Optimal Load Dispatch with Unit Commitment

Anurag Mandal[1] Ramjee Prasad Gupta[2]
[1]PG Scholar [2]Assistant Professor
[1,2]Department of Electrical Engineering
[1,2]B.I.T Sindri, Jharkhand, India

Abstract— An efficient and economic power generation has always held an important position in the electric power industry. Operational Economics involving power generation and delivery can be subdivided as – Economic Load Dispatch and Unit Commitment. The main objective of Economic Load Dispatch is the process of allocating the required load demand between the available generation units such that the cost of generation is minimum. Furthermore, Unit Commitment is an optimization technique that determines the units that are feasible and should be committed over a period of time to serve the load demand at minimum operating cost, satisfying all plant and system constraints. The test system is also analyzed under 3-phase symmetrical fault with its effect on generation. There exist various UC scheduling algorithms among which my research work is based on Dynamic Programming method which is robust in nature, takes less computation time and includes plant constraints like start-up cost, fuel cost etc. The performance of Dynamic Programming method is further enhanced by adopting Sequential Combination – DP method which involves reduction in the dimensionality state of the solution space and faster computation speed. The effectiveness of the proposed technique is investigated on 26-Bus Multi Machine system consisting of six thermal generating units and is carried out using MATLAB.

Key words: Optimum Power Flow, Newton-Raphson, Transmission Losses, Economic Load Dispatch, Unit Commitment, Dynamic Programming Method, System Constraints, Load

NOMENCLATURE

N	:	Number of Generating Units
i	:	Index of generating units (i = 1, 2,…., N)
H	:	Hour
P_{imin}	:	Minimum output power of unit i in MW
P_{imax}	:	Maximum output power of unit i in MW
P_{it}	:	Power produced by unit i in time t
P_{Gi}	:	Power generation of the plant i in MW
PD_t	:	Power demand at hour t in MW
MU_i	:	Minimum up time in hours
MD_i	:	Minimum down time in hours
CSH	:	Cold Start Hour in hours
S_{hi}	:	Hot start up cost in Rs
S_{ci}	:	Cold start up cost in Rs
SD_i	:	Shut down cost in Rs
ST_i	:	Start up cost in Rs
a_i, b_i & c_i	:	Fuel cost coefficients of unit i
$X_i^{on}(t)$	:	Continuously ON Duration of unit i in hour t
$X_i^{off}(a)$	:	Continuously OFF Duration of unit i in hour t
λ	:	Incremental Production Cost
Z_F	:	Fault Impedance
V_F	:	During - Fault Voltage
I_F	:	Fault Current

I. INTRODUCTION

Economic load dispatch (ELD) and Unit Commitment (UC) are significant research applications in power systems that optimize the total production cost of the predicted load demand. The solution to these problems has a potential to save millions of rupees per year in terms of fuel and related cost. In modern present era where the population is rapidly increasing, so is increasing the consumption and need, and as a result has led to an increase and unpredictability in the demand and generation. In the existing power system the load is not stable and it keeps varying depending on our requirement and consumption from hour to hour, day to day and reaches different peak values from one day to other day. At each period there will be distinct isolated load levels. So it is not worthwhile to run all the existing units all the time. Therefore, it is essential to forecast the starting up of the units, connection of the units to the network, the order for shutting down the units and the time period for the units to be in off state. Thus, determining which unit must be kept online and which ones should not constitutes a difficult problem for the operators seeking to minimize the system operational cost.

The solution to the above problem leads to the emergence of ELD-UC method which determines the units that are feasible and should be committed over a period of time, satisfying all system constraints. In solving the unit commitment problem, generally two basic decisions are involved, namely, the "Unit Commitment" decision and the "Economic Load Dispatch" decision. The "Unit Commitment" decision involves determining the units that are feasible and should be committed over a period of time to serve the load demand at minimum operating cost, satisfying all plant and system constraints. The "Economic load dispatch" decision involves in determining the optimum allocation of load among the committed generating units subject to satisfaction of power balance and capacity constraints, such that the total cost of operation is kept at a minimum [5].The unit commitment problem has commonly been formulated as a non-linear, large scale, mixed-integer combinatorial optimization problem with constraints [9]. Several mathematical programming techniques have been proposed to solve these time-dependent unit commitment problems. They typically include complete priority ordering and heuristic methods, dynamic programming method, the method of local variations, mixed integer programming, Lagrangian relaxation, the branch and bound method, bender decomposition etc. Among all these methods, dynamic programming method has been used most extensively throughout the power industry.

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II. METHODOLOGY

A. Economic Load Dispatch Problem

The objective of an ED problem is to find the optimal combination of power generations that minimizes the total generation cost while satisfying equality and inequality constraints [6]. The fuel cost curve for any unit is assumed to be approximated by segments of quadratic functions of the active power output of the generator. For a given power system network, the problem may be described as optimization (minimization) of total fuel cost under a set of operating constraints.

$$F_T = \sum_{i=1}^{n} F_i(P_i) = \sum_{i=1}^{n} (a_i P_i^2 + b_i P_i + c_i) \qquad (2.1.1)$$

Where

F_T = total fuel cost of generation in the system (Rs/hr),

$a_i, b_i \; and \; c_i$ = cost coefficient of the i^{th} generator,

P_i = the power generated by the i^{th} unit

n = the number of generators.

Economic Load dispatch can be further classified into two categories considering the effect of losses –

1) Economic Load Dispatch without Losses:

In this case, the transmission losses appearing up in the system is neglected and the total power generation by the units is equal to the load demand. That is,

$$\sum_{i=1}^{n} P_i = P_D \qquad (2.1.2)$$

And the condition for optimal load dispatch is -

$$\frac{\partial F_T}{\partial P_i} = \frac{dF_i}{dP_i} = \lambda \qquad (2.1.3)$$

$$b_i + 2a_i P_i = \lambda \qquad (2.1.4)$$

$$P_i = \frac{\lambda - b_i}{2a_i} \qquad (2.1.5)$$

$$\sum_{i=1}^{n} \frac{\lambda - b_i}{2a_i} = P_D \qquad (2.1.6)$$

$$\lambda = \frac{P_D + \sum_{i=1}^{n} \frac{b_i}{2a_i}}{\sum_{i=1}^{n} \frac{1}{2a_i}} \qquad (2.1.7)$$

Substituting the value of λ in eqn (2.1.5) we get the value of optimal scheduling of generating units -

$$P_i = \frac{\frac{P_D + \sum_{i=1}^{n} \frac{b_i}{2a_i}}{\sum_{i=1}^{n} \frac{1}{2a_i}} - b_i}{2a_i} \qquad (2.1.8)$$

2) Economic Load Dispatch with Losses:

In this case, the transmission losses appearing up in the system is considered into effect which is given by –

$$P_L = \sum_{i=1}^{n} \sum_{j=1}^{n} P_i B_{ij} P_j + \sum_{i=1}^{n} B_{0i} P_i + B_{00} \qquad (2.1.9)$$

The coefficients B_{ij} are called Loss coefficients or B-coefficients.

Here, the total power generation by the units is equal to the summation of load demand and losses. That is,

$$\sum_{i=1}^{n} P_i = P_D + P_L \qquad (2.1.10)$$

And therefore the condition for optimum dispatch is

$$\frac{dF_i}{dP_i} + \lambda \frac{\partial P_L}{\partial P_i} = \lambda \qquad i = 1, \ldots . n \qquad (2.1.11)$$

The above equation (2.1.11) is rearranged as follows –

$$\left(\frac{1}{1 - \frac{\partial P_L}{\partial P_i}} \right) \frac{dF_i}{dP_i} = \lambda \qquad i = 1, \ldots . , n \qquad (2.1.12)$$

$$L_i \frac{dF_i}{dP_i} = \lambda \qquad i = 1, \ldots . n \qquad (2.1.13)$$

Where L_i is known as the penalty factor of plant i and is given by-

$$L_i = \frac{1}{1 - \frac{\partial P_L}{\partial P_i}} \qquad (2.1.14)$$

$$\frac{\partial P_L}{\partial P_i} = 2 \sum_{j=1}^{n} B_{ij} P_j + B_{0i} \qquad (2.1.15)$$

Substituting the expression for the incremental production cost and the incremental transmission loss results in

$$b_i + 2a_i P_i + 2\lambda \sum_{j=1}^{n} B_{ij} P_j + B_{0i} \lambda = \lambda \qquad (2.1.16)$$

Or

$$\left(\frac{a_i}{\lambda} + B_{ii} \right) P_i + \sum_{\substack{j=1 \\ j \neq i}}^{n} B_{ij} P_j = \frac{1}{2} \left(1 - B_{0i} - \frac{b_i}{\lambda} \right) \qquad (2.1.17)$$

Extending eqn (2.1.17) to all plants results in the following linear equation in matrix form –

$$\begin{bmatrix} \frac{a_1}{\lambda} + B_{11} & B_{12} & \cdots & B_{1n} \\ B_{21} & \frac{a_2}{\lambda} + B_{22} & \cdots & B_{2n} \\ \vdots & \vdots & \ddots & \vdots \\ B_{n1} & B_{n2} & \cdots & \frac{\lambda_n}{\lambda} + B_{nn} \end{bmatrix} \begin{bmatrix} P_1 \\ P_2 \\ \vdots \\ P_n \end{bmatrix} = \frac{1}{2} \begin{bmatrix} 1 - B_{01} - \frac{b_1}{\lambda} \\ 1 - B_{02} - \frac{b_2}{\lambda} \\ \vdots \\ 1 - B_{on} - \frac{b_n}{\lambda} \end{bmatrix} \qquad (2.1.18)$$

Or in short form,

$$EP = D \qquad (2.1.19)$$

The optimal dispatch for all the generating units is obtained by –

$$P = \frac{D}{E} \qquad (2.1.20)$$

B. Economic Load Dispatch Constraints

1) Generator Capacity Constraints:

For normal system operations, the real power output of each generating unit should be restricted by its upper limit and lower limit as follows:

$$P_i^{min} \leq P_i \leq P_i^{max} \qquad (2.2.1)$$

Where P_i^{min} and P_i^{max} are the minimum and maximum power generated by the i^{th} generating unit respectively.

2) Power Balance Constraints:

The total power generation must cover the total demand and the real power loss in transmission lines. The relation can be described as follows:

$$\sum_{i=1}^{n} P_i = P_D + P_L \qquad (2.2.2)$$

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Where, P_D, P_L is the total system load and transmission loss. The transmission loss is described by using the B-coefficients as follows –

$$P_i = \sum_{i=1}^{n}\sum_{j=1}^{n} P_i B_{ij} P_j + \sum_{i=1}^{n} B_{oi} P_i + B_{oo} \qquad (2.2.3)$$

Where B_{ij}, B_{oi} and B_{oo} are the transmission network power loss B-coefficients [7].

C. Unit Commitment Problem

The main objective of optimal unit commitment is to determine the on/off states of the units in the system to meet the load demand and spinning reserve requirement at each time period, such that the overall cost of generation is minimized, while satisfying operational system constraints.

The solution to optimal unit commitment is obtained by using Dynamic Programming Method which is one of the simplest and best method of unit commitment scheduling. This method is applicable to a wide class of problems and through this method the optimum combination of units to use without calculating the cost of all possible combinations can be found. The essence of dynamic programming is that the problem of finding the optimum outputs of the various units for a given load is replaced by the problem of finding the optimum outputs of the various units for all the loads between the minimum and maximum capacity of the units [11].

The Dynamic Programming method can be further classified into two different operating schemes based on the number of states accessed during each stage –

- Conventional - DP method
- Sequential Combination – DP method

1) Conventional – DP method:

A state is a unique combination of committed and non-committed generators. Committed generators are designated with "1" and non-committed generators are designated with "0". For each hour, program finds the potentially feasible states.

Potentially feasible state is the one in which the committed units can supply the required load and that meets the minimum amount of capacity each period. In complete enumeration scheme, all possible combination of states are searched during each hour. If there are total N generating units then there exist 2^N possible combination of states to be searched during each hour which tends to be tedious and time consuming.

2) Sequential Combination – DP method:

In this scheme generating units are assigned priority depending upon their Average Full Load Cost (AFLC). Unit with the least value of AFLC is assigned the top most priority and the rest according to the increasing value of AFLC. This method is primarily based on the principle that unit with the least value of AFLC should be loaded to the maximum level and the unit with the highest value should be lightly loaded as this may fetch more economical unit commitment solution. In other words, Unit with the least value of AFLC is assigned the top most priority & the rest according to the increasing value of AFLC [28]. The value of AFLC is calculated as follows:

$$AFLC_i = \frac{a_i + (b_i P_{imax}) + (c_i P_{imax}^2)}{P_{imax}} \qquad (2.3.1)$$

In this scheme, if there are N generating units then there exists N possible combination of states to be searched during each hour. Thus, it takes less computational time and reduces the dimensionality problem encountered in complete enumeration scheme.

The recursive dynamic algorithm to compute the minimum cost in hour H with the ith combination is given by –

$$F_{cost}(H, I) = \min_{\{L\}}[\, P_{cost}(H, I) + S_{cost}(H-1, L: K, I) + F_{cost}(H-1, L) \qquad (2.3.2)$$

Where,

$F_{cost}(H, I)$ = least total cost to arrive at State (H,I)

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

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

D. Unit Commitment Constraints

1) Power Balance Constraint:

The total power generated (P_G) must supply the load demand (P_D) and system losses.

$$\sum_{i=1}^{n} P_G - (P_D + P_L) = 0 \quad t = 1,2,\ldots\ldots t \qquad (2.4.1)$$

2) Power Generating Limits:

The generated power of a unit should be within its minimum and maximum power limits.

$$P_{i,min} \le P_{it} \le P_{i,max} \qquad i = 1,2,3 \ldots . N \qquad (2.4.2)$$

3) Minimum Up and Down Time Constraints:

a) Minimum Up Time:

When a unit is brought in, it cannot be turned off immediately. Once it is committed, it has to be in the system for a minimum specified period of time.

$$MU_i \le X_i^{on}(t) \qquad (2.4.3)$$

b) Minimum Down Time:

When a unit is decommitted, it cannot be turned on immediately. It has to remain decommitted for a specified minimum down time.

$$MD_i \le X_i^{off}(t) \qquad (2.4.4)$$

4) Start Up Cost:

It is the cost incurred for turning a unit on. It can be further classified as –

- Cold Start Up Cost
- Hot Start Up Cost

$$ST_i = \begin{cases} S_{ci} \text{ if } X_i^{off} \ge CSH \\ S_{hi} \end{cases} \qquad (2.4.5)$$

a) Cold Start Up Cost:

It is the cost incurred for committing a unit that has been kept off for a long period of time.

b) Hot Start Up Cost:

It is the cost incurred for committing a thermal unit that has been recently turned off (temperature of the boiler is still high).

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III. DESCRIPTION OF THE TEST SYSTEM

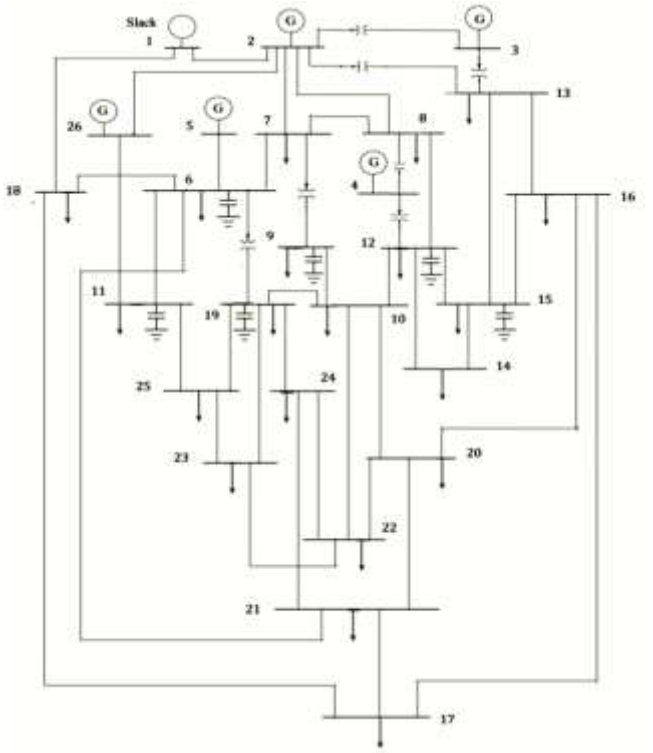

Fig. 1: Single Line Diagram of 26–Bus System

The test system that has been considered here is the 26 – Bus multi machine system which consist of twenty six Buses, six generator and seven transformer. Shunt capacitor has been used at bus 6,9,11,12,15 and 19 respectively. Bus 1 has been considered as slack bus or swing bus or reference bus. All the parameters or values are taken in p.u. The Bus data, Line data, Generator real power limits and generator cost functions has been tabulated below.

IV. INPUT PARAMETERS

Voltage magnitude, generation schedule and the reactive power limits for the regulated buses are tabulated below in Table 4.1. Bus 1 is taken as slack bus.

Bus No.	Voltage Magnitude	Generation MW	Mvar Limits	
			Minimum	Maximum
1	1.025			
2	1.020	79.0	40.0	250.0
3	1.025	20.0	40.0	150.0
4	1.050	100.0	40.0	80.0
5	1.045	300.0	40.0	160.0
26	1.015	60.0	15.0	50.0

Table 1: Generation Data

The Generator's real power limits is shown in Table 4.2

Generator	Minimum MW	Maximum MW
1	100	500
2	50	200
3	80	300
4	50	150
5	50	200
26	50	120

Table 2: Generator Real Power Limits

The MVar of the shunt capacitors installed at substations and the transformer tap settings are given below in Table 4.3 and 4.4

Bus No.	MVar
6	5
9	8
11	7
12	10
15	11
19	9

Table 3: Shunt Capacitors

Transformer Designation	Tap Setting
2-3	0.960
2-13	0.960
3-13	1.017
4-8	1.050
4-12	1.050
6-19	0.950
7-9	0.950

Table 4: Transformer Tap Settings

The line and transformer series resistance, reactance, transformer tap and one-half the total capacitive susceptance in per unit on a 100-MVA base are tabulated in Table 4.5

BUS FROM	BUS TO	R (P.U)	X (P.U)	$1/2B_{sh}$ (P.U)	Tap Setting value
1	2	0.00055	0.00480	0.03000	1
1	18	0.00130	0.01150	0.06000	1
2	3	0.00146	0.05130	0.05000	0.96
2	7	0.01030	0.05860	0.01800	1
2	8	0.00740	0.03210	0.03900	1
2	13	0.00357	0.09670	0.02500	0.96
2	26	0.03230	0.19670	0.00000	1
3	13	0.00070	0.00548	0.00050	1.017
4	8	0.00080	0.02400	0.00010	1.050
4	12	0.00160	0.02070	0.01500	1.050
5	6	0.00690	0.03000	0.09900	1
6	7	0.00535	0.03060	0.00105	1
6	11	0.00970	0.05700	0.00010	1
6	18	0.00374	0.02220	0.00120	1
6	19	0.00350	0.06600	0.04500	0.95
6	21	0.00500	0.09000	0.02260	1
7	8	0.00120	0.00693	0.00010	1
7	9	0.00095	0.04290	0.02500	0.95
8	12	0.00200	0.01800	0.02000	1
9	10	0.00104	0.04930	0.00100	1
10	12	0.00247	0.01320	0.01000	1
10	19	0.05470	0.23600	0.00000	1
10	20	0.00660	0.01600	0.00100	1
10	22	0.00690	0.02980	0.00500	1
11	25	0.09600	0.27000	0.01000	1
11	26	0.01650	0.09700	0.00400	1
12	14	0.03270	0.08020	0.00000	1
12	15	0.01800	0.05980	0.00000	1
13	15	0.01160	0.06100	0.00000	1
13	16	0.01793	0.08880	0.00100	1
14	15	0.00690	0.03820	0.00000	1
15	16	0.02090	0.05120	0.00000	1
16	17	0.09900	0.06000	0.00000	1
16	20	0.02390	0.05850	0.00000	1
17	18	0.00320	0.06000	0.03800	1
17	21	0.22900	0.44500	0.00000	1
19	23	0.03000	0.13100	0.00000	1
19	24	0.03000	0.12500	0.00200	1
19	25	0.11900	0.22490	0.00400	1
20	21	0.06570	0.15700	0.00000	1
20	22	0.01500	0.03660	0.00000	1
21	24	0.04760	0.15100	0.00000	1
22	23	0.02900	0.09900	0.00000	1
22	24	0.03100	0.08800	0.00000	1
23	25	0.09870	0.11680	0.00000	1

Table 5: Line Data (in p.u.)

The generator cost function for P_1, P_2, P_3, P_4, P_5 *and* P_{26} which is given by $C_i = a + bP_i + cP_i^2$ is shown in Table 4.6-

Generator	a	b	c
1	15120	441	0.4410
2	12600	630	0.5985
3	13860	535.5	0.5670
4	12600	693	0.5670
5	13860	661.5	0.5040

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26	11970	756	0.4725

Table 6: Generator Cost Function

The Load data considered for 26-bus multi machine system consisting of six generating units is shown in Table 4.7

Bus No.	Load		Bus No.	Load	
	MW	Mvar		MW	Mvar
1	51.0	41.0	14	24.0	12.0
2	22.0	15.0	15	70.0	31.0
3	64.0	50.0	16	55.0	27.0
4	25.0	10.0	17	78.0	38.0
5	50.0	30.0	18	153.0	67.0
6	76.0	29.0	19	75.0	15.0
7	0.0	0.0	20	48.0	27.0
8	0.0	0.0	21	46.0	23.0
9	89.0	50.0	22	45.0	22.0
10	0.0	0.0	23	25.0	12.0
11	25.0	15.0	24	54.0	27.0
12	89.0	48.0	25	28.0	13.0
13	31.0	15.0	26	40.0	20.0

Table 7: Load Data

The various parameters for 6-Unit system used in Unit Commitment method is Tabulated and shown in Table 4.8

PARAMETER	UNIT 1	UNIT 2	UNIT 3	UNIT 4	UNIT 5	UNIT 6
P_{MIN}(MW)	100	50	80	50	50	50
P_{MAX} (MW)	500	200	300	150	200	120
a (Rs)	240	200	220	200	220	190
b (Rs/MWh)	7	10	8.5	11	10.5	12
c(Rs/MWhr)	0.007	0.0095	0.009	0.009	0.008	0.0075
Min up time (h)	7	4	6	3	5	2
Min down Time(h)	6	3	5	2	4	1
Initial status(h)	+6	-4	+5	+3	-5	+2
Cold start time(h)	4	2	2	1	3	1
Inc Heat Rate (BTU/KWh)	5000	10000	6500	13500	8000	15000
No Load Cost(Rs/h)	20000	35000	25000	41500	30000	55000
Start Cost Cold (Rs)	30000	45000	35000	51500	40000	65000
Fuel cost(Rs/MBTU)	200	200	200	200	200	200
Start cost hot (Rs)	12000	27000	17000	35500	22000	47000
Shut down cost (Rs)	6000	18000	11000	22000	15000	30000

Table 8: 6-Unit System Parameters

V. RESULT AND DISCUSSIONS

A. Economic Load Dispatch

The Economic Load Dispatch using Newton-Raphson method is performed on 26-Bus multi machine system with the aim of minimizing the operation cost. Table 9 shows Economic Load Dispatch without losses where the total power generation is equal to the total load demand.

S.NO	LOAD (MW)	P_1 (MW)	P_2 (MW)	P_3 (MW)	P_4 (MW)	P_5 (MW)	P_{26} (MW)	λ (Rs/MWh)	COST (Rs/h)
1.	400	120	50	80	50	50	50	546.84	328129.2
2.	650	294.767	59.3023	145.9302	50	50	50	700.984	487389.24
3.	900	367.6636	113.0153	202.6272	63.7383	102.9556	50	765.279	671295.9
4.	1100	414.7511	147.7113	239.2508	100.3619	144.1572	53.7677	806.810	828576.40
5.	1263	446.7073	171.258	264.1057	125.2168	172.1189	83.5935	834.995	962383.61
6.	1400	473.5662	191.0488	284.9959	146.107	195.6204	108.6618	858.685	1078400.78

Table 9: Economic Load Dispatch without Losses

Whereas, Table 10 shows Economic Load Dispatch including losses where the total power generation is equal to the total load demand and losses.

S.NO	LOAD (MW)	P_1 (MW)	P_2 (MW)	P_3 (MW)	P_4 (MW)	P_5 (MW)	P_{26} (MW)	λ (Rs/MWh)	LOSS (MW)	COST (Rs/h)
1.	400	120.366	50	80	50	50	50	550.414	1.36656	329896.61
2.	650	296.3983	62.1403	145.4514	50	50	50	711.433	3.98995	490192.23
3.	900	367.011	114.3648	199.9791	72.5397	103.0251	50	778.775	8.91976	676640.58
4.	1100	413.84	148.9951	236.2406	110.5614	146.2704	59.7759	820.4058	9.69071	836485.33
5.	1263	447.3788	175.96	262.2593	137.8827	166.8980	86.7362	851.9997	12.3149	972782.54
6.	1400	479.333	197.8865	287.0348	150	190.5847	110.2701	882.1774	15.0896	1091425.36

Table 10: Economic Load Dispatch including Losses

Fig.2 determines the comparison of Incremental fuel cost curve while considering and neglecting losses for different load profiles. It increases gradually with increase in load demand.

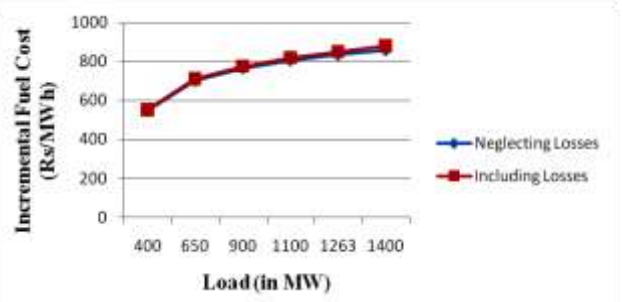

Fig. 2: Incremental Fuel Cost Curve

Fig.3 determines the comparison of Generation cost while neglecting and including losses. The generation cost is higher for the case including losses.

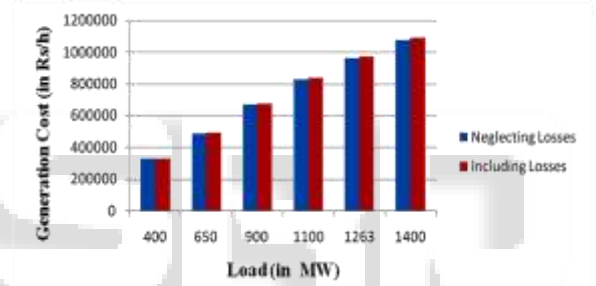

Fig. 3: Generation Cost Curve

There always exists loss in a practical transmission system. The below Fig.4 determines the loss load curve which determines the loss computed at different load demands.

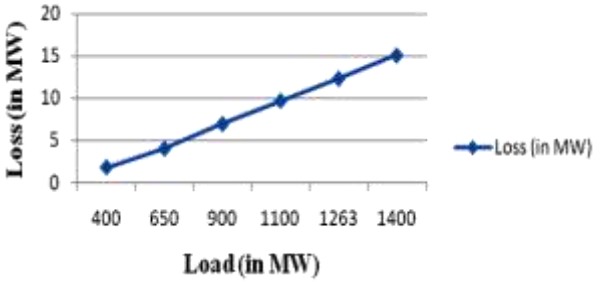

Fig. 4: Loss-Load Curve

Economic Load Dispatch is carried out for 26-Bus multi-machine system under normal condition without fault with shunt capacitance at buses- 6,9,11,12,15 and 19 which is tabulated below in Table

S.NO	C_4 (MVAr)	C_9 (MVAr)	C_{11} (MVAr)	C_{12} (MVAr)	C_{15} (MVAr)	C_{19} (MVAr)	P_1 (MW)	P_2 (MW)	P_3 (MW)	P_4 (MW)	P_5 (MW)	P_{26} (MW)	λ (Rs/MWh)	LOSS (MW)	COST (Rs/h)
1.	0	0	0	0	0	0	447.78	173.24	263.55	138.84	165.28	87.08	855.08	12.915	971980.85
2.	5	8	7	10	11	9	447.57	173.96	262.25	137.88	166.89	86.73	851.99	12.362	972782.54
3.	8	11	10	12	14	12	447.46	173.87	262.24	137.78	167.14	86.67	851.81	12.269	972886.22
4.	15	18	16	19	20	15	449.861	168	263.27	137.21	169.78	86.43	851.48	11.851	973234.16

Table 11: Economic Load Dispatch under normal conditions for 1263 MW load demand

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Fig.5 shows minimization of loss for 1263 MW load demand. Thus, it has been observed that losses decreases with increase in injected reactive power. Shunt capacitor has been used at bus 6, 9,11,12,15 and 19 respectively. And, Fig.6 shows minimization of total generation cost for 1263 MW load demand. Thus, it has been observed that generation cost decreases with increase in injected reactive power.

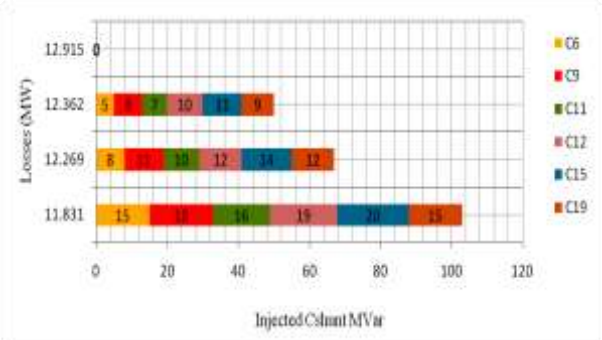

Fig. 5 Minimization of Loss for 1263 MW load demand

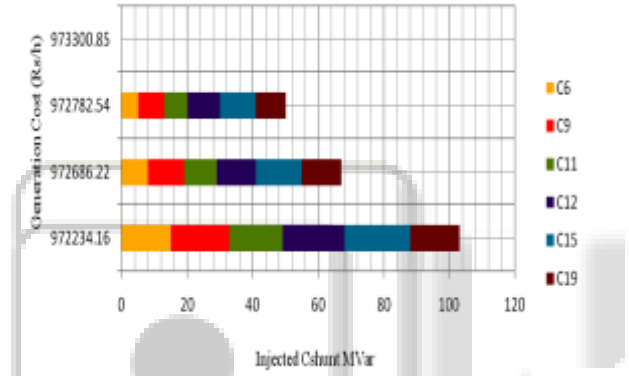

Fig. 6 Minimization of Loss for 1263 MW load demand

Thus, the above results show that the generation cost has been reduced by Rs 1,066.69 per hour which saves Rs 93,44,204.4 per annum by using shunt capacitor that injects 103 MVar in the system.

B. System Analysis Under 3-Phase Symmetrical Fault

The normal mode of operation of a power system is balanced on all the three phases. A number of undesired but unavoidable disturbances can temporarily disrupt this condition. Such a disturbance is said to be a fault. In other words, a fault is any failure that interferes with the normal system operation.

The 26-Bus multi-machine test system is subjected to 3-phase symmetrical fault at bus 12 and 16 and its effect on system and generation has been analyzed.

Fig. 7: Comparison of pre-fault and during-fault Voltage Magnitude

In Fig.5.2.1 V_i represents pre-fault voltage and V_f-12, V_f-16 represents during-fault voltage with fault at bus 12 and 16 respectively. It depicts the occurrence of Voltage Sag or Voltage Dip after the fault which involves reduction in voltage magnitude across all the buses.

Table 12 shows the pre-fault voltage magnitude at bus-12 and 16 respectively. It analyses the system behaviour under normal condition with power committed by all the generating units and generation cost for 1263 MW load demand.

S.NO	BUS No.	V_i (p.u)	P_1 (MW)	P_2 (MW)	P_3 (MW)	P_4 (MW)	P_5 (MW)	P_{26} (MW)	λ (Rs/MWh)	LOSS (MW)	COST (Rs/h)
1.	12	$1.003\angle -3.33$	447.5788	173.98	262.25	137.88	166.89	86.73	851.99	12.362	972782.54
2.	16	$0.99\angle -4.04$									

Table 12 Test System under normal condition without Fault

Table 13 shows the system behaviour under abnormal condition with fault at Bus-12 and 16 respectively and power generation for 1263 MW load demand. Test cases include voltage unbalance effect and fault impedance effect on during-fault voltages and currents. The results show that the during-fault voltages, currents and power generation have been greatly affected by both voltage unbalance and fault impedance.

S.No	BUS No.	Z_f (Ω)	I_f (p.u)	V_f (p.u)	%Voltage drop	P_1 (MW)	P_2 (MW)	P_3 (MW)	P_4 (MW)	P_5 (MW)	P_{26} (MW)	λ (Rs/MWh)	LOSS (MW)	COST (Rs/h)	%Cost Increased
1	12	0.05	$14.17\angle -33.03$	$0.7086\angle -33.03$	52.85	447.68	172.01	264.47	148.93	165.26	86.81	867.54	22.163	981253.81	0.87080
		0.1	$8.537\angle -21.64$	$0.8537\angle -21.64$	52.90	448.92	174.45	264.07	142.51	162.78	86.20	858.19	23.97	975922.88	0.32280
		0.3	$3.374\angle -18.92$	$0.9325\angle -18.92$	13.84	451.39	167.47	263.66	139.07	160.86	86.59	853.75	13.06	973384.25	0.06185
		0.5	$1.940\angle -8.697$	$0.9700\angle -8.697$	9.44	447.80	171.52	263.59	138.71	165.88	86.17	853.04	12.84	973280.62	0.04290
		1	$0.983\angle -6.632$	$0.9826\angle -6.632$	6.02	451.38	166.48	263.54	138.89	160.87	87.46	853.07	12.69	973087.06	0.03138
		3	$0.330\angle -5.346$	$0.9905\angle -5.346$	5.69	451.05	166.51	263.53	138.64	160.20	87.53	852.77	12.52	972958.75	0.01605
		5	$0.198\angle -5.088$	$0.9928\angle -5.088$	5.23	451.03	166.52	263.53	138.59	160.23	87.53	852.72	12.49	972908.75	0.01317
		15	$0.066\angle -4.829$	$0.9934\angle -4.829$	2.75	447.58	171.96	262.36	137.90	166.88	86.72	852.02	12.378	972796.02	0.00538
		25	$0.039\angle -4.778$	$0.9938\angle -4.778$	2.66	447.58	171.96	262.36	137.89	166.88	86.73	852.01	12.371	972786.62	0.00083
		50	$0.019\angle -4.739$	$0.9941\angle -4.739$	2.59	447.58	171.96	262.25	137.89	166.89	86.73	852.00	12.367	972780.57	0.00041
2	16	0.05	$11.57\angle -40.36$	$0.5788\angle -40.36$	69.21	448.56	174.76	264.73	148.33	161.43	86.87	866.79	23.516	980704.36	0.81430
		0.1	$7.885\angle -27.60$	$0.7885\angle -27.60$	42.88	448.06	174.35	263.78	142.86	163.74	86.53	858.60	26.574	976263.04	0.35778
		0.3	$3.039\angle -14.39$	$0.9119\angle -14.39$	19.30	448.39	173.66	264.61	140.33	164.35	85.46	854.03	13.645	973950.11	0.11735
		0.5	$1.884\angle -11.15$	$0.9420\angle -11.15$	13.31	447.94	171.37	264.12	139.88	165.94	86.25	853.64	13.168	973495.65	0.07530
		1	$0.963\angle -8.578$	$0.9637\angle -8.578$	8.53	447.70	174.02	262.61	138.20	166.48	86.90	852.44	12.386	973074.76	0.01975
		3	$0.325\angle -6.799$	$0.9738\angle -6.799$	5.20	451.03	166.56	263.60	138.61	160.13	87.51	852.77	12.509	972926.66	0.01480
		5	$0.196\angle -6.637$	$0.9805\angle -6.637$	4.53	447.60	171.96	262.22	137.94	166.83	86.69	852.08	12.403	972817.71	0.00961
		15	$0.065\angle -6.073$	$0.9858\angle -6.073$	3.03	447.58	171.96	262.28	137.90	166.87	86.72	852.02	12.375	972794.07	0.00138
		25	$0.039\angle -6.000$	$0.9815\angle -6.000$	3.71	447.58	171.96	262.27	137.89	166.88	86.73	852.01	12.370	972789.64	0.00070
		50	$0.019\angle -5.945$	$0.9819\angle -5.945$	3.61	447.58	171.96	262.26	137.88	166.88	86.73	852.00	12.366	972785.98	0.00035

Table 13 Test System under abnormal condition with Fault at Bus-12 and 16

Fig. 8: shows the effect of fault impedance variation on fault current. The fault current at faulted system bus-12, 16 is higher during the fault and is gradually reduced when the fault impedance is increased and the system returns to its steady state.

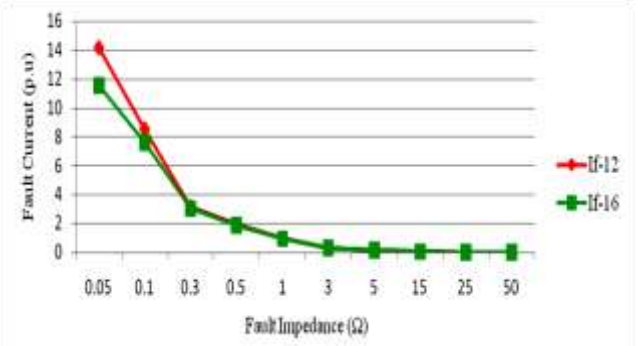

Fig. 9: Fault Current variations vs. Fault Impedance

The occurrence of fault leads to reduction in system bus voltage thus resulting in voltage sag or voltage dip which leads to power quality problems. Fig.10 shows the effect of fault impedance variation on during-fault voltage magnitude of system bus-12,16. The voltage drop of faulted

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bus-12,16 is more at lower impedance which diminishes gradually with increase in fault impedance. At higher fault impedance the during-fault voltage becomes equal to pre-fault voltage and the system returns to its normal steady-state condition.

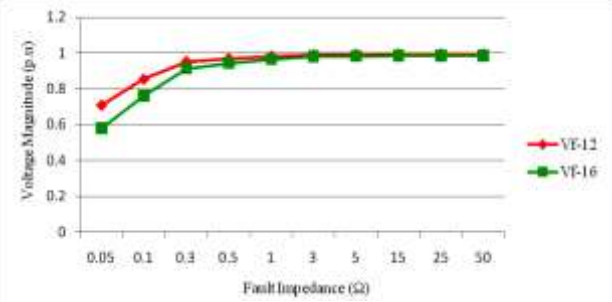

Fig. 10 During-Fault Voltage Magnitude variations vs. Fault Impedance

Fig. 11 shows the effect of fault impedance variations on %Voltage drop for faulted system bus-12,16. It has been observed that the %voltage drop is large at low fault impedance resulting in the development of voltage sag or dip and it gradually diminishes and the system retains back its normal operating condition at higher fault impedance.

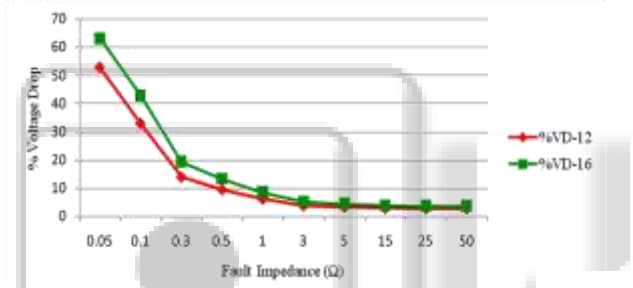

Fig. 11 %Voltage Drop vs. Fault Impedance

Fig.12 and Fig.13 shows the effect of fault impedance variations on generation cost for 1263 MW load demand. The generation cost is higher at lower impedance under unbalance condition which reduces with increase in fault impedance and system stabilizes to its normal operating condition.

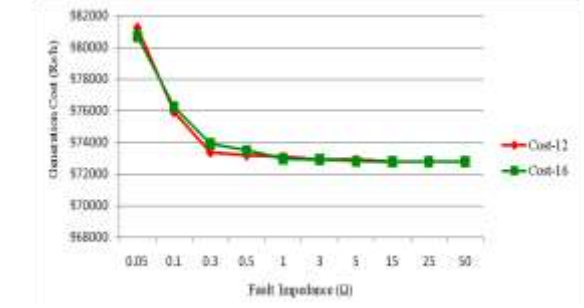

Fig. 12 During-Fault Generation Cost variations vs. Fault Impedance

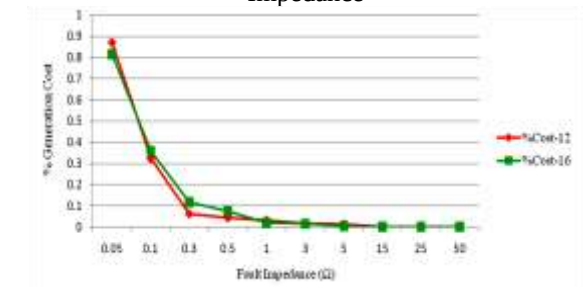

Fig. 13 %Generation Cost vs. Fault Impedance

Thus, all the above results show that the during-fault voltages and currents have been greatly affected by the system unbalance and the fault impedance. The increase of the fault impedance reduces the fault current and therefore the effect of the system unbalance on during-fault voltages and current diminishes. Larger fault impedance values produce fault current similar to nominal load current and therefore the effect of these fault in terms of during-fault voltages and currents cannot be differentiate from nominal operation conditions. Therefore, it has been observed that the faulty unbalance system returns to its steady-state normal condition at larger fault impedance.

C. Unit Commitment using Dynamic Programming Method

For proper scheduling of the feasible generating units, unit commitment is performed on 26-bus multi-machine system consisting of 6-thermal units using Dynamic Programming Method.

Fig. 14 shows the load profile on 26-Bus multi-machine system consisting of six thermal units for 24 hours in a day.

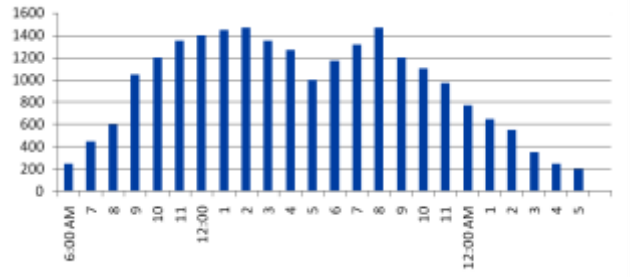

Fig. 14 Load Profile for 6-unit generating system

The feasible units committed for various load demand during a day has been illustrated in Fig. 15 using dynamic programming method.

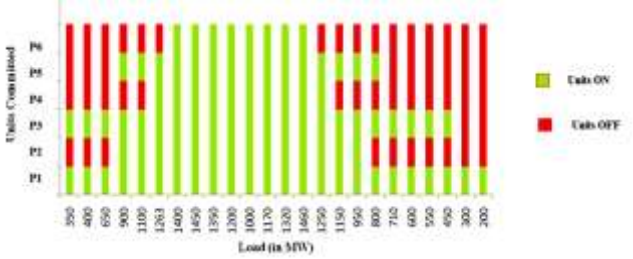

Fig. 15 Feasible Units Committed for various Load Demand

The simulation using Dynamic Programming method on the test system is carried out using two different schemes –

Conventional – DP method

Sequential Combination – DP method

PARAMETERS	Conventional - DP	Sequential Combination - DP
Total Number of States	64	6
Computational Time (sec)	19.221	0.7798
Total Generation Cost (Rs)	1,65,03,451	1,65,48,042

Table 14 Comparison of simulated result of Unit Commitment using Dynamic Programming Method

Thus, the above simulation result reveals that Dynamic Programme through SC – DP has many advantages over the C – DP, the chief advantage being a reduction in the dimensionality of the possible solution space, i.e the total number of states accessed is reduced from 64 in Conventional - DP to 6 in Sequential Combination - DP.

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Furthermore, the computation time of Sequential Combination - DP is 0.7798 sec which when compared to Conventional - DP with 19.221 sec shows that SC - DP is around 95.94% faster and thus is the most efficient method. The below Table 15 shows the feasible units committed along with their generation cost for 24 hrs load profile system. The generator having least AFLC is committed first followed by others.

Hours	P_1 (MW)	P_2 (MW)	P_3 (MW)	P_4 (MW)	P_5 (MW)	P_6 (MW)	Start-Up Cost (Rs)	Prod Cost (Rs)	Fuel Cost (Rs)
1	1	0	1	0	0	0	52000	225973.1	277973.1
2	1	0	1	0	0	0	0	259392.7	537365.8
3	1	0	1	0	0	0	0	445095	982460.8
4	1	1	1	0	1	0	85000	649995.2	1717455.9
5	1	1	1	0	1	0	0	814174.2	2531630.2
6	1	1	1	1	1	0	51500	954454.8	3537585
7	1	1	1	1	1	1	63000	1078400.8	4680985.8
8	1	1	1	1	1	1	0	1121376	5802561.8
9	1	1	1	1	1	1	0	1035682.7	6838244.4
10	1	1	1	1	1	1	0	910122	7748366.5
11	1	1	1	1	1	1	0	748882	8497248.5
12	1	1	1	1	1	1	0	885476.8	9382725.3
13	1	1	1	1	1	1	0	10102539.3	103929846
14	1	1	1	1	1	1	0	1130294	1152327B6
15	1	1	1	1	1	0	30000	943387.8	124966664
16	1	1	1	0	1	0	22000	856845.3	133755117
17	1	1	1	0	1	0	0	690064.2	140655758
18	1	0	1	0	1	0	18000	569499.4	146550752
19	1	0	1	0	0	0	15000	494277.5	151623527
20	1	0	1	0	0	0	0	405473.9	155678266
21	1	0	1	0	0	0	0	367693.1	159349198
22	1	0	1	0	0	0	0	294052.5	162289723
23	1	0	0	0	0	0	11000	187110	164270823
24	1	0	0	0	0	0	0	120060	165480423

Table 15 Units Committed and Cost for 6-Unit System

Figure 16 illustrates the total production cost for committing the feasible generating units to serve the load demand.

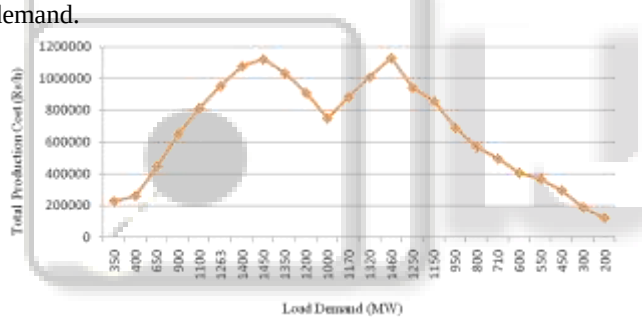

Fig. 16 Total Production Cost for Committed Units

Figure 17 shows the Total fuel cost computed for various load demand during a 24 hours load profile. The total fuel cost consists of start-up cost, shut-down cost and production cost of various generating units.

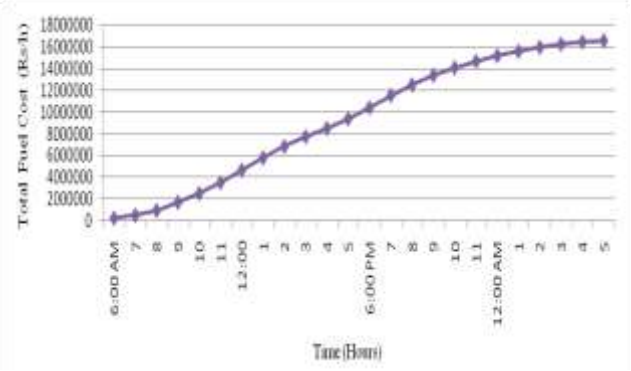

Fig. 17 Total Fuel Cost for 24 hours for 6-Unit system

The below Fig.17 and Table 16 shows the economic scheduling of all the feasible generating units for a 24 hrs load system. Thus, we observe that unit commitment involves proper selection of generating units that minimizes the total operating cost while serving the load demand.

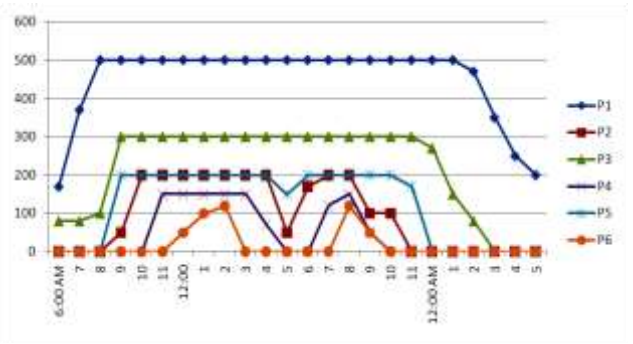

Fig. 18 Power Committed by all the Generating Units

Hours	Load (MW)	P_1 (MW)	P_2 (MW)	P_3 (MW)	P_4 (MW)	P_5 (MW)	P_6 (MW)
1	350	243.8	0	106.2	0	0	0
2	400	271.9	0	128.1	0	0	0
3	650	412.5	0	237.5	0	0	0
4	900	401.2	137.7	228.7	0	132.3	0
5	1100	460.2	181.2	274.6	0	183.9	0
6	1263	466.8	186	279.7	140.8	189.7	0
7	1400	473.6	191	285	146.1	195.6	108.7
8	1450	485.7	200	294.4	150	200	120
9	1350	463.8	183.8	277.4	138.5	187	99.5
10	1200	434.4	162.2	254.5	115.6	161.3	72.1
11	1000	391.7	130.7	221.3	82.4	124	50
12	1170	428.5	157.8	249.9	111	156.2	66.6
13	1320	457.9	179.5	272.8	133.9	181.9	94
14	1460	491.3	200	298.8	150	200	120
15	1250	463.6	183.7	277.3	138.4	186.9	0
16	1150	475	192.1	286.1	0	196	0
17	950	416	148.6	240.2	0	145.2	0
18	800	415.4	0	239.8	0	144.8	0
19	710	446.2	0	263.7	0	0	0
20	600	384.4	0	215.6	0	0	0
21	550	356.3	0	193.7	0	0	0
22	450	300	0	150	0	0	0
23	300	300	0	0	0	0	0
24	200	200	0	0	0	0	0

Table 16 Economic Scheduling of Committed Units for 6-Unit System

D. Generation Cost Minimization through Comparative Analysis between ELD & UC

Economic Load Dispatch involves generation of all the generating thermal units to serve the load demand. Thus, from economic aspects point of view its uneconomical and leads to higher generation cost of the units. Therefore, to overcome this problem Unit Commitment solution using Dynamic Programming method has been used which involves committing only feasible generating units to serve the load demand and is practical in nature and satisfies all the system constraints.

Fig.19 shows the comparison analysis of the feasible generating units in both Economic Load Dispatch and Unit Commitment method.

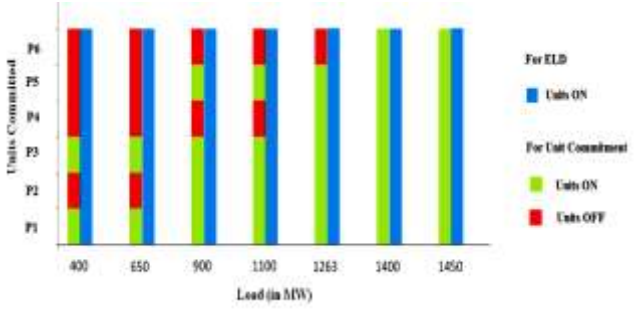

Fig. 19 Comparison of Feasible generating units to serve the Load Demand

A comparison of power committed by each feasible generating unit and production cost in Economic Load Dispatch and Unit Commitment has been shown in Table 17. It depicts that the production cost in Unit Commitment is less as compared to Economic Load Dispatch as only

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selective feasible generating units are committed to serve the load demand.

LOAD (MW)	ECONOMIC LOAD DISPATCH							UNIT COMMITMENT						
	P_1 (MW)	P_2 (MW)	P_3 (MW)	P_4 (MW)	P_5 (MW)	P_6 (MW)	TOTAL PRODUCTION COST (Rs)	P_1 (MW)	P_2 (MW)	P_3 (MW)	P_4 (MW)	P_5 (MW)	P_6 (MW)	TOTAL PRODUCTION COST (Rs)
400	121.7666	50	80	50	50	50	229896.61	271.9	0	128.1	0	0	0	230392.7
650	284.3883	82.1403	145.4514	50	50	50	490192.25	412.5	0	237.5	0	0	0	445895
900	367.011	114.3648	199.9791	72.5597	103.0251	50	676840.58	401.2	135.7	228.7	0	152.5	0	648995.2
1100	413.8473	148.9953	236.2406	110.5934	140.2704	59.7759	836405.11	460.2	180.2	274.6	0	183.9	0	814174.2
1263	447.3708	173.94	262.2593	137.8027	166.8988	86.7362	972782.54	466.8	186	279.7	140.8	189.7	0	954454.8
1400	478.3334	197.8695	287.0348	150	190.5847	110.2776	1089429.56	473.6	191	285	146.1	195.6	108.7	1078400.8
1450	486.9742	200	299.3872	150	199.9824	120	1133937.91	485.7	200	264.4	150	200	120	1123576

Table 17 Comparison of Generation Cost & Power Committed by Units in ELD and UC

Fig. 20 shows the comparison of total production cost in both the cases. The production cost is higher in case of Economic Load Dispatch as it involves committing all the available units, where as in Unit Commitment only feasible generating units are committed.

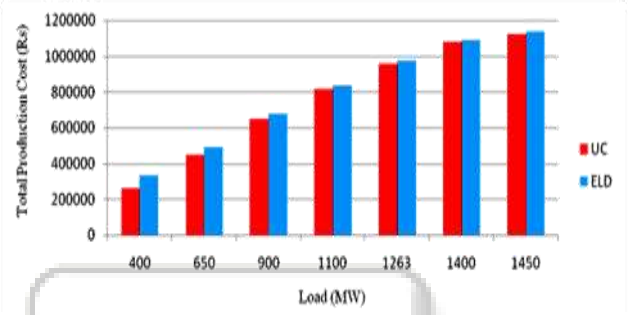

Fig. 21 Comparison of Total Production Cost

Thus, the total generation cost to serve the load in case of Economic Load dispatch is Rs 55,32,460.34 and in case of Unit Commitment is Rs 53,23,088.7. Therefore, a total amount of Rs 2,09,371.64 is saved which amounts to 3.78% cost reduction through Unit Commitment.

VI. CONCLUSION

Thus, from the above result analysis it has been observed that for energy conservation and from economic aspects view, allocating the load demand along with proper scheduling of feasible generating units is necessary. This gives arise to the concept of ELD-UC optimization technique using Dynamic Programming method. Both Economic Load Dispatch (ELD) and Unit Commitment (UC) problem has a significant influence on secure and economic operation of power system. Losses and Generation cost has been minimized by the inclusion of shunt capacitor in the system that injects reactive power. Furthermore, system is analyzed under 3-phase symmetrical fault and its effect on generation has been observed. Test cases revealed that the faulted system returns to its normal operating condition at larger fault impedance. The Dynamic Programming method using SC-DP removes the dimensionality curse and posses many advantages over other traditional methods like it is robust in nature, takes less computational time and satisfies all the given system constraints. Thus, finally conclusion emerges that optimal load dispatch with unit commitment can save huge amount of costs to electric utilities thus improving reliability of operation.

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