FAST ECONOMIC DISPATCH AND ALLEVIATION OF OVER-VOLTAGE UNDER-VOLTAGE CONDITIONS IN A LARGE POWER SYSTEM OPERATION

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ABSTRACT

This paper presents a methodology for evaluation of optimum active power generation scheduling and alleviation of over-voltage and under-voltage conditions in a day-to-day operation of large power systems. Sequential optimization approach is adopted for active and reactive power optimization problems to take the advantage of loose coupling between the two problems. Minimization of fuel cost is considered as an objective function for active power optimization, while for reactive power optimization the objective function selected is to minimize the sum of the voltage deviations by least square minimization technique. Voltage dependency of loads are included in the model. The method is computationally very fast and seems to be suitable to be implemented in real time dispatch centres. Results obtained for IEEE 30-bus test system are presented for illustration purposes.

INTRODUCTION

Active and reactive power optimization is becoming an increasingly important dispatching center function in order to improve the quality of power supply and to judiciously operate the existing resources by minimizing the generation costs, and system losses. While active power optimization is dominated by economic objective of minimizing generation costs, reactive power optimization concerns with re-distribution of reactive power to improve the system voltage profile. Since the solution of the complete problem needs more computer storage and time, this problem is usually decomposed into two phases. Due to loose coupling between the two problems, the sequential optimization provides a considerable advantage over the simultaneous optimization of active and reactive power control variables.

Reactive power dispatch can be defined as the control of generator excitations, variable transformer tap settings and adjustable VAR compensating devices to improve the system voltage profile. The associated analyses are performed minutes prior to its implementation. At heavy/light load periods voltage control is provided by the controllable reactive resources. These reactive power controls, which are scattered throughout the transmission network, function in coordination because the power system has a linear voltage versus reactive power characteristic. This linearity is maintained not only for normal operating conditions, but also for contingencies, which are within system planning criteria. It is worth noting that the voltage magnitudes throughout the system are very important as they must be high enough to support the loads and low enough to avoid equipment breakdown. Thus, we have to control, and, if necessary support or constrain the voltages at all the key points of the power system.

In recent years extensive work has been reported for optimum allocation of active and reactive power. Both linear programming and non-linear programming approaches have been employed. It is also reported that while the non-linear techniques have deficiencies such as unreliability or slowness of convergence, the need for a feasible starting point, gradient step control, using penalty functions, difficulties in recognizing infeasibility and post-optimal sensitivity analysis, etc., the linear methods are attractive in view of their reliability and computational fastness. Most of the researchers have considered minimization of real power losses as an objective function, while satisfying the system constraints. Generally, during heavy load conditions, improvement in the system voltage profile minimizes the real power losses in the system. However, during the light load conditions system may experience more over-voltage problem and minimization of real power losses do not lead to satisfactory voltage conditions.

This paper presents a methodology for evaluation of optimum active power generation scheduling and alleviation of over-voltage and under-voltage conditions in a day-to-day operation of a large power system. The algorithms have been tested on a few typical power systems and the results obtained on the IEEE 30-bus test system are presented for illustration purposes.

APPROACH

The approach is based on the decoupling of active and reactive power optimization. The major steps, with no interactive loops are:

STEP A: Input of system data, loads, production costs and constraints
STEB B: Active power optimization
STEP C: Security analysis for modification of the generating unit limits and branch flows.
STEP D: Confirmation of satisfactory steady state system performance

STEP E: Reactive power optimization
STEP F: Output results.

In the day-to-day operation of power systems, Step A gives the details of a set of forecasted load conditions, generation costs, import/export details and costs, and network configuration/constraints, etc. Step B gives an optimal combination of active power dominated by economic objectives of minimizing active power generation costs. Step C does the security analysis and gives the corrective measures. In Step D confirmation of satisfactory steady state system performance is obtained. At this stage we have a solution which has optimum active power generation and import/export schedule besides satisfying the security constraints. Step E performs reactive power optimization using the active power generation schedule obtained in the earlier steps as the input. After obtaining the results of this step again we go through the steps C and D to obtain the final solution, where active and reactive power is optimally scheduled and all the system performance constraints are met satisfactorily. This paper concentrates on the Steps B and E.

POWER FLOW MODEL INCORPORATING THE LOAD CHARACTERISTICS

The loads in a power system generally do not remain constant, they change continually and due to variation in the system frequency and voltage at the load buses. Though optimal power flow solution is generally assumes frequency to be nominal, the voltage profile in the system may be varied. It is necessary to consider the loads as function of voltage, particularly when the voltage profile is improved by reactive power optimization.

Load Model:

Active and reactive power loads at a bus modelled as

$$PL_i = PL_{oi}\ (A1 + A2 .\ V + A3 \ .\ V^2) \qquad (1)$$

$$QL_i = QL_{oi}\ (R1 + R2 \ .\ V + R3 \ .\ V^2) \qquad (2)$$

where P_{Loi}, Q_{Loi} : active, reactive loads specified at nominal voltage at bus i
A1, R1: portion of total load proportional to constant power
A2, R2: portion of total load proportional to constant current
A3,R3: portion of total load proportional to constant impedance.

FORMULATION OF THE P-OPTIMIZATION PROBLEM

Mathematically the problem can be stated as follows. Minimize the objective function

$$F_T = \sum_{i=1}^{g} F_i$$

subject to the conditions

$$\sum_{i=1}^{g} P_{Gi} = P_{Load}^{total} + P_{loss}^{total}$$

and

$$P_{Gi}^{max} \le P_{Gi} \le P_{Gi}^{max} \qquad (3)$$

The fuel cost function F_i can be expressed as

$$F_i = C0_i + C1_i P_i + C2_i P_i^2$$

The problem can be solved using Lagrange's multiplier method, i.e.

$$G = F_T + \lambda\ (\sum_{i=1}^{g} P_{Gi} - P_{load} - P_{loss})$$

for the object function to be minimum

$$\frac{dF_i}{dP_{Gi}} = \lambda (1 - \frac{\partial P_{loss}}{\partial P_{Gi}}) \quad \text{or} \quad L_i \frac{dF_i}{dP_{Gi}} = \lambda \qquad (4)$$

where, λ : Lagrangian multiplier,

$\frac{dF_i}{dP_{Gi}}$: Incremental cost rate (IC) of ith generator

$\frac{\partial P_{loss}}{\partial dP_{Gi}}$: Incremental transmission loss (ITL) for bus i

L_i is called the penalty factor for bus i.

The equations (3) and (4) are known as coordination equations.

Computation of Incremental Transmission Loss

From the Newton-Raphson power flow method the real and reactive power mismatch can be written as

$$\begin{bmatrix} dP \\ dQ \end{bmatrix} = [J] \begin{bmatrix} d\delta \\ dV \end{bmatrix} \qquad (5)$$

where

$$\begin{bmatrix} dP \\ dQ \end{bmatrix}^t : [dP_2, \ldots, dP_n,\ dQ_{g+1}, \ldots, dQ_n]$$

Node 1 is considered as reference bus

$$\begin{bmatrix} d\delta \\ dV \end{bmatrix}^t : [d\delta_2 \ldots d\delta_n,\ dV_{g+1} \ldots dV_n]$$

$$[J] : \begin{bmatrix} (\partial P/\partial \delta) & (\partial P/\partial V) \\ (\partial Q/\partial \delta) & (\partial Q/\partial V) \end{bmatrix} \text{ of (2n-g-1) (2n-g-1) size.}$$

The reference bus mismatch is

$$dP_1 = [\ \frac{\partial P_1}{\partial \delta}\ \ \frac{\partial P_1}{\partial V}\ ] \qquad (6)$$

where

$$\left[\frac{\partial P_1}{\partial \delta} \; \frac{\partial P_1}{\partial V}\right] : \left[\frac{\partial P_1}{\partial \delta_2} \; \cdots \; \frac{\partial P_1}{\partial \delta_n} \; \frac{\partial P_1}{\partial V_{g+1}} \; \cdots \; \frac{\partial P_1}{\partial V_n}\right]$$

$$dP_1 = \left[\frac{\partial P_1}{\partial \delta} \; \frac{\partial P_1}{\partial V}\right] [J^{-1}] \begin{bmatrix} dP \\ dQ \end{bmatrix} \quad (7)$$

$$dP_1 = [\phi] \begin{bmatrix} dP \\ dQ \end{bmatrix} \quad (8)$$

where $[\phi]^t : [\gamma_2 \cdots \gamma_n, \beta_{g+1} \cdots \beta_n]$

$$[\phi] = \left[\frac{\partial P_1}{\partial \delta} \; \frac{\partial P_1}{\partial V}\right] [J^{-1}]$$

or

$$[\phi]\,[J] = \left[\frac{\partial P_1}{\partial \delta} \; \frac{\partial P_1}{\partial V}\right]$$

$$[J]^t \, [\phi]^t = \left[\frac{\partial P_1}{\partial \delta} \; \frac{\partial P_1}{\partial V}\right]^t \quad (9)$$

Using sparse triangularization $[\phi]$ is obtained from the solution of (9).

The total transmission loss can be expressed as a function of bus powers

$$P_{loss} = P_{loss}\,(P_{Gi} \cdots P_{Gg})$$

This can be expanded by Taylor series expansion around the initial bus powers P^o_G as follows

$$P_{Loss}(P_G) = P_{loss}(P^o_G + dP) = P_{loss}(P_G^o) + P'_{loss}(PG)\,dP$$

$$P_{loss}(P_G) = P_{loss}\,(P^o_G) + dP_{loss}$$

The total transmission losses in a network is a function of bus loads and generations. From the power balance equation the total transmission loss is

$$P_{loss} = \sum_{i=1}^{n} P_i \quad (10)$$

$$dP_{loss} = dP_1 + \sum_{i=2}^{n} dP_i \quad (11)$$

Substituting for dP_1

$$dP_{loss} = \sum_{i=2}^{n} (1 + \gamma_i)\, dP_i + \sum_{i=g+1}^{n} \beta_i\, dQ_i \quad (12)$$

The incremental transmission loss $(ITL)_i$ is defined as change in transmission loss due to change in generation at ith bus keeping all other generations constant.

$$(ITL)_i = \frac{dP_{loss}}{dP_{Gi}} = \frac{dP_{loss}}{dP_i} = 1 + \gamma_i$$

for $i = 2,\ldots,g$

for slack bus $ITL_1 = 0$; $L_1 = 1$.

The penalty factor $L_i = -1/\gamma_i$, $i = 2,\ldots,g$ (13)

COMPUTATION OF OPTIMUM GENERATION P_{Gi}

For optimality we have,

$$dF_i/dP_{Gi} = \lambda(1 - ITL_i)$$

From the cost function $F_i = CO_i + C1_i\,P_G + C2_i P_{Gi}^2$

$$dF_i/dP_{Gi} = C1_i + 2C2_i\,P_{Gi}$$

$$P_{Gi} = \left[\frac{-\lambda\gamma_i - C1_i}{2C2_i}\right]$$

$$P_{Gi} = \left[\frac{\lambda}{L_i} - C1_i\right)/2C2_i \quad (14)$$

Computation λ in closed form

For economic dispatch operation, the total transmission loss at optimum dispatch is

$$P_{loss}(P_G) = P_{loss}(P_G^o) + \sum_{i=1}^{g} (1 + \gamma_i)\, dP_i$$

$$= P_{loss}(P_G^o) + \sum_{i=1}^{g} (1 + \gamma_i)\,(P_{Gi} - P_{Gi}^o)$$

Case A: No generator is violating its limits

$$\sum_{i=1}^{g} P_{Gi} = P_{load} + P_{loss}\,(P_G)$$

$$= P_{load} + P^o_{loss} + dP_{loss}$$

P_{loss} = initial loss (P^o_{loss}) + change in loss (dP_{loss}) due to change in the generation

$$\sum_{i=1}^{g} P_{Gi} = P_{load} + P^o_{loss} + \sum_{i=1}^{g} (1 - 1/L_i)\,(P_{Gi} - P^o_{Gi}) \quad (15)$$

Substituting for P_{Gi} from (14) into (15)

$$\lambda = \sum_{i=1}^{g} \left[\frac{P^o_{Gi}}{L_i} + \frac{C1_i}{L_i 2C2_i}\right] / \sum_{i=1}^{g} \frac{1}{2C2_i L_i^2} \quad (16)$$

Case B: When some generators violate their limits:

v - violating

nv - nonviolating.

$$\sum_{\substack{i=1 \\ v}}^{g} P_{Gi} + \sum_{\substack{i=1 \\ nv}}^{g} P_{Gi} = P_{load} + P^o_{loss} + dP_{loss} \quad (17)$$

where dP_{loss} is the change in losses due to the changes in the generations of the non-violating generators

$$\lambda = \left[P_{load} + P^o_{loss} - \sum_{\substack{i=1 \\ v}}^{m} P_{Gi} - \sum_{\substack{i=1 \\ nv}}^{m} P^o_{Gi} + \sum_{\substack{i=1 \\ nv}}^{m} 1/L_i\left(P^o_{Gi} + \frac{C1_i}{2C2_i}\right)\right] / \left[\sum_{\substack{i=1 \\ nv}}^{m} \frac{1}{2C2_i L^2_i}\right] \quad (18)$$

knowing λ, P_{Gi} optimum is obtained from Eq. (14).

COMPUTATIONAL PROCEDURE FOR P-OPTIMIZATION

STEP 1: Read the system data relating to
(a) transformer impedances, tap settings, limits and step size
(b) transmission line impedances, shunt capacitances
(c) switchable var compensating bus details
(d) generation schedule, its maximum and minimum limits and cost coefficients

STEP 2: Form the network matrices.

STEP 3: Perform initial power flow with arbitrary generation schedule

STEP 4: Compute the fuel cost of each generator and the total fuel cost

STEP 5: Compute the incremental transmission loss coefficients (ITL)

STEP 6: Compute λ

STEP 7: Compute active power generation for all the generators using λ

STEP 8: Check for the active power generation limits for all the generators

STEP 9: If no generators is violating the limits Go to Step 13

STEP 10: Limit the active power generation suitably for the violating generators.

STEP 11: Compute λ for the generators not violating the limits

STEP 12: Compute active power generations and go to step 8

STEP 13: Perform the power flow

STEP 14: Check for the violation of P-generation limits. If any generator is violated go to step 5

STEP 15: Compute the fuel cost of each generator and the total fuel cost. Print the optimum generation of generators, loss and fuel cost.

STEP 16: STOP.

REACTIVE POWER DISPATCH - PROBLEM FORMULATION

In a day-to-day operation of power systems, the system experiences over-voltage and under voltage conditions during light/heavy load conditions and also during certain contingencies. The dispatching engineer has to bring these voltages under control within a band of acceptable ranges by utilizing all the reactive power sources available in the system. Hence the objective function is selected as minimization of the sum of the squares of voltage deviations from pre-selected desired values. All the possible reactive power control variables considered are

* The transformer tap settings (T)
* The generator excitation settings (V)
* The switchable var compensator (SVC) settings.

The dependent variables are:

* The reactive power outputs of the generators (Q)
* The voltage magnitudes of the buses other than the generator buses (V)

Consider a system where,

n = number of total buses
g = the number of generator
t = the number of transformers
s = the number of SVS buses and
r = n-g-s the number of remaining buses.

It is assumed that
1,2,...,g are the generator buses, g+1, g+2,...,g+s are the SVC buses, and g+s+1, g+s+2, ..., n are the remaining buses.

The objective function is expressed as

$$\underset{X}{\text{Minimize}}\ J(X) = \sum_{i=g+1}^{n} [V_i^{des} - V_{i(x)}^{cal}]^2 \tag{19}$$

where X is a vector of control variables

$$[X]^t = [T_1 \dots T_t,\ V_1 \dots V_g,\ Q_{g+1} \dots Q_{g+s}]$$

The number of control variables are (t+g+s).

The condition for minimization of J(X) is $\nabla_x J(X) = 0$.

Defining

$$[H] = \begin{bmatrix} \frac{\partial V_{g+1}}{\partial T_1} & \dots & \frac{\partial V_{g+1}}{\partial T_t} & \frac{\partial V_{g+1}}{\partial V_1} & \dots & \frac{\partial V_{g+1}}{\partial V_g} & \frac{\partial V_{g+1}}{\partial Q_{g+1}} & \dots & \frac{V_{g+1}}{\partial Q_{g+1}} \\ \vdots \\ \frac{\partial V_n}{\partial T_1} & \dots & \frac{\partial V_n}{\partial T_t} & \frac{\partial V_n}{\partial V_1} & \dots & \frac{\partial V_n}{\partial V_g} & \frac{\partial V_n}{\partial Q_{g+1}} & \dots & \frac{\partial V_n}{\partial Q_{g+s}} \end{bmatrix}$$

We have

$$\nabla_x J(x) = -2\ [H]^t \begin{bmatrix} V_{g+1}^{des} - V_{g+1}^{cal} \\ \dots \\ V_n^{des} - V_n^{cal} \end{bmatrix} \tag{20}$$

To make $\nabla_x J(X)$ equal zero, Newton's method is applied which gives the corrections required for the control variables

$$\Delta X = \left[\frac{\partial \nabla_x J(X)}{\partial X} \right]^{-1} [-\nabla_x J(X)] \tag{21}$$

The Jacobian of $\nabla_x J(X)$ is calculated by treating [H] as a constant matrix

$$\frac{\partial \nabla_x J(X)}{\partial X} = \frac{\partial}{\partial X} [-2[H]^t \begin{bmatrix} V_{g+1}^{des} - V_{g+1}^{cal} \\ \dots \\ V_n^{des} - V_n^{cal} \end{bmatrix}$$

$$= 2[H]^t\ [H]$$

Hence

$$\Delta X = [2[H]^t\ [H]]^{-1}\ [-2[H]^t \begin{bmatrix} V_{g+1}^{des} - V_{g+1}^{cal} \\ \dots \\ V_n^{des} - V_n^{cal} \end{bmatrix}$$

$$\Delta X = [H^t\ H]^{-1}\ H^t \begin{bmatrix} V_{g+1}^{des} - V_{g+1}^{cal} \\ \dots \\ V_n^{des} - V_n^{cal} \end{bmatrix} \tag{22}$$

COMPUTATION OF (H) MATRIX

The elements of H matrix can not be defined directly and so it is evaluated as a sensitivity matrix relating to the dependent and control variables as follows. Considering the fact that the reactive power injections at a bus does not change for a small change in the phase angle of the bus voltage, the relation between the net reactive power change at any node due to change in the transformer tap settings and the voltage magnitudes can be written as,

$$\begin{bmatrix} \Delta Qg \\ \Delta Qs \\ \Delta Qr \end{bmatrix} = \begin{bmatrix} A1 & A2 & A3 & A4 \\ A5 & A6 & A7 & A8 \\ A9 & A10 & A11 & A12 \end{bmatrix} \begin{bmatrix} \Delta Tt \\ \Delta Vg \\ \Delta Vs \\ \Delta Vr \end{bmatrix} \qquad (23)$$

where,

$$(\Delta Qg) = [\Delta Q_1, \ldots, \Delta Q_g]^t$$

$$(\Delta Qs) = [\Delta Q_{g+1}, \ldots, \Delta Q_{g+s}]^t$$

$$(\Delta Qr) = [\Delta Q_{g+s+1}, \ldots, \Delta Q_n]^t$$

$$(\Delta Tt) = [\Delta T_1, \ldots, \Delta T_t]^t$$

$$(\Delta Vg) = [\Delta V_1, \ldots, \Delta V_g]^t$$

$$(\Delta V_s) = [\Delta V_{g+1}, \ldots, \Delta V_{g+s}]^t$$

$$(\Delta Vr) = [\Delta V_{g+s+1}, \ldots, \Delta V_n]^t$$

and the sub-matrices A1 to A12 are the corresponding terms of the partial derivatives

$$\frac{\partial Q}{\partial T} \quad \text{and} \quad \frac{\partial Q}{\partial V}$$

In the relation (23), by transferring all the control variables to the right hand side and the dependent variables to the left hand side and rearranging,

$$\begin{bmatrix} \Delta Qg \\ \Delta Vs \\ \Delta Vr \end{bmatrix} = \begin{bmatrix} S1 & S2 \\ S3 & S4 \end{bmatrix} \begin{bmatrix} \Delta Tt \\ \Delta Vg \\ \Delta Qs \end{bmatrix} \qquad (24)$$

From the above equation

$$\begin{matrix} \Delta Vs \\ \\ \Delta Vr \end{matrix} = [H] \begin{matrix} \Delta Tt \\ \Delta Vg \\ \Delta Qs \end{matrix}$$

where,

$$S1 = (B1) + (-B2.B4^{-1}).(B3)$$
$$S2 = (-B2.B4^{-1}).(B5)$$
$$S3 = (B4^{-1}).(B3)$$
$$S4 = (B4^{-1}).(B5)$$
$$B1 = [A1 \quad A2]$$
$$B2 = [-A3 \quad -A4]$$

$$B3 = \begin{bmatrix} A5 & A6 \\ A9 & A10 \end{bmatrix}; \quad B4 = \begin{bmatrix} -A7 & -A8 \\ -A11 & -A12 \end{bmatrix}$$

$$B5 = \begin{bmatrix} -I \\ 0 \end{bmatrix}$$; (I) is an identity matrix of (s x s) size

COMPUTATIONAL PROCEDURE

In a day-to-day operation of power systems, for a particular load and set of network conditions, an optimal combination of real power generation schedule has to be obtained from an active power optimization algorithm. This will be the starting point for the proposed reactive power optimization algorithm. The control variables are to be initialized in the P-optimization algorithm. The following steps are followed to obtain the optimal reactive power allocation in the system.

STEP 1: Perform the power flow
STEP 2: Compute the voltage error matrix $[V^{err}] = [V^{des} - V^{cal}]$
STEP 3: If $[V^{err}]$ is within the specified tolerance go to step 8
STEP 4: Compute [H] matrix
STEP 5: Compute the corrections required for the control variables $[\Delta X]$, using triangular factorization from $[H^tH][\Delta X] = [H^t][V^{err}]$
STEP 6: The computed ΔX are adjusted for suitable step lengths
STEP 7: Check for the limits of these control variables. Limit the suitable ones. If all the control variables are not limited go to Step 1.
STEP 8: Print the results.

SYSTEMS STUDIED AND RESULTS

Computer programs based on the models and solution techniques described in previous sections have been developed using personal computers (PCs) and implemented on different power systems. The results obtained for IEEE 30-bus test system are presented.

The single line diagrams is shown in Fig. 1. The system has 37 transmission lines, 21 P-Q loads, 6 generators, 4 regulating transformers and 11 SVC-buses. The initial power flow shows that the system total load is 272.6 MW (151.4 MVAR), loss 6.0 MW, cost per MW met is 16.2$. The voltage profile is unsatisfactory with as low as 0.89 p.u. Both P-optimization and Q-optimization are carried out on the system. The optimum generation, VAR control variables and the improved voltage profile are given in Tables 1, 2 and 3 respectively. The total load is increased to 281.5 MW (156.0 MVAR), losses reduced to 5.4 MW and the cost per MW load met is 15.9$. The overall computational time for the complete solution is about 48 seconds on an IBM compatible 80286 based PC/AT.

Table: 1 Generation Data/Results

Bus No.	Initial PG(MW)	Optimum PG(MW)	PG Max (MW)	PG Min (MW)	C0	C1	C2
1	58.6	36.9	90.0	30.0	213.00	1166.90	53.30
2	65.0	45.0	80.0	30.0	240.00	1083.30	74.10
5	45.0	65.0	80.0	30.0	240.00	1083.30	74.10
8	40.0	55.0	70.0	20.0	200.00	1033.30	88.90
11	35.0	45.0	70.0	20.0	200.00	1033.30	88.90
13	35.0	40.0	70.0	20.0	200.00	1033.30	88.90

The system total load at nominal 1 p.u. voltage specified is 283.5 MW (157.5 MVAR).

Table 2: Details of VAR Control Variables

VAR Control variables	Max.	Min	Step	Initial	Optimum
Transformer taps (p.u.)					
T_1	1.1	0.9	0.025	1.0	0.925
T_2	1.1	0.9	0.025	1.0	1.075
T_3	1.1	0.9	0.025	1.0	0.975
T_4	1.1	0.9	0.025	1.0	1.025
Generator excitations (p.u.)					
V_1	1.1	0.95	0.0125	1.0	1.025
V_2	1.1	0.95	0.0125	1.0	1.025
V_5	1.1	0.95	0.0125	1.0	1.025
V_8	1.1	0.95	0.0125	1.0	1.0
V_{11}	1.1	0.95	0.0125	1.0	1.0
V_{13}	1.1	0.95	0.0125	1.0	1.0
SVC reactive power (MVAR)					
Q_{10}	5.0	0.0	1.0	0.0	4.0
Q_{12}	5.0	0.0	1.0	0.0	3.0
Q_{15}	5.0	0.0	1.0	0.0	4.0
Q_{17}	5.0	0.0	1.0	0.0	4.0
Q_{20}	5.0	0.0	1.0	0.0	1.0
Q_{21}	5.0	0.0	1.0	0.0	5.0
Q_{23}	5.0	0.0	1.0	0.0	1.0
Q_{24}	5.0	0.0	1.0	0.0	5.0
Q_{26}	5.0	0.0	1.0	0.0	2.0
Q_{29}	5.0	0.0	1.0	0.0	1.0
Q_{30}	5.0	0.0	1.0	0.0	5.0

Table 3: Voltages at Load Buses in p.u.

Bus No	Initial	Optimum	Bus No	Initial	Optimum
3	0.986	1.002	19	0.918	0.950
4	0.983	0.997	20	0.921	0.954
6	0.985	0.996	21	0.923	0.959
7	0.983	0.999	22	0.924	0.960
9	0.972	1.012	23	0.920	0.954
10	0.936	0.968	24	0.912	0.950
12	0.955	0.978	25	0.918	0.952
14	0.937	0.963	26	0.901	0.950
15	0.932	0.962	27	0.930	0.955
16	0.940	0.968	28	0.980	0.994
17	0.931	0.965	29	0.905	0.950
18	0.921	0.952	30	0.888	0.950

CONCLUSIONS

Fast algorithms for economic dispatch and alleviation of over-voltage and under-voltage conditions is a day-to-day operation of large power system are presented. The method seems to be suitable to be implemented in real time dispatch centres with proper constraints such as spinning reserve, generator's pick-up characteristics taken into consideration.

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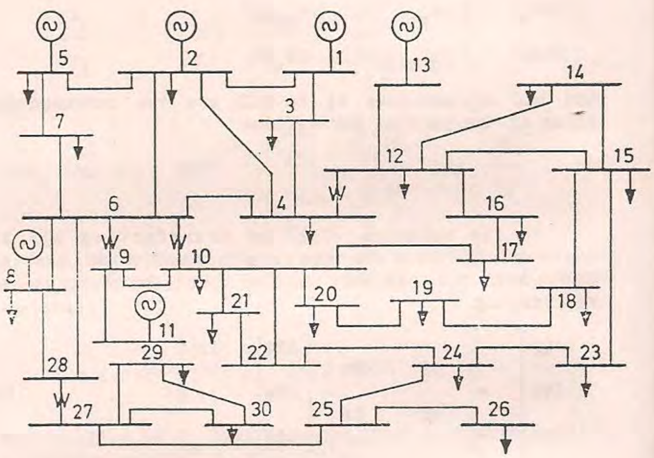

FIG. 1 SINGLE LINE DIAGRAM OF 30-BUS SYSTEM