UNIT-1

LOAD FLOW STUDIES

REVIEW OF NUMERICAL SOLUTION OF EQUATIONS

The numerical analysis involving the solution of algebraic simultaneous equations forms the basis for solution of the performance equations in computer aided electrical power system analyses, such as during linear graph analysis, load flow analysis (nonlinear equations), transient stability studies (differential equations), etc. Hence, it is necessary to review the general forms of the various solution methods with respect to all forms of equations, as under:

1. Solution Linear equations:
* **Direct methods**:
- Cramer‟s (Determinant) Method,
- Gauss Elimination Method (only for smaller systems),
- LU Factorization (more preferred method), etc.

*** Iterative methods**:
- Gauss Method
- Gauss-Siedel Method (for diagonally dominant systems)

3. Solution of Nonlinear equations:
Iterative methods only:
- Gauss-Siedel Method (for smaller systems)
- Newton-Raphson Method (if corrections for variables are small)

4. Solution of differential equations:
Iterative methods only:
- Euler and Modified Euler method,
- RK IV-order method,
- Milne‟s predictor-corrector method, etc.

It is to be observed that the nonlinear and differential equations can be solved only by the iterative methods. The iterative methods are characterized by the various performance features as under:
_ Selection of initial solution/ estimates
_ Determination of fresh/ new estimates during each iteration
_ Selection of number of iterations as per tolerance limit
_ Time per iteration and total time of solution as per the solution method selected
_ Convergence and divergence criteria of the iterative solution
_ Choice of the Acceleration factor of convergence, etc.

A comparison of the above solution methods is as under:
In general, the direct methods yield exact or accurate solutions. However, they are suited for only the smaller systems, since otherwise, in large systems, the possible round-off errors make the solution process inaccurate. The iterative methods are more useful when the diagonal elements of the coefficient matrix are large in comparison with the off diagonal elements. The round-off errors in these methods are corrected at the successive steps of the iterative process.The Newton-Raphson method is very much useful for solution of non –linear equations, if all the values of the corrections for the unknowns are very small in magnitude and the initial values of unknowns are selected to be reasonably closer to the exact solution.

LOAD FLOW STUDIES

Introduction: Load flow studies are important in planning and designing future expansion of power systems. The study gives steady state solutions of the voltages at all the buses, for a particular load condition. Different steady state solutions can be obtained, for different operating conditions, to help in planning, design and operation of the power system. Generally, load flow studies are limited to the transmission system, which involves bulk power transmission. The load at the buses is assumed to be known. Load flow studies throw light on some of the important aspects of the system operation, such as: violation of voltage magnitudes at the buses, overloading of lines, overloading of generators, stability margin reduction, indicated by power angle differences between buses linked by a line, effect of contingencies like line voltages, emergency shutdown of generators, etc. Load flow studies are required for deciding the economic operation of the power system. They are also required in transient stability studies. Hence, load flow studies play a vital role in power system studies. Thus the load flow problem consists of finding the power flows (real and reactive) and voltages of a network for given bus conditions. At each bus, there are four quantities of interest to be known for further analysis: the real and reactive power, the voltage magnitude and its phase angle. Because of the nonlinearity of the algebraic equations, describing the given power system, their solutions are obviously, based on the iterative methods only. The constraints placed on the load flow solutions could be:
_ The Kirchhoff‟s relations holding good,
_ Capability limits of reactive power sources,
_ Tap-setting range of tap-changing transformers,
_ Specified power interchange between interconnected systems,
_ Selection of initial values, acceleration factor, convergence limit, etc.

Classification of buses for LFA: Different types of buses are present based on the specified and unspecified variables at a given bus as presented in the table below:

Table 1. Classification of buses for LFA

Sl. No.	Bus Types	Specified Variables	Unspecified variables	Remarks
1	Slack/ Swing Bus	$\|V\|$, δ	P_G, Q_G	$\|V\|$, δ: are assumed if not specified as 1.0 and 0^0
2	Generator/ Machine/ PV Bus	P_G, $\|V\|$	Q_G, δ	A generator is present at the machine bus
3	Load/ PQ Bus	P_G, Q_G	$\|V\|$, δ	About 80% buses are of PQ type
4	Voltage Controlled Bus	P_G,Q_G, $\|V\|$	δ, a	'a' is the % tap change in tap-changing transformer

Importance of swing bus: The slack or swing bus is usually a PV-bus with the largest capacity generator of the given system connected to it. The generator at the swing bus supplies the power difference between the "specified power into the system at the other buses" and the "total system output plus losses". Thus swing bus is needed to supply the additional real and reactive power to meet the losses. Both the magnitude and phase angle of voltage are specified at the swing bus, or otherwise, they are assumed to be equal to 1.0 p.u. and 00 , as per flat-start procedure of iterative
solutions. The real and reactive powers at the swing bus are found by the computer routine as part of the load flow solution process. It is to be noted that the source at the swing bus is a perfect one, called the swing machine, or slack machine. It is voltage regulated, i.e., the magnitude of voltage fixed. The phase angle is the system reference phase and hence is fixed. The generator at the swing bus has a torque angle and excitation which vary or swing as the demand changes. This variation is such as to produce fixed voltage.

Importance of YBUS based LFA:

The majority of load flow programs employ methods using the bus admittance matrix, as this method is found to be more economical. The bus admittance matrix plays a very important role in load flow analysis. It is a complex, square and symmetric matrix and hence only n(n+1)/2 elements of YBUS need to be stored for a n-bus system. Further, in the YBUS matrix, Yij = 0, if an incident element is not present in the system connecting the buses „i" and „j". since in a large power system, each bus is connected only to a fewer buses through an incident element, (about 6-8), the coefficient matrix, YBUS of such systems would be highly sparse, i.e., it will have many zero valued elements in it. This is defined by the sparsity of the matrix, as under:

$$\text{Percentage sparsity of a given matrix of } n^{th} \text{ order:} = \frac{\text{Total no. of zero valued elements of } Y_{BUS}}{\text{Total no. of entries of } Y_{BUS}}$$

$$S = (Z / n^2) \times 100 \; \% \qquad (1)$$

The percentage sparsity of Y_{BUS}, in practice, could be as high as 80-90%, especially for very large, practical power systems. This sparsity feature of YBUS is extensively used in reducing the load flow calculations and in minimizing the memory required to store the coefficient matrices. This is due to the fact that only the non-zero elements YBUS can be stored during the computer based implementation of the schemes, by adopting the suitable optimal storage schemes. While YBUS is thus highly sparse, it"s inverse, ZBUS, the bus impedance matrix is not so. It is a FULL matrix, unless the optimal bus ordering schemes are followed before proceeding for load flow analysis.

THE LOAD FLOW PROBLEM

Here, the analysis is restricted to a balanced three-phase power system, so that the analysis can be carried out on a single phase basis. The per unit quantities are used for all quantities. The first step in the analysis is the formulation of suitable equations for the power flows in the system. The power system is a large interconnected system, where various buses are connected by transmission lines. At any bus, complex power is injected into the bus by the generators and complex power is drawn by the loads. Of course at any bus, either one of them may not be present. The power is transported from one bus to other via the transmission lines. At any bus *i*, the complex power Si (injected), shown in figure 1, is defined as

$$S_i = S_{Gi} - S_{Di} \quad (2)$$

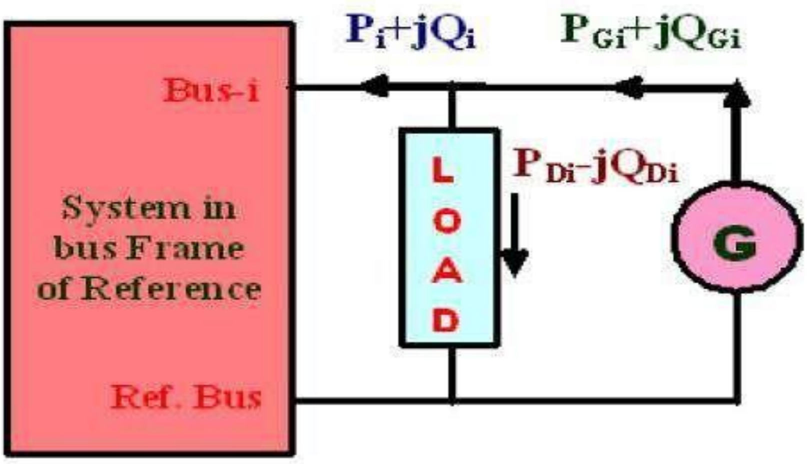


Fig.1 power flows at a bus-i

where Si = net complex power injected into bus *i*, SGi = complex power injected by the generator at bus *i*, and SDi = complex power drawn by the load at bus *i*. According to conservation of complex power, at any bus i, the complex power injected into the bus must be equal to the sum of complex power flows out of the bus via the transmission lines. Hence,

Si = _Sij " i = 1, 2,.............n
(3)
where Sij is the sum over all lines connected to the bus and *n* is the number of buses in the system (excluding the ground). The bus current injected at the bus-i is defined as

Ii = IGi – IDi " i = 1, 2, ………..n **(4)**

where IGi is the current injected by the generator at the bus and IDi is the current drawn by the load (demand) at that bus. In the bus frame of reference

IBUS = YBUS VBUS
(5)

where

$$I_{BUS} = \begin{bmatrix} I_1 \\ I_2 \\ . \\ . \\ I_n \end{bmatrix}$$ is the vector of currents injected at the buses,

Y_{BUS} is the bus admittance matrix, and

$$V_{BUS} = \begin{bmatrix} V_1 \\ V_2 \\ . \\ . \\ V_n \end{bmatrix}$$ is the vector of complex bus voltages.

Equation (5) can be considered as

$$I_i = \sum_{j=1}^{n} Y_{ij} V_j \qquad \forall\ i = 1, 2, \ldots\ldots\ldots n \qquad \textbf{(6)}$$

The complex power S_i is given by

$$S_i = V_i\, I_i^*$$

$$= V_i \left(\sum_{j=1}^{n} Y_{ij}\, V_j \right)^*$$

$$= V_i \left(\sum_{j=1}^{n} Y_{ij}^* V_j^* \right) \qquad \textbf{(7)}$$

Let $$V_i \,\underline{\underline{\Delta}}\, |V_i| \angle \delta_i = |V_i| (\cos \delta_i + j \sin \delta_i)$$

$$\delta_{ij} = \delta_i - \delta_j$$

$$Y_{ij} = G_{ij} + jB_{ij}$$

Hence from (7), we get,

$$S_i = \sum_{j=1}^{n} |V_i|\,|V_j|\,(\cos\delta_{ij} + j\sin\delta_{ij})\,(G_{ij} - jB_{ij}) \quad \textbf{(8)}$$

Separating real and imaginary parts in (8) we obtain,

$$P_i = \sum_{j=1}^{n} |V_i|\,|V_j|\,(G_{ij}\cos\delta_{ij} + B_{ij}\sin\delta_{ij}) \quad \textbf{(9)}$$

$$Q_i = \sum_{j=1}^{n} |V_i|\,|V_j|\,(G_{ij}\sin\delta_{ij} - B_{ij}\cos\delta_{ij}) \quad \textbf{(10)}$$

An alternate form of P_i and Q_i can be obtained by representing Y_{ik} also in polar form as

$$Y_{ij} = |Y_{ij}|\,\angle\theta_{ij} \quad \textbf{(11)}$$

Again, we get from (7),

$$S_i = |V_i|\angle\delta_i \sum_{j=1}^{n} |Y_{ij}|\,\angle-\theta_{ij}\,|V_j|\,\angle-\delta_j \quad \textbf{(12)}$$

The real part of (12) gives P_i.

$$P_i = |V_i| \sum_{j=1}^{n} |Y_{ij}|\,|V_j|\,\cos(-\theta_{ij} + \delta_i - \delta_j)$$

$$= |V_i| \sum_{j=1}^{n} |Y_{ij}|\,|V_j|\,\cos-(\theta_{ij} - \delta_i + \delta_j) \qquad \text{or}$$

$$P_i = \sum_{j=1}^{n} |V_i|\,|V_j|\,|Y_{ij}|\,\cos(\theta_{ij} - \delta_i + \delta_j) \qquad \forall\ i = 1, 2, \ldots\ldots\ldots.n, \quad \textbf{(13)}$$

Similarly, Q_i is imaginary part of (12) and is given by

$$Q_i = |V_i| \sum_{j=1}^{n} |Y_{ij}|\,|V_j|\,\sin-(\theta_{ij} - \delta_i + \delta_j) \qquad \text{or}$$

$$Q_i = -\sum_{j=1}^{n} |V_i|\,|V_j|\,|Y_{ij}|\,\sin(\theta_{ij} - \delta_i + \delta_j) \qquad \forall\ i = 1, 2, \ldots\ldots\ldots.n \quad \textbf{(14)}$$

Equations (9)-(10) and (13)-(14) are the „power flow equations" or the „load flow equations" in two alternative forms, corresponding to the n-bus system, where each bus-*i* is characterized by four variables, Pi, Qi, |Vi|, and di. Thus a total of 4n variables are

involved in these equations. The load flow equations can be solved for any 2n unknowns, if the other 2n variables are specified. This establishes the need for classification of buses of the system for load flow analysis into: PV bus, PQ bus, etc.

DATA FOR LOAD FLOW

Irrespective of the method used for the solution, the data required is common for any load flow. All data is normally in pu. The bus admittance matrix is formulated from these data. The various data required are as under:

System data: It includes: number of buses-*n*, number of PV buses, number of loads, number of transmission lines, number of transformers, number of shunt elements, the slack bus number, voltage magnitude of slack bus (angle is generally taken as 0o), tolerance limit, base MVA, and maximum permissible number of iterations.

Generator bus data: For every PV bus *i*, the data required includes the bus number, active power generation PGi, the specified voltage magnitude *i sp V* , , minimum reactive power limit Qi,min, and maximum reactive power limit Qi,max.

Load data: For all loads the data required includes the the bus number, active power demand PDi, and the reactive power demand QDi.

Transmission line data: For every transmission line connected between buses *i* and *k* the data includes the starting bus number *i*, ending bus number *k*,.*r*esistance of the line, reactance of the line and the half line charging admittance.

Transformer data:
For every transformer connected between buses *i* and *k* the data to be given includes: the starting bus number *i*, ending bus number *k*, resistance of the transformer, reactance of the transformer, and the off nominal turns-ratio *a*.

Shunt element data: The data needed for the shunt element includes the bus number where element is connected, and the shunt admittance (Gsh + j Bsh).

GAUSS – SEIDEL (GS) METHOD
The GS method is an iterative algorithm for solving non linear algebraic equations. An initial solution vector is assumed, chosen from past experiences, statistical data or from practical considerations. At every subsequent iteration, the solution is updated till convergence is reached. The GS method applied to power flow problem is as discussed below.

Case (a): Systems with PQ buses only:

Initially assume all buses to be PQ type buses, except the slack bus. This means that (n–1) complex bus voltages have to be determined. For ease of programming, the slack bus is generally numbered as bus-1. PV buses are numbered in sequence and PQ buses are ordered next in sequence. This makes programming easier, compared to random ordering of buses. Consider the expression for the complex power at bus-i, given from (7), as:

$$S_i = V_i \left(\sum_{j=1}^{n} Y_{ij} V_j \right)^*$$

This can be written as

$$S_i^* = V_i^* \left(\sum_{j=1}^{n} Y_{ij} V_j \right) \qquad \textbf{(15)}$$

Since $S_i^* = P_i - jQ_i$, we get,

$$\frac{P_i - jQ_i}{V_i^*} = \sum_{j=1}^{n} Y_{ij} V_j$$

So that,

$$\frac{P_i - jQ_i}{V_i^*} = Y_{ii} V_i + \sum_{\substack{j=1 \\ j \neq i}}^{n} Y_{ij} V_j \qquad \textbf{(16)}$$

Rearranging the terms, we get,

$$V_i = \frac{1}{Y_{ii}} \left[\frac{P_i - jQ_i}{V_i^*} - \sum_{\substack{j=1 \\ j \neq i}}^{n} Y_{ij} V_j \right] \qquad \forall\, i = 2, 3, \ldots\ldots\ldots n \qquad \textbf{(17)}$$

Equation (17) is an implicit equation since the unknown variable, appears on both sides of the equation. Hence, it needs to be solved by an iterative technique. Starting from an initial estimate of all bus voltages, in the RHS of (17) the most recent values of the bus voltages is substituted. One iteration of the method involves computation of all the bus voltages. In Gauss–Seidel method, the value of the updated voltages are used in the computation of subsequent voltages in the same iteration, thus speeding up convergence. Iterations are carried out till the magnitudes of all bus voltages do not change by more than the tolerance value. Thus the algorithm for GS method is as under:

Algorithm for GS method

1. Prepare data for the given system as required.
2. Formulate the bus admittance matrix YBUS. This is generally done by the rule of inspection.
3. Assume initial voltages for all buses, 2,3,…n. In practical power systems, the magnitude

of the bus voltages is close to 1.0 p.u. Hence, the complex bus voltages at all (n-1) buses (except slack bus) are taken to be $1.0\angle 0^0$. This is normally refered as the ***flat start*** solution.

4. Update the voltages. In any $(k+1)st$ iteration, from (17) the voltages are given by

$$V_i^{(k+1)} = \frac{1}{Y_{ii}}\left[\frac{P_i - jQ_i}{(V_i^{(k)})^*} - \sum_{j=1}^{i-1} Y_{ij} V_j^{(k+1)} - \sum_{j=i+1}^{n} Y_{ij} V_j^{(k)}\right] \forall \text{ i=2,3,…n} \quad \textbf{(18)}$$

Here note that when computation is carried out for bus-i, updated values are already available for buses 2,3….(i-1) in the current *(k+1)st* iteration. Hence these values are used. For buses *(i+1)…..n,* values from previous, *kth* iteration are used.

$$\left|\Delta V_i^{(k+1)}\right| = \left|V_i^{(k+1)} - V_i^{(k)}\right| < \varepsilon \qquad \forall \text{ i} = 2,3,\ldots\text{n} \quad \textbf{(19)}$$

Where,e is the tolerance value. Generally it is customary to use a value of 0.0001 pu. Compute slack bus power after voltages have converged using (15) [assuming bus 1 is slack bus].

$$S_1^* = P_1 - jQ_1 = V_1^*\left(\sum_{j=1}^{n} Y_{1j} V_j\right) \quad \textbf{(20)}$$

7. Compute all line flows.
8. The complex power loss in the line is given by Sik + Ski. The total loss in the system is calculated by summing the loss over all the lines.

Case (b): Systems with PV buses also present:

At PV buses, the magnitude of voltage and not the reactive power is specified. Hence it is needed to first make an estimate of Qi to be used in (18). From (15) we have

$$Q_i = -\operatorname{Im}\left\{V_i^* \sum_{j=1}^{n} Y_{ij} V_j\right\}$$

Where *Im* stands for the imaginary part. At any *(k+1)*st iteration, at the PV bus-*i*,

$$Q_i^{(k+1)} = -\operatorname{Im}\left\{(V_i^{(k)})^* \sum_{j=1}^{i-1} Y_{ij} V_j^{(k+1)} + (V_i^{(k)})^* \sum_{j=i}^{n} Y_{ij} V_j^{(k)}\right\} \qquad (21)$$

The steps for i^{th} PV bus are as follows:

1. Compute $Q_i^{(k+1)}$ using (21)

2. Calculate V_i using (18) with $Q_i = Q_i^{(k+1)}$

3. Since $|V_i|$ is specified at the PV bus, the magnitude of V_i obtained in step 2

has to be modified and set to the specified value $|V_{i,sp}|$. Therefore,

$$V_i^{(k+1)} = |V_{i,sp}| \angle \delta_i^{(k+1)} \qquad (22)$$

The voltage computation for PQ buses does not change.

Case (c): Systems with PV buses with reactive power generation limits specified:

In the previous algorithm if the Q limit at the voltage controlled bus is violated during any iteration, i.e (*k* +1) *i Q* computed using (21) is either less than Qi, min or greater than Qi,max, it means that the voltage cannot be maintained at the specified value due to lack of reactive power support. This bus is then treated as a PQ bus in the *(k+1)st* iteration and the voltage is calculated with the value of Qi set as follows:

If $Q_i < Q_{i,min}$ Then $Q_i = Q_{i,min}$.

If $Q_i > Q_{i,max}$ Then $Q_i = Q_{i,max}$. (23)

If $Q_i < Q_{i,min}$ Then $Q_i = Q_{i,min}$.

If $Q_i > Q_{i,max}$ Then $Q_i = Q_{i,max}$. (23)

If in the subsequent iteration, if Qi falls within the limits, then the bus can be switched back to PV status.

Acceleration of convergence

It is found that in GS method of load flow, the number of iterations increase with increase in the size of the system. The number of iterations required can be reduced if the correction in voltage at each bus is accelerated, by multiplying with a constant α, called the acceleration factor. In the (k+1)st iteration we can let

$$V_i^{(k+1)}(accelerated) = V_i^{(k)} + \alpha\left(V_i^{(k+1)} - V_i^{(k)}\right) \qquad (24)$$

where α is a real number. When α =1, the value of (k +1) is the computed value. If 1<α <2 then the value computed is extrapolated. Generally _ is taken between 1.2 to 1.6, for GS load flow procedure. At PQ buses (pure load buses) if the voltage magnitude violates the limit, it simply means that the specified reactive power demand cannot be supplied, with the voltage maintained within acceptable limits.

Examples on GS load flow analysis:

Example-1: *Obtain the voltage at bus 2 for the simple system shown in Fig 2, using the Gauss–Seidel method, if $V_1 = 1\angle 0^0$ pu.*

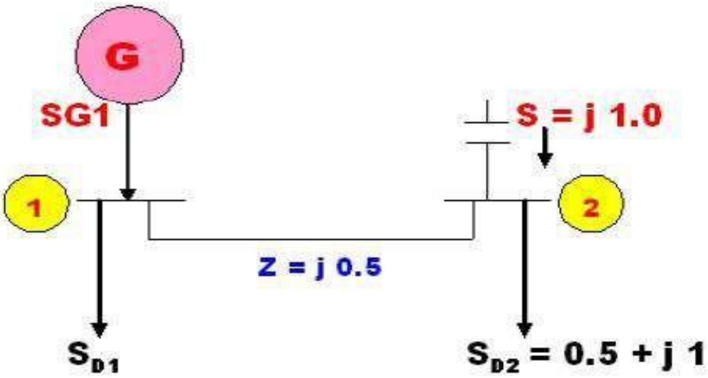


Fig : System of Example 1

Solution:

Here the capacitor at bus 2, injects a reactive power of 1.0 pu. The complex power injection at bus 2 is

$$S_2 = j1.0 - (0.5 + j\,1.0) = -0.5 \text{ pu.}$$

$$V_1 = 1\angle 0^0$$

$$Y_{BUS} = \begin{bmatrix} -j2 & j2 \\ j2 & -j2 \end{bmatrix}$$

$$V_2^{(k+1)} = \frac{1}{Y_{22}}\left[\frac{P_2 - jQ_2}{\left(V_2^{(k)}\right)^*} - Y_{21}V_1\right]$$

Since V_1 is specified it is a constant through all the iterations. Let the initial voltage at bus 2, $V_2^0 = 1 + j\,0.0 = 1\angle 0^0$ pu.

$$V_2^1 = \frac{1}{-j2}\left[\frac{-0.5}{1\angle 0^0} - (j2\times 1\angle 0^0)\right]$$
$$= 1.0 - j0.25 = 1.030776\ \angle -14.036^0$$

$$V_2^2 = \frac{1}{-j2}\left[\frac{-0.5}{1.030776\angle 14.036^0} - (j2\times 1\angle 0^0)\right]$$
$$= 0.94118 - j\ 0.23529\ = 0.970145\ \angle -14.036^0$$

$$V_2^3 = \frac{1}{-j2}\left[\frac{-0.5}{0.970145\angle 14.036^0} - (j2\times 1\angle 0^0)\right]$$
$$= 0.9375 - j\ 0.249999\ = 0.970261\ \angle -14.931^0$$

$$V_2^4 = \frac{1}{-j2}\left[\frac{-0.5}{0.970261\angle 14.931^0} - (j2\times 1\angle 0^0)\right]$$
$$= 0.933612 - j\ 0.248963 = 0.966237\ \angle -14.931^0$$

$$V_2^5 = \frac{1}{-j2}\left[\frac{-0.5}{0.966237\angle 14.931^0} - (j2\times 1\angle 0^0)\right]$$
$$= 0.933335 - j\ 0.25\ \ = 0.966237\ \angle -14.995^0$$

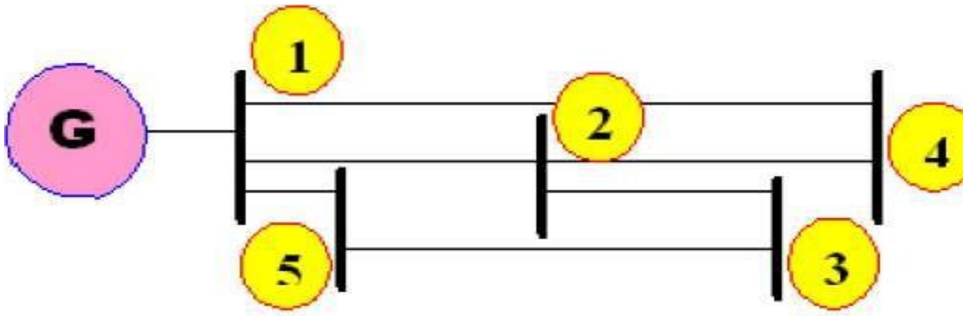
Since the difference in the voltage magnitudes is less than 10-6 pu, the iterations can be stopped. To compute line flow

$$I_{12} = \frac{V_1 - V_2}{Z_{12}} = \frac{1\angle 0^0 - 0.966237\angle -14.995^0}{j0.5}$$
$$= 0.517472\ \angle -14.931^0$$
$$S_{12} = V_1 I_{12}^* = 1\angle 0^0 \times 0.517472\ \angle\ 14.931^0$$
$$= 0.5 + j\ 0.133329\ \text{pu}$$
$$I_{21} = \frac{V_2 - V_1}{Z_{12}} = \frac{0.966237\angle -14.995^0 - 1\angle 0^0}{j0.5}$$
$$= 0.517472\ \angle -194.93^0$$
$$S_{21} = V_2 I_{21}^* = -\ 0.5 + j\ 0.0\ \text{pu}$$

The total loss in the line is given by S12 + S21 = j 0.133329 pu Obviously, it is observed that there is no real power loss, since the line has no resistance.

Example-2:

For the power system shown in fig. below, with the data as given in tables below, obtain the bus voltages at the end of first iteration, by applying GS method.



Power System of Example 2

Line data of example 2

SB	EB	R (pu)	X (pu)	$\frac{B_C}{2}$
1	2	0.10	0.40	-
1	4	0.15	0.60	-
1	5	0.05	0.20	-
2	3	0.05	0.20	-
2	4	0.10	0.40	-
3	5	0.05	0.20	-

Bus data of example 2

Bus No.	P_G (pu)	Q_G (pu)	P_D (pu)	Q_D (pu)	$\lvert V_{SP}\rvert$ (pu)	δ
1	-	-	-	-	1.02	0^o
2	-	-	0.60	0.30	-	-
3	1.0	-	-	-	1.04	-
4	-	-	0.40	0.10	-	-
5	-	-	0.60	0.20	-	-

Solution: In this example, we have,

- Bus 1 is slack bus, Bus 2, 4, 5 are PQ buses, and Bus 3 is PV bus
- The lines do not have half line charging admittances

$$P_2 + jQ_2 = P_{G2} + jQ_{G2} - (P_{D2} + jQ_{D2}) = -0.6 - j0.3$$

$P_3 + jQ_3 = P_{G3} + jQ_{G3} - (P_{D3} + jQ_{D3}) = 1.0 + jQ_{G3}$

Similarly $P_4 + jQ_4 = -0.4 - j0.1$, $\quad P_5 + jQ_5 = -0.6 - j0.2$

The Y_{bus} formed by the rule of inspection is given by:

$Y_{bus} =$

2.15685 -j8.62744	-0.58823 +j2.35294	0.0+j0.0	-0.39215 +j1.56862	-1.17647 +j4.70588
-0.58823 +j2.35294	2.35293 -j9.41176	-1.17647 +j4.70588	-0.58823 +j2.35294	0.0+j0.0
0.0+j0.0	-1.17647 +j4.70588	2.35294 -j9.41176	0.0+j0.0	-1.17647 +j4.70588
-0.39215 +j1.56862	-0.58823 +j2.35294	0.0+j0.0	0.98038 -j3.92156	0.0+j0.0
-1.17647 +j4.70588	0.0+j0.0	-1.17647 +j4.70588	0.0+j0.0	2.35294 -j9.41176

The voltages at all PQ buses are assumed to be equal to 1+j0.0 pu. The slack bus voltage is taken to be $V_1^0 = 1.02+j0.0$ in all iterations.

$$V_2^1 = \frac{1}{Y_{22}}\left[\frac{P_2 - jQ_2}{V_2^{o*}} - Y_{21}V_1^o - Y_{23}V_3^0 - Y_{24}V_4^0 - Y_{25}V_5^0\right]$$

$$= \frac{1}{Y_{22}}\left[\frac{-0.6 + j0.3}{1.0 - j0.0} - \{(-0.58823 + j2.35294)\times 1.02\angle 0^o\}\right.$$

$$\left. - \{(-1.17647 + j4.70588)\times 1.04\angle 0^o\} - \{(-0.58823 + j2.35294)\times 1.0\angle 0^0\}\right]$$

$$= 0.98140\angle -3.0665^o = 0.97999 - j0.0525$$

Bus 3 is a PV bus. Hence, we must first calculate Q_3. This can be done as under:

$$Q_3 = |V_3||V_1|(G_{31}\sin\delta_{31} - B_{31}\cos\delta_{31}) + |V_3||V_2|(G_{32}\sin\delta_{32} - B_{32}\cos\delta_{32})$$

$$+ |V_3|^2 (G_{33}\sin\delta_{33} - B_{33}\cos\delta_{33}) + |V_3||V_4|(G_{34}\sin\delta_{34} - B_{34}\cos\delta_{34})$$

$$+ |V_3||V_5|(G_{35}\sin\delta_{35} - B_{35}\cos\delta_{35})$$

We note that $\delta_1 = 0^o$; $\delta_2 = -3.0665^o$; $\delta_3 = 0^o$; $\delta_4 = 0^o$ and $\delta_5 = 0^o$

$\therefore\ \delta_{31} = \delta_{33} = \delta_{34} = \delta_{35} = 0^o$ $(\delta_{ik} = \delta_i - \delta_k)$; $\quad \delta_{32} = 3.0665^o$

$Q_3 = 1.04\ [1.02\ (0.0+j0.0) + 0.9814\ \{-1.17647 \times \sin(3.0665^o) - 4.70588$
$\times\cos(3.0665^o)\} + 1.04\{-9.41176 \times\cos(0^o)\} + 1.0\ \{0.0 + j0.0\} + 1.0\{-4.70588\times\cos(0^0)\}]$

$= 1.04\ [-4.6735 + 9.78823 - 4.70588] = 0.425204$ pu.

$$V_3^1 = \frac{1}{Y_{33}}\left[\frac{P_3 - jQ_3}{V_3^{o*}} - Y_{31}V_1^o - Y_{32}V_2^1 - Y_{34}V_4^0 - Y_{35}V_5^0\right]$$

Example-3:

Obtain the load flow solution at the end of first iteration of the system with data as given below. The solution is to be obtained for the following cases

(i) All buses except bus 1 are PQ Buses

(ii) Bus 2 is a PV bus whose voltage magnitude is specified as 1.04 pu

(iii) Bus 2 is PV bus, with voltage magnitude specified as 1.04 and 0.25_Q2_1.0 pu.

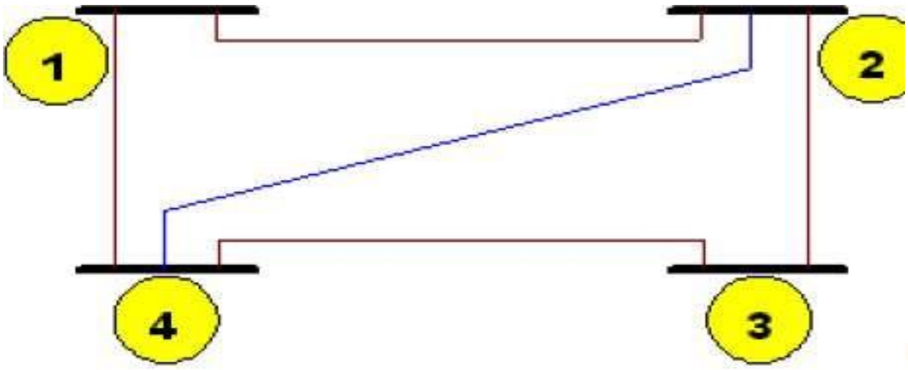


Fig. System for Example 3

Table: Line data of example 3

SB	EB	R (pu)	X (pu)
1	2	0.05	0.15
1	3	0.10	0.30
2	3	0.15	0.45
2	4	0.10	0.30
3	4	0.05	0.15

Table: Bus data of example 3

Bus No.	P_i (pu)	Q_i (pu)	V_i
1	–	–	$1.04\angle 0^0$
2	0.5	– 0.2	–
3	– 1.0	0.5	–
4	– 0.3	– 0.1	–

Solution: Note that the data is directly in terms of injected powers at the buses. The bus admittance matrix is formed by inspection as under:

$Y_{BUS} =$

3.0 – j9.0	–2.0 + j6.0	– 1.0 + j3.0	0
–2.0 + j6.0	3.666 – j11.0	– 0.666 + j2.0	– 1.0 + j3.0
–1.0 + j3.0	–0.666 + j2.0	3.666 – j11.0	–2.0 + j6.0
0	–1.0 + j3.0	– 2.0 + j6.0	3.0 – j9.0

Case(i): All buses except bus 1 are PQ Buses

Assume all initial voltages to be $1.0\angle 0^0$ pu.

$$V_2^1 = \frac{1}{Y_{22}}\left[\frac{P_2 - jQ_2}{V_2^{o*}} - Y_{21}V_1^o - Y_{23}V_3^0 - Y_{24}V_4^0\right]$$

$$= \frac{1}{Y_{22}}\left[\frac{0.5 + j0.2}{1.0 - j0.0} - \{(-2.0 + j6.0)\times(1.04\angle 0^o)\}\right.$$

$$\left. - \{(-0.666 + j2.0)\times(1.0\angle 0^o)\} - \{(-1.0 + j3.0)\times(1.0\angle 0^o)\}\right]$$

$$= 1.02014\angle 2.605^o$$

$$V_3^1 = \frac{1}{Y_{33}}\left[\frac{P_3 - jQ_3}{V_3^{o*}} - Y_{31}V_1^o - Y_{32}V_2^1 - Y_{34}V_4^0\right]$$

$$= \frac{1}{Y_{33}}\left[\frac{-1.0 - j0.5}{1.0 - j0.0} - \{(-1.0 + j3.0)\times(1.04\angle 0.0^o)\}\right.$$

$$\left. - \{(-0.666 + j2.0)\times(1.02014\angle 2.605^o)\} - \{(-2.0 + j6.0)\times(1.0\angle 0^0)\}\right]$$

$$= 1.03108\angle -4.831^o$$

$$V_4^1 = \frac{1}{Y_{44}}\left[\frac{P_4 - jQ_4}{V_4^{o*}} - Y_{41}V_1^o - Y_{42}V_2^1 - Y_{43}V_3^1\right]$$

$$= \frac{1}{Y_{44}}\left[\frac{0.3 + j0.1}{1.0 - j0.0} - \{(-1.0 + j3.0)\times(1.02014\angle 2.605^o)\}\right.$$

$$\left. - \{(-2.0 + j6.0)\times(1.03108\angle -4.831^o)\}\right]$$

$$= 1.02467\angle -0.51^o$$

Hence

$V_1^1 = 1.04\ \angle 0^0$ pu $\qquad V_2^1 = 1.02014\ \angle 2.605^0$ pu

$V_3^1 = 1.03108\ \angle -4.831^0$ pu $\qquad V_4^1 = 1.02467\ \angle -0.51^0$ pu

Case(ii): Bus 2 is a PV bus whose voltage magnitude is specified as 1.04 pu

We first compute Q_2.

$$Q_2 = |V_2|\left[|V_1|\left(G_{21}\sin\delta_{21} - B_{21}\cos\delta_{21}\right) + |V_2|\left(G_{22}\sin\delta_{22} - B_{22}\cos\delta_{22}\right)\right.$$
$$\left. + |V_3|\left(G_{23}\sin\delta_{23} - B_{23}\cos\delta_{23}\right) + |V_4|\left(G_{24}\sin\delta_{24} - B_{24}\cos\delta_{24}\right)\right]$$

$$= 1.04\,[1.04\,\{-6.0\} + 1.04\,\{11.0\} + 1.0\{-2.0\} + 1.0\,\{-3.0\} = 0.208 \text{ pu.}$$

$$V_2^1 = \frac{1}{Y_{22}}\left[\frac{0.5 - j0.208}{1.04\angle 0^0} - \{(-2.0 + j6.0)\times(1.04\angle 0^o)\}\right.$$
$$\left. - \{(-0.666 + j2.0)\times(1.0\angle 0^o)\} - \{(-1.0 + j3.0)\times(1.0\angle 0^0)\}\right]$$
$$= 1.051288 + j0.033883$$

The voltage magnitude is adjusted to 1.04. Hence $V_2^1 = 1.04\angle 1.846^0$

$$V_3^1 = \frac{1}{Y_{33}}\left[\frac{-1.0 - j0.5}{1.0\angle 0^0} - \{(-1.0 + j3.0)\times(1.04\angle 0.0^o)\}\right.$$
$$\left. - \{(-0.666 + j2.0)\times(1.04\angle 1.846^o)\} - \{(-2.0 + j6.0)\times(1.0\angle 0^0)\}\right]$$
$$= 1.035587\angle -4.951^o \text{ pu.}$$

$$V_4^1 = \frac{1}{Y_{44}}\left[\frac{0.3 + j0.1}{1.0 - j0.0} - \{(-1.0 + j3.0)\times(1.04\angle 1.846^o)\}\right.$$
$$\left. - \{(-2.0 + j6.0)\times(1.035587\angle -4.951^o)\}\right]$$
$$= 0.9985\angle -0.178^o$$

Hence at end of 1st iteration we have:

$V_1^1 = 1.04\angle 0^0$ pu $\qquad V_2^1 = 1.04\angle 1.846^0$ pu

$V_3^1 = 1.035587\angle -4.951^0$ pu $\qquad V_4^1 = 0.9985\angle -0.178^0$ pu

Case (iii): Bus 2 is PV bus, with voltage magnitude specified as 1.04 & $0.25 \le Q_2 \le 1$ pu.

If $0.25 \le Q_2 \le 1.0$ pu then the computed value of $Q_2 = 0.208$ is less than the lower limit. Hence, Q_2 is set equal to 0.25 pu. Iterations are carried out with this value of Q_2. The voltage magnitude at bus 2 can no longer be maintained at 1.04. Hence, there is no necessity to adjust for the voltage magnitude. Proceeding as before we obtain at the end of first iteration,

$$V_1^1 = 1.04 \angle 0^0 \text{ pu} \qquad V_2^1 = 1.05645 \angle 1.849^0 \text{ pu}$$

$$V_3^1 = 1.038546 \angle -4.933^0 \text{ pu} \qquad V_4^1 = 1.081446 \angle 4.896^0 \text{ pu}$$

Limitations of GS load flow analysis

GS method is very useful for very small systems. It is easily adoptable, it can be generalized and it is very efficient for systems having less number of buses. However, GS LFA fails to converge in systems with one or more of the features as under:

• Systems having large number of radial lines
• Systems with short and long lines terminating on the same bus
• Systems having negative values of transfer admittances
• Systems with heavily loaded lines, etc.

GS method successfully converges in the absence of the above problems. However, convergence also depends on various other set of factors such as: selection of slack bus, initial solution, acceleration factor, tolerance limit, level of accuracy of results needed, type and quality of computer/ software used, etc.

NEWTON –RAPHSON METHOD

Newton-Raphson (NR) method is used to solve a system of non-linear algebraic equations of the form f(x) =0. Consider a set of n non-linear algebraic equations given by

$$f_i(x_1, x_2 \ldots\ldots x_n) = 0 \qquad i = 1,2\ldots\ldots n \tag{25}$$

Let $x_1^0, x_2^0 \ldots\ldots\ldots x_n^0$, be the initial guess of unknown variables and $\Delta x_1^0, \Delta x_2^0 \ldots\ldots \Delta x_n^0$ be the respective corrections. Therefore,

$$f_i(x_1^0 + \Delta x_1^0, x_2^0 + \Delta x_2^0 \ldots\ldots\ldots x_n^0 + \Delta x_n^0) = 0 \qquad i = 1,2\ldots\ldots n \tag{26}$$

The above equation can be expanded using Taylor's series to give

$$f_i(x_1^0, x_2^0 \ldots\ldots x_n^0) + \left[\left(\frac{\partial f_i}{\partial x_1}\right)^0 \Delta x_1^0 + \left(\frac{\partial f_i}{\partial x_2}\right)\Delta x_2^0 + \ldots\ldots + \left(\frac{\partial f_i}{\partial x_n}\right)\Delta x_n^0\right]$$

$$+ \text{Higher order terms} = 0 \qquad \forall\ i = 1,2\ldots\ldots n \tag{27}$$

Where, $\left(\frac{\partial f_i}{\partial x_1}\right)^0, \left(\frac{\partial f_i}{\partial x_2}\right)^0, \ldots\ldots\ldots\ldots \left(\frac{\partial f_i}{\partial x_n}\right)^0$ are the partial derivatives of f_i with respect to $x_1, x_2 \ldots\ldots x_n$ respectively, evaluated at ($x_1^0, x_2^0 \ldots\ldots\ldots\ldots x_0^n$). If the higher order terms are neglected, then (27) can be written in matrix form as

$$\begin{bmatrix} f_1^0 \\ f_2^0 \\ \cdot \\ \cdot \\ \cdot \\ f_n^0 \end{bmatrix} + \begin{bmatrix} \left(\frac{\partial f_1}{\partial x_1}\right)^0 & \left(\frac{\partial f_1}{\partial x_2}\right)^0 & \cdot\ \cdot\ \cdot & \left(\frac{\partial f_1}{\partial x_n}\right)^0 \\ \left(\frac{\partial f_2}{\partial x_1}\right)^0 & \left(\frac{\partial f_2}{\partial x_2}\right)^0 & \cdot\ \cdot\ \cdot & \left(\frac{\partial f_2}{\partial x_n}\right)^0 \\ \cdot & \cdot & \cdot\ \cdot\ \cdot & \cdot \\ \cdot & \cdot & \cdot\ \cdot\ \cdot & \cdot \\ \cdot & \cdot & \cdot\ \cdot\ \cdot & \cdot \\ \left(\frac{\partial f_n}{\partial x_1}\right) & \left(\frac{\partial f_n}{\partial x_2}\right) & \cdot\ \cdot\ \cdot & \left(\frac{\partial f_n}{\partial x_n}\right) \end{bmatrix} \begin{bmatrix} \Delta x_1^0 \\ \Delta x_2^0 \\ \cdot \\ \cdot \\ \cdot \\ \Delta x_n^0 \end{bmatrix} = 0 \tag{28}$$

In vector form (28) can be written as

$$F^0 + J^0 \Delta X^0 = 0$$

Or $\qquad F^0 = -J^0 \Delta X^0$

Or $\qquad \Delta X^0 = -[J^0]^{-1} F^0 \qquad$ **(29)**

And $\qquad X^1 = X^0 + \Delta X^0 \qquad$ **(30)**

NR method for load flow solution in polar coordinates

In application of the NR method, we have to first bring the equations to be solved, to the form $f_i(x_1, x_2, ...x_n) = 0$, where $x_1, x_2, ...x_n$ are the unknown variables to be determined. Let us assume that the power system has n_1 PV buses and n_2 PQ buses. In polar coordinates the unknown variables to be determined are:

(i) δ_i, the angle of the complex bus voltage at bus *i*, at all the PV and PQ buses. This gives us $n_1 + n_2$ unknown variables to be determined.

(ii) $|V_i|$, the voltage magnitude of bus *i*, at all the PQ buses. This gives us n_2 unknown variables to be determined.

Therefore, the total number of unknown variables to be computed is: $n_1 + 2n_2$, for which we need $n_1 + 2n_2$ consistent equations to be solved. The equations are given by,

$$\Delta P_i = P_{i,sp} - P_{i,cal} = 0 \qquad \textbf{(31)}$$

$$\Delta Q_i = Q_{i,sp} - Q_{i,cal} = 0 \qquad \textbf{(32)}$$

Where $P_{i,sp}$ = Specified active power at bus *i*

$Q_{i,sp}$ = Specified reactive power at bus *i*

$P_{i,cal}$ = Calculated value of active power using voltage estimates.

$Q_{i,cal}$ = Calculated value of reactive power using voltage estimates

ΔP = Active power residue

ΔQ = Reactive power residue

The real power is specified at all the PV and PQ buses. Hence (31) is to be solved at all PV and PQ buses leading to $n_1 + n_2$ equations. Similarly the reactive power is specified at all the PQ buses. Hence, (32) is to be solved at all PQ buses leading to n_2 equations.

We thus have $n_1 + 2n_2$ equations to be solved for $n_1 + 2n_2$ unknowns. (31) and (32) are of the form F(x) = 0. Thus NR method can be applied to solve them. Equations (31) and (32) can be written in the form of (30) as:

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} J_1 & J_2 \\ J_3 & J_4 \end{bmatrix} \begin{bmatrix} \Delta\delta \\ \Delta|V| \end{bmatrix} \quad \textbf{(33)}$$

Where J_1, J_2, J_3, J_4 are the negated partial derivatives of ΔP and ΔQ with respect to corresponding δ and $|V|$. The negated partial derivative of ΔP, is same as the partial derivative of P_{cal}, since P_{sp} is a constant. The various computations involved are discussed in detail next.

Computation of P_{cal} and Q_{cal}:

The real and reactive powers can be computed from the load flow equations as:

$$P_{i,Cal} = P_i = \sum_{k=1}^{n} |V_i||V_k|(G_{ik}\cos\delta_{ik} + B_{ik}\sin\delta_{ik})$$

$$= G_{ii}|V_i|^2 + \sum_{\substack{k=1 \\ k\neq i}}^{n} |V_i||V_k|(G_{ik}\cos\delta_{ik} + B_{ik}\sin\delta_{ik}) \quad \textbf{(34)}$$

$$Q_{i,Cal} = Q_i = \sum_{k=1}^{n} |V_i||V_k|(G_{ik}\sin\delta_{ik} - B_{ik}\cos\delta_{ik})$$

$$= -B_{ii}|V_i|^2 + \sum_{\substack{k=1 \\ k\neq i}}^{n} |V_i||V_k|(G_{ik}\sin\delta_{ik} - B_{ik}\cos\delta_{ik}) \quad \textbf{(35)}$$

The powers are computed at any $(r+1)^{st}$ iteration by using the voltages available from previous iteration. The elements of the Jacobian are found using the above equations as:

Elements of J_1

$$\frac{\partial P_i}{\partial \delta_i} = \sum_{\substack{k=1 \\ k\neq i}}^{n} |V_i||V_k|\{G_{ik}(-\sin\delta_{ik}) + B_{ik}\cos\delta_{ik}\}$$

$$= -Q_i - B_{ii}|V_i|^2$$

$$\frac{\partial P_i}{\partial \delta_k} = |V_i||V_k|(G_{ik}(-\sin\delta_{ik})(-1) + B_{ik}(\cos\delta_{ik})(-1))$$

Elements of J3

$$\frac{\partial Q_i}{\partial \delta_i} = \sum_{\substack{k=1 \\ k\neq i}}^{n} |V_i||V_k|(G_{ik}\cos\delta_{ik} + B_{ik}\sin\delta_{ik}) = P_i - G_{ii}|V_i|^2$$

$$\frac{\partial Q_i}{\partial \delta_k} = -|V_i||V_k|(G_{ik}\cos\delta_{ik} + B_{ik}\sin\delta_{ik})$$

Elements of J2

$$\frac{\partial P_i}{\partial |V_i|}|V_i| = 2|V_i|^2 G_{ii} + |V_i|\sum_{\substack{k=1 \\ k\neq i}}^{n} |V_k|(G_{ik}\cos\delta_{ik} + B_{ik}\sin\delta_{ik}) = P_i + |V_i|^2 G$$

$$\frac{\partial P_i}{\partial |V_k|}|V_k| = |V_i||V_k|(G_{ik}\cos\delta_{ik} + B_{ik}\sin\delta_{ik})$$

Elements of J4

$$\frac{\partial P_i}{\partial |V_i|}|V_i| = -2|V_i|^2 B_{ii} + \sum_{\substack{k=1 \\ k\neq i}}^{n} |V_i||V_k|(G_{ik}\sin\delta_{ik} - B_{ik}\cos\delta_{ik}) = Q_i - |V_i|^2$$

$$\frac{\partial Q_i}{\partial |V_k|}|V_k| = |V_i||V_k|(G_{ik}\sin\delta_{ik} - B_{ik}\cos\delta_{ik})$$

Thus, the linearized form of the equation could be considered agai

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} H & N \\ M & L \end{bmatrix} \begin{bmatrix} \Delta\delta \\ \dfrac{\Delta|V|}{|V|} \end{bmatrix}$$

The elements are summarized below:

(i) $H_{ii} = \dfrac{\partial P_i}{\partial \delta_i} = -Q_i - B_{ii}|V_i|^2$

(ii) $H_{ik} = \dfrac{\partial P_i}{\partial \delta_k} = a_k f_i - b_k e_i = |V_i||V_k|(G_{ik}\sin\delta_{ik} - B_{ik}\cos\delta_{ik})$

(iii) $N_{ii} = \dfrac{\partial P_i}{\partial |V_i|}|V_i| = P_i + G_{ii}|V_i|^2$

(iv) $N_{ik} = \dfrac{\partial P_i}{\partial |V_k|}|V_k| = a_k e_i + b_k f_i = |V_i||V_k|(G_{ik}\cos\delta_{ik} + B_{ik}\sin\delta_{ik})$

(v) $M_{ii} = \dfrac{\partial Q_i}{\partial \delta_i} = P_i - G_{ii}|V_i|^2$

Strategy-1

(i) Calculate $\Delta P^{(r)}, \Delta Q^{(r)}$ and $J^{(r)}$

(ii) Compute $\begin{bmatrix} \Delta\delta^{(r)} \\ \dfrac{\Delta|V^{(r)}|}{|V^{(r)}|} \end{bmatrix} = \left[J^{(r)}\right]^{-1} \begin{bmatrix} \Delta P^{(r)} \\ \Delta Q^{(r)} \end{bmatrix}$

(iii) Update δ and $|V|$.

(iv) Go to step (i) and iterate till convergence is reached.

Strategy-2

(i) Compute $\Delta P^{(r)}$ and Sub-matrix $H^{(r)}$. From (37) find $\Delta\delta^{(r)} = \left[H^{(r)}\right]^{-1} \Delta P^{(r)}$

(ii) Up date δ using $\delta^{(r+1)} = \delta^{(r)} + \Delta\delta^{(r)}$.

(iii) Use $\delta^{(r+1)}$ to calculate $\Delta Q^{(r)}$ and $L^{(r)}$

(iv) Compute $\dfrac{\Delta|V^{(r)}|}{|V^{(r)}|} = \left[L^{(r)}\right]^{-1} \Delta Q^{(r)}$

(v)Update, $|V^{(r+1)}| = |V^{(r)}| + |\Delta V^{(r)}|$

(vi) Go to step (i) and iterate till convergence is reached.

In the first strategy, the variables are solved simultaneously. In the second strategy the sub-iteration is conducted by first solving for $\Delta\delta$ and using updated values of δ to calculate $\Delta|V|$. Hence, the second strategy results in faster convergence, compared to the first strategy.

FAST DECOUPLED LOAD FLOW

If the coefficient matrices are constant, the need to update the Jacobian at every iteration is eliminated. This has resulted in development of fast decoupled load Flow (FDLF). Here, certain assumptions are made based on the observations of practical power systems as under:

- $B_{ij} >> G_{ij}$ (Since the X/R ratio of transmission lines is high in well designed systems)

strategies as under:

- The voltage angle difference $(\delta_i - \delta_j)$ between two buses in the system is very small. This means $\cos(\delta_i - \delta_j) \cong 1$ and $\sin(\delta_i - \delta_j) = 0.0$
- $Q_i << B_{ii}|V_i|^2$

With these assumptions the elements of the Jacobian become

$$H_{ik} = L_{ik} = -|V_i||V_k|B_{ik} \qquad (i \neq k)$$

$$H_{ii} = L_{ii} = -B_{ii}|V_i|^2$$

The matrix (37) reduces to

$$[\Delta P] = \left[|V_i||V_j|B'_{ij}\right][\Delta\delta]$$

$$[\Delta Q] = \left[|V_i||V_j|B''_{ij}\right]\left[\frac{\Delta|V|}{|V|}\right] \qquad \textbf{(38)}$$

Where B'_{ij} and B''_{ij} are negative of the susceptances of respective elements of the bus admittance matrix. In (38) if we divide LHS and RHS by $|V_i|$ and assume $|V_j| \cong 1$, we get,

$$\left[\frac{\Delta P}{|V|}\right] = \left[B'_{ij}\right][\Delta\delta]$$

$$\left[\frac{\Delta Q}{|V|}\right] = \left[B''_{ij}\right]\left[\frac{\Delta|V|}{|V|}\right] \qquad \textbf{(39)}$$

Equations (39) constitute the Fast Decoupled load flow equations. Further simplification is possible by:

- Omitting effect of phase shifting transformers
- Setting off-nominal turns ratio of transformers to 1.0
- In forming B'_{ij}, omitting the effect of shunt reactors and capacitors which mainly affect reactive power
- Ignoring series resistance of lines in forming the Y_{bus}.

(i) Tap changing under load (TCUL) transformers (on load)

A = Ypq

B = (1/a -1) (1/a + 1 – Eq/Ep) Ypq

C = (1-1/a) (Ep/Eq) Ypq

Thus, here, in the case of TCUL transformers, the shunt admittance values are observed to be a function of the bus voltages.

COMPARISON OF LOAD FLOW METHODS

The comparison of the methods should take into account the computing time required for preparation of data in proper format and data processing, programming ease, storage requirements, computation time per iteration, number of iterations, ease and time required for modifying network data when operating conditions change, etc. Since all the methods presented are in the bus frame of reference in admittance form, the data preparation is same for all the methods and the bus admittance matrix can be formed using a simple algorithm, by the rule of inspection. Due to simplicity of the equations, Gauss-Seidel method is relatively easy to program. Programming of NR method is more involved and becomes more complicated if the buses are randomly numbered. It is easier to program, if the PV buses are ordered in sequence and PQ buses are also ordered in sequence.

The storage requirements are more for the NR method, since the Jacobian elements have to be stored. The memory is further increased for NR method using rectangular coordinates. The storage requirement can be drastically reduced by using sparse matrix techniques, since both the admittance matrix and the Jacobian are sparse matrices. The time taken for a single iteration depends on the number of arithmetic and logical operations required to be performed in a full iteration. The Gauss –Seidel method requires the fewest number of operations to complete iteration. In the NR method, the computation of the Jacobian is necessary in every iteration. Further, the inverse of the Jacobian also has to be computed. Hence, the time per iteration is larger than in the GS method and is roughly about 7 times that of the GS method, in large systems, as depicted graphically in figure below. Computation time can be reduced if the Jacobian is updated once in two or three iterations. In FDLF method, the Jacobian is constant and needs to be computed only once. In both NR and FDLF methods, the time per iteration increases directly as the number of buses.

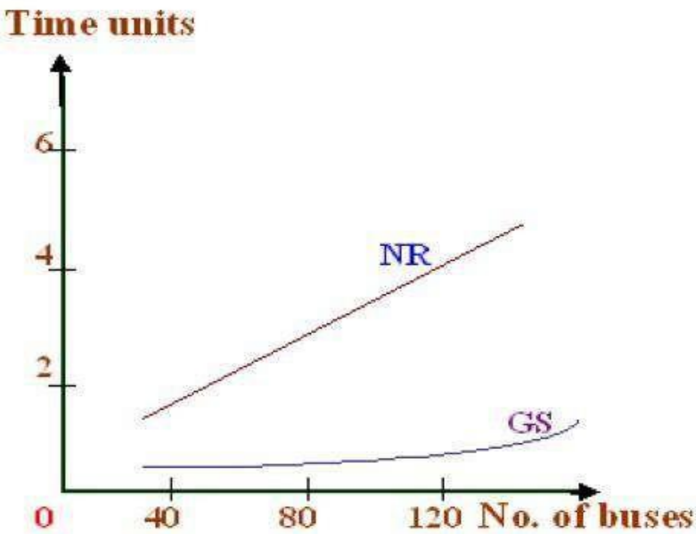


Figure 4. Time per Iteration in GS and NR methods

The number of iterations is determined by the convergence characteristic of the method. The GS method exhibits a linear convergence characteristic as compared to the NR method which has a quadratic convergence. Hence, the GS method requires more number of iterations to get a converged solution as compared to the NR method. In the GS method, the number of iterations increases directly as the size of the system increases. In contrast, the number of iterations is relatively constant in NR and FDLF methods. They require about 5-8 iterations for convergence in large systems. A significant increase in rate of convergence can be obtained in the GS method if an acceleration factor is used. All these variations are shown graphically in figure below. The number of iterations also depends on the required accuracy of the solution. Generally, a voltage tolerance of 0.0001 pu is used to obtain acceptable accuracy and the real power mismatch and reactive power mismatch can be taken as 0.001 pu. Due to these reasons, the NR method is faster and more reliable for large systems. The convergence of FDLF method is geometric and its speed is nearly 4-5 times that of NR method.

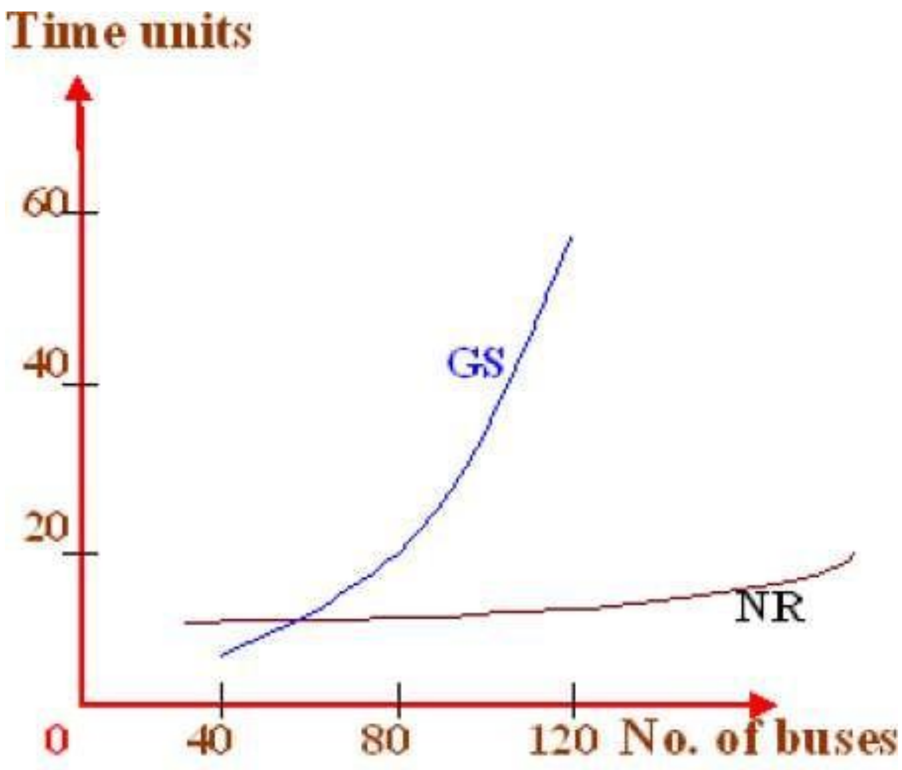


Figure 5. Total time of Iteration in GS and NR methods

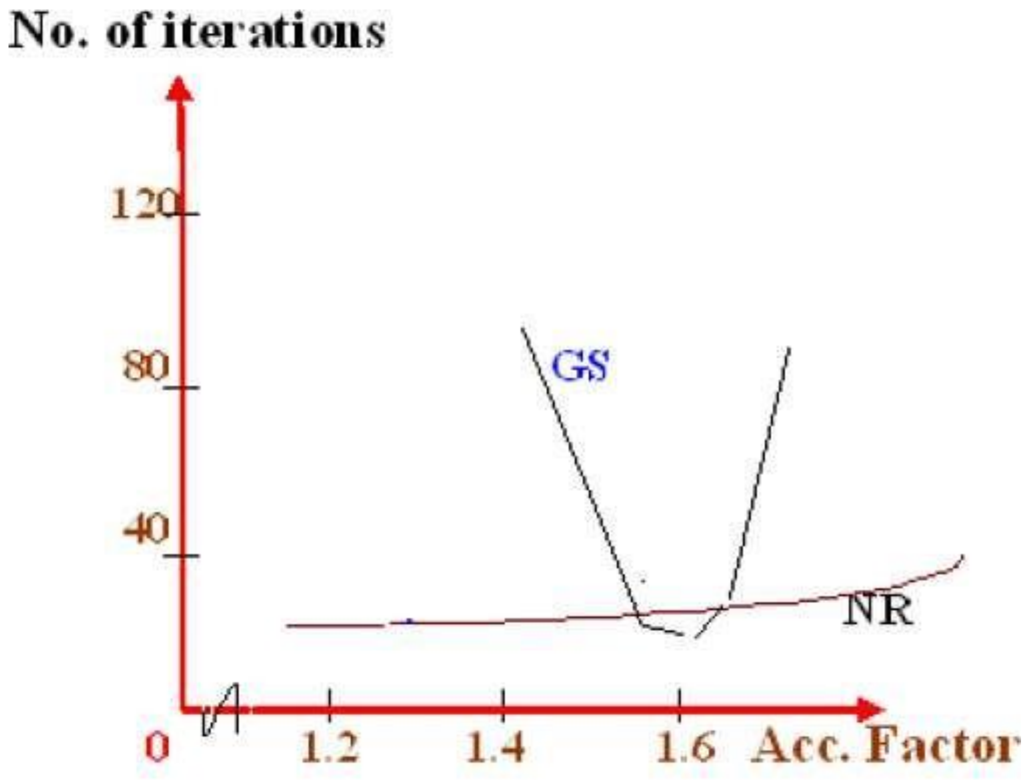


Figure 6. Influence of acceleration factor on load flow methods

FINAL WORD

In this chapter, the load flow problem, also called as the power flow problem, has been considered in detail. The load flow solution gives the complex voltages at all the buses and the complex power flows in the lines. Though, algorithms are available using the impedance form of the equations, the sparsity of the bus admittance matrix and the ease of building the bus admittance matrix, have made algorithms using the admittance form of equations more popular. The most popular methods are the Gauss-Seidel method, the Newton-Raphson method and the Fast Decoupled Load Flow method. These methods have been discussed in detail with illustrative examples. In smaller systems, the ease of programming and the memory requirements, make GS method attractive. However, the computation time increases with increase in the size of the system. Hence, in large systems NR and FDLF methods are more popular. There is a trade off between various requirements like speed, storage, reliability, computation time, convergence characteristics etc. No single method has all the desirable features. However, NR method is most popular because of its versatility, reliability and accuracy.

UNIT-II
ECONOMIC OPEARATION OF POWER SYSTEM

INTRODUCTION

One of the earliest applications of on-line centralized control was to provide a central facility, to operate economically, several generating plants supplying the loads of the system. Modern integrated systems have different types of generating plants, such as coal fired thermal plants, hydel plants, nuclear plants, oil and natural gas units etc. The capital investment, operation and maintenance costs are different for different types of plants. The operation economics can again be subdivided into two parts.

i) Problem of *economic dispatch*, which deals with determining the power output of each plant to meet the specified load, such that the overall fuel cost is minimized.

ii) Problem of *optimal power flow*, which deals with minimum – loss delivery, where in the power flow, is optimized to minimize losses in the system. In this chapter we consider the problem of economic dispatch.

During operation of the plant, a generator may be in one of the following states:

i) Base supply without regulation: the output is a constant.

ii) Base supply with regulation: output power is regulated based on system load.

iii) Automatic non-economic regulation: output level changes around a base setting as area control error changes.

iv) Automatic economic regulation: output level is adjusted, with the area load and area control error, while tracking an economic setting.

Regardless of the units operating state, it has a contribution to the economic operation, even though its output is changed for different reasons. The factors influencing the cost of generation are the generator efficiency, fuel cost and transmission losses. The most efficient generator may not give minimum cost, since it may be located in a place where fuel cost is high. Further, if the plant is located far from the load centers, transmission losses may be high and running the plant may become uneconomical. The economic dispatch problem basically determines the generation of different plants to minimize total operating cost.

Modern generating plants like nuclear plants, geo-thermal plants etc, may require capital investment of millions of rupees. The economic dispatch is however determined in terms of fuel cost per unit power generated and does not include capital investment, maintenance, depreciation, start-up and shut down costs etc.

PERFORMANCE CURVES

INPUT-OUTPUT CURVE

This is the fundamental curve for a thermal plant and is a plot of the input in British thermal units (Btu) per hour versus the power output of the plant in MW as shown in Fig1.

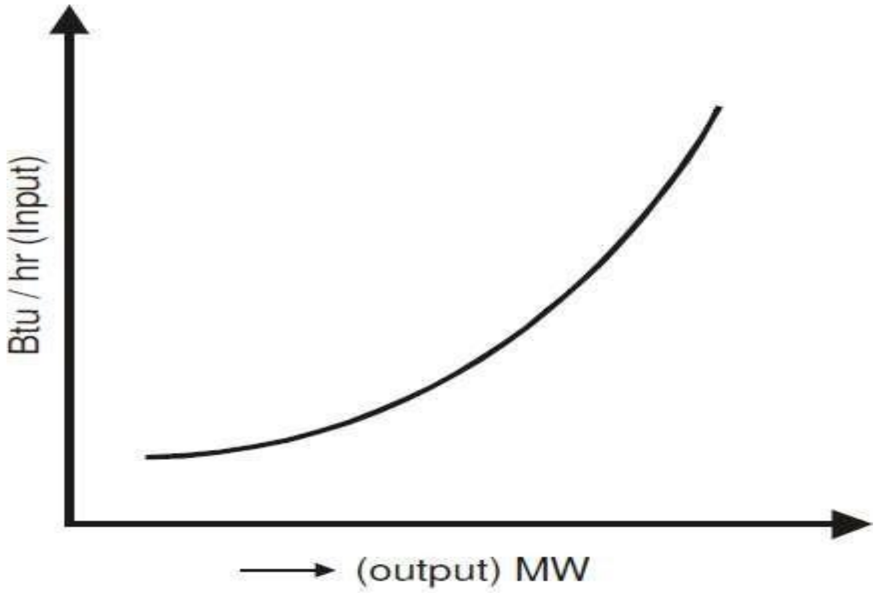


Fig 1: Input – output curve

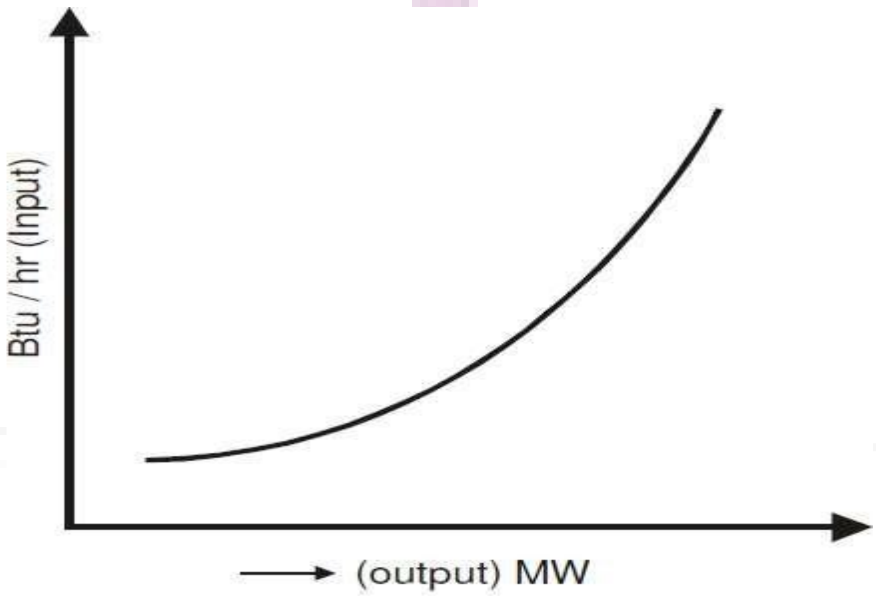


Fig 1: Input – output curve

HEAT RATE CURVE

The heat rate is the ratio of fuel input in Btu to energy output in KWh. It is the slope of the input – output curve at any point. The reciprocal of heat – rate is called fuel –efficiency.

The heat rate curve is a plot of heat rate versus output in MW. A typical plot is shown in Fig .2

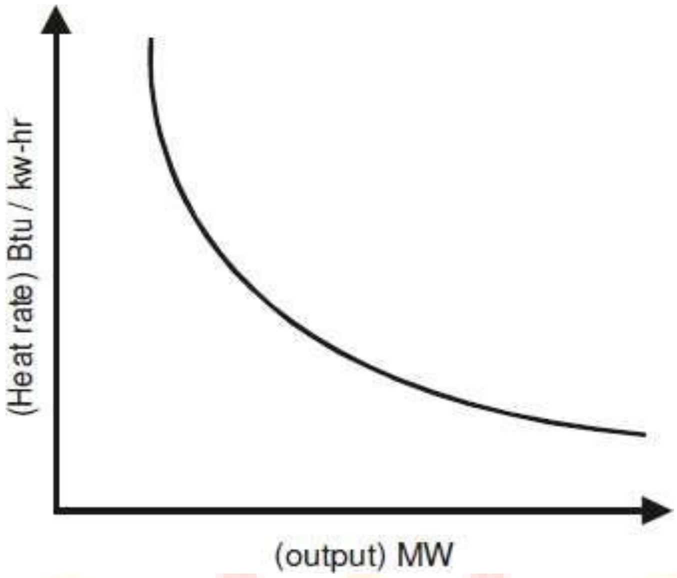


Fig .2 Heat rate curve.

INCREMENTAL FUEL RATE CURVE

The incremental fuel rate is equal to a small change in input divided by the corresponding change in output.

$$\text{Incremental fuel rate} = \frac{\Delta Input}{\Delta Output}$$

The unit is again Btu / KWh. A plot of incremental fuel rate versus the output is shown inFig 3

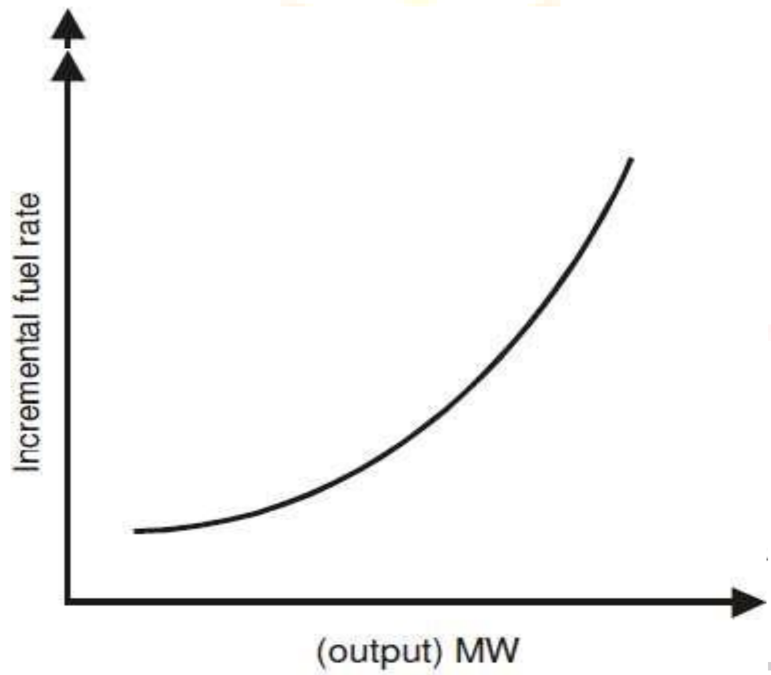


Fig 3: Incremental fuel rate curve

Incremental cost curve

The incremental cost is the product of incremental fuel rate and fuel cost (Rs / Btu or $ / Btu). The curve in shown in Fig. 4. The unit of the incremental fuel cost is Rs / MWh or $ /MWh.

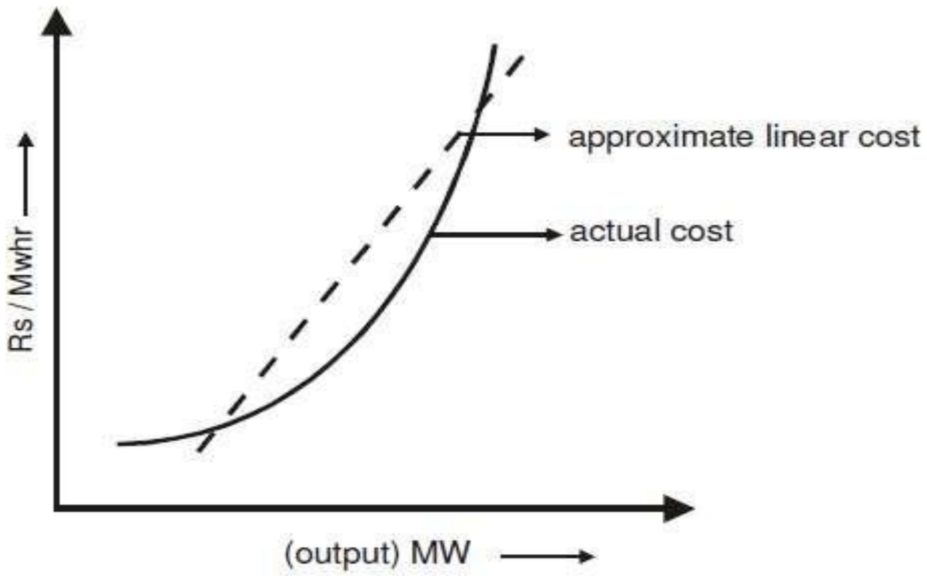


Fig 4: Incremental cost curve

In general, the fuel cost Fi for a plant, is approximated as a quadratic function of the generated output PGi.

$$F_i = a_i + b_i P_{Gi} + c_i P_{Gi}^2 \quad Rs/h$$

The incremental fuel cost is given by

$$\frac{dF_i}{dP_{Gi}} = b_i + 2c_i P_{Gi} \quad Rs/MWh$$

The incremental fuel cost is a measure of how costly it will be produce an increment of power. The incremental production cost, is made up of incremental fuel cost plus the incremental cost of labour, water, maintenance etc. which can be taken to be some percentage of the incremental fuel cost, instead of resorting to a rigorous mathematical model. The cost curve can be approximated by a linear curve. While there is negligible operating cost for a hydel plant, there is a limitation on the power output possible. In any plant, all units normally operate between PGmin, the minimum loading limit, below which it is technically infeasible to operate a unit and PGmax, which is the maximum output limit.

ECONOMIC GENERATION SCHEDULING NEGLECTING LOSSES AND GENERATOR LIMITS

The simplest case of economic dispatch is the case when transmission losses are neglected. The model does not consider the system configuration or line impedances. Since losses are neglected, the total generation is equal to the total demand PD. Consider a system with **n**g number of generating plants supplying the total demand PD. If Fi is the cost of plant ***i*** in Rs/h, the mathematical formulation of the problem of economic scheduling can be stated as follows:

Minimize $$F_T = \sum_{i=1}^{n_g} F_i$$

Such that $$\sum_{i=1}^{n_g} P_{Gi} = P_D$$

where F_T = total cost.
P_{Gi} = generation of plant i.
P_D = total demand.

This is a constrained optimization problem, which can be solved by Lagrange‟s method.

LAGRANGE METHOD FOR SOLUTION OF ECONOMIC SCHEDULE

The problem is restated below:

Minimize $$F_T = \sum_{i=1}^{n_g} F_i$$

Such that $$P_D = \sum_{i=1}^{n_g} P_{Gi} = 0$$

The augmented cost function is given by

$$£ = F_T + \lambda\left(P_D - \sum_{i=1}^{n_g} P_{Gi} \right)$$

The minimum is obtained when

$$\frac{\partial £}{\partial P_{Gi}} = 0 \text{ and } \frac{\partial £}{\partial \lambda} = 0$$

$$\frac{\partial £}{\partial P_{Gi}} = \frac{\partial F_T}{\partial P_{Gi}} - \lambda = 0$$

$$\frac{\partial £}{\partial \lambda} = P_D - \sum_{i=1}^{n_g} P_{Gi} = 0$$

The second equation is simply the original constraint of the problem. The cost of a plant

Fi depends only on its own output PGi, hence

$$\frac{\partial F_T}{\partial P_{Gi}} = \frac{\partial F_i}{\partial P_{Gi}} = \frac{dF_i}{dP_{Gi}}$$

Using the above,

$$\frac{\partial F_i}{\partial P_{Gi}} = \frac{dF_i}{dP_{Gi}} = \lambda \;; \qquad i = 1 \ldots\ldots n_g$$

We can write

$$b_i + 2c_i P_{Gi} = \lambda \qquad i = 1 \ldots\ldots n_g$$

The above equation is called the co-ordination equation. Simply stated, for economic generation scheduling to meet a particular load demand, when transmission losses are neglected and generation limits are not imposed, all plants must operate at equal incremental production costs, subject to the constraint that the total generation be equal to the demand. From we have

$$P_{Gi} = \frac{\lambda - b_i}{2c_i}$$

We know in a loss less system

$$\sum_{i=1}^{n_g} P_{Gi} = P_D$$

Substituting (8.16) we get

$$\sum_{i=1}^{n_g} \frac{\lambda - b_i}{2c_i} = P_D$$

An analytical solution of λ is obtained from (8.17) as

$$\lambda = \frac{P_D + \sum_{i=1}^{n_g} \frac{b_i}{2c_i}}{\sum_{i=1}^{n_g} \frac{1}{2c_i}}$$

Example 1.

The fuel costs of two units are given by

$F_1 = 1.5 + 20\ P_{G1} + 0.1\ P_{G1}^2$ Rs/h

$F_2 = 1.9 + 30\ P_{G2} + 0.1\ P_{G2}^2$ Rs/h

P_{G1}, P_{G2} are in MW. Find the optimal schedule neglecting losses, when the demand is 200 MW.

Solution:

$$\frac{dF_1}{dP_{G1}} = 20 + 0.2P_{G1} \quad \text{Rs / MWh}$$

$$\frac{dF_2}{dP_{G2}} = 30 + 0.2P_{G2} \quad \text{Rs / MWh}$$

$$P_D = P_{G1} + P_{G2} = 200\ \text{MW}$$

For economic schedule

$$\frac{dF_1}{dP_{G1}} = \frac{dF_2}{dP_{G2}} = \lambda$$

$$20 + 0.2\ P_{G1} = 30 + 0.2\ (200 - P_{G1})$$

Solving we get,

$$P_{G1} = 125\ \text{MW}$$

$$P_{G2} = 75\ \text{MW}$$

$$\lambda = 20 + 0.2\ (125) = 45\ \text{Rs / MWh}$$

Example 2

The fuel cost in \$ / h for two 800 MW plants is given by

$F_1 = 400 + 6.0\ P_{G1} + 0.004\ P_{G1}^2$

$F_2 = 500 + b_2\ P_{G2} + c_2\ P_{G2}^2$

where P_{G1}, P_{G2} are in MW

(a) The incremental cost of power, λ is \$8 / MWh when total demand is 550MW. Determine optimal generation schedule neglecting losses.

(b) The incremental cost of power is \$10/MWh when total demand is 1300 MW. Determine optimal schedule neglecting losses.

(c) From (a) and (b) find the coefficients b_2 and c_2.

Solution:

a) $$P_{G1} = \frac{\lambda - b_1}{2c_1} = \frac{8.0 - 6.0}{2 \times 0.004} = 250\ \text{MW}$$

$$P_{G2} = P_D - P_{G1} = 550 - 250 = 300\ \text{MW}$$

b) $$P_{G1} = \frac{\lambda - b_1}{2C_1} = \frac{10-6}{2\times 0.004} = 500 \text{ MW}$$

$$P_{G2} = P_D - P_{G1} = 1300 - 500 = 800 \text{ MW}$$

c) $$P_{G2} = \frac{\lambda - b_2}{2c_2}$$

From (a) $$300 = \frac{8.0 - b_2}{2c_2}$$

From (b) $$800 = \frac{10.0 - b_2}{2c_2}$$

Solving we get $b_2 = 6.8$

$c_2 = 0.002$

ECONOMIC SCHEDULE INCLUDING LIMITS ON GENERATOR (NEGLECTING LOSSES)

The power output of any generator has a maximum value dependent on the rating of the generator. It also has a minimum limit set by stable boiler operation. The economic dispatch problem now is to schedule generation to minimize cost, subject to the equality constraint.

$$\sum_{i=1}^{n_g} P_{Gi} = P_D$$

and the inequality constraint

$$P_{Gi\,(min)} \le P_{Gi} \le P_{Gi\,(max)} ;\ i = 1, \ldots\ldots\ldots n_g$$

The procedure followed is same as before i.e. the plants are operated with equal incremental fuel costs, till their limits are not violated. As soon as a plant reaches the limit (maximum or minimum) its output is fixed at that point and is maintained a constant. The other plants are operated at equal incremental costs.

Example 3

Incremental fuel costs in $ / MWh for two units are given below:

$$\frac{dF_1}{dP_{G1}} = 0.01P_{G1} + 2.0 \ \$ / \text{MWh}$$

$$\frac{dF_2}{dP_{G2}} = 0.012P_{G2} + 1.6 \ \$ / \text{MWh}$$

The limits on the plants are P_{min} = 20 MW, P_{max} = 125 MW. Obtain the optimal schedule if the load varies from 50 – 250 MW.

Solution:

The incremental fuel costs of the two plants are evaluated at their lower limits and upper limits of generation.

At $P_{G\,(min)}$ = 20 MW.

$$\lambda_{1(min)} = \frac{dF_1}{dP_{G1}} = 0.01 \text{x } 20 + 2.0 = 2.2\$ / \text{MWh}$$

$$\lambda_{2(min)} = \frac{dF_2}{dP_{G2}} = 0.012 \text{ x } 20 + 1.6 = 1.84 \ \$ / \text{MWh}$$

At $P_{G\,(Max)}$ =125 Mw

$\lambda_{1(max)}$ = 0.01 x 125 + 2.0 = 3.25 $ / MWh

$\lambda_{2(max)}$ = 0.012 x 125 + 1.6 = 3.1 $ / MWh

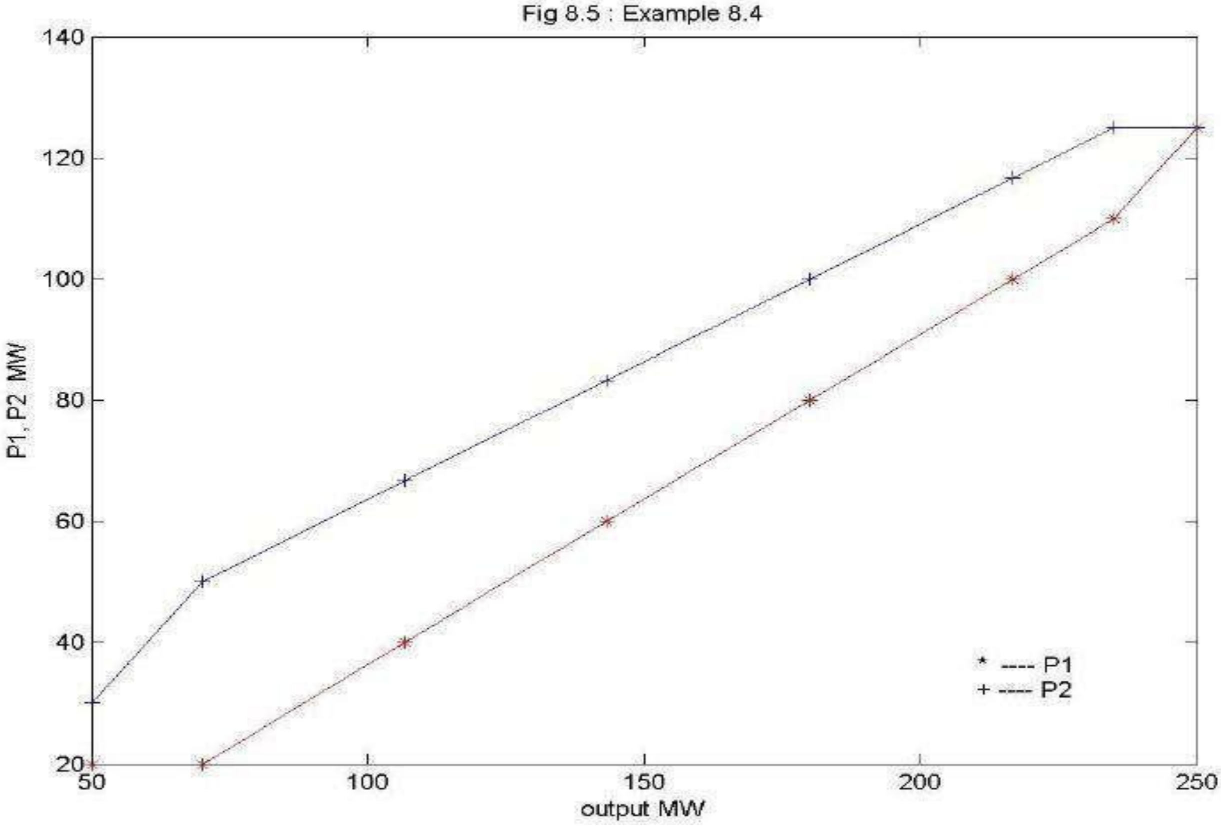
Now at light loads unit 1 has a higher incremental cost and hence will operate at its lower limit of 20 MW. Initially, additional load is taken up by unit 2, till such time its incremental fuel cost becomes equal to 2.2$ / MWh at PG2 = 50 MW. Beyond this, the two units are operated with equal incremental fuel costs. The contribution of each unit to meet the demand is obtained by assuming different values of l; When l = 3.1 $ / MWh, unit 2 operates at its upper limit. Further loads are taken up by unit 1. The computations are show in Table

Table Plant output and output of the two units

$\frac{dF_1}{dP_{G1}}$ \$/MWh	$\frac{dF_2}{dP_{G2}}$ \$/MWh	Plant λ \$/MWh	P_{G1} MW	P_{G2} MW	Plant Output MW
2.2	1.96	1.96	20^+	30	50
2.2	2.2	2.2	20^+	50	70
2.4	2.4	2.4	40	66.7	106.7
2.6	2.6	2.6	60	83.3	143.3
2.8	2.8	2.8	80	100	180
3.0	3.0	3.0	100	116.7	216.7
3.1	3.1	3.1	110	125*	235

For a particular value of l, PG1 and PG2 are calculated using (8.16). Fig 8.5 Shows plot of each unit output versus the total plant output.

Fig 8.5 : Example 8.4



In example 3, what is the saving in fuel cost for the economic schedule compared to the case where the load is shared equally. The load is 180 MW.

Solution:

From Table it is seen that for a load of 180 MW, the economic schedule is PG1 = 80 MW and PG2 = 100 MW. When load is shared equally PG1 = PG2 = 90 MW. Hence, the generation of unit 1 increases from 80 MW to 90 MW and that of unit 2 decreases from

100 MW to 90 MW, when the load is shared equally. There is an increase in cost of unit 1 since PG1 increases and decrease in cost of unit 2 since PG2 decreases.

$$\text{Increase in cost of unit 1} = \int_{80}^{90} \left(\frac{dF_1}{dP_{G1}} \right) dP_{G1}$$

$$= \int_{80}^{90} (0.01P_{G1} + 2.0) dP_{G1} = 28.5\ \$ / \text{h}$$

$$\text{Decrease in cost of unit 2} = \int_{100}^{90} \left(\frac{dF_2}{dP_{G2}} \right) dP_{G2}$$

$$= \int_{100}^{90} (0.012P_{G2} + 1.6) dP_{G2} = -27.4\ \$ / \text{h}$$

Total increase in cost if load is shared equally = 28.5 – 27.4 = 1.1 \$ / h

Hence the saving in fuel cost is 1.1 \$ / h if coordinated economic schedule is used.

ECONOMIC DISPATCH INCLUDING TRANSMISSION LOSSES

When transmission distances are large, the transmission losses are a significant part of the generation and have to be considered in the generation schedule for economic operation. The mathematical formulation is now stated as

Minimize $$F_T = \sum_{i=1}^{n_g} F_i$$

Such That $$\sum_{i=1}^{n_g} P_{Gi} = P_D + P_L$$

where P_L is the total loss.

The Lagrange function is now written as

$$£ = F_T - \lambda\left(\sum_{i=1}^{n_g} P_{Gi} - P_D - P_L\right) = 0$$

The minimum point is obtained when

$$\frac{\partial £}{\partial P_{Gi}} = \frac{\partial F_T}{\partial P_{Gi}} - \lambda\left(1 - \frac{\partial P_L}{\partial P_{Gi}}\right) = 0;\ i = 1\ldots\ldots n_g$$

$$\frac{\partial £}{\partial \lambda} = \sum_{i=1}^{n_g} P_{Gi} - P_D + P_L = 0 \qquad \text{(Same as the constraint)}$$

Since $\dfrac{\partial F_T}{\partial P_{Gi}} = \dfrac{dF_i}{dP_{Gi}}$, (8.27) can be written as

$$\frac{dF_i}{dP_{Gi}} + \lambda\frac{\partial P_L}{\partial P_{Gi}} = \lambda$$

$$\lambda = \frac{dF_i}{dP_{Gi}}\left(\frac{1}{1 - \frac{\partial P_L}{\partial P_{Gi}}}\right)$$

The term $\dfrac{1}{1 - \dfrac{\partial P_L}{\partial P_{Gi}}}$ is called the penalty factor of plant ***i***, $\mathbf{L_i}$. The coordination equations including losses are given by

$$\lambda = \frac{dF_i}{dP_{Gi}} L_i;\ i = 1\ldots\ldots n_g$$

The minimum operation cost is obtained when the product of the incremental fuel cost and the penalty factor of all units is the same, when losses are considered. A rigorous general expression for the loss PL is given by

$$P_L = \Sigma_m \Sigma_n P_{Gm} B_{mn} P_{Gn} + \Sigma_n P_{Gn} B_{no} + B_{oo}$$

where Bmn, Bno , Boo called loss – coefficients , depend on the load composition. The assumption here is that the load varies linearly between maximum and minimum values. A simpler expression is

$$P_L = \Sigma_m \Sigma_n P_{Gm} B_{mn} P_{Gn}$$

The expression assumes that all load currents vary together as a constant complex fraction of the total load current. Experiences with large systems has shown that the loss of accuracy is not significant if this approximation is used. An average set of loss coefficients may be used over the complete daily cycle in the coordination of incremental production costs and incremental transmission losses. In general, Bmn = Bnm and can be expanded for a two plant system as

$$P_L = B_{11} P_{G1} + 2 B_{12} P_{G1} P_{G2} + B_{22} P_{G2}^2$$

Example 5

A generator is supplying a load. An incremental change in load of 4 MW requires generation to be increased by 6 MW. The incremental cost at the plant bus is Rs 30 /MWh. What is the incremental cost at the receiving end?

Solution:

$$\frac{dF_1}{dP_{G1}} = 30$$

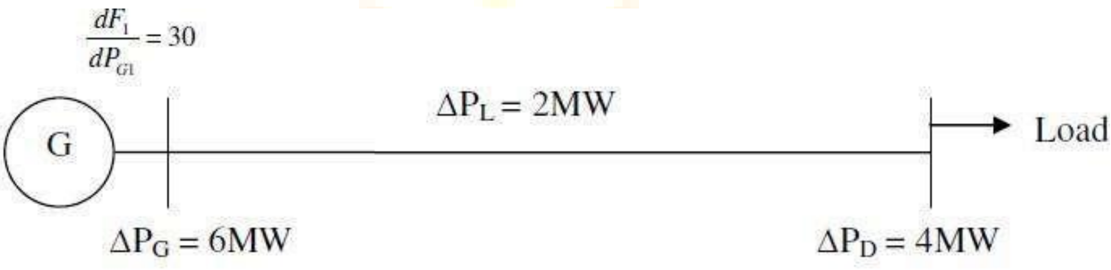


Fig ; One line diagram of example 5

$$\Delta P_L = \Delta P_G - \Delta P_D = 2 \text{ MW}$$

λ at receiving end is given by

$$\lambda = \frac{dF_1}{dP_{G1}} \times \frac{\Delta P_G}{\Delta P_D} = 30 \times \frac{6}{4} = 45 \text{ Rs / MWh}$$

$$\text{or } \lambda = \frac{dF_1}{dP_{G1}} \times \frac{1}{1 - \frac{\Delta P_L}{\Delta P_G}} = 30 \times \frac{1}{1 - \frac{2}{6}} = 45 \text{ Rs / MWh}$$

Example 6

In a system with two plants, the incremental fuel costs are given by

$$\frac{dF_1}{dP_{G1}} = 0.01P_{G1} + 20 \text{ Rs / MWh}$$

$$\frac{dF_2}{dP_{G2}} = 0.015P_{G2} + 22.5 \text{ Rs / MWh}$$

The system is running under optimal schedule with $P_{G1} = P_{G2} = 100$ MW.

If $\frac{\partial P_L}{\partial P_{G2}} = 0.2$, find the plant penalty factors and $\frac{\partial P_L}{\partial P_{G1}}$.

Solution:

For economic schedule,

$$\frac{dF_i}{dP_{Gi}} L_i = \lambda \text{ ;} \qquad L_i = \frac{1}{1 - \frac{\partial P_L}{\partial P_{Gi}}} \text{ ;}$$

For plant 2, $P_{G2} = 100$ MW

$$\therefore (0.015 \times 100 + 22.5)\frac{1}{1 - 0.2} = \lambda.$$

Solving, $\lambda = 30 \text{ Rs / MWh}$

$$L_2 = \frac{1}{1 - 0.2} = 1.25$$

$$\frac{dF_1}{dP_{G1}} L_1 = \lambda \Rightarrow (0.01 \times 100 + 20)\ L_1 = 30$$

$L_1 = 1.428$

$$L_1 = \frac{1}{1 - \frac{\partial P_L}{\partial P_{G1}}}$$

$$1.428 = \frac{1}{1 - \frac{\partial P_L}{\partial P_{G1}}} \text{ ; Solving } \frac{\partial P_L}{\partial P_{G1}} = 0.3$$

Example 7

A two bus system is shown in Fig. 8.8 If 100 MW is transmitted from plant 1 to the load, a loss of 10 MW is incurred. System incremental cost is Rs 30 / MWh. Find P_{G1}, P_{G2} and power received by load if

$$\frac{dF_1}{dP_{G1}} = 0.02P_{G1} + 16.0 \text{ Rs / MWh}$$

$$\frac{dF_2}{dP_{G2}} = 0.04P_{G2} + 20.0 \text{ Rs / MWh}$$

Fig One line diagram of example 7

Solution;

Since the load is connected at bus 2 , no loss is incurred when plant two supplies the load.

Therefore in (8.36) $B_{12} = 0$ and $B_{22} = 0$

$$P_L = B_{11}P_{G1}{}^2; \qquad \frac{\partial P_L}{\partial P_{G1}} = 2B_{11}P_{G1}; \qquad \frac{\partial P_L}{\partial P_{G2}} = 0.0$$

From data we have $P_L = 10$ MW, if $P_{G1} = 100$ MW

$10 = B_{11}\,(100)^2$

$B_{11} = 0.001 \quad MW^{-1}$

Coordination equation with loss is

$$\frac{dF_i}{dP_{Gi}} + \lambda\frac{\partial P_L}{\partial P_{Gi}} = \lambda$$

For plant 1 $\quad \frac{dF_1}{dP_{G1}} + \lambda\frac{\partial P_L}{\partial P_{G1}} = \lambda$

$(0.02\ P_{G1} + 16.0) + 30\ (2 \times 0.001 \times P_{G1}) = 30$

$0.08\ P_{G1} = 30 - 16.0$. From which, $P_{G1} = 175$ MW

For Plant 2 $\quad \frac{dF_2}{dP_{G1}} + \lambda\frac{\partial P_L}{\partial P_{G2}} = \lambda$

$0.04\ P_{G2} + 20.0 = 30$ or $P_{G2} = 250$ MW

Loss $= B_{11}\ P_{G1}{}^2 = 0.001 \times (175)^2 = 30.625$ MW

$P_D = (P_{G1} + P_{G2}) - P_L = 394.375$ MW

DERIVATION OF TRANSMISSION LOSS FORMULA

An accurate method of obtaining general loss coefficients has been presented by Kron. The method is elaborate and a simpler approach is possible by making the following assumptions:

(i) All load currents have same phase angle with respect to a common reference

(ii) The ratio X / R is the same for all the network branches.

Consider the simple case of two generating plants connected to an arbitrary number of loads through a transmission network as shown in Fig a

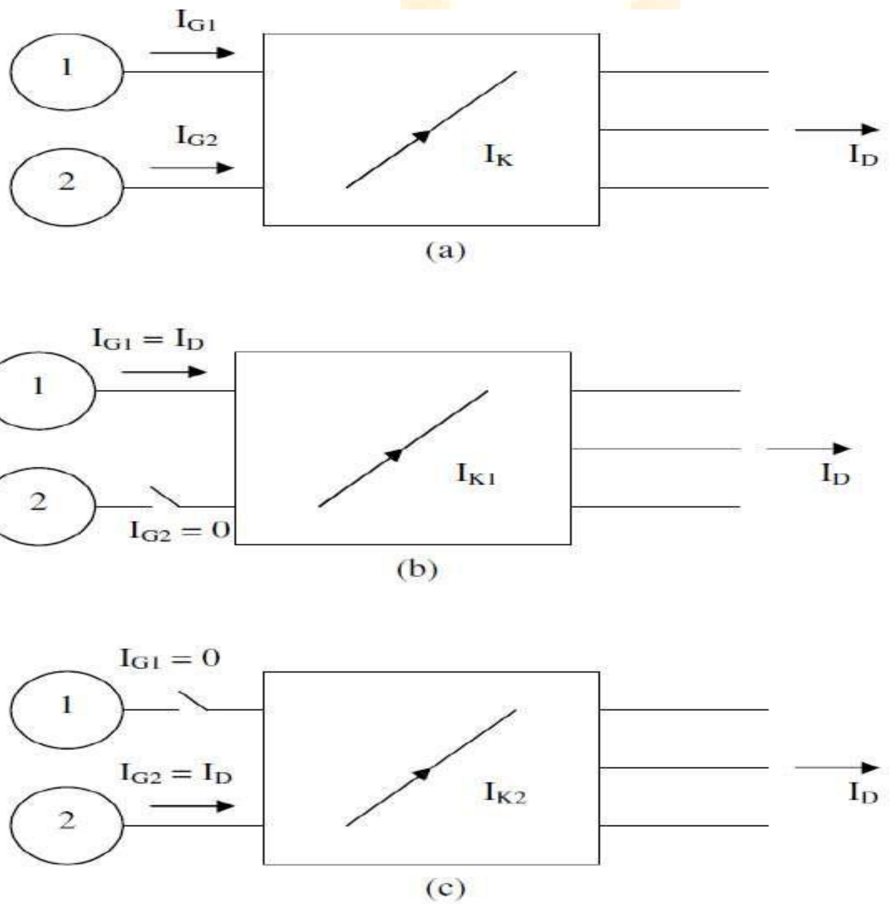


Fig Two plants connected to a number of loads through a transmission network

Let's assume that the total load is supplied by only generator 1 as shown in Fig 8.9b. Let the current through a branch K in the network be I_{K1}. We define

$$N_{K1} = \frac{I_{K1}}{I_D}$$

It is to be noted that $I_{G1} = I_D$ in this case. Similarly with only plant 2 supplying the load current I_D, as shown in Fig 8.9c, we define

$$N_{K2} = \frac{I_{K2}}{I_D}$$

N_{K1} and N_{K2} are called current distribution factors and their values depend on the impedances of the lines and the network connection. They are independent of I_D. When both generators are supplying the load, then by principle of superposition

$$I_K = N_{K1}\, I_{G1} + N_{K2}\, I_{G2}$$

where I_{G1}, I_{G2} are the currents supplied by plants 1 and 2 respectively, to meet the demand I_D. Because of the assumptions made, I_{K1} and I_D have same phase angle, as do I_{K2} and I_D. Therefore, the current distribution factors are real rather than complex. Let

$$I_{G1} = |I_{G1}|\angle\sigma_1 \text{ and } I_{G2} = |I_{G2}|\angle\sigma_2 .$$

where σ_1 and σ_2 are phase angles of I_{G1} and I_{G2} with respect to a common reference. We can write

$$|I_K|^2 = (N_{K1}|I_{G1}|\cos\sigma_1 + N_{K2}|I_{G2}|\cos\sigma_2)^2 + (N_{K1}|I_{G1}|\sin\sigma_1 + N_{K2}|I_{G2}|\sin\sigma_2)^2$$

$$= \begin{matrix} N_{K1}{}^2|I_{G1}|^2[\cos^2\sigma_1 + \sin^2\sigma_1] + N_{K2}{}^2|I_{G2}|^2[\cos^2\sigma_2 + \sin^2\sigma_2] \\ + 2[N_{K1}|I_{G1}|\cos\sigma_1 N_{K2}|I_{G2}|\cos\sigma_2 + N_{K1}|I_{G1}|\sin\sigma_1 N_{K2}|I_{G2}|\sin\sigma_2] \end{matrix}$$

$$= N_{K1}{}^2|I_{G1}|^2 + N_{K2}{}^2|I_{G2}|^2 + 2N_{K1}N_{K2}|I_{G1}||I_{G2}|\cos(\sigma_1 - \sigma_2)$$

Now $|I_{G1}| = \dfrac{P_{G1}}{\sqrt{3}|V_1|\cos\phi_1}$ and $|I_{G2}| = \dfrac{P_{G2}}{\sqrt{3}|V_2|\cos\phi_2}$

where P_{G1}, P_{G2} are three phase real power outputs of plant1 and plant 2; V_1, V_2 are the line to line bus voltages of the plants and ϕ_1, ϕ_2 are the power factor angles.

The total transmission loss in the system is given by

$$P_L = \sum_K 3|I_K|^2 R_K$$

where the summation is taken over all branches of the network and R_K is the branch resistance. Substituting we get

$$P_L = \frac{P_{G1}{}^2}{|V_1|^2(\cos\phi_1)^2}\sum_K N_{K1}{}^2 R_K + \frac{2P_{G1}P_{G2}\cos(\sigma_1 - \sigma_2)}{|V_1||V_2|\cos\phi_1\cos\phi_2}\sum_K N_{K1}N_{K2}R_K$$
$$+ \frac{P_{G2}{}^2}{|V_2|^2(\cos\phi_2)^2}\sum_K N_{K2}{}^2 R_K$$

$$P_L = P_{G1}{}^2 B_{11} + 2P_{G1}P_{G2}B_{12} + P_{G2}{}^2 B_{22}$$

where $$B_{11} = \frac{1}{|V_1|^2(\cos\phi_1)^2}\sum_K N_{K1}{}^2 R_K$$

$$B_{12} = \frac{\cos(\sigma_1 - \sigma_2)}{|V_1||V_2|\cos\phi_1 \cos\phi_2} \sum_K N_{K1} N_{K2} R_K$$

$$B_{22} = \frac{1}{|V_2|^2 (\cos\phi_2)^2} \sum_K N_{K2}{}^2 R_K$$

The loss – coefficients are called the B – coefficients and have unit MW^{-1}.

For a general system with n plants the transmission loss is expressed as

$$P_L = \frac{P_{G1}{}^2}{|V_1|^2 (\cos\phi_1)^2} \sum_K N_{K1}{}^2 + \ldots\ldots + \frac{P_{Gn}{}^2}{|V_n|^2 (\cos\phi_n)^2} \sum_K N_{Kn}{}^2 R_K$$
$$+ 2 \sum_{\substack{p,q=1 \\ p \neq q}}^{n} \frac{P_{GP} P_{Gq} \cos(\sigma_p - \sigma_q)}{|V_p||V_q|\cos\phi_p \cos\phi_q} \sum_k N_{KP} N_{Kq} R_K$$

In a compact form

$$P_L = \sum_{p=1}^{n} \sum_{q=1}^{n} P_{Gp} B_{Pq} P_{Gq}$$

$$B_{Pq} = \frac{\cos(\sigma_p - \sigma_q)}{|V_p||V_q|\cos\phi_P \cos\phi_q} \sum_K N_{KP} N_{Kq} R_K$$

B – Coefficients can be treated as constants over the load cycle by computing them at average operating conditions, without significant loss of accuracy.

<u>Example 8</u>

Calculate the loss coefficients in pu and MW^{-1} on a base of 50MVA for the network of Fig below. Corresponding data is given below.

$I_a = 1.2 - j\,0.4$ pu $\quad Z_a = 0.02 + j\,0.08$ pu

$I_b = 0.4 - j\,0.2$ pu $\quad Z_b = 0.08 + j\,0.32$ pu

$I_c = 0.8 - j\,0.1$ pu $\quad Z_c = 0.02 + j\,0.08$ pu

$I_d = 0.8 - j\,0.2$ pu $\quad Z_d = 0.03 + j\,0.12$ pu

$I_e = 1.2 - j\,0.3$ pu $\quad Z_e = 0.03 + j\,0.12$ pu

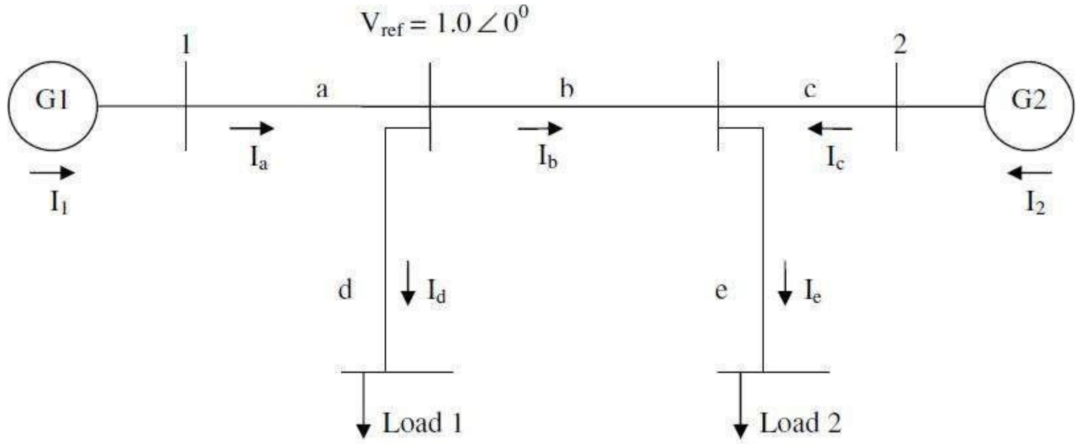


Fig : Example 8

Solution:

Total load current

$I_L = I_d + I_e = 2.0 - j\,0.5 = 2.061\ \angle -14.03^0 A$

$I_{L1} = I_d = 0.8 - j\,0.2 = 0.8246\ \angle -14.03^0\ A$

$\frac{I_{L1}}{I_L} = 0.4; \qquad \frac{I_{L2}}{I_L} = 1.0 - 0.4 = 0.6$

If generator 1, supplies the load then $I_1 = I_L$. The current distribution is shown in Fig a.

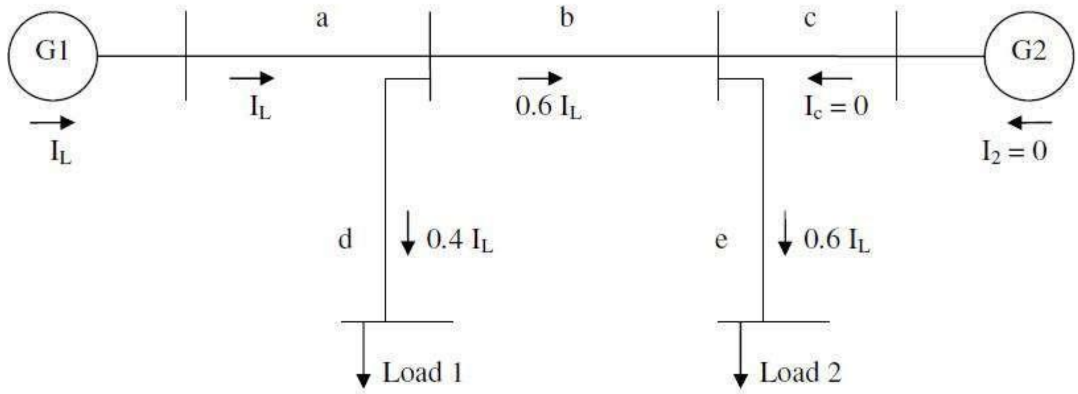


Fig a : Generator 1 supplying the total load

$N_{a1} = \frac{I_a}{I_L} = 1.0;\ N_{b1} = \frac{I_b}{I_L} = 0.6;\ N_{C1} = 0;\ N_{d1} = 0.4;\ N_{e1} = 0.6.$

Similarly the current distribution when only generator 2 supplies the load is shown in Fig b.

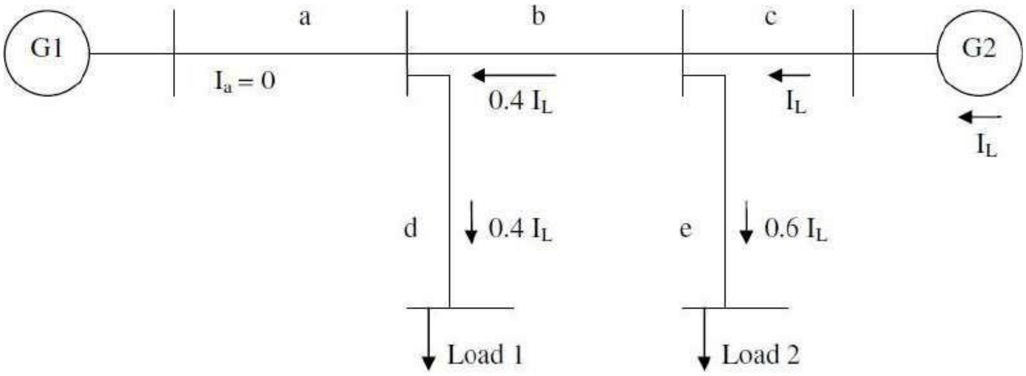


Fig b: Generator 2 supplying the total load

$N_{a2} = 0$; $N_{b2} = -0.4$; $N_{c2} = 1.0$; $N_{d2} = 0.4$; $N_{e2} = 0.6$

From Fig 8.10, $V_1 = V_{ref} + Z_a I_a$

$$= 1\angle 0^0 + (1.2 - j\,0.4)\,(0.02 + j0.08)$$

$$= 1.06 \angle 4.78^0 = 1.056 + j\,0.088 \text{ pu.}$$

$$V_2 = V_{ref} - I_b Z_b + I_c Z_c$$

$$= 1.0\ \angle 0^0 - (0.4 - j\,0.2)\,(0.08 + j\,0.32) + (0.8 - j\,0.1)\,(0.02 + j\,0.08)$$

$$= 0.928 - j\,0.05 = 0.93\ \angle\text{-}3.10^0 \text{ pu.}$$

Current Phase angles

$$\sigma_1 = \text{angle of } I_1(=I_a) = \tan^{-1}\left(\frac{-0.4}{1.2}\right) = -18.43^0$$

$$\sigma_2 = \text{angle of } I_2(=I_c) = \tan^{-1}\left(\frac{-0.1}{0.8}\right) = -7.13^0$$

$$\cos(\sigma_1 - \sigma_2) = 0.98$$

Power factor angles

$$\phi_1 = 4.78^0 + 18.43 = 23.21^0; \cos\phi_1 = 0.92$$

$$\phi_2 = 7.13^0 - 3.10^0 = 4.03^0; \cos\phi_2 = 0.998$$

$$B_{11} = \frac{\sum_K N_{K1}{}^2 R_K}{|V_1|^2 (\cos\phi_1)^2} = \frac{1.0^2 \times 0.02 + 0.6^2 \times 0.08 + 0.4^2 \times 0.03 + 0.6^2 \times 0.03}{(1.06)^2 (0.920)^2}$$

$= 0.0677$ pu

$$= 0.0677 \text{ x } \frac{1}{50} = 0.1354 \times 10^{-2}\,\text{MW}^{-1}$$

$$B_{12} = \frac{Cos(\sigma_1 - \sigma_2)}{|V_1||V_2|(\cos\phi_1)(\cos\phi_2)} \sum_K N_{K1} N_{K2} R_K$$

$$= \frac{0.98}{(1.06)(0.93)(0.998)(0.92)}\left[-0.4\times0.6\times0.08+0.4\times0.4\times0.03+0.6\times0.6\times0.03\right]$$

= - 0.00389 pu

= - 0.0078 x 10^{-2} MW^{-1}

$$B_{22} = \frac{\sum_K N_{K2}{}^2 R_K}{|V_2|^2 \left(\cos\phi_2{}^2\right)}$$

$$= \frac{(-0.4)^2\, 0.08 + 1.0^2\times0.02 + 0.4^2\times0.03 + 0.6^2\times0.03}{(0.93)^2(0.998)^2}$$

$$= 0.056\text{pu} = 0.112\times10^{-2}\text{MW}^{-1}$$

Coordination between LFC and Economic Dispatch

A good business practice is the one in which the production cost is minimized without sacrificing the quality. This is not any different in the power sector as well. The main aim here is to reduce the production cost while maintaining the voltage magnitudes at each bus. In this chapter we shall discuss the economic operation strategy along with the turbine-governor control that are required to maintain the power dispatch economically.

A power plant has to cater to load conditions all throughout the day, come summer or winter. It is therefore illogical to assume that the same level of power must be generated at all time. The power generation must vary according to the load pattern, which may in turn vary with season. Therefore the economic operation must take into account the load condition at all times. Moreover once the economic generation condition has been calculated, the turbine-governor must be controlled in such a way that this generation condition is maintained. In this chapter we shall discuss these two aspects.

Economic operation of power systemsIntroduction:

One of the earliest applications of on-line centralized control was to provide a central facility, to operate economically, several generating plants supplying the loads of the system. Modern integrated systems have different types of generating plants, such as coal fired thermal plants, hydel plants, nuclear plants, oil and natural gas units etc. The capital investment,

operation and maintenance costs are different for different types of plants.

The operation economics can again be subdivided into two parts.

i) Problem of *economic dispatch*, which deals with determining the power output of each plant to meetthe specified load, such that the overall fuel cost is minimized.

ii) Problem of *optimal power flow*, which deals with minimum – loss delivery, where in the power flow, is optimized to minimize losses in the system.

In this chapter we consider the problem of economic dispatch. During operation of the plant, a generator may be in one of the following states:

i) Base supply without regulation: the output is a constant.

ii) Base supply with regulation: output power is regulated based on system load.

iii) Automatic non-economic regulation: output level changes around a base setting as area control error changes.

iv) Automatic economic regulation: output level is adjusted, with the area load and area control error, while tracking an economic setting. Regardless of the units operating state, it has a contribution to the economic operation, even though its output is changed for different reasons.

The factors influencing the cost of generation are the generator efficiency, fuel cost and transmission losses. The most efficient generator may not give minimum cost, since it may be located in aplace where fuel cost is high. Further, if the plant is located far from the load centers, transmission losses may be high and running the plant may become uneconomical. The economic dispatch problem basically determines the generation of different plants to minimize total operating cost.

Modern generating plants like nuclear plants, geo-thermal plants etc, may require capital investment of millions of rupees. The economic dispatch is however determined in terms of fuel cost per unit power generated and does not include capital investment, maintenance, depreciation, start-up and shut downcosts etc.

Performance Curves Input-Output Curve

This is the fundamental curve for a thermal plant and is a plot of the input in British

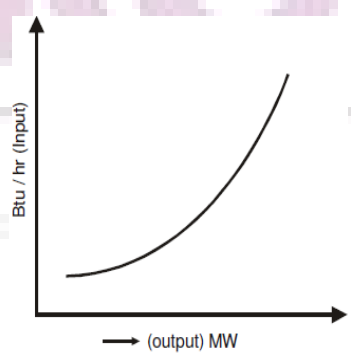


Fig 1: Input – output curve

Thermal units (Btu) per hour versus the power output of the plant in MW as shown in Fig1

Incremental Fuel Rate Curve

The incremental fuel rate is equal to a small change in input divided by the corresponding change in output.

$$\text{Incremental fuel rate} = \frac{\Delta Input}{\Delta Output}$$

The unit is again Btu / KWh. A plot of incremental fuel rate versus the output is shown in Fig 3

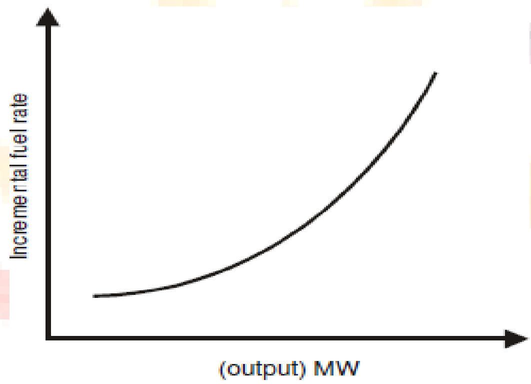


Fig 3: Incremental fuel rate curve

Incremental cost curve

The incremental cost is the product of incremental fuel rate and fuel cost (Rs / Btu) the curve isshown in Fig. 4. The unit of the incremental fuel cost is Rs / MWhr.

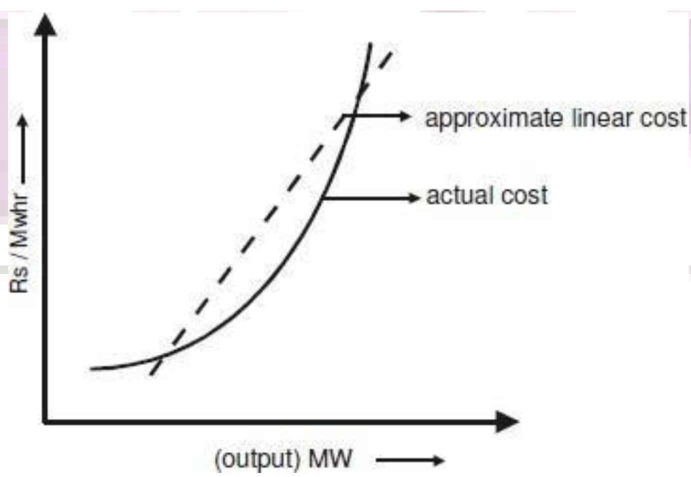


Fig 4: Incremental cost curve

In general, the fuel cost Fi for a plant, is approximated as a quadratic function of the generated

$$F_i = a_i + b_i P_{Gi} + c_i P_{Gi}^2 \ \ Rs / h$$

outputPGi.

The incremental fuel cost is given by

$$\frac{dF_i}{dP_{Gi}} = b_i + 2c_i P_{Gi} \quad Rs / MWh$$

The incremental fuel cost is a measure of how costly it will be produce an increment of power. The incremental production cost, is made up of incremental fuel cost plus the incremental cost of labor, water, maintenance etc. which can be taken to be some percentage of the incremental fuel cost, instead of resorting to a rigorous mathematical model. The cost curve can be approximated by a linear curve. While there is negligible operating cost for a hydel plant, there is a limitation on the power output possible. In any plant, all units normally operate between PGmin, the minimum loading limit, below which it is technically infeasible to operate a unit and PGmax, which is the maximum output limit. **Section I: Economic Operation of Power System**

- **Economic Distribution of Loads between the Units of a Plant**
- **Generating Limits**
- **Economic Sharing of Loads between Different Plants**

In an early attempt at economic operation it was decided to supply power from the most efficient plant at light load conditions. As the load increased, the power was supplied by this most efficient plant till the point of maximum efficiency of this plant was reached. With further increase in load, the next most efficient plant would supply power till its maximum efficiency is reached. In this way the power would be supplied by the most efficient to the least efficient plant to reach the peak demand. Unfortunately however, this method failed to minimize the total cost of electricity generation. We must therefore search for alternative method which takes into account the total cost generation of all the unitsof a plant that is supplying a load.

Economic Distribution of Loads between the Units of a Plant

To determine the economic distribution of a load amongst the different units of a plant, the variable operating costs of each unit must be expressed in terms of its power output. The fuel cost is the main cost in a thermal or nuclear unit. Then the fuel cost must be expressed in terms of the power output. Other costs, such as the operation and maintenance costs, can also be expressed in terms of the power output. Fixed costs, such as the capital cost, depreciation etc., are not included in the fuel cost.

The fuel requirement of each generator is given in terms of the Rupees/hour. Let us define the input cost of an unit- i, f_i in Rs/h and the power output of the unit as P_i. Then the input cost can be expressed in terms of the power output as

$$f_i = \frac{a_i}{2}P_i^2 + b_iP_i + c_i \quad \text{Rs/h} \qquad (1.1)$$

The operating cost given by the above quadratic equation is obtained by approximating the power in MW versus the cost in Rupees curve. The incremental operating cost of each unit is then computed as

$$\lambda_i = \frac{df_i}{dP_i} = a_iP_i + b_i \quad \text{Rs/MWhr} \qquad (1.2)$$

Let us now assume that only two units having different incremental costs supply a load. There will be a reduction in cost if some amount of load is transferred from the unit with higher incremental cost to the unit with lower incremental cost. In this fashion, the load is transferred from the less efficient unit to the more efficient unit thereby reducing the total operation cost. The load transfer will continue till the incremental costs of both the units are same. This will be optimum point of operation for both the units. The above principle can be extended to plants with a total of N number of units. The total fuel cost will then be the summation of the individual
fuel cost f_i , i = 1, ... , N of each unit, i.e.,

$$f_T = f_1 + f_2 + \cdots + f_N = \sum_{k=1}^{N} f_k \qquad (1.3)$$

Let us denote that the total power that the plant is required to supply by P_T , such that

$$P_T = P_1 + P_2 + \cdots + P_N = \sum_{k=1}^{N} P_k \quad (1.4)$$

Where P_1 , ... , P_N are the power supplied by the N different units.

The objective is minimizing f_T for a given P_T. This can be achieved when the total difference df_T becomes zero, i.e.

$$df_T = \frac{\partial f_T}{\partial P_1} dP_1 + \frac{\partial f_T}{\partial P_2} dP_2 + \cdots + \frac{\partial f_T}{\partial P_N} dP_N = 0 \quad (1.5)$$

Now since the power supplied is assumed to be constant we have

$$dP_T = dP_1 + dP_2 + \cdots + dP_N = 0 \quad (1.6)$$

Multiplying (1.6) by λ and subtracting from (1.5) we get

$$\left(\frac{\partial f_T}{\partial P_1} - \lambda\right) dP_1 + \left(\frac{\partial f_T}{\partial P_2} - \lambda\right) dP_2 + \cdots + \left(\frac{\partial f_T}{\partial P_N} - \lambda\right) dP_N = 0 \quad (1.7)$$

The equality in (5.7) is satisfied when each individual term given in brackets is zero. This gives us

$$\frac{\partial f_T}{\partial P_i} - \lambda = 0, \quad i = 1, \ldots, N \quad (1.8)$$

Also the partial derivative becomes a full derivative since only the term f_i of f_T varies with P_i, i = 1... N.

We then have

$$\lambda = \frac{df_1}{dP_i} = \frac{df_2}{dP_2} = \cdots = \frac{df_N}{dP_N} \quad (1.9)$$

Generating Limits

It is not always necessary that all the units of a plant are available to share a load. Some of the units may be taken off due to scheduled maintenance. Also it is not necessary that the less efficient units are switched off during off peak hours. There is a certain amount of shut down and start up costs associated with shutting down a unit during the off peak hours and servicing it back on-line during the peak hours. To complicate the problem further, it may take about eight hours or more to restore the boiler of a unit and synchronizing the unit with the bus. To meet the sudden change in the power demand, it may therefore be necessary to keep more units than it necessary to meet the load demand during that time. This safety margin in generation is called spinning reserve.

The optimal load dispatch problem must then incorporate this startup and shut down cost for without endangering the system security.

The power generation limit of each unit is then given by the inequality constraints

$$P_{min,i} \le P_i \le P_{max,i}, \quad i = 1, \ldots, N \qquad (1.10)$$

The maximum limit P_{Gmax} is the upper limit of power generation capacity of each unit. On the other hand, the lower limit P_{Gmin} pertains to the thermal consideration of operating a boiler in a thermal or nuclear generating station. An operational unit must produce a minimum amount of power such that the boiler thermal components are stabilized at the minimum design operating temperature.

Example 1

Consider two units of a plant that have fuel costs of

$f_1 = \frac{0.8}{2} P_1^2 + 10P_1 + 25$ Rs/h and $f_2 = \frac{0.7}{2} P_2^2 + 6P_2 + 20$ Rs/h

Then the incremental costs will be

$\lambda_1 = \frac{df_1}{dP_1} = 0.8P_1 + 10$ Rs/MWhr and $\lambda_2 = \frac{df_2}{dP_2} = 0.7P_2 + 6$ Rs/MWhr

If these two units together supply a total of 220 MW, then P_1 = 100 MW and P_2 = 120 MW will result in an incremental cost of

$\lambda_1 = 80 + 10 = 90$ Rs/MWhr and $\lambda_2 = 84 + 6 = 90$ Rs/MWhr

This implies that the incremental costs of both the units will be same, i.e., the cost of one extra MW ofgeneration will be Rs. 90/MWhr. Then we have

$f_1 = \frac{0.8}{2}100^2 + 10 \times 100 + 25 = 5025$ Rs/h and $f_2 = \frac{0.7}{2}120^2 + 6 \times 120 + 20 = 5780$ Rs/h

And total cost of generation is p

$f_T = f_1 + f_2 = 10{,}805$ Rs/h

Now assume that we operate instead with P 1 = 90 MW and P 2 = 130 MW. Then the individual cost ofeach unit will be

$f_1 = \frac{0.8}{2}90^2 + 10 \times 90 + 25 = 4{,}165$ Rs/h and $f_2 = \frac{0.7}{2}130^2 + 6 \times 130 + 20 = 6{,}175$ Rs/h

And total cost of generation is

$f_T = f_1 + f_2 = 10{,}880$ Rs./h

This implies that an additional cost of Rs. 75 is incurred for each hour of operation with this non-optimal setting. Similarly it can be shown that the load is shared equally by the two units, i.e. $P_1 = P_2 = 110$ MW, then the total cost is again 10,880 Rs/h.

Example 2

Let us consider a generating station that contains a total number of three generating units. The fuel costsof these units are given by

$$f_1 = \frac{0.8}{2}P_1^2 + 10P_1 + 25 \text{ Rs/h}$$

$$f_2 = \frac{0.7}{2}P_2^2 + 5P_2 + 20 \text{ Rs/h}$$

$$f_3 = \frac{0.95}{2}P_3^2 + 15P_3 + 35 \text{ Rs/h}$$

The generation limits of the units are

$$30 \text{ MW} \le P_1 \le 500 \text{ MW}$$

$$30 \text{ MW} \le P_2 \le 500 \text{ MW}$$

$$30 \text{ MW} \le P_3 \le 250 \text{ MW}$$

The total load that these units supply varies between 90 MW and 1250 MW. Assuming that all the three units are operational all the time, we have to compute the economic operating settings as the load changes.

The incremental costs of these units are

$$\frac{df_1}{dP_1} = 0.8P_1 + 10$$ Rs/MWhr

$$\frac{df_2}{dP_2} = 0.7P_2 + 5$$ Rs/MWhr

$$\frac{df_3}{dP_3} = 0.95P_3 + 15$$ Rs/MWhr

At the minimum load the incremental cost of the units are

$$\frac{df_1}{dP_1} = \frac{0.8}{2}30^2 + 10 = 34$$ Rs/MWhr

$$\frac{df_2}{dP_2} = \frac{0.7}{2}30^2 + 5 = 26$$ Rs/MWhr

$$\frac{df_3}{dP_3} = \frac{0.95}{2}30^2 + 15 = 43.5$$ Rs/MWhr

Since units 1 and 3 have higher incremental cost, they must therefore operate at 30 MW each. The incremental cost during this time will be due to unit-2 and will be equal to 26 Rs/MWhr. With the generation of units 1 and 3 remaining constant, the generation of unit-2 is increased till its incremental cost is equal to that of unit-1, i.e., 34 Rs/MWhr. This is achieved when P_2 is equal to 41.4286 MW, at a total power of 101.4286 MW.

An increase in the total load beyond 101.4286 MW is shared between units 1 and 2, till their incremental costs are equal to that of unit-3, i.e., 43.5 Rs/MWhr. This point is reached when P_1 = 41.875 MW and P_2

= 55 MW. The total load that can be supplied at that point is equal to 126.875. From this point onwards the load is shared between the three units in such a way that the incremental costs of all

$$P_1 + P_2 + P_3 = 200$$

$$0.8P_1 + 10 = 0.7P_2 + 5$$

$$0.7P_2 + 5 = 0.95P_3 + 15$$

the units are same. For example for a total load of 200 MW, from (5.4) and (5.9) we have

Solving the above three equations we get P_1 = 66.37 MW, P_2 = 80 MW and P_3 = 50.63 MW and an incremental cost (λ) of 63.1 Rs./MWhr. In a similar way the economic dispatch for various other load settings are computed. The load distribution and the incremental costs are listed in Table 5.1 for various total power conditions.

At a total load of 906.6964, unit-3 reaches its maximum load of 250 MW. From this point onwards then, the generation of this unit is kept fixed and the economic dispatch problem

$$P_1 + P_2 = 1000 - 250$$

$$0.8P_1 + 10 = 0.7P_2 + 5$$

involves the other two units. For example for a total load of 1000 MW, we get the following two equations from (1.4) and (1.9)

Solving which we get P_1 = 346.67 MW and P_2 = 403.33 MW and an incremental cost of 287.33 Rs/MWhr. Furthermore, unit-2 reaches its peak output at a total load of 1181.25. Therefore any further increase in the total load must be supplied by unit-1 and the incremental cost will only be borne by this unit. The power distribution curve is shown in Fig. 5.

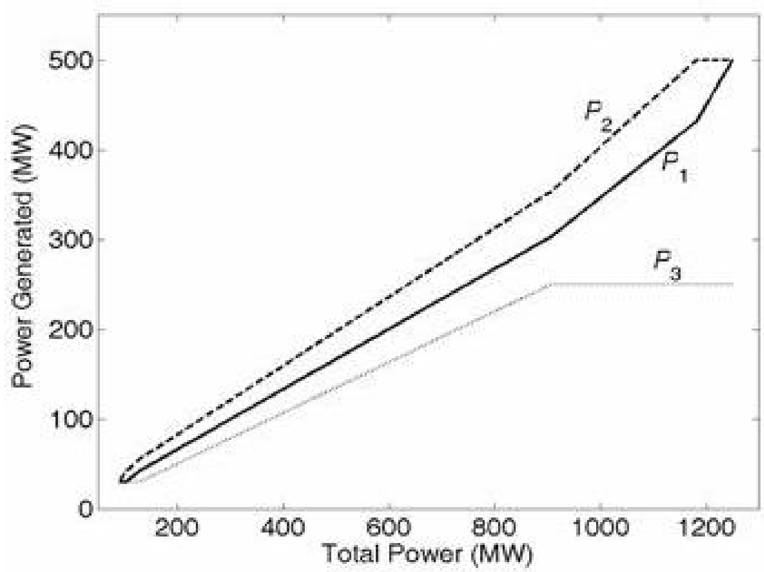


Fig5. Power distribution between the units of Example 2

Example 3

Consider two generating plant with same fuel cost and generation limits. These are given by

$$f_i = \frac{0.8}{2}P_i^2 + 10P_i + 25 \text{ Rs./h} \quad i = 1,2$$

$$100 \text{ MW} \le P_i \le 500 \text{ MW}, \quad i = 1,2$$

For a particular time of a year, the total load in a day varies as shown in Fig. 5.2. Also an additional cost of Rs. 5,000 is incurred by switching of a unit during the off peak hours and switching it back on during the during the peak hours. We have to determine whether it is

economical to have both units operational all the time.

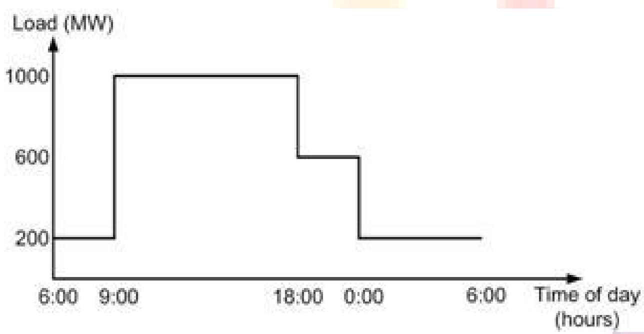


Fig.6. Hourly distribution of a load for the units of Example 2

Since both the units have identical fuel costs, we can switch of any one of the two units during the off peak hour. Therefore the cost of running one unit from midnight to 9 in the morning while delivering 200 MW is

$$\left(\frac{0.8}{2}200^2 + 10 \times 200 + 25\right) \times 9 = 162{,}225$$

Rs.

Adding the cost of Rs. 5,000 for decommissioning and commissioning the other unit after nine hours, thetotal cost becomes Rs. 167,225. 0

On the other hand, if both the units operate all through the off peak hours sharing power equally, then weget a total cost of

$$\left(\frac{0.8}{2}100^2 + 10 \times 100 + 25\right) \times 9 \times 2 = 90{,}450$$

Rs.

Which is significantly less that the cost of running one unit alone?

Table 1.1 Load distribution and incremental cost for the units of Example 1

P_T (MW)	P_1 (MW)	P_2 (MW)	P_3 (MW)	λ (Rs./MWh)
90	30	30	30	26
101.4286	30	41.4286	30	34
120	38.67	51.33	30	40.93
126.875	41.875	55	30	43.5
150	49.62	63.85	36.53	49.7
200	66.37	83	50.63	63.1
300	99.87	121.28	78.85	89.9
400	133.38	159.57	107.05	116.7
500	166.88	197.86	135.26	143.5
600	200.38	236.15	163.47	170.3
700	233.88	274.43	191.69	197.1
800	267.38	312.72	219.9	223.9
906.6964	303.125	353.5714	250	252.5
1000	346.67	403.33	250	287.33
1100	393.33	456.67	250	324.67
1181.25	431.25	500	250	355
1200	450	500	250	370
1250	500	500	250	410

DERIVATION OF TRANSMISSION LOSS FORMULA:

An accurate method of obtaining general loss coefficients has been presented by Kroc. Themethod is elaborate and a simpler approach is possible by making the following assumptions:

(i) All load currents have same phase angle with respect to a common reference

(ii) The ratio X / R is the same for all the network branches

Consider the simple case of two generating plants connected to an arbitrary number of loads through atransmission network as shown in Fig a

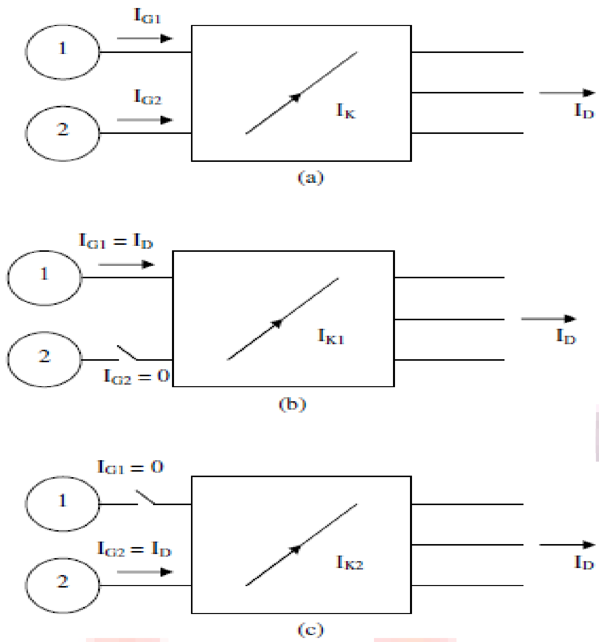


Fig.2.1 Two plants connected to a number of loads through a transmission network

Let‟s assume that the total load is supplied by only generator 1 as shown in Fig 8.9b. Let

$$N_{K1} = \frac{I_{K1}}{I_D}$$

the currentthrough a branch K in the network be IK1. We define

It is to be noted that IG1 = ID in this case. Similarly with only plant 2 supplying the loadCurrent ID, as shown in Fig 8.9c, we define

$$N_{K2} = \frac{I_{K2}}{I_D}$$

NK1 and NK2 are called current distribution factors and their values depend on the impedances of the lines and the network connection. They are independent of ID. When both generators are supplying the load, then by principle of superposition IK = NK1 IG1 + NK2 IG2

Where IG1, IG2 are the currents supplied by plants 1 and 2 respectively, to meet the demand ID. Because of the assumptions made, IK1 and ID have same phase angle, as do IK2 and ID. Therefore, the current distribution factors are real rather than complex. Let

$$I_{G1} = |I_{G1}| \angle \sigma_1 \text{ and } I_{G2} = |I_{G2}| \angle \sigma_2 .$$

Where σ_1 and σ_2 are phase angles of IG1 and IG2 with respect to a common reference. We can write

$$|I_K|^2 = \left(N_{K1}|I_{G1}|\cos\sigma_1 + N_{K2}|I_{G2}|\cos\sigma_2\right)^2 + \left(N_{K1}|I_{G1}|\sin\sigma_1 + N_{K2}|I_{G2}|\sin\sigma_2\right)^2$$

$$= \begin{array}{l} N_{K1}{}^2|I_{G1}|^2\left[\cos^2\sigma_1 + \sin^2\sigma_1\right] + N_{K2}{}^2|I_{G2}|^2\left[\cos^2\sigma_2 + \sin^2\sigma_2\right] \\ + 2\left[N_{K1}|I_{G1}|\cos\sigma_1 N_{K2}|I_{G2}|\cos\sigma_2 + N_{K1}|I_{G1}|\sin\sigma_1 N_{K2}|I_{G2}|\sin\sigma_2\right] \end{array}$$

$$= N_{K1}{}^2|I_{G1}|^2 + N_{K2}{}^2|I_{G2}|^2 + 2N_{K1}N_{K2}|I_{G1}||I_{G2}|\cos(\sigma_1 - \sigma_2)$$

Now $|I_{G1}| = \dfrac{P_{G1}}{\sqrt{3}|V_1|\cos\phi_1}$ and $|I_{G2}| = \dfrac{P_{G2}}{\sqrt{3}|V_2|\cos\phi_2}$

Where PG1, PG2 are three phase real power outputs of plant1 and plant 2; V1, V2 are the line to line bus voltages of the plants and Φ_1 and Φ_2 are the power factor angles.

The total transmission loss in the system is given by

$$P_L = \sum_K 3|I_K|^2 R_K$$

Where the summation is taken over all branches of the network and RK is the branchresistance. Substituting we get

$$P_L = \frac{P_{G1}^{2}}{|V_1|^2(\cos\phi_1)^2}\sum_K N_{K1}^{2}R_K + \frac{2P_{G1}P_{G2}\cos(\sigma_1-\sigma_2)}{|V_1||V_2|\cos\phi_1\cos\phi_2}\sum_K N_{K1}N_{K2}R_K + \frac{P_{G2}^{2}}{|V_2|^2(\cos\phi_2)^2}\sum_K N_{K2}^{2}R_K$$

$$P_L = P_{G1}^{2}B_{11} + 2P_{G1}P_{G2}B_{12} + P_{G2}^{2}B_{22}$$

where $$B_{11} = \frac{1}{|V_1|^2(\cos\phi_1)^2}\sum_K N_{K1}^{2}R_K$$

$$B_{12} = \frac{\cos(\sigma_1-\sigma_2)}{|V_1||V_2|\cos\phi_1\cos\phi_2}\sum_K N_{K1}N_{K2}R_K$$

$$B_{22} = \frac{1}{|V_2|^2(\cos\phi_2)^2}\sum_K N_{K2}^{2}R_K$$

The loss – coefficients are called the B – coefficients and have unit MW^{-1}

For a general system with n plants the transmission loss is expressed as

$$P_L = \frac{P_{G1}^{2}}{|V_1|^2(\cos\phi_1)^2}\sum_K N_{K1}^{2} + \dots\dots + \frac{P_{Gn}^{2}}{|V_n|^2(\cos\phi_n)^2}\sum_K N_{Kn}^{2}R_K$$
$$+2\sum_{\substack{p,q=1\\p\neq q}}^{n}\frac{P_{GP}P_{Gq}\cos(\sigma_p-\sigma_q)}{|V_p||V_q|\cos\phi_p\cos\phi_q}\sum_k N_{KP}N_{Kq}R_K$$

In a compact form

$$P_L = \sum_{p=1}^{n}\sum_{q=1}^{n}P_{Gp}B_{Pq}P_{Gq}$$

$$B_{Pq} = \frac{\cos(\sigma_p-\sigma_q)}{|V_p||V_q|\cos\phi_p\cos\phi_q}\sum_K N_{KP}N_{Kq}R_K$$

B – Coefficients can be treated as constants over the load cycle by computing them at average operating conditions, without significant loss of accuracy.

Economic Sharing of Loads between Different Plants

So far we have considered the economic operation of a single plant in which we have discussed how a particular amount of load is shared between the different units of a plant. In this problem we didnot have to consider the transmission line losses and assumed that the losses were a part of the load supplied. However if now consider how a load is distributed between the different plants that are joined by transmission lines, then the line losses have to be explicitly included in the economic dispatchproblem. In this section we shall discuss this problem.

When the transmission losses are included in the economic dispatch problem

$$P_T = P_1 + P_2 + \cdots + P_N - P_{LOSS} \quad (2.1)$$

$$0 = dP_1 + dP_2 + \cdots + dP_N - dP_{LOSS} \quad (2.2)$$

Where P_{LOSS} is the total line loss. Since P_T is assumed to be constant, we have

$$dP_{LOSS} = \frac{\partial P_{LOSS}}{\partial P_1} dP_1 + \frac{\partial P_{LOSS}}{\partial P_2} dP_2 + \cdots + \frac{\partial P_{LOSS}}{\partial P_N} dP_N \quad \text{................ (2.3}$$

In the above equation dP_{LOSS} includes the power loss due to every generator, i.e.,

Also minimum generation cost implies $df_T = 0$ as given in (1.5). Multiplying both (2.2) and (2.3) by λ andcombining we get

$$0 = \left(\lambda \frac{\partial P_{LOSS}}{\partial P_1} - \lambda\right) dP_1 + \left(\lambda \frac{\partial P_{LOSS}}{\partial P_2} - \lambda\right) dP_2 + \cdots + \left(\lambda \frac{\partial P_{LOSS}}{\partial P_N} - \lambda\right) dP_N \quad (2.4)$$

$$0 = \sum_{i=1}^{N} \left(\frac{\partial f_T}{\partial P_i} + \lambda \frac{\partial P_{LOSS}}{\partial P_i} - \lambda \right) dP_i \quad (2.5)$$

Adding (2.4) with (1.5) we obtain

$$\frac{\partial f_T}{\partial P_i} + \lambda \frac{\partial P_{LOSS}}{\partial P_i} - \lambda = 0, \quad i = 1, \ldots, N \quad (2.6)$$

The above equation satisfies when

$$\frac{\partial f_T}{\partial P_i} = \frac{df_T}{dP_i}, \quad i = 1, \ldots, N$$

Again since

$$\lambda = \frac{df_1}{dP_i} L_1 = \frac{df_2}{dP_2} L_2 = \cdots = \frac{df_N}{dP_N} L_N \quad (2.7)$$

From (2.6) we get

$$L_i = \frac{1}{1 - \partial P_{LOSS} / \partial P_i}, \quad i = 1, \ldots, N \tag{2.8}$$

Where L_i is called the **penalty factor** of load- i and is given by

$$P = [P_1 \quad P_2 \quad \cdots \quad P_N]^T$$

Consider an area with N number of units. The power generated are defined by the vector

$$P_{LOSS} = P^T BP \tag{2.9}$$

Then the transmission losses are expressed in

$$B = \begin{bmatrix} B_{11} & B_{12} & \cdots & B_{1N} \\ B_{12} & B_{22} & \cdots & B_{2N} \\ \vdots & \vdots & \ddots & \vdots \\ B_{1N} & B_{2N} & \cdots & B_{NN} \end{bmatrix}$$

general asWhere B is a symmetric matrix given by

The elements B_{ij} of the matrix B are called the **loss coefficients.** These coefficients are not constant but vary with plant loading. However for the simplified calculation of the penalty factor L_i these coefficients are often assumed to be constant.

When the incremental cost equations are linear, we can use analytical equations to find out the economic settings. However in practice, the incremental costs are given by nonlinear equations that may even contain nonlinearities. In that case iterative solutions are required to find the optimal generator settings.

UNIT-III
LOAD FREQUENCY CONTROL

OVERVIEW OF POWER SYSTEM CONTROL:

- Speed regulation of the governor
- Controls the boiler pressure, temperature & flows
- Speed regulation concerned with steam input to turbine
- Load is inversely proportional to speed
- Governor senses the speed & gives command signal
- Steam input changed relative to the load requirement.

Governor Control

Governor is A device used to control the speed of a prime mover. A governor protects the prime mover from overspeed and keeps the prime mover speed at or near the desired revolutions per minute. When a prime mover drives an alternator supplying electrical power at a given frequency, a governor must be used to hold the prime mover at a speed that will yield this frequency. An unloaded diesel engine will fly to pieces unless it is under governor control.

Load frequency control

1. Sense the bus bar frequency &power frequency
2. Difference fed to the integrator & to speed changer
3. Tie line frequency maintained constant

Economic dispatch control

1. When load distribution between a number of generator units considered optimum schedule affected when increase at one replaces a decreases at other.
2. Optimum use of generators at each station at various load is known as economic dispatch control.

Automatic voltage regulator

1. Regulate generator voltage and output power
2. Terminal voltage & reactive power is also met

System voltage control

Control the voltage within the tolerable limits. Devices used are

1. Static VAR compensator
2. Synchronous condenser
3. Tap changing transformer
4. Switches
5. Capacitor
6. Reactor

Security control

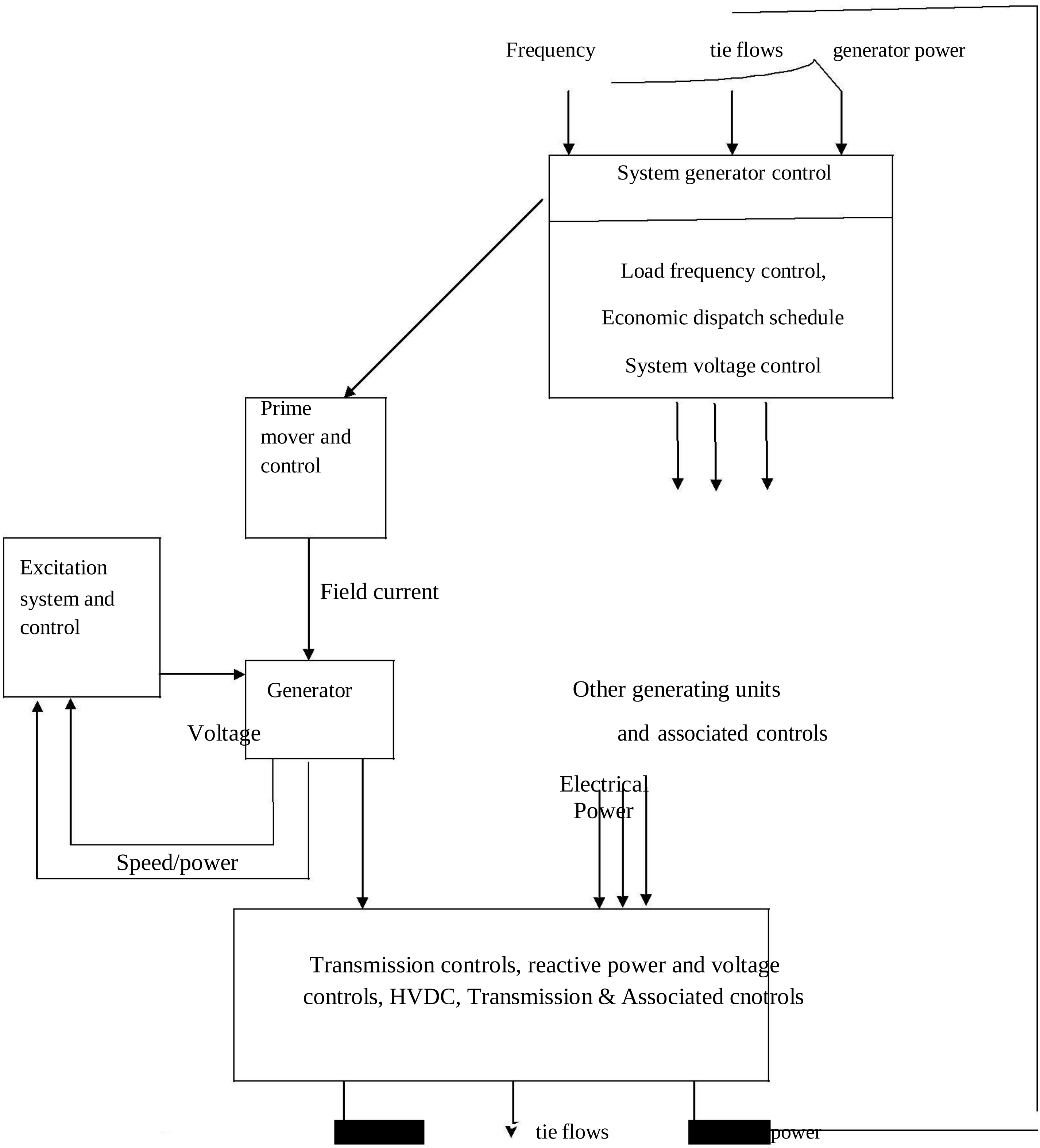
1. Monitoring & decision
2. Control

Monitoring & decision:

1. Condition of the system continuously observed in the control centers by relays.
2. If any continuous severe problem occurs system is in abnormal condition.

Control:

1. Proper commands are generated for correcting the abnormality in protecting the system
2. If no abnormality is observed, then the normal operation proceeds for next interval.
3. Central controls are used to monitor the interconnected areas
4. Inter connected areas can be tolerate larger load changes with smaller frequency deviations
5. Central control centre monitors information about frequency, generating unit outputs and tie line power flows to interconnected areas.
6. This information is used by automation load frequency control in order to maintain area frequency at its scheduled value.



Overview of system operation and control

Governor:

The power system is basically dependent upon the synchronous generator and its satisfactory performance. The important control loops in the system are:

(i) Frequency control, and

(ii) Automatic voltage control.

Frequency control is achieved through generator control mechanism. The governing systems for thermal and hydro generating plants are different in nature since, the inertia of water that flows into the turbine presents additional constrains which are not present with steam flow in a thermal plant. However, the basic principle is still the same; i.e. the speed of the shaft is sensed and compared with a reference, and the feedback signal is utilized to increase or decrease the power generated by controlling the inlet valve to turbine of steam or water

Speed Governing Mechanism

The speed governing mechanism includes the following parts.

Speed Governor:

It is an error sensing device in load frequency control. It includes all the elements that are directly responsive to speed and influence other elements of the system to initiate action.

Governor Controlled Valves:

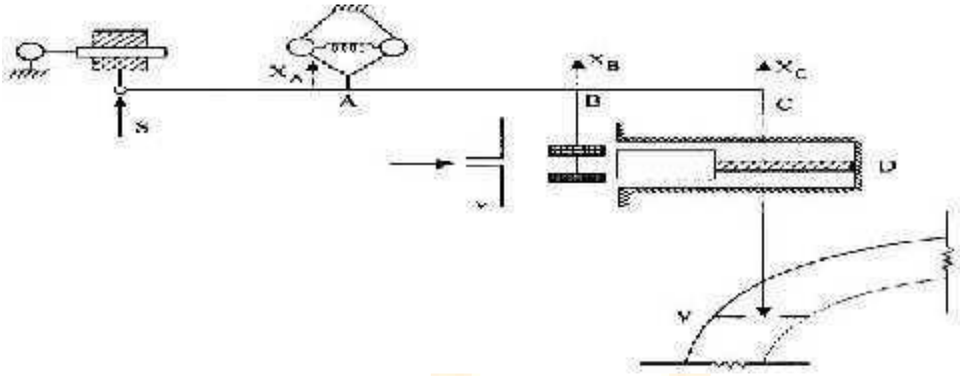
They control the input to the turbine and are actuated by the speed control mechanism.

Speed Control Mechanism:

It includes all equipment such as levers and linkages,servomotors, amplifying devices and relays that are placed between the speed governor and the governor controlled valves.

Speed Changer:

It enables the speed governor system to adjust the speed of the generator unit while in operation.



The pilot valve v operates to increase or decrease the opening of the steam inlet valve V. Let XB and Xc be the changes in the position of the pilot valve v and control valve V responding to a change in governor position. X_A due to load. When the pilot valve is closed XB= 0 and Xc == 0, (Le.,) the control valve is not completely closed, as the unit has to supply its no-load losses. Let be the no-load angular speed of the turbine. As load is applied, the speed falls and through the linkages the governor operates to move the piston P downwards along with points A and B. The pilot valve v admits soil under n and lifts it up so that the input is increased and speed rise. If the link B_e is removed then the pilot valve comes

to rest only when the speed returns to its original value. An "isochronous" characteristic will be obtained with such an arrangement where speed is restored to its preload.

With the link Be, the steady state is reached at a speed slightly lower than the no load speed giving a drooping characteristic for the governor system. A finite value of the steady state speed regulation is obtained with this arrangement. For a given speed changer position, the per unit steady state speed regulation is defined by

Steady state speed regulation = No-Nr/N

Where No = Speed at no - load

N r = Rated speed

N = Speed at rated load

P-F AND Q-V CONTROL STRUCTURE

Q-V CONTROL LOOP

The automatic voltage regulator circuit is used for voltage control .This bus bar voltage is stepped down using a potential transformer to a small value of voltage. This is sent to the rectifier circuit which converts Ac voltage into DC voltage and a filter circuit is used in this removes the harmonics .The voltage V, thus rectified is compared with a reference voltage v_{ref} in the comparator and a voltage error signal is generated .The amplified form of this voltage gives a condition for the generator is stepped up using a transformer and fed to the bus bar .Thus the voltage is regulated and controlled in the control loop circuit.

P-F CONTROL LOOP

Primary ALFC:

The circuit primarily controls the steam valve leading to the turbine .A speed senses the speed of the turbine. This is compared with a reference speed, governor whose main activity is to control the speed of the steam by closing and opening of the control valve ie if the differential speed is low ,then the control valve is opened to let out the steam at high speed, thereby increasing turbine’s speed and vice versa. The control of speed in turn controls the frequency.

Secondary ALFC:

The circuit involves a frequency sensor that senses the frequency of the bus bar and compare it with tie line power frequencies in the signal mixer.The output of this is an area control error which is sent to the speed changer through integrator .The speed changer gives the reference speed to the governor. Integral controller is used to reduce the steady state frequency change to zero. After this part of the circuit, is the introduction of the primary ALFC loop whose function has already been described.

SYSTEM LOAD VARIATION

The variation of load on power station with respect to time.

SYSTEM LOAD

From system‟s point of view, there are 5 broad categories of loads:

1. Domestic
2. Commercial
3. Industrial
4. Agriculture
5. Others - street lights, traction.

Domestic:

Lights, fans, domestic appliances like heaters, refrigerators, air conditioners, mixers, ovens, small motors etc.

Demand factor = 0.7 to 1.0; Diversity factor = 1.2 to 1.3; Load factor = 0.1 to 0.15

Commercial:

Lightings for shops, advertising hoardings, fans, AC etc.

Demand factor = 0.9 to 1.0; Diversity factor = 1.1 to 1.2; Load factor = 0.25 to 0.3

Industrial:

Small scale industries: 0-20kW

Medium scale industries: 20-

100kW Large scale industries:

above 100kW

Industrial loads need power over a longer period which remains fairly uniform throughout the day

For heavy industries:

Demand factor = 0.85 to 0.9; Load factor = 0.7 to 0.8

Agriculture:

Supplying water for irrigation using pumps driven by motors

Demand factor = 0.9 to 1; Diversity factor = 1.0 to 1.5; Load factor = 0.15 to 0.25

Other Loads:

Bulk supplies, street lights, traction, government loads which have their own peculiar characteristics

System load characteristics

- Connected load
- Maximum demand
- Average load
- Load factor
- Diversity factor
- Plant capacity factor
- Plant use factor

Plant Capacity Factor:

It is the ratio of actual energy produced to the maximum possible energy that could have been produced during a given period.

Plant Use Factor:

It is the ratio of kWh generated to the product of plant capacity and the number of hours for which the plant was in operation.

$$\text{Plant use factor} = \frac{\text{Station output}}{\text{Plant capacity} \times \text{Hours of use}}$$

Load duration curve

When an elements of a load curve are arranged in the order of descending magnitudes.

Load curves

The curve showing the variation of load on the power station with respect to time

Types of Load Curve:

- Daily load curve–Load variations during the whole day
- Monthly load curve–Load curve obtained from the daily load curve
- Yearly load curve-Load curve obtained from the monthly load curve

Base Load:

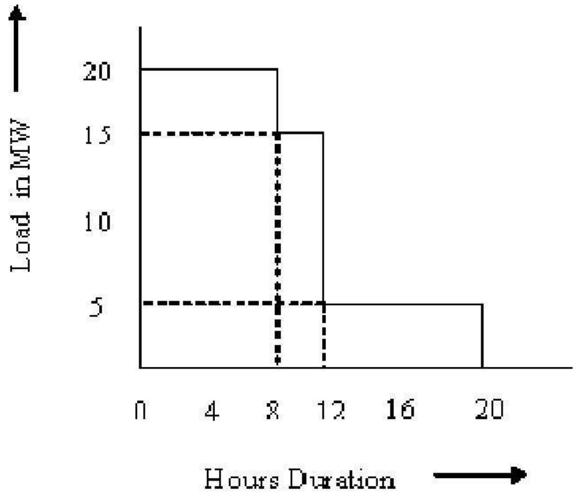
The unvarying load which occurs almost the whole day on the station

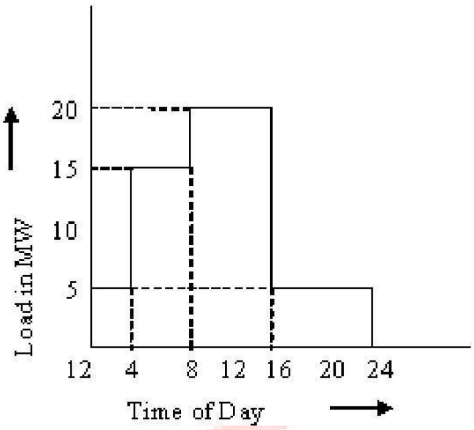
Peak Load:

The various peak demands so load of the station

Load duration curve:

When an elements of a load curve are arranged in the order of descending magnitudes.





The load duration curve gives the data in a more presentable form

- The area under the load duration curve is equal to that of the corresponding load curve
- The load duration curve can be extended to include any period of time

Load factor

The ratio of average load to the maximum demand during a given period is known as load factor.

Load factor = (average load)/ (maximum demand)

Diversity factor

The ratio of the sum of individual maximum demand on power station is known as diversity factor.

Diversity factor = (sum of individual maximum demand)/(maximum demand).

TECHNICAL TERMS

Control area: Most power systems normally control their generators inunison. The individual control loops have the same regulation parameters. The individual generator turbines tend to have the same response characteristics then it is possible to let the control loop in the whole system which then would be referred to as a control area.

Power Pool: An association of two or more interconnected electric systems havingan agreement to coordinate operations and planning for improved reliability and efficiencies.

Prime Mover: The engine, turbine, water wheel, or similar machine that drives anelectric generator; or, for reporting purposes, a device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cell(s)).

Pumped-Storage Hydroelectric Plant: A plant that usually generates electric energy duringpeak-load periods by using water previously pumped into an elevated storage reservoir during off-peak periods when excess generating capacity is available to do so. When additional generating capacity is needed, the water can be released from the reservoir through a conduit to turbine generators located in a power plant at a lower level.

Regulation: The governmental function of controlling or directing economic entitiesthrough the process of rulemaking and adjudication

Reserve Margin (Operating): The amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability.

Restructuring: The process of replacing a monopoly system of electric utilities with competing sellers, allowing individual retail customers to choose their electricity supplier but still receive delivery over the power lines of the local utility. It includes the reconfiguration of the vertically-integrated electric utility.

Retail Wheeling: The process of moving electric power from a point of generation across oneor more utility-owned transmission and distribution systems to a retail customer.

Revenue: The total amount of money received by a firm from sales of its products and/orservices, gains from the sales or exchange of assets, interest and dividends earned on investments, and other increases in the owner's equity except those arising from capital adjustments.

Scheduled Outage: The shutdown of a generating unit, transmission line, or otherfacility, for inspection or maintenance, in accordance with an advance schedule.

Real power: The real power in a power system is being controlled by controlling thedriving torque of the individual turbines of the system.

LOAD FREQUENCY CONTROL

The following basic requirements are to be fulfilled for successful operation of the system:

1. The generation must be adequate to meet all the load demand
2. The system frequency must be maintained within narrow and rigid limits.
3. The system voltage profile must be maintained within reasonable limits and
4. In case of interconnected operation, the tie line power flows must be maintained at the specified values.

When real power balance between generation and demand is achieved the frequency specification is automatically satisfied. Similarly, with a balance between reactive power generation and demand, voltage profile is also maintained within the prescribed limits. Under steady state conditions, the total real power generation in the system equals the total MW demand plus real power losses. Any difference is immediately indicated by a change in speed or frequency. Generators are fitted with speed governors which will have varying characteristics: different sensitivities, dead bands response times and droops. They adjust the input to match the demand within their limits. Any change in local demand within permissible limits is absorbed by generators in the system in a random fashion.

An independent aim of the automatic generation control is to reschedule the generation changes to preselected machines in the system after the governors have accommodated the load change in a random manner. Thus, additional or supplementary regulation devices are needed along with governors for proper regulation.

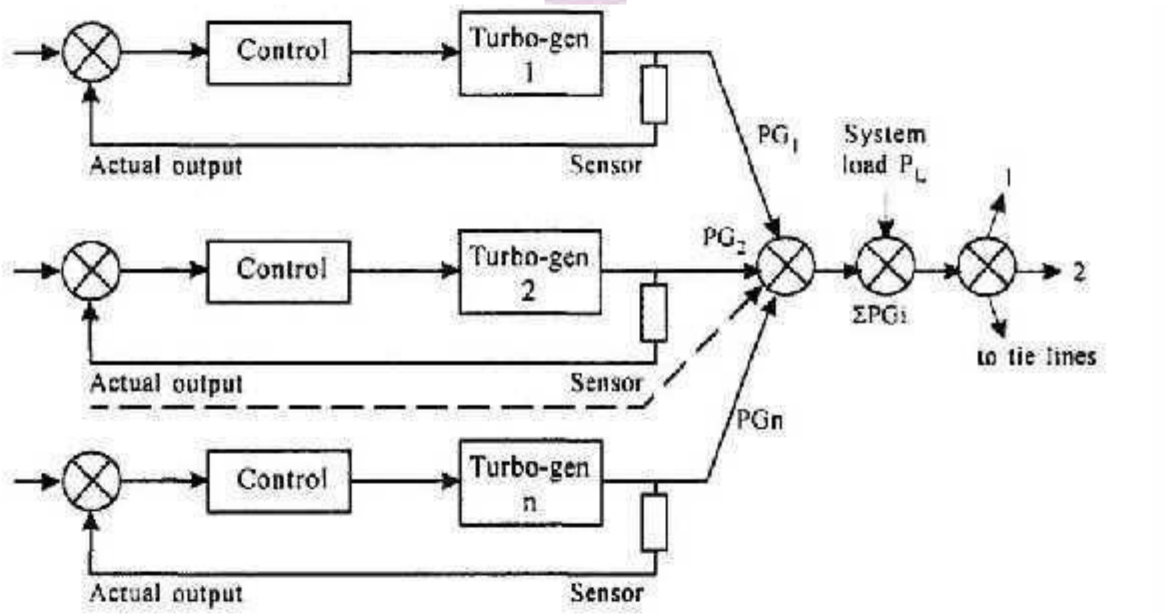
The control of generation in this manner is termed load-frequency control. For interconnected operation, the last of the four requirements mentioned earlier is fulfilled by deriving an error signal from the deviations in the specified tie-line power flows to the neighboring utilities and adding this signal to the control signal of the load-frequency control system. Should the generation be not adequate to balance the load demand, it is imperative that one of the following alternatives be considered for keeping the system in operatingcondition:

I. Starting fast peaking units.

2. Load shedding for unimportant loads, and

3. Generation rescheduling.

It is apparent from the above that since the voltage specifications are not stringent. Load frequency control is by far the most important in power system control.



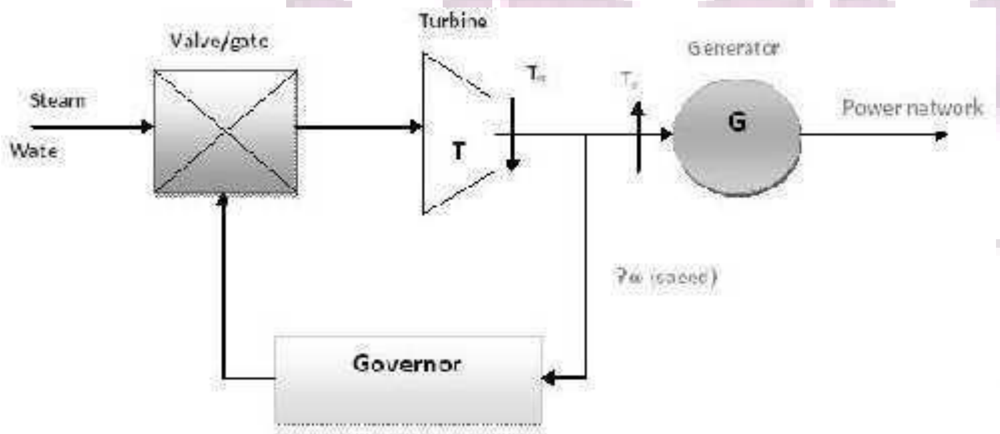
The block schematic for Load frequency control

In order to understand the mechanism of frequency control, consider a small step increase in load. The initial distribution of the load increment is determined by the system impedance; and the instantaneous relative generator rotor positions. The energy required to supply the load increment is drawn from the kinetic energy of the rotating machines. As a result, the system frequency drops. The distribution of load during this period among the various machines is determined by the inertias of the rotors of the generators partaking in the process. This problem is studied in stability analysis of the system.

After the speed or frequency fall due to reduction in stored energy in the rotors has taken place, the drop is sensed by the governors and they divide the load increment between the machines as determined by the droops of the respective governor characteristics. Subsequently, secondary control restores the system frequency to its normal value by readjusting the governor characteristics.

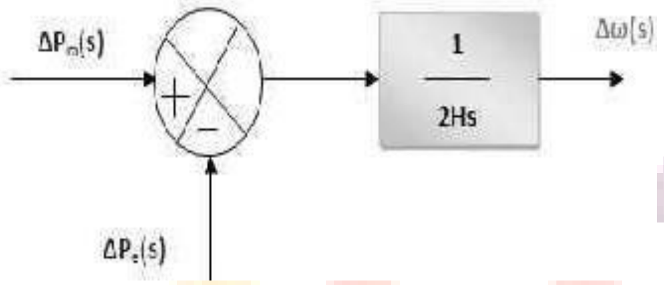
AUTOMATIC LOAD FREQUENCY CONTROL

The ALFC is to control the frequency deviation by maintaining the real power balance in the system. The main functions of the ALFC are to i) to maintain the steady frequency; ii) control the tie-line flows; and iii) distribute the load among the participating generating units. The control (input) signals are the tie-line deviation ΔP_{tie} (measured from the tie- line flows), and the frequency deviation Δf (obtained by measuring the angle deviation $\Delta\delta$). These error signals Δf and ΔP_{tie} are amplified, mixed and transformed to a real power signal, which then controls the valve position. Depending on the valve position, the turbine (prime mover) changes its output power to
establish the real power balance. The complete control schematic is shown in Fig3.3



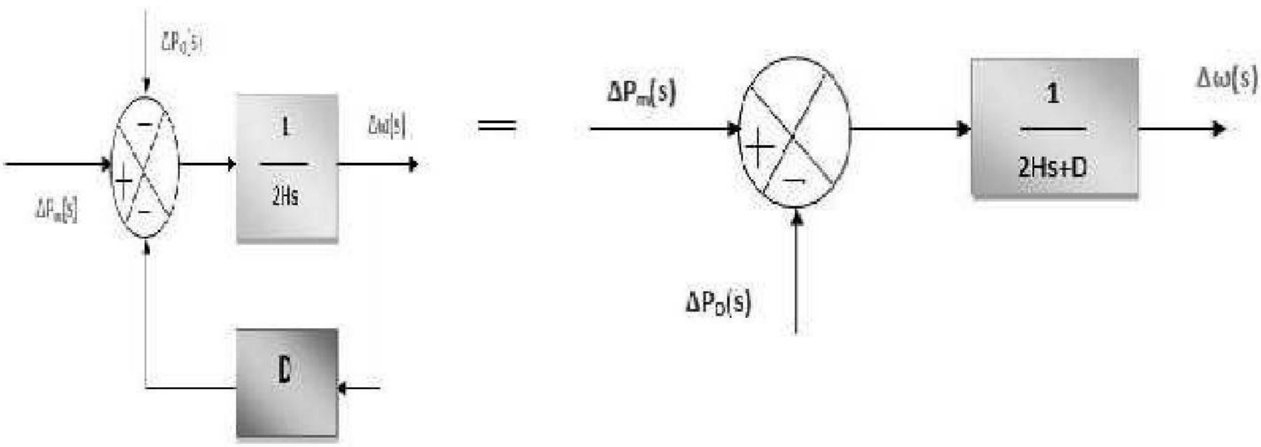
The Schematic representation of ALFC system

For the analysis, the models for each of the blocks in Fig2 are required. The generator and the electrical load constitute the power system. The valve and the hydraulic amplifier represent the speed governing system.Using the swing equation, theegenerator can b Using the swing equation, the generator can be modeled by



Block Diagram Representation Of The Generator

The load on the system is composite consisting of a frequency independent component and a frequency dependent component. The load can be written as Pe = P0 + Pf



Block Diagram Representation Of The Generator And Load

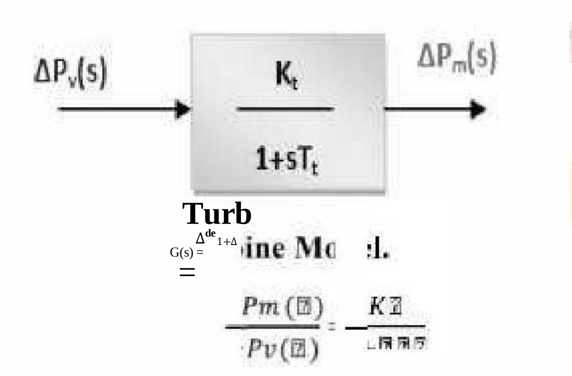
where, Pe is the change in the load;
P0 is the frequency independent load component; Pf is the frequency dependent

load component.

Pf = D where, D is called frequency characteristic of the load (also called as damping constant) expressed in percent change in load for 1% change in frequency. If D=1.5%, then a

1% change in frequency causes 1.5% change in load. The combined generator and the load (constituting the power system) can then be represented as shown in Fig3.5

The turbine can be modeled as a first order lag as shown in the Fig2.6



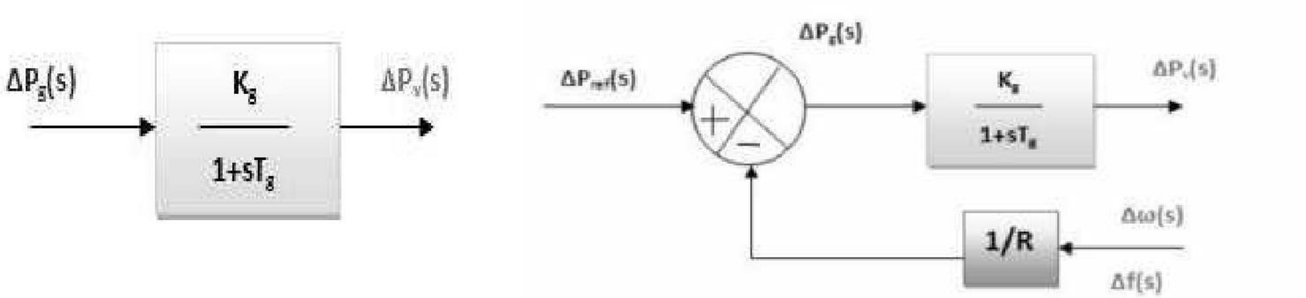
Gt(s) is the TF of the turbine; ΔPV(s) is the change in valve output (due toaction). Pm(s) is the change in the turbine output

The governor can similarly modeled as shown inig2F.7. The output of the governor is by

Where ΔP_{ref} is the reference set power, and Δw/R is the power given by governor speed characteristic. The hydraulic amplifier transforms this signal Pg into valve/gate position corresponding to a power PV.

Thus

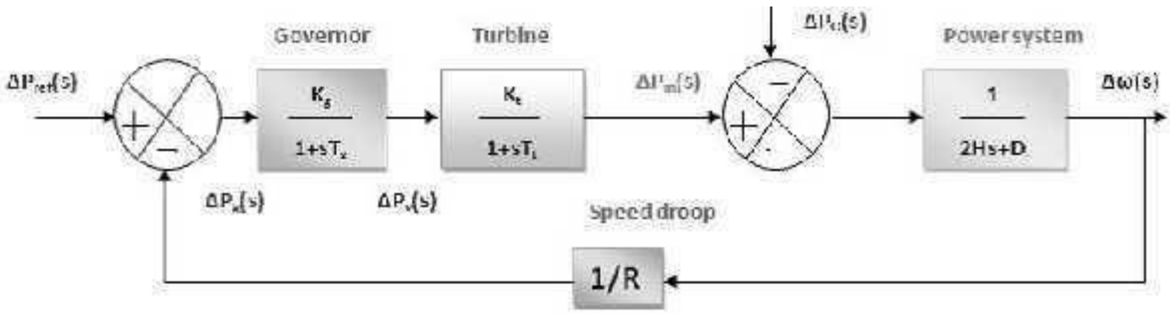
PV(s) = (Kg/ (1+sTg)) _Pg(s).



Block Diagram Representation Of The Governor

LFC control of single area and derive the steady state frequency error.

All the individual blocks can now be connected to represent the complete ALFC loop as



Block diagram representation of the ALFCStatic

Power Generation

We have

$\Delta P_G(s) = k_G k_t / (1+sT_G)(1+sT_t)[\Delta P_c(s) - 1/R \Delta F(s)]$

The generator is synchronized to a network of very large size. So, the speed or frequency will be essentially independent of any changes in a power output of the generator

ie, $\Delta F(s) = 0$

Therefore $\Delta P_G(s) = k_G k_t / (1+sT_g)(1+sT_t) * \Delta P_c(s)$

Steady state response

(i) Controlled case:

To find the resulting steady change in the generator output:

Let us assume that we made a step change of the magnitude ΔP_C of the speed changer For step change, $\Delta P_C(s) = \Delta P_C/s$

$\Delta P_G(s) = k_G k_t/(1+sT_g)(1+sT_t).\ \Delta P_C(s)/s$

$s\Delta P_G(s) = k_G k_t/(1+sT_g)(1+sT_t).\ \Delta P_C(s)$

Applying final value theorem,

$\Delta P_{G\,(stat)} = \Delta$

(ii) Uncontrolled case

Let us assume that the load suddenly increases by small amount ΔP_D. Consider there is no external work and the generator is delivering a power to a single load.

Since $\Delta P_C=0$, kgkt=1

It has been shown that the load frequency control system posses inherently steady state error for a step input. Applying the usual procedure, the dynamic response of the control loop can be evaluated so that the initial response also can be seen for any overshoot.

For this purpose considering the relatively larger time constant of the power system the governor action can be neglected, treating it as instantaneous action. Further the turbine generator dynamics also may be neglected at the first instant to derive a simple expression for the time response

$\Delta P_G(s) = 1/(1+sT_G)(1+sT_t)\ [-\Delta F(s)/R]$ For a step change $\Delta F(s) = \Delta f/s$ Therefore

$\Delta P_G(s) = 1/(1+sT_G)(1+sT_t)[-\Delta F/sR]$

$\Delta f/\Delta P_{G\,(stat)} = -R$ Hz/MW

Steady State Performance of the ALFC Loop

In the steady state, the ALFC is in 'open' state, and the output is obtained by substituting s→0 in the TF.

With s→0, Gg(s) and Gt(s) become unity, then,(note that ΔPm =ΔPT = PG =ΔPe = ΔPD; That is turbine output = generator/electrical output = load demand)

ΔPm = ΔPref – (1/R) Δω or ΔPm = ΔPref – (1/R)Δf

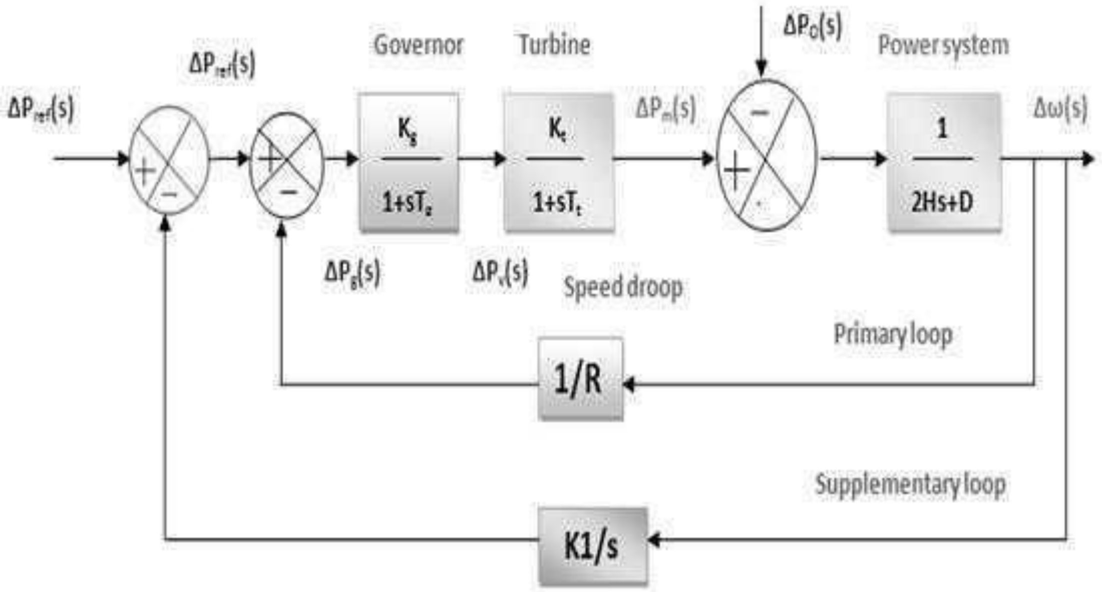
When the generator is connected to infinite bus (Δf = 0, and ΔV = 0), then ΔPm = ΔPref .

If the network is finite, for a fixed speed changer setting (ΔPref = 0), then

ΔPm = (1/R)Δf orΔf=RPm.

Concept of AGC (Supplementary ALFC Loop)

The ALFC loop shown in is called the primary ALFC loop. It achieves the primary goal of real power balance by adjusting the turbine output ΔPm to match the change in load demand ΔPD. All the participating generating units contribute to the change in generation. But a change in load results in a steady state frequency deviation Δf. The restoration of the frequency to the nominal value requires an additional controlloop called the supplementary loop. This objective is met by using integral controller which makes the frequency deviation zero. The ALFC with the supplementary loop is generally called the AGC. The block diagram of an AGC is shown in Fig3.9. The main objectives of AGC a r e i) to regulate t h e frequency (using b o t h primary a n d supplementary controls); ii) and to maintain the scheduled tie-line flows. A secondary objective of the AGC is to distribute the required change in generation among the connected generating units economically (to obtain least operating costs).



Block diagram representation of the AGC

AGC in a Single Area System

In a single area system, there is no tie-line schedule to be maintained. Thus the function of the AGC is only to bring the frequency to the nominal value. This will be achieved using the supplementary loop (as shown in Fig.3.9) which uses the integral controller to change the reference power setting so as to change the speed set point.

The integral controller gain KI n e ed s to be adjusted for satisfactory response (in terms of overshoot, settling time) of the system. Although each generator will be having a separate speed governor, all the generators in the control area are replaced by a single equivalent generator, and the ALFC for the area corresponds to this equivalent generator.

Dynamic Response of the One-Area System

`Now we are going to study the effect of a disturbance in the system derived above. Both loss of generation and loss of load can be simulated by imposing a positive or negative step input on the variable P_{load}. A change of the set value of the system frequency f_0 is not considered as this is not meaningful in real power systems. From the block diagram in Figure 3.9 it is straightforward to derive the transfer function between

ΔP_{load} and Δf $(\Delta P^{set}_{ref} - 0)$:

$$\Delta f(s) = \frac{1 + sT_t}{\frac{1}{S} + \frac{1}{D_l}(1+sT_t) + (\frac{2W_0}{f_0} + \frac{2HS_B}{f_0})s(1+sT_t)} \Delta P_{load}(s)$$

The step response for

$$\Delta P_{load}(s) = \frac{\Delta P_{load}}{s}$$

$$\Delta f_\infty = \lim_{s \to 0}(s \cdot \Delta f(s)) = \frac{\Delta P_{load}}{\frac{1}{S} + \frac{1}{D_l}} = \frac{\Delta P_{load}}{\frac{1}{D_R}} = -\Delta P_{load} \cdot D_R$$

with

$$\frac{1}{D_R} = \frac{1}{S} + \frac{1}{D_l}$$

In order to calculate an equivalent time constant Teq, Tt is put to 0. This can be done since for realistic systems the turbine controller time constant Tt is much smaller than the time constant

AGC IN A MULTI AREA SYSTEM

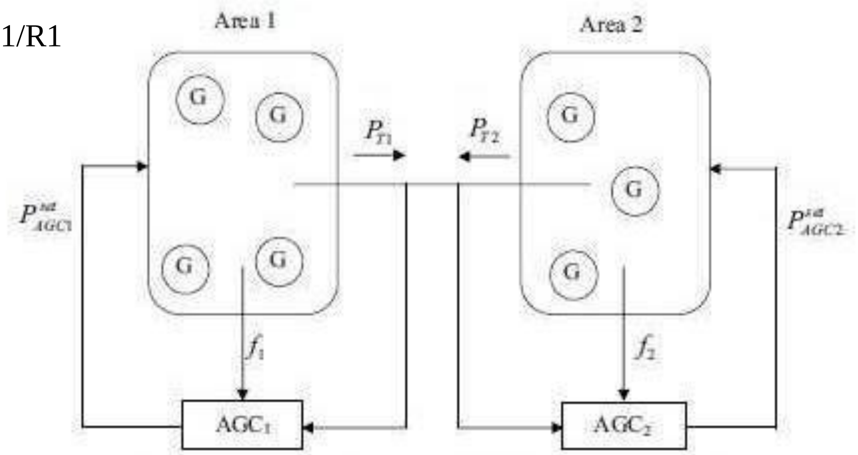
In an interconnected (multi area) system, there will be one ALFC loop for each control area (located at the ECC of that area). They are combined as shown in Fig2.10 for the interconnected system operation. For a total change in load of ΔPD, the steady state Consider a two area system as depicted in Figure 3.10. The two secondary frequency controllers, AGC1 and AGC2, will adjust the power reference values of the generators participating in the AGC. In an N-area system, there are N controllers AGCi, one for each area

A block diagram of such a controller is given in Figure 4.2. A common way is to implement this as a proportional-integral (PI) controller:

Deviation in frequency in the two areas is given by

$\Delta f = \Delta\omega_1 = \Delta\omega_2$

$\beta1 = D1+1/R1$

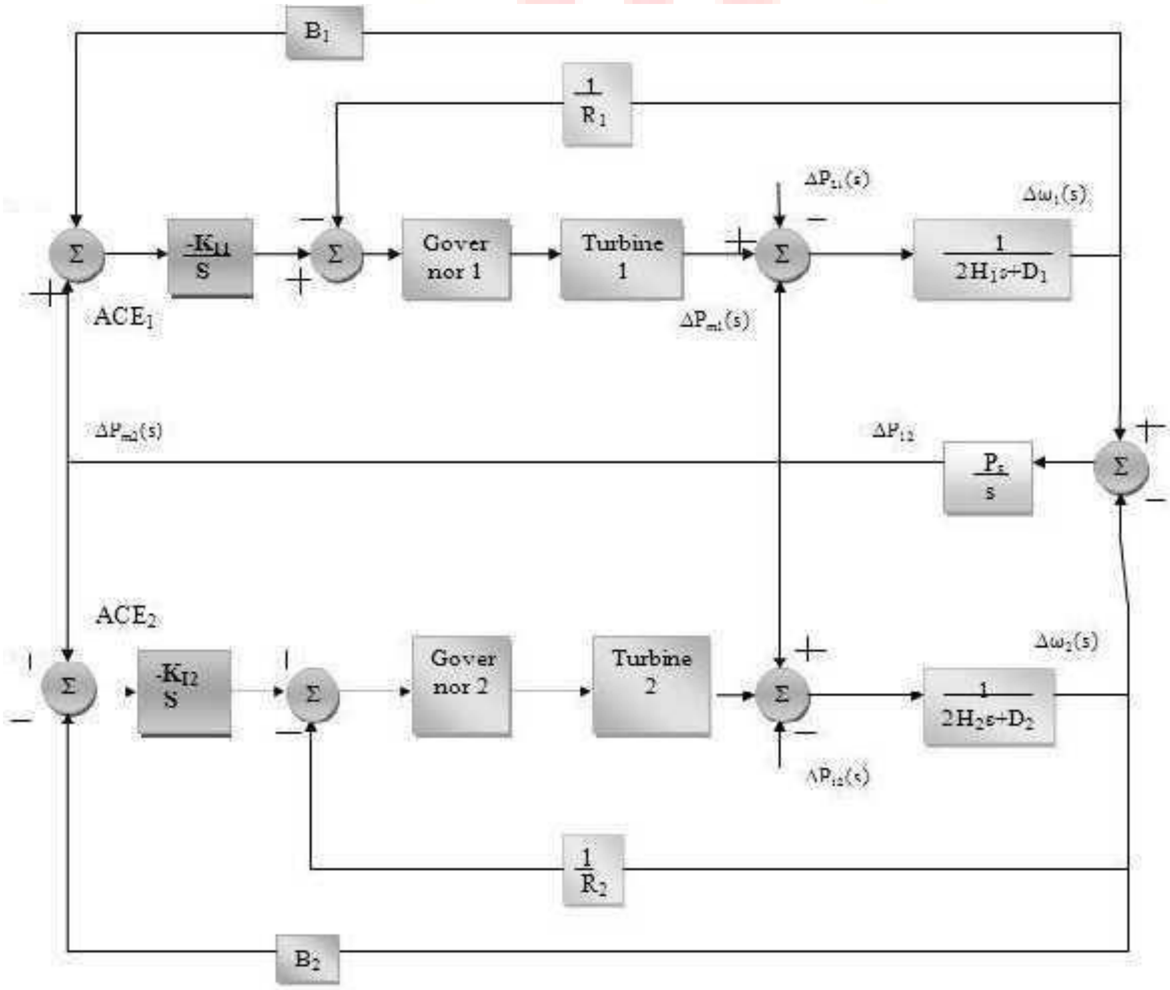


P_{T1} = Tie line power for Area 1 = $\sum_{j \in \Omega_1} P^j_{T1}$ = Sum over all tie lines

Substituting these equations, yields

$(1/R1+ D1)\ \Delta f = -\Delta P12 - \Delta Pm$

$(1/R2+ D2)\ \Delta f = -\Delta P12 - \Delta Pm$



A G C for a multi-area operation

DYNAMIC RESPONSE OF LOAD FREQUENCY CONTROLLOOPS

It has been shown that the load frequency control system posses inherently steady state error for a step input. Applying the usual procedure, the dynamic response of the control loop can be evaluated so that the initial response also can be seen for any overshoot.

For this purpose considering the relatively larger time constant of the power system the governor action can be neglected, treating it as instantaneous action. Further the turbine generator dynamics also may be neglected at the first instant to derive a simple expression for the time response.

It has been proved that

$$\Delta F(S) = -\frac{G_P}{1+\frac{1}{R}G_S G_{TG} G_P}\Delta P_D(S)$$

For a step load change of magnitude k

$$\Delta P_D(S) = \frac{-k}{S}$$

Neglecting the governor action and turbine dynamics

$$\Delta F(S) = -\frac{G_P}{1+\frac{1}{R}G_P}\frac{k}{S}$$

$$= -\left(\frac{K_P}{1+ST_P}\right)\frac{1}{\left(1+\frac{1}{R}\frac{K_P}{1+ST_P}\right)}\frac{k}{S}$$

Applying partial fractions

$$\Delta F(S) = -\frac{K_P k}{T_P}\left(\frac{1}{S\left[S+\left(\frac{1}{T_P}+\frac{K_P}{RT_P}\right)\right]}\right) - \frac{K_P k}{T_P}\left[\frac{1}{S\left[S-\frac{1}{T_P}+\frac{K_P}{RT_P}\right]}\right]$$

INTERCONNECTED OPERATION

Power systems are interconnected for economy and continuity of power supply. For the interconnected operation incremental efficiencies, fuel costs. Water availability, generation limits, tie line capacities, spinning reserve allocation and area commitment's are important considerations in preparing load dispatch schedules.

Flat Frequency Control of Inter- connected Stations

Consider two generating stations connected by a tie line as in Fig3.12.For a load increment on station B, the kinetic energy of the generators reduces to absorb the same. Generation increases in both the stations A and B, and frequency will be less than normal at the end of the governor response period. The load increment will be supplied partly by A and partly by B. The tie line power flow will change thereby. If a frequency controller is placed at B, then it will shift the governor characteristic at B parallel to itself as shown in Fig and the frequency will be restored to its normal value fs' reducing the change in generation in A to zero.

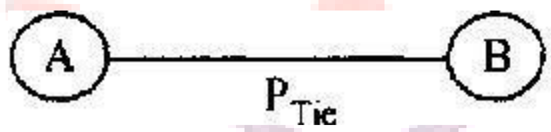


Figure 3.12.Two area with tie line power

Assumption in Analysis:

The following assumptions are made in the analysis of the two area system:

1. The overall governing characteristic of the operating units in any area can be represented by
   a linear curve of frequency versus generation.
2. The governors in both the areas start acting simultaneously to changes in their respective areas.
3. Supplementary control devices act after the initial governor response is over

The following time instants are defined to explain the control sequence:

To=is the instant when both the areas are operating at the scheduled frequency and Tie=line interchange and load change takes place.

tl = the instant when governor action is initiated at both A and B.

t2 =the instant when governor action ceases.

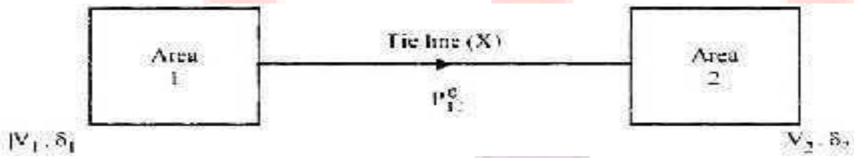
t3 =the instant when regulator action begins.

t4 = the instant when regulator action ceases.

`While the initial governor response is the same as for the previous case, the action of the controller in B will force the generation in area B to absorb the load increment in area A. When the controller begins to act at t3, the governor characteristic is shifted parallel to itself in B till the entire load increment in A is absorbed by B and the frequency is restored to normal. Thus, in this case while the frequency is regulate on one hand, the tie-line schedule is not maintained on the other hand.

If area B, which is in charge of frequency regulation, is much larger than A, then load changes in A will not appreciably affect the frequency of the system. Consequently, it can be said that flat frequency control is useful only when a small system is' connected to a much larger system.

3.10.4. Two Area Systems - Tie-Line Power Model:



Two Area Systems - Tie-Line Power

Consider two inter connected areas as shown in figure operating at the same frequency fl while a power Power flow from area I to area 2

let V1 and V 2 be the voltage magnitudes

δ 1, δ 2 voltage phase angles at the two ends of the tie-line While P flows from area I to area 2 then,

$$P_{12}^0 = \frac{|V_1||V_2|}{X}\sin(\delta_1^0 - \delta_2^0)$$

Where X is the reactance of the line. If the angles change by f1o1, and f102 due to load changes in areas I and 2 respectively. Then, the tie-line power changes by

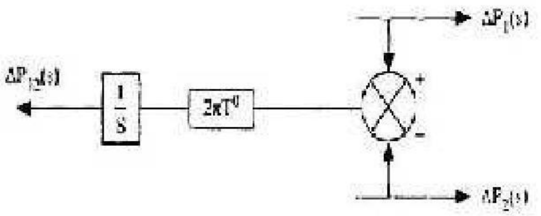
$$\Delta P_2 = \frac{|V_1^0||V_2^0|}{X}\cos(\delta_1^0 - \delta_2^0)(\Delta P_1 \quad \Delta P_2)$$

$$\frac{\Delta P_{12}}{\Delta\delta_1 - \Delta\delta_2} = \frac{\Delta P_{12}}{\Delta\delta} \text{ MW/radian}$$

$$\Delta P_{12} = T^0(\Delta\delta_1^0 - \Delta\delta_2^0)$$

$$\Delta\omega = \frac{d}{dt}\Delta\delta$$

Block diagram for tie-line power



$$\frac{P_{r1}}{P_{r2}} = a_{12}$$

$$\Delta P_{21}(S) = \frac{2\pi T_{21}^0}{S}\left[\Delta F_2(S) - \Delta F_1(S)\right]$$

$$\frac{2\pi T_{21}^0 \cdot a_{12}}{S}\left[\Delta F_1(S) - \Delta F_2(S)\right]$$

Dynamic Response:

Let us now turn our attention during the transient period for the sake of simplicity. We shall assume the two areas to be identical .Further we shall be neglecting the time constants of generators and turbines as they are negligible as compared to the time constants of power systems. The equation may be derived for both controlled and uncontrolled cases. There are four equations with four variables, to be determined for given PDl and PD2. The dynamic response can be obtained; even though it is a little bit involved. For simplicity assume that the two areas are equal. Neglect the governor and turbine dynamics, which means that the dynamics of the system under study is much slower than the fast acting turbine-governor system in a relative sense. Also assume that the load does not change with frequency (D, = D2 = D = 0).

$$\left\{-\frac{1}{R_1}\Delta F_1(S)\left[\frac{K_S}{1+ST_{S1}}\right]\left[\frac{K_{TG1}}{1+ST_{TG2}}\right] - \Delta P_{D1}(S) - \Delta P_{12}(S)\right\}\frac{K_{P1}}{1+ST_{P1}} = \Delta F_1(S)$$

$$\left\{-\frac{1}{R_2}\Delta F_2(S)\left[\frac{K_{S2}}{1-ST_{S2}}\right]\left[\frac{K_{TG2}}{1+ST_{TG2}}\right] - \Delta P_{D2}(S) - \Delta P_{21}(S)\right\}\frac{K_{P2}}{1+ST_{P2}} = \Delta F_2(S)$$

$$\Delta P_{12}(S) = \frac{2\pi T^0}{S}\left[\Delta F_1(S) - \Delta F_2(S)\right]$$

$$\Delta P_{21}(S) = -\Delta P_{21}(S)$$

We obtain under these assumptions the following relations

$$\Delta P_{12}(S) = \frac{\left[\Delta P_{D2}(S) - \Delta P_{D1}(S)\right]\frac{f^0}{2SH}}{\frac{S}{2\pi T^0} + \frac{2f^0}{2\pi T^0} + \frac{Sf^0}{2\pi R T^0 2SH}}$$

$$= \frac{\left[\left[\Delta P_{D2}(S) - \Delta P_{D1}(S)\right]\frac{\pi f^0 T^0}{SH}\right]}{S + \frac{2f^0 \pi T^0}{SH} + \frac{f^0}{2RH}}$$

$$= \frac{\pi f^0 T^0}{H} \frac{\left[\Delta P_{D2}(S) - \Delta P_{D1}(S)\right]}{S^2 + \left(\frac{f^0}{2RH}\right)S + \left(\frac{2f^0 \pi T^0}{H}\right)}$$

The denominator is of the form

$$\left(S^2 + 2KS + \omega^2\right) = (S + K)^2 + (\omega^2 - K^2)$$

where $K = \frac{f^0}{4RH}$ and $\omega = \sqrt{\frac{2\pi f^0 T^0}{H}}$

setting $\sqrt{\omega^2 - K^2}$ as ω_0.

$$\omega_0 = \sqrt{\frac{2\pi T^0 f^0}{H} - \left(\frac{f^0}{4RH}\right)^2}$$

Note that both K and ro2 are positive. From the roots of the characteristic equation we notice tha e system is stable and damped. The frequency of the damped oscillations is given by Since Hand f_0 are constant, the frequency of oscillations depends upon the regulation parameter R. Low R gives high K and high damping and vice versa .We thus conclude from the preceding analysis that the two area system, just as in the case of a single area system in the uncontrolled mode, has a steady state error but to a lesser extent and the tie line power deviation and frequency deviation exhibit oscillations that are damped out later.

UNIT-IV
POWER SYSTEM STBILITY

The bus impedance matrix Z_{BUS} can be determined for a $'N-bus'$ power system by using the algorithm described as below. By using this algorithm Z_{BUS} can also be modified. The existing Z_{BUS} can be modified either by addition of a new bus or a new link. A new bus can be added to the system by connecting it to either reference bus through a link or an existing bus through a link. A new link can be added to the system by connecting it between reference bus and existing bus or between two existing bus. Thus Z_{BUS} can be modified in four ways.

The block diagram of $'N-bus'$ power system is shown in Fig.-2.1.

Where,

$'V_i'$ - Voltages at the $'i^{th}'$ bus

$'I_i'$ - Currents injected at the $'i^{th}'$ bus

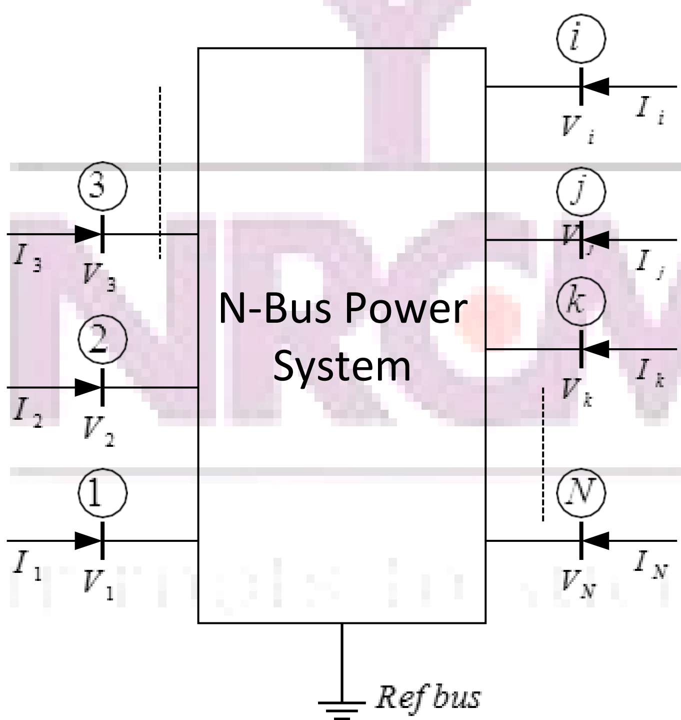


FIG.-2.1 BLOCK DIAGRAM OF N-BUS POWER SYSTEM

The original bus impedance matrix Z_{BUS} can be given by (2.1).

$$Z_{BUS} = \begin{bmatrix} Z_{11} & Z_{12} & \cdots & Z_{1N} \\ Z_{21} & Z_{22} & \cdots & Z_{2N} \\ \vdots & \vdots & \vdots & \vdots \\ Z_{N1} & Z_{N2} & \cdots & Z_{NN} \end{bmatrix} \quad (2.1)$$

The system voltage can be given by (2.2)

$$V_{BUS} = Z_{BUS} I_{BUS} \quad (2.2)$$

Where

$$V_{BUS} = \begin{bmatrix} V_1 \\ V_2 \\ \vdots \\ V_N \end{bmatrix} \quad (2.3)$$

$$I_{BUS} = \begin{bmatrix} I_1 \\ I_2 \\ \vdots \\ I_N \end{bmatrix} \quad (2.4)$$

Therefore the system can be described by (2.5)

$$\begin{bmatrix} V_1 \\ V_2 \\ \vdots \\ V_N \end{bmatrix} = \begin{bmatrix} Z_{11} & Z_{12} & \cdots & Z_{1N} \\ Z_{21} & Z_{22} & \cdots & Z_{2N} \\ \vdots & \vdots & \vdots & \vdots \\ Z_{N1} & Z_{N2} & \cdots & Z_{NN} \end{bmatrix} \begin{bmatrix} I_1 \\ I_2 \\ \vdots \\ I_N \end{bmatrix} \quad (2.5)$$

It means

$$V_i = I_1 Z_{i1} + I_2 Z_{i2} + \cdots + I_i Z_{ii} + I_j Z_{ij} + \cdots + I_N Z_{iN} \quad (2.6)$$

For all $i = 1,2,3,\cdots,N$

CASE-1 ADDITION OF A NEW BUS $'p'$ TO REFERENCE BUS THROUGH LINK Z_b

The system is modified by addition of a new bus $'p'$ to a reference bus through link Z_b as shown in Fig.-2.2.

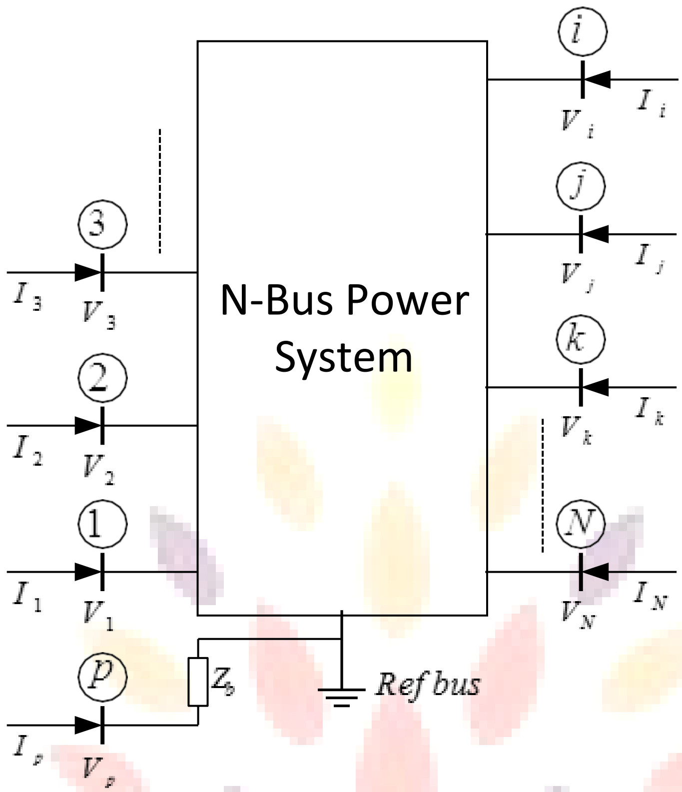


FIG. 2.2 ADDITION OF NEW BUS $'p'$ TO REFERENCE BUS

The system voltage equation of (2.5) is modified as a new bus $'p'$ is added because the current injected at bus $'p'$ introduces the voltage drop $I_p Z_b$ and the voltage of bus $'p'$, V_p equals this voltage drop. It implies the system is modified by the addition of a new row in (2.5) as follows.

$$\begin{bmatrix} V_1 \\ V_2 \\ \vdots \\ V_N \\ \cdots \\ V_p \end{bmatrix} = \begin{bmatrix} Z_{11} & Z_{12} & \cdots & Z_{1N} & \vdots & 0 \\ Z_{21} & Z_{22} & \cdots & Z_{2N} & \vdots & 0 \\ \vdots & \vdots & \cdots & \vdots & \vdots & \vdots \\ Z_{N1} & Z_{N2} & \cdots & Z_{NN} & \vdots & 0 \\ \cdots & \cdots & \cdots & \cdots & \cdots & \cdots \\ 0 & 0 & \cdots & 0 & \vdots & Z_b \end{bmatrix} \begin{bmatrix} I_1 \\ I_2 \\ \vdots \\ I_N \\ \cdots \\ I_p \end{bmatrix} \quad (2.7)$$

$$Z_{BUS,New} = \begin{bmatrix} Z_{11} & Z_{12} & \cdots & Z_{1N} & \vdots & 0 \\ Z_{21} & Z_{22} & \cdots & Z_{2N} & \vdots & 0 \\ \vdots & \vdots & \cdots & \vdots & \vdots & \vdots \\ Z_{N1} & Z_{N2} & \cdots & Z_{NN} & \vdots & 0 \\ \cdots & \cdots & \cdots & \cdots & \cdots & \cdots \\ 0 & 0 & \cdots & 0 & \vdots & Z_b \end{bmatrix} \quad (2.8)$$

$$Z_{BUS,New} = \begin{bmatrix} & & & & \vdots & 0 \\ & & & & \vdots & 0 \\ & & Z_{BUS,Original} & & \vdots & \vdots \\ & & & & \vdots & 0 \\ \cdots & \cdots & \cdots & \cdots & \cdots & \cdots \\ 0 & 0 & \cdots & 0 & \vdots & Z_b \end{bmatrix} \tag{2.9}$$

CASE-2 ADDITION OF A NEW BUS $'p'$ TO AN EXISTING BUS $'k'$ THROUGH Z_b

The bus impedance matrix can be modified with the addition of a new bus to an existing bus through a link as shown in Fig.-2.3.

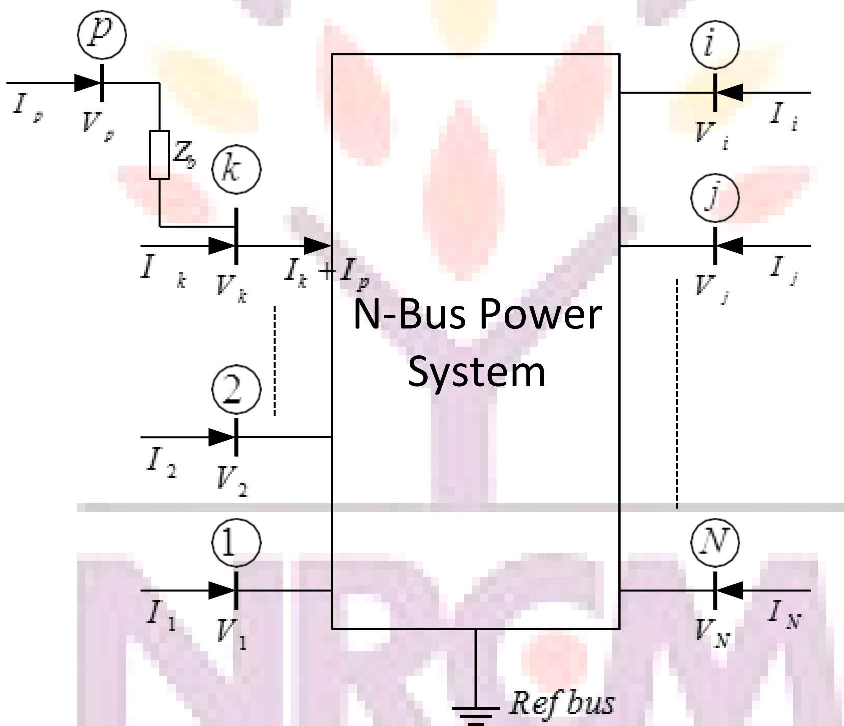


FIG. 2.3 ADDITION OF NEW BUS $'p'$ TO AN EXISTING BUS $'k'$

With the addition of a link, the voltage at the $k^{th}-bus$ is updated by the voltage drop of I_pZ_{pp} due to current injection of $'i_p'$ at the $p^{th}-bus$ and given by

$$V_{k,new} = V_{k,original} + I_pZ_{kk} \tag{2.10}$$

Where

$$V_{k,original} = I_1Z_{k1} + I_2Z_{k2} + \cdots + I_kZ_{kk} + \cdots + I_NZ_{kN} \tag{2.11}$$

The voltage at the $p^{th}-bus$ thus is given by

$$V_p = V_k + I_p Z_b = V_{k,original} + I_p Z_{kk} + I_p Z_b \tag{2.12}$$

$$V_p = \underbrace{I_1 Z_{k1} + I_2 Z_{k2} + \cdots}_{V_{k,original}} + I_N Z_{kN} + I_p\left(Z_{kk} + Z_b\right) \tag{2.13}$$

Thus the system voltage as mentioned in (2.5) can be modified as per (2.14) and so is the bus impedance matrix (2.15).

$$\begin{bmatrix} V_1 \\ V_2 \\ \vdots \\ V_N \\ \cdots \\ V_p \end{bmatrix} = \begin{bmatrix} Z_{11} & Z_{12} & \cdots & Z_{1N} & \vdots & Z_{1k} \\ Z_{21} & Z_{22} & \cdots & Z_{2N} & \vdots & Z_{2k} \\ \vdots & \vdots & \cdots & \vdots & \vdots & \vdots \\ Z_{N1} & Z_{N2} & \cdots & Z_{NN} & \vdots & Z_{Nk} \\ \cdots & \cdots & \cdots & \cdots & \cdots & \cdots \\ Z_{k1} & Z_{k2} & \cdots & Z_{kN} & \vdots & Z_{kk} + Z_b \end{bmatrix} \begin{bmatrix} I_1 \\ I_2 \\ \vdots \\ I_N \\ \cdots \\ I_p \end{bmatrix} \tag{2.14}$$

$$Z_{BUS,New} = \begin{bmatrix} Z_{11} & Z_{12} & \cdots & Z_{1N} & \vdots & Z_{1k} \\ Z_{21} & Z_{22} & \cdots & Z_{2N} & \vdots & Z_{2k} \\ \vdots & \vdots & \cdots & \vdots & \vdots & \vdots \\ Z_{N1} & Z_{N2} & \cdots & Z_{NN} & \vdots & Z_{Nk} \\ \cdots & \cdots & \cdots & \cdots & \cdots & \cdots \\ Z_{k1} & Z_{k2} & \cdots & Z_{kN} & \vdots & Z_{kk} + Z_b \end{bmatrix} \tag{2.15}$$

$$Z_{BUS,New} = \begin{bmatrix} & & & & \vdots & Z_{1k} \\ & & & & \vdots & Z_{2k} \\ & & Z_{BUS,Original} & & \vdots & \vdots \\ & & & & \vdots & Z_{Nk} \\ \cdots & \cdots & \cdots & \cdots & \cdots & \cdots \\ Z_{k1} & Z_{k2} & \cdots & Z_{kN} & \vdots & Z_{kk} + Z_b \end{bmatrix} \tag{2.16}$$

ADDITION OF NEW LINK HAVING IMPEDANCE Z_b **BETWEEN THE EXISTING** *BUS 'k' AND REFERENCE BUS*

The addition of new link having impedance Z_b between the existing bus $'k'$ and reference bus can be achieved as Fig.-2.4.

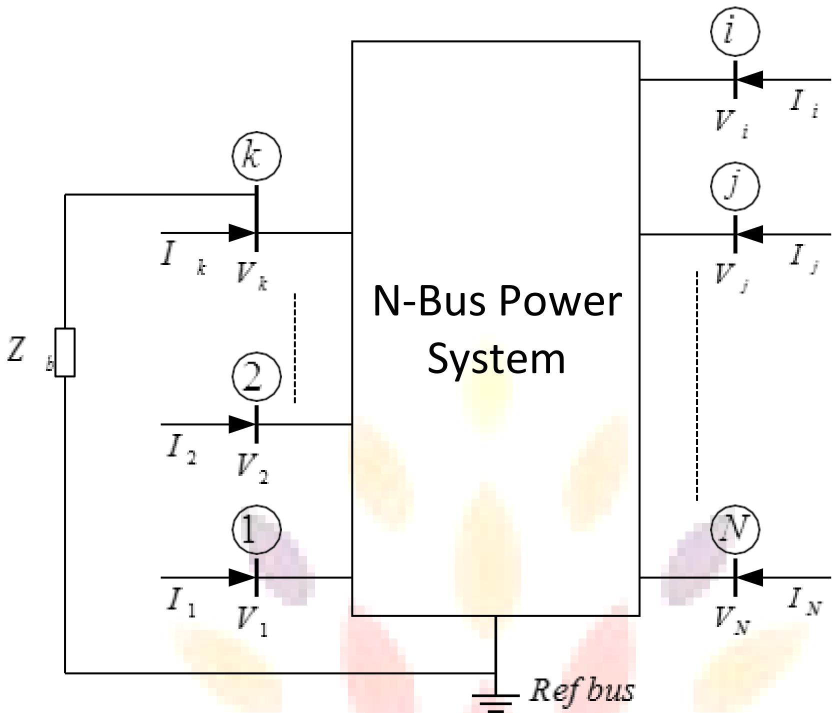


FIG.-2.4 ADDITION OF NEW LINK BETWEEN THE EXISTING BUS 'k' AND REFERENCE BUS

The addition of new link having impedance Z_b between the existing bus 'k' and reference bus can be regarded as the addition of a new bus 'p' to an existing bus 'k' through Z_b. Then new bus 'p' is shorted with the reference bus. That means the voltage equations shall be updated by as per (2.14) then V_p equals to zero as follows.

$$\begin{bmatrix} V_1 \\ V_2 \\ \vdots \\ V_N \\ \hline 0 \end{bmatrix} = \begin{bmatrix} Z_{11} & Z_{12} & \cdots & Z_{1N} & \vdots & Z_{1k} \\ Z_{21} & Z_{22} & \cdots & Z_{2N} & \vdots & Z_{2k} \\ \vdots & \vdots & \cdots & \vdots & \vdots & \vdots \\ Z_{N1} & Z_{N2} & \cdots & Z_{NN} & \vdots & Z_{Nk} \\ \hline Z_{k1} & Z_{k2} & \cdots & Z_{kN} & \vdots & Z_{kk}+Z_b \end{bmatrix} \begin{bmatrix} I_1 \\ I_2 \\ \vdots \\ I_N \\ \hline I_p \end{bmatrix} \tag{2.17}$$

$$\begin{bmatrix} V_1 \\ V_2 \\ \vdots \\ V_N \\ \hline 0 \end{bmatrix} = \begin{bmatrix} & \vdots & Z_{1k} \\ & \vdots & Z_{2k} \\ Z_{Bus,Original} & \vdots & \vdots \\ & \vdots & Z_{Nk} \\ \hline Z_{k1} \quad Z_{k2} \quad \cdots \quad Z_{kN} & \vdots & Z_{kk}+Z_b \end{bmatrix} \begin{bmatrix} I_1 \\ I_2 \\ \vdots \\ I_N \\ \hline I_p \end{bmatrix} \tag{2.18}$$

The new bus impedance matrix can be calculated after reducing the Z_{BUS} in (2.18) by eliminating the last row and last column using Kron's reduction.

$$Z_{hi,new} = Z_{hi,old} - \frac{Z_{h(n+1)}\, Z_{(n+1)i}}{Z_{kk} + Z_b} \tag{2.19}$$

The resulting $Z_{hi,new}$ shall be new bus impedance matrix $Z_{BUS,new}$.

ADDITION OF NEW LINK HAVING IMPEDANCE Z_b **BETWEEN TWO EXISTING** *BUSES 'j' AND 'k'*

A new link having impedance Z_b can be added between two existing buses $'j'$ and $'k'$ as shown in Fig.-2.5

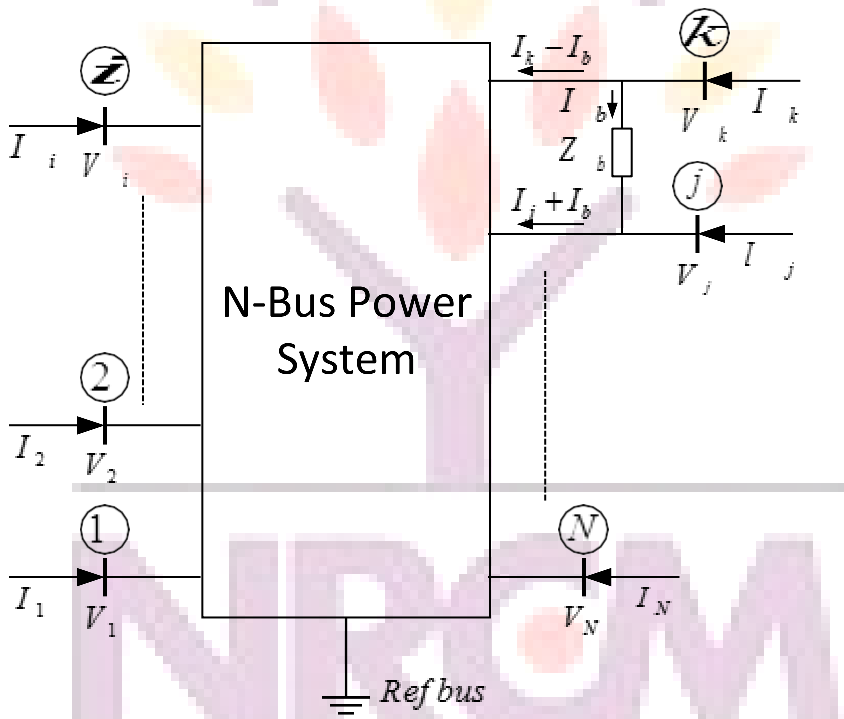


FIG.-2.5 ADDITION OF NEW LINK BETWEEN TWO EXISTING BUSES

By adding a link between $j^{th}-bus$ and $k^{th}-bus$ the current injected at the $j^{th}-bus$ and $k^{th}-bus$ are modified to $I_j + I_b$ and $I_k - I_b$ where I_b is current flowing through the link Z_b.

Therefore the voltage at the bus-1 can be updated as follows.

$$V_1 = I_1 Z_{11} + I_2 Z_{12} + \cdots + (I_j + I_b) Z_{1j} + (I_k - I_b) Z_{1k} + \cdots + I_N Z_{1N} \tag{2.20}$$

$$\Rightarrow V_1 = I_1 Z_{11} + I_2 Z_{12} + \cdots + I_j Z_{1j} + I_k Z_{1k} + \cdots + I_N Z_{1N} + I_b (Z_{1j} - Z_{1k}) \tag{2.21}$$

$$\Rightarrow V_1 = \underbrace{I_1 Z_{11} + I_2 Z_{12} + \cdots + I_j Z_{1j} + I_k Z_{1k} + \cdots + I_N Z_{1N}}_{V_1^0} + \underbrace{I_b (Z_{1j} - Z_{1k})}_{\Delta V_1} \quad (2.22)$$

$$\Rightarrow V_1 = V_1^0 + \Delta V_1 \quad (2.23)$$

Similarly

$$V_j = V_j^0 + \Delta V_j$$

$$V_k = V_k^0 + \Delta V_k$$

$$V_j = I_1 Z_{j1} + I_2 Z_{j2} + \cdots + I_j Z_{jj} + I_k Z_{jk} + \cdots + I_N Z_{jN} + I_b (Z_{jj} - Z_{jk}) \quad (2.24)$$

$$V_k = I_1 Z_{k1} + I_2 Z_{k2} + \cdots + I_j Z_{kj} + I_k Z_{kk} + \cdots + I_N Z_{kN} + I_b (Z_{kj} - Z_{kk}) \quad (2.25)$$

Subtracting (2.25) from (2.24)

$$V_j - V_k = (Z_{j1} - Z_{k1}) I_1 + (Z_{j2} - Z_{k2}) I_2 + \cdots + (Z_{jj} - Z_{kj}) I_j + (Z_{kj} - Z_{kk}) I_k + \cdots + (Z_{jN} - Z_{kN}) I_N + (Z_{jj} - 2Z_{jk} + Z_{kk}) I_b \quad (2.26)$$

But the addition of link Z_b has resulted in the network equation (2.26)

$$V_k - V_j = I_b Z_b \quad (2.27)$$

$$\Rightarrow I_b Z_b + V_j - V_k = 0 \quad (2.28)$$

$$I_b Z_b + (Z_{j1} - Z_{k1}) I_1 + (Z_{j2} - Z_{k2}) I_2 + \cdots + (Z_{jj} - Z_{kj}) I_j + (Z_{kj} - Z_{kk}) I_k + \cdots + (Z_{jN} - Z_{kN}) I_N + (Z_{jj} - 2Z_{jk} + Z_{kk}) I_b = 0 \quad (2.29)$$

$$(Z_{j1} - Z_{k1}) I_1 + (Z_{j2} - Z_{k2}) I_2 + \cdots + (Z_{jj} - Z_{kj}) I_j + (Z_{kj} - Z_{kk}) I_k + \cdots + (Z_{jN} - Z_{kN}) I_N + (Z_{jj} - 2Z_{jk} + Z_{kk} + Z_b) I_b = 0 \quad (2.30)$$

(2.30) suggests addition of new row and new column in (2.5) as follows.

$$\begin{bmatrix} V_1 \\ V_2 \\ \vdots \\ V_N \\ \cdots \\ 0 \end{bmatrix} = \begin{bmatrix} Z_{11} & Z_{12} & \cdots & Z_{1N} & \vdots & (Z_{1j} - Z_{1k}) \\ Z_{21} & Z_{22} & \cdots & Z_{2N} & \vdots & (Z_{2j} - Z_{2k}) \\ \vdots & \vdots & \cdots & \vdots & \vdots & \vdots \\ Z_{N1} & Z_{N2} & \cdots & Z_{NN} & \vdots & (Z_{Nj} - Z_{Nk}) \\ \cdots & \cdots & \cdots & \cdots & \cdots & \cdots \\ (Z_{j1} - Z_{k1}) & (Z_{j2} - Z_{k2}) & \cdots & (Z_{jN} - Z_{kN}) & \vdots & (Z_{jj} - 2Z_{jk} + Z_{kk} + Z_b) \end{bmatrix} \begin{bmatrix} I_1 \\ I_2 \\ \vdots \\ I_N \\ \cdots \\ I_b \end{bmatrix}$$

(2.31)

$$\begin{bmatrix} V_1 \\ V_2 \\ \vdots \\ V_N \\ \square \\ 0 \end{bmatrix} = \begin{bmatrix} & & Z_{BUS,Original} & & \vdots & (Z_{1j} - Z_{1k}) \\ & & & & \vdots & (Z_{2j} - Z_{2k}) \\ & & & & \vdots & \vdots \\ & & & & \vdots & (Z_{Nj} - Z_{Nk}) \\ (Z_{j1} - Z_{k1}) & (Z_{j2} - Z_{k2}) & \cdots & (Z_{jN} - Z_{kN}) & \vdots & (Z_{jj} - 2Z_{jk} + Z_{kk} + Z_b) \end{bmatrix} \begin{bmatrix} I_1 \\ I_2 \\ \vdots \\ I_N \\ \square \\ I_b \end{bmatrix} \quad (2.32)$$

The new bus impedance matrix can be calculated after reducing the Z_{BUS} in (2.32) by eliminating the last row and last column using Kron's reduction.

$$Z_{hi,new} = Z_{hi,old} - \frac{Z_{h(n+1)}\, Z_{(n+1)i}}{(Z_{jj} - 2Z_{jk} + Z_{kk} + Z_b)} \quad (2.33)$$

The resulting $Z_{hi,new}$ shall be new bus impedance matrix $Z_{BUS,new}$.

As described above the bus impedance matrix for a power system can be formed by using above algorithm by consideration of adding either one bus or one link at a time.

Advantages

- It can be used for fault analysis.
- For any single modification in case of any single outage of a link or a node, new bus impedance matrix can be obtained with less computation time.
- Removal of a branch can be considered by adding negative of link impedance Z_b between the same node.

The system voltage for a $'N-bus'$ power system shown in Fig.-2.1 is given in (2.2)

$$V_{BUS} = Z_{BUS} I_{BUS} \tag{2.34}$$

It can be rewritten as

$$I_{BUS} = Y_{BUS} V_{BUS} \tag{2.35}$$

Where Y_{BUS} is the bus admittance matrix and given by (2.36).

$$Y_{BUS} = \begin{bmatrix} Y_{11} & Y_{12} & \cdots & Y_{1N} \\ Y_{21} & Y_{22} & \cdots & Y_{2N} \\ \vdots & \vdots & \vdots & \vdots \\ Y_{N1} & Y_{N2} & \cdots & Y_{NN} \end{bmatrix} \tag{2.36}$$

The bus admittance matrix Y_{BUS} for a $'N-bus'$ power system shown in Fig.-2.1 can be determined by inverting bus impedance matrix Z_{BUS} or the vice versa as in (2.37)

$$Y_{BUS} = \left[Z_{BUS}\right]^{-1} \tag{2.37}$$

$$Z_{BUS} = \left[Y_{BUS}\right]^{-1} \tag{2.38}$$

The equation (2.35) can be expanded as follow (say for $i^{th}-bus$)

$$I_i = V_1 Y_{i1} + V_2 Y_{i2} + \cdots + V_i Y_{ii} + V_j Y_{ij} + \cdots + V_N Y_{iN} \tag{2.39}$$

For all $i = 1,2,3,\cdots,N$

(2.39) can be written as

$$I_i = \sum_{i=1}^{N} Y_{ii} V_i \tag{2.40}$$

The diagonal element of the Y_{BUS} such as Y_{ii} is the self-admittance of $i^{th}-bus$. It can be determined by adding all the admittances connected at $i^{th}-bus$.

The off-diagonal element of the Y_{BUS} such as Y_{ij} is the transfer admittance between the

$i^{th} - bus$

$i^{th} - bus$

andand

$j^{th} - bus$. It can be determined by adding all the admittances connected between the

$j^{th} - bus$.

UNIT-V
ELECTRICAL INSTALLATIONS

ENERGY CONTROL CENTRE:

The energy control center (ECC) has traditionally been the decision-center for the electric transmission and generation interconnected system. The ECC provides the functions necessary for monitoring and coordinating the minute-by-minute physical and economic operation of the power system. In the continental U.S., there are only three interconnected regions: Eastern, Western, and Texas, but there are many *control areas*, with each control area having its own ECC.

Maintaining integrity and economy of an inter-connected power system requires significant coordinated decision-making. So one of the primary functions of the ECC is to monitor and regulate the physical operation of the interconnected grid.

Most areas today have a two-level hierarchy of ECCs with the Independent System Operator (ISO) performing the high-level decision-making and the transmission owner ECC performing the lower-level decision-making.

A high-level view of the ECC is illustrated. Where we can identify the substation, the remote terminal unit (RTU), a communication link, and the ECC which contains the energy management system (EMS). The EMS provides the capability of converting the data received from the substations to the types of screens observed.

In these notes we will introduce the basic components and functionalities of the ECC. Note that there is no chapter in your text which provides this information.

Regional load control centre:

It decides generation allocation to various generating stations within the region on the basics of equal incremental operating cost considering line losses are equal and Frequency control in the region.

Plant load control room:

It decides the allocation of generation of various units in the plant on the basis of:

1. Equal incremented operating cost of various units
2. Minimize the reactive power flow through line so as to minimize line loss and maintain voltage levels and Frequency control in the plant

ECC Components:

The system control function traditionally used in electric utility operation consists of three main integrated subsystems: the energy management system (EMS), the supervisory control and data acquisition (SCADA), and the communications interconnecting the EMS and the SCADA (which is often thought of as part of the SCADA itself). Figure 3 provides a block diagram illustration of these three integrated subsystems. The SCADA and communications subsystems are indicated in

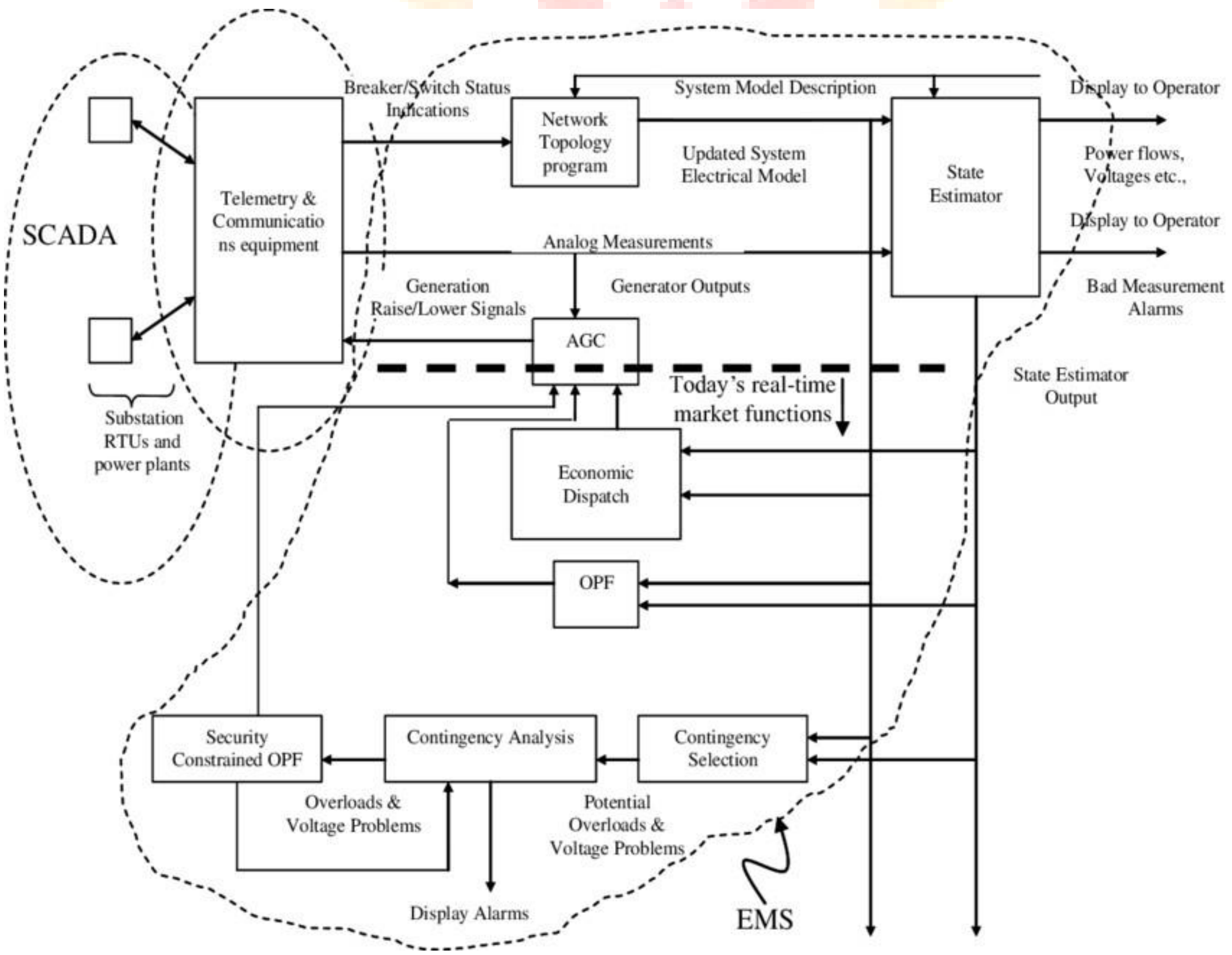


Fig.1:Block diagram of ECC

the dotted ovals at the top left hand corner of the figure. The res1of the figure indicates the EMS. We will describe each one in the following subsections.We distinguish EMS from distribution management systems (DMS). Both utilize their own SCADA, but for different functions. Whereas EMS/SCADA serves the high voltage bulk transmission system from the ECC, the DMS/SCADA serves the low voltage, distribution system from a distribution dispatch center. We are addressing in these notes the EMS/SCADA.

Operation of control centre:

- **Monitoring**
- **Data acquisition and Remote control level control**

1. Turbine – governor to adjust generation to balance changing load-instantaneous control.
2. AGC (called load frequency control (LFC)) maintains frequency and net power interchange.
3. Economic Dispatch Control (EDC) distributes the load among the units such that fuel cost is minimum.

B. Primary Voltage control

1. Excitation control
2. Transmission voltage control, SVC, Shunt capacitors, transformer taps.

2. SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA)

There are two parts to the term SCADA *Supervisory control* indicates that the operator, residing in the energy control center (ECC), has the ability to control remote equipment. *Data acquisition* indicates that information is gathered characterizing the state of the remote equipment and sent to the ECC for monitoring purposes.

The monitoring equipment is normally located in the substations and is consolidated in what is known as the remote terminal unit (RTU). Generally, the RTUs are equipped with microprocessors having memory and logic capability. Older RTUs are equipped with modems to provide the communication link back to the ECC, whereas newer RTUs generally have intranet or internet capability.

Relays located within the RTU, on command from the ECC, open or close selected control circuits to perform a supervisory action. Such actions may include, for example, opening or closing of a circuit breaker or switch, modifying a transformer tap setting, raising or lowering generator MW output or terminal voltage, switching in or out a shunt capacitor or inductor, and the starting or stopping of a synchronous condenser.

Information gathered by the RTU and communicated to the ECC includes both analog information and status indicators. Analog information includes, for example, frequency, voltages, currents, and real and reactive power flows. Status indicators include alarm signals (over-temperature, low relay battery voltage, illegal entry) and whether switches and circuit breakers are open or closed. Such information is provided to the ECC through a periodic scan of all RTUs. A 2 second scan cycle is typical.

Functions of SCADA Systems

1. Data acquisition
2. Information display.
3. Supervisory Control (CBs: ON/OFF, Generator: stop/start, RAISE/LOWER command)
4. Information storage and result display.
5. Sequence of events acquisition.
6. Remote terminal unit processing.
7. General maintenance.
8. Runtime status verification.
9. Economic modeling.
10. Remote start/stop.
11. Load matching based on economics.
12. Load shedding.

Control Functions:

1.Control and monitoring of switching devices, tapped transformers, auxiliary devices etc..

2. Bay-and a station-wide interlocking Automatic functions such as load shedding, power restoration, and high speed bus bar transfer, Time synchronization by radio clock satellite signal.

Monitoring Functions:

1. Measurement and displaying of current, voltage, frequency, active and reactive power, energy, temperature, etc..

Alarm Functions:

1. Storage and evaluation of time stamped events.

Protection functions:

1. Substation protection functions includes the monitoring of events like start and trip.
2. Protection of bus bars. Line feeders, transformers, generators.

Communication technologies:

The form of communication required for SCADA is *telemetry*. Telemetry is the measurement of a quantity in such a way so as to allow interpretation of that measurement at a distance from the primary detector. The distinctive feature of telemetry is the nature of the translating means, which includes provision for converting the measure into a representative quantity of another kind that can be transmitted conveniently for measurement at a distance. The actual distance is irrelevant.

Telemetry may be analog or digital. In analog telemetry, a voltage, current, or frequency proportional to the quantity being measured is developed and transmitted on a communication channel to the receiving location, where the received signal is applied to a meter calibrated to indicate the quantity being measured, or it is applied directly to a control device such as a ECC computer.

Forms of analog telemetry include variable current, pulse-amplitude, pulse- length, and pulse-

rate, with the latter two being the most common. In digital telemetry, the quantity being measured is converted to a code in which the sequence of pulses transmitted indicates the quantity. One of the advantages to digital telemetering is the fact that accuracy of data is not lost in transmitting the data from one location to another. Digital telemetry requires analog to digital (A/D) and

possible digital to analog (D/A) converters, as illustrated in the earliest form of signal circuit used for SCADA telemetry consisted of twisted pair wires; although simple and economic for short distances, it suffers from reliability problems due to breakage, water ingress, and ground potentialrisk during faults. Improvements over twisted pair wires came in the form of what is now the most common, traditional type of telemetry mediums based on leased-wire, power-line carrier, or microwave. These are *voice grade* forms of telemetry, meaning they represent communication channels suitable for the transmission of speech, either digital or analog, generally with a frequency range of about 300 to 3000 Hz.

SCADA requires communication between Master control station and Remote control station:

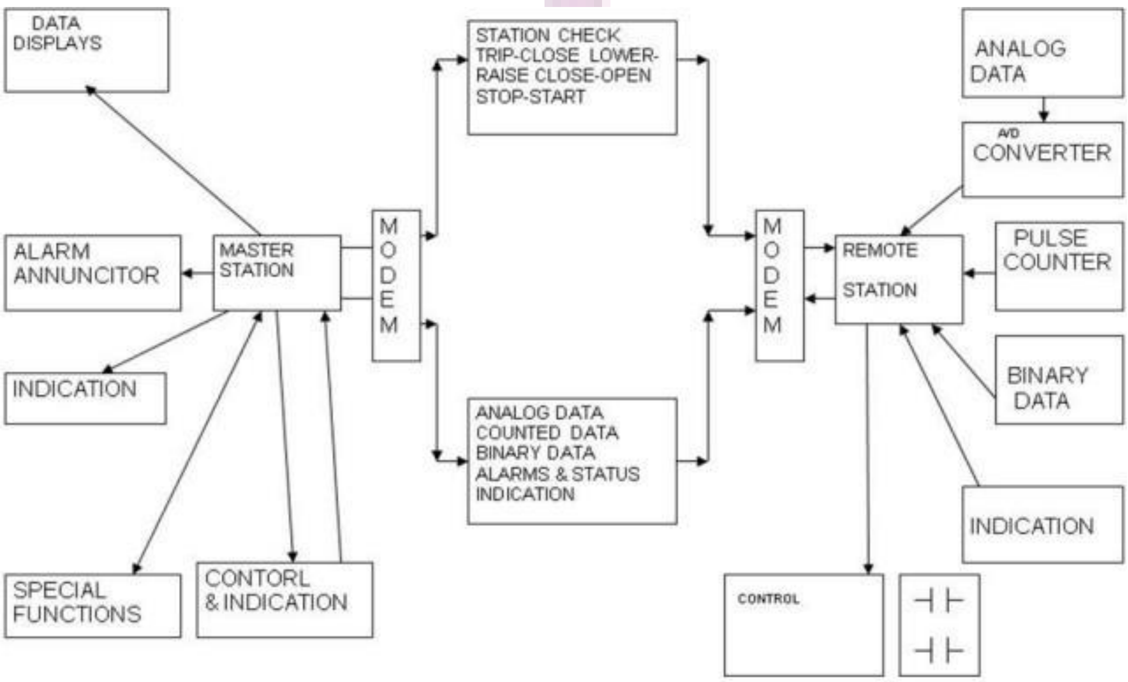


Fig.2:Communication between master and remote control station

Master and Remote station:

Leased-wire means use of a standard telephone circuit; this is a convenient and straightforward means of telemetry when it is available, although it can be unreliable, and it requires a continual outlay of leasing expenditures. In addition, it is not under user control and requires careful coordination between the user and the telephone company. Power-line carrier (PLC) offers an inexpensive and typically more reliable alternative to leased-wire. Here, the transmission circuit itself is used to modulate a communication signal at a frequency much greater than the 60 Hz power frequency. Most PLC occurs at frequencies in the range of 30-500 kHz. The security of PLC is very high since the communication equipment is located inside the substations through open disconnects, i.e., when the transmission line is outaged. Often, this is precisely the time when the communication signal is needed most. In addition, PLC is susceptible to line noise and requires careful signal-to-noise ratio analysis. Most PLC is strictly analog although digital PLC has become available from a few suppliers during the last few years.

Microwave radio refers to ultra-high-frequency (UHF) radio systems operating above 1 GHz. The earliest microwave telemetry was strictly analog, but digital microwave communication is now quite common for EMS/SCADA applications. This form of communication has obvious advantages over PLC and leased wire since it requires no physical conducting medium and therefore no right-of-way. However, line of sight clearance is required in order to ensure reliable communication, and therefore it is not applicable in some cases.

A more recent development has concerned the use of fiber optic cable, a technology capable of extremely fast communication speeds. Although cost was originally prohibitive, it has now decreased to the point where it is viable. Fiber optics may be either run inside underground power cables or they may be fastened to overhead transmission line towers just below the lines. They may also be run within the shield wire suspended above the transmission lines.

One easily sees that communication engineering is very important to power system control. Students specializing in power and energy systems should strongly consider taking communications courses to have this background. Students specializing in communication should consider taking power systems courses as an application area.

ENERGY MANAGEMENT SYSTEM (EMS):

The EMS is a software system. Most utility companies purchase their EMS from one or more EMS vendors. These EMS vendors are companies specializing in design, development, installation, and maintenance of EMS within ECCs. There are a number of EMS vendors in the U.S., and they hire many power system engineers with good software development capabilities during the time period of the 1970s through about 2000, almost all EMS software applications.

An attractive alternative today is, however, the application service provider, where the software resides on the vendor‟s computer and control center personnel access it from the Internet. Benefits from this arrangement include application flexibility and reliability in the software system and reduced installation cost.

One can observe from Figure 3 that the EMS consists of 4 major functions: network model building (including topology processing and state estimation), security assessment, automatic generation control, and dispatch. These functions are described in more detail in the following subsections.

Energy management is the process of monitoring, coordinating, and controlling the generation, transmission and distribution of electrical energy. The physical plant to be managed includes generating plants that produce energy fed

through transformers to the high-voltage transmission network (grid), interconnecting generating plants, and load centers. Transmission lines terminate at substations that perform switching, voltage transformation, measurement, and control. Substations at load centers transform to sub transmission and distribution levels. These lower-voltage circuits typically operate radially, i.e., no normally closed paths between substations through sub transmission or distribution circuits.(Underground cable networks in large cities are an exception.)

Since transmission systems provide negligible energy storage, supply and demand must be balanced by either generation or load. Production is controlled by turbine governors at generating plants, and automatic generation control is performed by control center computers remote from generating plants. Load management, sometimes called demand- Side management, extends remote supervision and control to sub-transmission and distribution circuits, including control of residential, commercial, and industrial loads.

Functionality Power EMS:

1. System Load Forecasting-Hourly energy, 1 to 7 days.
2. Unit commitment-1 to 7days.
3. Economic dispatch.
4. Hydro-thermal scheduling- up to 7 days.
5. MW interchange evaluation- with neighboring system.
6. Transmission loss minimization.
7. Security constrained dispatch.
8. Maintenance scheduling Production cost calculation.

Power System Data Acquisition and Control

A SCADA system consists of a master station that communicates with remote terminal units (RTUs) for the purpose of allowing operators to observe and control physical plants. Generating plants and transmission substations certainly justify RTUs, and their installation is becoming more common in distribution substations as costs decrease. RTUs transmit device status and measurements to, and receive control commands and setpoint data from, the master station. Communication is generally via dedicated circuits operating in the range of 600 to 4800 bits/s with the RTU responding to periodic requests initiated from the master station (polling) every 2 to 10 s, depending on the criticality of the data.

The traditional functions of SCADA systems are summarized:

- Data acquisition: Provides telemetered measurements and status information to operator.
- Supervisory control: Allows operator to remotely control devices, e.g., open and close circuit breakers. A "select before operate" procedure is used for greater safety.
- Tagging: Identifies a device as subject to specific operating restrictions and prevents unauthorized operation.

Alarms: Inform operator of unplanned events and undesirable operating conditions. Alarms are sorted by criticality, area of responsibility, and chronology. Acknowledgment may be required

- Logging: Logs all operator entry, all alarms, and selected information.
- Load shed: Provides both automatic and operator-initiated tripping of load in response to system emergencies.
- Trending: Plots measurements on selected time scales.

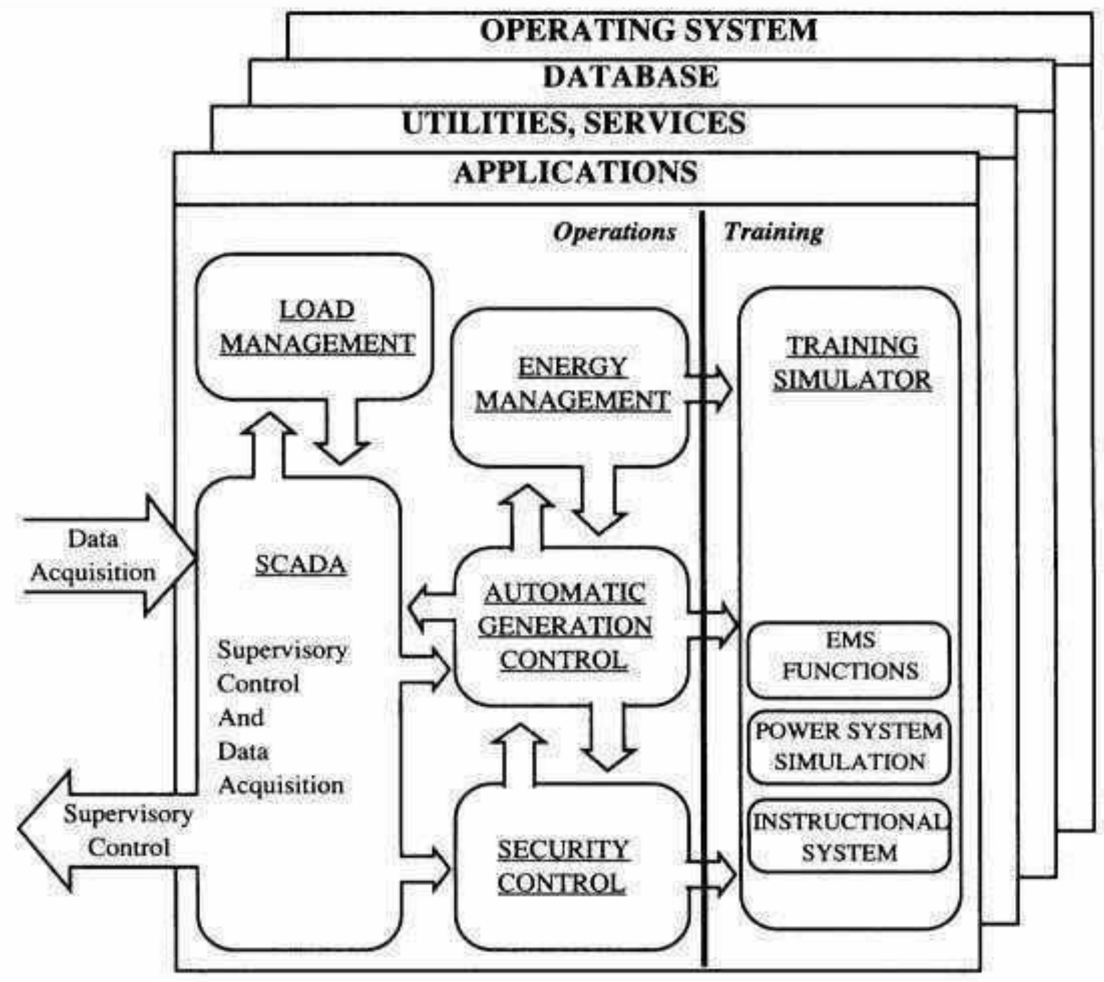


Fig.3.Layers of EMS

Layers of a modern EMS:

Since the master station is critical to power system operations, its functions are generally distributed among several computer systems depending on specific design. A dual computer system configured in primary and standby modes is most common. SCADA functions are listed below without stating which computer has specific responsibility.

- Manage communication circuit configuration
- Downline load RTU files
- Maintain scan tables and perform polling
-
-
- Check and correct message errors
- Convert to engineering units
- Detect status and measurement changes
- Monitor abnormal and out-of-limit conditions
- Log and time-tag sequence of events
- Detect and annunciate alarms
- Respond to operator requests to:

– Display information
– Enter data
– Execute control action
– Acknowledge alarms Transmit control action to RTUs

- Inhibit unauthorized actions
- Maintain historical files
- Log events and prepare reports
- Perform load shedding

Automatic Generation Control:

Automatic generation control (AGC) consists of two major and several minorfunctions that operate online in real time to adjust the generation against load at minimum cost. The major functions are load frequency control and economic dispatch, each of which is described below. The minor functions are reserve monitoring, which assures enough reserve on the system; interchange scheduling, which initiates and completes scheduled interchanges; and other similar monitoring and recording functions.

Load Frequency Control:

Load frequency control (LFC) has to achieve three primary objectives, which are stated below in priority order:

1. To maintain frequency at the scheduled value
2. To maintain net power interchanges with neighboring control areas at the scheduled values
3. To maintain power allocation among units at economically desired values.

The first and second objectives are met by monitoring an error signal, called *area control error* (ACE), which is a combination of net interchange error andfrequency error and represents the power imbalance between generation and load at any instant. This ACE must be filtered or smoothed such that excessive and random changes in ACE are not translated into control action. Since these excessive changes are different for different systems, the filter parameters have to be tuned specifically for each control area.

The filtered ACE is then used to obtain the proportional plus integral control signal. This control signal is modified by limiters, dead bands, and gain constants that are tuned to the particular system. This control signal is then divided among the generating units under control by using participation factors to obtain *unit control errors* (UCE).

These participation factors may be proportional to the inverse of the second derivative of the cost of unit generation so that the units would be loaded according to their costs, thus meeting the third objective.

However, cost may not be the only consideration because the different units may have different response rates and it may be necessary to move the faster generators more to obtain an acceptable response. The UCEs are then sent to the various units under control and the generating units monitored to see that the corrections take place. This control action is repeated every 2 to 6 s. In spite of the integral control, errors in frequency and net interchange do tend to accumulate over time. These time errors and accumulated interchange errors have to be corrected by adjusting the controller settings according to procedures agreed upon by the whole interconnection. These accumulated errors as well as ACE serve as performance measures for LFC.

The main philosophy in the design of LFC is that each system should follow its own load very closely during normal operation, while during emergencies; each system should contribute according to its relative size in the interconnection without regard to the locality of the emergency. Thus, the most important factor in obtaining good control of a system is its inherent capability of following its own load. This is guaranteed if the system has adequate regulation margin as well as adequate response capability. Systems that have mainly thermal generation often have difficulty in keeping up with the load because of the slow response of the units.

SECURITY ANALYSIS & CONTROL:

Security monitoring is the on line identification of the actual operating conditions of a power system. It requires system wide instrumentation to gather the system data as well as a means for the on line determination of network topology involving an open or closed position of circuit breakers. A state estimation has been developed to get the best estimate of the status and the state estimation provides the database for security analysis shown .

- **Data acquisition**:
  1. To process from RTU
  2. To check status values against normal value
  3. To send alarm conditions to alarm processor
  4. To check analog measurements against limits.
- **Alarm processor:**
  1. To send alarm messages
  2. To transmit messages according to priority
- **Status processor:**
  1. To determine status of each substation for proper connection.
- **Reserve monitor:**
  1. To check generator MW output on all units against unit limits
- **State estimator:**
  1. To determine system state variables
  2. To detect the presence of bad measures values.
  3. To identify the location of bad measurements
  4. To initialize the network model for other programs

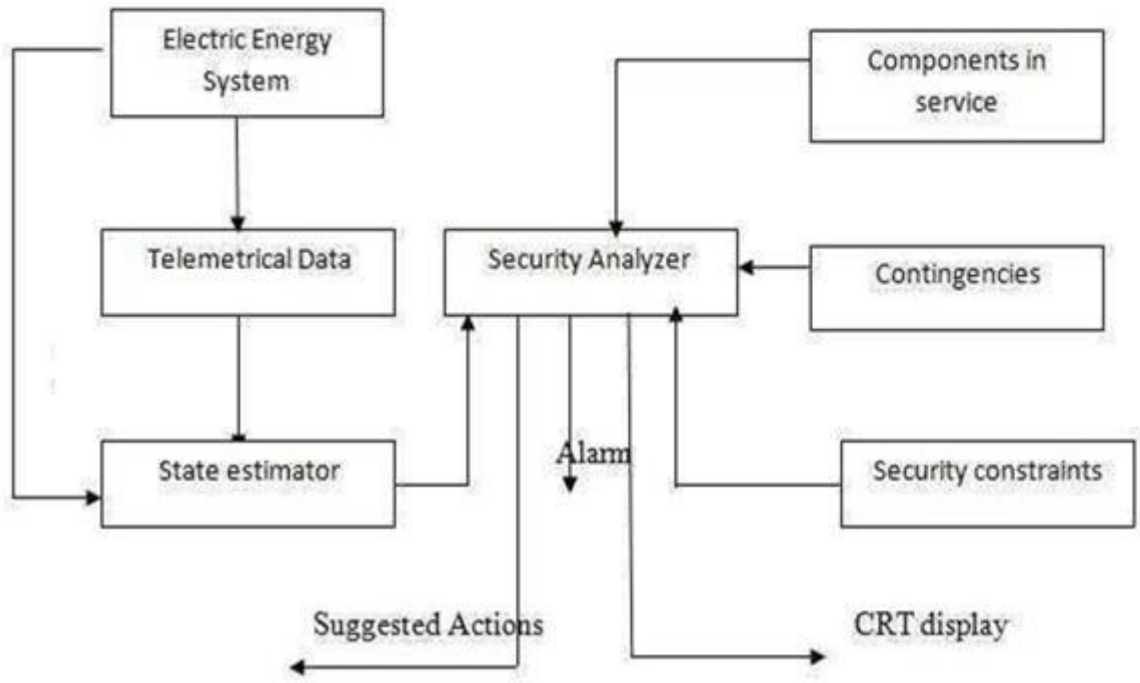


Fig.4: Practical Security Monitoring System

System Security:

1. System monitoring.
2. Contingency analysis.
3. Security constrained optimal power flow

Security Assessment:

Security assessment determines first, whether the system is currently residing in an acceptable state and second, whether the system would respond in an acceptable manner and reach an acceptable state following any one of a pre-defined contingency set. A *contingency* is the unexpected failure of a transmission line, transformer, or generator. Usually, contingencies result from occurrence of a *fault*, or short-circuit, to one of these components. When such a fault occurs, the protection systems sense the fault and remove the component, and therefore also the fault, from the system. Of course, with one less component, the overall system is weaker, and undesirable effects may occur. For example, some remaining circuit may overload, or some bus may experience an under voltage condition. These are called *static* security problems.

Dynamic security problems may also occur, including uncontrollable voltage decline, generator over speed (loss of synchronism), or undamped oscillatory behavior.

Security Control:

Power systems are designed to survive all probable contingencies. A contingency is defined as an event that causes one or more important components such as transmission lines, generators, and transformers to be unexpectedly removed from service. Survival means the system stabilizes and continues to operate at acceptable voltage and frequency levels without loss of load. Operations must deal with a vast number of possible conditions experienced by the system, many of which are not anticipated in planning. Instead of dealing with the impossible task of analyzing all possible system states, security control starts with a specific state: the current state if executing the real-time network sequence; a postulated state if executing a study sequence. Sequence means sequential execution of programs that perform the following steps:

1. Determine the state of the system based on either current or postulated conditions.
2. Process a list of contingencies to determine the consequences of each contingency on the system in its specified state.
3. Determine preventive or corrective action for those contingencies which represent unacceptable risk.

Security control requires topological processing to build network models and uses large-scale AC network analysis to determine system conditions. The required applications are grouped as a network subsystem that typically includes the following functions:

•**Topology processor**: Processes real-time status measurements to determine an electrical connectivity (bus) model of the power system network.

•**State estimator:** Uses real-time status and analog measurements to determine the„„best""

estimate of the state of the power system. It uses a redundant set of measurements; calculates voltages, phase angles, and power flows for all components in the system; and reports overload conditions.

•**Power flow:** Determines the steady-state conditions of the power system network fora specified generation and load pattern. Calculates voltages, phase angles, and flows across the entire system.

•**Contingency analysis:** Assesses the impact of a set of contingencies on the state ofthe power system and identifies potentially harmful contingencies that cause operating limit violations.

•**Optimal power flow:** Recommends controller actions to optimize a specified objective function (such as system operating cost or losses) subject to a set of power system operating constraints.

•**Security enhancement:** Recommends corrective control actions to be taken to alleviate an existing or potential overload in the system while ensuring minimal operational cost.

•**Preventive action:** Recommends control actions to be taken in a "preventive" mode before a contingency occurs to preclude an overload situation if the contingency were to occur.

•**Bus load forecasting:** Uses real-time measurements to adaptively forecast loads for the electrical connectivity (bus) model of the power system network.

•**Transmission loss factors:** Determines incremental loss sensitivities for generating units;

calculates the impact on losses if the output of a unit were to be increased by 1 MW.

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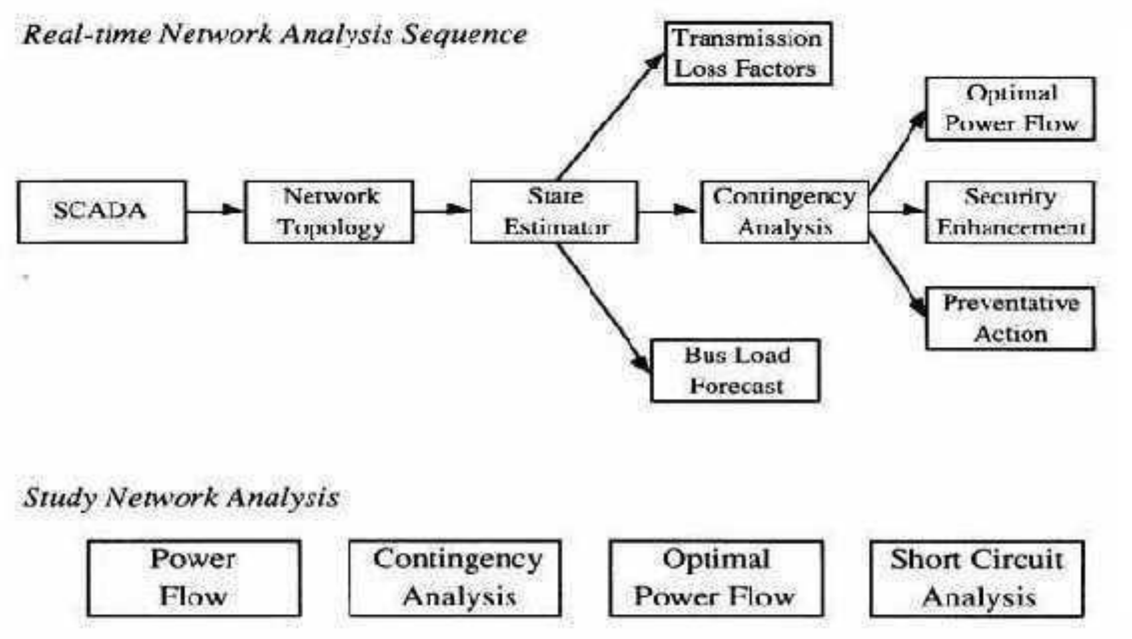
Short-circuit analysis: Determines fault currents for single-phase and three-phase faults for fault



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s across the entire power system network.

Fig.5:Real time network

analysis sequence VARIOUS OPERATING STATES:

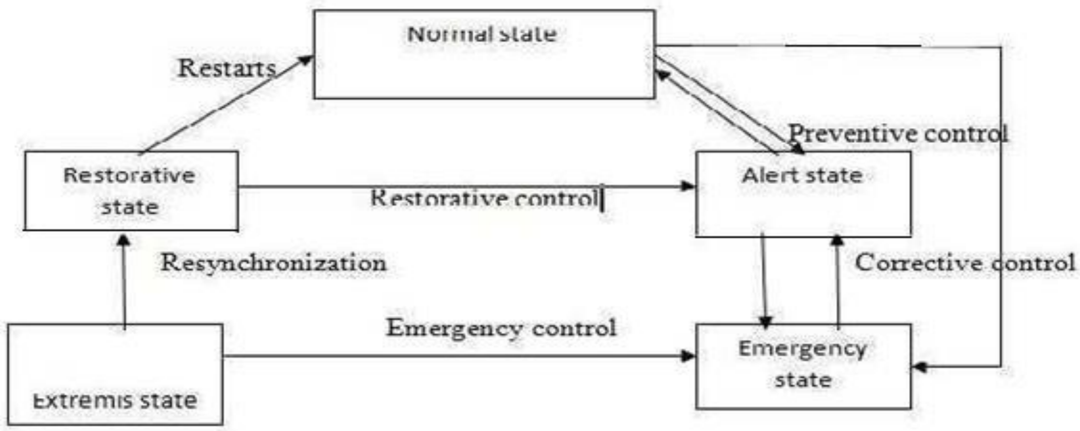

Fig.6:Various operating states

Operating states are:

1. Normal state
2. Alert state
3. Emergency state
4. Extremis state
5. Restorative state

➢ Normal state:

A system is said to be in normal if both load and operating constraints are satisfied .It is one in which the total demand on the system is met by satisfying all theoperating constraints.

➢ **Alert state**:

A normal state of the system said to be in alert state if one or more of the postulated contingencystates, consists of the constraint limits violated. When the system security level falls below acertain level or the probability of disturbance increases, the system may be in alert state .Allequalities and inequalities are satisfied, but on the event of a disturbance, the system may nothave all the inequality constraints satisfied. If severe disturbance occurs, the system will pushinto emergency state. To bring back the system to secure state, preventive control action is carried out.

➢ **Emergency state:**

The system is said to be in emergency state if one or more operating constraints are violated, but the load constraint is satisfied .In this state, the equality constraints are unchanged. The system will return to the normal or alert state by means of corrective actions, disconnection of faulted section or load sharing.

➢ **Extremis state:**

When the system is in emergency, if no proper corrective action is taken in time, then it goes to either emergency state or extremis state. In this regard neither the load or nor the operating constraint is satisfied, this result is islanding. Also the generating units are strained beyond their capacity .So emergency control action is done to bring back the system state either to the emergency state or normal state.

- **Restorative state:**

From this state, the system may be brought back either to alert state or secure state .The latter is aslow process. Hence, in certain cases, first the system is brought back to alert state and then to the secure state .This is done using restorative control action.