E4.48/C3.2

The Answers 07/08

1.

a) Why is the current so important consideration in lightning protection design? [2]

The electrical property of lightning is characterised by very short lived high current (micro-seconds-kA). The specification of the pilot wire, tower and tower footing resistance to limit the impact of the current is very much influenced by the current.

b) How is the switching transient in power transmission network characterised? [3]

In EHV lines when circuits are opened because of fault, large over voltage appears across the switch (circuit breaker). Typically for a 400 kV system, this can be around 2 times (depends on the switching arrangement) the rated value and last for 200 microseconds to 2000 microseconds.

c) How does the phenomenon of sub synchronous resonance (SSR) develop and manifest in the system? [3]

During network events (switching) high current will flow temporarily through generator stator circuits. Usually these are due to transformer EMF and have power frequency (50/60 Hz). The contribution of this component during transient to total generation voltage is insignificant. Their exclusions from modelling make the analysis simpler to establish better understanding. Various sections of turbine mass dynamically interact with the network particularly when long transmission lines are series compensated. The frequencies of oscillations are in the range of 10 to 48 Hz and that is why they are classified as sub synchronous resonance (SSR).

*d) In a salient pole synchronous generator, the voltage current relations along the **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 symbol carry there 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 δ.

The terminal voltage and current vector of the machine 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 relationship of the machine.*

[6]

ii) *For the following values of the variables in p.u. obtain the real and reactive power output of the machine in p.u.*

$X_d = 2.0$, $X_q = 1.8$, $V_t = 1.05$, $E_{fd} = 3.0$ *and* $\delta = 20$ *degrees*

[3]

iii) *Suddenly the machine loses excitation. Justify through load angle computation whether the stability will be maintained if the mechanical input was to remain unchanged.*

[3]

i) Algebraic summation of voltage along q-axis

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

Along d-axis

$$V_d + I_q X_q = 0$$

From the relation: $V_d = -V_t \sin\delta; V_q = V_t \cos\delta; V_t = V_q + jV_d; I_t = I_q + jI_d$

The currents in the voltage equations can be solved as function of voltage and substituted in the complex expression for power $V_t I_t^*$. On simplification the real and reactive power will be

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

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

ii)

Ans: Real power = 0.56; reactive power 0.92 p.u.

iii)

The maximum power due to saliency that could be developed is 0.0306 p.u. (the student has to apply the understanding of the saliency power concept with the help of power angle relation and compute the maximum power from it under loss of excitation. which is far too lower than the input power 0.56. The machine will loose the stability immediately following loss of excitation.

2

Briefly describe the functions of the following components in excitation systems:

i) *voltage regulator* [3]

ii) *power system stabiliser* [3]

iii) *limiter and protective circuits* [3]

iv) *field forcing* [3]

Regulator

It processes and amplifies input control signals to a level and form appropriate for control of the exciter. This includes regulating and excitation system stabilising function (rate feedback and lead-lag compensation). In early days it used to be amplidyne or alternator. Modern voltage regulator is high gain fast acting thyristor system to produce high DC excitation.

Voltage and current sensor

Senses generator terminal voltage and currents and feed to the regulator block for voltage regulation and load current compensation. These quantities are important to compute the excitation level of the machine, flux level in stator and rotor and also current loading in stator as well as rotor winding. Through voltage and current transducers high voltage and current are brought down to control level and operating point of the machine is assessed.

Power system stabilizer

This block provides an additional input signal to the regulator to damp power system oscillations. Some commonly used input signals are rotor speed deviation, accelerating power and frequency deviation. This is very important for post fault small signal stability of the system. This results when machine is equipped with high gain fast acting excitation system for improved transient stability performance.

Limiter and protective circuits

These include a wide array of control and protective functions that ensure that the capability limits of the exciter and synchronous generator are not exceeded. Some of the commonly used functions are the field current limiter, maximum excitation limiter, terminal voltage limiter, volt/Hz regulator and protection and under excitation limiter. These are normally distinct circuits and their output signals may be applied to the excitation system at various locations as a summing input or a gated input.

b) Other than synchronous generator, mention various other options of voltage control and describe two of them in reasonable detail.

[8]

Overhead lines and cables
Tap changing transformer
Loads

- Typically a 400-KV single circuit line produces 60-70 MVAR per 100 km
- 400-KV cable produces 20 MVAR per km.

The line is modelled as nominal pi or T section to represent effect of series inductance and capacitance

- At light load (during night) generation is more than the absorption: hence the system voltage is higher than nominal.
- At higher load (during peak hours) absorption in the series branch is considerably higher than the generation in the shunt branch: the net effect brings the system voltage lesser than normal.
- At surge impedance load (when shunt var generation is line inductor absorption) voltage remains fault along the length of the line or cable, the voltage and current at any section of the line are in phase too. This is ideal situation but rarely achieved in practice.

Tap changing transformer:

- Provides discrete voltage control
- Can be on-load or off-load.
- Transformers always absorb as the leakage impedance is reactive.

For a transformer with $X_T\, p.u.$ and full load rating $3VI_{rated}$

The var absorbed

$$X_T(\Omega) = VX_T(p.u.)/I_{rated}$$

$$3I^2X_T(\Omega) = 3I^2VX_T(p.u.)/I_{rated} = 3I^2V^2X_T(p.u)/VI_{rated}$$

$$\left(\frac{VA_{load}}{VA_{rated}}\right)^2 X_T(p.u)$$

3

a) Briefly describe the nature and importance of the primary frequency control in power system.

[3]

The primary frequency response 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) when meets sudden increase in demand. This is not enough to sustain the demand for more than few seconds and the decline in frequency can not 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 results in settling at a frequency at lower than the earlier steady state value.

Load generation dynamic response: Any balance between the generation and demand will give rise to the dynamic response of the system. The primary response can improve the frequency deviation through governor droop characteristic. It is very important to maintain the system frequency deviation within the prescribed tolerance as specified in the network operator's grid code.

b) Including the effect of governor droop characteristic, establish the following relation

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

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

[8]

The student is expected to draw the governor control loop to establish the relation between the change in demand to the change in frequency in transfer function domain. They are expected to derive the steady state condition there upon.

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 ΔP_{elec} into the expression for dynamic response equation one gets

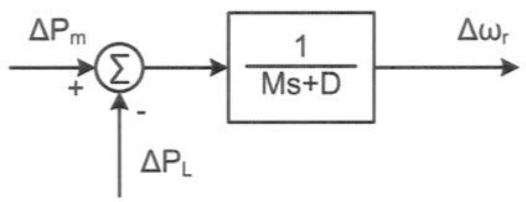
$$\Delta P_m - \Delta P_L - D\Delta\omega_r = Ms\Delta\omega_r \ .$$

Rearranging the term, the following expression is obtained.

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

This is shown in the following block diagram. The perturbation in mechanical input (ΔP_m) will be zero when governor action is not represented. This will further simplify the above expression to

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



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 $G_t(s)$.

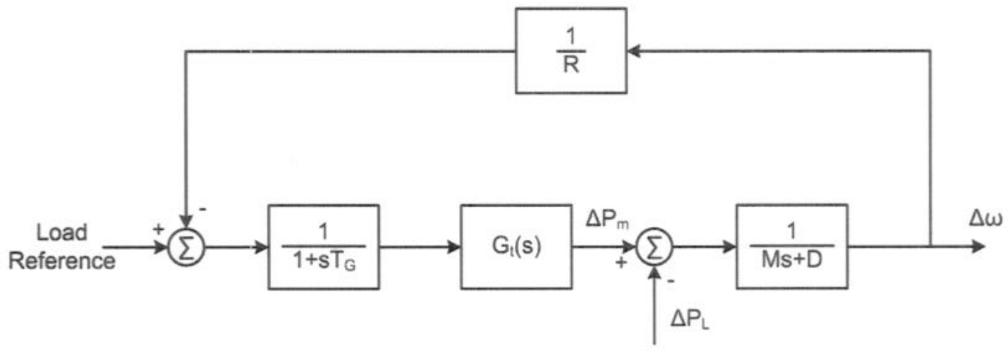


Fig: Block diagram of governor with droop for generator speed control

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 ΔP_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

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

It is interesting to note that the denominator is now dominated by the reciprocal of the droop (R). This will reduce the steady state speed deviation because of change in demand.

c) A small 50 Hz system consists of 5 identical 600 MVA units feeding a total load of 1550 MW. The H constant of each unit is 6.0 sec on their own base MVA. Each unit has 5% governor droop mechanism fitted into. The load varies by 2% for 1% change in frequency. For a sudden increase in 50 MW of load find the steady state frequency deviation in Hz. Obtain the frequency deviation

i) without droop

[4]

ii) with droop.

[4]

iii) comment on the effectiveness of droop control in view of the results obtained above.

[1]

It is will be convenient to lump all the units into one equivalent one. Let's choose base MVA as the combined MVA of all the 5 units, i.e. 3000 MVA. The damping co-efficient will be computed on 1600 MW (1550+50) loads. Change in load = 50 MW = 50/3000 p.u. D = 2% of 1600 per 1% of frequency change i.e. 64 MW/ Hz i.e 64/3000 p.u load/ 1 Hz = 0.0213/Hz. The droop of all the units combined will be equivalent R/5 and on 3000 MVA it will be R again i.e. 5% or 0.05.

The steady state frequency deviation without droop will be 0.01666/0.0213 = 0.78 Hz and with governor droop will be 0.01666/ (0.0213+1/0.05) =0.00083 Hz. It is very clear that with governor droop the frequency deviation is comparably smaller than without governor droop action.

4

a) Briefly describe the necessity of area wise load frequency control

[2]

When two utility connect together they do for several reasons. One is to be able to buy and sell power with neighbouring systems whose operating costs make such transactions profitable. Further even if no power is being transmitted over ties to neighbouring systems, if one system has sudden loss of generating unit, the units throughout all the interconnection will experience a frequency change and can help in restoring frequency.

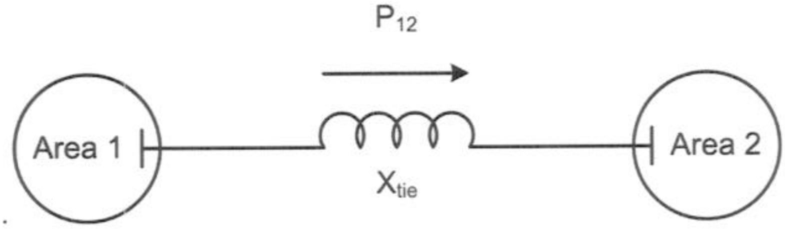
b) Establish the steady state power frequency characteristics of a two-area system. Assume that each area has the following characteristic parameters:

Area 1: inertia constant: M_1, droop: R_1 and damping co-efficient: D_1

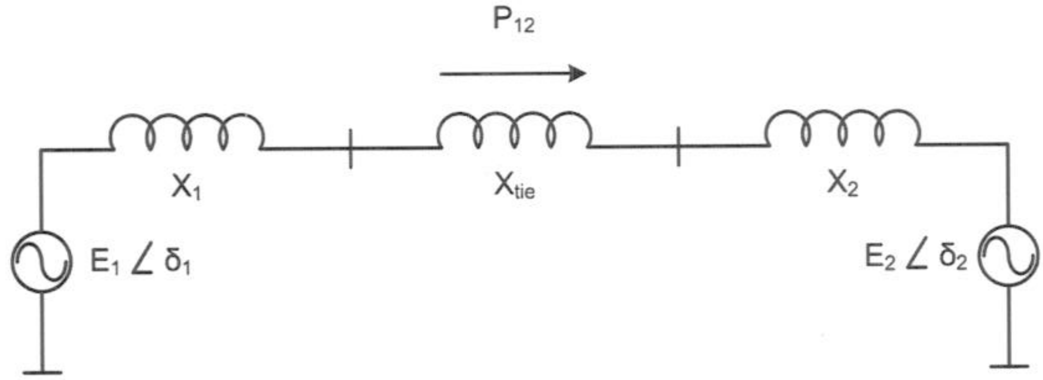
Area2: inertia constant: M_2, droop: R_2 and damping co-efficient: D_2

[6]

For interconnected system schedule tie line power is an additional variable.



The electrical equivalent is as follows:

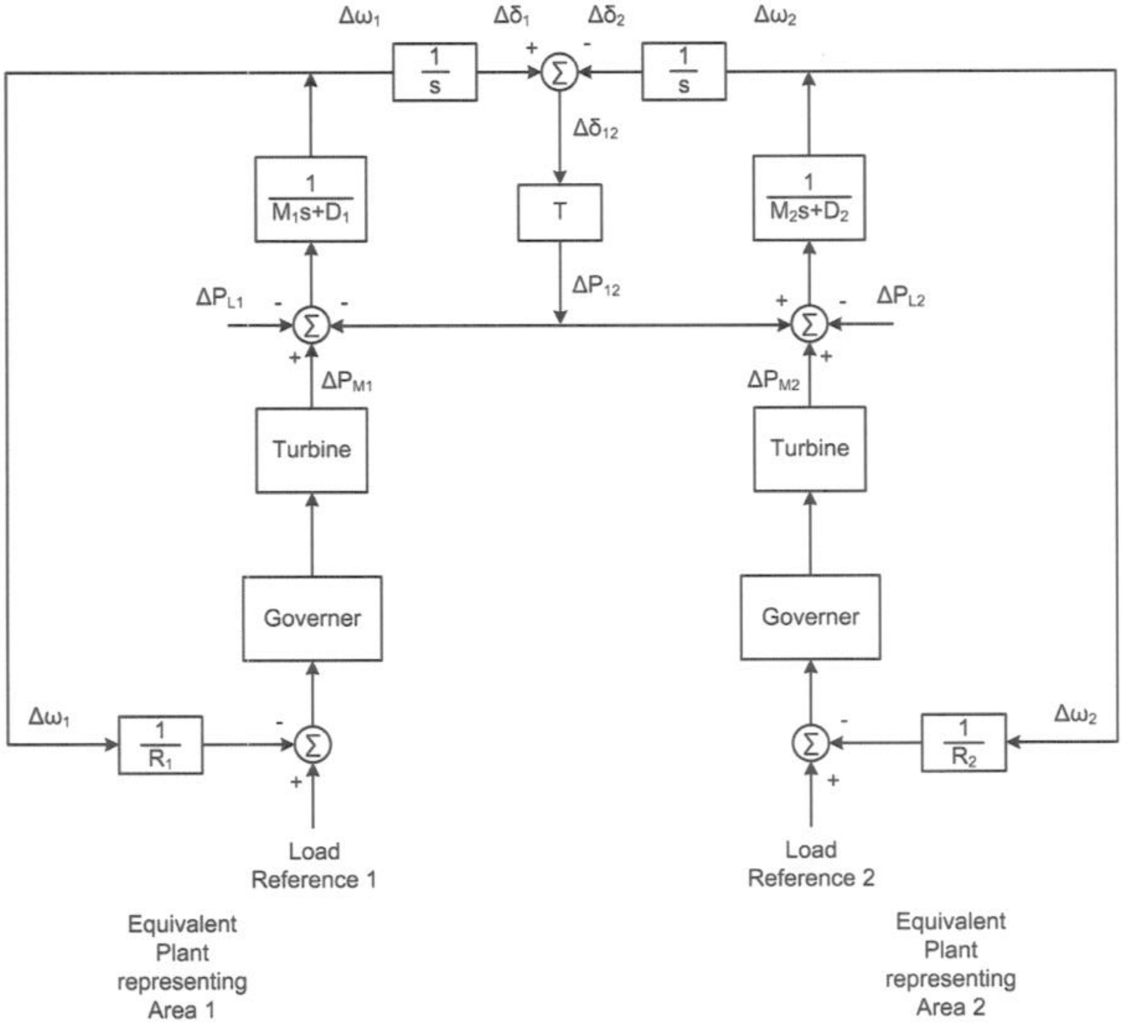


In an interconnected system operation as shown in the figure, it is important to consider the scheduled interchange power. These two areas can be modelled as two equivalent voltage sources behind source reactance and tie line reactance.

$$P_{12} = \frac{E_1 E_2}{X_T} sin(\delta_1 - \delta_2)$$

The linearized form of the above equation is:

$\Delta P_{12} = T(\Delta\delta_1 - \Delta\delta_2)$ where $T = \frac{E_1 E_2}{X_T} cos(\delta_{10} - \delta_{20})$ is the synchronising power co-efficient. The block diagram below shows this. Note each area is represented by its composite load damping and frequency characteristic. The frequency deviation $\Delta\omega_1 = \Delta\omega_2 = \Delta\omega = \Delta f$ is common in both area connected by tie. The tie power deviation ΔP_{12} will be seen as load in area 1 and generation in area 2 (import) and its sign will be assumed accordingly.



This two area system with primary governor control can easily be characterised by the following equation or relation:

$$\Delta f = -\frac{\Delta P_L}{D_1 + D_2 + \frac{1}{R_1} + \frac{1}{R_2}}$$ (I would learn it by heart for ever or till the final exam)

Let us assume that there is a change in area 1 load. It will be natural to see the implication of this change on system frequency, area loads and interchange.

In the steady state following hold

Area1: $\Delta P_{m1} - \Delta P_{L1} - \Delta P_{12} = D_1 \Delta f$

Area 2: $\Delta P_{m2} + \Delta P_{12} = D_2 \Delta f$

From droop characteristics: $\Delta P_{m1} = -\frac{\Delta f}{R_1}; \Delta P_{m2} = -\frac{\Delta f}{R_2}$

On substitution $\Delta P_{m1}, \Delta P_{m2}$ into the first two equations and solving for Δf

$$\Delta f = -\frac{\Delta P_{L1}}{D_1 + D_2 + \frac{1}{R_1} + \frac{1}{R_2}} = -\frac{\Delta P_{L1}}{\beta_1 + \beta_2} \quad \Delta P_{12} = \left(D_2 + \frac{1}{R_2} \right) \Delta f = \beta_2 \Delta f$$

Where β_1, β_2 are defined as composite area stiffness. Tie power deviation can also be expressed as: $\Delta P_{12} = -\frac{\beta_2}{\beta_1 + \beta_2} \Delta P_{L1}$

Similarly implications on frequency and tie power deviation for change in area 2 load can be derived to be

$$\Delta f = -\frac{\Delta P_{L2}}{\beta_1 + \beta_2}; \Delta P_{12} = \Delta P_{L2} \frac{\beta_1}{\beta_1 + \beta_2}$$

c) *Consider two interconnected areas as follows: Area 1: Gen 19,000 MW, Load 20,000 MW: Area 2: Gen 41000 MW, Load: 40,000 MW. The load in each area varies by 1% with 1% change in frequency (D = 1.0). The speed regulation, R, is 5% for all the units. Area 1 is importing 1000 MW from Area 2.*

Area 1 is operating with a spinning reserve of 1000 MW spread uniformly over a generation of 4000 MW capacity, and Area 2 is operating with a spinning reserve of 1000 MW spread uniformly over a generation of 10,000 MW. The nominal frequency is 50 Hz.

Determine the steady state frequency, generation and load of each area, and the tie line power for each of the following contingencies, when the generation carrying spinning reserve in each area is on supplementary control with frequency bias factor settings of 250 MW/0.1 Hz for Area 1 and 500 MW/0.1 Hz for Area 2.

i) *Loss of 1000 MW load in Area 1 without supplementary control*

[6]

ii) Loss of 2000 MW generation in area 1 which is not part of spinning reserve with supplementary control.

[6]

Ans:

1/R1 = 20000/(0.05*50) = 8000 MW/Hz ; 1/R2 = 42000/(0.05*50) = 16800 MW/Hz

1/R1+1/R2 = 24800 MW/Hz; D1 = 19000/100 *(100/50) = 380 MW/Hz

D2 = 40000/100*(100/50) = 800 MW/Hz

Total effective damping D1+D2 = 1180 MW/Hz

Change in system frequency for 1000 MW of loss of load = - (-1000)/ (D1+D2+1/R1+1/R2) = 0.0385 Hz, steady state frequency is 50.0385 Hz

Change in area1 load for change in frequency = D1*0.0385 = 14.62 MW, change in load in area 2 load D2*0.0385 = 30.79 Hz; change in generation in area 1 is - 1/R1*0.0385 = -307.92, in area 2 -1/R2*0.0385 = -646.65 MW

Area 1 generation: 19000-307.92 = 18692 MW, load = 20000+14.62-1000 = 19014.62 MW

Area 2: generation: 41000-646.65 = 40353.34 MW, load 40000+30.79 = 40030.79 MW

Tie line flow = Area2 gen – Area2 load = 677 MW

Part (ii) = area1 bias factor, beta1 = 2500 MW/Hz; area2 bias factor beta2 = 5000 MW/Hz

Area1 has lost generation of 2000 MW not part of spinning reserve of 1000 MW. The spinning reserve will meet 1000 MW and the balance has to come from area 2. It is possible to have t from area 2 as it has that much of reserve. The area control error in area 2

Delta_P21+beta2*delta_f = 0. ; delat_P21 = -delta_P12 = delta_f*beta2; the total change in generation in area 1 will be equal to export from area2 (delta_P21) and change in demand in area D1*delta_f;

Beta2*delta_f+D1*delta_f = delta_PG1 = -1000 (negative sign for drop in generation), the frequency drop is -0.1858 Hz; delta_P12 = -5000*0.1858 = 929 MW; change in load in area 1 = D1*delta_f = -70.63 MW ; in area 2 D2*delta_f = -148.7 MW

Area1 geneartion: 20000-2000+1000 = 18000, load = 20000-70.63 = 19929.3 MW

Area2 generation: 41000+delta_P21+D2*delta_f = 41780 MW, load = 40000-148.7 = 39851.3 MW

5.

a) *Describe the purpose of the protection systems.*

[4]

Electrical power system operates at various voltage levels from 440 V to 765 kV or even more. Electrical apparatus used may be enclosed (e.g., motors) or placed in open (e.g., transmission lines). They meet uncertain operating circumstances (both internal and external) because of various reasons. For example, a worn out bearing may cause overloading of a motor. A tree falling or touching an overhead line may cause a fault. A lightning strike (act of nature) can cause insulation failure. Pollution may result in degradation in performance of insulators which may lead to breakdown. Under or over speeding of generators may result in mechanical shaft damage that must be prevented through generator protection. When a part of the system is subjected to such abnormal situations, it should be taken off the system to minimize the impact of such events on the overall system operation. This is achieved through properly planned, designed and implemented protection strategy.

b) *Discuss various components and functionalities of numerical relays.*

[5]

The block diagram of a numerical relay is shown in Fig below. It involves analogue to digital (A/D) conversion of analogue voltage and currents obtained from secondary of CTs and VTs. These current and voltage samples are fed to the microprocessor or Digital Signal Processors (DSPs) where the protection algorithms or programs process the signals and decide whether a fault exists in the apparatus under consideration or not. In case, a fault is diagnosed, a trip decision is issued. Numerical relays provide maximum flexibility in defining relaying logic. The hardware comprising of numerical relay can be made scalable i.e., the maximum number of v and i input signals can be scaled up easily. A generic hardware board can be developed to provide multiple functionalities. Changing the relaying functionality is achieved by simply changing the relaying program or software. Also, various relaying functionalities can be multiplexed in a single relay. It has all the advantages of solid state relays like self checking etc. Enabled with communication facility, it can be treated as an Intelligent Electronic Device (IED) which can perform both control and protection functionality. Also, a relay that communicates can be made adaptive i.e. it can adjust to changing apparatus or system conditions. For example, a differential protection scheme can adapt to transformer tap changes. An overcurrent relay can adapt to different loading conditions. Numerical relays are both "the present and the future".

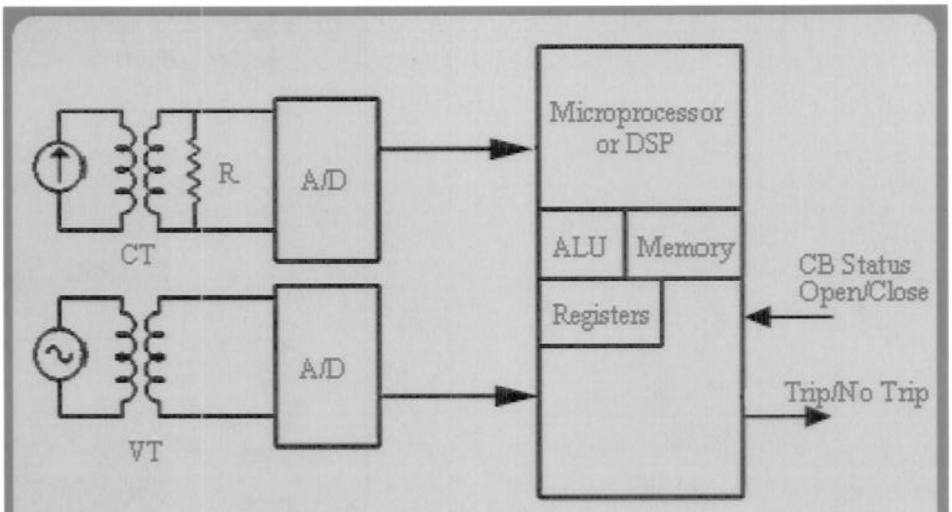


Fig 9.4 Block Diagram of Numerical Relay

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 14 times, out of which 12 were correct trips. If the relay failed to issue trip decisions on 3 occasions, compute dependability, security and reliability of the relay as a percentage of ideal performance.*

[7]

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

$$= \frac{12}{15} \times 100 = 80\%$$

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

$$= \frac{12}{14} \times 100 = 85.71\%$$

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

$$= \frac{12}{15+2} = 70.59\%$$

Note that even though dependability and security are individually above 80%, overall reliability much poor (only 70.55%).

6

a) Why should the secondary of a current transformer never be left open?

[3]

The working principle of an electromagnetic current transformer is very simple. It is essentially a simple transformer with large number of secondary turns and few or even one (bar primary) primary turn. The primary is connected in series with the line supplying load. Current in the secondary has to flow through a low impedance (known as burden) otherwise high excitation voltage will develop that would saturate the magnetic core of the CT. The CT secondary should never be open circuited otherwise the primary ampere turn would be magnetically unbalanced leading to damagingly high voltage at the CT secondary terminal. This clearly suggests that a CT is essentially a current source as far as secondary side is concerned.

b) List two primary types of current transformer and briefly describe the functional requirement and design specifications of any one of them.

[6]

The CTs can be classified into following types: Measurement CTs and Protection CTs. The answer must address the standard current, core linearity, saturation, accuracy, phase angle error and ratio error aspects. It should also address the magnetisation characteristic and low burden etc. If protection CT is addressed then various type and designation need mentioning.

c) What is the function of a tuning inductor in a capacitive coupled voltage transformer (CCVT)?

[3]

In CCVT, because of voltage division across capacitor and drawal of primary magnetising current the input voltage to electromagnetic transformer is phase shifted from the line voltage. This affects the voltage received by the relay. To achieve high level of accuracy, it is therefore necessary to compensate for this voltage drop and phase shift 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).

$$\omega L = \frac{1}{\omega(C_1 + C_2)}$$

With this arrangement the voltage drop across C is neutralized and the relay sees the actual voltage to be measured.

d) A 1200/5, C400 CT is connected on the 1000/5 tap. The secondary winding resistance is 0.51 Ω. Obtain the maximum allowable burden in the CT at 20 times the rated symmetrical secondary current with rated accuracy.

[8]

The secondary voltage V_S *corresponding to the tap 1000/5,* $V_S = \frac{1000}{1200} \times 400$ = *333V*

Secondary current $I_S = 20 \times 5 = 100A$

$V_S = I_S(R_S + R_B)$

$R_S = 0.51\Omega$

$333 = 100(0.51+R_B)$

Secondary burden $= 3.33 - 0.51 = 2.72\ \Omega$

This is the maximum allowable secondary burden