the cold temperature
 Length B is $-T$ plus the hot or working temperature
 Length C is the cold resistance
 Length D is the hot resistance

The best way of illustrating the above is to consider an example.

Example:

A generator rotor takes 4000 A at 400 V at 20°C and 4000 A at 480 Volts when operating at its operating temperature. The rotor is wound using a copper conductor. What is the operating temperature of the conductor?

$$\text{Cold resistance} = \frac{V}{I} = \frac{400}{4000} = 0.1$$

$$\text{Hot resistance} = \frac{480}{4000} = .12$$

Substituting the above in the equation:

$$\frac{A}{B} = \frac{C}{D}$$

$$\text{gives } \frac{20 + 234.5}{B} = \frac{.1}{.12}$$

The value of $-T$ of -234.5°C is obtained from Table 1.

$$\text{Length } B = \frac{.12}{.1} \times 254.5 = 305^{\circ}\text{C above } -T^{\circ}\text{C}$$

$$\text{Hot Temp} = 305^{\circ} - 234.5^{\circ} = 70.5^{\circ}\text{C above } 0^{\circ}\text{C}$$

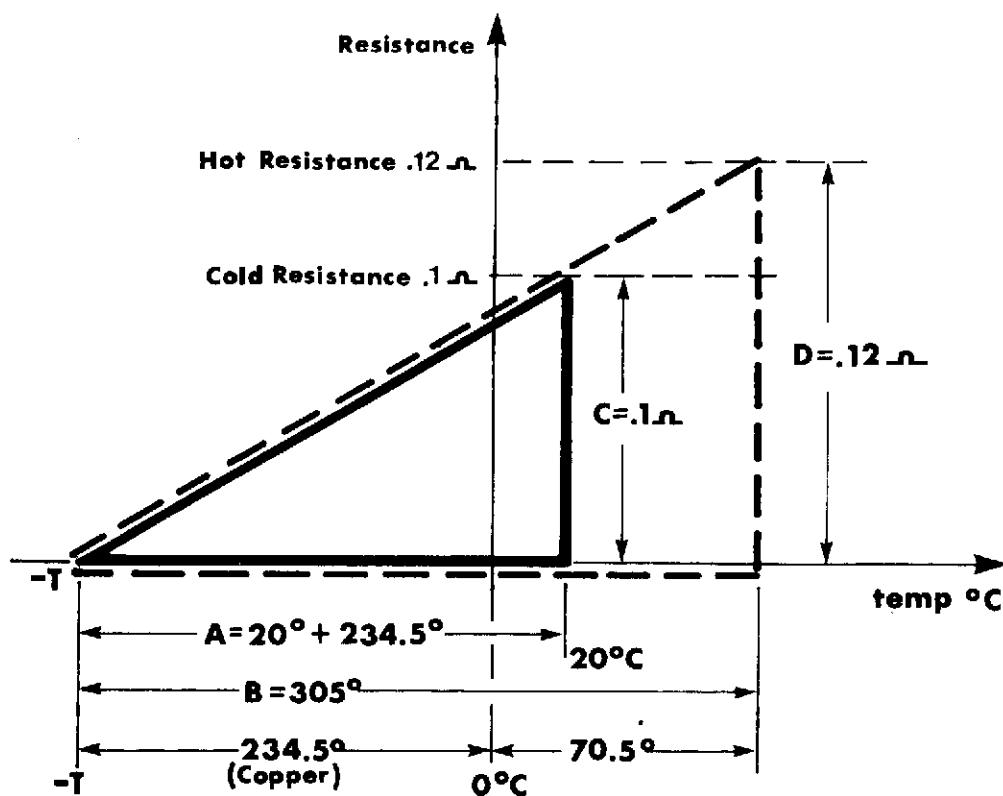


Figure 11: Diagram Illustrating Example.

Table 1: Values of $-T$ for Some Common Electrical Conductor Materials

CONDUCTOR MATERIAL	$-T$ (in $^{\circ}\text{C}$)
Silver	-243
Copper	-234.5
Aluminum	-236
Tungsten	-202
Nickel	-147

Where a spot or a single reading is required, the voltage and current are measured with the winding cold and then a further reading is taken of voltage and current when the winding is hot. A calculation will then give the winding temperature.

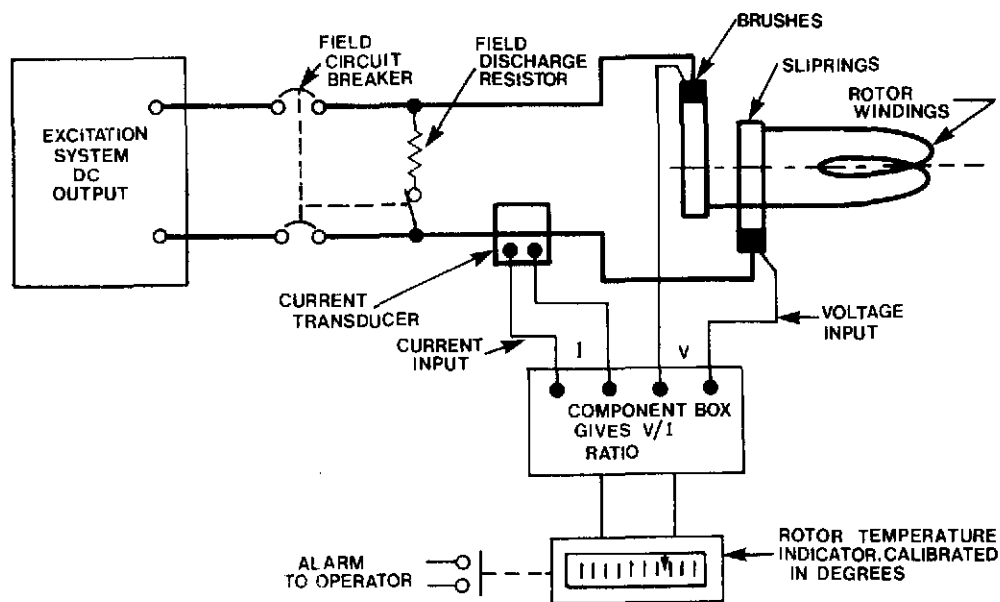


Figure 12: Circuit for rotor temperature indicator.

Where continuous monitoring of temperature is required, for example on the dc rotor of a turbine-generator, an instrument called a **rotor temperature indicator** has been devised. This indicator measures the resistance by comparing the ratio of voltage to current. Figure 12 shows the basic circuitry of a rotor temperature indicator for a turbo-generator. The indicator is supplied with alarm contacts which warn the operator when the rotor temperature limit has been exceeded.

ASSIGNMENT

1. By considering "in zone" and "through" faults, explain, using labelled diagrams, how differential protection is used to protect a busbar.
2. (a) By considering "in zone" and "through" faults, explain, using labelled diagrams, how differential protection is used to protect a busbar with a Teed connection.
(b) Will all the current transformers have the same ratio? Why/why not?
3. Explain, using labelled diagrams, why:
(a) percentage differential relays are required for protecting generators.
(b) percentage differential relays with harmonic restraint are required for protecting transformers.
4. (a) Explain how a transformer can be protected using a gas and oil relay.
(b) State why the gas and oil relay can protect the internal components in a transformer but cannot protect the rest of the circuit.
(c) Given an outline diagram of a gas and oil relay, label the principal components and explain their function.
5. Using a labelled diagram, explain how to accurately measure the temperature of the windings of a loaded transformer.
6. Using a labelled diagram, explain how to accurately measure the temperature of the rotor windings in a turbo generator. The turbo-generator is assumed to be on full load.

J.R.C. Cowling

Electrical Systems - Course 135

COMPOSITE ELECTRICAL PROTECTIVE SCHEMES: PART I

BUSES AND TRANSFORMERS1.0 INTRODUCTION

Following on from lesson 135.03-1, this lesson shows composite protective schemes for buses and large transformers. The actions of the **ac** part of the protection (fed from CT's) are described together with the **dc** tripping to the respective breakers.

2.0 PROTECTION OF CIRCUITS2.1 Essential Features

All forms of electrical protection must:

- (a) **Protect all sections** of the circuit in question. There must not be any section or sections which are not fully protected.
- (b) Be **stable**. Operation of the protection is only permitted when a fault occurs within its designated **zone**. Operation is not permitted for faults occurring outside the designated zone.
- (c) Have an adequate **sensitivity**. It must be able to distinguish between healthy and fault conditions, ie, to detect, operate and initiate tripping before serious damage occurs.
- (d) Have an adequate operating **speed**. When electrical faults or short circuits occur, the damage produced is largely dependent upon the time the fault persists. Therefore electrical faults must be interrupted as quickly as possible.

3.0 PROTECTION SYSTEMS FOR BUSES

The previous lesson 135.03-1, sections 2.1 and 2.2 showed the principles of busbar protection when it is applied to single and teed busbars.

3.1 Generating Station Distribution Buses

Figure 1 shows a distribution bus similar to that used for the 13.8 kV system at Bruce NGS'A'. Note that the currents flowing into the bus from the supply transformers and the currents flowing to the load circuits are monitored by CT's, each CT having the same ratio. The bus will be healthy provided that the currents leaving the bus **exactly** equal the currents feeding the bus. Under this condition, the CT secondary currents will also balance and there will be no current in the differential relays (87 and 87N).

In the event of a fault on the bus, the differential relays (87 and 87N) will operate and trip all sources of infeed, ie, supply breakers #1 and #2 and the feeder breakers.

Note that the three 87 relays will operate for busbar to busbar (ie, line to line) faults within the bus while the 87 neutral relay will operate only when a line to ground fault occurs.

The actual tripping circuit and devices are covered in detail in the next few pages.

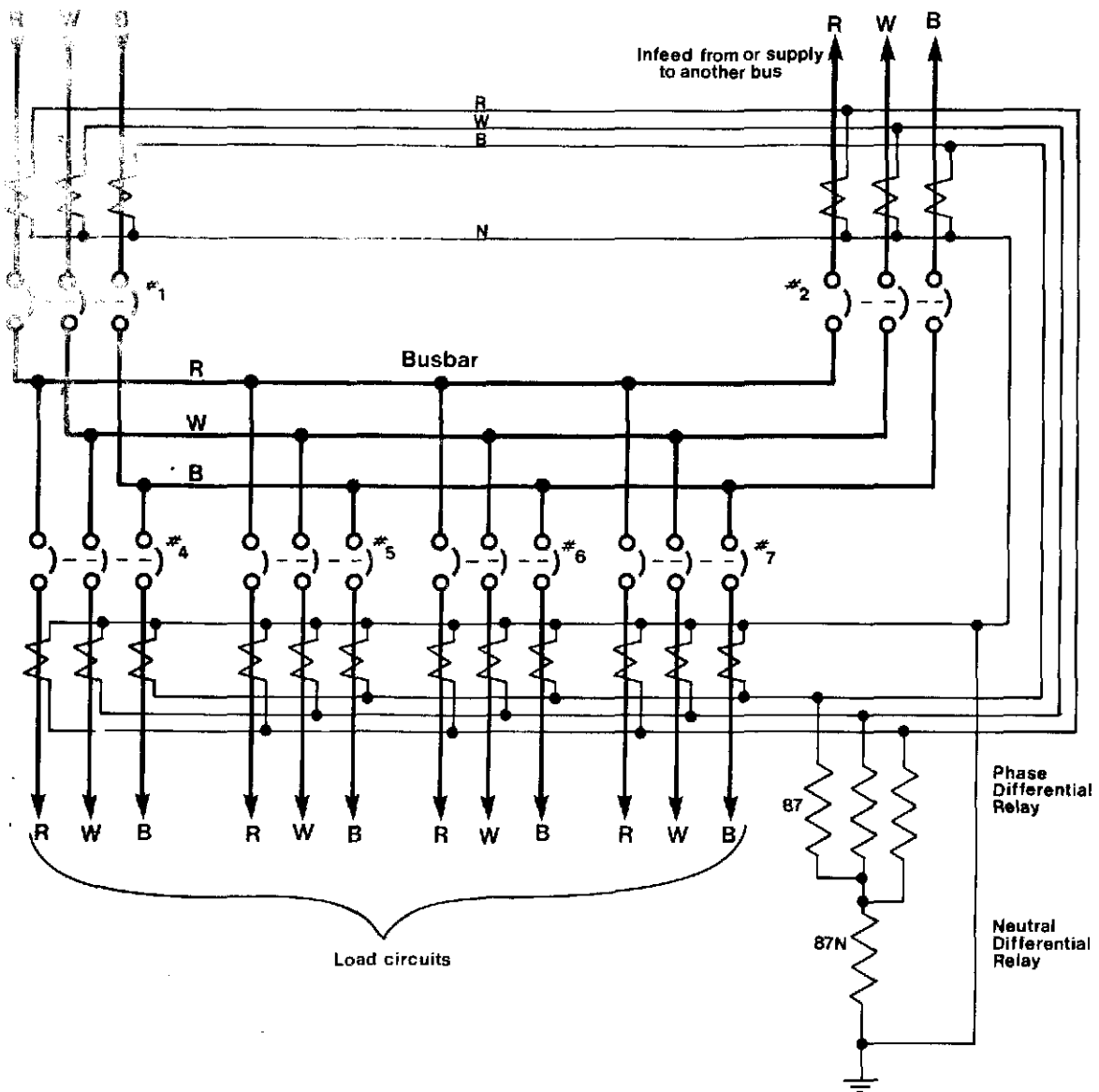


Figure 1: Differential busbar protection applied to a 13.8 kV station bus.

3.2 Generating Station Switchyard Buses

Figure 2 shows the type of ring bus layout used at Pickering and other generating stations. The bus is shown divided into four sections, A, B, C, D. Breakers separate each section from the two adjacent sections.

Section 'A' of the busbars is protected by a differential protection relay (87-A). This relay compares the currents leaving breakers A-B, and A-D with the current entering the bus from generator G1.

Section 'D' of the busbars is directly connected to line L1, and as far as the protection is concerned, this bus is part of L1. Because the system services transformers SST-1 is also directly connected to bus 'D', any current taken from the bus by this transformer must be subtracted from the currents flowing through breakers A-D and C-D. Failure to do this will give incorrect measured values of current flowing down the line.

Section 'B' of the bus is protected in a similar manner to bus 'D' and L1. Section 'C' of the bus is protected in a similar manner to bus 'A'.

In the event of a fault at F1 on bus 'A' all sources of infeed to the fault must be tripped.

Because the fault is inside the zone of bus 'A', relay 87-A will operate and open breakers (A-B) and (A-D). Generator G1 and the unit services transformer also provide an infeed to the fault. Therefore they must both be tripped by relay 87-A.

For a fault at F2 on Bus 'D' or the line L1, the protection for line L1 and Bus 'D' will operate. Breakers C-D and A-D will trip. In addition, the systems services transformer SST T-1 LV breakers must trip and the line L1 must also trip at the remote end. The tripping of the line at the remote end is done by the protection at the far end of the line sensing the fault and/or the protection at the local end sending a signal (usually called a **transfer trip**), to the breaker at the far end of the line.

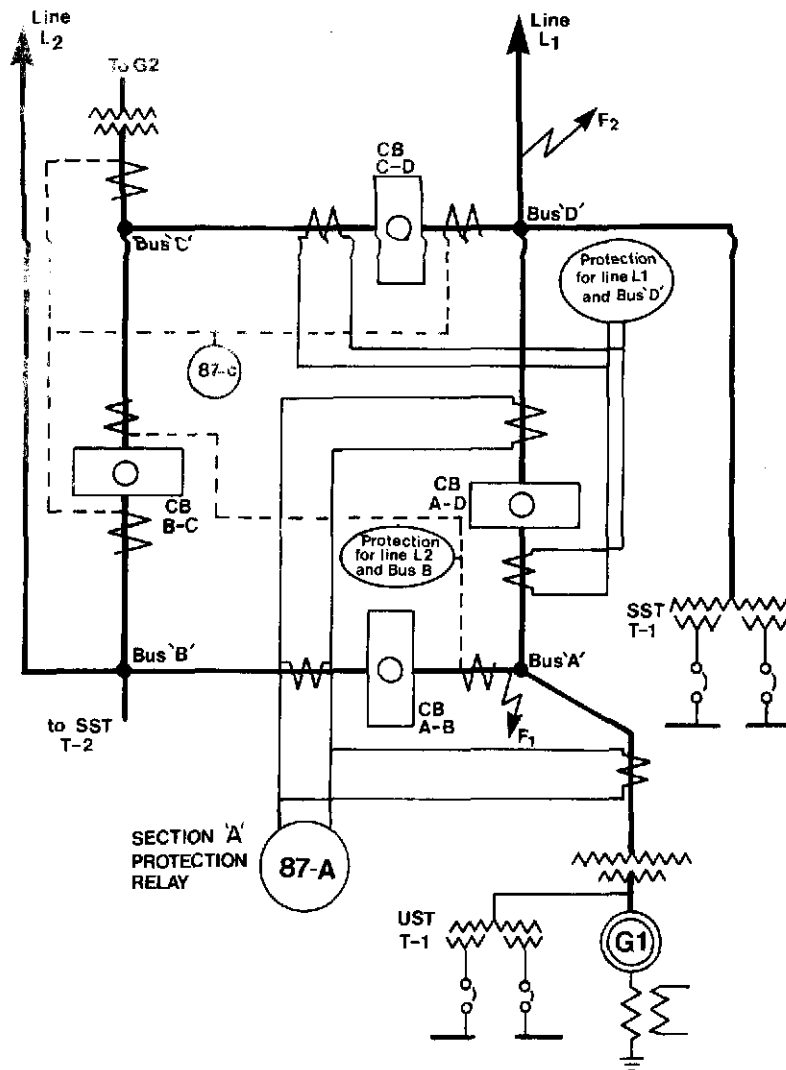


Figure 2: Differential and line protection protecting sections of a ring bus.

Figures 3(a) and 3(b) show the basic circuit of the dc tripping associated with bus 'A' and bus 'D', line L1 and systems services transformer SST T-1.

In Figure 3(a) note that the bus 'A' protection relay (87-A) operates its associated trip relay 94. This relay in turn trips breaker (A-B), Breaker (A-D) and the generator. Generator protection also feeds into the trip relay.

In Figure 3(b), the protection for Bus 'D' operates its associated trip relay 94. This relay in turn trips all sources of infeed to the fault, tripping breaker (C-D), breaker (A-D) and the system services transformer LV breaker. At the same time, a transfer trip is sent to trip the breaker at the remote end of the line.

The protection tripping from SST T-1 also trips the same breakers. This is because a fault on SST T-1 requires the interruption of the same current infeeds or supplies.

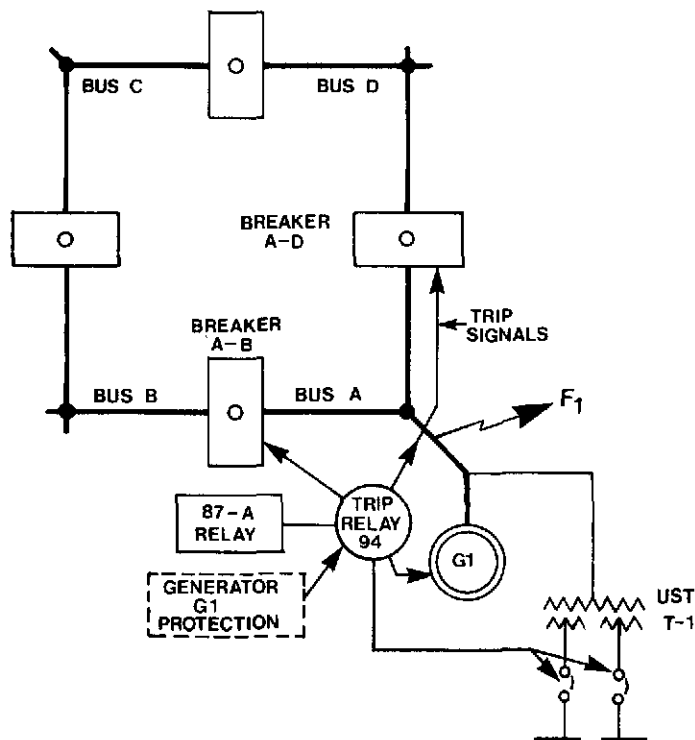


Figure 3(a): Tripping associated with Bus 'A' and Generator G1.

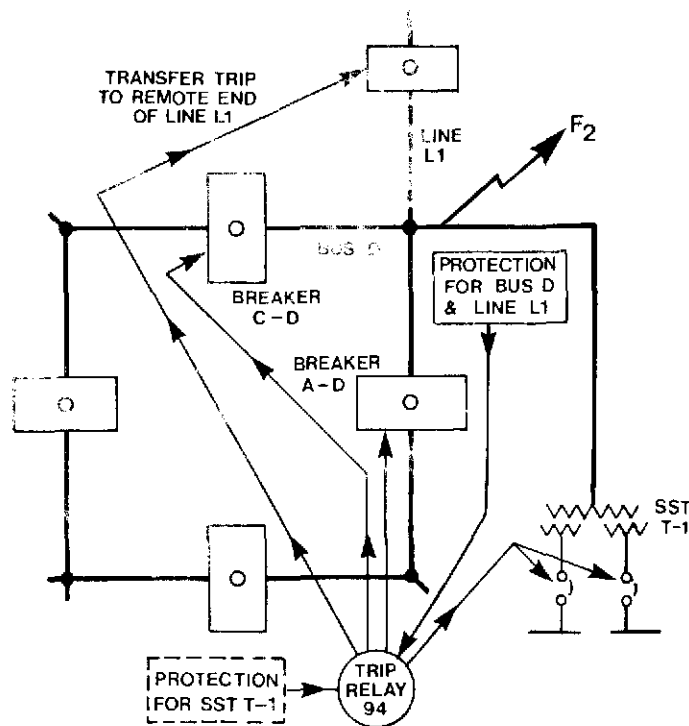


Figure 3(b): Tripping associated with Bus 'D' line L1 and SST T1.

4.0 PROTECTION OF TRANSFORMERS

With small transformers, (up to approximately 4 MVA, the cost of differential protection cannot be justified. Consequently small transformers are protected using one or more of the following:

- (a) Fuses.
- (b) Overcurrent relays (time delayed or instantaneous).
- (c) Ground fault relays.
- (d) Gas and oil relays.
- (e) Oil or coolant temperature detecting devices.
- (f) Winding temperature detecting device.
- (g) Oil level detecting device.

4.1 Differential Protection Applied to Transformers

With larger transformers, (above approximately 4 MVA), the cost of differential protection is justified. The principle of differential protection, whether applied to buses or transformers is the same, ie, the current(s) entering the transformer must equal the current(s) leaving the transformer. Because the

ratio between transformer windings is rarely 1:1, the ratios of the current transformers on the primary and secondary supply lines have to compensate for any change in current. To illustrate this, the following example is considered.

A single phase 20 MVA 230 kV/13.8 kV transformer is protected using differential protection.

- (a) Taking the HV current transformer ratio to be 100/5, calculate the ratio of the LV current transformer.
- (b) Draw a diagram showing the transformer, current transformer and differential relay. (See Figure 4.)

Solution

- (a) For a single phase transformer

$$U = VI, \quad VA.$$

$$\text{For the HV, } 20 \times 10^6 = 230 \times 10^3 \times I$$

$$I = 87 \text{ A}$$

On full load, this current will cause a current of

$$87 \times \frac{5}{100} = 4.35 \text{ A}$$

to flow in the secondary of the current transformer.

$$\text{For the LV,} \quad U = VI$$

$$20 \times 10^6 = 13800 I$$

$$I = 1449 \text{ A}$$

For the LV current transformer to balance with HV current transformer, it must also give an output of 4.35 A when the 20 MVA transformer is on full load. Consequently the LV current transformer must have a ratio of 1449/4.35. However the ratio is usually quoted with a 5.0 ampere secondary and this will give a primary current value of

$$\frac{5.0}{4.35} \times 1449 = 1666 \text{ A}$$

The CT ratio will therefore be 1666/5.

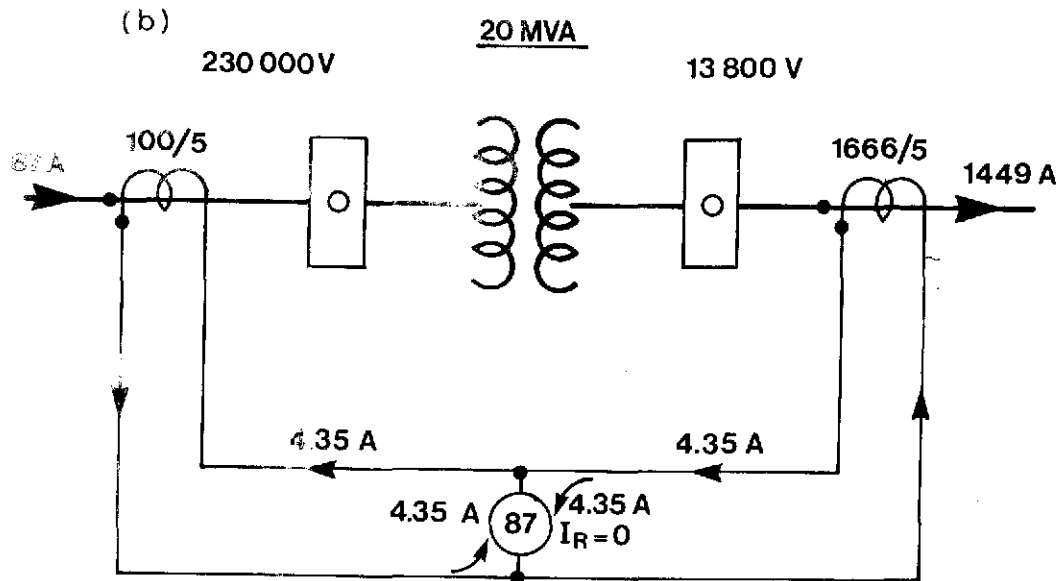


Figure 4: 20 MVA single phase transformer protected by a simple differential scheme.

In the case of a three phase transformer, three CT's are required on the HV and three are required on the LV. Three relays are also required. If there is a phase shift through the transformer because of star and delta connections, the CT circuits will have to compensate by having the same phase shift. This is done by connecting the CT's in delta and star.

4.2 Tripping Schemes for Large Transformers

For the purpose of this lesson, consider a 50 MVA star HV, star LV transformer. In order to protect this transformer fully, the following protection is required:

- (a) Overcurrent (50, 51), HV and LV.
- (b) Differential (87) to cover the complete transformer and the HV and LV cables.
- (c) Ground fault (64) HV and LV.
- (d) Winding temperature (49).
- (e) Gas and oil (63G).
- (f) Oil level (63L).

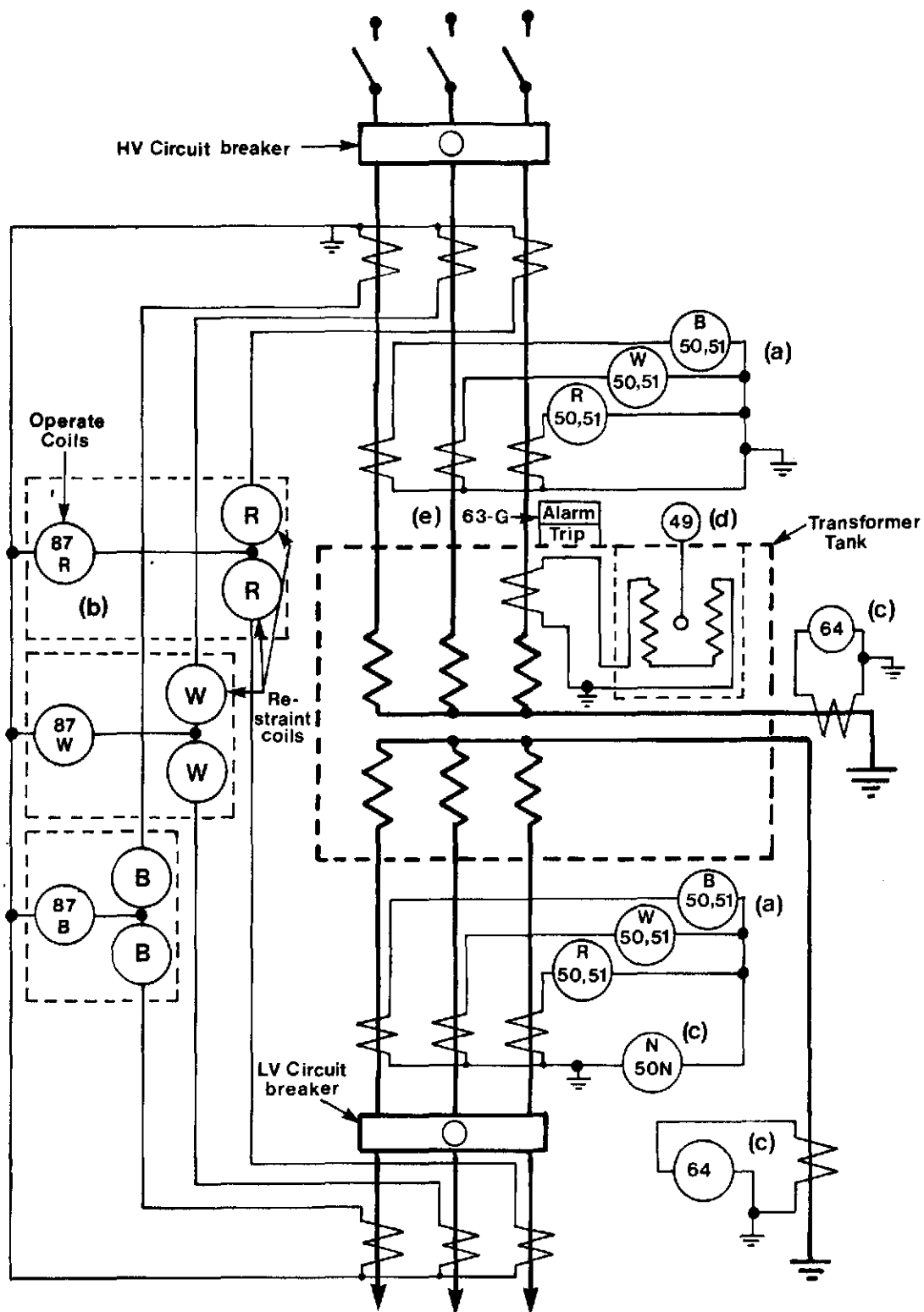


Figure 5: A 50 MVA transformer with its protective devices.

4.2.1 Detailed Protection Schemes. The circuits associated with the transformer and its CT's are shown in Figure 5, Figure 6 shows the dc tripping.

- (a) Overcurrent Protection (50, 51) is provided on the HV and LV sides of the transformer. In the event of an overcurrent occurring on the LV side of the transformer, for example due to overload, then this protection must trip the LV breaker. There is no need to trip the HV breaker, and the transformer can remain energized ready for re-loading after the overloading problem has been cleared. It should be appreciated that to ensure correct operation, the HV overcurrent relay must have a higher current setting and longer time setting than the LV overcurrent relay.

In the event of the HV overcurrent relay operating, it is assumed that either the LV breaker has failed to clear the fault and/or the fault is inside the transformer. Under this condition, the HV and LV breakers must be tripped to take the transformer off line.

- (b) Differential Protection (87) is provided to cover the complete transformer and the HV and LV cables. Note the location of the CT's. Restraint coils are installed in the relays to allow for current unbalances due to tap changing and CT errors. Lesson 135.03-1 gives the reasons for this requirement. Differential protection trips both HV and LV breakers.

- (c) Ground Fault Protection is provided on the HV and LV sides of the transformer.

On the HV Side, a current transformer supplies the relay (64). If a ground fault occurs on the HV system, current must flow in the HV neutral connection. The relay will sense this current and will operate if the current exceeds the relay setting in time and current magnitude.

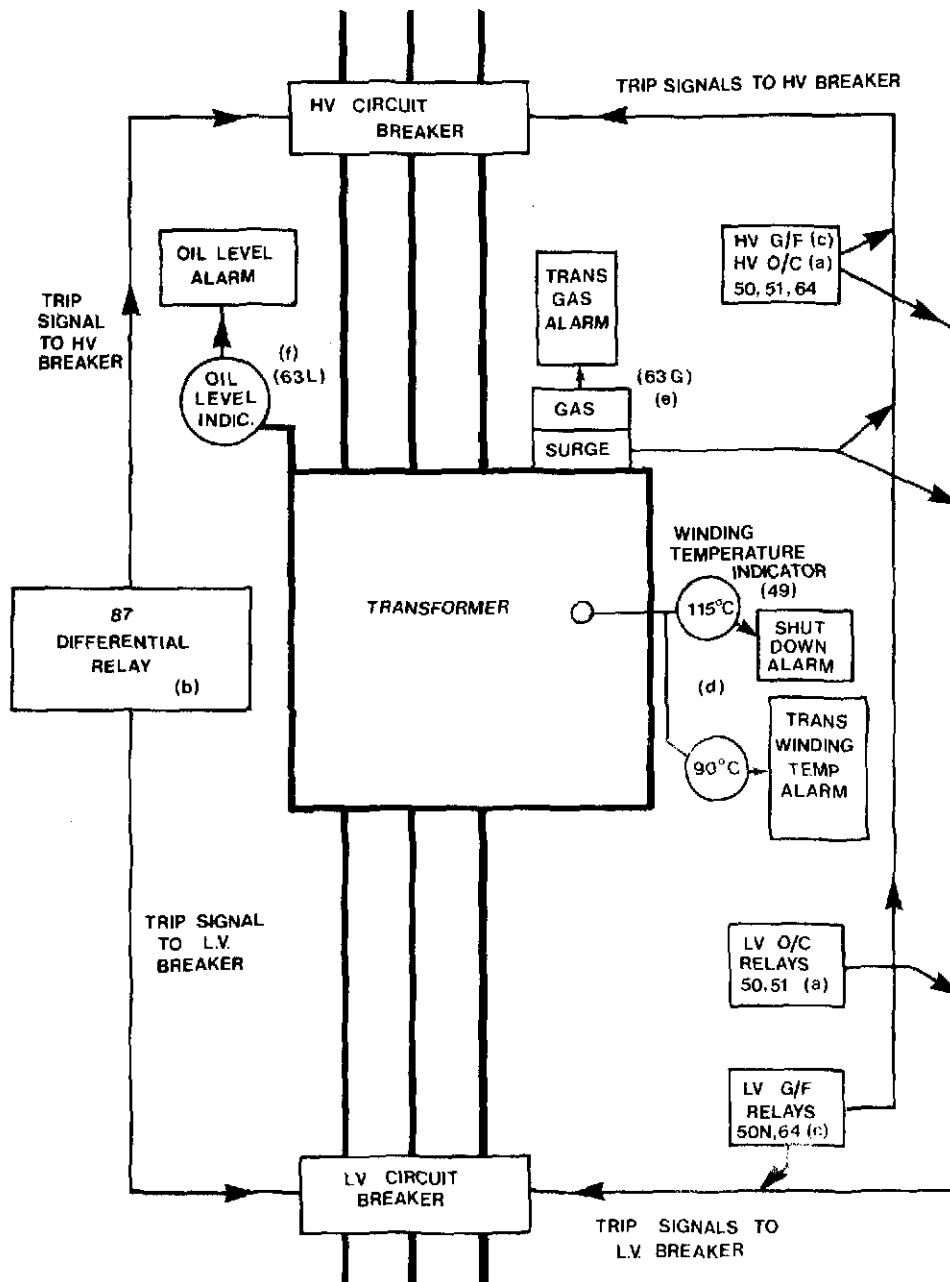


Figure 6: Diagram showing tripping from relays to breakers. Alarms are also shown.

On the LV Side, the ground fault protection is provided by relays 50N and 64. The 50N relay is connected in the neutral of the LV overcurrent CT's. In the event of a ground fault occurring, the CT's will not give a balanced output and the out of balance current will cause relay 50N to operate.

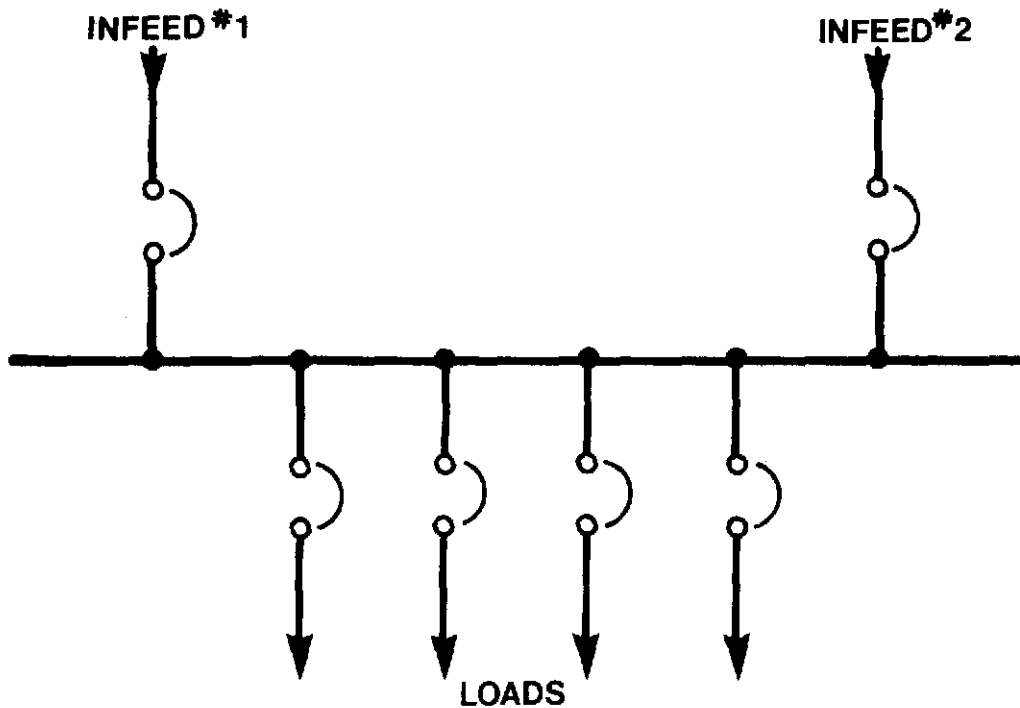
Relay 64 is connected in the neutral connection, in a similar manner to the HV ground fault relay. This relay is provided to trip the LV circuit breaker when a ground fault of low current magnitude persists for a longer period of time. An example of this type of fault would be an uncleared ground fault on a motor circuit which is supplied from the LV bus.

- (d) A Winding Temperature Instrument (49) measures the top tank oil temperature and has a heater to give "thermal image". The operation of this device is described in Lesson 135.03-1. The setting of the winding temperature instrument, if connected for alarm is 90°C to 105°C. At the 115°C a shutdown alarm is given. At this temperature the operator must de-load or shut down the transformer.
- (e) The Gas Collection and Oil Surge Relay (63G) is attached at the top of the tank. Gases formed by arcing and sparking will collect in the top of the relay and when sufficient has been collected, the alarm will operate. If an explosion occurs within the tank, the resulting oil surge will cause the microswitch in the pressure chamber to operate and trip the transformer.
- (f) An Oil Level Alarm (63L) is commonly provided. The alarm is taken from contacts on a microswitch which is operated by the conservator level monitoring indicator. An alarm is given whenever the conservator level is dangerously low.

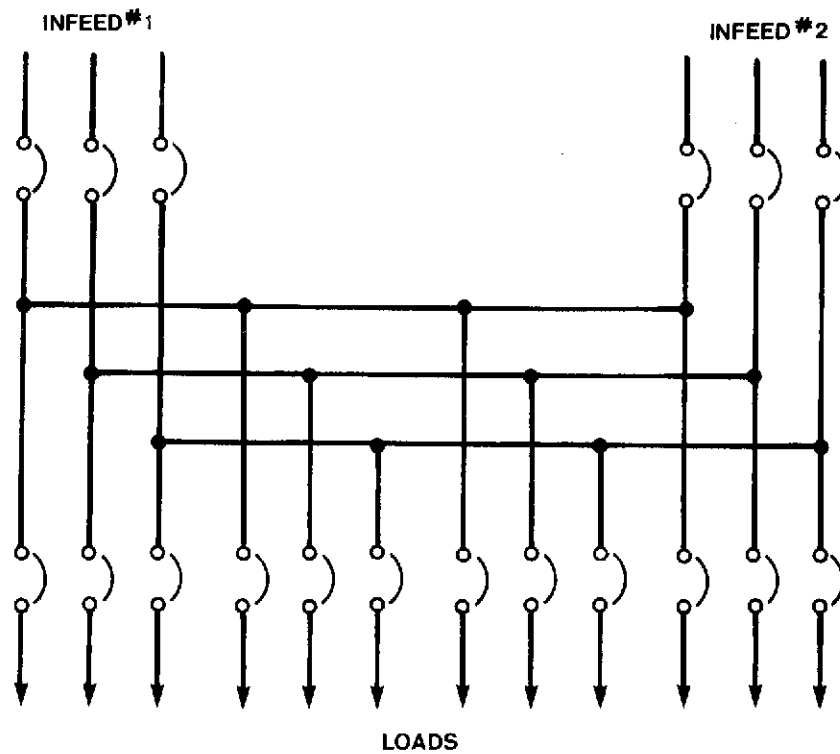
Figure 7 is provided to show the tripping from the relays to the breakers. The alarm initiating devices are also shown.

ASSIGNMENT

1. The diagram below shows a single line diagram for a three phase HV bus. Show on the diagram:
 - (a) The positions of the bus protection current transformers.
 - (b) How the bus protection relays are connected to the CT's. A detailed diagram is not necessary, a single line diagram is sufficient.
 - (c) The breakers that are tripped by the bus protection.



2. The diagram below shows a three phase bus. Show on the diagram.
- (a) The positions of the bus protection current transformers.
 - (b) How the bus protection relays are connected to the CT's. Single line information is sufficient.
 - (c) The breakers that are tripped by the bus protection.



3. The accompanying single line diagram shows a power station HV bus. The bus is supplied by a generator which in turn feeds a power line and a system services transformer. Show on the diagram:
- (a) The protection used for bus 'A' and the positions of the current transformers.
 - (b) The protection used for bus 'D' and the line. Show the positions of the current transformers.
 - (c) The breakers that are tripped when faults occur at the F1 and F2 positions, respectively.

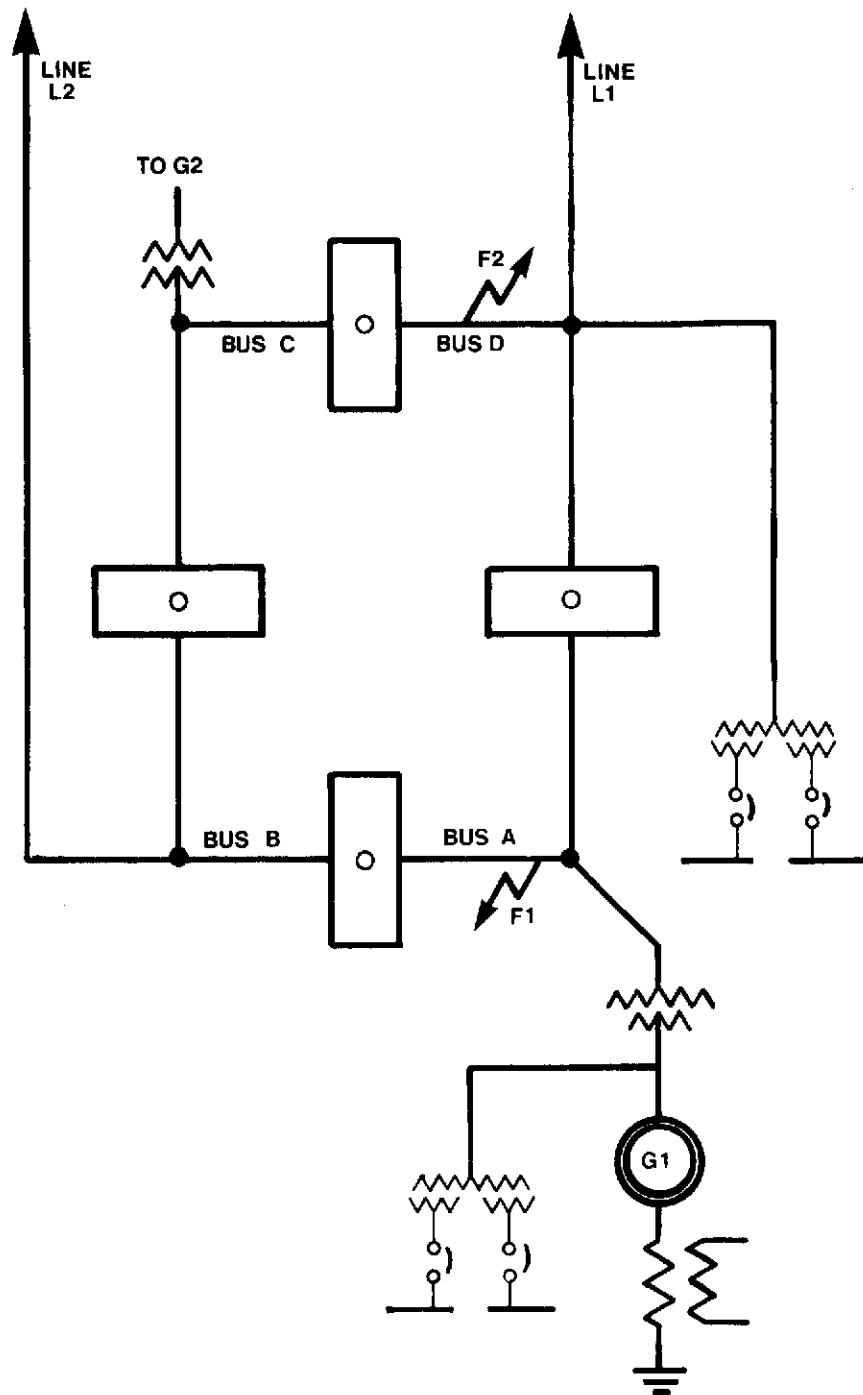


Diagram for Question #3

4. Figure 6 shows the protection applied to a transformer. For each of the protective devices:
 - (a) State the name of the protection.
 - (b) Briefly explain how and when each device operates.
 - (c) State which breaker each relay trips.

5. The accompanying diagram shows a star/star transformer. The transformer has the following protection.
 - (a) Overall differential (87).
 - (b) HV overcurrent (50, 51).
 - (c) HV ground fault (64).
 - (d) LV ground fault (64).
 - (e) LV overcurrent (50, 51, 50N).
 - (f) Gas and oil (63G).
 - (g) Winding temperature.
 - (h) Oil level (63L).

On the diagram:

 - (a) Mark the designated number for each relay.
 - (b) Show how each relay is connected.
 - (c) Show the grounding of each CT circuit.

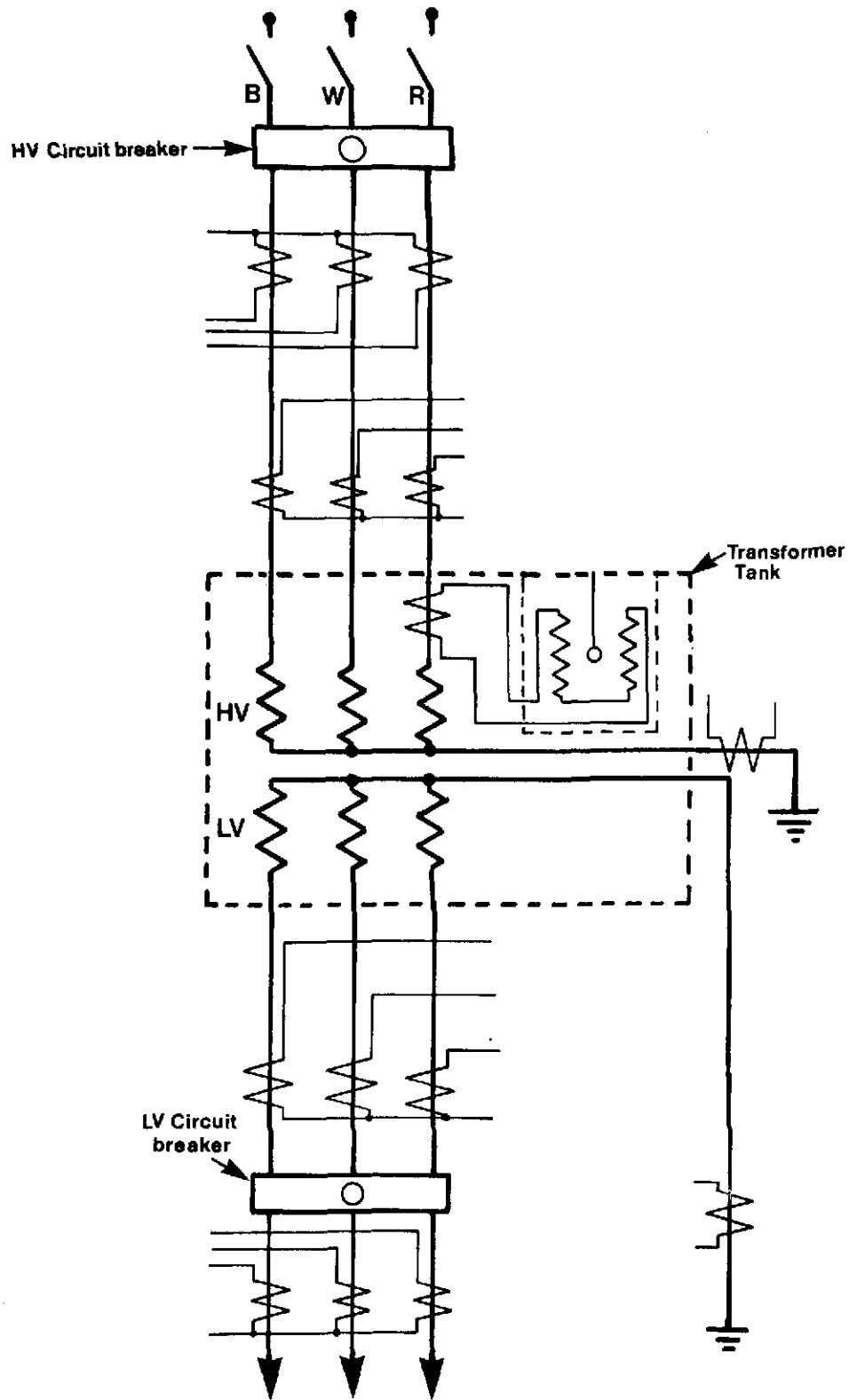


Diagram for Question #5

Electrical Systems - Course 135

COMPOSITE ELECTRICAL PROTECTIVE SCHEMES: PART II

TURBINE-GENERATOR: TRIPPING AND ALARM CIRCUITS1.0 INTRODUCTION

Following on from Lessons 135.03-1 and 135.04-1, this lesson shows composite protective schemes for Turbine-Generators. The actions of the protection (fed from CT's and PT's) are described together with the tripping to the respective breakers and other devices. A simplified version of electrical protection diagram for a Turbine-Generator, and its associated circuits, is used to illustrate a typical protective scheme.

2.0 PROTECTION SYSTEMS FOR TURBINE-GENERATORS

Unlike large transformers, whose protections systems are to a large extent similar, the protection systems for turbine-generators vary a great deal. For example, the protection systems used on a 30 MW turbine-generator will be less complex than the protection for a 500 MW or an 800 MW turbine-generator.

Figure 1 shows a simplified single line protection diagram for a Turbo-Generator. Note that the main and unit services transformers are also shown.

2.1 Protection Details

The following protective features are used on Turbine-Generators. See Figure 1.

2.1.1 Generator Protection: Tripping

(G1) The main protection for the generator is provided by the differential relay, (87). Note that the zone of protection only covers the generator windings and connections close to the generator.

(G2) Ground fault protection is provided by relay (64). This relay will operate for a ground fault in the generator windings, main connections and in the two transformer windings **directly connected** to the generator.

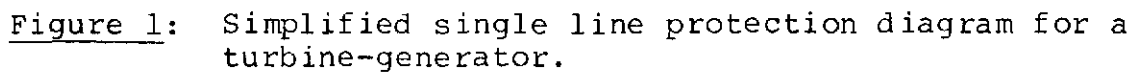
(G3) Phase unbalance protection (46) protects the generator rotor against excessive heating due to phase unbalance. Lesson 135.02-1 explains the reasons for and the method of operation of this protection.

(G4) Loss of field protection (40) trips the generator if there is insufficient excitation for a given load. The relay has current input from the generator CT's and a potential input from the 13.8 kV PT's. When the generator has insufficient excitation for a given load, it may be operating at a **leading power** factor with a large load angle. The loss of field protection relay senses this condition and will trip the unit before the load angle becomes excessive and serious pole slipping occurs.

(G5) Generator inter-turn protection (60) relay operates from the output of the three potential transformers connected in open delta. Under healthy conditions, the output from the open delta is zero. Under inter-turn fault conditions, the phase voltages will not balance. Consequently, there will be a voltage output from the open delta and this output will operate the inter-turn protection relay.

(G6) Excitation rectifier overcurrent (51) relay is supplied from a current transformer which is connected between the exciter and the rectifiers. An excess of current taken by the rectifiers (or the dc system fed from the rectifiers) will operate the relay and trip the unit.

(G7) Underfrequency protection (81) is provided to protect the turbine-generator in the even of an excessive fall in **system frequency**. At 57.5 Hz, the trip is time delayed and at 56 Hz the trip is instantaneous. The protection is only in service after the HV breaker or breakers have been closed and only trips the HV breakers.



(G8) Out of step protection (78). In the event of the generator coming out of synchronism with the 230 kV system, this protection will trip the 230 kV breakers. Instability in the generator on the system will usually cause a generator to lose synchronism. The instability can be due to an excitation failure or a transmission fault which is slow to clear. Course 235 describes instability in detail.

(G9) Overexcitation protection (59) protects the generator during start-up. If the generator voltage to frequency ratio is too high it will cause **overfluxing** in the generator stator iron and in the iron cores of the main and services transformers. The problems associated with overfluxing are explained in Lesson 230.20-4. This protection will only trip the field breaker if the 230 kV breaker(s) are open. Once a 230 kV breaker is closed this protection is removed from service.

2.1.2 Generator Protection: Alarms

- (i) Rotor ground fault relay (64 FA) will detect a ground fault on the generator rotor and its associated excitation system.
- (ii) Rotor temperature indication (Rotor TI) gives a continuous indication of rotor temperature. If the rotor copper temperature exceeds the predetermined temperature setting, an alarm will be given in the control room.
- (iii) Other alarms are provided to give warning of abnormal conditions in the following systems.
 - hydrogen cooling
 - hydrogen seals
 - stator water

Details of these alarms are covered in the manufacturer's instruction book.

2.2 Unit Services Transformer

2.2.1 Tripping

(UST1) The main protection for the Unit Services transformer is provided by the differential relay (87). Note that the zone of this protection covers the transformer, LV cables and the LV breaker.

(UST2) Overcurrent protection is provided on the high voltage side of the transformer. The instantaneous relay, (50) is provided to ensure that when high values of fault currents occur, the fault is quickly cleared. The timed relay (51) has a lower current setting. It initiates tripping in the event of a persistent fault which is of low current magnitude.

(UST3) Ground fault protection is provided by relay (64). This relay will only operate for a ground fault in the unit services transformer LV windings, LV cables and LV bus. Note that this is **not** a differential protection. Consequently, the protected zone will depend upon the magnitude of the fault current and the relay setting.

(UST4) The gas detector relay (63-G) will trip the unit in the event of an oil surge.

2.2.2 Alarms. An alarm will be given in the control room for the following:

- (i) operation of the gas element of the gas detector relay.
- (ii) winding temperature.
- (iii) low oil level.

2.3 Main Transformer Protection

2.3.1 Tripping

(MT1) The main protection for the main transformer is provided by relay (87). Note the zone of protection only covers the main generator, main transformer and main connections.

(MT2) Ground fault protection is provided by relay (64B). The relay is supplied from a current transformer whose primary is connected between the transformer HV neutral and ground. The relay will operate for a ground fault in the main transformer HV windings, the HV connections to the switchyard and the HV bus. Because this protection is not of the differential type, its operation will depend on the magnitude of the ground fault current and the setting applied to the relay.

(MT3) The gas detector relay (63G) will trip the unit in the event of an oil surge.

2.3.2 Alarms. The alarms for the main transformer are similar to those for the services transformer, ie,

(i) operation of the gas element of the gas detector relay.

(ii) winding temperature.

(iii) low oil level.

In addition, alarms are provided to warn of problems with the oil coolers.

2.4 HV Bus and Back-Up Tripping

(SY1) Differential protection (87) is used to protect the 230 kV HV bus, breakers and the connections as far as the transformer HV bushings.

(SY2) Differential protection (87D) is used to give overall back-up protection to the generator, main transformer and HV bus. The reason for this protection is to ensure the unit is safely shut down in the event of a failure of any of the individual protective relays or if any of the breakers fail to trip. Normally this protection is time delayed to give the other protections time to operate and complete their respective tripping functions.

Tripping From Switchyard

(SY1) Differential Bus (87)
 (SY2) Differential Back-Up (87D)

Tripping From Main Transformer

(MT1) Differential (87)
 (MT2) Ground Fault (64B)
 (MT3) Gas Detector (63-G)

Tripping From Generator

(G1) Differential (87)
 (G2) Ground Fault (64)
 (G3) Phase Unbalance (46)
 (G4) Loss of Field (40)
 (G5) Excitation Rectifier O/C (51)
 (G6) Generator Inter Turn (60)
 (G7) Under-frequency (81)
 (G8) Out of Step (78)
 (G9) Over-excitation (59)

Tripping From Unit Services Transformer

(UST1) Differential (87)
 (UST2) Overcurrent (50, 51)
 (UST3) Ground Fault (64)
 (UST4) Gas Detector (63-G)

Tripping From Turbine

(T1) Manual Trip Local and Remote
 (T2) Low Vacuum 21" Hg (71 kPa)
 (T3) Low Lube Oil Pressure
 (T4) H1 HP Turbine Exhaust Pressure
 (T5) Low Stator Coolant Flow
 (T6) Overspeed
 (T7) Turing Gear Motor Overspeed

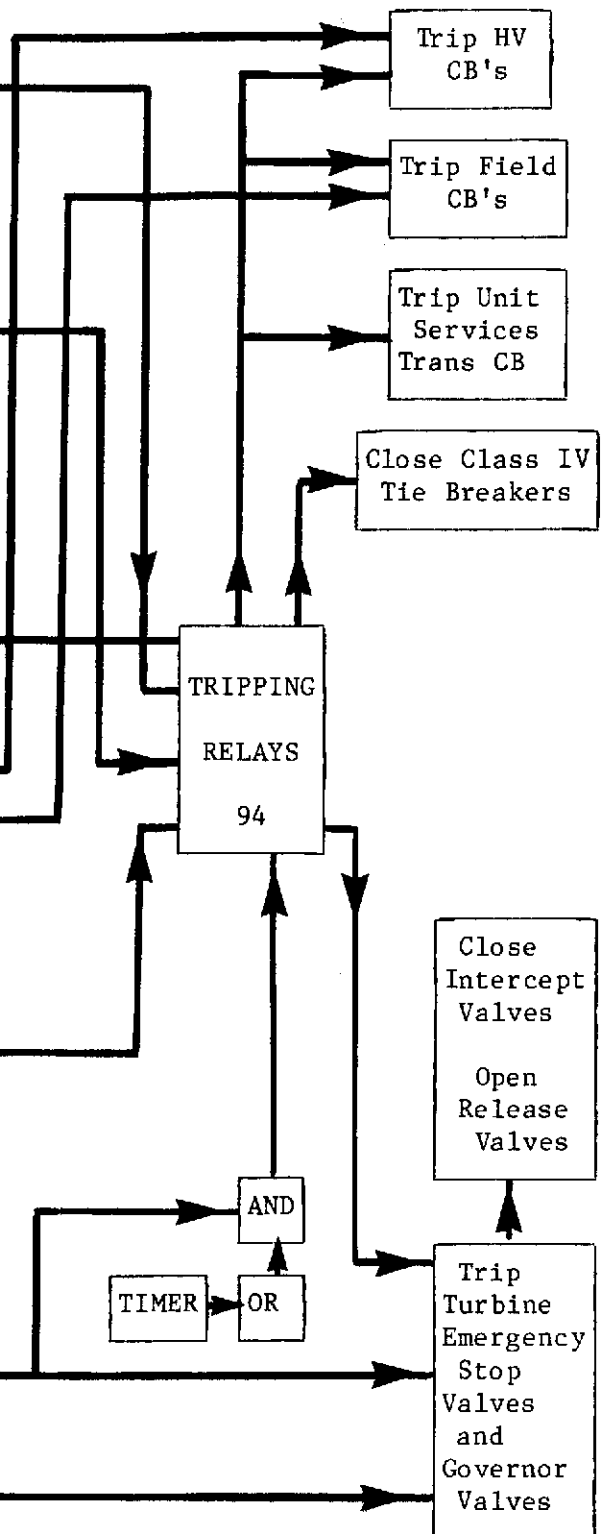


Figure 2: Block diagram showing the simplified tripping for a turbine generator and its associated circuits.

3.0 PROTECTION FOR THE COMPLETE TURBINE GENERATOR

3.1 Tripping

Figure 2 shows in block diagram form, the simplified tripping for a large turbine-generator and its associated circuits.

It must be understood that the information on Figures 1 and 2 is typical for a large turbine-generator. To ensure correctness of all details for a particular turbine-generator, it is necessary to study the tripping and control diagrams for that particular unit.

3.1.1 Points to Note on Figure 2

- (a) With the exception of the underfrequency, out of step and over-excitation protections which only trip the HV breakers, the tripping from the electrical protection will trip the complete unit.
- (b) The tripping from the turbine is divided into two sections:
 - (i) The first part consisting of trips 1-5 which trip the stop valves **directly**. The breakers are then **sequentially** tripped. This sequential tripping is only allowed after the emergency stop valves (ESV's) have all closed or a timer has operated. The reason for this sequential tripping is to ensure that the steam supply to the turbine has been shut off **and** the steam pressure in the turbine has fallen to a low value **before** the breakers are opened. Operating the ESV's in this manner minimizes the risk of overspeeding the turbine-generator which can occur when the HV breakers open and reject the load.

- (ii) The second section consisting of trips 6 and 7 only close the ESV's. When these trips operate, it is assumed there is no electrical fault associated with the turbine-generator and therefore it is not necessary to operate the electrical protection. Under this condition, the turbine-generator remains connected to the system and "motors".

ASSIGNMENT

1. For the protection shown on the accompanying diagram, Figure A1:
 - (a) State the name of each of the protective relays.
 - (b) Briefly explain the protection given by each of the protective relays. State the "zone" covered by each relay.
 - (c) State the breakers or other devices which are tripped by each of the protective relays.
2. For the protection and other devices given on Figure A2, show the tripping between the:
 - (a) Protective relays and the tripping relays.
 - (b) Tripping relays and the devices that are tripped (or closed).
 - (c) Other protective relays or devices and the items they trip.
3. State and briefly explain the alarms associated with:
 - (a) The generator.
 - (b) Unit Services Transformer.
 - (c) Main Transformer.

J.R.C. Cowling

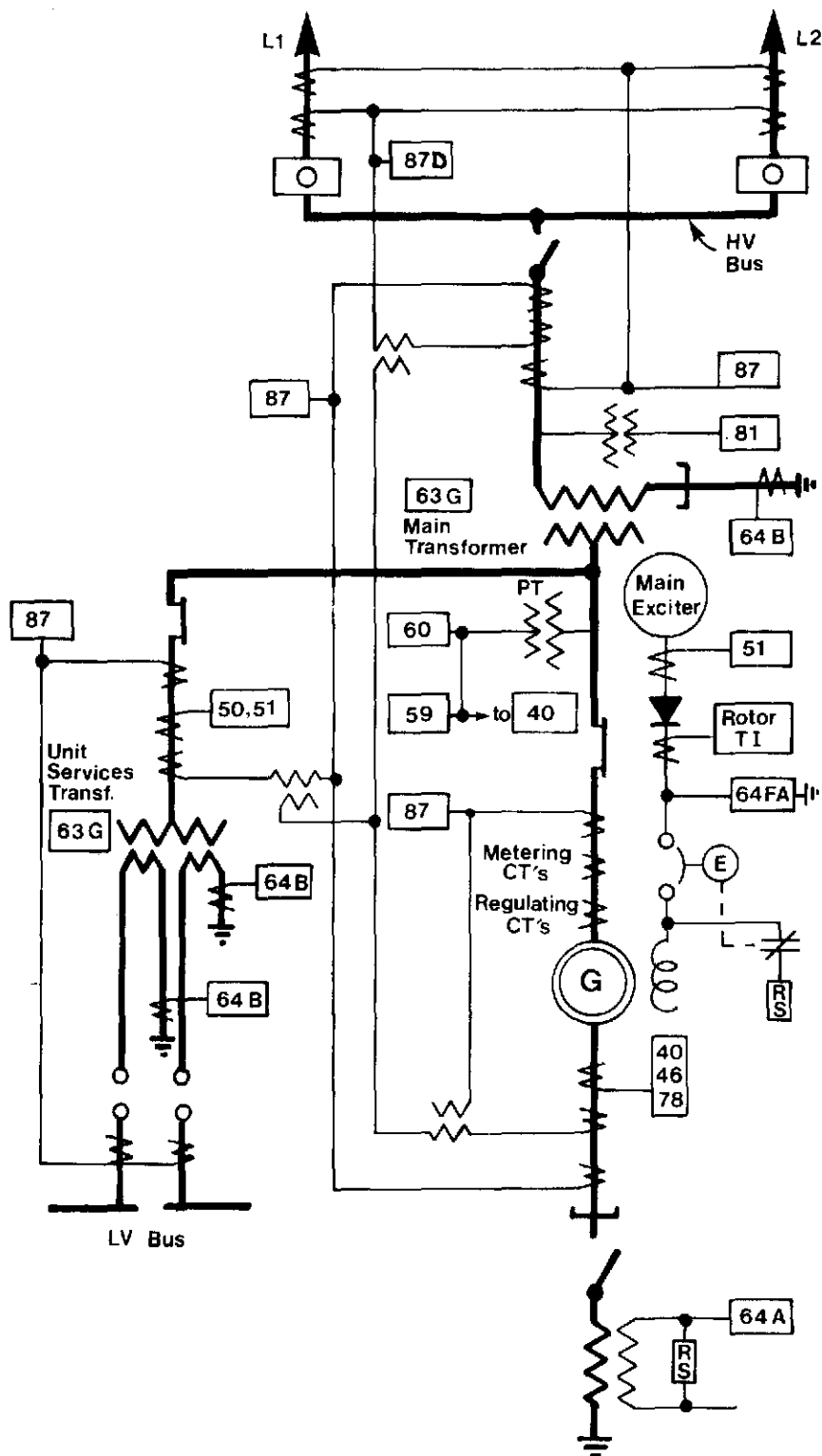


Figure A1: Simplified single line protection diagram for a turbine-generator.

Tripping From Switchyard

(SY1) Differential Bus (87)
 (SY2) Differential Back-Up (87D)

Trip HV
 CB's

Trip Field
 CB's

Tripping From Main Transformer

(MT1) Differential (87)
 (MT2) Ground Fault (64B)
 (MT3) Gas Detector (63-G)

Trip Unit
 Services
 Trans CB

Close Class IV
 Tie Breakers

Tripping From Generator

(G1) Differential (87)
 (G2) Ground Fault (64)
 (G3) Phase Unbalance (46)
 (G4) Loss of Field (40)
 (G5) Excitation Rectifier O/C (51)
 (G6) Generator Inter Turn (60)
 (G7) Under-frequency (81)
 (G8) Out of Step (78)
 (G9) Over-excitation (59)

TRIPPING
 RELAYS
 94

Tripping From Unit Services Transformer

(UST1) Differential (87)
 (UST2) Overcurrent (50, 51)
 (UST3) Ground Fault (64)
 (UST4) Gas Detector (63-G)

Close
 Intercept
 Valves

 Open
 Release
 Valves

AND

Tripping From Turbine

(T1) Manual Trip Local and Remote
 (T2) Low Vacuum 21" Hg (71 kPa)
 (T3) Low Lube Oil Pressure
 (T4) H1 HP Turbine Exhaust Pressure
 (T5) Low Stator Coolant Flow
 (T6) Overspeed
 (T7) Turing Gear Motor Overspeed

TIMER

OR

Trip
 Turbine
 Emergency
 Stop
 Valves
 and
 Governor
 Valves

Figure A2: Turbine-Generator Tripping.