EE4-48 Power system control, measurement and protection

SOLUTIONS

## The Questions

1.

a)

i) **How is the switching surge in a power network characterised?** [2]

Ans:

It is an over voltage, voltage is expressed in kilo volts (RMS) over time. Time is generally expressed in micro seconds. The students are expected to show the voltage versus time.

ii) **Why is the consideration of switching surge so important in power system design and operation?** [2]

Excessive over voltage results in stress in insulation of major components. It is very important to have an estimate about the over voltage for insulation design and coordination.

iii) **Why is sub synchronous resonance (SSR) a major problem in steam driven power plants?.** [2]

Steam turbine in fossil fuelled power plant is pressure compounded to improve the overall efficiency of power production. So there are multiple sections which is essentially a multi-mass system. Under certain operating conditions of the network, the natural frequencies of these sections interact with the system. In hydro turbine or gas turbine such situation does not arise.

iv) **Why is high gain fast acting excitation system is good for transient stability but not so for oscillatory or small signal stability?** [4]

High gain and fast acting excitation system improves transient stability by producing large excitation voltage fast. That produces extra or maintains electrical torque during short circuit in the vicinity. The machine remain in synchronism (thus transiently stable) but such fast action of the excitation controller produces negative damping torque for low frequency range at some operating cases. So even if the system is transiently stable – it can be oscillatory unstable after surviving through first few swings.

v) **Why is the rotor of a synchronous generator of solid construction while the stator made up of laminated steel?** [4]

Stator always carries power frequency current, so having stator laminated minimises the eddy current losses and hysteresis losses in the stator core.

Rotor carries DC current and the magnetic effect of three phase stator winding current is non-interacting with rotor body (no relative velocity between the rotor body and stator flux). So under steady state operating condition there is no circulating current in the rotor that could result from the electromagnetic interaction between the stator and rotor body. Keeping rotor laminated will be an expensive option also. Under the situation of rotor swing circulating current is established in the rotor body. This provides torque against the swing – hence damping action.

vi) **Why is it easier to control a steam turbine than a hydro turbine?** [3]

The students are expected to describe the nature of the transfer functions of steam turbine and hydro turbine. I would expect them to mention the non-minimum phase nature of the hydro turbine and controlling a system with right half plane zero is difficult.

vii) **Modern synchronous generators are designed to have large steady state synchronous reactance (between 1.0 to 2.0 pu). Whenever a direct terminal short circuit occurs initial currents are several times the load current. Why is it so?** [3]

Immediately after the inception of fault, the stator reactance is very less (about 0.25 pu). This is because the flux produced by the fault current is largely in the air (opposed by the rotor). So for several cycles of power frequency the fault current is really high.

2.

a)

i) **Why does one neglect the stator and network circuit transients in assessing transient stability of a synchronous generator?** [2]

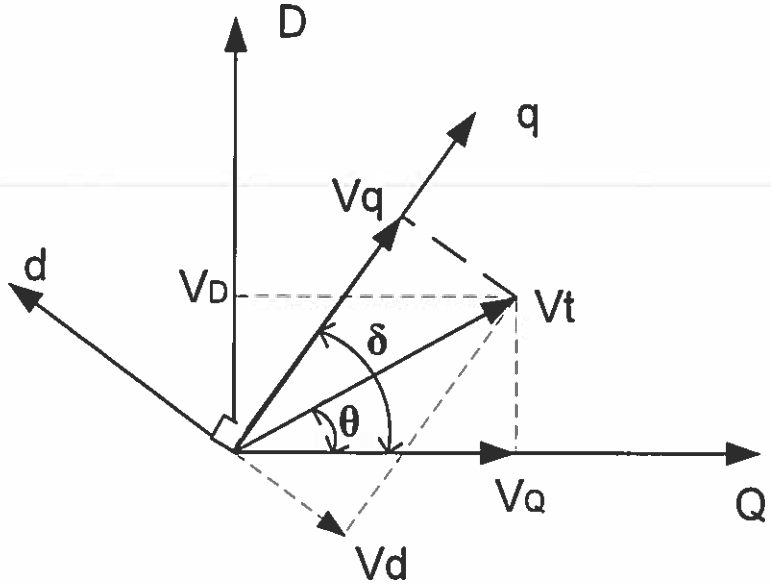
In transient stability one is concerned about the stability of the rotor (staying in synchronism) in the first 1-2 seconds. The speed voltage is very high compared to the transformer voltage in the stator circuit. The transformer voltage results through stator transients. Because they are of power frequency and beyond – they are ignored.

ii) **Why is individual machine d-q to network transformation necessary in multi-machine power system stability computation and analysis?** [1]

In a power network many machines are connected. Where as a single machine is analysed in d-q frame with respect to its terminal voltage as reference, in reality terminal voltage of each machine will have non zero angles. They are expressed with respect to a network reference angle. So another stage of transformation is necessary

iii) **Derive the relationship between the quantities in two reference frame when the angle difference between the two reference frames is $\delta$-$\theta$.** [4]

Let us assume that the network reference frame is expressed as DQ and that of machine as dq. If V is a voltage of a bus with an angle $\theta$ with respect to DQ reference: its corresponding component in machine reference frame would be a rotation of ($\delta$-$\theta$).




$VQ + j\,VD = Vt\,e^{j\theta}$
$VQ = Vt\cos\theta$
$VD = Vt\sin\theta$
Resolving VQ and VD along machine reference d-q will produce
$Vq = VQ\cos\delta + VD\sin\delta$
$Vd = -VQ\sin\delta + VD\cos\delta$

$$Vq + j\,Vd = Vt\,e^{-j(\delta-\theta)}$$

iv) A synchronous generator supports a terminal voltage of 23.5 kV line to line at the generator terminal bus. This bus is part of a large network which has a reference bus at another location. The power flow solution produces an angle (θ) of 10 degree for this bus voltage. The generator load angle (δ) is 30 degree. Compute the direct and quadrature axis components of this terminal voltage. [3]

Solutions

$$V_{machine} = V_{network}\,e^{-j(\text{angle between two references})}$$

In this case

$$V_{machine} = 23.5\,e^{-j(30-10)}$$

$$V_{machine} = 23.5\,e^{-j20}$$

$= 22.08 - j\,8.03$ kV.
$Vq = 22.08$ kV
$Vd = -8.03$ kV

This reference frame transformation is an orthogonal (rotation can be easily visualized in two dimension) – does preserve line length.

b) **In a salient pole synchronous generator, the voltage-current relationship along the generator d and q axis are as follows:**

$$E_{fd} - V_q + I_d X_d = 0$$

$$V_d + I_q X_q = 0$$

**where the symbols carry their usual meanings.**

**Taking the terminal voltage $\bar{V}_t$ as the reference vector, the q-axis is defined to lead $\bar{V}_t$ by an angle $\delta$.**

**The terminal voltage and current vector of the generator are related by:**

$$\bar{V}_q + j\bar{V}_d = \bar{V}_t e^{-j\delta};\ \bar{I}_q + j\bar{I}_d = \bar{I}_t e^{-j\delta}$$

i) **Making use of the above information, derive the power angle expression of the generator.** [5]

Let's neglect the stator resistance for simplicity and denote synchronous reactance along d and q axis by $X_d, X_q$ respectively. The tip of the vector $V_t + jI_a X_q$ lies on the q- axis (we avoid the poof that is neither very complex nor needed in the context of this course).

Algebraic summation of voltage along q-axis

$$E_{fd} - V_q + I_d X_d = 0;$$

Along d-axis

$$V_d + I_q X_q = 0$$

We know $V_d = -V_t \sin\delta; V_q = V_t \cos\delta; V_t = V_q + jV_d; I_t = I_q + jI_d$

The terminal power output expression can be written as usual $V_t I_t^*$

$$P = V_d I_d + V_q I_q = \frac{E_{fd} V_t}{X_d} \sin\delta + \frac{V_t^2}{2}\left(\frac{1}{X_q} - \frac{1}{X_d}\right)\sin 2\delta$$

$$Q = \frac{E_{fd} V_t}{X_d} \cos\delta + \frac{V_t^2}{2}\left[\frac{1}{X_q} - \frac{1}{X_d}\right]\cos 2\delta - \frac{V_t^2}{2}\left[\frac{1}{X_q} + \frac{1}{X_d}\right]$$

ii) **For the following values of the variables in per unit, obtain the per unit real power output of the generator.**

**$X_d$ = 2.3, $X_q$ = 1.6, $V_t$ = 1.05, $E_{fd}$ = 3.8 and $\delta$ = 25 degrees** [2]

**Substituting the value into real power equation provides = 0.838 pu**

iii) **Suddenly the generator loses excitation. What percentage of power obtained in (ii) can still be produced with the loss of excitation?** **[3]**

the students are expected to compute two parts of the real power from excitation terms and from saliency term. They should express in percentage the saliency power of the total power: 0.104/0.838 *100 = 12.5%

3

a)

i) **How much excitation power is approximately required to operate a 300 MW synchronous machine?** [2]

One needs 2.0 to 3.5 KW for each MVA. A 300 MW machine will have MVA rating of 300/0.85 (typical power factor) = 353 MVA. So one would need 706 KW to 1235 KW of excitation power for this machine

ii) **What is the purpose of field forcing in excitation system control?** [3]

During close in dead short circuit fault the terminal voltage collapses – the only way the some electrical power can be produced is to increase excitation voltage – this achieved through field forcing. The field current is increased to a very high value for few seconds.

iii) **What is the purpose of a power system stabilizer (PSS) in a large synchronous generator with fast acting voltage control?** [2]

Particularly high gain fast acting excitation system produces at times negative damping. PSS provides additional damping against post transient stability oscillations of the machine and the system.

iv) **How does transformer with taps control the network voltage control?** [2]

The student start from basic volt and turns relationship and show that once the volt per turn is fixed – by changing the number of turns slightly voltage can be made to change.

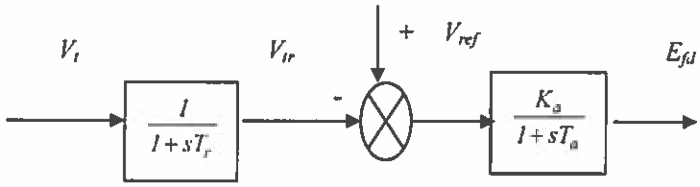
v) **Why is the voltage rise problem in a 400 kV cable network more severe than that of an overhead line of similar rating?** [2]

The student should start this answer by stating that cable capacitance is much higher than overhead line of similar rating. Then go on to elaborate reactive power production from capacitance is higher so voltage rises.

vi) **Why are the fixed shunt capacitors not as effective as the automatic voltage control in synchronous generators?** [3]

Synchronous generator is an active device , it can produce reactive power irrespective of network voltage – capacitor is passive , it can produce reactive power when connected to network. When network voltage is low reactive power produced by the capacitor drops sharply.

b) **A simplified model of a fast excitation system is shown in Figure 3.1. It is required to produce a 4.0 p.u. of $E_{fd}$ in the steady state. The voltage regulator has a gain of 400 and time constant of 0.02 s. Compute the reference voltage $V_{ref}$ that needs to be set in order to maintain a terminal voltage of 1.07 p.u.**




3.1 Block Diagram of a Fast Excitation System [6]

Solution:
A set of differential equation can be written as follows :
dVtr / dt = 1/Tr [-Vtr + Vt]
dEfd / dt = 1/TA [(Vref-Vtr )-Efd]
At steady state
Vtr = Vt ; Efd = KA (Vref-Vtr )
Vref = Efd/KA + Vtr
Vref = Efd / KA + Vt
4.0/400 + 1.07 = 1.08 pu

4.

a) Briefly discuss the nature, importance and model of the primary frequency control in power systems. [5]

This is automatic, online and real-time in less than 30 seconds time frame. The generator slows down initially to produce extra MW (release of stored kinetic energy). This is not enough to sustain the demand for more than few seconds and the decline in frequency cannot be prevented. When frequency drops, in the absence of any other control, rate of frequency fall is limited by the inertia of the machines and frequency sensitive component of the load (motor load) also releases some demand. The combined action can be modelled through a first order block diagram with associated derivation

Load generation dynamic response: Any balance between the generation and demand will give rise to the dynamic response of the system. Let's consider a generator with combined inertia constant M. The balance between input mechanical power and output electrical power (in p.u) will govern the drive the turbine governed by the following equation:

$$P_{mech} - P_{elec} = Ms\omega_r$$

The perturbation of the above equation will result in

$$\Delta P_{mech} - \Delta P_{elec} = Ms\Delta\omega_r$$

Change in electrical power can be factored into two components as

$$\Delta P_{elec} = \Delta P_L + D\Delta\omega_r$$

D is known as load damping constant that represents frequency sensitivity component of load. Substituting the expression for $\Delta P_{elec}$ into the expression for dynamic response equation one gets

$$\Delta P_m - \Delta P_L - D\Delta\omega_r = Ms\Delta\omega_r \ .$$

Rearranging the term, the following expression is obtained.

$$\Delta\omega_r = \frac{\Delta P_m - \Delta P_L}{Ms + D}$$

b) Including the effect of the governor droop characteristic, develop the following load frequency control characteristic:

$$\Delta\omega_{ss} = -\frac{\Delta P_L}{D+\frac{1}{R}}$$

where, D is the load damping co-efficient, $\Delta P_L$ is change in demand, R is the droop and $\Delta\omega_{ss}$ is the steady state angular frequency deviation in p.u. [7]

This is managed by including a droop in the feedback path. The droop can be set at different values for different generators in order to define their relative shares on the total change in demand. This will also allow insertion of new input load reference point.

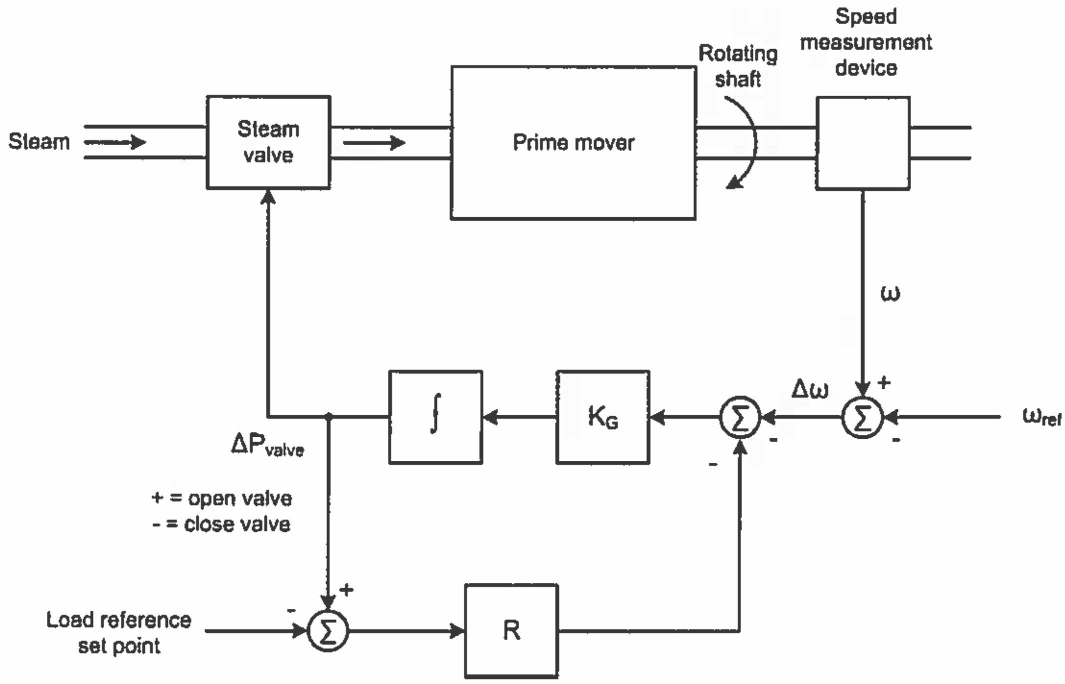
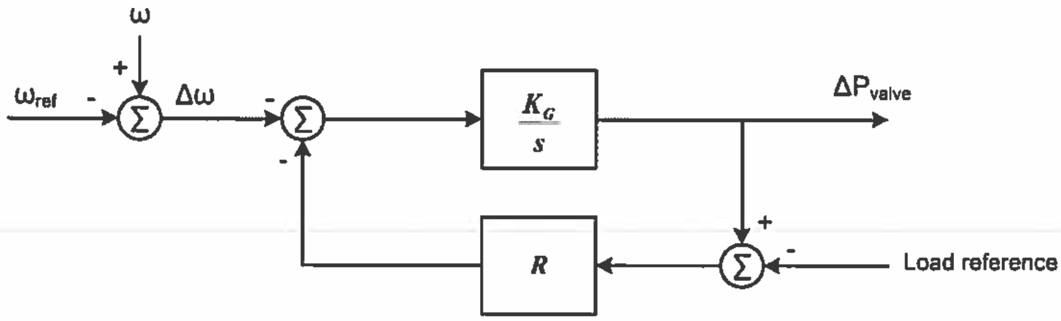
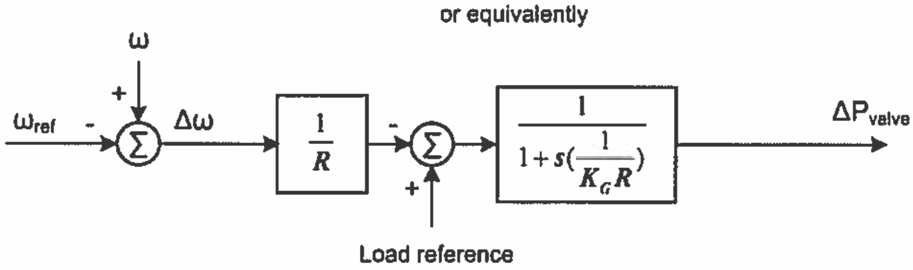



Figure: Governor control block diagram




or equivalently




Let $\frac{1}{K_G R} = T_G$ (Governor time constant)

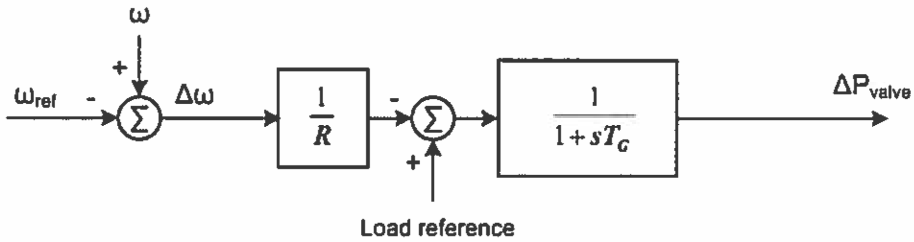



Figure: Simplified block diagram of governor control

In steady state the unit output in response to system frequency deviation will have droop (negative slope) as shown in the following figure.

Let's now turn our attention to the influence of speed governing control on the frequency deviation due to change in load. We assume a generic turbine model $G_t(s)$.

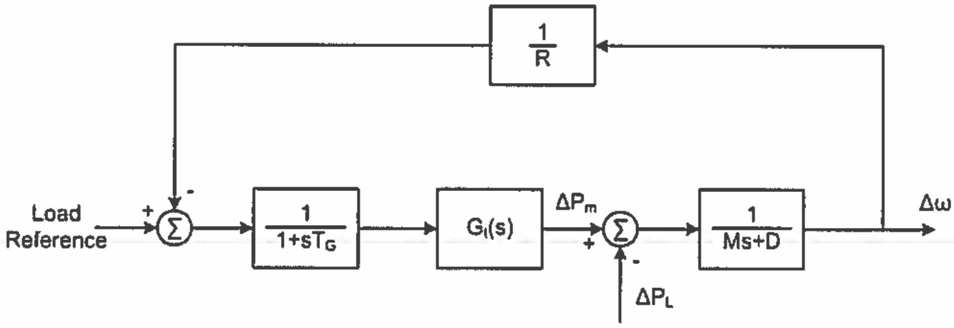



Fig: Block diagram of governor with droop for generator speed control

Let us assume that generic transfer function of turbine (steam as well as hydro) is expressed as $G_t(s)$. Assuming 100% efficiency the gain between the power input to the turbine to the power output will be unity. The transfer characteristic between $\Delta P_L$ and $\Delta\omega$ can be expressed as

$$\frac{\Delta\omega}{\Delta P_L} = -\frac{R(1+sT_G)}{G_t(s)+(Ms+D)R(1+sT_G)}$$

The steady state frequency deviation

$$\Delta\omega_{ss} = -\frac{\Delta P_L}{D+\frac{1}{R}}$$

c) A 60 Hz power system consists of 5 identical 700 MVA , 600MW, units feeding a total load of 2500 MW. The H constant of each unit is 6.0 sec on their own base MVA. Each unit has 5% governor droop mechanism fitted. The demand varies by 2% for 1% change in frequency. For a sudden increase of 100 MW of load find the steady state frequency deviation in Hz:

i) without droop [3]

when 100 MW load is increased the net D will be on 2600 MW . 2% of 2600 MW = 52 MW. 1% change in frequency = 0.6 Hz ; D = 52/0.6 = 86.7 MW/Hz, change in demand = 100 MW

change in frequency = -100/86.7 = -1.15 Hz , the steady state frequency = 58.85 Hz

ii) with droop [3]

five governors are operating with five units in parallel : R = 0.05 pu ; 5% of 60 / 600 = Hz/MW, 1/R = 200, five governors will produce a combined droop = 5/R = 1000.

Change in frequency = -100/(86.7+1000) = 0.0920 Hz

iii) justify the effectiveness of droop control in steady state frequency deviation in view of the results obtained above. [2]

The governor brought the frequency deviation to 0.0920 Hz or to 59.080 Hz

5.

a) **What are the fundamental differences between apparatus protection and system protection?** [3]

Apparatus protection deals with detection of a fault in the apparatus and consequent protection action. Apparatus protection can be further classified into following:

- Transmission line protection and feeder protection
- Transformer protection
- Generator protection
- Motor protection
- Busbar protection

System protection deals with detection of proximity of system to unstable operating region and consequent control actions to restore stable operating point and/or prevent damage to equipment. Loss of system stability can lead to partial or complete system blackouts. Under-frequency relays, out-of-step protection, islanding systems, rate of change of frequency relays, reverse power flow relays, voltage surge relays etc are used for system protection. Wide Area Measurement (WAM) systems are also being deployed for system protection. Control actions associated with system protection may be classified into preventive or emergency control actions.

b) **Discuss various advantages of solid state relays.** [5]

With the advent of transistors, operational amplifiers etc, solid state relays were developed. They realise the functionality through various operations like comparators etc. They provide more flexibility and have less power consumption than their electromechanical counterpart. A major advantage with the solid state relays is their ability to provide self-checking facility i.e. the relays can monitor their own health and raise a flag or alarm if its own component fails. Some of the advantages of solid state relays are low burden, improved dynamic performance characteristics, high seismic withstand capacity and reduced panel space.

Relay burden refers to the amount of volt amperes (VA) consumed by the relay. Higher is this value, more is the corresponding loading on the current and voltage sensors i.e. current transformers (CTs) and voltage transformers (VTs) which energizes these relays. Higher loading of the sensors leads to deterioration in their performance. A performance of CT or VT is gauged by the quality of the replication of the corresponding primary waveform signal. Higher burden leads to problem of CT saturation and inaccuracies in measurements. Thus it is desirable to keep CT/VT burdens as low as possible.

c) **Distinguish between the dependability and security of a relay.** [4]

Dependability

A relay is said to be dependable if it trips only when it is expected to trip. This happens either when the fault is in its primary jurisdiction or when it is called upon to provide the back-up protection. However, false tripping of relays or tripping for faults that is either not within its jurisdiction, or within its purview, compromises system operation. Power system may get unnecessarily stressed or else there can be loss of service. Dependability is the degree of certainty that the relay will operate correctly:

$$\% \ Dependability = \frac{Number\ of\ correct\ trips}{Number\ of\ desired\ trips} \times 100$$

Dependability can be improved by increasing the sensitivity of the relaying system.

Security

On the other hand, security is a property used to characterize false tripping of the relays. A relay is said to be secure if it does not trip when it is not expected to trip. It is the degree of certainty that the relay will not operate incorrectly:

$$\% \ Security = \frac{Number\ of\ correct\ trips}{Total\ number\ of\ trips} \times 100$$

False trips do not just create nuisance. They can even affect system security. For example, tripping of a tie-line in a two area system can result in load-generation imbalance in each area which can be dangerous. Even when multiple paths for power flow are available, under peak load conditions, overloads or congestion in the system may result. Dependability and security are contrasting requirements. Typically, a relay engineer biases his setting towards dependability. This may cause some nuisance tripping, which can in the worst case, trigger partial or complete blackout! Security of the relaying system can be improved by improving selectivity of the relaying system

**d)** **The performance of an over current relay was monitored for a period of one year. It was found that the relay operated 15 times, out of which 13 were correct trips. If the relay failed to issue trip decisions on 3 occasions, compute the dependability, security and reliability of the relay as a percentage of its ideal performance.** **[6]**

*Number of correct trips = 13; Number of desired trips = 13 + 3 = 16*

$$\% \ Dependability = \frac{Number\ of\ correct\ trips}{Number\ of\ desired\ trips} \times 100$$

13/16*100= 81.25%

[2]

$$\% \ Security = \frac{Number\ of\ correct\ trips}{Total\ number\ of\ trips} \times 100$$

13/15*100=86.7%

[2]

$$\% \ Reliability = \frac{Number\ of\ correct\ trips}{Number\ of\ desired\ trips + Number\ of\ incorrect\ trips} \times 100$$

13/(16+3)*100=68.5%

[2]

**e)** **Power transformer usually draws huge amount of inrush current during starting. What type of protection can you suggest to distinguish between the normal starting and closing on fault?** **[2]**

Inrush current is characterised by DC offset and second harmonics. The student should be able to point that out. Second harmonics restraint relays will be required. In digital version , this can be done once the frequency components are available.

6

a) A 1000/5 C400 current transformer (CT) is connected to a relay with a burden of 2.50 Ω. The secondary resistance of the CT is 0.5 Ω. A secondary current of 120 A flows through the relay coil.

i) For this secondary current, is the CT still expected to behave in a linear manner? Justify your answer. [3]

Secondary voltage developed = 120*(2.50+0.5) = 360 V. This is less than 400 V, the highest permissible voltage in the linear zone.

ii) With added generation the fault level of the substation where the CT remains connected is increased. It was decided not to replace the CT rather upgrade some of the relays with lower burden so that when primary fault current is 30 kA, the CT could faithfully reflect the primary current to the relay input terminal. Find the upper limit of the relay burden to realise this. [3]

Primary fault current = 30 KA, secondary fault current = 30000/1000*(5) = 150 A , total permissible secondary resistance = 400/150 =2.67 Ω., secondary lead resistance = 0.5 Ω., maximum permissible relay burden = 2.17 Ω.

b) How is % ratio error in CTs defined? [3]

CT performance is usually gauged from the ratio error. The ratio error is the percentage deviation in the current magnitude in the secondary from the desired value. In other words, if the current measured in the secondary is $I_s$, true or actual value is $I_p/N$, where N is nominal ratio (e.g. N for a 100:5 CT is 20) and $I_p$ is the primary current then ratio error is given by $\frac{\left|\frac{I_P}{N}\right|-|I_S|}{|I_S|}\times 100$. When the CT is not saturated ratio error $\frac{\frac{I_P}{N}-I_S}{I_S}\times 100$ is a consequence of magnetizing current $I_E$ since $\frac{I_P}{N}-I_S=I_E$. Therefore, % ratio error is equal to $\frac{I_E}{I_S}\times 100$.

c) What will be the approximate ratio error (%) if a 500:5 class C CT is connected to a secondary burden of 2.5 Ω when carrying 70 A in the secondary and 5 A exciting current? [3]

5/70*100 = 7%

d) This question relates to capacitive coupled voltage transformer(CCVT)

i) **Why is capacitive coupled voltage transformer (CCVT) preferred over normal electromagnetic voltage transformer (VT)?** [2]

Electromagnetic VTs are expensive and just for measurement and protection purpose a 400kV/11kV VT will look like a power transformer. It will occupy a plenty of space. CCVT is cheap and can be realised with small engineering footprint.

ii) **Draw the equivalent circuit of a capacitive coupled voltage transformer (CCVT).** [3]

Typically, the secondary voltage of the VT is standardized to 110 V (ac). Hence, as the primary voltage increases, the turns ratio $N_1:N_2$ increases and transformer becomes bulky. A capacitance potential divider is used (Fig 10.8) **to cut down the cost**. Thus, a reduced voltage is fed to primary of the transformer. This reduces the size of VT. This leads to development of coupling capacitor voltage transformers (CCVT) or simply as capacitive voltage transformer (CVT).

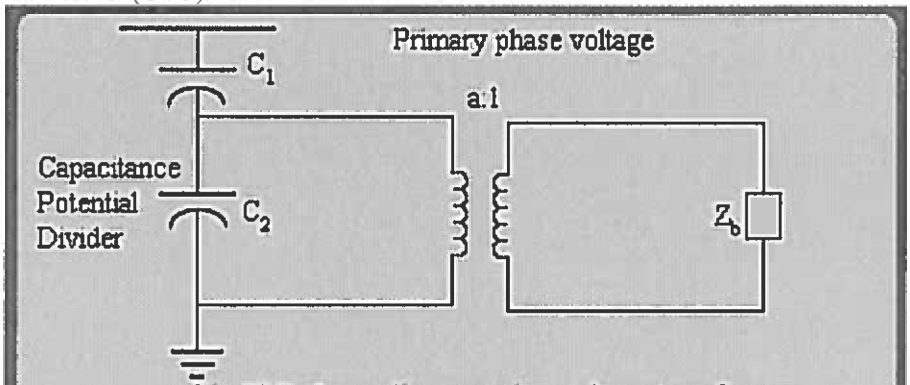


**Fig 10.8: A coupling capacitor voltage transformer**

iii) **Briefly describe the purpose of the tuning inductor in a CCVT** [3]

**Role of Tuning Reactor L:** Assuming, the transformer to be ideal, and source with negligible reactance, the Thevenin's equivalent circuit of CCVT is shown in Fig 10.9.

It is now obvious that $Z_{th}$ due to the capacitance divider affects the voltage received by the relay. To achieve high level of accuracy, it is therefore necessary to compensate for this voltage drop by connecting a tuning inductor. The tuning inductor's value is so chosen that it compensates for the 'net C' at power frequency (50/60Hz).

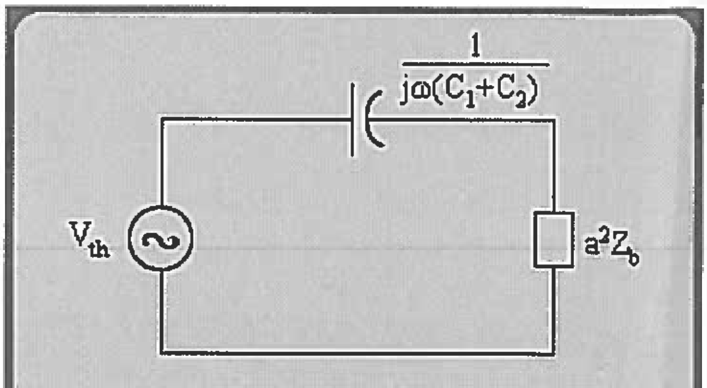



Fig 10.9: CCVT as seen from primary of VT

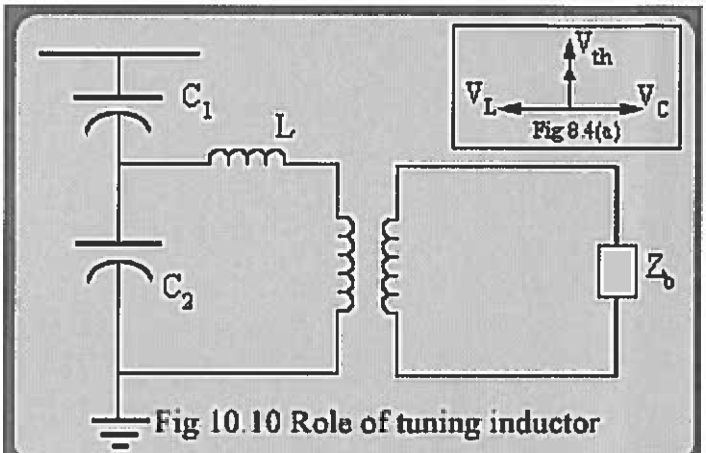



Fig 10.10 Role of tuning inductor

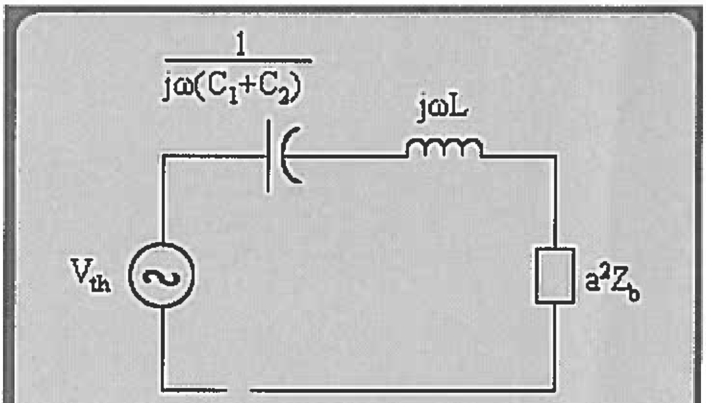



Fig 10.11: Final equivalent circuit of CCVT