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A NETWORK PLANNING MODEL FOR POWER GENERATION AND TRANSMISSION SYSTEM: A SUGGESTED MODULE FOR WASP PROGRAMME

by

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A NETWORK PLANNING MODEL FOR POWER GENERATION AND TRANSMISSION SYSTEM: A SUGGESTED MODULE FOR WASP PROGRAMME

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SUMMARY

This paper describes a Network Planning Model formulation for power generation and transmission system planning in detail, illustrated by an application for the Northern regional power network in India. The Network planning model simulates the operation of existing and proposed generating plants and transmission lines and the locational aspects of the generating plants and the topology of the transmission network is considered. The application of the Network planning model is expected to provide a capability for simulteneous optimization of the generation and transmission system expansion in a power system.

1. INVESTMENT PLANNING MODELS FOR ELECTRIC POWER GENERATION AND TRANSMISSION SYSTEMS

Given an existing power system for a region containing a mix of generating plants spatially located and connected through a transmission network to load centres, and its demand growth pattern over a given planning horizon, the purpose of optimal investment planning studies is to attempt answering the following questions:

1. What combination of available technology (out of nuclear, thermal, and hydrol) should be selected for addition to the system to meet the increasing load?

2. What should be the capacity of these generating plants when different sizes are available with possible economies-of-scale?

3. Where should these new plants be located among alternative sites?

4. Which additional transmission links should be built, connecting generating centres and load centres?

5. What should be the KV-ratings of the new transmission links, and how many circuits should be used?

6. When during the planning horizon should these generating plants and transmission lines be commissioned?

An excellent survey of various approaches towards developing models for least-cost investment planning beginning with the pioneering work at Electricite' de France is given by Anderson (1). Various approaches at optimization has been attempted including marginal analysis, simulation models, dynamic programming, linear, non-linear and mixed-integer programming (1,3,4,6,8). The concentration in most of the studies has been towards optimal choice of type (i.e. hydro, thermal and nuclear), capacity and time-phasing of generating plants, with little or no consideration regarding the planning of the transmission networks. Thus the studies were mostly single-area studies and neglected transmission between various generating plants and between generating plants and load centres. There has been a few studies (6,8) where multi-region models were considered with transmission lines joining various regions but still neglecting transmission within the regions.

Transmission networks are explicitly considered in load-flow studies which are undertaken to determine the actual voltages and currents, the corresponding phase angles and power losses in an electrical network given certain power inputs and outputs at the various nodes. Load flow studies are useful as they simulate the behaviour of a particular power system under normal conditions and under various contingencies induced by the outage of generating plants and transmission lines, and give valuable information regarding system reliability. Load flow studies involve the solution of a set of nonlinear a-c flow equations and no optimization in terms of optimal choice of generating plants or transmission lines could be attempted through load flow studies. However, they could be useful in comparing system reliability under various contingencies of alternative power system designs where economic or least-cost studies have already been carried out.

Planning for the power generating system expansion should not be carried out in isolation from the transmission systems planning. Same generating plant located at different places in a power system could result in varying costs due to additional investments needed in augmenting the transmission network. Also transmission system bottlenecks could result in failures to meet peak demand at the load centres even when sufficient generating capacity is present. Optimal investment planning models for power systems should, therefore, have a reasonably accurate representation of the various existing and proposed generating plants, their alternative locations, if any, the existing and proposed transmission lines, the system network indicating the way load centres are connected to the generating centres, and the operation of the total system for meeting power demand at the load centres. The Network Model (11) described in the paper was developed to satisfy the requirements of such a model under certain simplifying assumptions regarding the operation of an electric power system.

The Network model attempts to answer the first five questions listed above while minimizing the overall system cost. Additions to generation and transmission system are planned to meet the projected demand at the end of the planning horizon with the assumption that system additions are made at appropriate times during the planning horizon to keep pace with the growing demand. In this sense the model is a static one as it does not answer the scheduling problem during the planning horizon, the last question in the above list. A dynamic model could be formulated wherein the planning horizon is divided into a number of periods and optimal scheduling of generation and transmission projects are obtained as the solution of the model. Such a dynamic model is developed by integrating the network model in a dynamic programming framework (2).

The dynamic programming approach determines the number of periods, not necessarily all equal, into which the total planning horizon should be divided and the length of each such period. The network model is applied to obtain optimal power generation and transmission system expansions needed to satisfy peak demands at the load centres at the end of each of these periods. The number of optimal periods will depend on the discount rate used in the dynamic programming-network model for computing present worth of future investments and operating costs which is the objective function to be minimized.

The Network model uses a simple, but integrated representation of the generation and transmission system and its spatial nature. But the Network model as formulated represents the power generation and transmission system operation only during the peak period or at any other period of a particular year. By using a simple device of providing two generation arcs for each power plant it can also provide a two-block representation of a thermal generating plant with different base and peak operating costs. Similarly, by providing multiple arcs for each transmission link it can represent existing or proposed transmission lines of different KVA ratings or simulate the effect of nonlinear power loss function. The main characteristic of the Network model is that it uses information on the topology of the power system to simultaneously optimize the capacities and locations of generating plant and transmission system expansions.

The Network model is however limited as it can simulate only one load condition at a time, as compared to various linear programming and mixed-integer programming power system planning models (1,6,8) or WASP (9,10) model which simulates the operation of the power system using either a discretized or a continuous load duration curve.

2. THE NETWORK PLANNING MODEL FOR POWER GENERATION AND TRANSMISSION SYSTEM

In this paper, a Network Programming Model for least cost investment in electric power generation and transmission systems is presented (1). This model could be applied as a module for planning the electric power generation and transmission system network for supplying the projected peak demand at a number of dispersed but connected load centres. The model described in this section is essentially an operations research model based on the power system network in which electric power flow from the generating nodes to the load centres through existing or proposed transmission lines is simulated and costs of generation and transmission of power including power and energy losses in the transmission network are accounted for. The model with the aid of a network computer programme obtains a least cost flow pattern in the conceptual network and determines the optimal investments in generating plants and transmission network. The optimal solution obtained should be tested with load flow studies to determine system reliability under various contingencies as is done in case of any other modelling approach.

A power system could be easily visualized as a network consisting of a set of 'nodes' denoting spatially dispersed generating plants and load centres linked together by 'arcs' which denote the transmission lines. In the investment planning network model used for capacity expansion decisions the detailed power distribution network is not included in the model. The load centres included in the power network represent electrical substations, where transformers reduce voltage from high tension transmission lines for distribution over a large area. The load at a particular node is equal to the consumption within that area, plus the distribution losses. It should be noted that optimal distribution network design is also a network optimization problem and can be handled using similar modelling approach.

The power system network described above consisting of generating plants and load centres as nodes, and transmission lines as arcs is augmented by the addition of other fictitious or conceptual nodes and arcs for model formulation. One specific node S, called the 'source' node is added and this is connected to all generation nodes, representing existing as well as proposed generating plants by a set of conceptual arcs called the generation arcs. Similarly, another specific node T, called the 'sink' or the demand node is added and all nodes representing load centres are connected to the demand node by conceptual arcs to be called the consumption arcs. It could be conceived as if all power is being generated at the source node S and flows through the generating nodes and the transmission network to be finally consumed at the demand node T after passing through the load centres. A conceptual network representation of a hypothetical power system is shown in Figure 1.

Thus, in the augmented network, we have a generation arc, terminating in a generation node corresponding to each existing or proposed generating plants and flow in a generation arc corresponds to generation of a certain amount of power in megawatts in the generating plant. Similarly, corresponding to each load centre there is a consumption arc and any flow in this arc represent the consumption of electricity at the load centre. In addition to this, each transmission line is represented by one arc joining two nodes which could be generating plants, load centres or junction points where two or more transmission lines meet. Transmission lines in which the direction of power flow is not specified and it is possible for power to flow in either direction are represented by a pair of arcs oriented in opposite directions so that model solution can choose either of the arcs to indicate the direction of power flow. By convention, all arcs in the model network are directed and flow can take place in an arc only along the orientation of the arc. The orientation of an arc is specified by the order of the nodes at its extremities and flow takes place from the initial to the terminal node.

Each arc in the model network is associated with three other parameters: lower and upper bounds on arc flow which should not be violated and unit cost of flow in the arc, ~~being the~~ cost of sending for one unit of time, one megawatt of power through an arc of the network. Total cost of flow through an arc could be a nonlinear function of the flow in the arc specifically for transmission arcs due to nonlinear power losses and also for generation arcs if economies-of-scale are present, but for the time being these costs are assumed to be linear. Nonlinear costs functions could be handled by solving the network model in an iterative fashion using a special network algorithm developed for this purpose which showed excellent convergence properties. The bounds of flow and unit cost of flow in specific arcs of the network are judiciously specified so that the model network gives a realistic representation of the system constraints and costs.

Each generation arc representing a generating plant has a lower bound of zero and an upper bound equal to the maximum available capacity of power generation in megawatts (MW). An unit cost of flow is also specified for each generation arc given by the cost of operating one unit (MW) of generating capacity for one hour (or any other chosen unit of time). This unit cost consists of the variable costs due to fuel and lubricants for generating one megawatt-hour (MWh) of power and the hourly allocation of the annualised cost of plant installation and fixed maintenance costs for proposed generating plants. The hourly allocation is obtained by distributing the annualised installation cost per MW over the maximum available hours of plant operation in a year considering maintenance and forced outage. In case of proposed hydro plants, the annual hydro energy availability determines the maximum available hours. In case of existing plants, the unit arc cost consists only of the variable operating costs due to fuel and lubricants and hourly fixed maintenance costs. A two-block representation of a generating plant is possible by using two generating arcs for each plant to a represent base and peaking blocks, the latter having a higher unit cost. The base block will be loaded first as the corresponding arc has lower unit cost and the lower and upper bounds are equal to zero and the base capacity. The arc representing peak block would have lower and upper bounds equal to zero and peaking capacity.

The consumption arcs have both lower and upper bounds equal to the peak demand and the unit cost of flow is taken as zero or a given value to reflect the cost of distribution of one MWh of power and energy losses in distribution network. Revenue for electrical energy sold could also be considered in the model by defining appropriate negative unit costs in these arcs and defining lower and upper bounds of flow as the minimum and maximum amount of power that could be sold at the load centre. The capacities of the transmission lines, based on their KVA rating, number of circuits and conductor size, determine the upper bounds of flow in the transmission arcs, the lower bound being zero. Unit costs of flow in a proposed transmission arc is set equal to the hourly allocation of the annualised installation and maintenance cost per megawatt of transmission capacity plus costs due to power and energy losses evaluated in economic terms for a power flow of one megawatt during one hour. For existing transmission lines the installation cost is not included in the unit arc cost.

The constraints of the network model and the objective or criterion function to be minimized can now be expressed by mathematical relationships for a given power system. Let there by m generating plants, n load centres and p junction nodes in the transmission network in addition to the source node S and the demand node T. We define the following notations:

f_{Sg} = Power generated by the generating plant g, in MW; $g = 1, 2, \ldots, m$.

f_{dT} = Power consumed by the load centre d, in MW; $d = 1, 2, \ldots, n$.

f_{ij} = Power flow in transmission line (i,j), where node i and node j are connected by a directed arc and each of them is either a generation node, a load centre or a junction point. $i,j \neq S$; $i,j, \neq T$.

U_{ij} = Upper bound on flow in transmission arc (i,j).

L_{ij} = Lower bound on flow in transmission arc (i,j).

c_g = Unit cost of power generation for one hour at the generating plant g per MW, $i = 1,2,\ldots,n$.

d_{ij} = Unit cost of power transmission for one hour through transmission line (i,j) per MW; $i,j \neq S$; $i,j \neq T$.

e_d = Unit cost of power consumption (including distribution cost and/or revenue earned) for one hour at the load centre d per MW; $d = 1,2,\ldots,n$.

P_g = Available capacity of the generating plant g during peak period, MW.

L_d = Peak demand at the load centre d in MW.

The following constraints must be satisfied by any flow solution to the model network:

Generating capacity constraints	$0 \leq f_{Sg} \leq P, \ g = 1,2,\ldots, m$	(1)
Load constraints	$L_d \leq f_{dT} \leq L_d, \ d = 1,2,\ldots, n$	(2)
Transmission capacity constraints	$0 = L_{ij} \leq f_{ij} \leq U_{ij}; \ i,j \neq S; \ i,j \neq T$	(3)

Subject to the above constraints, the objective function (TC) corresponding to the total generation and transmission cost in the network has to be minimised for satisfying the peak demand at all load centres for one hour

$$\text{Minimize TC} = \sum_{g=1}^{m} c_g f_{Sg} + \sum_{\text{all}(i,j)} d_{ij} f_{ij} + \sum_{d=1}^{n} e_d f_{dT} \quad \ldots(4)$$

A solution of the network model expressed as a set of flows in the arcs which satisfies constraints (1) - (3) and minimizes the objective function (4) is termed as an optimal solution and represents a design of the system network. The optimal values of flows in the generation arcs denote the optimal capacities of the various generating plants, and the optimal flow distribution in the transmission network denotes the transmission network design. This is an optimal choice based on the hourly cost of operation to supply system annual peak demand from a set of existing and proposed plants at different locations and through a set of existing and proposed transmission links. As the generating plants can run at any capacity above their minimum operating capacity and below their rated installed capacity, the optimal flow solution could be used to reach a decision regarding the optimal capacity of proposed plants and retirement of existing plants. Similarly, the KV rating and number of circuits of proposed transmission lines could be determined from the optimal solution based on the flow in a transmission line.

The optimization of the network flow problem described by Equations (1) - (4) is a linear programming problem and an optimal solution can be obtained by using the Simplex method (5) for which standard computer routines are available. However, the network structure of the problem makes it amenable to a simpler and much faster network flow solution procedure described by Ford and Fulkerson (7) as the 'Out-ofKilter' algorithm. As described later, the solution procedure may have to be judiciously applied in an iterative manner if nonlinear cost functions are encountered or the optimal solution includes some generating plants and transmission lines at a very low capacity.

The Network model objective function as defined by equation (4) above minimizes the cost of operation of the generation and transmission system for one hour during the period of peak demand (or any other critical period) in the last year of the planning horizon. The cost coefficients c_g and d_{ij} are defined in such a way that while for proposed plants and transmission lines they also include hourly allocation of the installation costs, for existing generating plants and transmission lines they only include the costs of operation, mainly due to fuel used in the generating plants and energy lost in the transmission lines. Due to this flexibility, the network model could also be used as short term operational model for planning generating plant commitments. Given a set of existing generating plants spatially dispersed and connected to the load centres through a transmission network, the short term operational planning model determines the optimal loading of the generating plants and power flow pattern in the transmission network for demands at all load centres while minimizing the total cost due to power generation and transmission. Further the network model used in this manner as an operational planning model could be utilzed to study the effects of planned maintenance of plants, plant outages, and transmission line failures on the system performance and operating costs. A large number of alternative possibilities could be examined at minimal computational effort due to the extremely fast solution technique available. Used as an interactive model with a visual display of the system network, the appeal of the network model to the user and its advantages in the load despatching, maintenance planning and unit commitment functions would be considerable.

The objective function (4) of the Network model used for short term operational planning purposes does not include any allocation for the installation costs as it is used for optimal operation of plants and transmission lines already installed. If a discretized version of the annual load duration curve is used and minimal operating costs and optimal operating schedules for a set of existing generating plants are determined for each step of the load duration curve, then from these solutions the minimal annual cost of operation of the power system and optimal operating schedules for the year could be obtained.

The Network model as formulated earlier for the solution of the medium term investment planning problem for capacity expansion of the power system does not provide the minimum cost of annual operation in the final year of the planning horizon directly as the solution of the model. The Network model essentially ensures that during the period of maximum (peak) demand for power, sufficient generating and transmission capacity is available in the system and the investments decisions are made to minimize system operating cost including the allocation of investment costs during the peak period. The alternative generating plants consisting of hydro, nuclear and thermal plants are also compared on an equivalent basis in terms of how economically they will operate during the whole year. Their capital costs, annual availability of energy in megawatt-hours, and cost of operation per megawatt-hour is taken into account in determining the optimal plant mix.

The objective function represented by equation (4) associated with the Network model for optimal investment planning could be considered as a surrogate for the more desirable objective function which would involve minimization of the annual cost of operation in the target year, including annualised capacital amortisation costs and new investments. The cost coefficients for the generation arcs (c_g) and the transmission arcs (dij) are defined to include both the costs due to investment and operation for the proposed generating plants and transmission lines and if the power demand at load centres were uniform throughout the year, the minimization of the objective function (4) would have been equivalent to minimizing the annual cost of operation in the target year. Also, as the capacity and energy availability of the hydro plants are usually limited by the water level in the reservoir, and the annual storage capacity (or river discharge in case of run-of river plants) the hourly allocation of annualized investment cost for the hydro plants in c_g

have been normalized to make one megawatt of hydro generating capacity equivalent to that for the thermal plants which are assumed to be available for operation at their full capacity at any time when they are not under planned maintenance or repair following a forced outage. Different thermal plants requiring varying period for planning maintenance and forced outage have also been normalized similarly.

The cost coefficient (c_g) of hydro, thermal or nuclear plants obtained by diving the annualised total installatior cost for one megawatt capacity by the number of operating hours available in a year and adding the variable cost of generating one megawatt-hour of energy, thus represents the true cost of generating one unit of energy using any of these plants if they are utilized to their maximum available number of operating hours. Investments made in one or the other new plants for additional generating capacity in megawatts are then evaluated on an equivalent basis for meeting the system load during the peak demand hour. Due to the nature of variability of the system load, the optimal mix of generating plants though all needed during peak hour for generating energy or for providing reserve, cannot be utilized to their fullest capacity at other times. During any time of the year the plants will be operated following their economic loading order and other system constraints so that the plant having the highest operating cost will be brought into operation only when all other plants higher up in the economic merit order are already operating or they are under planned maintenance or repair.

The cost of annual operation of the generating system will thus be given by adding the annualised investment cost and fixed maintenance costs to the product of the actual hours of operation of each plant and its hourly operating cost, and summing this over all the plants. Similarly the annualised cost of transmission system investments added together to the operating costs of the transmission system including energy losses will give the annual cost of operating the transmission system. If the power system is operated in an optimal fashion using the Network model or any other model for operational planning, following investments made as recommended by the investment planning Network model, then the annual cost of system operation will be minimized for the given power system. The Network model applied during the peak period determines the optimal system configuration in meeting peak system demand. The annual load duration curve could be approximated by a step function and the optimal system configuration determined from the peak demand conditions used as the existing system in an operational Network model, and solved sequentially for system loads corresponding to all other steps in the load duration curve would provide the optimal schedule of plant operations and the hours of operation of each plant during the year. The annual cost of system operation following optimal utilization of the system configuration generated by the Network investment planning model could then be easily obtained.

The investment planning problem for power system essentially is a fixed-charge type of problem due to discrete capacities in which standard-sized generating plants and transmission lines are available and ideally a mixed integer linear (or nonlinear) programming formulation (6,8) would be suitable. But the computational efforts for large sized power systems with detailed representation of generating plants and transmission network would be considerable. In the Network model the generating plants and transmission line capacities are treated as continuous variables. It is seen that for most of the generating plants in a typical solution of the Network model, either the maximum capacity of a plant is suggested or the generating plant is rejected. In case a generating plant is included in the optimal solution at a very low capacity, an alternative plant of a lower capacity would be recommended. Similarly if certain transmission arcs are shown to have very low flow values in the optimal solution when compared to their maximal capacity for power transmission, a lower capacity transmission line could be recommended. With such adjustments a few iterations of Network model would usually provide a more realistic system configuration.

The Network model proposed here approximates the flow of electric power in a network by taking into account the First law of Kirchoff and assumes flow conservation at the arcs and nodes of the network. The power losses in the transmission network could be approximately estimated and the demands at the load centres proportionately increased.

An improved Network model is also available which takes into account the losses in the transmission arcs by using a multiplier for each such arc which approximately denotes the efficiency of power transmission in that arc. As power loss is a nonlinear function of the flow in a transmission line the multiplier estimates actual power loss with a certain degree of accuracy. If more accurate representation of the power losses is desired an iterative approach could be used in which the arc multipliers are recomputed after each Network model solution, based on the optimal flow in the transmission arc. This is the same strategy that has been successfully used to represent nonlinear cost functions in the Network model related to energy losses in the transmission arc or fuel costs in the generation arcs.

A more accurate representation of an electrical power transmission system would involve using a Electricity Network model satisfying both the First and Second laws of Kirchoff, which uses a linear approximation (d-c load flow) and considers the electrical characteristics of the various elements in the power network. Both the node-arc incidence matrix (used in the present model) and the independent cycles matrix are used in this formulation to satisfy the Kirchoff's laws. The Electricity Network model of the d-c load flow type could be formulated from the electrical characteristics of the power system elements and the topology of the network.

The Electricity Network model of the d-c load flow type is recommended if the Network model presented here results in larger errors in predicting the flow patterns in the transmission network as could be checked with nonlinear a-c load flow studies. The Electricity Network model represents the power system network as a linear system and its solution technique is the application of the well-known simplex method of linear programming (5). The Network model presented here uses a much faster network cost minimization programme known as the 'out of Kilter' algorithm (7), and is capable of analysing very large power network problems - involving hundred of nodes and arcs with only minimal computer effort, which is one of the main attractions of this model.

3. APPLICATION OF THE NETWORK MODEL IN NORTHERN REGION

The Network model for power generation and transmission system planning discussed in this section was applied for analysing the power system expansion for the Northern region grid of India to meet the system load at the end of the 5th Five Year Plan period (1978-79). For the purpose of coordinated development and operation of electric power system in India, the country is divided into five power regions. The Northern region includes the States of Jammu & Kashmir, Punjab, Haryana, Rajasthan, Uttar Pradesh, Himachal Pradesh, and Union Territory of Delhi. The power system in the Northern region is connected and the operation of the system is coordinated by the Northern Region Electricity Board, though each of the State power systems are governed by the respective State Electricity Boards. The Central Electricity Authority, the technical planning and coordinating body of the Central Government is the sanctioning authority for investments for system expansion in the States of India and they use a regional approach in planning and deciding on system expansion.

The basic data regarding the existing and proposed generating plants and transmission lines, peak demands at load centres and cost data used in the study were very similar to those used by Chakravarti et al (4) and Shiralkar and Parikh (12). The annual peak demand for electricity at various load centres in the Northern region for the year 1978-79 is shown in Table 1. To meet the gap between the existing generating capacity and the system peak demand for 1978-79, several project proposals for new generating plants were considered. A list of existing as well as proposed generating plants, their types and capacities is shown in Table 2. The existing transmission system also needed augmentation by the addition of new links and by strengthening the existing links, wherever necessary for carrying the increased power load and for connecting new generating stations to the load centres. Several new 400 KV lines were also proposed to interconnect major generating and load centres, to reduce the transmission losses and to improve the reliability of the system. A list of existing as well as proposed transmission lines with their KV ratings and route strength in Kilometres is shown in Table 3. Only transmission lines of 132 KV, 220 KV, and 400 KV have been included in the representation of transmission system in the Network model. For transmission lines with lower KV rating and distribution network, the demands were grouped and added to the load centre where they are connected to a transmission line of 132 KV or higher rating. The demand considered for each load centre was the annual peak demand in 1978-79, expected to occur during the working days of the week in summer months, and these demands have been augmented by certain reserve margin to account for plant failures and power losses in the transmission network. The capacity of a transmission line in megawatts is limited by its KV rating, the number of circuits and the size of the conductors. Table 4 shows the ranges assumed for transmission lines of different KV ratings as well as their capital costs, conductor sizes and the K factor values which expresses the power loss in watts per megawatt for one kilometer length.

In the network model the higher values of the ranges were used as upper bounds on the transmission arcs and lower bounds were fixed at zero. If flow in any proposed transmission arc was below the recommended range, then a transmission line of lower KV rating would be recommended unless there are other considerations such as system reliability or future demand growth to justify a transmission line of high KV rating.

Different assumptions were made for the existing and proposed plants regarding their costs of generation as explained earlier. Thermal and hydel plants on which construction work had begun or was about to begin soon were assumed to be ready for power generation in 1978-79 and treated as existing plants. All the other plant proposals for which sanction had not been given were considered as proposed plants. Among the proposed plants a nuclear generating unit at four proposed locations, Narora, Matatila, Rupar and RAPP were considered. Subsequently Narora was chosen as the location for this plant and other locations were dropped from the model.

It was observed that in many cases more than one generating plant was located at the same place as in Obra, Kanpur, Delhi, etc. These locations were defined as generating regions and an additional node was assigned to each of these regions where generated electricity from all the plants flows in for further transmission to the load centres. Some of the generating regions and load centres were at the same location, i.e., Kanpur Delhi, etc. In these situations, separate nodes in the network were defined to represent generating regions and load centres and these were connected with high-capacity transmission arcs with zero or very low unit cost of flow in these arcs.

In case of existing generating plants the capital cost is a sunk cost and hence it is not considered. Cost of generation for existing plants include fuel cost and only 2.5% of their capital cost as annual maintenance charges. For the proposed plants, the cost of generation includes fuel cost and annual charge of 12.5% of the capital cost (this consists of 6% interest charges, 4% for depreciation and insurance and 2.5% for maintenance charges). This cost differential between existing and proposed plants will ensure that in the network model solution the existing plants will be utilized to their installed capacity before proposed plants are called in. Only in the case of old thermal plants of very low efficiency and high operating costs, the model might recommend their retirement.

The annual cost of transmission also has fixed and variable components. The fixed costs are due to annual capital charges (interest, depreciation, etc.) and the variable costs are due to power and energy losses during transmission. To counteract the power lost during transmission, additional capacity must be commissioned and the costs of this can be ascertained. Similarly, the energy losses could be priced to obtain a monetary value. Both these costs have been more or less standardized for 132 KV SC/DC, 220 KV SC/DC and 400 KV SC lines and for any line they are directly proportional to the length in kilometres. Again a distinction is made between existing and proposed transmission lines and no capital charges are shown against existing lines.

Given the KV rating and the number of circuits for a transmission line, the amount of power in megawatts that can be economically and safely transmitted is given by a range as described earlier. If the amount of power to be transmitted is known, then transmission costs per megawatt can be computed. Whereas the variable operating costs due to fuel costs are approximately linear for generating plants, the cost due to power and energy losses is a nonlinear function of power transmitted and is proportional to the square of power transmitted in megawatts.

The nonlinearity of the power loss function creates some difficulties in the network model for existing transmission lines. However for proposed lines though the annual cost of capital charges per megawatt (a decreasing function of the amount of power transmitted, in MW) and the annual cost of power losses per megawatt (an increasing function of the amount of power transmitted, in MW) are both nonlinear functions the resulting total cost of power transmission per megawatt was found to be reasonably linear for a wide range near the transmission capacity of the line. Within this range, the cost of transmission for proposed lines could be taken as linear. These costs have been computed following the assumptions given below and are listed in Table 5. For existing lines an average unit cost is used for a range, in Table 5, and based on the actual power flow in the transmission line this unit cost value can be corrected in an iterative fashion.

An optimal solution of the network model specifies a distribution of power flow in the transmission network. From this data the efficiency of the transmission lines and power loss in them could be easily computed. The optimum solution could be corrected by either generating additional power at the generating nodes to counteract the power loss or augmenting demand at each load centre by the amount of power loss in transmission from the generating node and obtaining a new solution with the augmented values of demands. Thus power generated in the system could be computed in an iterative fashion to provide for the power lost in the system in addition to the demands at the load centres and this method of computation should converge quickly. An alternative way of accommodating power losses due to transmission in a network model is to use a special kind of network formulation known as 'networks with gains' discussed earlier.

4. COMPUTER SOLUTION OF THE NETWORK MODEL FOR NORTHERN REGION

From the available data on the existing and proposed generating plants existing and proposed transmission lines, capital and operating costs and demand for power at various load centres of Northern Electricity Region, the conceptual network was constructed following the procedure described earlier. The generating plants were grouped into 18 generating regions each represented by a node and the load centres were grouped into 43 nodes. There were 100 transmission lines (existing and proposed) and the conceptual network for the investment planning model consisted of 259 arcs, some of which were needed to satisfy various system constraints and characteristics of the generating and transmission system.

The network model was solved by using NETFLOW code, a version of Ford and Fulkerson's 'Out-of Kilter' algorithm in IBM 360/44 computing system and each run took approximately 1.0 - 1.5 minutes of computer time. Starting solution was provided by assigning initial flow values in all the arcs of the network which were judiciously chosen based on the knowledge of the power system and satisfying flow conservation (flow into a node = flow out) at each node of the network. Six computer runs were made as described below to systematically improve the accuracy of the model and to obtain solutions under alternative assumptions regarding the available capacity of hydro plants during system peak demand. The generation schedule obtained as solution of these runs are summarised in Table 6. One of the optimal solutions (solution No.5) obtained as a result of the study is shown in Figure 2 plotted on a diagram of the Norther Region power network. The optimal capacities of existing and generating plants and optimal values of power flows in the transmission lines are also shown in Figure 2.

In the optimal solution obtained in the first computer run, it was observed that flow in some of the arcs were outside the prescribed ranges which were used to compute the unit costs for the model. New unit arc costs were computed based on optimal flows obtained in the 1st Computer run and with these augmented costs, the second computer run was made. The optimal flow solution obtained in the arcs were now within the prescribed ranges and this solution was considered satisfactory. During the first and second runs, it was assumed that all hydro plants were available for power generation at their installed capacity during the peak demand period.

In the third computer run the available capacity during peak demand period was reduced to 75% of the installed capacity for all hydro plants. In addition to this, locations of the nuclear plant at Rupar and RAPP were suppressed from further consideration as during the first two runs these locations were not used. The result of reducing available hydro capacity is an increase in the utilization of existing and proposed thermal plants and nuclear plants and an increase in total system cost.

In the fourth and fifth computer runs, the available hydro capacity was further reduced to 50% of the installed capacity. This might correspond to a dry year and indicated the additonal thermal capacity that should be built in to counteract the adverse effects of a dry year. The nuclear plant locations at Narora and Matatila were compared in the fourth and fifth runs, the fourth run considered Matatila and the fifth run had Narora as the location. The Narora location ensures a higher utilization of the nuclear plant with a corresponding reduction of system cost by Rs. 23 million per year.

The last run was made to increase the accuracy of the model solution and new unit transmission arc costs were computed for the arcs where power flow was outside the range originally used for computing the unit costs. The hydro plants at Kistwar and Pakal Dal were not utilized fully in earlier computer runs and hence these were dropped from consideration in the sixth run. The resulting generation schedule and utilization of existing as well as proposed plants are shown in Table 6.

In all the solutions, the hydro plants were being utilized to the maximum possible extent except the proposed plants at Kistwar and Pakal Dal, as the cost of generation in hydro plants were the cheapest. Thus highest priority should be given to exploit the hydro resources and implement the proposed schemes. As the total installed hydro capacity may not be available during the peak demand period, specially following a dry year, proposed thermal plants at Faridabad, Panipat, Bhatinda, Kota and RAPP must be considered. Along with these plants, the existing plants at Kanpur and Harduaganj would provide enough capacity during a dry year, if hydro capacity is not fully available. Proposed plants at Panki and Harduaganj were found uneconomical with the cost data used, whereas the existing and proposed plants at Obra were utilized almost fully due to their better thermal efficiency and low cost of coal at Obra.

TABLE-1

Load Centres in Northern Region & Their Peak Demands in 1978-79

S.No.	Load Centre	Peak Demand(MW)	S.No.	Load Centre	Peak Demand (MW)
1	Pipri	283	23	Yamuna	37
2	Mughalsarai	293	24	Jullundar	327
3	Gorakhpur	261	25	Ludhiana	411
4	Sultanpur	183	26	Muktasar	97
5	Allahabad	149	27	Sangrur	118
6	Kanpur	423	28	Bhatinda	148
7	Lucknow	218	29	Bhakra	381
8	Mainpuri	149	30	Rupar	56
9	Bareilly	141	31	Amritsar	276
10	Harduaganj	189	32	Udaipur	132
11	Moradabad	162	33	Kota	225
12	Muradnagar	326	34	RAPP	89
13	Narora	63	35	Jaipur	192
14	Shamli	98	36	Alwar	47
15	Saharanpur	71	37	Sawaimadhopur	61
16	Delhi	660	38	Jodhpur	29
17	Ballabhgarh	252	39	Khetri	46
18	Nehtaur	56	40	Ratnagarh	26
19	Panipat	135	41	Bihaner	23
20	Hissar	214	42	Beawar	40
21	Rishikesh	101	43	Bhilwara	40
22	Roorkee	81			

TABLE-2

Existing and Proposed Generating Stations Upto 1978-79 for Northern Region

S.No.	Generating Station	Type	Existing / Proposed	Maximum Capacity (MW)
1	Obra	Hydel	Existing	100
2	Rihand	Hydel	Existing	300
3	Obra	Thermal	Existing	1500
4	Kanpur	Thermal	Existing	155
5	Fanki	Thermal	Proposed	220
6	Harduaganj	Thermal	Existing	190
7	Harduaganj(Extn.)	Thermal	Proposed	550
8	Tehri	Hydel	Proposed	300
9	Ramganga	Hydel	Existing	240
10	Delhi	Thermal	Existing	360
11	Faridabad	Thermal	Proposed	400
12	Panipat	Thermal	Proposed	220
13	Yamuna (Stages I to IV)	Hydel	Existing	800
14	Maneri Bhali	Hydel	Proposed	405
15	Vishnu Prag	Hydel	Proposed	120
16	Bhakra L.B.	Hydel	Existing	450
17	Bhakra R.B.	Hydel	Existing	600
18	Dehar	Hydel	Existing	340
19	Dehar (Extn.)	Hydel	Existing	660
20	Siul	Hydel	Existing	200
21	Thein	Hydel	Proposed	420
22	Seawa	Hydel	Proposed	100
23	Salal	Hydel	Existing	270
24	Kistwar	Hydel	Proposed	200
25	Pakal dal	Hydel	Proposed	200
26	Bhatinda	Thermal	Existing	220
27	Bhatinda (Extn.)	Thermal	Proposed	220
28	RP Sagar	Thermal	Existing	172
29	Kota	Thermal	Proposed	440
30	RAPP	Thermal	Proposed	400
31	Rupar*	Nuclear	Proposed	470
32	Narora*	Nuclear	Proposed	470
33	Matatila*	Nuclear	Proposed	470
34	RAPP*	Nuclear	Proposed	470

* These are 4 alternative locations for the proposed Nuclear plant.

TABLE-3

Existing and Proposed Transmission Lines Upto 1978-79

S.No.	Transmission Lines	Existing(E) or Proposed(P)	Rating KV and No.of Circuits	Route Length (KM)
1	Obra - Pipri	E	132 DC	34
2	Obra - Pipri	P	220 DC	34
3	Pipri - Mughalsarai	E	132 DC	129
4	Mughalsarai - Gorakhpur	E	132 DC	204
5	Mughalsarai - Gorakhpur	P	220 DC	204
6	Obra - Mughalsarai	E	220 DC	97
7	Obra - Mughalsarai	P	400 SC	97
8	Obra - Sultanpur	E	400 SC	253
9	Sultanpur - Gorakhpur	E	220 SC	148
10	Obra - Allahabad	E	220 DC	177
11	Obra - Allahabad	P	400 SC	177
12	Allahabad - Sultapur	E	132 SC	111
13	Allahabad - Kanpur	E	220 DC	208
14	Kanpur(Gen.) - Kanpur	E	220 DC	0
15	Kanpur - Lucknow	E	220 DC	90
16	Kanpur - Lucknow	P	132 SC	90
17	Kanpur - Lucknow	P	220 SC	90
18	Sultanpur - Lucknow	P	220 SC	130
19	Kanpur - Mainpuri	E	220 DC	150
20	Matatila - Kanpur	E	132 SC	257
21	Matatila - Kanpur	P	220 SC	257
22	Matatila - Allahabad	P	220 SC	230
23	Matatila - RAPP	P	220 SC	230
24	Lucknow - Bareilly	E	132 DC	259
25	Tehri - Bareilly	P	220 DC	200
26	Mainpuri - Harduaganj	E	220 DC	128
27	Harduaganj(Gen) - Harduaganj	P	220 DC	0
28	Harduaganj - Muradnagar	E	220 DC	105
29	Harduaganj - Muradnagar	P	400 SC	105
30	Narora - Harduaganj	P	220 SC	65
31	Narora - Muradabad	P	220 SC	65
32	Narora - Mainpuri	P	220 SC	135
33	Mordabad - Bareilly	E	132 DC	85
34	Muradnagar - Muradabad	E	132 SC	128

SC - Single Circuit DC - Double Circuit

contd..

TABLE-3 (Contd..)

S.No.	Transmission Lines	Existing(E) or Proposed(P)	Rating KV and No.of Circuits	Route Length (KM)
35	Rishikesh(Gen) - Rishikesh	P	220 DC	0
36	Rishikesh - Muradnagar	P	400 SC	175
37	Rishikesh - Moradabad	P	400 SC	160
38	Moradabad - Nehtaur	E	132 DC	64
39	Nehtaur - Roorkhee	E	132 DC	83
40	Rishikesh - Muradnagar	E	220 SC	175
41	Rishikesh - Roorkhee	E	132 SC	49
42	Saharanpur - Roorkhee	E	132 SC	31
43	Muradnagar - Shamli	E	220 SC	48
44	Shamli - Sharanpur	E	220 SC	50
45	Yamuna - Saharanpur	E	220 SC	85
46	Yamuna - Rishikesh	E	220 SC	70
47	Shamli - Panipat	E	220 SC	160
48	Muradnagar - Delhi	E	220 DC	43
49	Hissar - Panipat	E	132 SC	115
50	Hissar - Delhi	E	220 DC	198
51	Hissar - Ballabhgarh	P	220 DC	225
52	Bhakra - Panipat	E	400 SC	280
53	Bhakra - Panipat	P	400 SC	280
54	Bhakra - Rupar	E	132 DC	70
55	Rupar - Ludhiana	E	132 DC	100
56	Rupar - Sangrur	P	220 DC	135
57	Bhakra - Ludhiana	E	220 DC	86
58	Bhakra - Ludhiana	E	220 DC	86
59	Ludhiana - Jullundar	E	220 DC	58
60	Ludhiana - Jullundar	E	132 DC	58
61	Ludhiana - Jullundar	E	220 SC	58
62	Dasuya - Jullundar	E	220 DC	56
63	Dasuya - Jullundar	P	220 SC	56
64	Jullundar - Amritsar	E	220 SC	80
65	Jullundar - Amritsar	E	132 SC	80
66	Ludhiana - Bhatinda	E	220 SC	128
67	Bhatinda - Sangrur	E	220 SC	112
68	Ludhiana - Muktasar	E	132 DC	144
69	Ludhiana - Sangrur	E	220 DC	240
70	Sangrur - Hissar	E	220 DC	144
71	Hissar - Khetri	E	220 SC	115
72	Jaipur - Khetri	E	220 SC	144
73	Hissar - Ratangarh	E	132 SC	208
74	Panipat - Jaipur	E	220 SC	280
75	Panipat - Jaipur	P	400 SC	280

contd...

TABLE-3 .(Contd..)

S.No.	Transmission Lines	Existing(E) or Proposed(P)	Rating KV and No.of Circuits	Route Length (KM)
76	Alwar - Delhi	E	220 SC	125
77	Jaipur - Alwar	E	220 SC	100
78	Jaipur - Alwar	E	132 SC	100
79	Alwar - Harduaganj	E	132 SC	210
80	Mainpuri - Swaimadhopur	E	132 SC	325
81	Swaimadhopur - Jaipur	E	132 SC	128
82	Swaimadhopur - Jaipur	P	220 SC	128
83	Jaipur - Bewar	E	132 SC	200
84	Jaipur - Beawar	P	220 SC	200
85	Beawar - Jodhpur	E	132 SC	152
86	Bhilwara - Jodhpur	E	132 SC	245
87	Bhilwara - Beawar	E	132 SC	93
88	RAPP - Bhilwara	E	132 SC	120
89	Kota - Bhilwara	E	132 SC	120
90	Kota - RAPP	E	220 DC	43
91	Kota - Jaipur	E	220 DC	187
92	RAPP - Jaipur	P	400 SC	230
93	Kota - Beawar	P	220 SC	187
94	Kota - Swaimadhopur	E	132 DC	112
95	Kota - Swaimadhopur	P	220 SC	112
96	Moradabad - Nehtaur	P	220 DC	64
97	Yamuna - Saharanpur	P	220 SC	85
98	Saharanpur - Roorkhee	P	132 SC	31
99	Yamuna - Muradnagar	P	400 SC	260
100	Hissar - Panipat	P	220 SC	115

TABLE-4

Characteristics for Various Transmission Lines

Sr. No.	Transmission Line KV rating	Conductor Size, mm	K Factor Watts.	Capital Cost Rs. 'ooo/Km.	Range of power Transmission KW
1	400 KV SC	325	0.505	275	150 - 600
2	220 KV DC	325	0.835	230	100 - 300
3	220 KV SC	325	1.669	137	50 - 150
4	132 KV DC	185	4.065	127	50 - 100
5	132 KV SC	185	8.13	78	0 - 50

SC - Single Circuit; DC - Double Circuit

TABLE-5

Cost of Transmission Used for the Study

(Values are taken from the graphs plotted for individual cost function)

	Cost (Rs./Km/Year/MW)	Capacity Range (MW)
EXISTING LINES		
132 KV SC	140	40 - 50
132 KV DC	140	80 - 100
220 KV SC	85	120 - 150
220 KV DC	85	240 - 300
400 KV SC	110	500 - 600
PROPOSED LINES		
132 KV SC	370	40 - 50
132 KV DC	335	80 - 100
220 KV SC	200	120 - 150
220 KV DC	185	200 - 300
400 KV SC	150	400 - 600

TABLE-6

Pattern of Plant Utilization under Different Assumptions : Summary of Computer Runs

Type	Generating Stations	Max. Capacity MW	Power generated in MW in optimal solution 1st run	2nd run	3rd run	4th run	5th run	6th run
Existing Hydro Plants	Rihand ◊ Obra ◊	(400)	400	400	300	200	200	200
	Ramganga	(240)	240	240	200	120	120	120
	Yamuna	(800)	650	650	400	400	400	400
	(Bhakra L.B., R.B., Dehar I &II)	(2050)	2050	2050	1600	1025	1025	1025
	Siul	(200)	200	200	160	100	100	100
	Salal	(270)	270	270	220	130	130	130
Existing Thermal Plants	Obra	(1500)	1219	1219	1319	1419	1419	1419
	Kanpur	(155)	-	-	-	155	155	143
	Harduaganj	(190)	-	-	162	190	190	190
	Delhi	(360)	360	360	360	360	360	360
	Bhatinda	(220)	72	116	220	220	220	220
	RP Sagar	(172)	172	172	172	172	172	172
	Tehri	(300)	300	300	250	150	150	150
Proposed Thermal Plants	Panki	(220)	-	-	-	-	-	-
	Harduaganj	(550)	-	-	-	-	-	-
	Faridabad	(400)	-	-	-	-	400	400
	Panipat	(220)	-	-	-	220	220	220
	Bhatinda	(220)	-	-	-	103	90	128
	Kota & RAPP	(840)	-	-	275	840	840	840
Proposed Hydro Plants	Tehri	(300)	300	300	250	150	150	150
	Rishikesh	(525)	525	525	420	260	260	260
	(Maneri bhali & Vishnu Prag)	(520)	520	520	420	260	260	260
	Dasuya (Thein & Seawa)	(520)	520	520	420	260	260	260
	Amritsar (Kistwar & Pakal Dal)	(400)	113	-	157	26	26	-

contd..

TABLE-6 (contd..)

Type	Generating Stations	Max. Capacity MW	Power generated in MW 1st run	2nd run	3rd run	4th run	5th run	6th run
Proposed Locations for a Nuclear Plant	Rupar	(470)	-	-	-	-	-	-
	Narora	(470)	-	20	212	-	363	363
	Matatila	(470)	123	178	273	350	-	-
	RAPP	(470)	6	-	-	-	-	-
Total Cost per annum (in Rs. million)			1471	1488	1858	2576	2553	2557

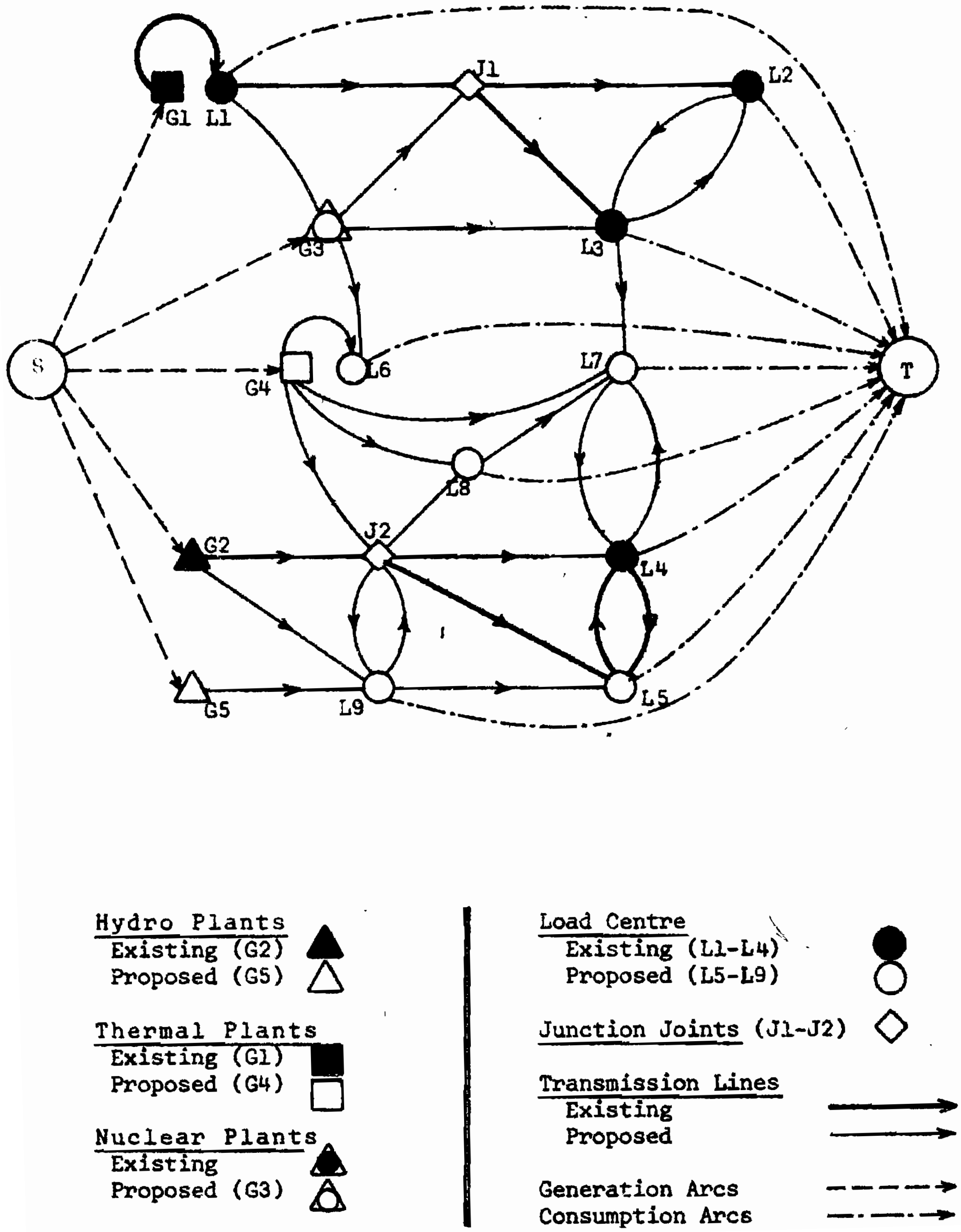
Notes: In 3rd run Hydro capacity was reduced to 75% of maximum and Rupar, RAPP locations were neglected for proposed neclear plant.

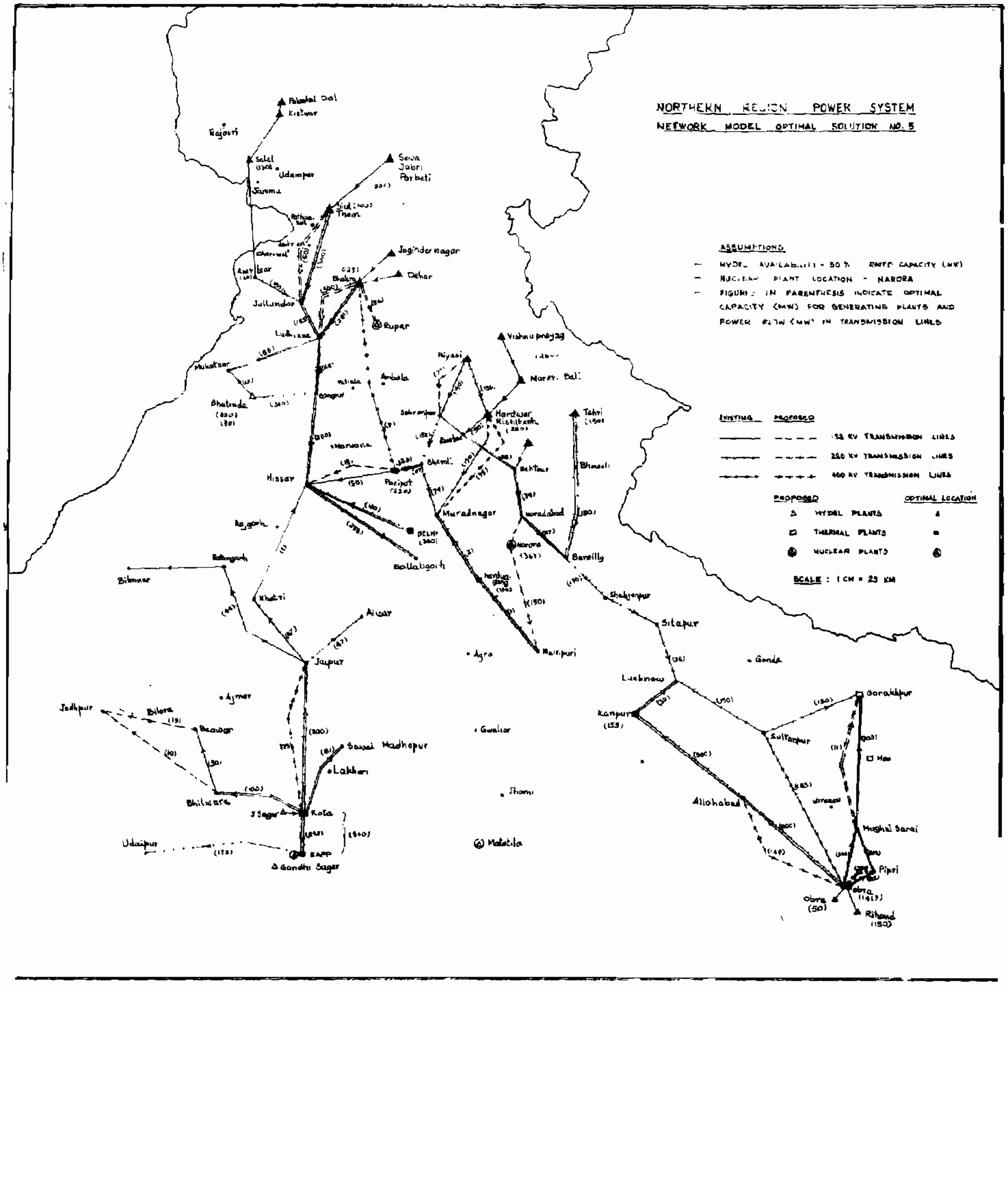
In 4th run Hydro capacity was reduced to 50% of maximum and nuclear plant location at Matatila was considered.

In 5th run Hydro capacity was reduced to 50% of maximum and nuclear plant location at Narora was considered.

In 6th run proposed hydro plants at Kistwar and Pakal Dal were neglected and costs on some transmission lines were changed for increasing accuracy.

FIGURE 1. NETWORK MODEL PRESENTATION OF A HYPOTHETICAL POWER SYSTEM.




NORTHERN REGION POWER SYSTEM
NETWORK MODEL OPTIMAL SOLUTION NO. 5
ASSUMPTIONS
— HYDEL AVAILABILITY = 50 % RATED CAPACITY (MW)
— NUCLEAR PLANT LOCATION - NARORA
— FIGURES IN PARENTHESIS INDICATE OPTIMAL CAPACITY (MW) FOR GENERATING PLANTS AND POWER FLOW (MW) IN TRANSMISSION LINES
EXISTING PROPOSED
132 KV TRANSMISSION LINES
220 KV TRANSMISSION LINES
400 KV TRANSMISSION LINES
PROPOSED OPTIMAL LOCATION
HYDEL PLANTS
THERMAL PLANTS
NUCLEAR PLANTS
SCALE : 1 CM = 25 KM
Kishtwar
Rajouri
Salal
Udampur
Jammu
Sewa
Jobri
Parbati
Thein
Jogindernagar
Dehar
Bhakra
Jullundar
Ludhiana
Ruper
Mukatsar
Bhatinda
Ambala
Vishnu prayag
Riyasi
Narer. Bal
Hardwar
Rishikesh
Tehri
Hissar
Panipat
Muradnagar
Moradabad
Bareilly
Narora
Ballabgarh
Bikaner
Khetri
Alwar
Jaipur
Shahjanpur
Sitapur
Gonda
Lucknow
Kanpur
Gorakhpur
Sultanpur
Agra
Ajmer
Jodhpur
Beawar
Gwalior
Sawai Madhopur
Lakheri
Bhilwara
Kota
Udaipur
Gandhi Sagar
Allahabad
Mughal Sarai
Pipri
Obra
Rihand

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