INTERNAL ASSESMENT TEST-1
POWER SYSTEM OPERATION AND CONTROL
SOLUTION

1. Draw and explain the functional block diagram of the dual computer configuration for control and monitoring of power system.

ENERGY CONTROL CENTER:

A focal point where generators, lines, sub-stations, transformers, switchgear operation is monitored and controlled; is called as Energy Control Center.

DIGITAL COMPUTER CONFIGURATION

[DUAL COMPUTER CONFIGURATION].

* For remote data acquisition, control, energy manageme and system security a redundant set of dual digital computers are used.
* Both the computers have their own memory and Input/Output devices.
* ~~Online~~ Online computer monitors and controls the power syste
* The Backup computer executes off-line programs such as load forecasting and unit commitment.
* The On-line computer periodically updates a disk memory shared between the two computers.
* Upon a failover or switch in status command, the stored information of the common disk is inserted in the memory of the on-coming computer.

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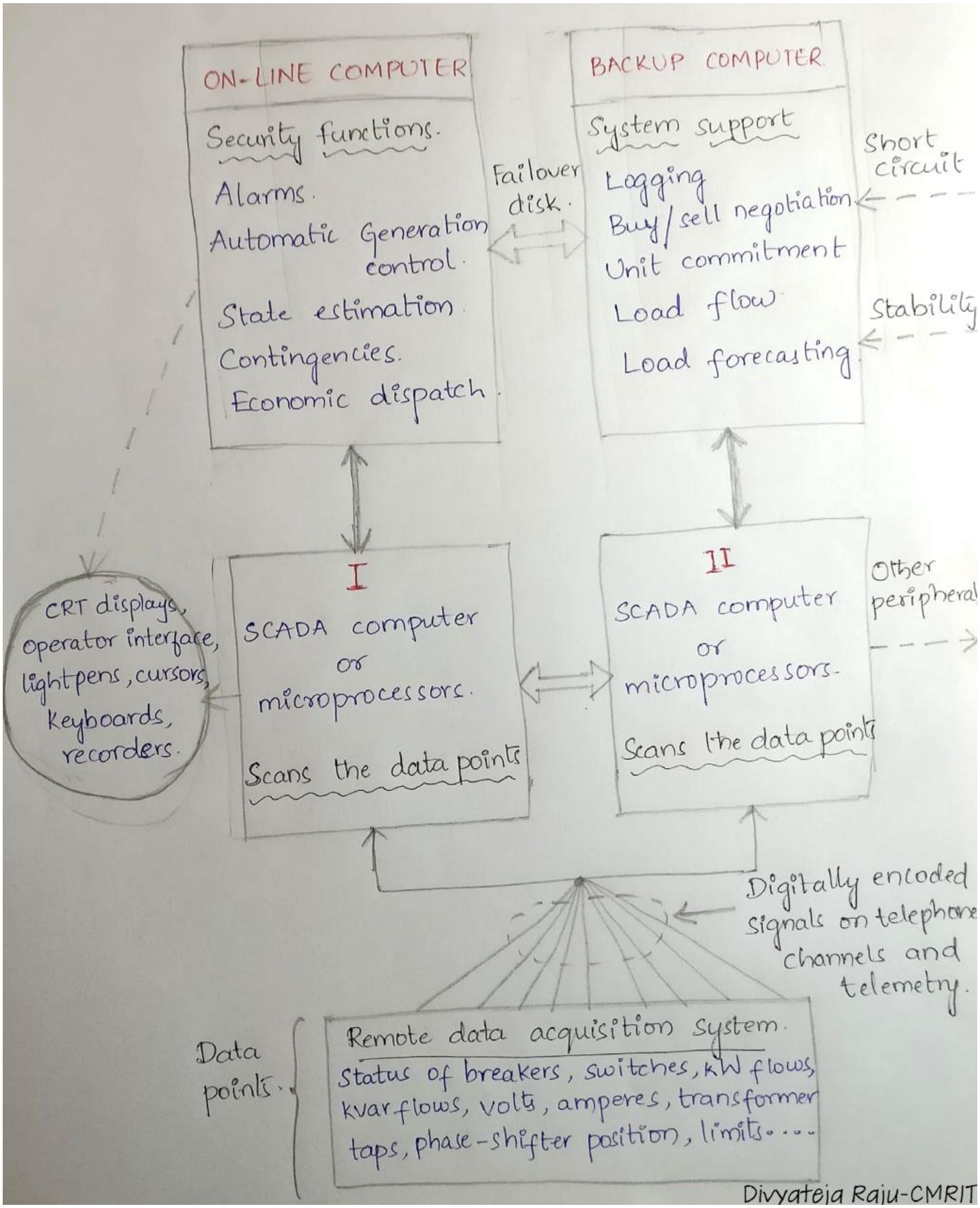

*. The digital computers are usually employed in fixed cycles. With priority interrupts the computer periodically performs a list of operations.

*. The most critical functions have the fastest scan cycle such as

- Switchgear position
- Substation loads
- Transformer tap positions
- Tie-line flows etc.

Here the scan cycle is 2 seconds.

*. The turbine generators are frequently adjusted to the new power levels every 4 seconds.

*. The other system operations such as

- Recording of load
- Forecasting of load
- Determination of which generators to start up or stop

All these are non-critical operations hence the computer executes these programs on on hourly basis.

*. Most low-priority programs may be executed on demand by the operator for study purposes or to intialize power system.

*. An operator may also alter the digital computer code in the execution if a parameter changes in the system.

2. Derive an expression for Tie-line power and frequency deviation for two area system.

INTERNAL ASSESMENT TEST-1
POWER SYSTEM OPERATION AND CONTROL
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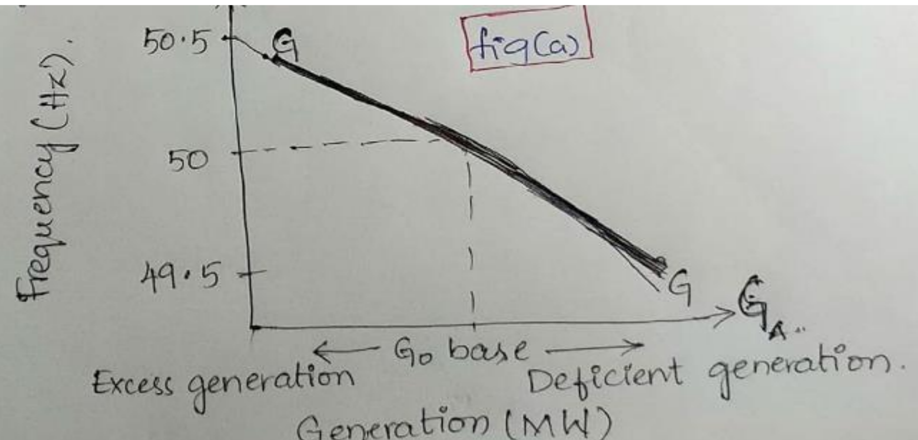
[EXPRESSION FOR TIE-LINE FLOW POWER AND FREQUENCY DEVIATION]

* Power systems are capable of operating without a central computer or AGC.
* This is due to turbine generator speed controls built into generating stations and natural load regulation.
* These characteristics force generators within an area to share load and cause interconnected power areas to share load
* Considering a two area model, with breaker T open (no tie-line flow).

Assumptions :

* Area D represents an operating area of interconnected power system in which sudden load or generation change occurs, Area A forms the rest of the power system.
* Areas share a disturbance in proportion to their generating capacity size and operating characteristics.
* Let the area A overall generation frequency be represented by curve GG.



INTERNAL ASSESMENT TEST-1
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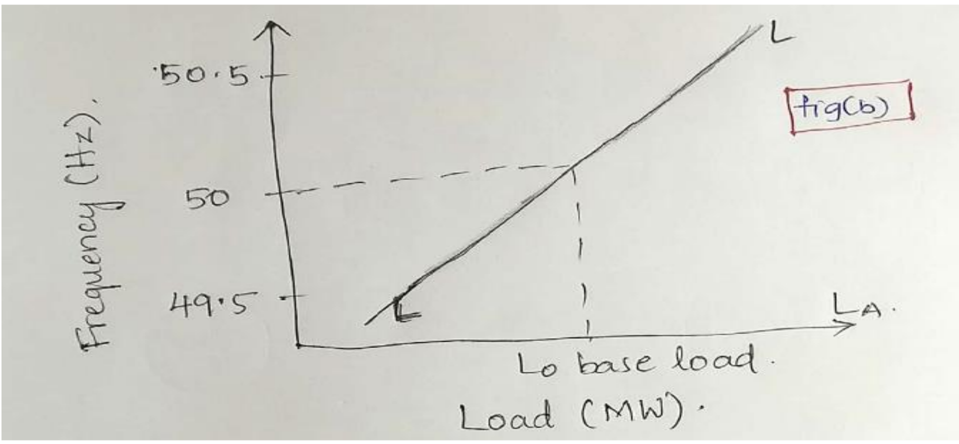
SOLUTION

* The shaft speed and consequently the electrical line frequency changes with load reflected onto the prime mover.
* The generation-frequency characteristic curve has a negative slope or droop.
* The area connected load is defined by curve LL as shown below.



* Basic equations describing generation and load are

$$G_A = G_0 + 10\beta_1 (f_{act} - f_0) \text{ MW} \quad \text{——— (2)}$$

$$L_A = L_0 + 10\beta_2 (f_{act} - f_0) \text{ MW} \quad \text{——— (3)}$$

where G_A = total generation on system A, MW.
G_0 = base generation on system, MW at Hz
L_A = total load on system A, MW.
L_0 = base load on system, MW at Hz.
f_{act} = system frequency, Hz.
f_0 = base frequency (Hz).
β_1 = contangent of generation-frequency characteristic in MW/0.1 Hz; $\beta_1 < 0$.
β_2 = contangent of load frequency characteristic MW/0.1 Hz, $\beta_2 > 0$.

* For a steady-state frequency, total generation must be equal to total effective load and prevailing frequency is defined by point of intersection I_0 of the GG and LL curves.

INTERNAL ASSESMENT TEST-1
POWER SYSTEM OPERATION AND CONTROL
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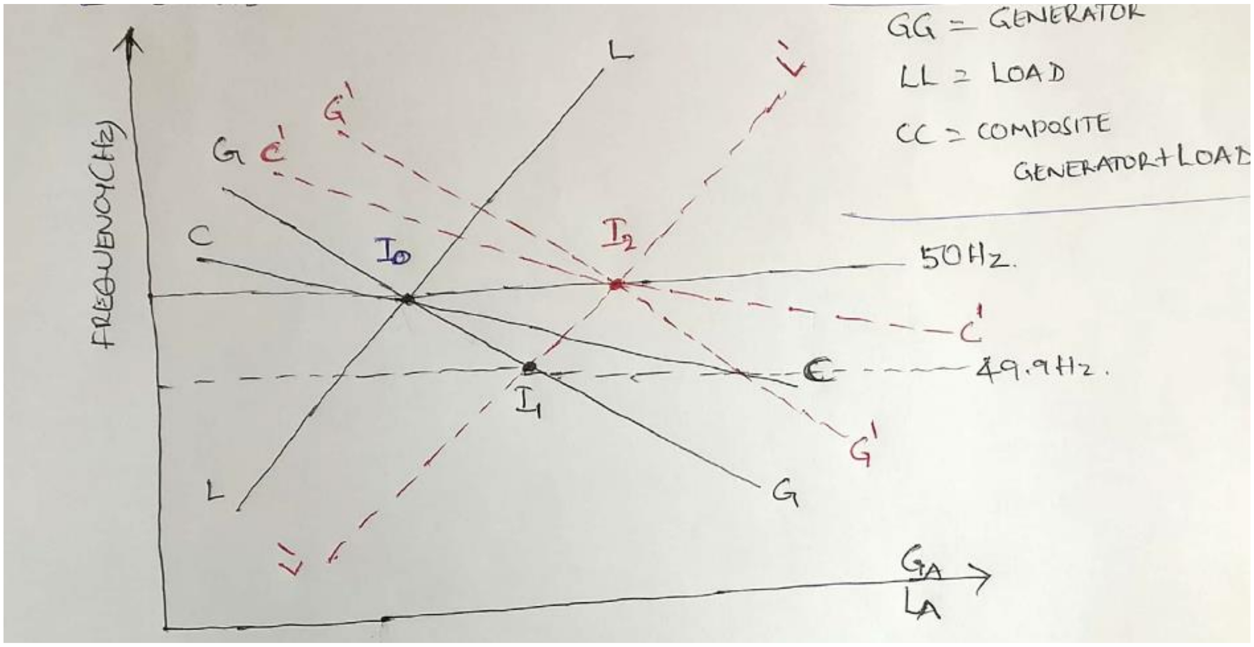


* Now the generation characteristic and the load characteristic can be added algebraically to obtain the combined area characteristic as shown by curve CC.
* The composite generation load-frequency characteristic is given by

$$G_A - L_A = G_0 + 10B_1(f_{act} - f_0) - L_0 - 10B_2(f_{act} - f_0) \quad (4)$$

* Now assume that there's load increase in area A of magnitude to move the load-frequency characteristic to position L'L'.

* The new system frequency be defined by the intersection of GG generation line and new load line L'L' (i.e I_1) as shown in figure.

* If it's desired to return to system frequency to 50Hz and it's possible by shifting generation curve GG to G'G'.
* Now the combined characteristic of G'G' and L'L' is shown by c'c'.
* Equation (4) can be written in terms of increments as.

$$\Delta_A = G_A - G_0 + L_A - L_0 = 10B_1(f_{act} - f_0) - 10B_2(f_{act} - f_0)$$

$$= 10B_A X_A (f_{act} - f_0).$$

$$= 10B_A X_A \Delta f \text{ MW} \quad \text{——— (5)}.$$

where B_A = Natural regulation characteristic of area A expressed in percent of generation per 0.1 Hz

X_A = Generating capacity of area A in MW.

∴ Thus the load increase, Δ_A (or generation decrease) in area A leads to a frequency deviation

$$\Delta f = \frac{\Delta_A}{10B_AX_A} \text{ Hz. } (< 0) \quad \text{——— (6)}.$$

*. Define a real power tie-line flow, ΔT_L, as a quantity out of area, the combined effect on frequency for a load increase (or generation decrease) and positive tie flow on area A is then

$$\Delta f = \frac{\Delta_A + \Delta T_L}{10B_AX_A} \text{ Hz} \quad \text{——— (7)}.$$

where $\Delta_A + \Delta T_L$ is net megawatt change.

TIE – LINE FLOW. (17)

*. Consider areas A and D interconnected with breaker T, closed with generation and load equal 50 Hz in both areas. So no tie-line flow between two areas A and D.

*. Some disturbance occurs in D and causes system frequency to drop to 49.9 Hz. Since they are interconnected the generation no longer matches with effective load in area A.

*. Now the tie-line flow between A and D is

$$\Delta T_L = \Delta G_A - \Delta L_A \text{ MW} \quad \text{—— (8)}$$

where ΔT_L is the net change in tie-line power flow which is a positive value directed from A to D

ΔG_A — Increase of generation in area A.

ΔL_A — Decrease in load power in area A.

* For area D, ΔT_L is the tie-line power flow directed from A to D,

$$\Delta f = \frac{\Delta_D - \Delta T_L}{10 B_D X_D} \text{ Hz.} \quad \text{—— (9).}$$

Let $\Delta_{AD} = \Delta_D$ be the magnitude of the disturbance that occurs in area D and $\Delta_A = 0$

Since the frequency is common to both systems

$$\Delta f = \frac{\Delta T_L}{10 B_A X_A} = \frac{\Delta_{AD} - \Delta T_L}{10 B_D X_D} \text{ Hz} \quad \text{—— (10).}$$

Solving eq (10) for tie-line flow ΔT_L,

$$\boxed{\Delta T_L = \frac{(10 B_A X_A)\Delta_{AD}}{10 B_A X_A + 10 B_D X_D}} \text{ MW} \quad \text{—— (11).}$$

→ Expression for Tie-line power.

The net power change in area D is

$$\Delta_{AD} - \Delta T_L = \frac{(10 B_D X_D)\Delta_{AD}}{10 B_A X_A + 10 B_D X_D} \text{ MW} \quad \text{—— (12).}$$

From eq (12) it is clear that interconnected power system having area A and D both share disturbance as weighted by their generating capacity.

$$\Delta_{AD} = 10 B_A X_A \Delta f + 10 B_D X_D \Delta f$$

$$= (10 B_A X_A + 10 B_D X_D) \Delta f \quad MW \quad — (13).$$

Eq (13) is rewritten in transfer function form as

$$\frac{\Delta f}{\Delta_{AD}} = \frac{1}{10 B_A X_A + 10 B_D X_D} \quad Hz/MW \quad — (14)$$

$$\boxed{\Delta f = \frac{\Delta_{AD}}{10 B_A X_A + 10 B_D X_D}} \quad Hz$$

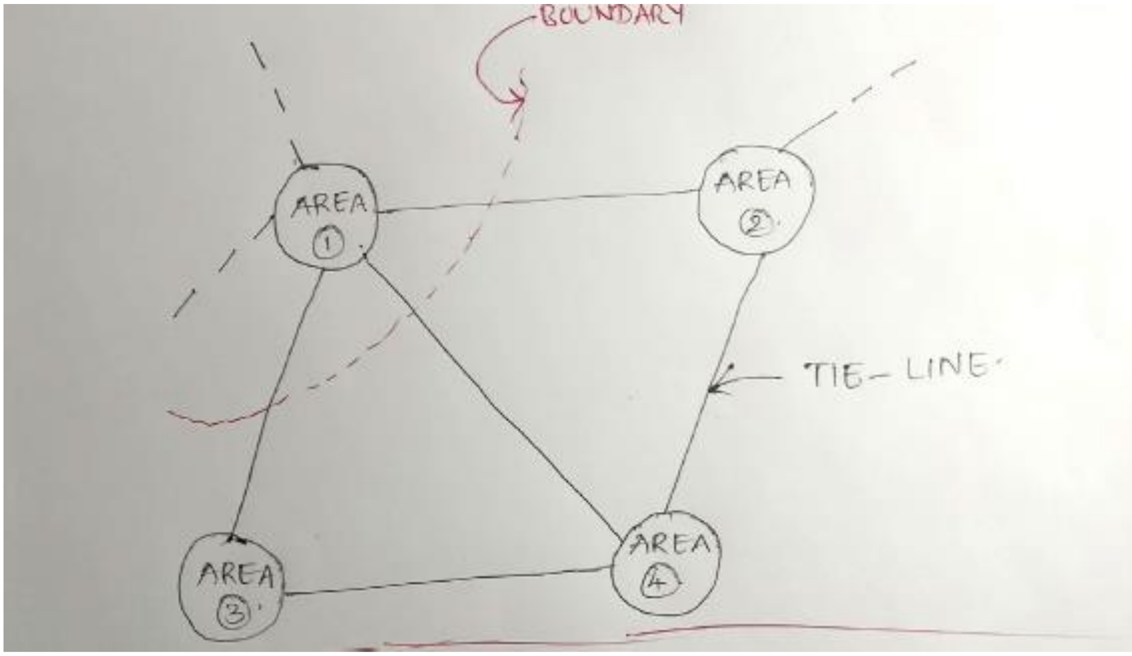
Expression for Frequency Deviation.

3a.What is a control area in an interconnected power system? Define area control error.

THE 'CONTROL AREA' CONCEPT

* A control area is a separate power system under the control of an AGC in a central digital computer.

* The boundaries of control area are the points on the tie lines where the utility's ownership, maintenance, and ~~accounting~~ loss accounting ends and those of neighbors begin.
* Interconnections are made so that operating areas can share generation and load.
* This sharing is normally on a scheduled basis as directed by AGC.



AREA CONTROL ERROR (ACE) (11)

* To maintain a net interchange of power with its area neighbors, an AGC uses real power flow measurements of all tie lines emanating from the area and subtracts the scheduled interchange to calculate an error value.

* The net power interchange, together with a ga..., called frequency bias, as multiplier B (MW/0.1 Hz), on frequency deviation is called the area control error (ACE).

$$ACE = \left[\sum_{K=1}^{K} P_K\right] - P_S + 10B(f_{act} - f_0) \text{ MW.} \quad \text{— ①}$$

where P_K = MW tie line flow
$\left\{ \begin{array}{l} +ve \text{ out of area} \\ -ve \text{ into area} \end{array} \right\}$.

P_S = scheduled MW interchange (if system is interconnected).

f_0 = scheduled base frequency.

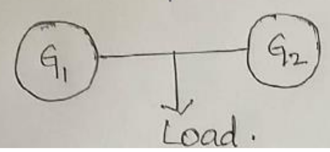
*. ACE > 0 ; Flow out of area (Over-Gen) (Gen-Generation)
ACE < 0 ; Flow into area (Under-Gen). (Gen-Generation)
ACE = 0 ; Ideal case.

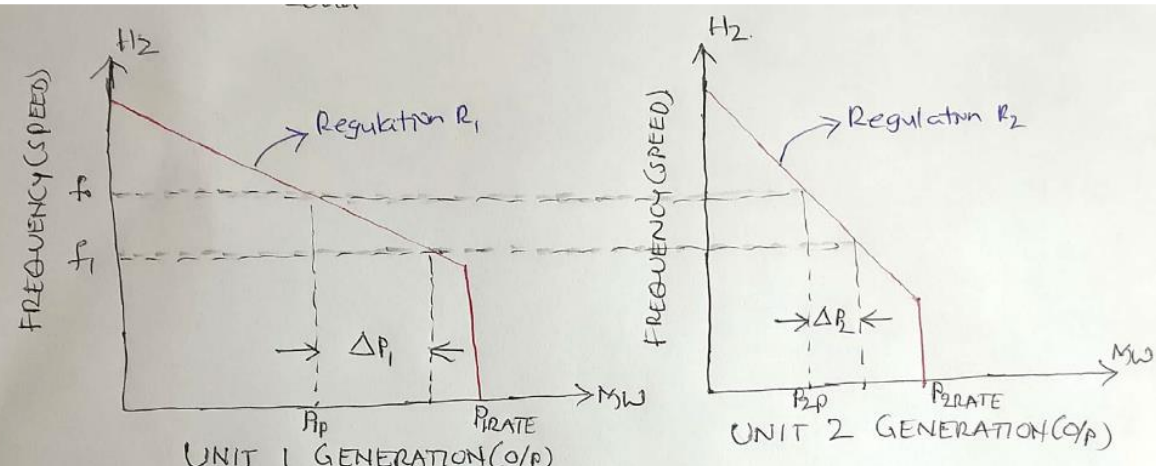
3b. For two generators operating in parallel deduce,

$\text{Rsys} = \frac{1}{\left[\frac{\text{P1rate}}{\text{R1}} + \frac{\text{P2rate}}{\text{R2}}\right]}$,Where R1 and R2 are droop characteristics of Generator 1 and Generator 2.

PARALLEL OPERATION OF GENERATORS (23)

Two units of different capacity and regulation characteristics are operated in parallel as shown in figure.





and their regulation characteristics are

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POWER SYSTEM OPERATION AND CONTROL
SOLUTION

$$R_1 = \frac{\Delta f\,(p.u.)}{\Delta P_1\,(p.u.)} = \frac{\Delta f/50}{\Delta P_1/P_{1rate}} \quad p.u. \quad \text{——} \quad (1).$$

$$R_2 = \frac{\Delta f/50}{\Delta P_2/P_{2rate}} \quad p.u. \quad \text{——} \quad (2).$$

Since the frequency is common to both units, they will share according to the ratio

$$\frac{(1)}{(2)} \Rightarrow \quad \frac{\Delta P_1}{\Delta P_2} = \frac{R_2}{R_1} \frac{P_{1rate}}{P_{2rate}} \quad \text{——} \quad (3).$$

If the initial load is $P_{1p} + P_{2p}$, a change in load is satisfied by.

$$\Delta L = \Delta P_1 + \Delta P_2 = \frac{\Delta f\, P_{1rate}}{R_1} + \frac{\Delta f\, P_{2rate}}{R_2} \quad MW \quad \text{——} \quad (4).$$

[from (1) & (2)].

Hence the equivalent regulation of the paralled system is

$$\bar{R}_{system} = \frac{\Delta f}{\Delta L} = \frac{1}{\frac{P_{1rate}}{R_1} + \frac{P_{2rate}}{R_2}} \quad 1/MW \quad \text{——} \quad (5).$$

or in terms of per unit, with the system capacity as base

$$R_{system} = \bar{R}_{system}\,(P_{1rate} + P_{2rate}) \quad p.u. \quad \text{——} \quad (6).$$

4a. Two synchronous generators are initially supplying a common load at 1.0 pu and frequency of 50Hz. The rating of unit 1 is 337MW and has 0.03 pu droop built into its governor, unit 2 is rated at 420MW and has 0.05 pu droop. Find each unit share of 10% increase in load demand. Also find new line frequency. Assume free governor action.

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POWER SYSTEM OPERATION AND CONTROL

SOLUTION

A. $P_{1rate} = 331\ MW$, $R_1 = 0.03$ p.u. | $P_{2rate} = 420\ MW$, $R_2 = 0.05$ p.u. | $\Delta L = 0.1$ p.u. (75.7 MW or 10% Total generation)

System Regulation, $R_{sys} = \dfrac{\Delta f}{\Delta L} = \dfrac{1}{\left[\dfrac{P_{1rate}}{R_1} + \dfrac{P_{2rate}}{R_2}\right]} (P_{1rate} + P_{2rate})$

$= 0.038$ (Always <0) p.u.

$\Delta f = R_{sys} \times \Delta L = 0.038$ p.u $= 0.038 \times 50 = 0.19$ Hz.

New system frequency, $f_{new} = f - \Delta f = 49.81$ Hz.

$\Delta P_1 = \dfrac{\Delta f\,(p.u.)}{R_1} = 0.192$ p.u.

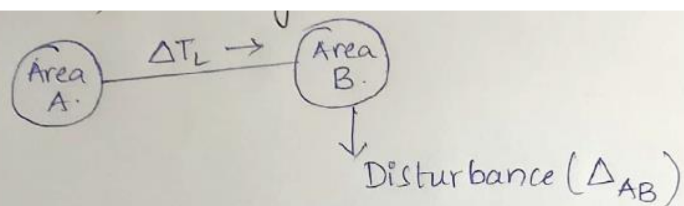
$\Delta P_1 = \dfrac{\Delta f\,(p.u.)}{R_1} \cdot P_{1rate} = 43.3\ MW$

$\Delta P_2 = \dfrac{\Delta f\,(p.u.)}{R_2} = 0.0771$ p.u.

$\Delta P_2 = \dfrac{\Delta f\,(p.u.)}{R_2} \cdot P_{2rate} = 32.4\ MW$

4b.Two areas A and B interconnected by tie-line. The generating capacity of area A is 25,000MW and its regulating characteristic is 2.5% of capacity per 0.1Hz. Area B has a generating capacity 5000MW and its regulating characteristic is 1.5% of capacity per 0.1Hz. Find each area share of a 800MW disturbance (load increase) occurring in area B and resulting tie line.

A.



$X_A = 25{,}000\ MW$ | $B_A = 2.5\% = 0.025\ MW/0.1\,Hz$.

$X_B = 5000\ MW$ | $B_B = 1.5\% = 0.015\ MW/0.1\,Hz$.

Disturbance $\Delta_{AB} = 800\ MW$.

Area A's share ; $\Delta T_L = \dfrac{(10 B_A X_A)\,\Delta_{AB}}{10 B_A X_A + 10 B_B X_B} = 714.25\ MW$. → Tie-line power.

Area B's share ; $\Delta_{AB} - \Delta T_L = 800\ MW - 714.25\ MW$.

$= 85.75\ MW$.

Frequency deviation ; $\Delta f = \dfrac{\Delta_{AB}}{10 B_A X_A + 10 B_B X_B}$

$= 0.11$ Hz.

5. State the problem of unit commitment. What are the constraints in solving unit commitment problem. Explain each of it?

*. STATEMENT OF UNIT COMMITMENT PROBLEM (UCP) :

The UCP in electrical power production is a large family of mathematical optimization problems where the production of set of generators is coordinated to match the energy demand at minimum cost or maximize revenues from energy production.

*. CONSTRAINTS IN UNIT COMMITMENT :

1. SPINNING RESERVE :

*. Spinning Reserve is the term used to describe the total amount of generation available from all units synchronized (i.e. Spinning) on the system minus the present load and losses being supplied.

$$\text{Spinning Reserve} = P_g - P_{Load} - P_{Loss}.$$

*. Spinning reserve must be carried so that the loss of one or more units does not cause a drop in system frequency

* Spinning reserve must be

→ The capacity of largest generation + Fraction of peak load
(OR)
→ Sufficient to make up for a generation-unit failure. (OR)
→ Sufficient to meet the losses of the entire system.

* Reserves must be allocated among

a) Fast-responding units – Quick start diesel, gas-turbine units, hydro units, pumped storage hydro units

b) Slow responding units – Thermal power plants.

*. The Unit Commitment Problem may involve various classes of 'scheduled reserves' or 'off-line reserves'.

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POWER SYSTEM OPERATION AND CONTROL
SOLUTION

(2)

2. THERMAL UNIT CONSTRAINTS:

a. Minimum up time : Once the unit is running, it should not be turned off immediately.

b. Minimum down time : Once the unit is decommitted, there is a minimum time before it can be recommitted.

c. Crew Constraints : If a plant consists of two or more units, they cannot both be turned on at the same time since there are not enough crew members to attend both units while starting up.

d. Pressure And Temperature Constraints : Since the temperature and pressure of the thermal unit must be moved slowly, a certain amount of energy must be expended to bring the unit on-line.

* This energy doesnot result in any MW generation from the unit and is brought into the unit commitment problem as a start-up cost.

*. Start-up cost when cooling $= C_c(1 - e^{-t/\alpha}) \times F + C_f$

where C_c = cold-start cost (MBtu)

F = fuel cost

C_f = fixed cost (crew + maintenance expenses) (in R)

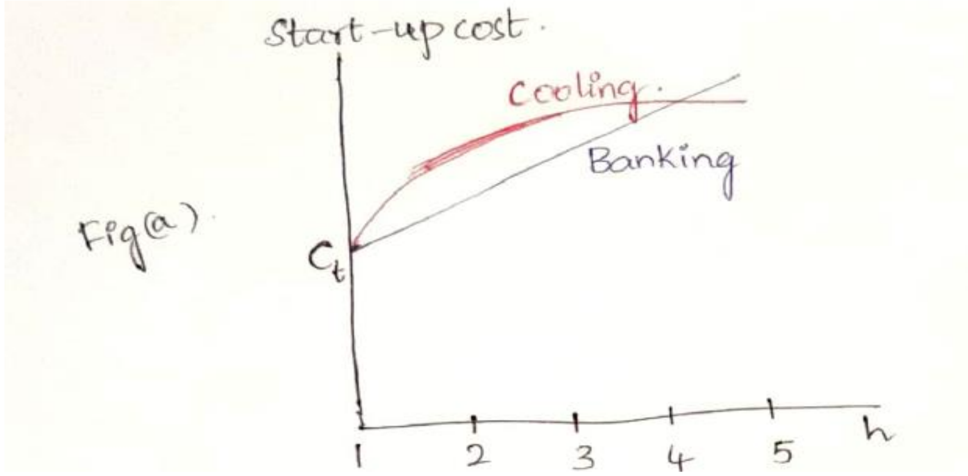
α = thermal time constant for the unit.

t = time (h) the unit was cooled.

* Start-up cost when banking $= C_t \times t \times F + C_f$.

where C_t = cost (MBtu/h) of maintaining unit at operating temperatures.

*. Upto a certain number of hours, the cost of banking will be less than the cost of cooling. as shown in Fig(a).



e. Must Run: Some units are given a must-run sta certain times of the year for reason of voltage support on the transmission network or for such purposes as supply of steam for uses outside the steam plant itself.

f. Fuel Constraints: A system in which some units have limited fuel or else have constraints that require them to burn a specified amount of fuel in a given time.

6. With the help of flow chart, explain the dynamic programming method in unit commitment problem.

b. DYNAMIC PROGRAMMING SOLUTION:

Dynamic programming has many advantages over the enumeration scheme, the chief advantage being a reduction in the dimensionality of the problem. Suppose we have found 4 units in a system and any combination of them could serve the (single) load. There would be a maximum of $2^4-1=15$ combinations to test. However, if a strict priority order is imposed, there are only four combinations to try:

Priority 1 unit
Priority 1 unit + Priority 2 unit
Priority 1 unit + Priority 2 unit + Priority 3 unit
Priority 1 unit + Priority 2 unit + Priority 3 unit + Priority 4 unit

* The imposition of a priority list arranged in order of the full-load average cost rate would result in a theoretically correct dispatch and commitment only if:

a. No load costs are zero
b. Unit input-output characteristics are linear between zero output and full load.
c. There are no other restrictions.
d. Start-up costs are a fixed amount.

*. In the dynamic-programming approach that follows, we assume that:

a. A state consists of an array of units with specified units operating and the rest off-line.
b. The start-up cost of a unit is independent of the time it has been off-line.

(7)

c. There are no costs for shutting down a unit.

d. There is a strict priority order, and in each interval a specified minimum amount of capacity must be operating.

* A feasible state is one in which the committed units can supply the required load and that meets the minimum amount of capacity each period.

C. FORWARD DP APPROACH :

* One could set up the dynamic programming algorithm to run backward in time starting from the final hour to be studied, back to the initial hour.
* Conversely, one could set up the algorithm to run forward in time from the initial hour to the final hour.
* The forward approach has distinct advantages in solving generator unit commitment. For example, if the start-up cost of a unit is a function of the time it has been off-line (i.e. its temperature), then a forward dynamic-program approach is more suitable since the previous history of the unit can be computed at each stage.
* There are other practical reasons for going forward.
* The initial conditions are easily specified and the computations can go forward in time as long as required.
* A forward dynamic-programming algorithm is shown by the flowchart.
* The recursive algorithm to compute the minimum cost in hour K with combination I is :

$$F_{cost}(K,I) = \min\left[P_{cost}(K,I) + S_{cost}(K-1, L:K,I) + F_{cost}(K-1,L)\right]$$

where $F_{cost}(K, I)$ = least total cost to arrive at state (K, I) (8)

$P_{cost}(K, I)$ = production cost for state (K, I).

$S_{cost}(K-1, L : K, I)$ = transition cost from state $(K-1, L)$ to state (K, I).

* State (K, I) is the I^{th} combination in hour K. For the forward dynamic programming approach, we define a strategy as the transition, or path, from one state at a given hour to a state at the next hour.

* Note that two new variables, X and N, have been introduced in figure

X = number of states to search each period

N = number of strategies, or paths, to save at each step.

These variables allow control of the computational effort (see below figure). For complete enumeration, the maximum number of the value of X or N is $2^n - 1$.

Find flowchart in next page

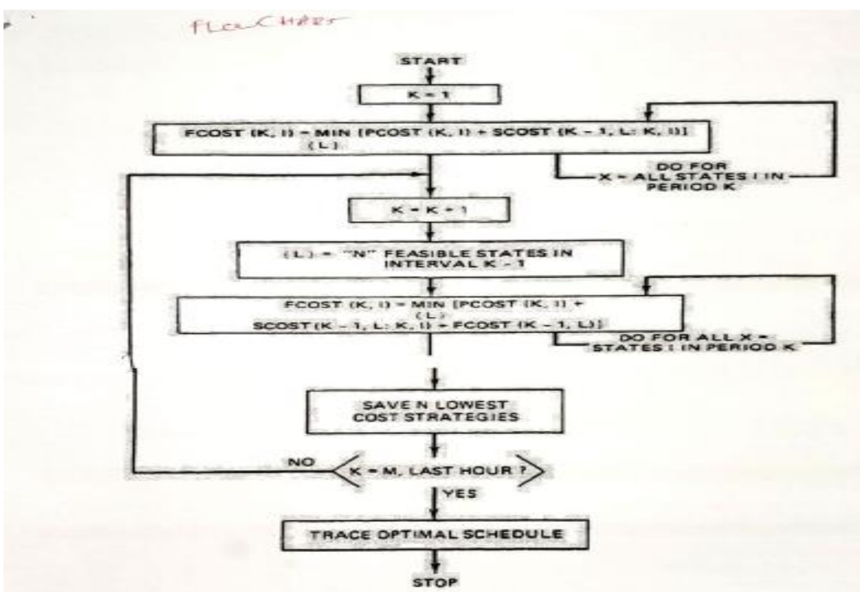
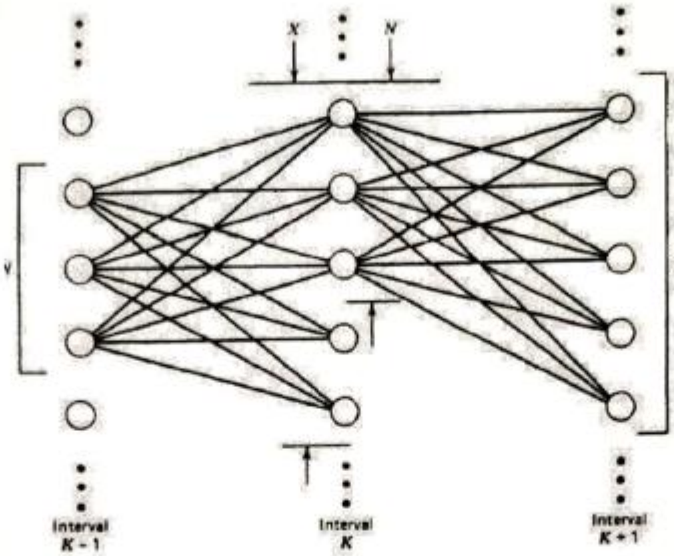


Figure: Forward DP Approach



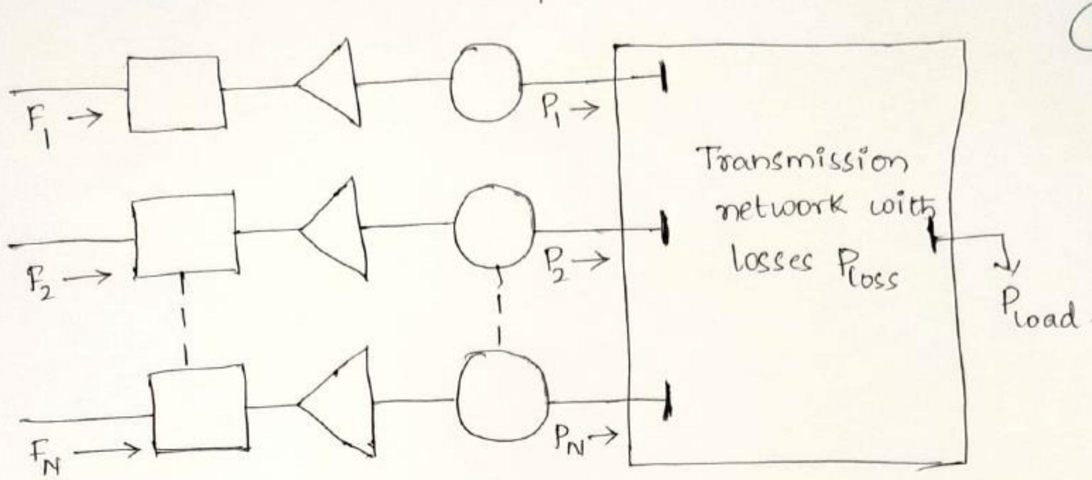
Restricted search paths in DP algorithm with N = No. of strategies and X = No. of states to search in each period.

Compute the minimum cost

7.Derive the exact coordination equation for optimum loading of thermal power plants considering line losses.

THERMAL SYSTEM DISPATCHING WITH NETWORK LOSSES CONSIDERE

(13)



N thermal units serving load through transmission network.

* Figure shows all thermal power generation system connected to an equivalent load bus through a transmission network.
* The economic dispatching problem associated with this particular configuration is more complicated than without transmission losses.

Objective function, $F_T = \sum_{i=1}^{N} F_i$ —— (1).

Constraint function, $P_{load} + P_{loss} - \sum_{i=1}^{N} P_i = \phi = 0$ —— (2)

* To establish the necessary conditions for the extreme value of objective function, use Lagrange function.

$$L = F_T + \lambda\phi \quad \text{—— (3)}$$

where L = Lagrange function

F_T = Objective function.

λ = Lagrange multiplier

ϕ = constraint function.

(14)

Differentiating eq(3).

$$\frac{dL}{dP_i} = \frac{dF_i}{dP_i} - \lambda\left(1 - \frac{dP_{loss}}{dP_i}\right) = 0.$$

$$\frac{dF_i}{dP_i} + \lambda\frac{dP_{loss}}{dP_i} = \lambda.$$

∴ Co-ordination equations

$$\left.\begin{aligned} &\frac{dF_i}{dP_i} + \lambda\frac{dP_{loss}}{dP_i} = \lambda. \\ &P_{load} + P_{loss} - \sum_{i=1}^{N} P_i = 0. \end{aligned}\right\}$$

* Difficult to solve this set of equations.
* Two approaches to solve this problem.
  a. Development of a mathematical expression for the losses in the network solely as a function of the power output of each of the units.
  b. To incorporate the power flow equations as essential constraints in the formal establishment of the optimization problem.

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