LOSS MINIMIZATION IN TRANSMISSION AND DISTRIBUTION SYSTEM

A THESIS

submitted in fulfilment of the
requirements for the award of the degree
of
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in
WATER RESOURCES DEVELOPMENT

By

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CERTIFICATE

I hereby certify that the work which is being presented in this thesis entitled, ' LOSS MINIMIZATION IN TRANSMISSION AND DISTRIBUTION SYSTEM' in fulfilment of the requirement for the award of the Degree of Doctor of Philosephy, submitted in the Department of Water Resources Development of the University of Roorkee, Roorkee is an authentic record of my own work carried out during the period from November 1981 to December 1984 under the supervision of Prof. O.D. Thapar and Dr. J.D. Sharma.

The matter embodied in this thesis has not been submitted by me for the award of any other degree.

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A B S T R A C T

The demand for electrical energy is increasing exponentially with the time and it has become necessary for the electrical industry to transport a large amount of power over large and complex transmission and distribution system. Further, the increasing cost of new generation, transmission and distribution facilities, and continuous power shortages have made the industry conscious of energy lost in transportation to the customer. The first step in conservation of energy is elimination of all waste. Electric power system must be made as efficient as possible so that the power that is generated from scarce energy sources reaches the consumer to the maximum possible extent. This study is directed towards the development of efficient mathematical models and methods to minimize the losses in large transmission and distribution networks in the design and operation phases.

The first model presented in this study minimizes the real power losses, the deviation from the optimal active power despatch, and the difference between percentage sharing of reactive power among generators. The objective function is optimized such that the power flow equations and constraints imposed upon the variables by the system operating conditions and design considerations are satisfied. All problem variables are decomposed in two sets i.e. independent and dependent variables to reduce the complexity of the

problem. Generator terminal voltage magnitudes, transformer tap positions, and setting of reactive power sources available in the system are taken as independent variables. Load node voltage magnitudes and reactive power generation from various generating sources are taken as dependent variables. The reduced gradient is then calculated using sensitivity relationship between dependent and independent variables.

Two types of formulation of loss minimization problem are in use at present. The first is linear programming approach and the second is hessian approach. Both of these methods are time consuming and require more computer storage. These methods are not suitable to solve large power system problems. Based on approximation of hessian or its inverse with first order derivatives and exploiting sparsity and symmetry, three new approaches are suggested to solve the problem of losses minimization in transmission system. The new approaches are suitable to solve large power systems as these methods require less computer storage and computation time. First method is based on the Quasi Newton method of updating the inverse Hessian. The Broyden-Fletcher-Gold farb-Shanno (BFGS) update is used in this study which is the best current update formula for use in un-constrained minimization. It overcomes the conditioning problem resulting into computational efficiency. The method has global convergence and is robust and stable. The step length is calculated by using unidimensional search technique. In the second method much of the computation which takes place in unidimensional search for step length is avoided. It is based on Fletcher's method and uses an approximate step size, which helps further in reducing the computer storage and computational burden. Third method is based on the Toint's sparse hessian updating procedure which exploits sparsity and symmetry of the hessian matrix. Thereby the computer time and storage requirement is further reduced. This method has a global convergence and Q-super linear rate of convergence. These new approaches are suitable to solve large power systems as these methods require less computer storage and computation time. Correction in the groups of decision variables are carried out simultaneously as well as hierarchically.

Provision of reactive compensation at the load nodes is another important way to reduce transmission losses. A model is presented in this study to reduce transmission losses via optimum reactive compensation planning in the system. In this model the cost function is the summation of the cost of real power losses, installation and O & M cost of reactive compensation, and the difference between percentage sharing of reactive power by generators. The power flow equations and the limit on variables are taken as constraints. Because of large number of variables and constraints involved, and both the cost function and constraints being non-linear, the problem is quite a challenging one from computational considerations. The complexity and size of problem has motivated the decomposition of the problem variables into two groups comprising of state and decision variables. Sensitivity relationship between dependent and independent variables is used to find out the reduced gradient. Three new approaches based on Quasi Newton method, Fletcher's method, and sparse hessian method of non-linear programming are presented to solve this problem. These methods have significant advantages over the linear programming technique and other second order derivative methods, as described in previous paragraph.

Large power systems have to handle large quantum of power to be transported over long distances. As the power system size increases it becomes extremely difficult to handle the problem of loss minimization due to large number of variables. Besides, computational effort and storage requirement increases exponentially with the increase in number of variables. To overcome these difficulties, a decomposition method is developed. In this method a large power system is decomposed into a number of sub-systems and each sub-system is solved independently. This method is very efficient for large power systems.

The distribution system constitutes a significant part of a total power system. Since the distribution voltage level is low and the low distribution system is extensive, this system is prone to have more losses compared to the other parts of the system. Moreover the energy cost at the distribution level will be maximum and it will lead to more severe financial implications. Minimization of losses in distribution system therefore, yields maximum benefits. One way to achieve it is by optimal conductor gradation in the distribution system. In all the methods in use for distribution system planning economic benefits arising out of voltage boost along the feeder are neglected to simplify the procedure, which is incorrect. These benefits are significant and by neglecting them only suboptimal solutions are arrived at. In the present formulation of optimal conductor gradation for multi-ended radial feeder and interconnected system, these economic benefits are accurately accounted for. The cost function includes the summation of cost of power (KW) and energy (KWH) losses, installation, operation and maintenance cost of distribution lines. Group variational method is used to solve the problem. The proposed model takes into account the non-uniform distribution of loads in the distribution system, load growth, growth in load factor with the time, and growth in cost of electrical energy and distribution system equipments.

Application of shunt capacitor in distribution system to improve power factor is another way to reduce losses significantly in the distribution system. The application of shunt capacitor results in a heavy reduction of system losses, appreciable release in system capacity, and produces a uniform voltage boost along the distribution system. In the methods in use for optimal shunt capacitor installation, benefits arising from the voltage boost due to application of shunt capacitor in the system is neglected to simplify the problem. These economic benefits are significant and their neglect results in the sub-optimal solution. The solution procedure presented in this study takes into account, the benefits arising from the voltage boost due to application of shunt capacitor in the system. The method is capable of solving multi-ended and interconnected radial feeders. The method takes into account the non-uniform distribution of loads, growth in cost of energy, growth in labour and power system equipment cost, load growth, growth in load factor with time, and graded conductor in the distribution system. The cost function includes the cost of installation, operation and maintenance of shunt capacitors and cost of power (KW) and energy (KWH) losses. Group variational method is used to solve this problem.

The lack of importance attached to the design of sub-transmission and distribution system in comparison with generation and transmission system has increased the losses in distribution system. Another factor leading to more losses in this system is off shoot of distribution system planning studies. To account for all these deficiencies, it becomes necessary to improve upon the existing distribution system by changing the conductor in distribution lines and install shunt capacitors at load centres. Therefore, a model is presented for system improvement in distribution system. Cost function consists of cost of power (KW) and energy (KWH) losses, cost of conductor replacement and installation, maintenance and operation cost of shunt capacitors.

The general purpose software are developed for all the methods developed in the present study and are tested on DEC 2050. These programs have been tested on MPEB Jabalpur (an electric utility in India) power system and the results are reported.

It is expected that the new techniques suggested in this study for loss minimization in transmission and distribution systems will find a great utility in power industry. The proposed solution methods are simple, more efficient, reliable and quite promising.

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NOMENCLATURE

The list of principal symbols used in the thesis is given below. The other symbols are explained where they have occurred.

AK	=	Weightage to reactive power sharing.
A	=	Constant
B_i	=	Reactive power capability range of ith generator
B	=	Hessian matrix
BP_i	=	Active power flow in Branch i
C_i	=	Reactive compensation at node i
C_i^m	=	Minimum allowable reactive compensation at node i
C_i^M	=	Maximum allowable reactive compensation at node i
CT_1	=	Per unit cost of transmission system losses
CI_i	=	Installation cost of reactive compensation at node i
$CADL_i$	=	Per unit demand cost of losses for the ith year.
CP	=	Per unit production cost
CT	=	Per unit transmission system cost
$CAEL_i$	=	Per unit energy cost of losses for the ith year
CBP_i	=	Calculated active power flow in branch i
CD_1	=	Per unit cost of distribution system losses
CS_i	=	Per unit cost of ith distribution line
CM_i	=	Per unit cost of maintenance for ith capacitor.
CST	=	Per unit subtransmission system cost

CTO_i	=	Per unit cost for taking out the conductor in ith distribution line.
CDT_i	=	Difference in two conductor costs for ith distribution line.
CMT_i	=	Difference in maintenance cost of two conductors for ith distribution line
CH_i	=	Conductor change out cost for ith distribution line
e	=	Price escalation rate P.U.
EC	=	Per unit energy cost
FC_1	=	Cost of power and energy losses
F_A	=	Summation of square of differences between scheduled active power and calculated active power.
F_S	=	Summation of differences of reactive power sharing among generators with weightages.
F_C	=	Installation, operation, and maintenance cost of reactive compensation
$g(x_k)$	=	$[\nabla_r f(y,x)]^k$
H^k	=	Inverse hession at kth iteration
I_{ij}	=	Current flowing in the line connecting nodes i and j from i node to j node.
I	=	Unit matrix
i	=	Interest rate P.U.
LAF	=	Loss allowance factor
LSF_i	=	Loss factor for the ith year

LF_k	=	Load factor in kth year
LF_u	=	Ultimate load factor
LF_p	=	Present load factor
LM_i	=	Per unit maintenance cost of ith distribution line.
NG	=	No. of Generator Buses.
N	=	No. of total nodes in the system.
NT	=	No. of transformers
NC	=	No. of reactive compensation source nodes
NLE	=	No. of lines
NY	=	No. of years
NBC	=	No. of cut branches
P_{ij}	=	Real power flow from node i to node j in the line connecting node i and j.
$P_{Li,j}$	=	Real power losses in line L connecting node i and j.
PS_i	=	Scheduled active power at node i
PC_i	=	Calculated active power at node i
PRF	=	Peak responsibility factor
Q_{ij}	=	Reactive power flow from node i to node j in the line connecting node i and j
Q_i	=	Net reactive power injection at node i
Q_i^m	=	Minimum allowable reactive power generation of ith generator
Q_i^M	=	Maximum allowable reactive power generation of ith generator.

RF	=	Reserve factor
RP	=	Production fixed cost rate P.U.
RT	=	Transmission system fixed cost rate P.U.
RL_i	=	Length of distribution line
RST	=	Sub-transmission fixed cost rate P.U.
SC_i	=	Switched capacitor capacity at node i
SF_i	=	Fixed cost of switched capacitor at node i
SV_i	=	Per unit variable cost of capacitor at node i.
T_i	=	Tap ratio of ith transformer
T_i^m	=	Minimum allowable tap ratio of ith transformer
T_i^M	=	Maximum allowable tap ratio of ith transformer
TCDL	=	Total demand cost of losses P.U.
TCEL	=	Total energy cost of losses P.U.
TIME	=	Time in hours per year
V_i	=	Voltage magnitude at node i
V_i^m	=	Minimum allowable voltage magnitude at node i
V_i^M	=	Maximum allowable voltage magnitude at node i.
W	=	A constant
Y_{ij}	=	ijth element of the nodal admittance matrix (G_{ij} + B_{ij}).
Z_k	=	Change in reduced gradient between the iteration K and K-1.

θ_i = Voltage phase angle at node i

θ_{ij} = Voltage phase angle difference between node i and j.

$\langle A,B \rangle$ = Multiplication of column matrix A with transpose of matrix B where B is a column matrix.

$|| A ||_2$ = $\left[\sum_{i=1}^{N} |A_i|^2 \right]^{1/2}$

λ = Step length

ϵ = Accuracy factor a small quantity

$\Delta_x^{(k)}$ = Vector from $x^{(k)}$ to $x^{(k+1)}$

$\Delta_g^{(k)}$ = $\nabla f(x^{k+1}) - \nabla f(x^k)$

M.U. = Money unit.

CHAPTER - I

INTRODUCTION

In the process of delivering electrical energy to the consumers, losses are incurred in the transmission and distribution system. Reduction in these transmission and distribution losses will increase the transmission and distribution system efficiency. Also, the present day energy crisis calls for more efficient use of transmission and distribution system. Although the transmission and distribution system is more efficient than any other part of the energy system, but the efficiency of this system can further be improved by adjusting the system operating conditions and with little investment.

This investigation is directed towards the development of efficient mathematical models and methods to minimize the losses in large size transmission and distribution systems in the design and operation phases.

1.1 LOSSES IN TRANSMISSION SYSTEM

With the development of integrated power systems and increase in electrical energy demand, the size and complexity of transmission system have grown tremendously. Inadequate planning and operating studies coupled with rapid expansion has resulted in excessive losses in transmission system. These losses can be reduced considerably by proper planning, operation, and expansion of the system.

It is the responsibility of the system planner to design a transmission system with minimum losses. At the same time he has to consider the overall economics. During the operation of the transmission the operator is required to operate the system in the most efficient manner to have minimum losses without disturbing system security and other constraints. The losses in the Indian transmission systems ranges between 4 percent to 8 percent.

1.2 LOSSES IN DISTRIBUTION SYSTEM

The distribution system losses are much more in comparison to the transmission system losses. These losses are approximately 10 percent to 16 percent in the Indian distribution system, but in low load density areas the losses are as high as 25 percent to 30 percent. The major portion of these losses consists of I^2R losses. The effective ways for reducing distribution system losses are the proper planning of distribution system and proper modification in the existing distribution system. Significant reduction in distribution system losses can be achieved by replacing the conductor of heavily loaded distribution lines by higher size conductor and installation of shunt capacitors at load centres in low voltage areas of distribution system.

1.3 PRESENT STATUS OF THE WORK

The control of voltage and reactive power in the transmission system is necessary to provide electrical energy of good quality to the customers and economical operation of power system which ultimately reduces the losses considerably. The voltage and reactive power are controlled by effective use of various regulating devices such as voltage and reactive power controlled generators, on load tap changing transformers, shunt capacitors, and reactors.

During the last few years increasing attention has been paid to the problem of real power losses minimization. The objective of most reactive power and voltage control schemes have been to determine optimum operating pattern, which is defined as a voltage profile and reactive power schedule minimising the system operating cost and real power transmission system losses. In available methods for losses minimization, reactive power and voltage control during light load conditions have not been considered. Under light load conditions, generators absorb the reactive power from the system and will be under-excited. Also when losses are minimized, the power flow in the system changes from the one which is obtained on the basis of minimization of production cost, which is not desirable because it may result in overall uneconomical operation of the electrical energy system.

Two types of formulation of loss minimization problem are in use at present. The first is the linear programming approach and the second is non-linear programming approach.

In linear programming approach the objective function assumes its minimum or maximum at a corner of the convex polyhedron while in case of nonlinear programming its minimum or maximum can be located at a corner, on an edge, or even in the interior of the polyhedron. Therefore results obtained with linear programming methods may be sub optimal. The lagrangian multipliers technique assumes that the Kuhn-Tucker conditions of optimality are satisfied at the solution and if this is not the case, the method performspoorly. In some cases, the penalty functions require initial feasible point which may not be available. The choice of initial value of penalty function is a very sensitive factor which can govern the whole out-come of the optimization process. Wrong choice of initial values will increase the computational effort.

Installation of reactive compensation in the transmission system is necessary for maintaining adequate voltage at critical points and for controlling undesirable reactive power flows during emergency as well as normal mode of operation. This reduces system losses, and increases power transfer capability. Linear programming models have been extensively used for reactive compensation planning problem in the transmission system. These models tend to provide solution at the extremities of the operating region whereas the optimal solution may be located at a corner, on an edge, or even in the interior of the polyhedron which can be observed by solving the nonlinear programming formulation. Thus the linear programming models may give suboptimal solution. The nonlinear programming methods in addition to linear programming have also been used. The formulations presented so far are time consuming and not suitable to solve large power system problems. Light load conditions have not been considered when the generators are under excited in the present methods. This condition is important from stability consideration of the electrical energy system.

Inter-connections have become vital to electric energy systems for many reasons. Inter-connection make feasible the coordinated operation of power system resulting in reduced losses. Thus the ever increasing size of power system imposes great burden on computation methods used for transmission losses minimization. This requires excessive storage and computation time to solve the problem of transmission losses minimization.

The effective way to reduce the losses in distribution system is the optimal conductor gradation. The available methods for determining the size of the conductor for the distribution lines neglect the economic benefits arising out of voltage boost along the lines to simplify the procedure and the models used consider radial feeders by neglecting laterals and lumping their load to the main feeder. All these approximations lead to sub-optimal results.

Application of shunt capacitors in distribution system to improve power factor is another important way to reduce distribution losses. The methods in practice do not take full benefits arising out of voltage boost in the distribution system. Multi ended radial feeders have not been considered at all. The uniform cross section along the radial feeders has been assumed to simplify the calculations. All these approximation will affect the results appreciably.

The improvement of distribution system taking into account the off shoots of the planning studies has not taken the important place in the literature.

1.4 SCOPE OF THE WORK

The aim of the present work is to develop more realistic and simple mathematical models and efficient methods for minimising the transmission and distribution system losses in a large power system at planning, post planning, and operating stage.

The following is the summary of contribution in this area of research.

An efficient and reliable algorithm based on the Broyden-Fletcher-Goldafarb -shano (BFGS) inverse hessian update and sensitivity relationship between state and control variables is developed for optimum losses reduction via reactive power and voltage control in a transmission system. To reduce the size of the problem reduced gradient is used. The computational difficulties arising out of conditioning problem is overcome by using BFGS update of approximate inverse hessian.

Another efficient algorithm based on Fletcher's method of non-linear programming is developed for losses minimization in transmission system via reactive power and voltage control. Generalized reduced gradient method is used to reduce the size of the problem. An approximate step size is chosen to reduce computation time and storage.

A more efficient algorithm based on sparse hessian update and reduced gradient for transmission system losses minimization via reactive power and voltage control is presented. Sparsity and symmetry of hessian is exploited fully to reduce computer storage.

Chapter - II deals with the above mentioned three methods of losses minimization in transmission system via voltage and reactive power control.

Reactive compensation planning problem in transmission system for losses minimization is formulated and solution procedure described in Chapter - III. The objective function consists of cost of real power losses, cost of reactive compensation installation, operation and maintenance, and difference between percentage sharing of reactive power among generators. All the three mathematical models as described in Chapter - II are modified to solve the problem of reactive compensation planning.

A decomposition procedure suitable for losses minimization in large power systems is described in Chapter - IV. The power system is decomposed in to smaller sub-systems, each with its own goals and constraints. The subsystems are then optimized independently in a sequence to obtain the solution of the original system.

An algorithm based on the group variational method is developed for optimal conductor gradation to reduce the distribution system losses. Economic benefits due to improvement in voltage profile of distribution system is accounted for. This algorithm is applied on multi-ended and interconnected distribution system. This procedure of conductor gradation is described in Chapter - V.

In Chapter - VI the problem of distribution system losses minimization by shunt capacitor installation is formulated and solved by group variational method. Multi-ended and interconnected distribution system and full benefits due to improvement in voltage profile of the system is considered in this study.

An algorithm for system improvement by effective use of conductor replacement and shunt capacitor installation is presented in Chapter - VII.

The mathematical models and methods developed in this investigation are successfully tested on 6 Bus, 30 Bus, and 103 Bus transmission systems. 30 Bus and 103 Bus transmission system belongs to Madhya Pradesh Electricity Board (MPEB) Jabalpur (an electric utility in India). Distribution system mathematical models and methods are tested on 40 Bus distribution system of MPEB. Results obtained are given at appropriate places.

CHAPTER - II

TRANSMISSION SYSTEM LOSSES REDUCTION BY REACTIVE POWER CONTROL

The transmission system losses for a given load are function of reactive power flow and voltage magnitudes. During the last few years increasing attention has been paid to the problem of real power loss reduction and reactive power control. The objective of most reactive power control schemes have been to determine optimum operating pattern, which is defined as a voltage profile and reactive power production schedule minimising system operating cost and hence minimisation of real power transmission system losses [76]. The reactive power control is necessary for maintaining adequate voltage at critical points and for controlling undesirable reactive power flows. This is done by adjusting generator terminal voltage magnitudes, transformer tap positions, and output from variable reactive power sources like capacitors and reactors to achieve operating benefits such as reduced losses, increased power transfer capability, and improved voltage regulation. A bibliography of reactive power control techniques is given by Sullivan [76].

The effect of losses in economics of power system operation was considered early by Estrada [22] and a mathematical form for considering it in terms of incremental efficiency terms was introduced by Steinberg and Smith [74].

Song [73] suggested the minimization of real power transmission losses by adjusting the controllable voltages. Dopazo et. al [19] presented a method of minimizing the production costs by coordinating real and reactive power allocations in the transmission system. Reactive power allocation was optimized by a gradient approach, using system losses reduction as an objective function. Peschon et.al [58] presented a method of minimizing the system losses by judicious selection of reactive power injections into the system and transformer tap settings. Dommel and Tinney [18] developed a nonlinear optimization technique to determine the optimal power flow solution by considering production costs or transmission losses as objective function. Hano et.al [31] presented a method of controlling the system voltage and reactive power distribution in the transmission system. They determined the required sensitivity relationships between controlled and controllable variables and loss sensitivity indices and then employed a direct search technique to minimize the system losses.

Narita and Hamman [56] used the sensitivity analysis of power systems and the method of Box to minimize the voltage deviations from their desired values. As a secondary step, they minimized the system losses. Control variables considered were transformer tap positions and switchable sources of reactive power at load nodes. Shoults and Chen [72] presented a method for calculation of transformer tap positions and generator terminal voltages to reduce the reactive power flow in lines and improve poor Bus voltages to the desired value. Saveluscu [68] presented an approach to determine loss sensitivity, reactive power transmittance and steady state stability indices. Based on these indices, he employed a search procedure to move towards the required optimal system conditions. Fernandes et. al [24] minimized the system losses by adjusting transformer tap positions and generator voltages. They used the technique of Dommel and Tinney [18]. Hobson [37] developed a linearised model for reactive power control problem and solved the same by linear programming technique. Mamandur and Chenoweth [51] used dual linear programming to minimise losses by adjusting transformer tap positions, generator terminal voltages, and switchable reactive power sources. In the above mentioned work only system losses are minimised. They have not considered the light load conditions when the generators are under-excited. Also, when losses are minimized, the real power flow in the system may change from the one obtained on the basis of minimization of production cost, which is not desired.

In most of the present day systems, the magnitude of reactive power involved is very large. Because of high operating voltages the controlling of system reactive power to reduce real power losses, is an extremely important aspect of system operation.

Due to wide fluctuations in the system load pattern during normal operation and change in network configuration during system contingencies, the system reactive power flows differ widely under different conditions. The voltage magnitudes at load nodes may fall below the specified limits during the heavy load periods and therefore switchable shunt capacitors have to be pressed into service for voltage control and to reduce the current flow on the lines and transformers resulting in reduced losses. On the other hand, during light load conditions the capacitive reactive power generation may exceed the MVAR requirement even when the system capacitors are disconnected and therefore the node voltage magnitudes may exceed their upper limits [6]. This extra reactive power in the transmission system should be utilized judiciously since it is desirable and economical to have the reactive power located as near the load as possible to maintain the real power capacities at their desired values. The capacitive power of the system may be absorbed by operating the system generators under-excited [77]. However, since the system stability depends to a large extent on the stiffness of its generators, their operation in under-excited region is a definite threat to system stability. Alternative means must therefore be adopted for the absorption of the reactive power like tap adjustment of transformers, installation of reactors in the system, and switching off of the lines (not very desirable though) in order to ensure a reliable system operation.

The available literature suggests reactive power and voltage control problems to be formulated and solved by linear programming (LP) and nonlinear programming techniques. The power system problems are in general nonlinear and are approximated as linearized problem for the application of LP. In a linear optimization, the objective function assumes its optimal value at a corner of the convex polyhedron while in nonlinear programming formulation, the optimum value is obtained either at a corner, on an edge, or even in the interior of the polyhedron. Since the LP tends to provide the solution at the extremities of the operating region, in some of the cases it may not give the optimal solution. The linear programming may give rise to a poor search direction if the objective function is highly nonlinear. Very often the problem of reactive power control has been formulated as unconstrained optimization problem by using two nonlinear programming approaches. The first is the Lagrangian multipliers approach using dual variable for each equality and violated inequality constraint, while in the other approach penalty parameters are used for converting constrained problem into unconstrained one. The lagrangian multipliers technique assumes that the Kuhn-tucker conditions of optimality are satisfied at the solution and if this is not the case, the method performs poorly. The method also critically depends on having good estimate of lagrangian multipliers. This is a difficult problem even in case of linearly constrained optimization. In the penalty function methods a sequence of unconstrained minimization problems are solved. This method requires an initial feasible point. In case of losses minimization problem initial feasible point is not available in quite a few number of cases. It is observed that many problems concerning their application remain unresolved. The choice of initial feasible point and penalty multipliers are very sensitive factors. The wrong selection requires more computational efforts and sometimes converge prematurely to a sub-optimal solution.

Based on approximate hessian or its inverse with first order derivatives, three new approaches are suggested to solve the problem of losses minimization in transmission system. The new approaches are suitable to solve large power systems as these methods require less computer storage and computation time. These methods have faster convergence, and are robust, stable and reliable.

In this chapter the problem of transmission system losses reduction by optimal reactive power and voltage control is formulated by using sensitivity relationship between state and decision variables. The objective function considered consists of real power losses, difference between percentage sharing of reactive power among the generators ,and the deviations from the real power flow determined on the basis of production cost. The decision variables, are generator terminal voltage magnitudes, transformer tap positions, and setting of switchable sources of reactive power at load nodes. Transformation of the formulated problem is done by using generalized Reduced gradient to reduce the size and complexity of the problem, correction to the groups of decision variables are applied simultaneously as well as hierarchically and the results are compared for 6 Bus, 30 Bus and 103 Bus sample power systems. The test system details are given in Appendix - A. The test systems (30 Bus and 103 Bus) belong to power system of Madhya Pradesh Electricity Board (an electric utility in India).

2.1 PROBLEM FORMULATION

The problem of real power losses minimization in transmission system via reactive power and voltage control is so formulated as to minimize an objective function consisting of real power losses, differences between percentage sharing of reactive power among generators, and deviation from the active power flow determined on the basis of production cost subject to the inequality and equality constraints imposed by reactive power output from generators, voltage magnitude of load nodes, transformer tap positions, output of switchable VAR sources, and power flow equations. It has been assumed that active and reactive power load is known with certainty at all the load nodes.

2.1.1 Objective Function

The system losses for a given load are function of reactive power flow, which is mainly dictated by the system node voltage magnitudes.

Power flow in a line connecting node i and j of the system from node i to j is

$$P_{ij} + jQ_{ij} = V_i I_{ij}^{*} = V_i \left[(V_i - V_j) Y_{ij} \right]^{*} \qquad (2.1)$$

Similarly power flow in a line connecting node j and i of the system from j node to i node is

$$P_{ji} + jQ_{ji} = V_j I_{ji}^{*} = V_j \left[(V_j - V_i) Y_{ij} \right]^{*} \qquad (2.2)$$

where * is a complex conjugate.

Real power losses in a line connecting nodes i and j is

$$P_{Li,j} = P_{ij} + P_{ji} \qquad (2.3)$$

By simplifying equation (2.1), (2.2), and using (2.3) we get,

$$P_{Li,j} = -G_{ij} \left[V_i^2 + V_j^2 - 2V_i V_j \cos(\theta_i - \theta_j) \right] \qquad (2.4)$$

or

$$P_{Li,j} = -G_{ij} \left[(V_i - V_j)^2 + 2V_i V_j (1 - \cos(\theta_i - \theta_j) \right] \qquad (2.5)$$

Expanding Cos term of (2.5) and assuming Sin $\frac{1}{2}(\theta_i - \theta_j) = \frac{1}{2}(\theta_i - \theta_j)$ the above equation can be written as

$$P_{Li,j} = -G_{ij} \left[(V_i - V_j)^2 + V_i V_j (\theta_i - \theta_j)^2 \right] \qquad (2.6)$$

Total power losses in the system are therefore

$$F_L = \sum_{L=1}^{NLE} P_{Li,j} \tag{2.7}$$

Losses are minimized after solving optimal load flow problem which provides real power and phase angle values for the minimum cost of generation. With the variations in reactive power flow, the node phase angles may change and thus real power flows deviate from the one obtained by solving optimal power flow problem, which will increase the production cost. Therefore while minimizing transmission losses, this deviation should be minimized and can be expressed as :

$$F_A = \sum_{i=2}^{N} (PS_i - PC_i)^2 \tag{2.8}$$

where first bus is taken as slack bus.

Also, active power equality constraints are soft constraints, they can be taken out from constraint set to simplify the problem and absorbed in the objective function as shown in (2.8) above.

In a power system with number of generators operating to meet the demand, it is observed that the generators have a greater tendency to absorb reactive power during light load periods and that the reactive power loadings are not equitably distributed among the generators, even during peak load periods. The capacitive reactive power of the transmission system may be absorbed by operating the generators under excited. Since the system stability depends to a large extent on stiffness of its generators, their operation in under-excited region is a definite threat to system stability. Alternative means must be adopted for the absorption of the reactive power like tap adjustment of transformers and reactive power sources. Therefore from stability consideration, sharing of reactive power by the generators should be proportional to their reactive power capability limit [75] which is expressed by

$$F_S = AK \sum_{i=1}^{NG-1} \sum_{j=i+1}^{NG} (Q_i/B_i - Q_j/B_j)^2 \qquad (2.9)$$

From the generator operating chart shown in Fig.2.1 it can be seen that the operating point of a generator away from the theoretical stability limit line would ensure more stable operation of the generator. The reactive power capability limit of machine is defined as the total reactive power that a machine can handle. By varying the value of AK, a constant multiplier, the reactive power sharing between the machines can be altered and it is possible to operate them at any desirable percentage of their reactive power capabilities.

Hence the objective function to be minimized is

$$F = F_L + F_A + F_S \qquad (2.10)$$

Subject to the power flow constraints (section 2.1.2) and bounds on variables (section 2.1.3).

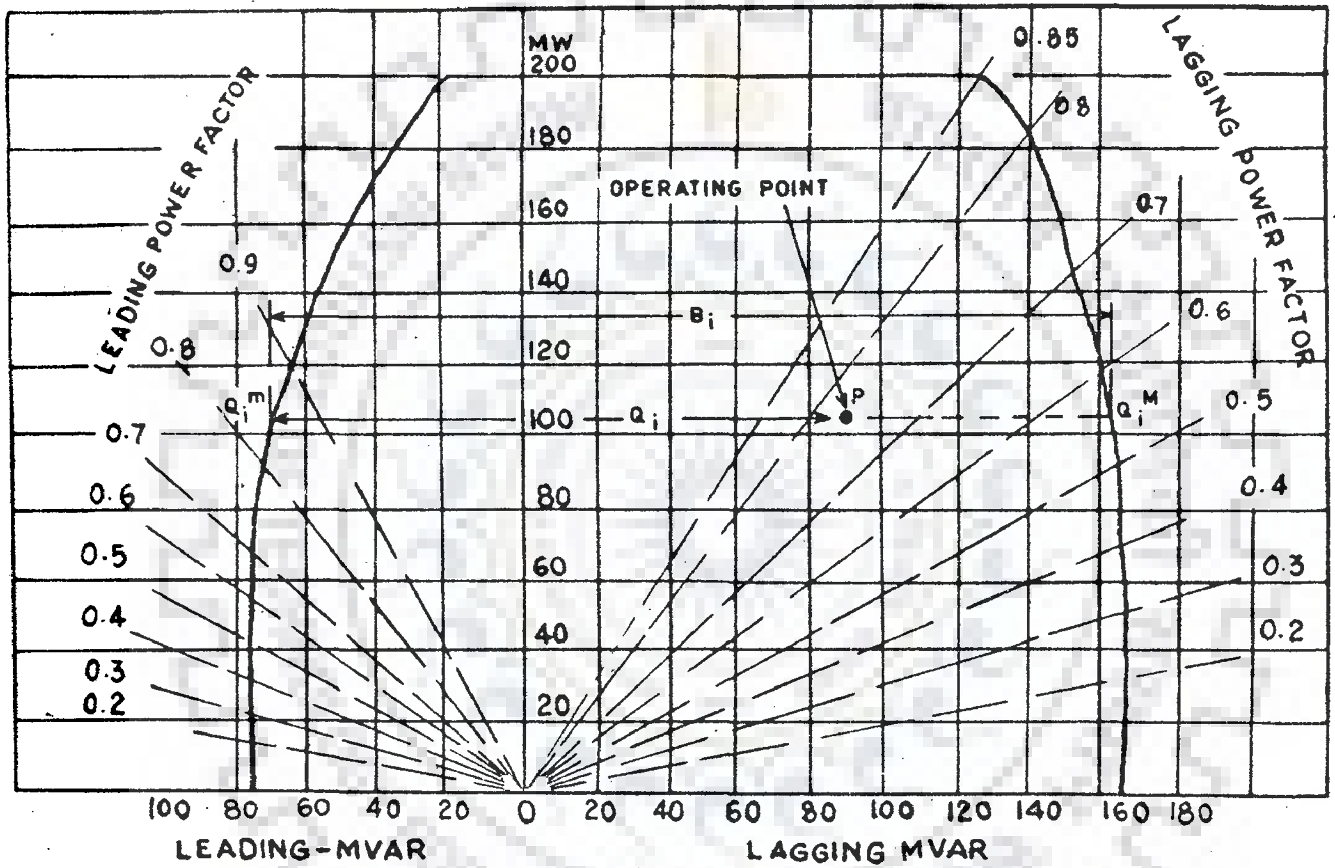


FIG. 2.1 GENERATOR CAPABILITY CURVE

200 MW SET

2.1.2 Power Flow Constraints

Under steady state operation of power system, active and reactive power balance must be satisfied at each node.

The active power equality constraints are absorbed in the objective function and hence, active power equalities and inequalities can be excluded. In N Bus system, the reactive power flow equations can be expressed as :

$$h_i\ (v) = -Q_i + V_i \sum_{j=1}^{N} V_j (G_{ij} \operatorname{Sin} \Theta_{ij} - B_{ij} \operatorname{Cos} \Theta_{ij})$$

$$i = NG + 1, \ldots\ldots N \qquad (2.11)$$

2.1.3 Bounds on Variables

The reactive power output of any generator must lie between its specified upper and lower limits i.e.

$$Q_i^m \leq Q_i \leq Q_i^M, \qquad i = 1, \ldots\ldots NG \qquad (2.12)$$

limits for reactive power output of generators are taken from their capability curves.

The voltage magnitude at each node must lie between specified upper and lower limits.

$$V_i^m \leq V_i \leq V_i^M, \qquad i = 1, \ldots\ldots N \qquad (2.13)$$

limits for voltage are taken between 0.90 P.U. to 1.1 P.U. considering continuous variation in voltage within these limits.

Transformer tap positions are variable but no tap position shall be out side the allowable range i.e.

$$T_i^m \leq T_i \leq T_i^M, \qquad i = 1, \ldots\ldots NT \qquad (2.14)$$

limits for transformer tap are taken from 0.95 to 1.1 in the steps of 0.0125.

Switchable VAR sources can supply reactive power within their specified lower and upper limits.

$$C_i^m \leq C_i \leq C_i^M, \qquad i = 1, \ldots\ldots NC \qquad (2.15)$$

limits for switchable VAR sources are considered - 0.1 P.U. to + 0.2 P.U. in the steps of 0.001.

It is ensured at each load bus that power factor will never be-comes more than unity.

To simplify the calculations continuous variation of transformer tap positions and switchable VAR sources are considered and at the end of each iteration these are rounded off to the nearest standard value.

2.1.4 Calculation of Reduced Gradient

To reduce the problem size and complexity, the problem variables are divided into two groups i.e.

Decision variables x and,

state variables y, where

$$x = \begin{cases} V_i & i = 1, \ldots\ldots NG \\ T_i & i = 1, \ldots\ldots NT \\ C_i & i = 1, \ldots\ldots NC \end{cases} \tag{2.16}$$

and

$$y = \begin{cases} Q_i & i = 1, \ldots\ldots NG \\ V_i & i = 1, \ldots\ldots N \end{cases} \tag{2.17}$$

In terms of these variables, the reactive power control problem can be expressed as

$$\text{Min} \quad F(y,x) \tag{2.18}$$

$$\text{Subject to} \quad h_i\ (y,x) = 0 \qquad i = 1, \ldots\ldots N \tag{2.19}$$

$$x^m \leq x \leq x^M \tag{2.20}$$

$$y^m \leq y \leq y^M \tag{2.21}$$

on differentiating (2.18) and (2.19)

$$df = \nabla_x f(y,x)^T\, dx + \nabla_y f\,(y,x)^T\, dy \tag{2.22}$$

$$dh = \nabla_x h\,(y,x)\, dx + \nabla_y h(y,x)\, dy \tag{2.23}$$

$$\text{where} \quad \nabla_x f(y,x) = \left[\partial f/\partial x_1,\quad \partial f/\partial x_2 \;\ldots\; \partial f/\partial x_k\right] \tag{2.24}$$

$$\nabla_y f(y,x) = \left[\partial f/\partial y_1,\quad \partial f/\partial y_2 \;\ldots\; \partial f/\partial y_m\right] \tag{2.25}$$

$$\nabla_x h(y,x) = \begin{bmatrix} \partial h_1/\partial x_1 & \partial h_1/\partial x_2 & \partial h_1/\partial x_k \\ \partial h_m/\partial x_1 & \partial h_m/\partial x_2 & \partial h_m/\partial x_k \end{bmatrix}_{m\times k} \tag{2.26}$$

$$\nabla_y h(y,x) = \begin{bmatrix} \partial h_1/\partial y_1 & \partial h_1/\partial y_2 & \partial h_1/\partial y_m \\ \partial h_m/\partial y_1 & \partial h_m/\partial y_2 & \partial h_m/\partial y_m \end{bmatrix}_{m x m} \tag{2.27}$$

From (2.23) we get

$$d_y = - \left[\nabla_y h(y_1 x)\right]^{-1} \nabla_x h(y_1 x)\ dx \tag{2.28}$$

Substituting (2.28) into (2.22) and rearranging yields the linear approximation to the reduced gradient.

$$\nabla_r f(y,x)^T = \nabla_r f(y,x)^T - \nabla_y f(y,x)^T \left[\nabla_y h(y,x)\right]^{-1} \nabla_x h(y,x) \tag{2.29}$$

The reduced gradient (2.29) defines the rate of change of the objective function with respect to decision variables with the state variables adjusted to maintain feasibility.

It is generally true that inverse of a sparse matrix will not be sparse. Therefore a method [90] is used to represent inverse implicitly.

In (2.29) we define a transformation matrix T equal to the matrix product

$$T = [A]^{-1} \mid \nabla_x h(y,x) \tag{2.30}$$

where

$$A^{-1} = [\nabla_y h(y,x)]^{-1} \tag{2.31}$$

rearranging (2.30) we can arrive at the form

$$AT = \nabla_x h\ (y,x) \tag{2.32}$$

The matrix T can be constructed a column at a time using ordering, Bi-factorisation and direct solution [90].

2.2 QUASI NEWTON METHOD

Methods based on approximate hessian matrix calculated from first order derivatives have faster convergence rate. But computational difficulties arises when the smallest eigen value of hessian approaches zero. This is called conditioning problem. The computational difficulties arising out of conditioning problem can be overcome by using Quasi Newton method of inverse hessian update.

Quasi Newton methods seek to approximate the hessian matrix (or its inverse) for the k^{th} step by accumulating information from the $(K-1)^{th}$ step using only first order derivatives (or their finite-difference approximation). This is in contrast to Newton type methods where the hessian matrix for the K^{th} step depends on derivative information computed in the immediate neighbourhood of $x^{(k)}$ alone. The Quasi Newton methods have proved themselves in dealing with practical problems of the following two types.

(A) Systems of N equations in N unknowns,

(B) Un-constrained minimization of functions.

There are four Quasi Newton updates [16] which are globally and superlinearly convergent for linear problems (even in the absence of orthogonality assumptions or exact line searches), and locally and superlinearly convergent for non-linear problems. The best among them is the Broyden-Fletcher-Goldfarb-Shano (BFGS) update. This update is some times called the complementary DFP update and that the under lying single rank method. There is a growing evidence that the BFGS update is the best current update formula for use in unconstrained minimization. This method has global convergence, and is robust and stable.

2.2.1 Solution Algorithm

Flow chart showing the various steps is given in Fig. 2.2 for this method. Discrete steps of solution algorithm are given below :

(i) Perform load flow analysis

(ii) Calculate reduced gradient using equation (2.29)

(iii) Check for convergence

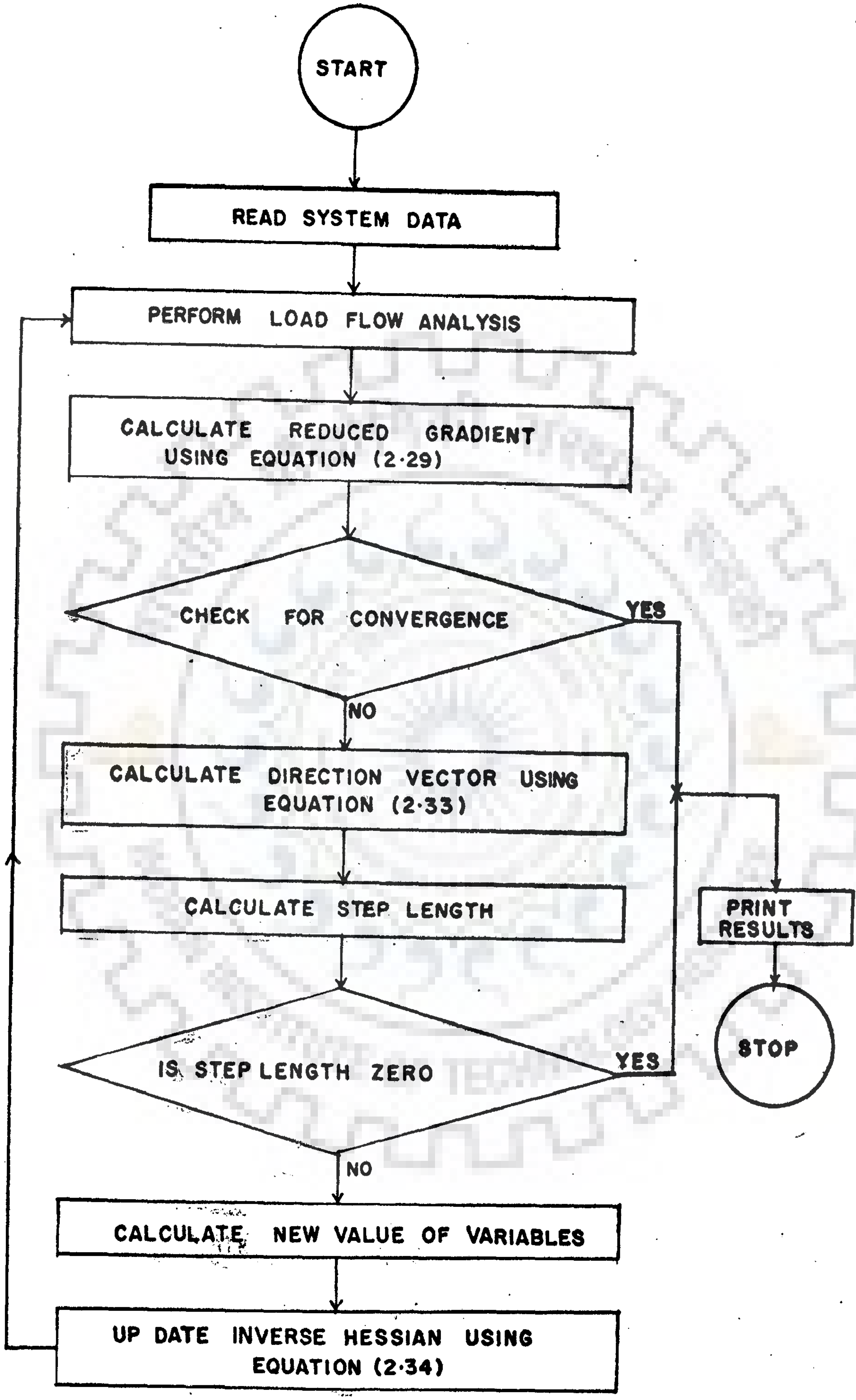
Reduced problem is said to be converged, when the change in the value of objective function becomes less than a predetermined small quantity.

If the problem gets converged, stop. Otherwise go to next step.

(iv) Calculate direction vector using equation (2.33)

Direction vector S_k is given by equation (2.33)

$$S_k = H^K \left[\nabla_r(y,x) \right]^K - \left[\nabla_r(y,x)\right]^{K-1} \qquad (2.33)$$



FLOW CHART FOR QUASI NEWTON METHOD.

Fig 2·2

(v) Calculate step length, if zero stop. Otherwise go to next step.

Step length is calculated using DSC and Powell's uni-dimensional minimization method [30]. Details of the method are given in Appendix - B.

(vi) Calculate new value of variables

(vii) Update inverse hessian using equation (2.34) and go to step (i).

BFGS update for inverse hessian can be written in the form

$$H_{BFGS}^{K+1} = \left[I - \frac{S_K Z_K^T}{\langle Z_K \; S_K \rangle} \right] H^K \left[I - \frac{Z_K \; S_K^T}{\langle Z_K , S_K \rangle} \right] + \left[\frac{S_K \; S_K^T}{\langle Z_K , S_K \rangle} \right] \tag{2.34}$$

where

$$Z_K = \left[\nabla_r f(y,x) \right]^K - \left[\nabla_r f(y,x) \right]^{K-1} \tag{2.35}$$

2.3 FLETCHER'S METHOD

The minimization algorithm described in section 2.2 requires the determination of the step size accurately in each iteration such that maximum reduction in function value achieved during every iteration. In Fletcher's method an approximate step size is selected. This helps in reducing the storage and computational burden.

2.3.1 Algorithm

Discrete steps in solution algorithm are given below and a flow chart in Fig. 2.3.

i) Perform load flow analysis

ii) Calculate reduced gradient using equation (2.29)

iii) Check for convergence

minimum of reduced problem occurs when the elements of the reduced gradient satisfy the following conditions

$$\nabla_r f(y,x)_i \geq \quad \text{if } X_i = X_i^m \tag{2.36}$$

$$\nabla_r f(y,x)_i = 0 \text{ if } X_i^m \leq X_i \leq X_i^M \tag{2.37}$$

$$\nabla_r f(y,x)_i \leq 0 \quad \text{if } X_i = X_i^M \tag{2.38}$$

If converged, stop. Otherwise go to next step.

iv) Calculate the direction vector using equation (2.39)

Direction vector S_K is given by equation (2.39)

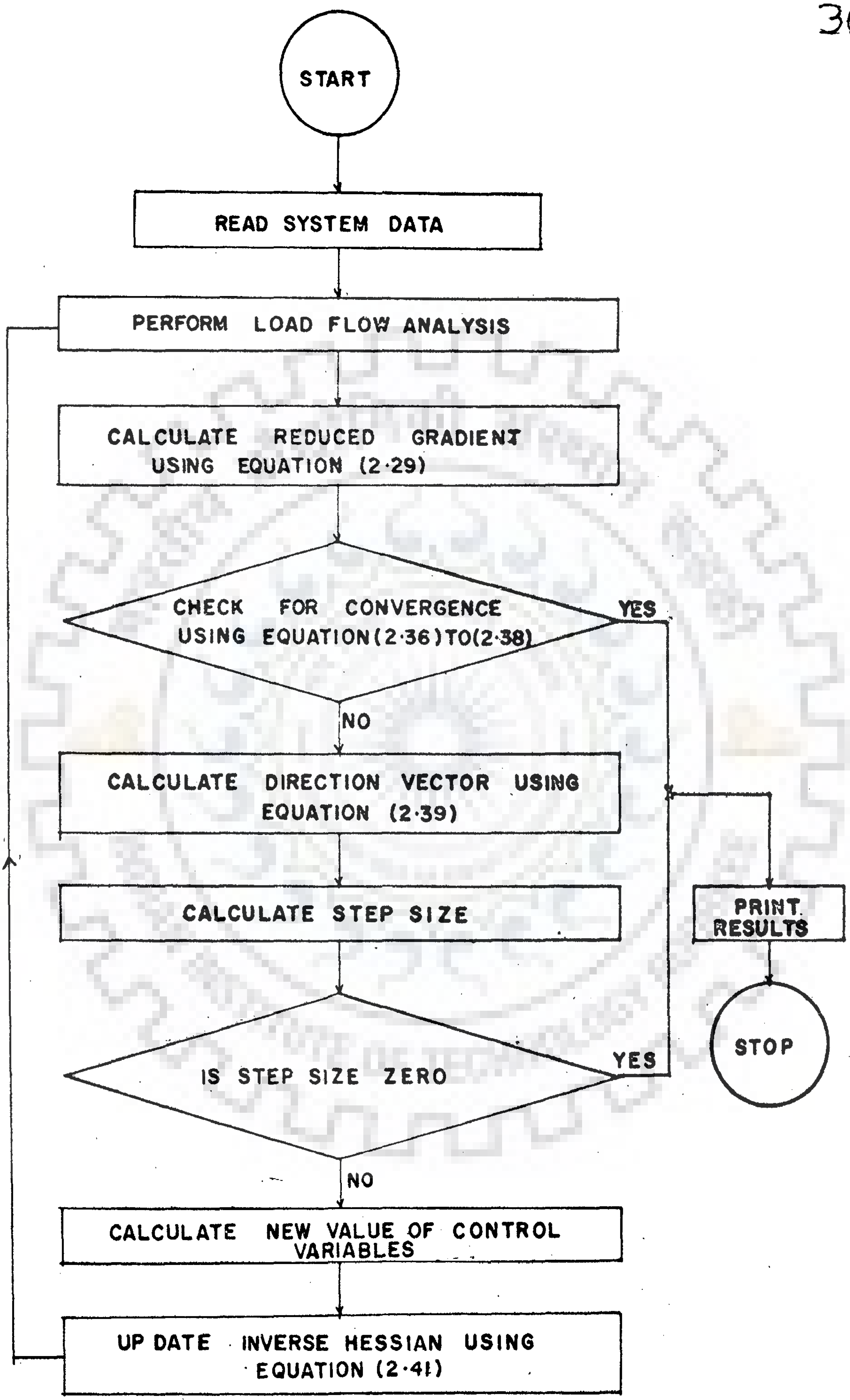
$$S_K = H^{(K)} \left[\nabla_r f(y,x)\right]^{(K)} \tag{2.39}$$

where K is the iteration number.

v) Calculate step size. If zero, stop. Otherwise go to next step.

Fletcher limited the value of λ (the step size) to be the smaller of 1.

The value of λ first chosen as 1 and if found successful in reducing value of the function, it is accepted. Otherwise equation (2.40) is tried.



FLOW CHART FOR FLETCHER'S METHOD.

Fig 2·3

$$\lambda = \lambda \times 0.1 \tag{2.40}$$

This process is repeated till the desired results are obtained. The use of any linear search technique would also involve few functional evaluations before the optimum step size is obtained. Therefore, the choice of approximate step size will not involve many additional function evaluations but will definitely result in saving of computer memory required for storing linear search programme.

vi) Calculate new value of control vector.

vii) Update inverse hessian using equation (2.41) and go to step (i).

$$H^{K+1} = \left[I - \frac{\Delta_x^{(K)} (\Delta_g^{(K)})^T}{(\Delta_x^{(K)})^T \Delta_g^{(K)}} \right] H^K \left[I - \frac{\Delta_g^{(K)} (\Delta_x^{(K)})^T}{(\Delta_x^{(K)})^T \Delta_g^{(K)}} \right] + \left[\frac{x^{(K)} (\Delta_x^{(K)})^T}{(\Delta_x^{(K)})^T \Delta_g^{(K)}} \right] \tag{2.41}$$

where

$$\Delta_x^{(K)} = - \lambda^{(K)} H^{(K)} \left[\nabla_r f(y,x) \right]^{(K)} \tag{2.42}$$

2.3.2 The Fletcher's method is less sensitive to the accuracy of the linear search for step size determination. It avoids the computation of second order derivatives of the function. The method is basically stable because the hessian matrix is always positive definite. The stability is further improved by recycling, proper scaling of variables, and increased precision of computations.

2.4 SPARSE HESSIAN METHOD

The two methods as described in Section 2.2 and 2.3 uses approximate hessian, calculated from first order derivatives have faster convergence rate. But they do not exploit the symmetry and sparsity of approximated hessian and therefore require large storage. In sparse hessian updating procedure [80,81] sparsity and symmetry of the hessian is fully exploited. This results in reduction of computer storage.

2.4.1 Algorithm

Discrete steps of solution procedure are given below:

i) Perform load flow analysis

ii) Calculate reduced gradient using equation (2.29)

iii) Check for convergence. If $//g(x_k)// < \epsilon$ (2.43)

solution has been obtained.

If converged, stop. Otherwise go to next step.

iv) Calculate direction vector using equation (2.44) and (2.45).

Direction vector S_K is calculated by minimizing equation (2.44).

Minimize

$$\phi(x,K) \triangleq \frac{1}{2} (\langle X_D, B_K X_D\rangle + \langle g(X_K), X_D\rangle + f(X_K) \tag{2.44}$$

Subject to

$$|| S_K ||_2 \leq \Delta_K \tag{2.45}$$

where $S_K + X_K$ is the value of X and now it will be denoted by X_N and $X_D = X - X_K$.

Objective function (2.44) subject to (2.45) is solved by using Levenberg - Marquardt procedure [50,53].

v) Calculate step size using equation (2.46 to 2.50). If zero, stop. Otherwise go to next step.

Step size Δ_N can be calculated with the help of equation (2.46) to (2.50).

If $\left[f(X_N) - f(X_K)\right] > 0.1 \left[\phi(X_N) - f(X_K)\right]$ (2.46)

Set $\Delta_N = \frac{1}{2} \| S_K \|$

else define

$$\lambda = \begin{cases} +\infty \text{ if } \langle g(X_N), S_K \rangle \leq \langle g(X_K), S_K \rangle \\ \dfrac{\langle g(X_K), S_K \rangle}{\langle g(X_K) - g(X_N), S_K \rangle} \quad \text{if } \langle g(X_N), S_K \rangle > \langle g(X_K), S_K \rangle \end{cases} \tag{2.47}$$

Then if $\lambda \geq 2$ or if $\| g(X_N) - g(X_K) - B_K S_K \|^2$ (2.48)

Set $\Delta_N = \text{Min } 2 \| S_K \|$ (2.49)

else set $\Delta_N = \| S_K \|_2$ (2.50)

vi) Multiply S_K with step length.

vii) Assign new value to X using equation (2.51)

If $F(X_K + S_K) < F(X_K)$, set $X_{K+1} = X_K + S_K$ (2.51)

else set $X_{K+1} = X_K$

vii) Update hessian matrix solving equation (2.52) subject to (2.53) to (2.55).

New approximation to B_{K+1} will be find out by solving equation (2.52) subject to equation (2.53) to (2.55) using the sparse and symmetric matrix update described in [80].

$$\text{Min} \; // B_K - B_{K+1} //_F \tag{2.52}$$

Subject to

$$B_{K+1} = B_{K+1}^T \tag{2.53}$$

$$B_{K+1} S_K = g(X_{K+1}) - g(X_K) \tag{2.54}$$

$$[B_{K+1}]_{ij} = 0 \;\; \forall (I,J) \in I \tag{2.55}$$

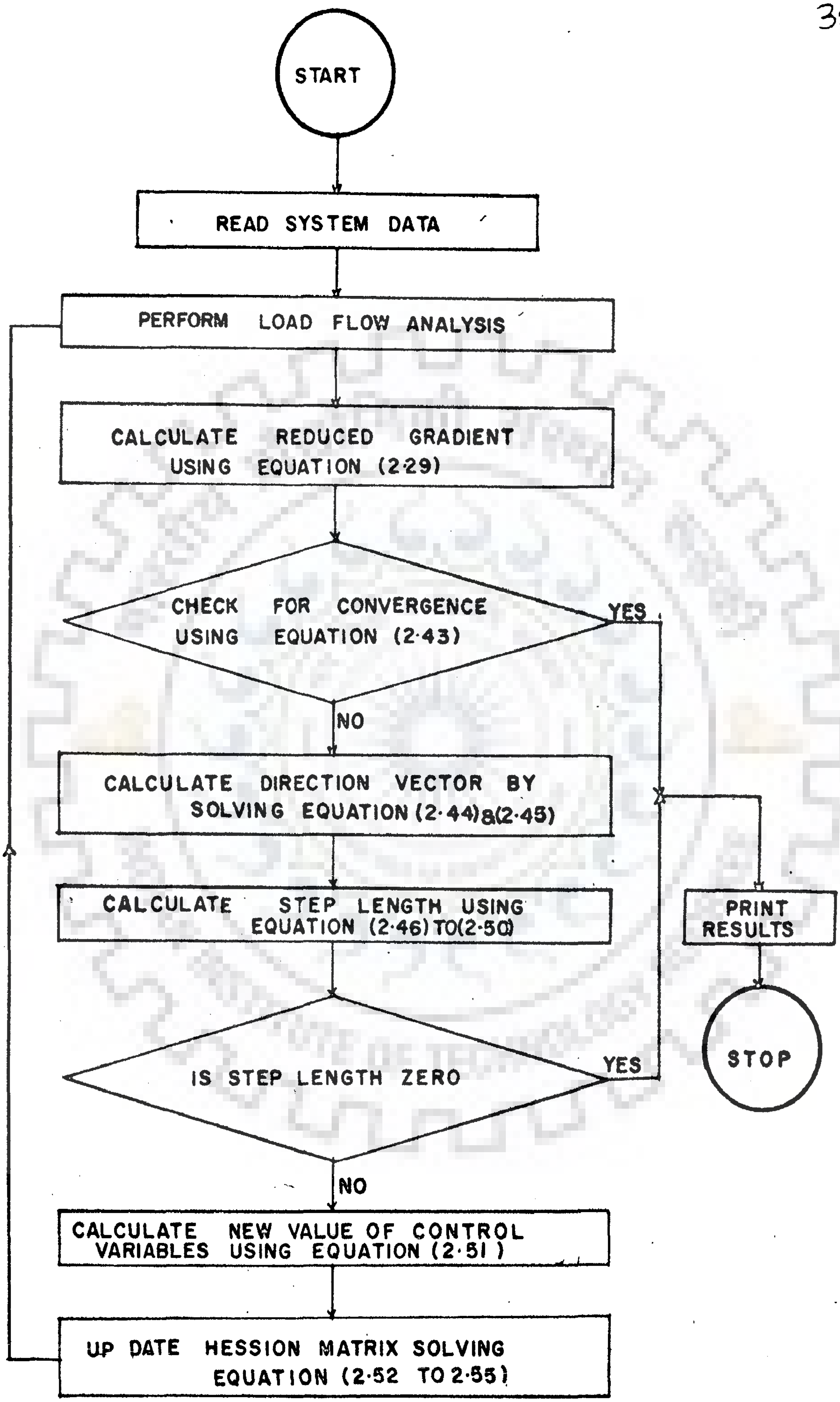
viii) Go to step (i). A flow chart for this procedure is given in Fig. 2.4.

Note : Initially hessian is set 0.01 $// g(X_o) //$ times the unit matrix.

2.4.2 This method has a good and Q super linear fast fate of convergence and therefore useful in practical problem considered here. Sparse update formula is used to update the hessian resulting in less computer storage. In this method sparsity and symmetry is fully exploited.

2.5 APPLICATION TO SAMPLE SYSTEMS AND RESULTS

Computer programs implementing the proposed algorithms are prepared and used on DEC SYSTEM 2050, to test the methods



FLOW CHART FOR SPARSE HESSIAN METHOD.

Fig 2.4

on 6 Bus, 30 Bus and 103 Bus problems of transmission network of Madhya Pradesh Electricity Board (MPEB) Jabalpur (an electric utility in India) power system.

Initially the system voltage under heavy load condition is less than the minimum specified limit of 0.90 P.U., in all the three test systems. The system voltage obtained with the help of developed techniques lies within the limit of 0.90 P.U. and 1.1 P.U.

There are three groups of decision variables controlling the reactive power flow in loss minimization and voltage control. These are generator terminal voltage magnitudes, transformer tap positions, and setting of switchable reactive power sources. Correction to the groups of decision variables are done simultaneously as well as hierarchically. The sequence followed was generator terminal voltage magnitudes, transformer tap positions, and setting of switchable reactive power sources in case corrections are done hierarchically. In Table 2.1 details of loss reduction are given. Table 2.2 gives the losses at the end of each iteration. No. of iterations and computer time used is given in Table 2.3. Table 2.4 to 2.6 gives the voltage magnitude at different nodes, transformer tap settings, settings of switchable reactive power sources, and reactive power output of generators for all the three methods and three test systems. Computer storage requirement variation between the methods is given in Table 2.7.

It is evident from the Table 2.1 that when the correction is applied hierarchically optimum loss reduction is more than that of simultaneous correction to the decision variable groups.

2.6 CONCLUSION

Three new mathematical formulations for finding the optimal generator terminal voltage magnitudes, transformer tap positions, and setting of switchable VAR sources, to reduce transmission losses and improve voltage profile without disturbing system security is presented in this chapter. The effect of simultaneous corrections and hierarchical corrections in decision variables are studied. These algorithms would be useful tools to assist the system operators in making control decisions to improve the voltage profile in the system and to minimize the system losses. The methods are successfully tested on actual systems and the results are presented.

TABLE 2.1

Details of Loss Reduction

Initial losses MW	6 BUS SYSTEM 6.228			30 BUS SYSTEM 44.7428			103 BUS SYSTEM 68.9029		
Types of correction/ method used	Losses in MW	Reduction in losses in MW	Percentage reduction	Losses in MW	Reduction in losses in MW	Percentage reduction	Losses in MW	Reduction in losses in MW	Percentage reduction
Quasi Newton Method									
Simultaneous	4.547	1.681	26.99	37.2481	7.4947	16.75	57.9728	10.9301	15.86
Hierarchical	4.5281	1.6999	27.29	37.0865	7.6563	17.11	57.9583	10.9446	15.88
Fletcher's Method									
Simultaneous	4.5989	1.6291	26.15	37.1957	7.5471	16.87	58.3133	10.5896	15.37
Hierarchical	4.5089	1.7191	27.60	36.8786	7.8642	17.58	57.8706	11.0323	16.01
Sparse Hessian Method									
Simultaneous	4.5876	1.6404	26.34	36.8601	7.8827	17.62	57.8874	11.0155	15.99
Hierarchical	4.5876	1.6404	26.34	36.8547	7.8881	17.63	57.7559	11.147	16.18

TABLE 2.2

Convergence Characteristic for Loss Reduction
(Hierarchical Correction)

Iteration No./ Test System	Losses in MW Quasi Newton Method	Fletcher's Method	Sparse Hessian Method
6 BUS SYSTEM			
(6.228 MW)			
1	5.0653	5.2381	5.6895
2	4.5281	4.5089	4.5876
30 BUS SYSTEM			
(44.7428 MW)			
1	41.5314	40.6588	39.1604
2	37.0865	36.8786	37.3982
3			36.9208
4			36.8547
103 BUS SYSTEM			
(68.9029 MW)			
1	68.2098	68.5442	62.5856
2	64.4592	64.6098	60.7849
3	63.7208	62.9751	59.2030
4	57.9583	57.8706	57.7559

Note: Fig. in bracket shows initial losses.

TABLE 2.3

Computer Time Requirement

	Quasi Newton Method		Fletcher's Method		Sparse Hessian Method	
	No. of iteration	CPU time sec	No. of iteration	CPU time sec.	No. of iteration	CPU time sec.
6 Bus system						
Simultaneous	2	2.02	4	1.46	2	1.47
Hirarchical	2	1.64	2	0.97	2	0.92
30 Bus System						
Simultaneous	5	13.13	4	13.39	4	12.90
Hirarchical	2	12.41	2	12.34	4	12.12
103 Bus System						
Simultaneous	5	120.82	4	120.95	4	116.52
Hirarchical	2	111.15	4	108.57	4	104.26

TABLE 2.4.1

Voltage Magnitude at Various Buses
(6 Bus System)

Bus No.	Initial	Quasi Newton method	Fletcher's method	Sparse Hessian method
1	1.0	1.09	1.06	1.1
2	1.1846	1.0385	1.1	1.1
3	.9247	.9534	.9998	.9659
4	.9288	.9644	1.0055	.985
5	.9390	.9860	.9705	.9406
6	.92	1.0108	.9600	.9683

TABLE 2.4.2

Transformer Tap Position
(6 Bus System)

Transformer No.	Between the buses	Initial	Quasi Newton method	Fletcher's method	Sparse Hessian Method
1	3-4	1.00	.95	1.0	1.0
2	5-6	1.00	1.1	.95	1.0

TABLE 2.4.3

Shunt Capacitor Settings
(6 Bus System)

Shunt Capacitor Capacity Dispatched, MVAR

Shunt capacitor No.	Bus No.	Initial	Quasi Newton method	Fletcher's method	Sparse Hessian Method
1	3	5	6.5	6.5	6.5
2	5	5	9.0	9.0	9.0

TABLE 2.4.4

Reactive Power Output of Generators

(6 Bus System off-Peak Load 75 percent of peak load)

Node No.	Initial		Quasi Newton Method				Fletcher's Method				Sparse Hessian Method			
Losses	3.1799		AK = 0		AK = 100		AK = 0		AK = 100		AK = 0		AK = 100	
MW			2.5835		2.6095		2.5521		2.5835		2.5807		2.6121	
	MVAR	Percent	MVAR	Percent	MVAR	Percent	MVAR	Percent	MVAR	Percent	MVAR	Percent	MVAR	Percent
1	15.86	64.65	13.84	59.60	12.86	57.15	4.78	36.95	6.30	40.75	13.02	57.55	11.74	54.35
2	6.24	56.2	-3.95	5.20	-3.47	7.65	6.12	55.6	4.04	45.2	-3.04	9.80	-2.27	13.65

Results for 30 Bus system(Table 2.5.1 to 2.5.4)

TABLE 2.5.1

Voltage Magnitude at Various Buses P.U.

Bus No.	Initial	Quasi Newton Method	Fletcher's Method	Sparse Hessian Method
1	1.0	1.014	1.019	1.0513
2	.9959	.9663	1.0245	1.0534
3	1.00	1.09	1.0994	1.09
4	1.00	1.1	1.1	1.05
5	.9857	.9987	1.0156	1.0478
6	1.00	1.0287	1.0431	1.05
7	1.00	1.0366	1.0397	1.05
8	1.00	1.0339	1.0397	1.05
9	1.00	1.052	1.0339	1.05
10	1.00	.9644	1.0697	1.05
11	1.00	.9127	1.0704	1.05
114	.835	.91	.9343	.9342
127	.9759	.9977	1.0052	1.0339
177	.9219	.9626	.9697	.9895
194	.9591	.9968	1.0051	1.0152
198	.9707	.9959	1.0302	1.0292
221	.8456	.9441	.9650	.9522
222	.8305	.9260	.9481	.9378
223	.8344	.9252	.9479	.9398
227	.9594	.9990	1.0676	1.0441
228	.9758	.9462	1.0672	1.0445
229	.8192	9256	.9443	.9310
230	.9428	1.0167	1.0541	1.0314
231	.9508	1.0433	1.0587	1.0373
232	.9794	1.073	1.0835	1.0593
234	.9278	1.0046	1.014	1.0079
235	.9825	1.0329	1.0357	1.043
240	.9779	1.0181	1.0233	1.0344
241	.9282	.9704	.9767	.9955
242	.8942	.9500	.9483	.9691

TABLE 2.5.2

Transformer Tap Position

Transformer No.	Between the buses	Initial	Quasi Newton method	Fletcher's method	Sparse Hessian Method
1	1-127	1.00	.9625	1.1	1.0
2	2-114	1.00	1.025	1.1	1.0
3	3-232	1.00	1.00	1.1	.975
4	4-232	1.00	.95	1.05	.95
5	6-194	1.00	1.00	1.025	1.00
6	7-240	1.00	1.00	1.00	1.025
7	8-240	1.00	1.00	1.00	1.025
8	9-235	1.00	1.0125	.975	1.0125
9	10-198	1.00	.975	1.0125	.975
10	241-177	1.00	1.00	1.00	1.00
11	5-177	1.00	1.00	1.1	.9875
12	240-194	1.00	1.00	1.0	1.00
13	223-114	1.00	1.075	1.00	1.05
14	235-198	1.00	.95	1.00	1.00
15	11-228	1.00	1.00	1.00	.9875

TABLE 2.5.3

Shunt Capacitor Capacity Dispatch (MVAR)

Capacitor No.	Bus No.	Initial	Quasi Newton Method	Fletcher's Method	Sparse Hessian Method
1	114	1	4.8	2.2	4.0
2	229	1	4.4	4.8	5.0
3	242	1	5.5	6.0	6.0
4	223	1	0.0	0.0	0.0

TABLE 2.5.4

Reactive Power Output of Generators
(30 Bus System Off-Peak Load 75 percent of Peak Load)

	Initial		Quasi Newton Method AK = 0		Quasi Newton Method AK=100		Fletcher's Method AK = 0		Fletcher's Method AK = 100		Sparse hessian Method AK = 0		Sparse hessian Method AK = 100	
Losses MW	20.0378		17.6794		18.1217		17.5834		18.0992		17.7061		18.0208	
Node No.	MVAR	Percent	MVAR	Per-cent	MVAR	Per-cent	MVAR	Per-cent	MVAR	Per-cent	MVAR	Per-cent	MVAR	Percent
3	-4.48	11.73	19.64	25.51	18.66	24.95	-7.11	10.22	-6.71	10.45	10.88	20.50	10.36	20.21
1	23.26	53.62	13.68	42.98	13.00	42.22	2.44	30.49	2.32	30.36	12.42	41.58	11.83	40.92
2	16.49	75.44	6.71	57.65	6.38	57.05	21.12	83.85	20.06	81.93	11.51	66.38	10.96	65.38
4	-0.23	14.15	-21.19	2.18	20.16	2.77	-3.49	12.29	-3.29	12.40	-25.00	0.0	-23.11	1.08
5	15.36	73.38	13.92	70.76	13.22	69.49	3.72	52.22	3.53	51.87	12.50	68.18	11.90	67.09
6	19.05	62.93	17.74	61.06	16.85	59.79	8.38	47.69	7.96	47.09	17.08	60.11	16.27	58.96
7	17.28	33.82	9.72	27.78	9.23	27.38	9.98	27.98	9.48	27.58	9.19	27.35	8.75	27.00
8	17.73	29.47	11.13	24.91	10.57	24.53	1.01	17.94	0.96	17.90	10.51	24.49	10.00	24.14
9	-2.13	15.77	-124.97	.02	-23.76	0.86	31.77	39.15	30.18	38.06	-17.67	5.06	-7.09	12.35
10	+5.75	55.91	9.26	62.29	8.80	61.45	-25.00	0.0	124.90	0.18	3.38	51.60	3.22	51.31
11	-4.20	37.82	-4.77	36.78	-4.53	37.28	-25.00	0.0	-23.90	2.0	-12.69	22.38	-11.73	24.13

TABLE 2.6.1

Voltage Magnitude at Various Buses P.U.

Bus No.	Initial	Quasi Newton Method	Fletcher's method	Sparse hessian method
1	2	3	4	5
1	.9786	1.0071	1.01	1.0082
2	1.014	1.0425	1.035	1.0427
3	1.017	1.09	1.0698	1.09
4	1.017	1.0795	1.0835	1.0754
5	.9841	.9823	.9671	1.0134
6	1.017	1.0552	1.0432	1.057
7	1.017	1.0173	1.0215	1.057
8	1.017	1.0084	1.0570	1.057
9	1.017	1.1	1.058	1.057
10	1.017	1.0572	1.0567	1.057
11	1.017	1.0602	1.0528	1.057
60	.9506	1.0357	1.028	1.0339
61	.9046	.9922	.9854	.992
62	.8870	.9753	.9689	.9759
63	.8716	.9595	.9540	.9617
64	.8604	.9494	.9438	.9516
101	.8848	1.0279	1.0256	1.0135
102	.8803	1.0239	1.0217	1.0095
103	.8808	1.0239	1.0216	1.0096
104	.8857	1.027	1.0246	1.0129
105	.8776	1.0268	1.0245	1.0113
106	.8221	1.0128	1.0102	.9907
107	.8054	1.0089	1.0061	.9845
108	.7955	1.0052	1.0023	.9998
109	.8841	1.0187	1.0167	1.0056
110	.9023	1.0344	1.0324	1.0214
111	.8980	1.0244	1.0236	1.0119
112	.8922	1.0183	1.018	1.0058
113	.8858	1.0111	1.0108	.9987

Contd.

Table 2.6.1 (Contd.)

1	2	3	4	5
114	.8955	1.0115	1.0116	1.0004
115	.8705	.9963	.9989	.9831
116	.8491	.9839	.9886	.9684
117	.8451	.9813	.9865	.9658
118	.8545	.9858	.9915	.9715
126	.9355	1.0133	1.015	1.0074
127	.9647	1.0151	1.0177	1.0128
128	.9164	.9755	.9795	.9710
129	.9104	.9709	.9750	.9663
130	.9130	.9723	.9763	.9679
140	.8893	1.0065	1.0053	.9955
141	.9139	1.0281	1.0249	1.0178
142	.9149	1.0289	1.0257	1.0186
143	.8994	1.0146	1.0128	1.0041
144	.9089	1.0222	1.0192	1.0123
145	.9542	1.0579	1.0525	1.0496
146	.9566	1.059	1.053	1.051
147	.9793	1.0761	1.0690	1.0691
148	.9674	1.0656	1.0585	1.0586
149	.9655	1.0632	1.069	1.0485
150	.9763	1.0681	1.0726	1.0563
151	.9803	1.0712	1.0755	1.0598
152	.9875	1.0848	1.0859	1.0737
153	.9874	1.0878	1.0859	1.0772
154	.9647	1.0711	1.0679	1.0591
155	.9470	1.0549	1.0505	1.0425
158	.9214	1.0397	1.0388	1.0241
159	.9121	1.0321	1.0312	1.0163
161	.9607	1.0558	1.047	1.0464
162	.9391	1.0367	1.0277	1.0271
163	.9554	1.0510	1.0421	1.0416
164	.9112	1.0233	1.0166	1.0097

Contd.

Table 2.6.1 (Contd.)

1	2	3	4	5
165	.8821	1.0023	.9980	.9869
166	.8610	0.9881	.9862	.9710
167	.8450	.9796	.9801	.9599
168	.8399	.9768	.9779	.9573
169	.8385	.9751	.9753	.9552
171	.9135	.9841	.9899	.9980
172	.8830	.9680	.9632	.9713
176	.9123	.9754	.9749	.9891
177	.9194	.9426	.9498	.9761
178	.9067	.9303	.9377	.9645
179	.9008	.9144	.9305	.9721
180	.8919	.9015	.9248	.9650
181	.8951	.9085	.9251	.9676
182	.8932	.9064	.9231	.9665
183	.9052	.9288	.9362	.9629
184	.8975	.9213	.9288	.9558
187	.8868	.9142	.9207	.9451
188	.9070	.9339	.9401	.9640
189	.9390	.9673	.9723	.9928
191	.9488	.9781	.9818	.9998
192	.9258	.9561	.96	.9784
193	.9512	.9865	.9842	1.002
194	.9848	1.0128	1.0163	1.0334
196	.9803	1.0251	1.0211	1.0321
197	.9893	1.335	1.0295	1.0403
198	1.0087	1.0616	1.0528	1.0591
199	1.0094	1.0637	1.0547	1.0611
221	.9141	1.0384	1.0356	1.0269
222	.9024	1.0275	1.0261	1.0155
223	.9033	1.026	1.0246	1.0144
227	.9882	1.0875	1.0849	1.0776

Contd.

Table 2.6.1(Contd.)

1	2	3	4	5
228	.9916	1.0783	1.0761	1.0658
229	.8943	1.0303	1.0277	1.0171
230	.9724	1.0725	1.0669	1.0645
231	.9901	1.0823	1.0745	1.0761
232	1.009	1.0908	1.0821	1.0868
233	1.0241	1.1062	1.0973	1.1000
234	.9763	1.0656	1.0554	1.0567
235	1.0114	1.0735	1.0584	1.0643
240	.9963	1.0144	1.026	1.0434
241	.9299	.9523	.9613	.9867
242	.9079	.9237	.9357	.9769

TABLE 2.6.2

Transformers Tap Settings
(103 Bus System)

Transformer No.	Between the Buses	Initial	Quasi Newton Method	Fletcher's Method	Sparse hessian method
1	1-127	1.00	1.00	1.00	1.00
2	2-114	1.00	1.00	1.00	1.00
3	3-232	1.00	1.00	1.00	1.00
4	4-232	1.00	1.00	1.00	1.00
5	5-177	1.00	1.00	1.00	1.00
6	6-194	1.00	1.00	1.00	1.00
7	7-240	1.00	.95	.9625	.95
8	8-240	1.00	.95	.9625	.95
9	9-235	1.00	1.05	1.0125	1.05
10	10-198	1.00	1.00	1.00	1.00
11	11-228	1.00	1.025	1.0125	1.0125
12	172-63	1.00	1.00	1.00	1.00
13	221-110	1.00	1.00	1.00	1.00
14	222-111	1.00	.975	1.00	.975
15	223-114	1.00	.975	.95	.9875
16	227-153	1.00	.95	.9875	.95
17	228-151	1.00	.9875	.9625	.9625
18	229-104	1.00	.975	1.1	.9875
19	230-145	1.00	1.0875	1.0375	1.1
20	231-147	1.00	1.0625	1.0125	1.05
21	232-60	1.00	1.00	1.1	1.00
22	234-161	1.00	.975	1.0	.975
23	235-198	1.00	.975	1.0	.9875
24	240-194	1.00	1.05	1.0125	1.0125
25	241-177	1.00	1.0625	1.025	1.05
26	242-179	1.00	1.00	.9875	1.00

TABLE 2.6.3

Shunt Capacitor Settings(MVAR)

Shunt Capacitor No.	Bus No.	Initial	Quasi Newton Method	Fletcher's Method	Sparse hessian method
1	102	7	7.2	7.2	7.2
2	106	8	8.2	8.2	8.2
3	108	6.5	6.7	6.7	6.7
4	111	5	5.9	5.9	5.9
5	112	20	20	20	20
6	116	15	16	17.20	17.2
7	117	5	5.5	5.5	5.5
8	118	15	16	20	20
9	128	10	11	11.5	11.5
10	129	7.5	7.5	7.5	7.5
11	149	5.0	7	7.9	8.2
12	151	7.5	8	14.6	15.4
13	158	5.0	6	7.6	7.6
14	167	5.0	6	10.60	10.6
15	105	7.5	7.8	7.80	7.8
16	107	5.0	5.5	5.50	5.5
17	142	5.0	5.3	5.3	5.3
18	154	7.5	7.8	7.8	7.8
19	164	5.0	6.0	4.7	4.9
20	171	5.0	5.6	5.6	5.6
21	189	5.0	7.0	6.5	6.9
22	110	8.0	8.3	8.3	8.3
23	169	2.5	3.0	2.2	2.5
24	180	5.0	1.0	7.1	7.1
25	182	8.0	7.1	7.1	7.1

TABLE 2.6.4

Reactive Power Generation- Off-Peak Load Condition

(103 Bus Test System)

	Initial		Quasi Newton Method				Fletcher's Method				Sparse Hessian Metho			
AK			0.0		100.00		0.0		100.0		0.0		100.0	
Losses in MW	34.9719		31.3631		31.3852		31.243		31.2688		31.4294		32.454	
Node	MVAR	Percent	MVAR	Per-cent	MVAR	Per-cent	MVAR	Per-cent	MVAR	Per-cent	MVAR	Per-cent	MVAR	Per-cent
3	-25.00	0.0	-25.00	0	-25.00	0	-25.00	0	-25.00	0	-24.24	0.43	-23.08	1.1
1	31.10	62.33	6.46	34.96	6.14	34.6	3.70	31.89	3.52	31.69	12.59	41.77	11.99	41.1
2	14.39	71.62	8.94	61.71	8.49	60.89	0.54	46.44	0.51	46.38	1.84	48.80	1.75	48.6
4	-20.99	2.29	-25.00	0	-23.75	0.71	-25.00	0	-23.45	0.89	-25.00	0.0	-24.20	0.4
5	19.82	31.49	4.26	53.20	4.05	52.82	3.57	51.95	3.39	51.62	16.44	75.35	15.66	73.9
6	8.65	48.07	-13.63	16.24	-12.95	17.21	-13.85	15.93	-13.16	16.91	- 3.64	30.51	- 3.46	30.7
7	9.62	27.70	- 8.46	13.23	- 8.04	13.57	- 6.83	14.54	- 6.50	14.80	- 3.95	16.84	- 3.76	16.9
8	11.09	14.73	29.60	37.66	28.12	36.63	36.56	42.46	34.73	41.19	- 0.60	16.82	- 0.57	16.8
9	- 22.06	2.02	-25.00	0	-23.65	0.93	-25.00	0	-22.95	1.41	-25.00	0	-23.80	0.8
10	- 3.98	38.22	-11.00	25.35	-10.45	26.45	- 9.32	28.51	- 8.85	29.36	- 8.45	30.09	- 8.05	30.8
11	- 3.70	40.25	-25.00	0	-22.80	4.00	-25.00	0	-22.80	4.0	-20.16	8.80	-19.20	10.5

TABLE 2.7

Computer Memory Requirement
(103 Bus System)

Quasi Newton	100.4 K (100%)
Fletcher	100 K (99.6%)
Sparse Hessian	95 K (94.6%)

CHAPTER - III

TRANSMISSION SYSTEM LOSSES MINIMIZATION BY OPTIMAL VAR PLANNING

Transmission system losses are dependent on system voltage and reactive power flow. In electric system, low voltages may occur at various points of the system due to large loads or line/ generator outages. The need for adding reactive compensation in the system in an optimal manner has been recognized by utility planners and operators for voltage control and reduction in transmission system losses. The reactive power and voltage control through reactive compensation is necessary for maintaining adequate voltage at critical points and for controlling undesirable reactive power flows during emergency as well as normal mode of operation, reduced system losses, and increased power transfer capability. With the increase in size and complexity of the system, the determination of size and location of the reactive compensation has become quite an involved problem as many alternate solutions are possible. The trial-and-error procedure relying on engineering experience and multiple load flow studies are time consuming and may not give the optimal allocation in terms of amount of compensation and location.

During the past few years increasing attention has been paid to the problem of reactive compensation planning. A bibliography on reactive compensation planning is given by Sachdeva and Billinton [65] . Maliszewski et.al. [52].

Solved the problem using a combination of linear programming and a.c. load flows, assuming that static capacitor could generate any amount of kiloVars. Young [88] presented a technique for determining the least costly allocation of fixed and switched capacitor banks for maintaining voltage within specified limits under all anticipated network conditions using discrete programming. The solution is based on the method developed by Lawler and Bell [46]. Pretelt [61] solved this problem by linear programming and partial load flows. Kishore and Hill [41] developed a method using sensitivity parameters and linear programming to determine the minimum amount of reactive power capacity installation required to satisfy system conditions. Kuppurjulu and Nayar [44] proposed a nonlinear programming method using gradient technique to minimize the total reactive power installation required in a net work for voltage correction, generator reactive power capabilities were taken in to account. Sachdeva and Billinton [65] used nonlinear programming for long range VAR planning problem in order to maintain the system voltage within the desired limits while operating under various contingency states, effect of other system elements such as generator and auto-transformers have been considered. Kohli et. al. [42] minimized capital outlay for the capacitor banks required to control voltages under all anticipated contingencies by 0-1 programming. Ramchandran and Sharma [62] presented a mixed integer programming method for finding static capacitor allocations in a power system under various modes of operation. Happ and Wirgau [35] developed a method using linear programming for planning reactive compensation in power systems so as to maintain voltages in acceptable ranges during contingencies and addition of further VAR compensation as may be economically justified.

In literature, reactive compensation planning problem is formulated as linear programming and non-linear programming. Linear programming models have been extensively used for reactive compensation planning problem in the transmission system. In a linear programming problem, the objective function and constraints are linear, but the problem of reactive compensation planning is nonlinear. To apply linear programming this nonlinear problem is approximated as linear. In a linear optimization the objective function assumes its minimum or maximum at a corner of the convex polyhedron while in the case of nonlinear programming, the minimum or maximum can be located at a corner, on an edge, or even in the interior of the polyhedron. Since linear programming tends to provide the solution at the extremities of the operating region, it may not give the optimal solution in some of the cases. The linear programming solution may give rise to a poor search direction if the objective function is highly nonlinear [30].

In non-linear programming approach the problem of reactive compensation planning have been formulated as unconstrained optimization problem by using two popular non-linear programming approaches. The first is the lagrangian multipliers approach using dual variable for each equality and violated in_equality constraint, while in the other approach penalty parameters are used for converting constrained problem into an unconstrained one. The lagrangian multipliers technique assumes that the Kuhn-Tucker conditions of optimality are satisfied at the solution and if this is not the case, the method performs poorly. The method also critically depends on having good estimate of lagrangian multipliers. This is a difficult problem even in the case of linearly constrained optimization. In the penalty function methods, a sequence of unconstrained minimization problems are solved. The penalty function requires an initial feasible point. In most of the cases initial feasible point is not available. The choice of initial feasible point is a very sensitive factor which can govern the whole outcome of the process. If a large value is selected, the constraints are originally weighed too heavily, and a large number of sequential unconstrained minimization or iterations are necessary. If too small a value is used, a large number of steps are required in each iteration. In both cases, if many constraint boundaries are hit during the initial part of the process, the minimization becomes exceedingly difficult and often converge prematurely to a sub-optimal point.

Further, light load conditions when the generators are under excited need special attention. It is desirable that reactive power absorbed by each generator should be as less as possible and also the difference between percentage sharing of reactive power among generators should be as less as possible. This has not been considered in the available methods.

Based on approximation of hessian or its inverse with first order derivatives, three new approaches are suggested to solve the problem of reactive compensation planning in transmission system. The new approaches are suitable to solve large power systems as these methods require less computer storage and computation time. These methods have faster convergence rate, and are robust, stable and reliable.

In this chapter three new formulations for long range optimum VAR planning to reduce transmission losses is presented considering the normal, emergency, peak load and light load operation of power system. The objective function considered consists of cost of real power losses, cost of reactive compensation installation, operation and maintenance cost of reactive compensation, and differences between percentage sharing of reactive power among the generators with weightages. The decision variables are generator terminal voltage magnitudes, transformer tap positions, and switchable source of reactive power at load buses. The generalized reduced gradient is used to transform the problem, which reduces the size and complexity of the problem. Three solution procedures are presented in this chapter. Results for 6 Bus [86], 30 Bus, and 103 Bus MPEB power systems are given.

3.1 PROBLEM FORMULATION

The reactive compensation planning problem in high voltage system for reduction of transmission system losses and voltage improvement during normal, emergency, peak load and light load operation of the system can be stated as to minimize an objective function consisting of cost of real power losses, cost of reactive compensation installation, operation, and maintenance, and differences between percentage sharing of reactive power among generators subject to the equality and inequality constraints imposed by reactive power output from generators, voltage magnitudes, transformer tap positions, switchable VAR source capacities, and power flow equations.

It has been assumed that active and reactive power load is known with certainty at all the nodes.

3.1.1 Objective Function

The transmission system losses for a given load are function of reactive power flow, which is mainly dictated by the system bus voltage magnitudes. As derived in section 2.1.1 transmission system losses are function of node voltage and phase angles (2.7).

Cost of total losses in the transmission system is therefore,

$$FC_{\ell} = CT_{\ell} \sum_{L=1}^{NLE} P_{Lij} \tag{3.1}$$

Installation, operation and maintenance cost of reactive compensation is given by

$$F_c = \sum_{i=1}^{NC} CI_i + C_i CM_i \tag{3.2}$$

As discussed in Section 2.1.1 from stability considerations sharing of reactive power by the generators should be proportional to their reactive power capability limit [75].

$$F_s = AK \sum_{i=1}^{NG-1} \sum_{j=i+1}^{NG} (Qi/Bi - Qj/Bj)^2 \tag{3.3}$$

Hence the objective function to be minimized is

$$F = FC_{\ell} + F_c + F_s \tag{3.4}$$

3.1.2 Power Flow Constraints

Under steady state operation of power system, active and reactive power balance must be satisfied at each node. Since there is a little change in voltage angle and active power, therefore, active power equalities and inequalities are excluded from constraint set. In N bus system, the reactive power flow equations can be expressed as

$$h_i(v) = -Q_i + V_i \sum_{j=1}^{N} V_j(G_{ij} \text{ SIN } \theta_{ij} - B_{ij} \text{ COS } \theta_{ij}) \tag{3.5}$$

3.1.3 Limits on Variables

The reactive power output of any generator must lie between its specified upper and lower limits i.e.

$$Q_i^m \leq Q_i \leq Q_i^M, \qquad i = 1 \;\ldots\; NG \tag{3.6}$$

Limits for reactive power output of generators are taken from their capability curves (Fig. 2.1)

The voltage magnitude at each node must lie between specified upper and lower limits.

$$V_i^m \leq V_i \leq V_i^M, \qquad i = 1, \;\ldots\ldots\; N \tag{3.7}$$

Limit for voltage were taken between 0.9 P.U. to 1.1 P.U. considering continuous variation in voltage with-in these limits. Transformer tap positions are variable but no tap position shall be out side the allowable range i.e.

$$T_i^m \leq T_i \leq T_i^M, \qquad i = 1, \;\ldots\ldots\; NT \tag{3.8}$$

Limits for transformer tap were taken from 0.95 to 1.1 in the steps of 0.0125. To simplify the calculations, continuous variation of transformer tap positions was considered and at the end of each iteration these are rounded off to the nearest standard value.

Switchable VAR sources can supply reactive power with in their specified lower and upper limits.

$$C_i^m \leq C_i \leq C_i^M, \qquad i = 1, \;\ldots\ldots\; NC \tag{3.9}$$

Limits for switchable VAR sources considered were - 0.1 P.U. to 0.20 P.U. in steps of 0.001. To simplify the calculations continuous variation of switchable VAR sources was considered and at the end of each iteration rounding-off to the nearest standard value is done. It is also ensured that at no time the Bus Power factor becomes leading.

3.2 COST COMPONENTS

3.2.1 Demand Cost of Losses

The annual per unit demand cost incurred to maintain sufficient system capacity to supply the losses in a transmission system is given by the expression

$$CADL_i = PRF \times LAF \times RF \times (CPXRP + CTXRT) \times (1 + e)^{i-1} \quad (3.10)$$

The total per unit demand cost is given by

$$TCDL = \sum_{i=1}^{NY} CADL_i \quad (3.11)$$

3.2.2 Energy Cost of Losses

The annual per unit energy cost of losses in a transmission system is given by (3.12)

$$CAEL_i = TIME \times EC \times LSF_i \times LAF \times (1+e)^{i-1} \quad (3.12)$$

Total per unit energy cost of losses is given by

$$TCEL = \sum_{i=1}^{NY} CAEL_i \quad (3.13)$$

Hence the total per unit cost of power and energy losses is given by

$$CT_i = TCEL + TCDL \qquad (3.14)$$

3.2.3 Installation Cost

The investment cost CI_i is divided into the fixed cost CF_i and the variable cost CV_i, CF_i involves the installation and erection cost, which remain constant for closely rated capacitors, CV_i represents the price of the capacitors and depends on its ratings.

Hence

$$CI_i = CF_i + CV_i \times (C_i - SC_i) + SF_i + SV_i(SC_i) \qquad (3.15)$$

3.2.4 Operation and Maintenance Cost

To account for the occasional inspection charges, replacement costs of the fuses and the other control accessories and for the power and energy losses with in the capacitor, a cost component in terms of annual expenditure is worked out.

$$CM_i = h_i \frac{(1+e)^{NY} - (1+i)^{NY}}{(1+i)^{NY-1}(e-i)} \qquad (3.16)$$

where h_i is the annual expenditure represented as per unit of the capital cost of the capacitor bank.

3.2.5 Effect of Price Escalation

The cost of equipment, materials, construction, labour, operation, and maintenance cost in a system increases with time. The cost of various elements in a power system may not increase in the same manner, as these costs are governed by demand and supply position of these elements, which differs from one element to other. The cost of electrical energy is increasing at a fast rate compared to other system costs. Therefore price escalation in operation and maintenance cost and electric power and energy cost is considered while calculating economic benefits from reactive compensation application.

3.3 CLASSIFICATION OF VARIABLES

The problem variables V_i, Q_i, T_i and C_i are divided in to two groups i.e. decision variables X and state variables Y where

$$X = \begin{bmatrix} V_i & i = 1, \ldots\ldots NG \\ T_i & i = 1, \ldots\ldots NT \\ C_i & i = 1, \ldots\ldots NC \end{bmatrix} \qquad (3.17)$$

and

$$Y = \begin{bmatrix} Q_i & i = 1, \ldots\ldots NG \\ & \\ V_i & i = NG+1 \ldots N \end{bmatrix} \qquad (3.18)$$

3.4 REDUCED GRADIENT

In terms of above mentioned variables, shunt compensation planning problem can be expressed as

$$\text{Min } F\,(Y,X) \qquad (3.19)$$

subject to

$$h_i\ (Y,X) = 0 \qquad i = 1, \ldots\ldots N \qquad (3.20)$$

$$Y^m \leq Y \leq Y^M \qquad (3.21)$$

$$X^m \leq X \leq X^M \qquad (3.22)$$

Applying the generalized reduced gradient as developed in section 2.1, reduced gradient is given by

$$\nabla_r f(y,x)^T = \nabla_x f(y,x)^T - \nabla_y f(y,x)^T \left[\nabla_y h(y,x)\right]^{-1} \nabla_x h(y,x) \qquad (3.23).$$

The reduced gradient defines the rate of change of objective function with respect to decision variables with the state variables adjusted to maintain feasibility.

3.5 QUASI NEWTON METHOD

Methods using approximate hessian matrix calculated from first order derivatives have faster convergence rate. But computational difficulty arises when the smallest eigen value of hessian becomes zero or tends to become zero. This is called conditioning problem. The computational difficulties arising out of the conditioning problem is overcome by using Quasi Newton method (BFGS) of inverse hessian update.

BFGS update is sometimes called the complementary DFP update and that the underlying single rank method. There is a growing evidence that the BFGS update is the best current update formula for use in unconstrained minimization. This method has global convergence and is robust, reliable and stable.

Solution algorithm is given in Section (2.2.1).

3.6 FLETCHER'S METHOD

The minimization algorithm described in Section 3.5 requires the determination of step size in each iteration such that maximum reduction in function value is achieved during every iteration. Fletcher's method has an advantage of avoiding the optimal determination of step size in each iteration by choosing an approximate step size. This helps in reducing the computer storage and computational burden.

The Fletcher's method is less sensitive to the accuracy of the linear search for step size determination. It avoids the computation of second order derivatives of the function. This method is basically stable because the hessian matrix is always positive definite. The stability is further improved if the algorithm is recycled.

Solution algorithm is given in Section (2.3.1).

3.7 SPARSE HESSIAN METHOD

The two methods as described in Section 3.5 and 3.6 and using approximate hessian matrix, calculated from first order derivatives have faster convergence rate. But they do not exploit the symmetry and sparsity of approximated hessian and therefore require large storage. In toint's procedure [80, 81] of hessian updating sparsity and symmetry of the hessian is fully exploited. This results in reduction of computer storage. Solution algorithm for this method is given in Section 2.4.1 .

This method has a good and Q super linear fast rate of convergence and therefore useful in practical problem considered here. Sparse update formula is used to update the hessian resulting in less computer storage. In this method sparsity and symmetry is fully exploited.

3.8 APPLICATION TO SAMPLE SYSTEMS AND RESULTS

Computer programs implementing the proposed algorithms are prepared and used on DEC 2050 to test the method on three power systems (6 Bus [86], 30 Bus, and 103 Bus Madhya Pradesh Electricity Board Power System).

Initially system voltage under heavy load conditions were lower than the minimum specified limit of 0.90 P.U. in all the cases considered. The system voltage obtained with the installation of capacitors lie with in the limit of 0.90 P.U. to 1.1 P.U.

Peak load condition, line outages of heavily loaded lines in peak load condition, and off peak load condition are studied before arriving at final decision. System details are given in Appendix-A and system cost details in Table 3.1. In Table 3.2 through 3.4 results are given for 6 Bus, 30 Bus, and 103 Bus system in detail about fixed and switched capacitors. Table 3.5 to 3.7 give the results for all the three systems about loss reduction with various methods. Details of computation time are given in Table 3.8.

3.9 CONCLUSION

Three new mathematical formulation of reactive compensation planning for reactive power control and loss reduction in high voltage transmission system using nonlinear programming are presented. Effect of generator terminal voltage and transformer tap on reactive power control is considered before considering installation of reactive compensation. These methods overcome the limitations observed in the available techniques. These algorithms would be useful tools to assist the system operators and planning engineers in making decisions. By incorporating a series of contingencies in order of their severity a full list of reactive switching schedule can be compiled.

TABLE 3.1

System Cost Details

Life of the shunt compensation	= 25 years
Production fixed cost	= Rs.6000/KW
Production fixed cost rate	= 0.11
Transmission fixed cost	= Rs.2000/KW
Transmission fixed cost rate	= .106
Energy cost	= Rs.0.288/KWH
Peak responsibility factor	= 0.45
Loss allowance factor	= 1.09
Reserve factor	= 1.56
Interest rate	= 0.09 P.U.
Load factor	= 0.60
Price escalation rate for production and transmission system	= 0.07 P.U.
Price escalation rate for energy	= 0.09 P.U.
Reactive compensation cost	
(a) fixed type	= Rs.185/KVAR
(b) Switched type	= Rs.225/KVAR
Operation and Maintenance cost	= .02 P.U.

TABLE 3.2

Details of Reactive Compensation MVAR
(6 Bus System)

Bus No.	Fixed	Switched	Total
3	1.5	1.5	3.0
5	4.0	2.5	6.5
6	3.0	6.0	9.0
Total :	8.5	10.0	18.5

TABLE 3.3

Details of Shunt Compensation MVAR
(30 Bus System)

Bus No.	Fixed	Switched	Total
114	5	-	5
221	5	-	5
222	5	-	5
227	5	-	5
229	5	-	5
230	3	-	3
231	3	-	3
234	5	-	5
242	6	-	6
Total	41	-	41

TABLE 3.4

Details of Shunt Compensation MVAR
(103 Bus System)

Bus No.	Fixed	Switched	Total
60	1	1	2
61	0	1	1
62	2	1	3
63	0	1	1
64	1	0	1
102	5	2	7
103	3	1	4
104	6	0	6
105	5	2	7
106	5	3	8
107	3	2	5
108	4	2	6
109	6	0	6
110	5	3	8
111	4	1	5
112	16	4	20
113	6	0	6
114	6	0	6
115	1	1	2
116	12	5	17
117	1	0	1
118	2	0	2
126	1	1	2
127	2	1	3
128	8	3	11
129	5	2	7
130	4	2	6
140	8	0	8
141	0	1	1
142	3	2	5
143	3	1	4
144	4	2	6

Table 3.4 (contd.)

1	2	3	4
145	6	0	6
146	6	0	6
147	6	0	6
148	4	1	5
149	1	0	1
150	6	0	6
151	11	3	14
152	2	1	3
153	2	2	4
154	5	2	7
155	3	2	5
158	5	2	7
159	2	2	4
161	6	0	6
162	5	2	7
163	8	3	11
164	4	2	6
165	3	2	5
166	4	2	6
167	6	0	6
168	1	1	2
169	3	1	4
171	3	2	5
172	6	2	8
176	2	2	4
178	1	0	1
179	5	1	6
180	5	2	7
181	5	1	6
182	5	2	7
183	6	0	6
184	3	1	4
187	9	0	9
188	1	1	2
189	1	0	1

Table 3.4 (contd.)

1	2	3	4
191	3	1	4
192	6	0	6
193	6	0	6
194	5	1	6
196	3	1	4
197	4	2	6
198	6	0	6
199	3	1	4
Total	316	93	409

TABLE 3.5

Results for 6 Bus, 30 Bus and 103 Bus System (Quasi Newton Method)

	6 Bus	30 Bus	103 Bus
Initial losses (Peak load) MW	6.228	44.7428	68.9029
Losses after optimization (Peak load) MW	4.3782	35.6386	55.7892
Reduction in losses MW	1.8598	9.1042	13.1137
Total capacitors required MVAR	18.5	41.00	409.00
Fixed capacity of capacitor MVAR	8.5	41.00	316.00

TABLE 3.6

Results for 6 Bus, 30 Bus and 103 Bus System
(Fletcher's Method)

	6 Bus	30 Bus	103 Bus
Initial losses (peak load) MW	6.228	44.7428	68.9029
Losses after optimization (Peak load) MW	4.3024	35.3116	55.4561
Reduction in losses MW	1.9256	9.4312	13.4468
Total capacitors required MVAR	18.5	41.00	409.00
Fixed capacity of capacitor MVAR	8.5	41.00	316.00

TABLE 3.7

Results for 6 Bus, 30 Bus and 103 Bus System
(Sparse Hessian Method)

	6 Bus	30 Bus	103 Bus
Initial losses (peak load) MW	6.228	44.7428	68.9029
Losses after optimization (peak load) MW	4.3987	35.1594	55.099
Reduction in losses MW	1.8293	9.5834	13.8039
Total capacitors required MVAR	18.5	41.00	409.00
Fixed capacity of capacitor MVAR	8.5	41.00	316.00

TABLE 3.8

Computer time Requirement

	6 Bus System	30 Bus System	103 Bus System
Quasi Newton Method			
No.of iterations	2	2	2
CPU Time (seconds)	1.94	14.70	131.66
Fletcher's Method			
No.of iterations	2	2	4
CPU Time (Seconds)	1.15	14.62	128.60
Sparse Hessian Method			
No. of iterations	2	4	4
CPU Time (seconds)	1.10	14.36	123.50

CHAPTER - IV

LOSSES MINIMIZATION IN INTERCONNECTED AND LARGE POWER SYSTEMS

In Chapter II and III the problem of losses minimization by reactive power control and losses minimization by optimal VAR planning in transmission system are formulated and algorithms for its solution are discussed. The solution of these problems require large computer memory and time. A possible approach to overcome this problem is to divide the large power system into smaller ones by removing some interconnections. In this chapter a decomposition method suitable for losses minimization in large power transmission system is presented. The method for solution of losses minimization problem involves tearing of a power system into pieces and then solve the problem. This results into reduction of computation time and core storage.

Diakoptics was conceived and developed by Kron [43]. The name Diakoptics follows from Greek 'KOPTO' meaning to tear, and 'DIA' may be interpreted as system. Hence Diakoptics is system tearing. The basic idea of Diakoptics is to analyse a system by tearing it into its desirable component parts as if the other did not exist. The solution of the components parts are then combined and modified to take the interconnections into consideration. The results are as good as if the system had never been torn apart.

CHAPTER - IV

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Diakopetics or methods of tearing were not earlier applied to losses reduction methods. The different versions of Diakoptic are in use for load flow solutions. The Diakoptic technique was first applied to a matrix load flow by Andretich et. al. [4] and it was demonstrated that tearing is an effective method for overcoming the large size problems that are encountered. In this method, the load flow problem was solved by cutting the branches to isolate different sections from one another. This needs an additional interconnection matrix apart from the impedence matrix of each section. Dy Liacco [21] proposed that the system be decomposed by cutting through nodes instead of branches. The advantage of cutting through node is that the interconnection requirement becomes simple. All that is required is for the voltages of each torn node to be the same. An electrical decomposition is accomplished by connecting a voltage source to each node that will be torn, when the current through these voltage sources are zero, and all other conditions are met, the solution has been found. It is stressed here that the method cuts nodes and that it requires additional computations to adjust the introduced voltage source. Sasson [67] further improved upon by cutting the branches twice once on each of the two terminal nodes. The idea used was that of Dy Liacco [21] isolating through voltage source. Only the cut node on the far side of the interconnection branch will act as a source. The near node will be a normal load. The interconnected branch is a part of both systems. The method than proceeds iteratively from subsystem to subsystem. Happ [32] described two methods called as boundary iteration method and the diakoptic method. The boundary iteration method is a tearing technique which uses information from the previous iteration in an attempt to satisfy boundaries. The diakoptic approach [32, 33, 43] on the other hand, uses a network theory called orthogonal network theory that makes it unnecessary to iterate on the boundaries. Roy [63] presented a method to solve load flow problem piecewise applying the principle of super-position. Cut branch currents are computed from the actual voltage across the cut branch and its admittance. Correction voltages are calculated from cut line currents.

In this chapter a decomposition algorithm for losses minimization of large power systems is presented which is compatible with sparsity and condensation in analysis of large power systems. Two versions of handling the cut branch power flows and node voltages are presented. This algorithm has the following special features:

(a) The method building algorithm and solution procedures are independent of topology and graph of subdivision.

(b) Building algorithm does not require radial equivalent of subdivisions.

(c) Inter subdivision matrix is not needed.

(d) This method does not impose restrictions on a system subdivisions.

(e) A considerable reduction in computer time and storage is obtained.

4.1 TEARING THE NETWORK

The power system to be solved is torn up into an appropriate number of subdivisions. In this method branches are cut twice once on each of the two terminal nodes of the branch, and not on the branch itself. The cut node at far side of the interconnected branch will act as a special node. The near node will be a normal node of the section containing it. Figure 4.1 shows the decomposition technique that results in overlapping of subsystems.

A decision is made to cut through the branch between node 1 and 2. Subsystem A contains node 1 and node 2, node 1 appearing as normal node while node 2 will appear as a special node. The reverse is true for subsystem B. It is noted that interconnection branch is part of both subsystem. There is no need for any additional computation apart from the solution of each subsystem.

4.2 THE PROPOSED TECHNIQUE

A given large network is torn into n subdivisions by cutting connecting lines with only one restriction that no mutual coupling should exist between lines of different subdivision. Generally, an objective guide for tearing is to

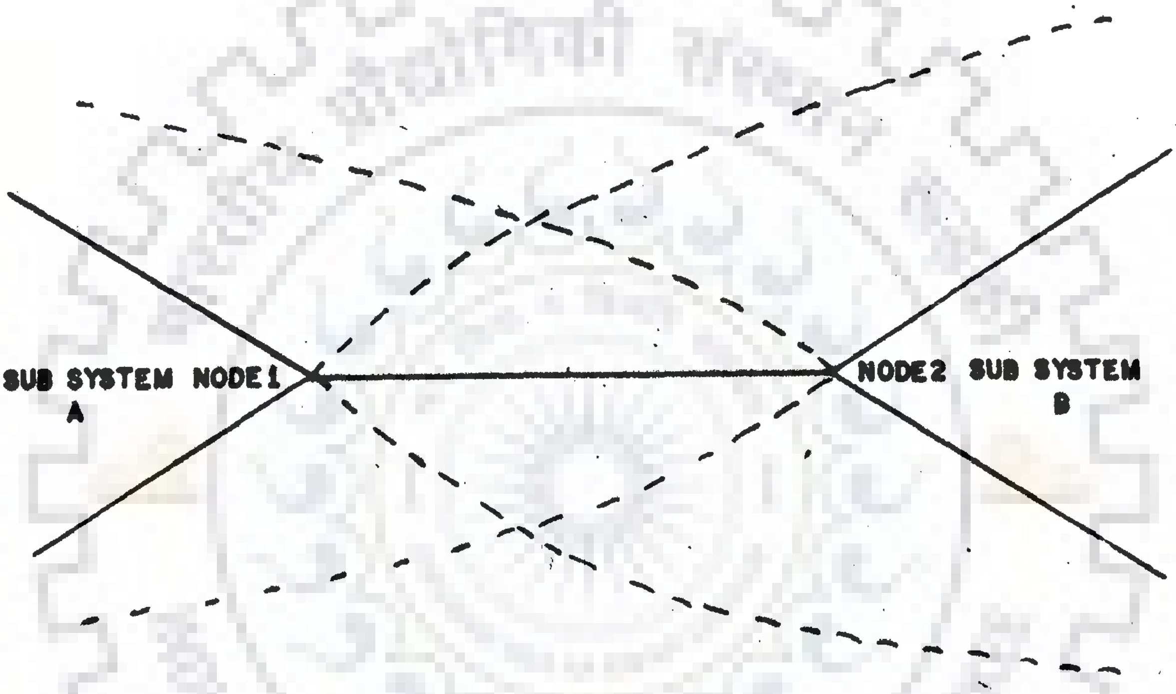


Fig 4.1 TEARING THE SYSTEM

separate networks of different utilities, identificable power pools etc. In addition to the slack bus of the original system which would lie in one sub-division, a temporary bus is selected for reference in each of the remaining sub-divisions.

4.2.1 Objective Function

The objective function to be minimized for a sub-system consists of original cost function plus difference between interconnected branch active power flow.

$$\text{Min } F = F(Y,X) + W \sum_{i=1}^{NBC} (BP_i - CBP_i)^2 \qquad (4.1)$$

Subject to

$$Y^m \leq Y \leq Y^M \qquad (4.2)$$

$$X^m \leq X \leq X^M \qquad (4.3)$$

Where X is independent variable vector and Y is dependent variable vector. The first part of the objective function, constraints and method of solution for untorn power system is well described in Chapter II and III.

4.2.2 Piecewise Algorithm for Losses Minimization

The program uses sparse hessian method for the losses minimization as referred above. It contains a number of sub-programs and utilizes both programs and data overlays in order to minimize the amount of core memory required. The tearing version of this program will also follow the philosophy, and will use storage areas already allocated in order to perform most of the required computation that is to be added.

The procedure to be followed in the initial version of this program will be described and each step will be discussed in some detail.

(a) Initialization

When system is solved in one piece, there are number of initial steps required. This includes the translation of the data from the form used in the input to the form needed in the calculations, the sorting of data, the optimal ordering of buses, and the initialization of variables. In a piecewise solution, these steps are essentially the same, with the difference being principally that the subsystems must be identified, and then each subsystem is separately initialized as before, since it can be treated as a single entity. In addition, the data relating to the lines between areas must be organized and initialized.

(b) Iterative Procedure

(i) Since the initial voltages are known (either from a flat voltage start, or from a previous case), the initial tie flows between subdivisions may be computed. This is done by solving the load flow problem for a combined system in one piece.

(ii) The network is torn up into desired number of sub-divisions.

(iii) The data for the first subdivision is separated out. The buses to which tie lines are connected are tagged as special buses by the input. (Two versions of the treatment to be given to these buses is described in Section 4.2.3).

(iv) The loss minimization problem is solved for the sub-division optimizing the objective function as outlined in Section 4.2.1.

(v) The procedure described in steps (iii) and (iv) is repeated for each of the subdivision in turn.

(vi) Check for convergence. It converged, stop. Otherwise go to step (iii).

(vii) The load flow analysis is performed for the total system and print the results.

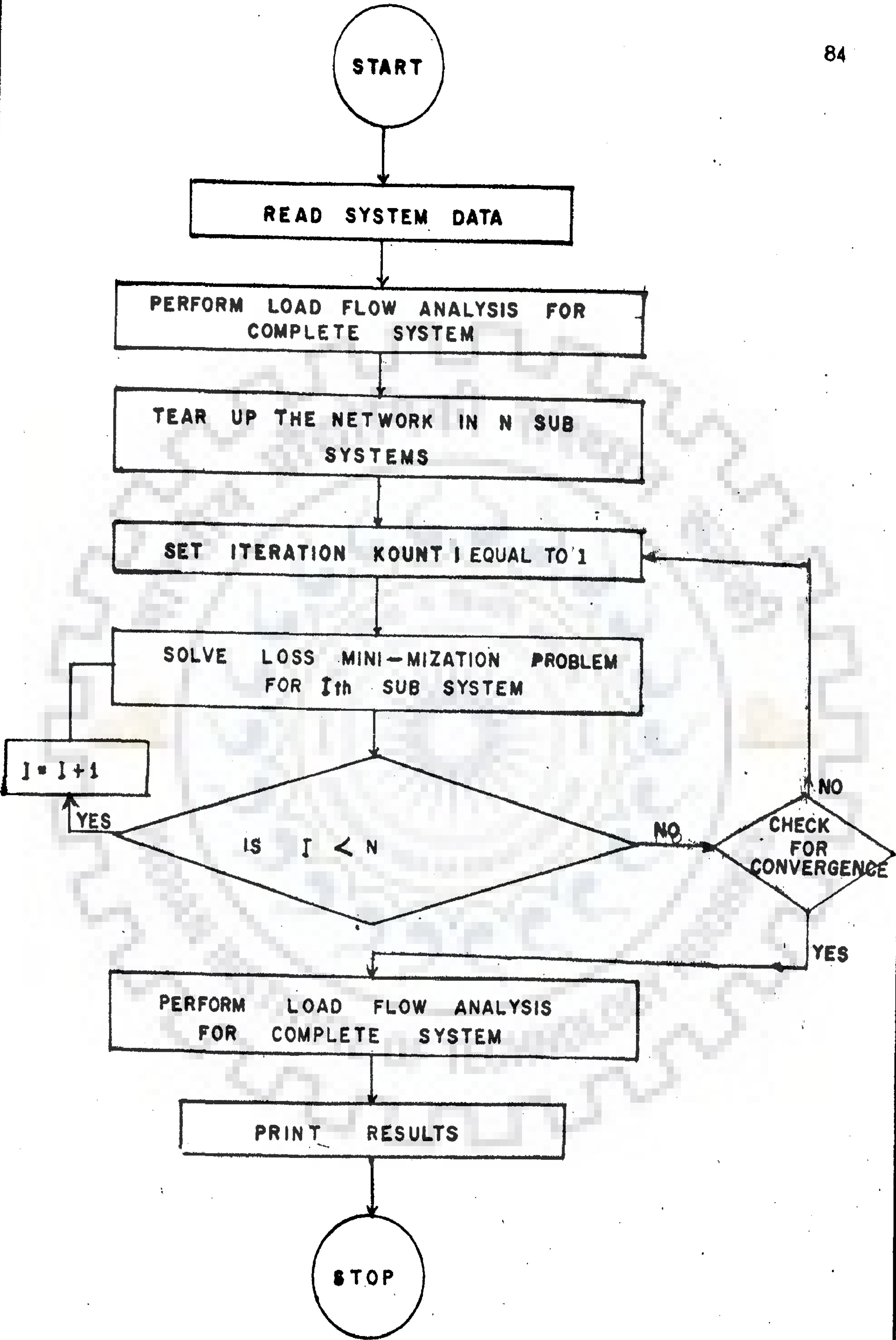
A simple flow chart for the above mentioned algorithm is given in Fig.4.2.

4.2.3 Handling of Special Buses

Two version of special buses treatment has been used in this investigation.

(a) Special buses are treated as load buses (P-Q Bus).

(b) Special buses are treated as generator buses(P-V Bus)



FLOW CHART FOR DECOMPOSITION. METHOD

Fig 4. 2

4.3 APPLICATION TO SAMPLE SYSTEMS AND RESULTS

Computer softwares implementing the proposed algorithm using the sparse hessian method as described in Chapter II and III are prepared and used on DEC 2050 to test the method on 30 Bus and 103 Bus power systems of Madhya Pradesh Electricity Board Jabalpur. Table 4.1 gives the percentage reduction in computer time required to solve above mentioned power system for this method. Reduction in computer storage was more than fifty percent in both the cases considered here.

4.4 CONCLUSION

A method for piece wise solution of power system loss minimization problems is proposed. Method is conceptually simple and easy to visualize and implement. In this approach the system is torn into subdivisions. Each subdivision is solved separately. Two versions of treatment of special buses are presented. The method offers freedom in the choice of choosing the line of cut and number of subdivisions. The method developed may be applied to large size electrical networks in general and to loss minimization problems in particular and offers an alternative powerful tool to power system engineers to solve their problems. There is no theoretical limit on the size of the problem that can be solved by this technique.

TABLE 4.1

Computation Time seconds

System size	No.of sub-systems	Time in Seconds Untorn system	Special Busses are treated PQ Bus	PV Bus
Reactive Power Control Problem				
30 Bus	2	12.12	11.15 (92)	10.23 (84)
103 Bus	2	104.26	85.27 (82)	75.04 (72)
Reactive compensation Planning				
30 Bus	2	14.36	13.02 (91)	11.94 (83)
103 Bus	2	123.50	99.16 (80)	87.04 (70)

Figures in brackets show the percentage to the untorn system time. C.P.U. time indicated here is for 4 iterations. Computation time saving is thus larger for tearing larger systems.

CHAPTER - V

DISTRIBUTION SYSTEM LOSSES MINIMIZATION BY CONDUCTOR GRADATION

The distribution system constitutes a significant part of a total power system. Since the distribution voltage system level is low and the distribution system is of extensively large size, this system is prone to have more losses compared to that in the other parts of the power system. Moreover power and energy cost will be maximum at distribution level and a loss of the same at the distribution level will lead to more severe financial implications. Improved planning and operation allows us to reduce distribution system losses significantly. Distribution lines, transformers, and metering equipments are the components responsible for distribution system losses. A major portion of distribution losses is contributed by distribution lines. With a given installation and load, energy losses cost varies inversely with the conductor size. However, initial cost varies directly with the conductor. This relationship can be utilized to select a conductor size which minimizes the sum of initial costs and the cost of energy losses. It is, therefore, essential to minimize the overall cost of the distribution lines including the capital investment and the present worth of the cost of power and energy losses in the life span of the system through an optimal conductor gradation.

Initially some useful attempts in this direction started with defining the several distribution system parameters and establishing the relationship between them by Vanwarmer [83] and Hopkins and Samson [38]. Funk Houser [26] had studied the problem of conductor gradation through an enumeration technique for distribution feeders, assuming uniform load distribution only. Later on several attempts have made in suggesting algorithms for optimization of distribution system parameters through simulation study [47, 12, 27, 28, 39, 7]. Adams and Laughton [1] solved the problem by representing each feeder line segment in terms of capacity of linearized cost and considering multiple time periods using mixed integer programming. They used the model to solve a small problem. Hindi and Brameller [36] proposed a branch and bound/capacitated mixed integer programming transhipment method using list processing technique for optimal lay out of a radial low voltage distribution network considering energy loss cost and uniform cross section of a radial feeder throughout their length. Wall et al. [85] optimized a uniform cross section for a radial feeder using a transhipment model. Sun et al. [79] proposed a formulation representing a progression from the linear programming transhipment problem to the mixed integer programming fixed charge network problem. They represented the primary circuit segments by a fixed and a variable (linear) cost component. Ponna-Vaikko and Rao [59] developed a conductor gradation procedure for radial distribution feeders using dynamic programming approach. Load growth, nonuniform distribution of loads along the feeder and increase in cost of energy has been considered by them.

Voltage dependent mathematical models for feeder installation, operation, and maintenance cost and the present worth of power and energy losses cost are developed in this Chapter. Load growth, increase in the cost of Power and energy, non-uniform distribution of loads, and increase in labour and material cost are considered.

Procedure for obtaining optimal conductor gradation for distribution system using group variational and dynamic programming approach is described. In the presented technique voltage dependency is considered and hence losses are calculated accurately. The procedure has the special features as given in Section 5.1.

5.1 SYSTEM REPRESENTATION AND OTHER PARAMETERS

In the present approach non-uniform distribution of load is assumed. Multi-ended radial feeders and interconnected distribution systems are considered, while the methods in use at present neglect the laterals by lumping their load to the main feeder. With the change of time, load growth takes place which is taken into account. Cost of losses and material increases due to change in demand and supply position of these items and the same is considered.

Economic benefits due to improvement in voltage profile along the feeder is neglected but here these benefits are taken into account to consider various costs accurately. As the load grows the load factor of the distribution system also increases which is considered.

Uniform cross section of the feeders is assumed alon the feeder which is not correct for actual system. In actu systems conductor cross section changes as the loading changes on the feeder. This assumption is removed.

5.2 PROBLEM FORMULATION

The problem of optimal losses reduction in distribution system via conductor gradation can be formulated as minimization of an objective function consisting of capital, operation, and maintenance costs of distribution line, and cost of energy (Kwh) and power (Kw) losses over the life span of the system considering growth in load, increase in energy and power cost, and increase in load factor, subject to permissible voltage regulation and available sizes of conductors. It is assumed that load and its power factor are known with certainty at all the nodes.

5.2.1 Objective Function

The distribution system power losses for a given load condition are function of current flowing in the lines, which is mainly dictated by the system bus voltage magnitudes and resistance of the distribution lines. As derived in section

2.1 distribution losses are function (2.7) of node voltage magnitude and phase angles, conductance, and susptance of the distribution lines.

Cost of the total power and energy losses in the distribution system is therefore :

$$FC_1 = CD_1 \sum_{L=1}^{NLE} P_{Lij} \tag{5.1}$$

Installation cost of distribution lines is given by

$$F_I = \sum_{i=1}^{NLE} CS_i \times RL_i \tag{5.2}$$

Operation and maintenance cost of a distribution line is given by

$$F_m = \sum_{i=1}^{NLE} LM_i \times RL_i \tag{5.3}$$

Hence the objective function to be minimized is

$$F = FC_1 + F_I + F_m \tag{5.4}$$

F_I is a single time expenditure incurred at the time of constructing the distribution line while F_1 and F_m are the summation of cost of losses and operation and maintenance cost over the life span of distribution system.

5.2.2 Limits on Variables

The voltage magnitude at each node must lie between specified upper and lower limits

$$V_i^m \le V_i \le V_i^M \qquad i = 1, \ldots\ldots N \tag{5.5}$$

Limits for voltage are taken between 0.9 P.U. to 1.1 P.U. considering continuous variation in voltage within these limits.

Conductor sizes are available in discrete sizes and should lie between specified upper and lower sizes to be used in the system. Per unit cost of conductor available for use in distribution lines vary as per (5.6).

$$CS_i^m \leq CS_i \leq CS_i^M \tag{5.6}$$

Limit for conductor sizes depend on the type of conductor to be considered. In the present study the conductor considered are WEASEL, FERRET, RABBIT, MINK, BEAVER, RACOON, OTTER, CAT and DOG.

5.3 COST OF LOSSES

Losses cost consists of two components, one is demand (Kw) cost of losses and other is energy (Kwh) cost of losses.

5.3.1 Demand Cost of Losses

The annual demand cost incurred to maintain sufficient system capacity to supply the losses in a distribution system is given by the expression :

$$CADL_i = (PRF)(LAF)(RF)(CP.RP + CT . RT + CST.RST) \\ (1 + e)^{i-1} \tag{5.6}$$

The demand cost is given by

$$TCDL = \sum_{i=1}^{NY} CADL_i \tag{5.7}$$

5.3.2 Energy Cost of Losses

Annual energy cost of losses is given by

$$CAEL_i = TIME(EC)(LSF_i)(LAF)(1+e)^{i-1} \tag{5.8}$$

Total energy cost is given by

$$TCEL = \sum_{i=1}^{NY} CAEL_i \tag{5.9}$$

Hence total cost of Power (Kw) and energy (Kwh) losses is given by (5.10).

$$CD_1 = TCEL + TCDL \tag{5.10}$$

5.4 LOAD CHARACTERISTICS

5.4.1 Effect of Load Growth

Load growth in an area with time is a natural phenomenon. The growth in distribution system load may be due to addition of new loads in the system or due to the incremental additions to the existing loads. A distribution system designed and constructed on long term basis can accept additional loads to the extent it can accomodate satisfying the voltage constraints. Once the load exceeds the feeder capacity, limited by either voltage regulation or thermal constraints, new facilities such as substation or additional feeders need to be created. Another alternative available to alliviate this problem is increase in the capacity of substation or use the higher size conductor or use of shunt compensation. Till such time the substation feed area and configuration of the main feeders may be assumed to remain constant. It is further assumed that the feeder load grows at a predetermined annual rate, g - in proportion to the load connected in the system, implying that the feeder load profile, on a per unit basis, remains unchanged with load growth. The effect of load growth can be introduced by multiplying loads by a factor $(1 + g)^n$, $n = 1, \ldots\ldots M$, where M is the plan period for which the distribution system is designed.

5.4.2 Effect of Growth in Load Factor

The system experiences growth in load factor due to many reasons such as increase in load diversity with load growth, increase in energy consumption per KW connected load with time, measures taken by the utilities to flatten load curve for improving system efficiency, and to curb the growth in peak demand etc. According to Scheer [69] the system load factor grows cutting the difference between an ultimate load factor and the present load factor in to half over a period of 16 years and the load factor at any year, K, is given by

$$LF_K = LF_u - Y_K(LF_u - LF_p) \tag{5.11}$$

where

$$Y_K = (0.5)^{K/16} \tag{5.12}$$

The corresponding annual loss load factor can be obtained by substituting the value of load factor in the expression used for the same.

$$LSF_K = A(LF_k) + (1-A) \times (LF_k)^2 \qquad (5.13)$$

5.5 SOLUTION APPROACH

Large number of feeders are there in service in a distribution system and the load distribution in them is different from each other and is mostly non-uniform in practice. Since every feeder in the system needs to be analysed individually, enumeration technique is not employed due to the requirement of massive computational efforts. It is, therefore, necessary to look for a simpler optimal grading method requiring reasonably less computational effort.

A closer examination will reveal that the present problem can be solved with group variational method. As stated in (5.4) and para 5.2.1, it is required to minimize a cost function with respect to the variable conductor cross sections subject to the constraints on voltage drop allowed.

5.5.1 Algorithm

Initially the conductor cross section which gives the lowest capital cost per unit length of feeder is assumed for all the feeder sections, from the alternate sizes available. The computational procedure for the problem solution is as follows :

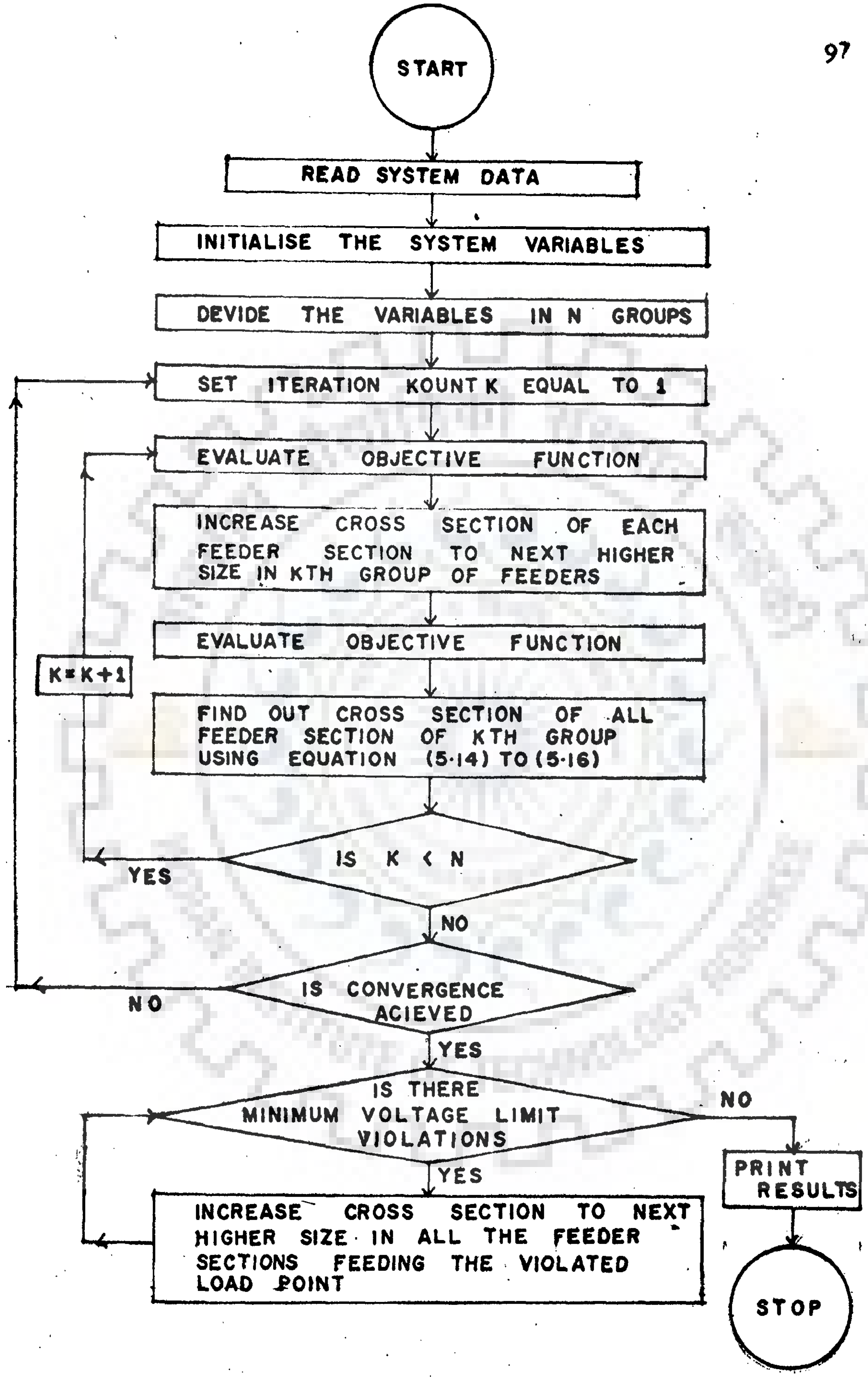


FIG. 5.1 FLOW CHART FOR OPTIMUM CONDUCTOR GRADATION

(vii) If $K < n$, set $K = K + 1$, go to step (iii).

(viii) Check for convergence.

Solution is said to be converged if there is no change even in the conductor cross section of a single feeder between two successive cycles or highest conductor cross section is encountered in one or more of the feeder sections.

If converged, go to step (ix)

Else goto step (ii)

(ix) Check for minimum voltage limit violations, if no limit violations, stop.

(x) Change conductor cross-section in all the feeder sections feeding the load point to next higher size and go to step (ix).

A Flow chart for the method is given in Fig.5.1.

5.5.2 Group Formation

A list of various feeder sections is prepared and groups are formed by taking two feeder sections from the list serially. The following are the various ways to prepare the above referred list.

(a) Prepare the list as per the distribution system data without changing the order in which feeder section details are given.

(b) Prepare the list in the increasing or decreasing order of voltage magnitude at the end of feeder section.

(c) Calculate (load at the end point of feeder section)^2 x distance between end point and substation . Arrange it in increasing or decreasing order and prepare the list accordingly. While calculating load at the end of the feeder losses are neglected.

5.6 APPLICATION AND RESULTS

The proposed method has been tested on a number of 11 KV distribution feeders of MPEB power system. The results of one such typical system with non-uniform loading are given here. The system details are given in Appendix - A, Table 5.1 gives the conductor cost and the details used in this study. Other system cost details are given in Table 3.1 and 6.1. Table 5.2 gives the feeders cross sections for different load levels. Ten percent increase in each load level is considered.

5.7 CONCLUSION

The proposed method is a generalized approach and is applicable to any type of feeder with any type of loading pattern, with same or different load power factors. The proposed model is also very useful to carry out sensitivity analysis of the dependent cost components on conductor gradation. The algorithm suggested considers the system growth factors, maximizing the life time benefits, and economic benefits due to voltage improvement along the feeders, thus giving the overall optimal solution to the problem. The proposed method is more efficient and quite promising.

TABLE 5.1

Conductor Cost and Other Parameters

Code Name	Conductor diameter mm	Conductor area mm^2	Resistance at 20° C ohm/km	Cost of the line per km M.U. x 10^3
WEASEL	7.77	36.88	0.9116	28.2
FERRET	9.00	49.48	0.6795	32.28
RABBIT	10.05	61.70	0.5449	34.56
MINK	10.98	73.65	0.4565	36.12
BEAVER	11.97	87.53	0.3841	39.72
RACOON	12.27	91.97	0.3656	40.68
OTTER	12.66	97.91	0.3434	42.00
CAT	13.50	111.30	0.3020	44.40
DOG	14.16	118.50	0.2745	45.96

TABLE 5.2

Conductor Details for Various Feeder Sections

Sl. No.	Between the Buses	Load Level-I		Load Level-II		Load Level-III		Load Level-IV		Load Level-V	
		Variable Voltage	Constant Voltage	Variable Voltage	Constant Voltage	Variable Voltage	Constant Voltage	Variable Voltage	Constant Voltage	Variable Voltage	Constant Voltage
	2	3	4	5	6	7	8	9	10	11	12
	11-12	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL
	11-13	DOG	DOG	DOG	DOG	DOG	DOG	DOG	DOG	DOG	DOG
	11-16	DOG	DOG	DOG	DOG	DOG	DOG	DOG	DOG	DOG	DOG
	13-14	RABBIT	RABBIT	RABBIT	RABBIT	RABBIT	RABBIT	MINK	MINK	MINK	MINK
	13-42	FERRET	FERRET	FERRET	FERRET	FERRET	FERRET	FERRET	FERRET	RABBIT	MINK
	14-15	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL
	16-17	FERRET	MINK	RABBIT	MINK	MINK	MINK	MINK	MINK	MINK	MINK
	16-18	MINK	RACOON	RACOON	DOG	DOG	DOG	DOG	DOG	DOG	DOG
	16-43	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	FERRET	FERRET	FERRET	FERRET	RABBIT
0	17-44	WEASEL	FERRET	WEASEL	FERRET	WEASEL	FERRET	FERRET	FERRET	FERRET	MINK
1	18-19	MINK	MINK	MINK	MINK	MINK	MINK	BEAVER	RACOON	DOG	DOG
2	19-20	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL
3	19-21	FERRET	FERRET	FERRET	FERRET	FERRET	FERRET	FERRET	FERRET	FERRET	MINK
4	21-22	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL
5	23-24	MINK	MINK	MINK	MINK	MINK	MINK	MINK	MINK	MINK	RACOON
6	23-26	MINK	MINK	MINK	MINK	MINK	MINK	MINK	MINK	MINK	RACOON
7	23-28	MINK	MINK	MINK	MINK	MINK	MINK	MINK	RACOON	RACOON	DOG
8	23-30	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	FERRET	FERRET	FERRET	FERRET	FERRET
9	23-31	MINK	MINK	MINK	MINK	MINK	MINK	MINK	BEAVER	RACOON	DOG
0	24-25	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	FERRET	FERRET	FERRET	FERRET	FERRET

Contd.

Table 5.2(Contd.)

1	2	3	4	5	6	7	8	9	10	11	12
21	26-27	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	FERRET	FERRET	FERRET	FERRET	FERRET
22	28-29	WEASEL	WEASEL	WEASEL	FERRET	FERRET	FERRET	FERRET	FERRET	FERRET	MINK
23	31-32	FERRET	RABBIT	RABBIT	MINK	MINK	MINK	MINK	MINK	MINK	MINK
24	32-33	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	FERRET	FERRET	FERRET	FERRET
25	34-35	DOG	DOG	DOG	DOG	DOG	DOG	DOG	DOG	DOG	DOG
26	34-35	MINK	MINK	MINK	MINK	MINK	BEAVER	BEAVER	RACOON	DOG	DOG
27	35-36	RACOON	DOG	DOG	DOG	DOG	DOG	DOG	DOG	DOG	DOG
28	35-37	FERRET	FERRET	FERRET	FERRET	FERRET	FERRET	FERRET	FERRET	FERRET	FERRET
29	36-46	MINK	MINK	MINK	MINK	MINK	BEAVER	BEAVER	RACOON	DOG	DOG
0	38-39	FERRET	FERRET	FERRET	FERRET	FERRET	RABBIT	MINK	MINK	MINK	MINK
1	38-40	MINK	BEAVER	BEAVER	DOG	DOG	DOG	DOG	DOG	DOG	DOG
2	40-41	FERRET	MINK	MINK	MINK	MINK	MINK	MINK	MINK	MINK	MINK
3	30-43	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	FERRET	FERRET	FERRET	FERRET	FERRET
4	33-46	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	FERRET	FERRET	FERRET
5	37-41	WEASEL	WEASEL	WEASEL	WEASEL	WEASEL	FERRET	FERRET	FERRET	FERRET	FERRET
jective nction lue U. $x10^3$		6803.914	7106.99	7105.43	7441.582	7434.51	7827.16	7847.41	8256.44	8251.07	8748.60

CHAPTER - VI

LOSSES REDUCTION IN DISTRIBUTION SYSTEM THROUGH OPTIMUM SHUNT CAPACITOR INSTALLATION

The shunt capacitor is considered to be a powerful tool for reducing the distribution system losses and for improving the general performance of distribution systems. The primary effects of the shunt capacitors are - heavy reduction of power (KW) and energy (KWH) losses on the distribution system, improvement in voltage regulation by improving the power factor, release in system capacities such as generation, transmission, sub-transmission, substation and feeder capacities, and increased revenue as a result of increased voltage levels.

Thus with the help of shunt capacitors larger blocks of active power can be supplied over the same system. For realising the best overall results, a number of factors should be taken into consideration for determining the number, location and size of fixed and switched capacitors for a given feeder or group of feeders.

Many attempts have been made in the past for optimally allocating shunt capacitors along the feeders. Neagle and Samson [57] have developed a general rule for finding the optimum size and location of capacitor banks on primary feeders for fixed reactive load level. They have neglected the benefits due to improvement in voltage profile along the feeder. Cook [13,14,15] developed an accurate formula to determine the exact energy losses reduction achieved by shunt capacitor in radial distribution feeders but economic benefits of reduced regulation cost and increased voltage levels were not considered. Schmill [70] extended the work further and presented the basic theory for the application of shunt capacitors to primary distribution feeders on a case by case basis. Based on Cook's [15] formula Duran [20] formulated theorms on the economics of capacitor allocations and suggested a dynamic programming approach for optimizing the number, location and size of shunt capacitors in radial distribution feeders. Chang [10] developed a method to derive the optimal capacitor size and location to maximize the net return due to energy and peak power loss reduction against the cost of capacitors. In an another paper [11] conditions for optimum loss reduction were determined and results were presented graphically. Bae [5] proposed an analytical method for allocating capacitor in primary feeders under various reactive load conditions. Lee and Grainger [29,48,49] defined three sub problems corresponding to location, size and switching time and suggested an iterative procedure for obtaining the optimal results. They also developed an equal area criteria for optimally sizing and locating fixed capacitors on radial feeders. Further they [29] developed a voltage dependent model for optimally sizing any specified number of fixed shunt capacitors while accounting for voltage variation along the feeder. In this method benefits due to reduction in energy losses are neglected. The analysis presented by Brown [9] considered a single idealized infinitely variable source of reactive power. Necessary conditions for optimally sizing, siting and operating the devices were presented and performance of the device was compared to that of a single fixed capacitor bank installation. This analysis was further extended to a number of capacitors by Desai and Brown [17]. Fawzi et. al. [23] presented a method for selection of capacitor size and location depending on the location of additional load that can be served with the present capacitors. Ponnavaiko and Rao [60] developed a method of optimally choosing fixed and switched shunt capacitors on radial distribution feeders, considering load growth, growth in load factor, and increase in cost of energy. They used the method of local variations.

But none of the above approaches have considered the full economic benefits due to voltage changes along the feeder for locating and sizing the fixed and switched capacitors simultaneously. Only Lee and Grainer [29] considered these benefits for placement of fixed capacitors in a limited way by neglecting benefits due to reduction in energy losses. Further all the investigators considered a single end radial feeder.

In this chapter a method of group variations for finding the optimum number, location, and size of fixed and switched shunt capacitors in a distribution system, is presented. The cost savings due to energy (KWH) and power (KW) loss reduction taking the growth factors into account, cost savings due to release in system capacity, and installation and O and M cost of capacitors are considered, in the formulation. Economic benefits due to voltage rise in the distributio system are accounted for.

6.1 SPECIAL FEATURES OF THE PRESENT METHOD

The economic benefits due to improvement of voltage in distribution system can not be ignored. As the choice and location of capacitors without considering these benefits will lead to sub-optimal solution. Therefore these benefits are taken into account. These benefits becomes more important as the cost of power and energy increases at a fast rate.

All the approaches available consider single end radial feeders by lumping the load of laterals to the main feeder. Thus laterals are neglected in finding out the optimum allocation. None of the researchers have solved the problem of shunt capacitor installation in multi ended radial feeders and interconnected distribution systems. In the present formulation multi-ended radial feeders and interconnected distribution systems are considered.

Many previous papers have analysed distribution system problems on the basis of uniform load distribution along the feeder. The assumption of uniformly distributed load imposes certain restrictions and leads to inaccurate results. Hence actual load distribution in a rural distribution systems which is accurate and realistic is considered instead of considering uniformly distributed loads.

The cost of the capacitor bank is considered as a function of the kilo-var capacity of the bank. Normally capacitors do not require any maintenance. However, to account for the occasional inspection charges, replacement costs of fuses and other control accessories, and for the power and energy losses within the capacitors, a cost component in terms of annual expenditure represented as a per unit of the capital cost of capacitor bank is considered.

In most of the methods the wire size of the radial feeder is assumed to be uniform through out the feeder. It is apparant that this assumption is far from what it would be under real circumstances. In the proposed method, this assumption is eliminated.

Economic benefits considered are revenues due to energy loss reduction in the feeder and released KVA at the substation. Effect of voltage boost along the feeder is taken into account.

Load growth is a natural phenomenon in a system. The growth in distribution system load may be due to the incremental additions to the existing loads or due to the addition of new loads to the distribution system. It is assumed that the feeder load grows at a predetermined annual rate i.e. in proportion to the loads connected at the tapping points, implying that the feeder load profile, on per unit basis remains unchanged with load growth.

As the system expands, it experiences a continuous growth in load factor with time due to various reasons such as increase in load diversity, increase in the energy consumption per KW connected load, measures taken by the utilities to curb the growth in peak demand etc. As the load factor increases it will affect the revenues due to energy loss reduction.

The cost of equipment, materials, construction, operation and maintenance in system increases with time. The cost of various elements in a system may not increase in the same manner, as these costs are governed by demand and supply position of these elements. The cost of electrical energy is increasing at a fast rate compared to other system costs. Therefore price escalation in O and M cost and electric power and energy cost is considered while calculating economic benefits from capacitor application.

6.2 PROBLEM FORMULATION

For a given distribution system having many section of different wire sizes with multi-ended interconnected radial feeders and known active and reactive load distribution along the distribution system, it is required to determine optimum location and/or size of fixed and switched shunt capacitor banks to achieve the optimum loss reduction in the distribution system over the life span of the system or plan period. The objective function to be minimized is cost of power and energy losses, cost of fixed and switched shunt capacitors including the O and M cost. Effects of load growth, load factor growth, and growth in energy cost are taken into account. Minimum and maximum voltage specified at all the load points in the distribution system are taken as constraint.

It is assumed that the active and reactive loads in the system are known with certainty.

6.2.1 Objective Function

The distribution system power loss for a given load condition is a function of current flowing in the lines, which is mainly dictated by the system bus voltage magnitudes. As derived in section 2.1.1 distribution losses depend on node voltage magnitudes and phase angles, conductance and susceptance of the distribution lines (2.7).

Cost of the total power and energy losses in the distribution system is therefore.

$$FC_1 = CD_1 \sum_{L=1}^{NLE} P_{Lij} \qquad (6.1)$$

where CD_1 is a cost of power (KW) and energy (KWH) losses in distribution system (5.10).

Installation cost of shunt capacitor is given by

$$F_C = \sum_{i=1}^{NC} CI_i \qquad (6.2)$$

operation and maintenance cost of shunt capacitor is given by

$$F_m = \sum_{i=1}^{NC} C_i \; CM_i \qquad (6.3)$$

Hence the objective function to be minimized is

$$F = FC_1 + F_c + F_m \qquad (6.4)$$

F_c is a single time expenditure incurred at the time of installation of the shunt capacitor, while F_c and F_m are the summation of cost of power and energy losses and operation and maintenance cost of shunt capacitor over the life span of the shunt capacitor or plan period.

6.2.2 Limits on Variables

The voltage magnitude at each node must lie between specified upper and lower limits

$$V_i^m \leq V_i \leq V_i^M, \quad i = 1 \text{---------} N \qquad (6.5)$$

limits for voltage are taken between 0.9 P.U. to 1.1 P.U. considering continuous variation in voltage within these limits.

Shunt capacitor can supply reactive power with in their specified lower and upper limits

$$C_i^m \leq C_i \leq C_i^M \quad i = 1 \text{-------} NC \qquad (6.6)$$

limits for the shunt capacitor are considered between 0 KVAR and minimum reactive load at the point where shunt capacitor is to be installed for fixed type of shunt capacitor. The limit for switched shunt capacitor were considered between 0 KVAR and maximum reactive load at the point minus capacity of fixed shunt capacitor at the point where shunt capacitor is to be installed.

6.3 COST COMPONENTS

The investment cost CI_i is divided into the fixed cost CF_i and the variable cost CV_i, CF_i involves the installation and erection cost, which remains constant for closely rated capacitors. CV_i represents the price of the capacitors and depends on its ratings.

$$\text{Hence } CI_i = CF_i + CV_i \times (C_i - SC_i) + SF_i + SV_i\,(SC_i) \qquad (6.7)$$

The capacitors generally do not require any maintenance However, to account for the occasional inspection charges, replacement costs of the fuses and the other control accessories and for the power and energy losses with in the capacitors, a cost component in terns of annual expenditure is taken.

$$CM_i = h_i \frac{(1+e)^{NY} - (1+i)^{NY}}{(1+i)^{NY-1} \; (e-i)} \qquad (6.8)$$

When h_i is the annual expenditure represented as a per unit of the capital cost of the capacitor bank. Value of h considered in the study is 2 percent of total cost.

Demand cost of losses and energy cost of losses is described in section 5.3.1 and 5.3.2.

Effect of load growth and growth in load factor is considered in the same way as described in section 5.4.

6.4 METHOD

A distribution system has large number of load points and the load distribution is different at different points. As every load point in the system needs to be analysed individually, enumeration technique is not employed due tothe requirement of massive computational efforts. Therefore a method based on group variational approach is developed.

As stated in (6.4) section 6.2 it is required to minimize cost function with respect to the variable shunt capacitor installation at various load points in the system subject to voltage drop constraints.

6.4.1 Algorithm

Discrete steps of solution procedure are given below. A flow chart for the solution algorithm is given in Fig.6.1.

i) Devide shunt capacitor locations into n groups (section 6.4.2.).

ii) Set iteration count k equal to 1

iii) Calculate objective function F_k.

iv) Increase shunt capacitor capacity at each load point of the kth group by an unit.

v) Calculate objective function F_{k+1}.

vi) Calculate shunt capacitor capacity at each load point of the kth group of capacitor using (6.9) to (6.11).

$$\text{If } F_{k+1} < F_k,\ C_L^{k+1} = C_L^{k+1}$$

$$L = 1 \ \ldots\ldots \ NLG \tag{6.9}$$

else change shunt capacitor only at the one load point of the group and calculate objective function value. Let it be called F_{k+1}.

$$\text{If } F_{k+1} < F_k \quad C_L^{k+1} = C_L^{k+1} \tag{6.10}$$

$$\text{else} \quad C_L^{k+1} = C_L^k \tag{6.11}$$

This procedure is repeated for all the members of kth group.

vii) If $k < n$, set $k = k+1$, GO TO step iii

viii) Check for convergence solution is said to be converged if there is no change in the shunt capacitor capacity even at one load point between two successive iterations.

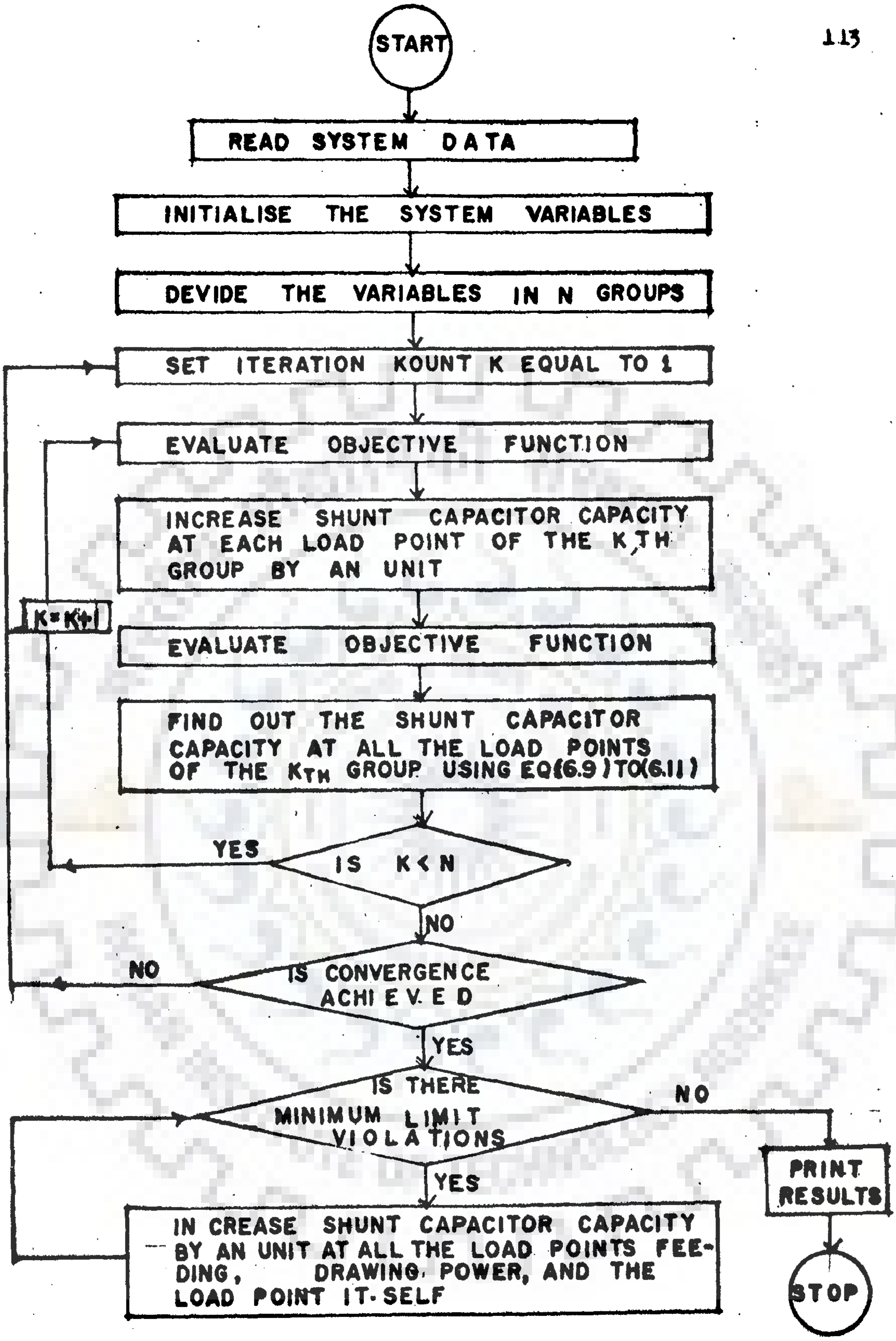


Fig 6·1 FLOW CHART FOR OPTIMUM SHUNT CAPACITOR INSTALLATION.

If converged, go to step IX
else go to step ii

ix) Check for minimum voltage limit violations. If no limit violation, stop. else go to next step.

x) Increase shunt capacitor capacity by an unit at all the load points feeding and drawing power and the load point itself. go to step ix.

6.4.2 Group formation

A list of various capacitor locations is prepared and groups are formed by taking two capacitor locations from the list serially. The following are the various ways to prepare the list.

(A) Prepare the list as per the data without changing the order in which load node data is given.

(B) Prepare the list in the increasing or decreasing order of voltage magnitude at the capacitor locations.

(C) Calculate the [(load at the capacitor location)^2 x distance of the location from the transformer] and arrange it in increasing or decreasing order and prepare the list accordingly. While calculating the load at the capacitor location point the losses are neglected.

6.5 APPLICATION AND RESULTS

The proposed method has been tested on a number of 11KV distribution feeders in MPEB distribution system. The results of one such system with non uniform loading are given here. The system details are given in Appendix-A. Table 6.1 and 3.1 gives the cost data used in this study. Table 6.2 gives the shunt capacitor capacity for different load levels.

6.6 CONCLUSION

The proposed method is simple generalized approach and is applicable to any type of distribution system with any type of realistic loading pattern, with same or different load power factors. It is also very useful to carry out sensitivity analysis of the dependent cost components on shunt capacitor installation. The algorithm suggested considers the system growth factors, maximizing the life time benefit and economic benefits due to voltage improvement along the feeders, thus giving the optimal solution to the problem.

TABLE 6.1

System Cost Details

Subtransmission and distribution fixed cost M.U.	4000/KW
Subtransmission and distribution fixed cost rate	.116
Loss allowance factor	1.14
Load factor	0.27
Cost of shunt capacitor M.U.(fixed)	115/KVAR
Life of shunt capacitor and distribution lines	25 years
Cost of shunt capacitor M.U.(switched)	165/KVAR
Growth in load (8 year cycle)	5 percent

TABLE 6.2 Fig.in KVAR

Capacitor Requirement at Various Load Points with Different Load Levels

...oad ...oint	Load Level-I		Load Level-II		Load Level-III		Load Level-IV		Load Level-V	
	Variable Voltage	Constant Voltage	Variable Voltage	Constant Voltage	Variable Voltage	Constant Voltage	Variable Voltage	Constant Voltage	Variable Voltage	Consta... Voltag...
	2	3	4	5	6	7	8	9	10	11
	15	30	30	30	30	45	45	45	45	60
	30	30	30	30	30	45	45	45	45	60
	30	30	45	45	45	45	60	60(15)	60(15)	60
	30	30	30	30	30	45(15)	45	45	45	45
	0	0	0	0	0	0	0	0	15	15
	15	15	30	30	30	30	30	30	45	45
	15	15	30	30	30	30	30	45	45	45
	15	15	30	30	30	30	30	30	45	45
	15	15	30	30	30	30	30	30	45	45
	0	15	0	15	15	30	15	30	30	45
	45	45	60	60	60	75(15)	75	75	90(15)	90(15)
	0	15	0	15	0	30	15	30	30	45
	45	60(15)	60	60	60	60	75	75	90(15)	75
	0	15	0	15	0	15	0	30	15	45
	45	60	60	75	75	75	90	90	90	105(15)
	0	15	0	30	15	45	30	45	45	60
	0	0	0	0	0	0	0	0	0	15
	30	30	30	30	30	30	30	30	45	45
	45(15)	45(15)	60(30)	60(30)	60(30)	60(30)	75	75	90(15)	75

Table 6.2(Contd.)

1	2	3	4	5	6	7	8	9	10	11
34	0	15	0	15	0	15	0	30	15	45
36	0	0	0	0	0	0	15	0	30	15
38	0	0	0	0	0	0	15	15	30	30
39	75	90(15)	105	105	120(15)	120(15)	135	135	165(45)	150(30)
41	0	0	0	0	30	0	45	0	60	15
42	45	60	60	60	60	75	75	90	90	90
43	15	30	30	45	30	45	45	60	90	75
44	45	30	45	30	60	45	75	60	90	75
45	60	90	90	105	105	120	120	135	150	150
46	75	90	105	105	120	120	135	135	165	150
Objective function value M.U.x10^3	1142.97	1266.67	1370.42	1511.86	1647.63	1816.35	1982.8	2182.39	2382.65	2625.11

Note - Fig. in brackets shows the switched type capacitor capacity.

CHAPTER - VII

LOSSES REDUCTION BY OPTIMAL DISTRIBUTION SYSTEM IMPROVEMENT

The lack of importance attached specially in India to proper planning and design of subtransmission and distribution facilities is an important reason for inefficient operation of distribution systems, in matters such as security of supply, maintenance of voltage, system losses, etc. Even if a sincere effort is made in this direction, it is not always possible to forecast the load accurately at the time of planning the distribution systems, as the development of load in a particular area depends on many factors. At the time of planning for distribution system, certain assumptions are made regarding load and load growth and distribution systems are planned accordingly. In actual practice, these assumptions may vary from time to time. These aberrations will subsequently result in numerous system problems such as high losses of power and energy, low voltage problems, over loading of the system, under utilisation of the investments in certain places, discontinuity of supply, loss of equipment, and production. It has been indicated by the various studies that without much difficulties the distribution system losses can be brought down significantly with economic reward, through appropriate system improvement measures. Such system improvement measures would not only cause reduction of power and energy losses, but also improve the service conditions.

The optimal conductor gradation problem and optimal shunt capacitor installation problem are solved on individual basis in Chapter V and Chapter VI respectively. The two problems (shunt capacitor installation and conductor replacement) are formulated in this chapter as a single problem and a solution procedure is developed using a group variational method.

7.1 PROBLEM FORMULATION

The problem of distribution system losses minimization via system improvement can be with its objective as to minimize cost of power and energy losses, cost of conductor replacement, installation, operation, and maintenance cost of shunt capacitors, subject to permissible voltage regulation, available sizes of conductors, and maximum permissible shunt capacitor installation at load nodes.

7.1.1 Objective Function

The cost of total power (KW) and energy (KWH) losses in a distribution system is given by (7.1)

$$FC_1 = CD_1 \sum_{L=1}^{NLE} P_{Lij} \tag{7.1}$$

where CD_1 is cost of power and energy losses in a distribution system (5.10) section 5.3.

Conductor replacement cost of distribution lines is given by

$$F_{CH} = \sum_{i=1}^{NLE} RL_i \times CH_i \tag{7.2}$$

Installation cost of shunt capacitor is given by

$$F_C = \sum_{i=1}^{NC} CI_i \tag{7.3}$$

Operation and maintenance cost of shunt capacitor is given by

$$F_m = \sum_{i=1}^{NC} C_i \quad CM_i \tag{7.4}$$

Hence the objective function to be minimized is

$$F = FC_1 + F_{CH} + F_c + F_m \tag{7.5}$$

7.1.2 Limits on Variables

The voltage magnitude at each node must lie between specified upper and lower limits.

$$V_i^m \leq V_i \leq V_i^M, \; i = 1, \ldots\ldots N \tag{7.6}$$

Lower and upper limits for voltages are taken as 0.9 P.U. and 1.1 P.U. respectively.

Conductor sizes are available in discrete sizes and should lie between specified upper and lower sizes to be used in the system. These conductor replacement cost vary between

$$CH_i^m \leq CH_i \leq CH_i^M \quad i = 1 \text{-------} NLE \tag{7.7}$$

Limit for the conductor sizes depend on the type of conductor to be considered. In the present study the conductors considered are FERRET, RABBIT, MINK, BEAVER, RACOON, OTTER, CAT AND DOG.

Shunt capacitors can supply reactive power with-in their specified lower and upper limits.

$$C_i^m \leq C_i \leq C_i^M \quad i = 1, \text{-------} NC \tag{7.8}$$

Limits for the shunt capacitor are considered between zero KVAR and minimum reactive load at the point where shunt capacitor is to be installed for fixed type of shunt capacitor. The limit for switched shunt capacitors are considered between zero KVAR and maximum reactive load at the point minus capacity of fixed shunt capacitor at the point where shunt capacitor is to be installed.

7.2 COST COMPONENT

7.2.1 Cost of power(KW) and energy (KWH) is given by (5.10) section 5.3.

7.2.2 Conductor replacement cost is the summation of the cost for taking out the conductor from the distribution line, difference in two conductor costs and difference in maintenance cost of two conductors.

$$CH_i = CTO_i + CDT_i + CMT_i \tag{7.9}$$

7.2.3 Cost of shunt capacitor installation and maintenance is given in section 6.3.

7.3 LOAD CHARACTERISTICS

Various load characteristics and other factors are described in detail in section 6.1.

7.4 METHOD

The present problem can be solved by group variational method.

Discrete steps of the method are given below -

i) Divide the distribution system feeder sections into n groups (section 5.5.2 and section 6.4.2).

ii) Set k = 1

iii) Evaluate objective function using second order decoupled load flow let it be called F_o.

iv) Change the conductor size to the next higher size conductor for all lines in kth group of feeder section.

v) Evaluate the objective function, let it be called F_r.

vi) Now assume an installation of one unitof shunt capacitor at receiving end of all the feeder sections of kth group.

vii) Evaluate the objective function let it be called FC_a.

viii) Decision about conductor replacement or shunt capacitor installation is taken using (7.10) and (7.11).

If $F_r < FC_a$ and $F_r < F_o$ conductors are to be replaced (7.10)

If $FC_a < F_r$ and $FC_a < F_o$ shunt capacitors are to be replaced (7.11).

else step iv) to step vii) are repeated for each feeder section of kth group of feeder sections. Decision about conductor replacement or shunt capacitor installation is taken using (7.10) to (7.12).

If $F_r < F_o$ and $FC_a < F_o$

No change required. (7.12).

ix) If $k < n$ go to step iii.

x) Check for convergence.

Solution is said to be converged if there is no change in objective function value between two successive iteration.

xi) If converged stop, else go to step ii.

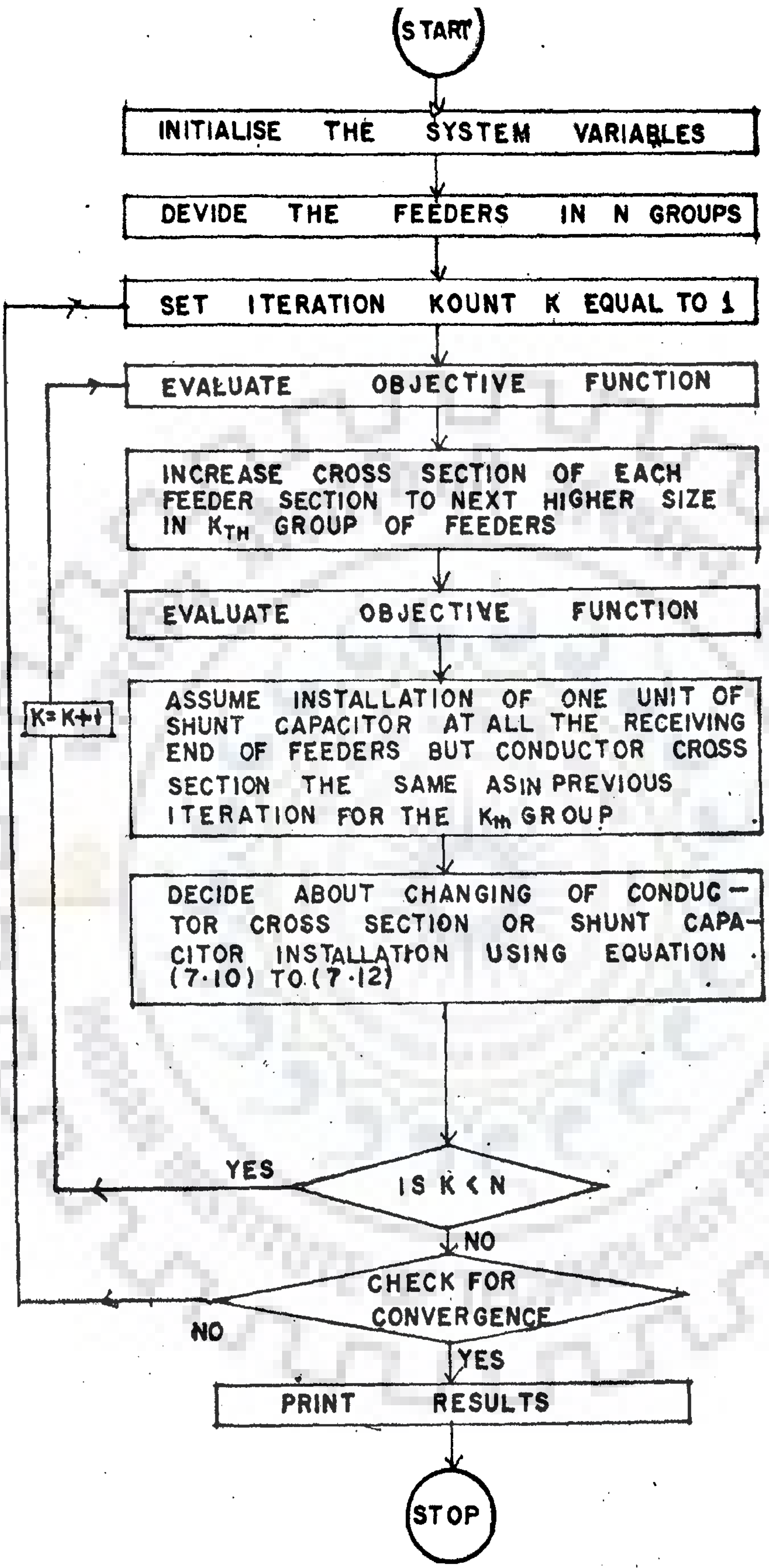


Fig 7.1 FLOW CHART FOR OPTIMUM DISTRIBUTION SYSTEM IMPROVEMENT

7.5 APPLICATION AND RESULTS

The proposed method is tested on a number of 11 KV distribution network of MPEB power system. The results of a distribution metwork with non uniform loading and graded conductor cross section are given in Table 7.2. Conductor replacement cost for various conductor sizes is given in Table 7.1. Cost details are given in Table 3.1 and 6.1.

7.6 CONCLUSION

The proposed method is simple generalized approach and is applicable to any type of distribution system with any type of realistic loading pattern with same or different load power factors at different load points. The proposed model is also very useful to carry out sensitivity analysis of the dependent cost components on various system improvement works. The method is voltage dependent and considers the system growth factors, maximising the life time benefit and economic benefits due to voltage improvement along the feeders, thus giving the overall optimal solution to the problem.

TABLE 7.1

Conductor Replacement Cost (M.U. x 10^3)

	FERRET	RABBIT	MINK	BEAVER	RACOON	OTTER	CAT	DOG
WESEL	4.42	6.70	8.26	11.86	12.82	14.14	16.54	18.10
	FERRET	2.54	4.10	7.70	8.66	9.98	12.38	13.94
		RABBIT	1.91	5.38	6.34	7.66	10.06	11.62
			MINK	3.90	4.80	6.12	8.52	10.08
				BEAVER	1.17	2.49	4.89	6.45
					RACOON	1.51	3.91	5.47
						OTTER	2.60	4.15
							CAT	1.75

TABLE 7.2

Conductor and Capacitor Detail at Various Load Levels

Line No.	Between the Buses	Load Level-I		Load Level-II		Load Level-III		Load Level-IV		Load Level-V	
		Conductor	Capacitor	Conductor	Capacitor	Conductor	Capacitor	Conductor	Capacitor	Conductor	Capacitor
1	2	3	4	5	6	7	8	9	10	11	12
1	11-12	WEASEL	15	WEASEL	30	WEASEL	30	WEASEL	45	WEASEL	45
2	11-16	RACOON	30	RACOON	30	RACOON	30	RACOON	45	DOG	45
3	16-11	DOG	0	DOG	0	DOG	0	DOG	0	DOG	0
4	13-14	RABBIT	30	RABBIT	45	RABBIT	45	RABBIT	60	RABBIT	60
5	13-42	FERRET	45	FERRET	60	FERRET	60	FERRET	75	FERRET	90
6	14-15	WEASEL	30	SEASEL	30	WEASEL	30	WEASEL	45	WEASEL	45
7	16-17	FERRET	0	FERRET	0	FERRET	0	MINK	0	MINK	0
8	16-18	MINK	0	MINK	0	MINK	0	BEAVER	0	DOG	0
9	16-43	WEASEL	15	WEASEL	30	WEASEL	30	WEASEL	45	WEASEL	60
10	17-44	WEASEL	45	WEASEL	45	WEASEL	45	WEASEL	60	WEASEL	75
11	18-19	MINK	15	MINK	30	MINK	30	MINK	30	MINK	30
12	19-20	WEASEL	15	WEASEL	30	WEASEL	30	WEASEL	30	WEASEL	45
13	19-21	FERRET	15	FERRET	30	FERRET	30	FERRET	30	FERRET	45
14	21-22	WEASEL	15	WEASEL	30	WEASEL	30	WEASEL	45	WEASEL	45
15	23-24	MINK	0	MINK	0	MINK	0	MINK	15	MINK	30
16	23-26	MINK	0	MINK	0	MINK	0	MINK	15	MINK	30
17	23-28	MINK	0	MINK	0	MINK	0	MINK	0	MINK	15
18	23-30	WEASEL	0	WEASEL	0	WEASEL	0	WEASEL	30	WEASEL	45
19	23-31	MINK	0	MINK	0	MINK	0	MINK	0	MINK	0

Contd.

Table 7.2(Contd.)

1	2	3	4	5	6	7	8	9	10	11	12
20	24-25	WEASEL	45	WEASEL	60	WEASEL	60	WEASEL	75	WEASEL	90
21	26-27	WEASEL	45	WEASEL	60	WEASEL	60	WEASEL	75	WEASEL	90
22	28-29	WEASEL	45	WEASEL	60	WEASEL	60	WEASEL	90	WEASEL	90
23	31-32	FERRET	30	FERRET	30	FERRET	30	FERRET	30	MINK	45
24	32-33	WEASEL	45	WEASEL	60	WEASEL	60	WEASEL	75	WEASEL	75
25	35-34	DOG	0	DOG	0	DOG	0	DOG	0	DOG	15
26	24-45	MINK	60	MINK	90	MINK	90	MINK	120	MINK	150
27	35-36	RACOON	0	RACOON	0	DOG	0	DOG	0	DOG	0
28	35-37	FERRET	0	FERRET	0	FERRET	0	FERRET	0	FERRET	0
29	36-46	MINK	75	MINK	105	MINK	105	MINK	120	MINK	150
30	38-39	FERRET	75	FERRET	90	FERRET	90	FERRET	120	FERRET	120
31	40-38	MINK	0	MINK	0	MINK	0	RACOON	0	DOG	0
32	40-41	FERRET	0	FERRET	0	MINK	0	MINK	0	MINK	0
33	30-43	WEASEL	15	WEASEL	30	WEASEL	30	WEASEL	45	WEASEL	60
34	33-46	WEASEL	75	WEASEL	105	WEASEL	105	WEASEL	120	WEASEL	120
35	37-41	WEASEL	0	WEASEL	0	WEASEL	0	FERRET	0	FERRET	0

Note - Capacitor capacity in KVAR.

CHAPTER - VIII

CONCLUSIONS

In recent years, because of energy crisis, electric utilities are paying more attention to reduce losses in transmission and distribution system which leads extensive investigation in this direction. The aim of this investigation is to develop efficient, reliable, and more realistic mathematical models and methods for losses minimization in large transmission and distribution systems at operating, planning and post planning level of power system.

In this study a model is formulated to reduce losses at transmission level via reactive power and voltage control. This model minimizes real power losses, active power mismatches and difference between percentage sharing of reactive power among generators. Active power mismatch minimization will try to keep the active power scheduling the same as obtained on the basis of economic active power dispatch. Percentage sharing of reactive power among generation will try to improve the stability of the power system under the condition of light load operation of the power system. The decision variables considered are generator terminal voltage magnitudes, transformer tap positions, and switchable sources of reactive power available in the system. To reduce the size of problem generalized reduced gradient is used.

Three methods, based on sensitivity relationship between state and decision variables are formulated to solve the above mentioned problem. These methods are, Quasi Newton method, Fletcher's method,and sparse hessian method. In Quasi Newton method, BFGS inverse update is used to update the approximate inverse hessian by using first order derivative terms. Initially inverse hessian matrix is assumed as unit matrix. This method overcomes the conditioning problems resulting into computational efficiency. The method has a global convergence and is robust and stable.

In the Fletcher's method hessian is updated by using the first order derivative terms. Additional computation which takes place in unidimensional search for step length is avoided by choosing an approximate step size. This helps further in reducing the storage and computational burden.

Sparse hessian method uses an update formula to update the sparse hessian matrix, resulting into less memory requirement. This method has a good and Q super linear fast rate of convergence and therefore useful in practical problem considered here.

Correction in the groups of decision variables can be done hierarchically or simultaneously. There is a possibility of computer time reduction by simultaneous correction in group of decision variables, but computer storage requirement will increase slightly.

In order to reduce transmission losses via reactive compensation installation at load centres, a problem of reactive compensation planning is formulated in this study. The objective function proposed includes cost of real power losses, cost of reactive compensation installation, operation and maintenance, and difference between percentage sharing of reactive power among generators. The decision variables considered are generator terminal voltage magnitudes, transformer tap positions, and installation of reactive compensation at load nodes. Generalized reduced gradient is used to decompose the variable sets into two sets, namely dependent variables set and independent variables set.

Three methods, based on sensitivity relationship between state and decision variables are presented to solve the problem of transmission losses reduction via reactive compensation installation at load nodes. The methods used are Quasi Newton method, using BFGS update, Fletcher's method and Sparse hessian method.

Decomposition method to reduce transmission losses in large transmission system is developed in which transmission system is decomposed into smaller systems by applying arbitrary voltage sources at the interconnection nodes to represent interconnection. No auxiliary matrix is required like ' matrix of removed network' as in the case of diakoptics decompositions. Computation time, memory and round off error are decreased substantially due to decomposition. The solved example in chapter-IV shows that a significant reduction in computation time and memory is achieved.

A voltage dependent model to reduce distribution losses by optimal conductor gradation is formulated. The model minimizes cost of power and energy losses, installation, operation and maintenance cost of distribution line via group variational method. Growth in load factor, growth in load, and increase in cost of power and energy, labour and equipment cost is considered. This model takes into consideration all the cost and benefits in a realistic manner. No approximation in load representation is done.

A new voltage dependent model for optimal shunt capacitor installation in a distribution system, resulting in reduced distribution losses is presented in this investigation which takes into account the increase in cost of energy and power loss, labour and equipment cost, growth in load and load factor. The model is solved by group variational method. This model accounts for all the cost and benefits in a realistic manner and represent shunt capacitor installation problem exactly.

Improvement in existing distribution system is the another aspect by which distribution losses can also be reduced significantly to an optimal level. Based on the models proposed earlier procedure to reduce distribution losses is described by changing the conductor of distribution lines and installation of shunt capacitors at load nodes. Utility of the procedure is shown by an example in chapter VII.

All the mathematical models presented in this study are tested on the examples taken out from MPEB power system, an electric utility in India. The mathematical models presented in this investigation are reliable, efficient, realistic and promising. It is hoped that work investigated in the thesis will be useful to power system operating and planning engineers.

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APPENDIX - A

TEST SYSTEM DATA

In this appendix system data for 6 Bus [86], 30 Bus (MPEB), 103 Bus (MPEB), and 40 Bus (MPEB) systems are given. 6 Bus, 30 Bus, and 103 Bus systems are transmission system. While 40 Bus system is a distribution system. The data is presented in the following manner :

(i) Generator Bus data

(ii) Load Bus data

(iii) Line data

(iv) Transformer data

(v) Shunt capacitor data

A.1 6 Bus Test System :

A single line diagram of a 6 Bus transmission system is shown in Fig. A.1, slack Bus is 1. Base MVA is 50 MVA.

TABLE - A.1.1

Generator Bus Data

Bus No.	Generation		
	Real MW	Reactive Min.	MVAR Max.
1	-	-10.0	30.0
2	25	- 5.0	15.00

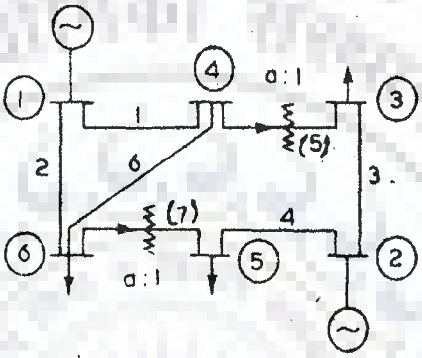

FIG. A·1 IEEE 6 BUS TEST SYSTEM

LEGEND

TRANSMISSION LINE

TRANSFORMER

GENERATOR

LOAD BUS

BUS NUMBER 4

LINE NUMBER 4

TABLE - A.1.2

Load Bus Data

Bus No.	Load Real MW	Load Reactive MVAR
3	27.5	6.5
4	-	-
5	15.0	9.0
6	25.0	2.5

TABLE - A.1.3

Line Data

Line No.	Between the buses	Line Impedance R P.U.	Line Impedance X P.U.	Half line charging susceptance P.U.
1	1 - 4	.08	.37	.007
2	1 - 6	.123	.518	.01
3	2 - 3	.723	1.05	0.0
4	2 - 5	.282	0.64	0.0
5	4 - 6	.097	0.407	0.0076

TABLE A.1.4

Transformer Data

Transformer No.	Between the Buses	Reactance P.U.
1	3 - 4	0.133
2	5 - 6	0.3

TABLE - A.1.5

Shunt Capacitor Data

Shunt Capacitor No.	Bus No.	Capacity MVAR
1	3	5
2	5	5

A.2 30 BUS TEST SYSTEM

Single line diagram of 30 Bus test system is given in Fig. A.2. Bus No. 3 has been taken as slack Bus. Base MVA is 100MVA

TABLE A.2.1

Generator Bus Data

Bus No.	Generation Real Power MW	Reactive Power MVAR Min.	Max.
1	105	-40	45
2	0	-40	45
3	-	-110	125
4	240	-110	200
5	0	- 30	30
6	70	- 30	60
7	176	-110	140
8	200	-110	140
9	200	-110	140
10	51	- 30	30
11	0	- 30	30

SINGLE LINE DIAGRAM 30 BUS SYSTEM

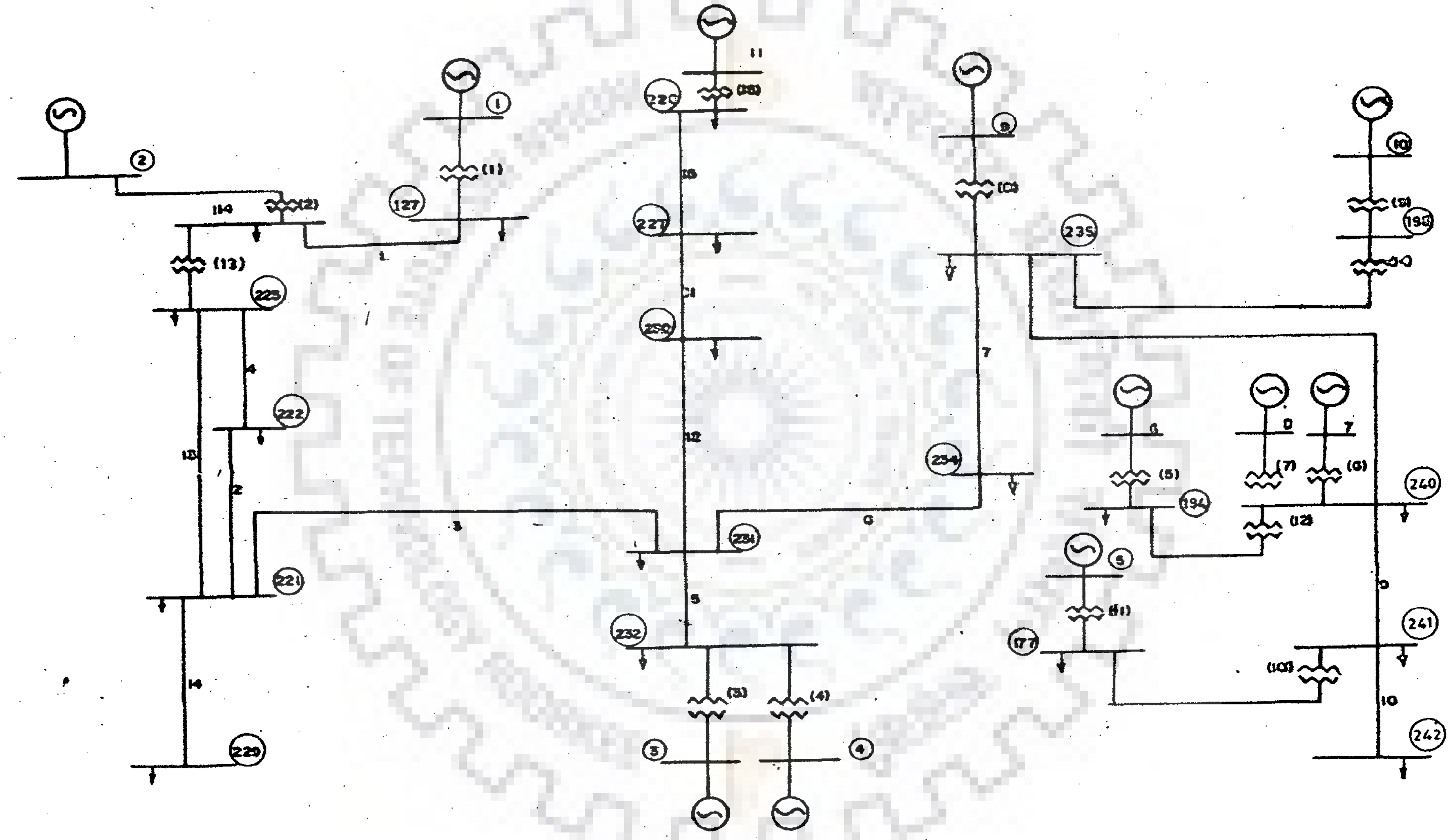

FIG. A-2

TABLE - A.2.2

Load Bus Data

Bus No.	LOAD Real MW	LOAD Reactive MVAR
114	96	50
127	75	17
177	140	65
194	125	55
198	45	20
221	80	26
222	60	24
223	0	0
227	30	8
228	30	15
229	45	19
230	50	20
231	95	36
232	15	10
234	175	78
235	0	0
240	100	62
241	0	0
242	40	20

TABLE - A.2.3

Line Data

Line No.	Between the Buses		Line R P.U.	Impedance X P.U.	Half line charging susceptance (P.U.)
1	114	127	.172	.427	.047
2	221	222	.0105	.0526	.0445
3	221	231	.0158	.08	.268
4	222	223	.0084	.0419	.0354
5	231	232	.0028	.0148	.21
6	231	234	.0185	.093	.314
7	234	235	.0155	.0777	.2627
8	235	240	.012	.06	.2
9	240	241	.0135	.076	.26
10	241	242	.038	.188	.16
11	227	230	.022	.11	.093
12	231	230	.0148	.074	.0625
13	221	223	.0105	.0526	.0445
14	221	229	.0185	.093	.078
15	227	228	.041	.204	.173

TABLE - A.2.4

Transformer Data

Transformer No.	Between the Buses		Reactance P.U.
1	1	127	.063
2	2	114	.4
3	3	232	.028
4	4	232	.036
5	6	194	.1313
6	7	240	.042
7	8	240	.0485
8	9	235	.0485
9	10	198	.2348
10	241	177	.015
11	5	177	.212
12	240	194	.061
13	223	114	.055
14	235	198	.103
15	11	228	.174

TABLE - A.2.5

Shunt Capacitor Data

Shunt Capacitor No.	Bus No.	Capacity MVAR
1	114	1
2	229	1
3	242	1
4	223	1

A.3 103 BUS TEST SYSTEM

A single line diagram of a 103 Bus power system is shown in Fig. A.3. Bus No. 3 is a slack Bus. Base MVA is 100 MVA

TABLE A.3.1

Generator Bus Data

Bus No.	Generation Real MW	Reactive MVAR Min.	Reactive MVAR Max.
1	105	-25	25
2	0	-25	30
4	240	-25	200
5	0	-25	30
6	70	-25	60
7	160	-25	140
8	200	-25	140
9	200	-25	140
10	51	-25	40
11	0	-25	30
3	-	-110	125

SINGLE LINE DIAGRAM 103 BUS SYSTEM

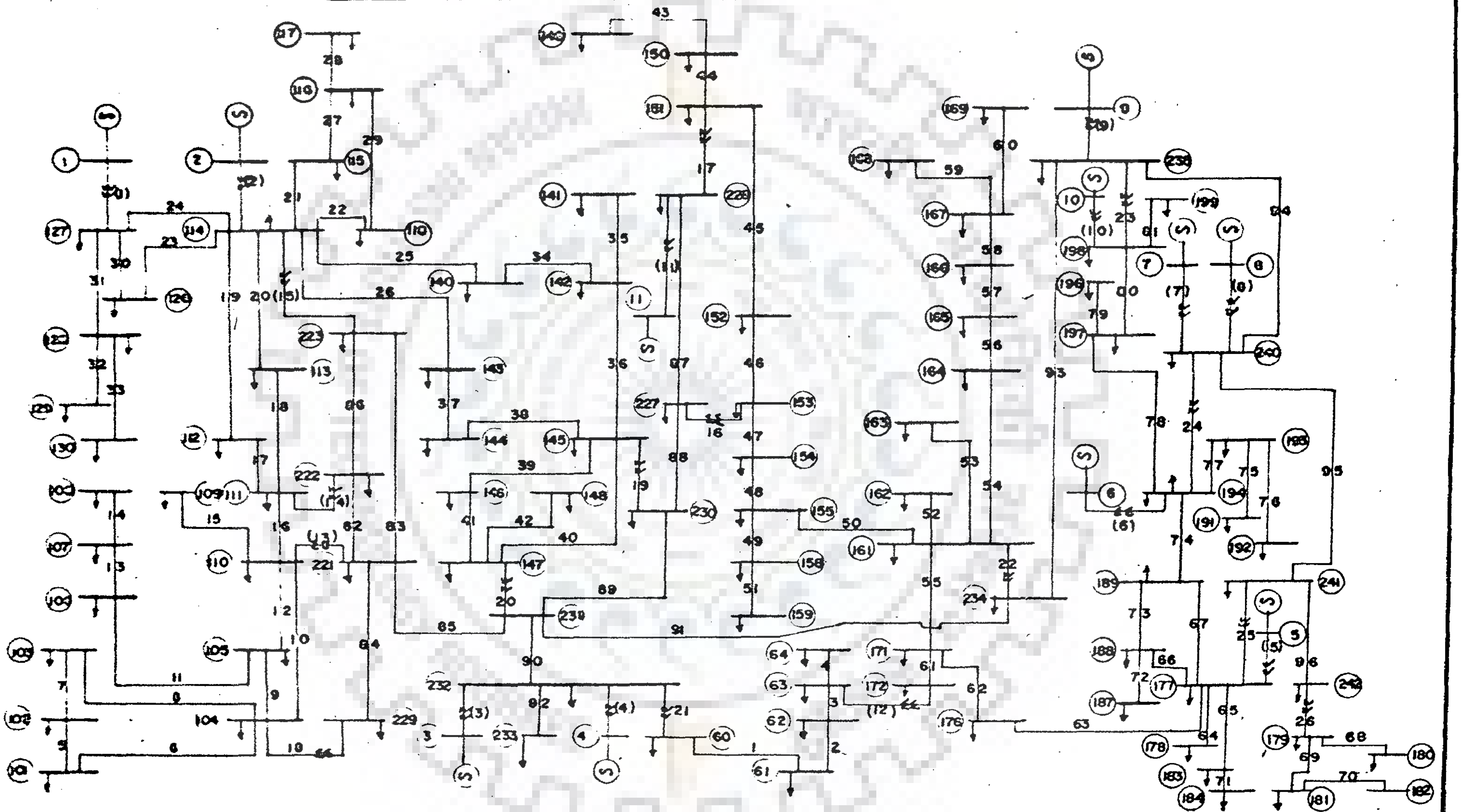

FIG. A·3

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GUPTA 20484

TABLE A.3.2.

Load Bus Data

Bus No.	LOAD Real MW	LOAD Reactive MVAR
60	3.4	2.1
61	2	1.25
62	5.55	3.45
63	2	1.25
64	2.6	1.6
101	0.0	0.0
102	11.6	7.2
103	7.25	4.5
104	28.1	17.4
105	12.6	7.8
106	13.2	8.2
107	6.5	5.5
108	10.9	6.75
109	18.6	11.5
110	13.4	8.3
111	8.0	5.9
112	38.9	24.1
113	30.6	19.
114	29.3	18.2
115	3.6	2.2
116	27.7	17.2
117	8.9	5.5
118	33.5	20.8
126	3.4	2.1
127	5.5	3.4
128	18.6	11.5
129	12.1	7.5
130	10.7	6.7
140	18.9	11.7
141	1.9	1.1

Contd.

Table A.3.2(Contd)

Bus No.	LOAD Real MW	Reactive MVAR
142	6.95	5.35
143	7.85	4.9
144	10.9	6.8
145	33.3	20.6
146	12.4	7.7
147	22.3	13.8
148	9.5	5.9
149	13.2	8.2
150	18.9	11.7
151	27.1	16.8
152	6.1	3.8
153	6.5	4.1
154	12.5	7.8
155	8.2	5.1
158	12.3	7.6
159	6.7	4.1
161	32.3	20.1
162	13.7	8.5
163	19.3	11.4
164	10.6	6.6
165	8.2	5.1
166	10.4	6.4
167	17.2	10.6
168	3.6	2.2
169	7.1	4.4
171	7.5	5.6
172	14.1	8.75
176	6.6	4.1
177	119.5	74.4
178	7.2	4.5
179	11.35	7.1

Table A.3.2(Contd.)

Bus No.	LOAD Real MW	Reactive MVAR
180	11.3	7.1
181	11.3	7.1
182	11.3	7.1
183	18.7	11.6
184	6.8	4.2
187	27.7	17.2
188	3.6	2.2
189	23.65	14.7
191	6.8	4.2
192	14.8	9.2
193	15.8	9.8
194	12.95	8.1
196	6.6	4.1
197	10.6	6.55
198	18.9	11.75
199	7.07	4.4
221	0.0	0.0
222	0.0	0.0
223	0.0	0.0
227	0.0	0.0
228	0.0	0.0
229	0.0	0.0
230	0.0	0.0
231	0.0	0.0
232	0.0	0.0
233	0.0	0.0
234	0.0	0.0
235	0.0	0.0
240	100	62
241	0.0	0.0
242	0.0	0.0

TABLE - A.3.3.

Line Data

Line No.	Between the buses		Impedance of the line R P.U.	X P.U.	Half line charging susceptance P.U.
1	2	3	4	5	6
1	60	61	.26	.175	.0016
2	61	62	.106	.127	.0006
3	62	63	.264	.189	.0016
4	63	64	.264	.189	. 016
5	101	102	.05	.126	.0135
6	101	104	.081	.2007	.0222
7	102	103	.01	.025	.0026
8	103	104	.02	.05	.0054
9	104	105	.054	.134	.015
10	104	110	.104	.254	.028
11	105	106	.108	.274	.0284
12	105	110	.0485	.1204	.0133
13	106	107	.056	.141	.0153
14	107	108	.051	.127	.014
15	109	110	.036	.087	.0099
16	110	111	.03	.073	.0323
17	111	112	.005	.012	.006
18	112	113	.01	.025	.003
19	112	114	.0506	.1255	.0139
20	113	114	.046	.118	.013
21	114	115	.046	.118	.013
22	114	118	.05	.126	.014
23	114	126	.102	.25	.028
24	114	127	.172	.427	.047
25	114	140	.05	.097	.0098
26	114	143	.066	.165	.0175
27	115	116	.046	.116	.0125
28	116	117	.0276	.0684	.0075
29	116	118	.036	.092	.0099

Contd.

Table A.3.3(Contd.)

1	2	3	4	5	6
30	126	127	.07	.177	.019
31	127	128	.071	.175	.019
32	128	129	.0423	.105	.012
33	128	130	.0101	.0310	.0028
34	140	142	.0812	.158	.0154
35	141	142	.036	.089	.0098
36	142	145	.0963	.187	.0184
37	143	144	.0414	.103	.0112
38	144	145	.09	.228	.025
39	145	146	.0258	.0639	.0071
40	145	147	.082	.206	.022
41	146	147	.057	.143	.016
42	147	148	.055	.139	.015
43	149	150	.05	.123	.0134
44	150	151	.006	.016	.007
45	151	152	.06	.15	.064
46	152	153	.055	.138	.061
47	153	154	.062	.155	.017
48	154	155	.062	.155	.017
49	155	158	.09	.216	.0245
50	155	161	.082	.206	.022
51	158	159	.063	.157	.017
52	161	162	.064	.164	.0176
53	161	163	.011	.029	.013
54	161	164	.043	.107	.047
55	161	171	.112	.282	.032
56	164	165	.03	.066	.008
57	165	166	.0267	.0661	.0073
58	166	167	.032	.08	.009
59	167	168	.11	.28	.03
60	167	169	.047	.118	.0128
61	171	172	.0701	.1756	.0194
62	171	176	.0701	.1756	.0194
63	176	177	.146	.365	.04

Contd.

Table - A.3.3 (Contd.)

1	2	3	4	5	6
64	177	178	.08	.2	.02
65	177	183	.022	.054	.006
66	177	188	.0589	.146	.0161
67	177	189	.11	.2737	.0302
68	179	180	.046	.12	.012
69	179	181	.016	.041	.017
70	181	182	.018	.046	.019
71	183	184	.047	.118	.013
72	187	188	.026	.0639	.0069
73	188	189	.0515	.1277	.0141
74	189	194	.039	.08	.039
75	191	193	.014	.035	.004
76	192	193	.07	.17	.019
77	193	194	.038	.092	.01
78	194	197	.096	.24	.026
79	196	197	.0735	.182	.02
80	197	198	.066	.16	.017
81	198	199	.075	.187	.075
82	221	222	.0105	.0526	.0445
83	221	223	.0105	.0526	.0445
84	221	229	.0185	.093	.078
85	221	231	.0158	.08	.268
86	222	223	.0084	.0419	.0354
87	227	228	.041	.204	.173
88	227	230	.022	.11	.093
89	230	231	.0148	.074	.0625
90	231	232	.0028	.0148	.21
91	231	234	.0185	.093	.314
92	232	233	.025	.126	.11
93	234	235	.0155	.0777	.2627
94	235	240	.012	.06	.2
95	240	241	.0135	.076	.26
96	241	242	.038	.188	.16

TABLE A.3.4

Transformer Data

Transformer No.	Between with buses		Reactance P.U.
1	1	127	.063
2	2	114	.4
3	3	232	.028
4	4	232	.036
5	5	177	.212
6	6	194	.1313
7	7	240	.042
8	8	240	.0485
9	9	235	.0485
10	10	198	.2348
11	11	228	.174
12	172	63	.4
13	221	110	.056
14	222	111	.0278
15	223	114	.055
16	227	153	.0555
17	228	151	.055
18	229	104	.056
19	230	145	.056
20	231	147	.056
21	232	60	.7032
22	234	161	.0278
23	235	198	.103
24	240	194	.061
25	241	177	.015
26	242	179	.0553

TABLE A.3.5.

Shunt Capacitor Data

Shunt capacitor No.	Bus No.	Capacity MVAR
1	102	7.
2	106	8.0
3	108	6.5
4	111	5.
5	112	20.
6	116	15.0
7	117	5.
8	118	15.0
9	128	10.
10	129	7.5
11	149	5.
12	151	7.5
13	158	5.
14	167	5.
15	105	7.5
16	107	5.
17	142	5.
18	154	7.5
19	164	5.
20	171	5.
21	189	5.
22	110	8.
23	169	2.5
24	180	5.
25	182	8.

A.4 40 Bus test system

A single line diagram of a 40 bus test system is shown in Fig.A.4. Base MVA is 1000 KVA.

TABLE A.4.1

Bus Data

Bus No.	LOAD Real KW	LOAD Reactive KVAR
1	0000.0	1000.0
2	0000.0	1000.0
3	0000.0	1000.0
4	0000.0	0.0
11	0.0	0.0
12	100.0	090.0
13	100.0	090.0
14	100.0	090.0
15	075.0	065.0
16	0.0	0.0
17	075.0	065.0
18	075.0	65.0
19	075.0	065.0
20	075.0	65.0
21	075.0	065.0
22	075.0	65.0
23	0.0	0.0
24	125.0	110.0
25	125.0	110.0
26	125.0	110.0
27	125.0	110.0
28	150.0	135.0
29	150.0	135.0
30	150.0	135.0
31	075.0	065.0
32	075.0	065.0
33	125.0	110.0
34	200.0	180.0
35	0.0	0.0
36	150.0	135.0
37	150.0	135.0
38	200.0	180.0
39	200.0	180.0
40	0.0	0.0
41	250.0	225.0
42	150.0	135.0
43	150.0	135.0
44	150.0	135.0
45	300.0	270.0
46	300.0	270.0

SINGLE LINE DIAGRAM 40 BUS SYSTEM

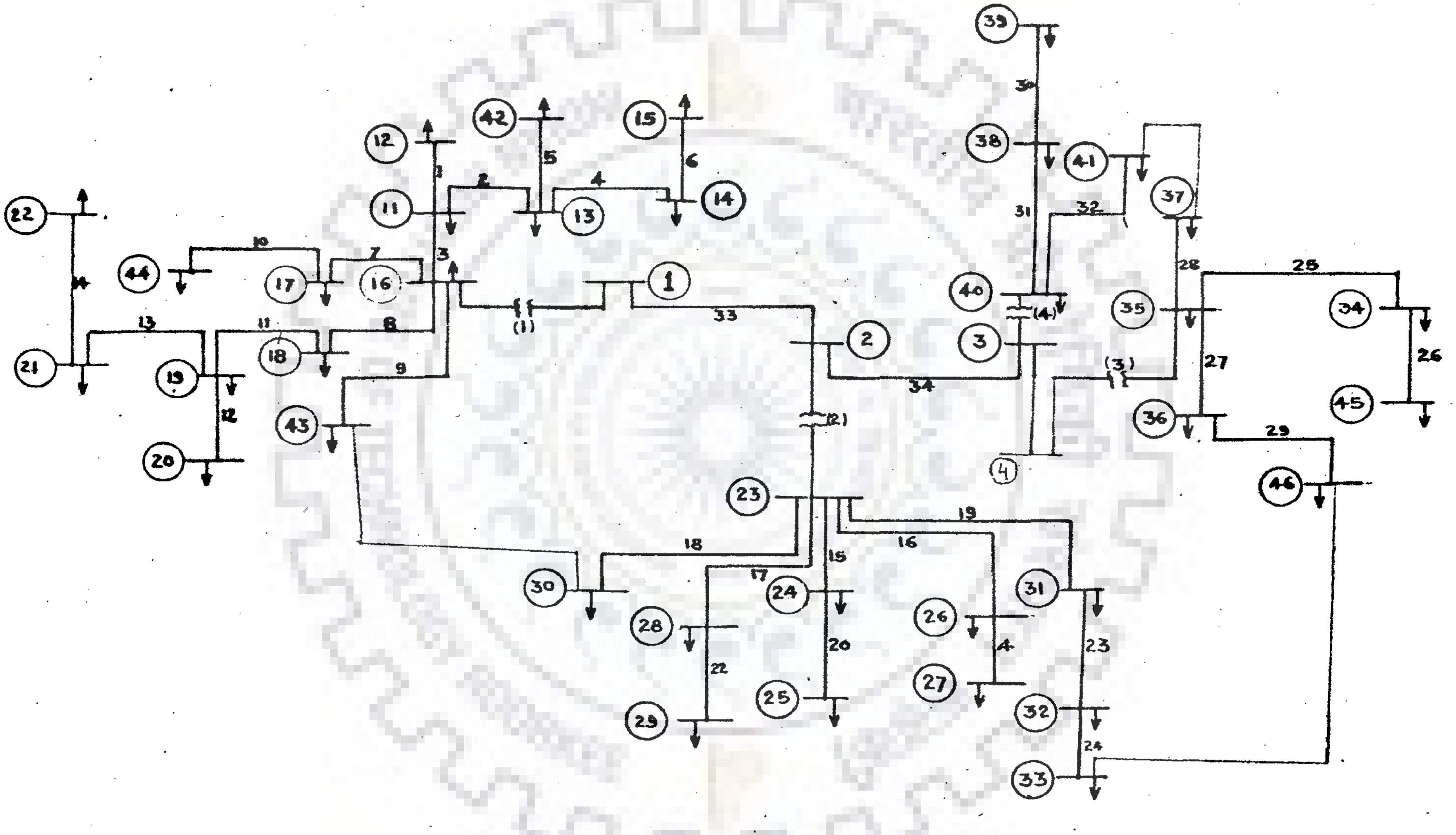
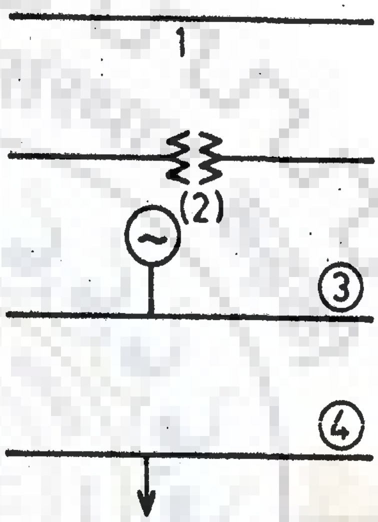


FIG. A.4

LEGENDS FOR FIGURES



TRANSMISSION LINE	1
TRANSFORMER	(2)
GENERATOR BUS	3
LOAD BUS	4
LINE NUMBER	5
BUS NUMBER	6
TRANSFORMER NUMBER	(7)

FIG. A·5

TABLE A.4.2.

LINE DATA

Line No.	Between the buses		Impedence of line R P.U.	X.P.U.	Length of line Kms.
1	2		3	4	5
1	11	12	0.0323	0.0138	4.25
2	11	13	0.0323	0.0138	4.25
3	16	11	0.0323	0.0138	4.25
4	13	14	0.0323	0.0163	4.25
5	13	42	0.0304	0.0130	4.0
6	14	15	0.0494	0.0211	6.5
7	16	17	0.0304	0.0130	4.0
8	16	18	0.0304	0.0130	4.0
9	16	43	0.0418	0.0179	5.5
10	17	44	0.0340	0.0146	4.5
11	18	19	0.0323	0.0138	4.25
12	19	20	0.0323	0.0138	4.25
13	19	21	0.023	0.0098	3.00
14	21	22	0.0304	0.0130	4.0
15	23	24	0.0494	0.0211	6.5
16	23	26	0.0475	0.0203	6.25
17	23	28	0.0323	0.0138	4.25
18	23	30	0.0340	0.0146	4.5
19	23	31	0.0323	0.0138	4.25
20	24	25	0.0703	0.0301	9.25
21	26	27	0.0817	0.0349	10.75
22	28	29	0.0475	0.0203	5.25
23	31	32	0.0646	0.0276	8.5
24	32	33	0.0323	0.0138	4.25
25	35	34	0.0323	0.0138	4.25
26	34	45	0.0323	0.0138	4.25
27	35	36	0.0304	0.0130	4.0
28	35	37	0.0323	0.0138	4.25

Contd.

Table A.4.2(Contd.)

1	2		3	4	5
29	36	46	0.0323	0.0138	4.25
30	38	39	0.0855	0.0366	11.25
31	40	38	0.0323	0.0138	4.25
32	40	41	0.0323	0.0138	4.25
33	30	43	0.304	0.013	4.00
34	33	46	0.304	0.013	4.00
35	37	41	0.304	0.013	4.00
36	1	2	0.0500	0.0216	20.00
37	2	3	0.0500	0.0216	20.00
38	3	4	0.0500	0.0216	20.00

TABLE A.4.3.

Transformer Data

Transformer No.	Between the buses		Reactance P.U.
1	1	16	.4
2	2	23	.200
3	3	35	.400
4	4	40	.4000

APPENDIX - B

UNIDIMENSIONAL SEARCH

The efficiency of the solution of the minimum of a function in a given direction is of particular importance in the solution of optimization problems. After establishing the direction of search in each iteration of the optimization process, optimal step size is determined by using single dimension search techniques so that maximum possible change in the function is obtained.

The method used employs quadratic interpolation and function values only. The method is due to Davies, Swann, and Campey (DSC) [30] with an addition by Powell. The combination of the DSC and Powell algorithms is found to be better than either of the individual algorithms. The combination uses the DSC algorithm to bracket the minimum and Powell algorithm for interpolation. Figure B.1 shows the successive step lengths chosen for finding its optimal value. The steps of the algorithm are given below.

Step 1

Set $k = 0$. Estimate $f(\alpha)$ at the initial point $\alpha^{(o)}$.

If $f(\alpha^{(o)} + \Delta\alpha) \leq f(\alpha^{(o)})$, go to step 2. If $f(\alpha^{(o)} + \Delta\alpha) > f(\alpha^{(o)})$, let $\Delta\alpha = -\Delta\alpha$ and go to step 2.

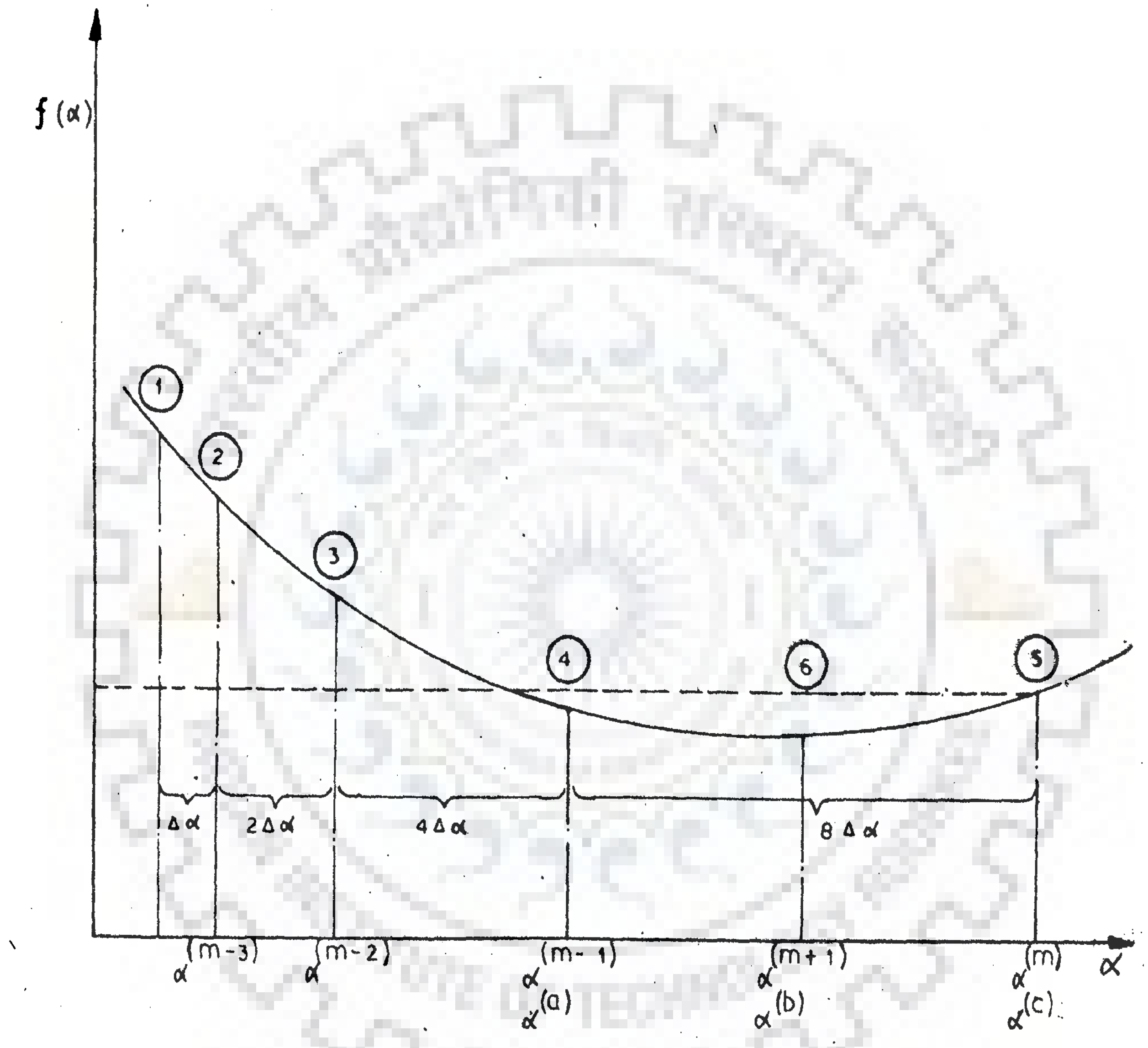


FIGURE B.1 UNIDIMENSIONAL MINIMIZATION PROCEDURE

Step 2

Compute

$$\alpha^{(k+1)} = \alpha^{(k)} + \Delta\alpha$$

Step 3

Compute

$$f(\alpha^{(k+1)})$$

Step 4

If $f(\alpha^{(k+1)}) \leq f(\alpha^{(k)})$, double $\Delta\alpha$ and return to step 2 with $k = k + 1$. If $f(\alpha^{(k+1)}) < f(\alpha^{(k)})$, denote $\alpha^{(k+1)}$ by $\alpha^{(m)}$, $\alpha^{(k)}$ by $\alpha^{(m-1)}$, etc., reduce $\Delta\alpha$ by one-half, and return to steps 2 and 3 for one more (only) calculation. See Figure B.1.

Step 5

Of the four equally spaced values of α in the set $\alpha^{(m+1)}$, $\alpha^{(m)}$, $\alpha^{(m-1)}$, $\alpha^{(m-2)}$, discard either $\alpha^{(m)}$ or $\alpha^{(m-2)}$, which-ever is farthest from the α corresponding to the smallest value of $f(\alpha)$ in the set. Let the remaining three values of α be denoted by $\alpha^{(a)}$, $\alpha^{(b)}$, and $\alpha^{(c)}$, where $\alpha^{(b)}$ is the center point and $\alpha^{(a)} = \alpha^{(b)} - \Delta\alpha$ and $\alpha^{(c)} = \alpha^{(b)} + \Delta\alpha$.

Step 6

Carry out a quadratic interpolation to estimate α^{*}.

$$\alpha^{*} = \alpha^{(b)} + \frac{\Delta\alpha\,[\,f(\alpha^{(a)}) - f(\alpha^{(c)})\,]}{2[\,f(\alpha^{(a)}) - 2f(\alpha^{(b)}) + f(\alpha^{(c)})\,]}$$

Step 2

Compute

$$\alpha^{(k+1)} = \alpha^{(k)} + \Delta\alpha$$

Step 3

Compute ,

$$f(\alpha^{(k+1)})$$

Step 4

If $f(\alpha^{(k+1)}) \leq f(\alpha^{(k)})$, double $\Delta\alpha$ and return to step 2 with $k = k + 1$. If $f(\alpha^{(k+1)}) < f(\alpha^{(k)})$, denote $\alpha^{(k+1)}$ by $\alpha^{(m)}$, $\alpha^{(k)}$ by $\alpha^{(m-1)}$, etc., reduce $\Delta\alpha$ by one-half, and return to steps 2 and 3 for one more (only) calculation. See Figure B.1.

Step 5

Of the four equally spaced values of α in the set $\alpha^{(m+1)}$, $\alpha^{(m)}$, $\alpha^{(m-1)}$, $\alpha^{(m-2)}$, discard either $\alpha^{(m)}$ or $\alpha^{(m-2)}$, which-ever is farthest from the α corresponding to the smallest value of $f(\alpha)$ in the set. Let the remaining three values of α be denoted by $\alpha^{(a)}$, $\alpha^{(b)}$, and $\alpha^{(c)}$, where $\alpha^{(b)}$ is the center point and $\alpha^{(a)} = \alpha^{(b)} - \Delta\alpha$ and $\alpha^{(c)} = \alpha^{(b)} + \Delta\alpha$.

Step 6

Carry out a quadratic interpolation to estimate α^{*}.

$$\alpha^{*} = \alpha^{(b)} + \frac{\Delta\alpha\,[f(\alpha^{(a)}) - f(\alpha^{(c)})]}{2[f(\alpha^{(a)}) - 2f(\alpha^{(b)}) + f(\alpha^{(c)})]}$$

Step 7

If α^* and whichever of $\alpha^{(a)}$, $\alpha^{(b)}$, $\alpha^{(c)}$ corresponding to the smallest $f(\alpha)$ differ by less than the prescribed accuracy in α, or the accuracy in the corresponding values of $f(\alpha)$, the search is terminated with α^* as the optimal step size. Otherwise evaluate $f(\alpha^*)$ and discard from the set $\alpha^{(a)}$, $\alpha^{(b)}$, $\alpha^{(c)}$ the one that corresponds to the greatest value of $f(\alpha)$ and go to step 8.

Step 8

Estimate the value of α^* by

$$\alpha^* = \frac{\left|(\alpha^{(b)})^2-(\alpha^{(c)})^2\right| f(\alpha^{(a)}) + \left|f(\alpha^{(c)})^2-f(\alpha^{(a)})^2\right| f(\alpha^{(b)}) + \left|f(\alpha^{(a)})^2-f(\alpha^{(b)})^2\right| f(\alpha^{(c)})}{(\alpha^{(b)}-\alpha^{(c)})f(\alpha^{(a)})+(\alpha^{(c)}-\alpha^{(a)})f(\alpha^{(b)})+(\alpha^{(a)}-\alpha^{(b)})f(\alpha^{(c)})}$$

and go to step 7.