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EVALUATION OF TWO AREA INTERCONNECTED SYSTEM AS A SINGLE AREA SYSTEM

BY

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A THESIS

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ABSTRACT

In long term generation expansion planning process, the evaluation of reliability and production cost are two important steps. The methodologies for the evaluation of these two aspects are different in case of single utility (power company) and in case of interconnected utilities. However, in case of a power system network having different zones connected by tie lines and owned by a single utility, the appropriate methodologies to be followed is not straight forward.

Bangladesh electric power generation system is a small one and is owned by a single utility having two distinct zones, Eastern Zone and Western Zone. These two zones are connected by a tie line with limited power transferring capacity. In this research, Bangladesh power generation system has been evaluated following both methodologies, that is, treating this system as a single power system and also treating as two interconnected systems. The results obtained are analysed to find out the appropriate method for evaluating a power system like that of Bangladesh.

CONTENTS

ABBREVIATIONS

BPDB = Bangladesh Power Development Board

CLC = Chronological Load Curve

CRR = Capacity Reserve Requirement

ECS = Economic Commitment Schedule

EFOR = Equivalent Forced Outage Rate

EWI = East-West Interconnector

FOR = Forced Outage Rate

HR = Heat Rate

IFC = Incremental Fuel Cost

IHR = Incremental Heat Rate

LDC = Load Duration Curve

PDF = Probability Density Function

NOTATIONS

A_{12}	= Assistance from system 1 to system 2
A_{21}	= Assistance from system 2 to system 1
C_k	= Capacity of the k-th generating unit
E_k	= Expected energy generations of the k-th unit
EB	= Energy Balance
EC_k	= Production cost for the k-th unit
F(L)	= Load probability distribution
$F^r(Le)$	= Probability distribution of equivalent load after convolving r units
GEC	= Global production cost
GES	= Expected energy generated by the global system
GS	= Global savings
IC	= Installed capacity
K_k	= k-th cumulant
L	= Random system load
Le	= Equivalent load
Lo_i	= Random outage load corresponding to the i-th unit
LOLP	= Loss of load probability
$LOLP_1$	= LOLP of system 1 without considering assistance from the connected system
$LOLP_2$	= LOLP of system 2 without considering assistance from the connected system
$LOLP_{12}$	= LOLP of system 1 considering assistance from system 2
$LOLP_{21}$	= LOLP of system 2 considering assistance from system 1

$LOLP_s$ = LOLP of the global system

$m_{i,j}$ = First moment or expected value of load corresponding to the (i,j)th segment

m_n = n-th moment about the origin

M_n = n-th moment about mean

n_1 = Total number of generating units in system 1

n_2 = Total number of generating units in system 2

N(z) = Normal distribution

$p_{i,j}$ = Joint probability of the (i,j)th segment

p_k = Availability of capacity C_k of the k-th unit

PL = Peak load

q_k = FOR of the k-th unit

R_1, R_2 = Reserve capacities in system 1 and 2 respectively

RM_1, RM_2 = Reserve margins in system 1 and 2 respectively

S^E = Total number of committed units in the exporting system

S^I = Total number of committed units in the importing system

T = Time period

t_1 = Number of segments in the direction of the x-axis corresponding to system 1

t_2 = Number of segments in the direction of the y-axis corresponding to system 2

T_{12} = Transfer limit of tie line from system 1 to system 2

T_{21} = Transfer limit of tie line from system 2 to system 1

TC = Tie line capacity

UE_{k^-} = Unserved energy before convolving the k-th unit

UE_k = Unserved energy after convolving the k-th unit

$\mathcal{E}(DNS)$ = Expected demand not served

$\mathcal{E}(ENS)$ = Expected energy not served

ΔC = Segment size

λ = Generating unit failure rate

λ_k = Average incremental cost of the k-th unit

μ = Generating unit repair rate

[redacted]

CHAPTER 1

INTRODUCTION

1.1 INTRODUCTION

The evaluation of reliability and production cost are two important aspects of generation expansion planning of power systems. Generation planning begins with estimates of peak demands and associated electrical energy consumption[1]. After identifying the need for generating capacity additions, the planner develops a number of feasible expansion alternatives on the basis of

1. Load growth,
2. Construction time,
3. Availability of sites,
4. Availability of fuel.

Given these alternative plans, it is a common practice to evaluate each plan on the basis of reliability to ensure that the adopted plans satisfy desired reliability level[1]. Plans that do not meet the reliability criteria are eliminated or appropriately modified, and plans which satisfy the required reliability level are evaluated on the basis of economics. For each potential plan, financial and environmental impacts are analyzed. Finally, the alternative plans are compared in order to identify the one that impacts on the power company as a whole in the most favourable manner. In Figure 1.1 the planning process is depicted in the form of block diagrams.

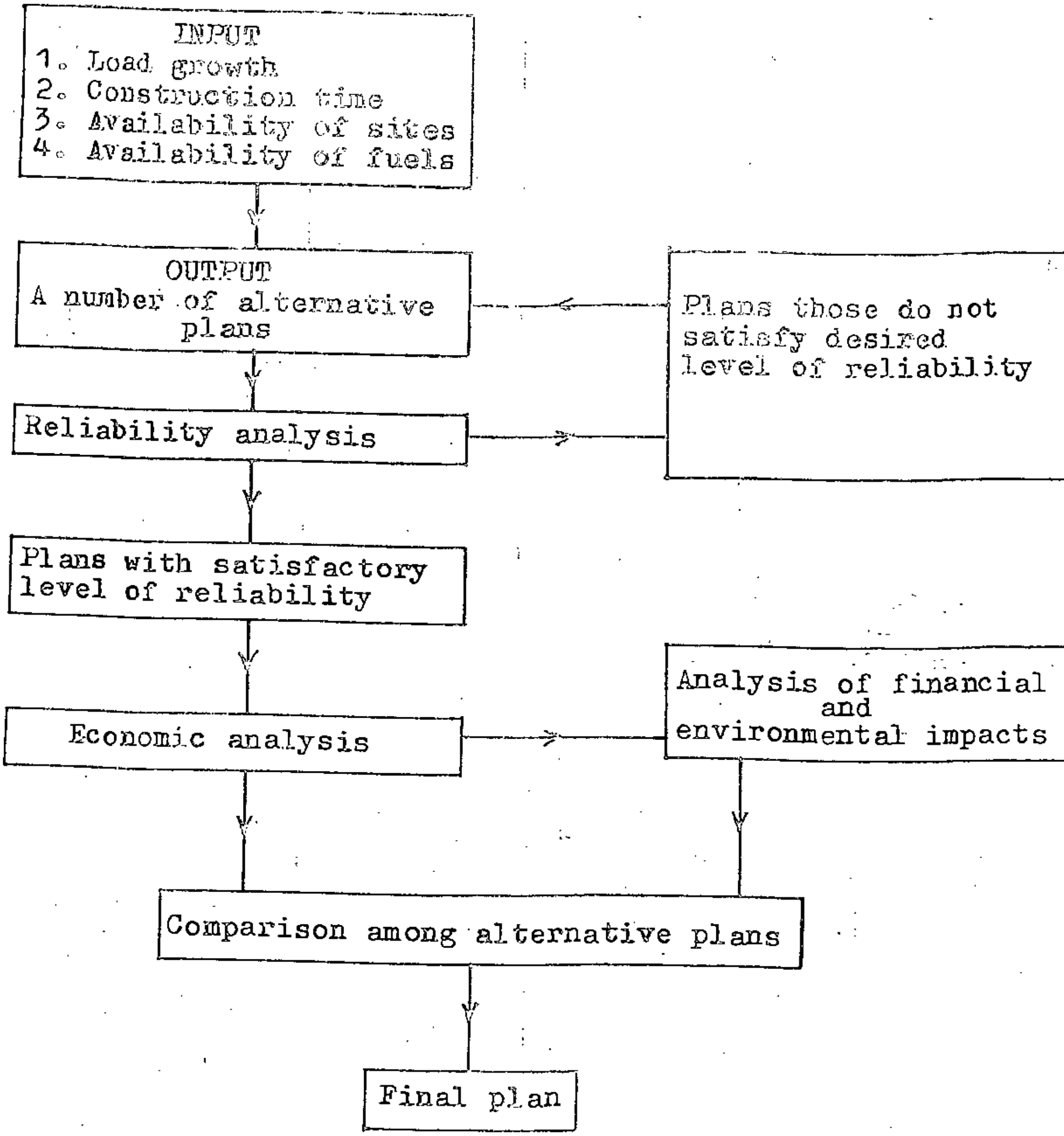


Figure 1.1: Generation expansion planning process.

Obviously, it is an enormous task to discuss in detail the entire planning process. Therefore, it is chosen to concentrate on the reliability and economic analysis of a generation expansion plan devised by the planner.

Several measures have been devised to evaluate the reliability performance of a given expansion plan. The simplest and most common of all is the loss of load probability (LOLP)[2,3].

The main factors which enter into the cost analysis of a given plan are:

1. Capacity cost,
2. Production cost,
3. Timing of unit additions.

The production cost includes the cost of fuel and the operation and maintenance cost. The evaluation of the energy production cost is by far the most complex part of cost analysis associated with a particular expansion plan.

The reliability and economic evaluation of interconnected systems is different from that of a single area system. If the available capacity in a geographical region can be transmitted wherever it is needed without tie line restrictions then this region may be treated as a 'single area'[4]. Although the simplest way of evaluating interconnected systems is to consider them as a single area system, however, there are very good reasons for keeping the identities of the constituent systems seperate. The reasons are the following[5,6].

i) A utility is primarily interested in the benefits that its own system can obtain from interconnections.

ii) The ties forming interconnections are usually limited in capacity and, in addition, are subject to failures.

iii) The load characteristics in the various interconnected networks may be different and, in addition, these load patterns may be independent or dependent on each other.

iv) It is necessary to incorporate the export/import of electrical energy between interconnected systems in the evaluation.

A 'single system' treatment of the entire interconnected system cannot take into account appropriately the above features.

The power generation system of Bangladesh is a typical one. The only electric utility which is responsible for the generation and transmission of electrical power throughout Bangladesh is 'Bangladesh Power Development Board' (BPDB). Hence it may seem to be relevant to evaluate the power system of Bangladesh as a single system. But a look at the overall structure of the power system of BPDB reveals that it can be divided into two zones: the East Zone and the West Zone seperated by the rivers Padma, Jamuna and Meghna. The only interconnection between these two Zones is the East-West Interconnector (EWI) which is a double circuit line. presently operating at 132 KV. The power transmission capacity of the EWI is limited to only 180 MVA per circuit at 132 KV. For this reason a two area approach for evaluating the overall power system of Bangladesh seems to be logical. The controversy whether to evaluate power systems like that of Bangladesh as a single area system or as a two area interconnected system has not yet been given adequate attention. In this research, an attempt is made to find out the approach which is more logical in evaluating such systems.

1.2 HISTORICAL BACKGROUND

Probability methods are used extensively at present for evaluating the reliability and production costs of power systems. The historical development of these methods is extremely interesting. Interest in the application of probability methods to the evaluation of capacity requirements became evident in 1933. The first large group of papers was published in 1947. The papers, by Calabrese(7), Lyman(8), Seelye(9), Loane and Watchorn(10) proposed some of the basic concepts upon which some of the methods in use at the present time are based. In 1948, the first AIEE Subcommittee on the Application of Probability Methods was organized. The Subcommittee submitted several reports containing comprehensive definitions of equipment outage classifications in 1949[11], 1954[12] and 1957[13]. The 1947 group of papers proposed the methods which with some modifications are now generally known as the 'Loss of Load Approach', and the 'Frequency and Duration of Outage Approach'. They are described in detail in a 1960 AIEE Committee Report[14]. The effect of interconnections and the determination and allocation of capacity benefits resulting from interconnections were discussed by Watchorn[15] and Calabrese[16] in 1950 and 1953 respectively. Until 1954 most probability studies had been done either by hand or using conventional desk calculators. The benefits associated with using digital computers were noted by Watchorn[17] in 1954 and illustrated in 1955 by Kirchmayer and his associates[18] in the evaluation of economic unit additions in system expansion studies. In 1960 Brown, Dean and Caprez[19] published the results of a statistical study of five years of data on 387 hydro-electric generating units. Shortly after this in 1961 the AIEE Subcommittee produced a manual[20] outlining reporting procedures and methods of analyzing forced outage data using digital equipment. Cook et al.[3] proposed in their paper the basic method for evaluating LOLP of two interconnected systems. The initial approach to the calculation of outage frequency and duration indices in generating capacity reliability evaluation was modified by the introduction of a recursive approach. This technique is described in detail in a series of four publications[21,22,23,24].

The most important development in the evaluation of LOLP and production cost by probabilistic simulation was suggested by Baleriaux[25] and Booth[26]. In 1980, Rau, Toy and Schenk[27] proposed a computationally fast method, which approximates the discrete distribution of load (equivalent load) through Gram-Charlier series expansion as a continuous function. Rau and Schenk[28] proposed the utilization of the bivariate Gram-Charlier expansion to evaluate the LOLPs of two interconnected systems. The bivariate Gram-Charlier expansion has also been utilized by Rau et al.[29], by Noyes[30] and by Ahsan et al.[31] in the evaluation of production costs of two interconnected systems. Schenk et al.[32], recently, proposed the segmentation method for the evaluation of expected energy generation and LOLP of a single area system. In this method the authors avoided the inherent inaccuracies of series expansion but still retaining the computational efficiency. The segmentation method has been extended by Schenk, Ahsan and Vassos[33] to incorporate the reliability evaluation of two interconnected systems. Ahsan and Schenk[34] have utilized the segmentation technique to evaluate the production cost of two interconnected systems.

1.3 THESIS ORGANISATION

This thesis consists of nine chapters. In Chapter 1, the background of this work is presented. The basic concepts of the evaluation of reliability and production cost are presented in Chapter 2. The generation and load models used in probabilistic simulation techniques are derived in Chapter 3. A brief discussion on various probabilistic simulation techniques is given in Chapter 4. The benefits of interconnection between seperate power systems and the impacts of tie line capacity on the reliability of interconnected systems are the subject matter of Chapter 5. In Chapter 6, the segmentation method for evaluating the LOLP of a single area system as well as that of two area interconnected systems is presented. The segmentation method, for the evaluation of production cost of a single area and that of two area interconnected systems is given in Chapter 7. Chapter 8 contains a brief discussion on the electric power generation system of Bangladesh. The generation and load models used in this research as well as the results obtained are also included in Chapter 8. Chapter 9 presents discussions and conclusions relating to the concerned problem. Some recommendations for further work are also presented in Chapter 9.

CHAPTER 2

BASIC CONCEPTS OF THE EVALUATION OF RELIABILITY AND PRODUCTION COST

2.1 INTRODUCTION

The objective an utility (power company) is to supply customers with reliable electrical energy at minimum price. The economic and reliability constraints make the decisions in the expansion planning and operation of a power system sometime complex. In generation expansion planning the reliability of a number of alternative expansion plans are first evaluated. The plans which do not comply with the desired reliability level are either modified or discarded. The plans satisfying the reliability constraints must be evaluated on the basis of economics in order to identify the one plan that impacts on the utility in the most favourable way.

In this chapter, a brief description of various reliability indices is presented. The procedure to evaluate the production cost is also discussed briefly.

2.2 POWER SYSTEM RELIABILITY

In order to quantify the reliability of a power system the term 'reliability' must be defined as precisely as possible. The classical definition of reliability is : (5)

> Reliability is the <u>probability</u> of a device or system performing its function <u>adequately</u>, for the <u>period of time</u> intended, under the <u>operating conditions</u> encountered.

Thus reliability is defined through the mathematical concept of <u>probability</u>. This is a fundamental association since uncertainity is a major element in the planning of an electric power system. For example, the random failures of the generating units is the most apparent source of uncertainty in the generating system.

Regarding the generation system, the concept of <u>adequate performance</u> relates to the amount of capacity needed to meet the demand under random failures of the generating units. Regarding transmission system, the term <u>adequate performance</u> relates to the ability of the system to withstand line overloads, to maintain adequate voltage levels within the system stability limits, etc. To obtain a quantitative assessment of system adequacy it is necessary to define suitable reliability criteria or indices which is highly dependent upon the generation mix, unit size, load characteristics and system interconnections. The considera-tion of these aspects together with other less tangible elements in the planning and operation of a power system is usually designated 'generating capacity reliability evaluation'. Also the <u>continuity of service</u> is important aspect for a power system. It is desirable that the supply of electric power is continuous during the period for which the service in wanted.

The operating conditions are also important in determining the reliability of a power system.

It is now clear that the reliability of a power system is the probability of providing the users with continuous service of satisfactory quality. The quality constraint refers to the requirement that the frequency and voltage of the power supply should remain within prescribed tolerances.

2.2.1 Value of Power System Reliability

Different customers may have different sensitivity to the service of the electric power company. Some may require most reliable service, others not. Therefore, a general approach is not applicable to find out the value of reliability. However, the reliability of a power system is usually quantified in terms of the financial losses resulting from an interruption of service. From the customer's point of view the value of reliability is dependent upon expected service requirement and the customer's perception of his losses. From the utility's point of view the determination of the value of reliability due to an interruption of service may be approached by assigning a cost to the loss of revenue from load not served.

The power supply industry should not spend less on reliability than the value of the loss, damage, or inconveniences of supplies and at the same time, it should not spend more. This concept may be depicted in Figure 2.1.

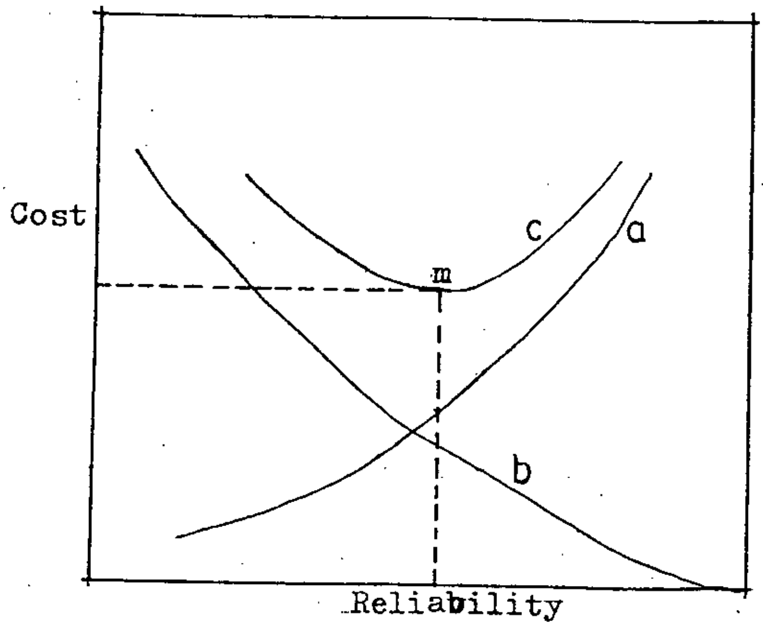


Figure 2.1 : Reliability vs. cost.

In Figure 2.1, curve 'a' is the utility's cost which increases greatly as the reliability (availability of supply) approaches 100%, curve 'b' represents the customer's costs for not getting the power supply. Note that this is clearly zero with 100% reliability. Curve 'c' is a combination of the two. Costs are minimized for the specified reliability at point m.

2.3 RELIABILITY REQUIREMENT IN GENERATION EXPANSION PLANNING

The time span for a power system is devided into two sectors: the planning phase and the operating phase. Accordingly it is customary to divide reliability assessment into two categories: static reliability assessment and spinning reliability assessment. Static reliability assessment applies to planning while spinning reliability assessment applies to operation.

For the assessment of reliability, distribution of forecasted load and the scheduled generation is required, especially for the assessment of static reliability. In the operation of a power system what is mainly required is the ability to operate the system as economically as possible with adequate operating reserve. In the assessment it may be necessary to include one or more of the following factors:

(i) rapid start units such as gas turbines and hydro-plant,

(ii) interruptable loads,

(iii) assistance from interconnected systems,

(iv) voltage and/or frequency reductions.

In what follows some of the terminologies related to static reliability assessment are defined (5,6).

a) Outages and interruptions

An outage describes the state of a component when it is not available to perform its intended function due to some event. A component outage may or may not lead to an interruption of service to consumers depending on system configuration.

An interruption is the loss of service to one or more consumers or other facilities as a result of one or more component outages.

b) Forced outage and Scheduled outage

The forced outage is an outage that results from emergency conditions directly associated with a component, requiring that component be taken out of service immediately either automatically or manually by switching operations. An outage may also be caused by improper operation of equipment or by human error.

The scheduled outage is an outage that results when a component is delibrately taken out of service at a selected time, usually for the purposes of construction, preventive maintenances or repair.

c) Outage Rate

For a particular classification of outage and type of component, the mean number of outages per unit exposure of time per component is called outage rate.

d) Generating Reserve Capacity (R)

Generating reserve capacity, or simply reserve capacity or reserve is defined as the difference between the installed capacity and the peak load during the specified period of time. Thus

$$R = IC - PL \tag{2.1}$$

where

R = Reserve capacity

IC = Installed capacity

PL = Peak load

e) Available Capacity (AC)

The installed capacity minus the outage capacities is called available capacity. Thus the available capacity may be expressed as

$$AC = IC - FOC - SC \tag{2.2}$$

In Equation 2.2 SC represents the scheduled outage capacity. The forced outage capacity (FOC) depends on the random failures of the generating units. This makes AC a random variable.

f) Capacity Reserve Margin (RM)

Capacity reserve margin, or simply reserve margin is defined as the difference between the available capacity and the peak load.

$$RM = AC - PL \tag{2.3}$$

Loss of load will occur when RM is negative. It is clear from Equation (2.3) that if the peak load exceeds that available generation the system will experience loss of load. The quantities IC, AC, PL, FOC, R and RM are shown schematically in Figure 2.2.

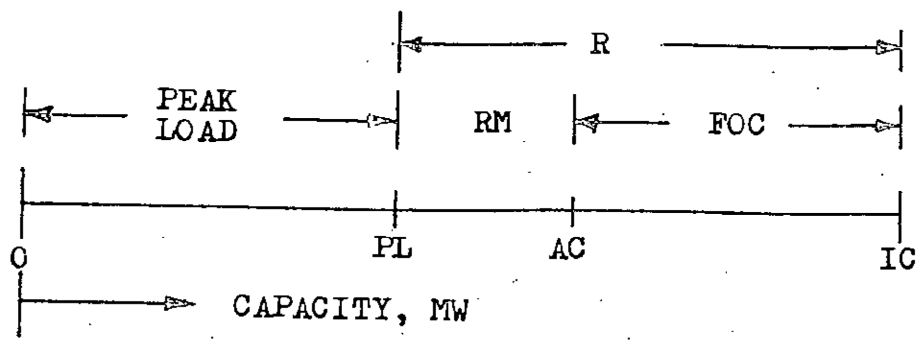


Figure 2.2: Schematic of reliability terms (SC has been neglected).

The terminologies defined above are graphically shown in Figure 2.3.

2.3.1 Major Factors Influencing Reserve Capacity

The major factors influencing reserve capacity and, therefore generating system reliability are:

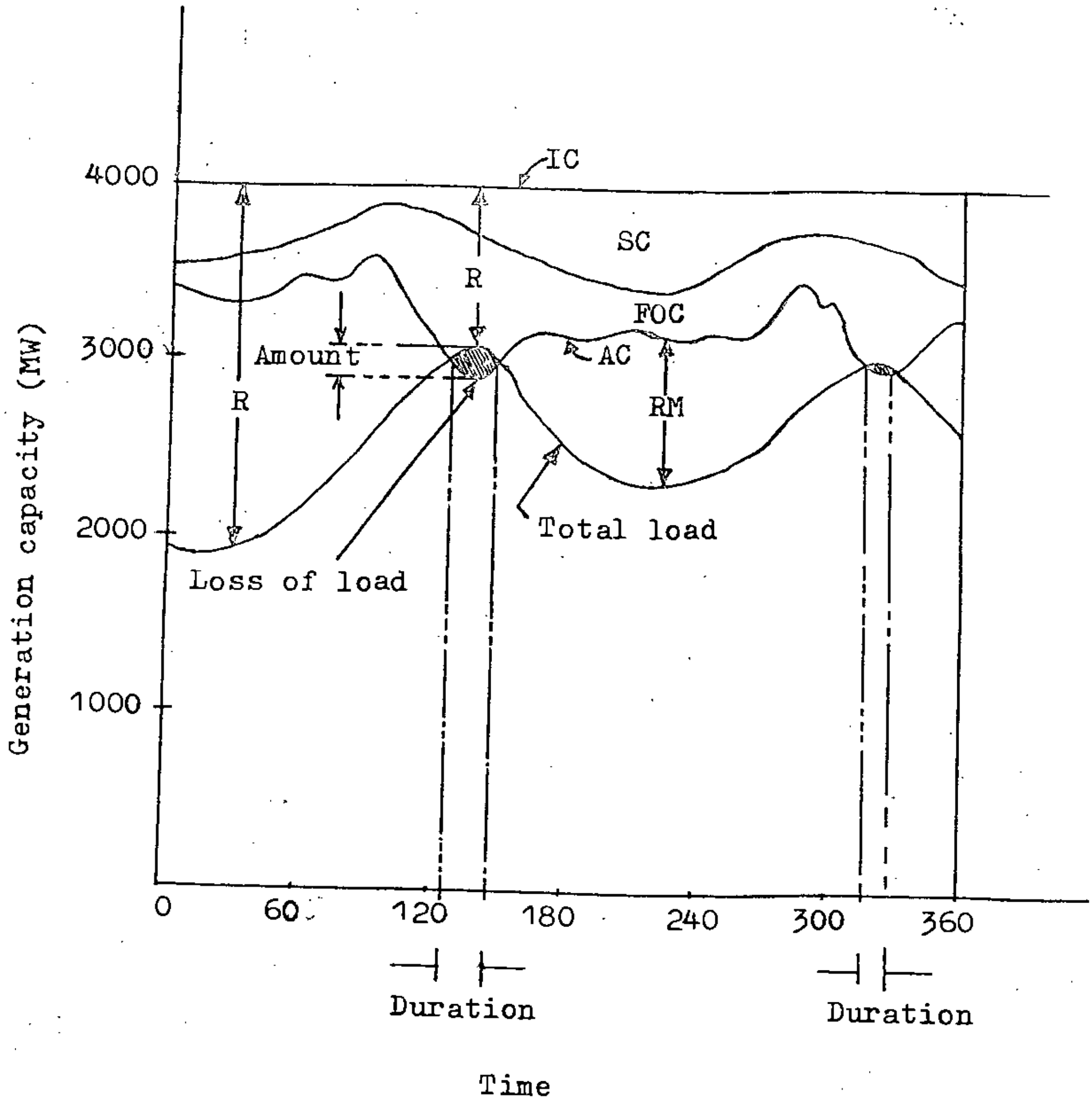


Fig. 2.3 Daily Load variation and Reliability parameters.

i) Unit size

Capacity reserve requirement (CRR) increases as the average unit size increases.

ii) Number of units

CRR increases as the number of unit increases.

iii) System load factor

CRR increases as the system load factor increases.

iv) Delayed capacity additions

CRR increases as delays in planned capacity addition increases.

v) Scheduled and forced outages

CRR is strongly affected by forced outages of generating units as well as by the scheduled outages.

vi) Interconnections with other systems

CRR decreases with addition of interconnections.

vii) Uncertain total energy and peak demand

CRR increases as the degree of uncertainty in future growth in electricity and peak load demand increases.

2.4 RELIABILITY INDICES

Till 1930s, the methods applied in evaluating the power system reliability were all based on deterministic approach. Their essential weakness is that they do not and can not account for the probabilistic or stochastic nature of system behaviour, of customer demands or of component failures. The need for probabilistic evaluation of system has been recognized since at least 1930s. The main reasons for not considering such stochastic nature of the system in the past is the limitation of computational resources. Now, the computing facilities are greatly enhanced and many probabilistic evaluation techniques have been developed. In order to quantify the reliability of power system a number of reliability indices have been deviced. Some of the commonly used indices are described below.

i) Loss of load probability (LOLP)

The loss of load probability is the probability that the available generating capacity of a system will be insufficient to meet its demand. Thus,

$$LOLP = \text{Prob}\,\{AC < L\} \tag{2.4}$$

The evaluation of LOLP can consider forced and scheduled outages of generating units as well as load forecast uncertainty and assistance due to interconnections. LOLP does not give an indication of the magnitude or duration of the generation deficiency. This reliability index only provides the probability of occurance of the loss of load. The LOLP for a system is a realistic indication than the reliability figure for an individual machine operating in the system or even of a section of the entire power system. As LOLP is the simplest and most commonly used reliability index[2,3] it will be used in this thesis.

ii) <u>Loss of energy probability (LOEP)</u>

The ratio of the expected amount of energy not supplied during some long period to the total energy required during the same period is defined as the Loss of Energy Probability. This index reflects the frequency, magnitude and duration of the capacity outage. However, the true loss of energy cannot be accurately computed on the basis of the cumulative load curve. For this reason, the loss-of-energy index is seldom used.

iii) <u>Frequency and duration (FAD)[35]</u>

This gives the average number of times and the average length of time during which available generation is inadequate to supply the load. This requires consideration of the daily load cycle and data on the frequency and duration of unit outages. One problem with the FAD technique is that it requires more detailed data than is usually available. In addition to failure rates of various components, repair times must also be available.

iv) Monte Carlo Simulation (MCS)

In MCS the actual realization of the life process of a component or a system is simulated on the computer and, after having observed the simulated process for some times, estimates are made of the desired reliability indices. Thus the simulation is treated as a series of real experiments. During its course, events are made to occur at times determined by random processes obeying predetermined probability distributions. The method is computationally expensive. However, it may produce a solution in cases where more traditional analytical techniques fail.

In order to evaluate any one of the these reliability indices, the following steps are required:

a) Development of a Generation Model.

b) Development of a Load Model.

c) Combination of these two (convolution) to define the appropriate index of reliability.

Chapter 4 describes the various probabilistic simulation techniques for evaluating LOLP.

2.5 PRODUCTION COSTING

The prediction of the cost of generation is an important aspect of system planning. The cost of generation includes capital and construction costs, the costs of maintenance, the cost of fuel, starting and shutdown costs. The evaluation of financial aspects listed above are large domains of expertise in themselves and there is continuing work in these areas for further sophistications in modeling. In this thesis only the evaluation of the cost of fuel will be considered. The cost of fuel along with the operation and maintenance costs constitute the production costs of a generating system.

The production costs of a particular expansion plan can be accurately determined only if

i) a realistic load model is known for each future week or month in the planning period, and

ii) the units are committed to supply load in a manner that reflects actual operating procedures and conditions.

The load models necessary for probabilistic production cost simulation are derived from the load duration curve (LDC) or directly from the chronological load curve (load model will be discussed in Chapter 3). To obtain a realistic commitment schedule for generating units, it is necessary to include not only the forced outages of a unit but also its scheduled outage for maintenance. The unit with lowest incremental cost is loaded first, then the unit with second lowest incremental cost and so on. This order of loading units which results in a minimum cost of energy production is referred to as the economic commitment schedule (ECS). Units must be convolved into the load distribution in this order if we are attempting to simulate the way units will actually be used if the expansion plan is indeed implemented. As units are convolved into the load distribution, the expected energies generated by each unit are calculated. Multiplying the expected energy generated by a unit with its average incremental fuel cost, the expected cost of energy production by that unit is obtained.

CHAPTER 3

GENERATION AND LOAD MODELS

3.1 INTRODUCTION

The evaluation of LOLP and production costs for generation expansion planning using any method require two basic models; the load model and the generation model. The various models for generation and, those for the system load, differ greatly in their degree of sophistication. The models suitable for incorporation of the probabilistic or stochastic nature of system behaviour are presented in this chapter. Such models are widely used in various probabilistic simulation techniques.

3.2 GENERATION CAPACITY MODEL

Different types of generating units are in use today and all types of units are randomly forced off-line because of technical problems during normal period of operation. To account for the random outage or availability of a unit, it is necessary to determine the probability density function (PDF) that describes the probability that a unit will be forced off-line or will be available during its normal period of operation. It may be assumed on the basis of historical data that the availability of the generating capacity of a given unit may be graphically represented as shown in Figure 3.1. This figure conveys the idea that random failure and repair of a unit can be defined as a two-state <u>stochastic process</u>. A stochastic process is defined as a process that develops in time in a manner controlled by probabilistic laws.

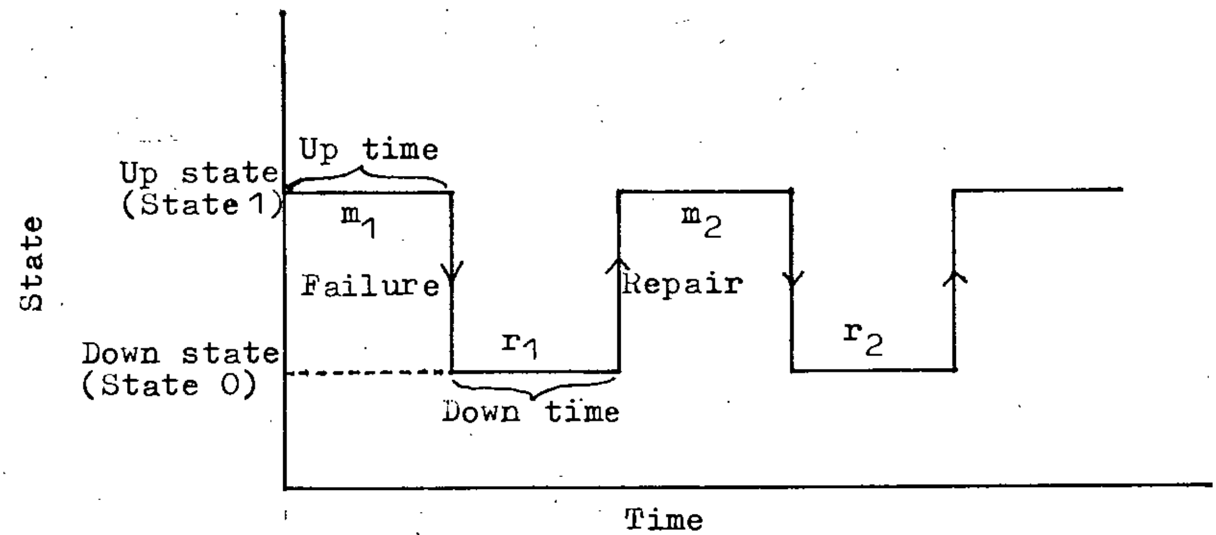


Figure 3.1: Run-fail-repair-run cycle for a generating unit.

The system alternates between an operating state, or, up state, followed by a failed state, or down state, in which repair is effected. For the i-th cycle, let

m_i = UP time

r_i = DOWN time

The random history of a generating unit may be represented in terms of an average (mean) UP time and an average DOWN time as follows:

$$m = \text{mean up time} = \frac{1}{N} \sum_i m_i$$

$$r = \text{mean down time} = \frac{1}{N} \sum_i r_i$$

where N is the total number of run-fail-repair-run cycles. Thus the unit failure rate λ and the repair rate μ may be expressed as

$$\lambda = \text{unit failure rate} = \frac{1}{m} \tag{3.1}$$

$$\mu = \text{unit repair rate} = \frac{1}{r} \tag{3.2}$$

With these two parameters the random failure and repair of a generating unit can be defined as a state-space diagram (two state) as shown in Figure 3.2.

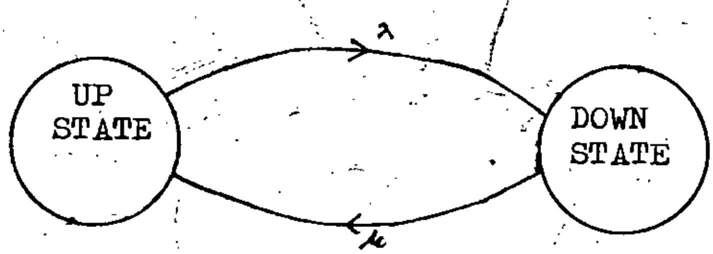


Figure 3.2 : Generating unit state-space diagram.

Two important parameters can be obtained from this model:(36)

1. Unit availability - the long term probability that the unit will be in the, UP state.
2. Unit unavailability - the long term probability that the unit will be in the DOWN state.

To obtain the expressions for long-term availability and unavailability of a generating unit, it is first necessary to recognize that the stochastic process we are considering is a very special one, called a zero-order, discrete state, continuous transition Markov process. Such a stochastic process has the following properties[36]:

1. Mutually exclusive and discrete states, that is, the generating unit can be in either the UP or the DOWN state, but not in both simultaneously.
2. Collectively exhaustive states, that is, since we assume that only possible states for a generating unit are the up and the down states, then these states define all the possible states we ever expect to find a unit in.
3. Changes of state are possible at any time.
4. The probability of departure from a state depends only on the current state and is independent of time.
5. The probability of more than one change of state during a small time interval Δt is negligible.

Let

$P_1(t+\Delta t)$ = Probability that the unit will be in the UP state at time $(t+\Delta t)$ (3.3)

Thus

$$P_1(t+\Delta t) = \begin{bmatrix}\text{Probability of being} \\ \text{in state 1 at time t} \\ \text{and not leaving that} \\ \text{state during interval} \\ \Delta t.\end{bmatrix} + \begin{bmatrix}\text{Probability of} \\ \text{being in state 2} \\ \text{at time t and} \\ \text{moving to state 1} \\ \text{during interval } \Delta t\end{bmatrix} \quad (3.4)$$

Consider that the distribution of a unit failure can be described by the exponential distribution.

$$F_1(t) = e^{-\lambda t} \triangleq \text{Probability of unit being available upto time t} \quad (3.5)$$

Expanding the right hand side of Equation (3.5) into infinite series and neglecting higher order terms, it is obtained as

$$F_1(t) = 1 - \lambda\Delta t + \frac{\lambda^2(\Delta t)^2}{2!} + \dots$$

$$\cong 1 - \lambda\Delta t \triangleq \text{Probability of unit being available during time } \Delta t \quad (3.6)$$

where

$$\lambda\Delta t \triangleq \text{Probability of transferring from state 1 to state 2 in time } \Delta t$$

Again

$$F_2(t) = e^{-\mu t} \triangleq \text{Probability of unit being unavailable upto time t} \quad (3.7)$$

Expanding into an infinite series and neglecting higher order terms, it is obtained as

$$F_2(t) \triangleq 1 - \mu\Delta t \triangleq \text{Probability of unit being unavailable during time } \Delta t \quad (3.8)$$

where

$\mu \Delta t =$ Probability of transferring from state 2 to state 1 in time Δt

Using the definitions of Equations (3.5) to (3.8), Equation (3.4) may be written as

$$P_1(t+\Delta t) = P_1(t)\,[1-\lambda\Delta t] + P_2(t)[\mu\Delta t] \tag{3.9}$$

Similarly,

$$P_2(t+\Delta t) = P_2(t)\,[1-\mu\Delta t] + P_1(t)\,[\lambda\Delta t] \tag{3.10}$$

Rearranging these two Equations, we have

$$\frac{P_1(t+\Delta t)-P_1(t)}{\Delta t} = -\lambda P_1(t)+\mu P_2(t)$$

$$\frac{P_2(t+\quad t)-P_2(t)}{t} = \lambda P_1(t) - \mu P_2(t)$$

Letting $\Delta t \to 0$, the following differential equations are obtained

$$\frac{dP_1}{dt} = -\lambda P_1 + \mu P_2 \tag{3.11}$$

$$\frac{dP_2}{dt} = -\lambda P_1 - \mu P_2 \tag{3.12}$$

with

$$P_1(t) + P_2(t) = 1$$

Equations (3.11) and (3.12) can be written in the matrix form as follows:

$$\begin{bmatrix} \dot{P}_1(t) \\ \dot{P}_2(t) \end{bmatrix} = \begin{bmatrix} P_1(t) & P_2(t) \end{bmatrix} \begin{bmatrix} -\lambda & \lambda \\ \mu & -\mu \end{bmatrix} \qquad (3.13)$$

Solving(6)

$$P_1(t) = \frac{\mu}{\lambda+\mu}\left[P_1(0)+P_2(0)\right] + \frac{e^{-(\lambda+\mu)t}}{\lambda+\mu}\left[\lambda P_1(0)-\mu P_2(0)\right] \qquad (3.14)$$

$$P_2(t) = \frac{\lambda}{\lambda+\mu}\left[P_1(0)+P_2(0)\right] + \frac{e^{-(\lambda+\mu)t}}{\lambda+\mu}\left[\mu P_2(0)-\lambda P_1(0)\right] \qquad (3.15)$$

where $P_1(0)$ and $P_2(0)$ represent initial states (conditions) such that

$$P_1(0) + P_2(0) = 1$$

Consider that at $t = 0$ the generating unit is in the UP state, i.e, state 1.

$$\therefore\ P_1(0) = 1 \quad \text{and} \quad P_2(0) = 0$$

$$\therefore\ P_1(t) = \frac{\mu}{\lambda+\mu} + \frac{\lambda e^{-(\lambda+\mu)t}}{\lambda+\mu} \qquad (3.16)$$

$$P_2(t) = \frac{\lambda}{\lambda+\mu} - \frac{\lambda e^{-(\lambda+\mu)t}}{\lambda+\mu} \qquad (3.17)$$

In generation expansion planning long-term (steady-state) probabilities are required. Hence, letting $t \to \infty$, Equations (3.16) and (3.17) are obtained as

$$P_1(\infty) = \frac{\mu}{\lambda + \mu}$$

$$P_2(\infty) = \frac{\lambda}{\lambda + \mu}$$

Thus the long-term probabilities of unit availability and unavailability are given by:

$$\text{Prob}\,\{\text{Up state}\} = p = \frac{\mu}{\lambda + \mu} = \frac{m}{m+r} \tag{3.18}$$

$$\text{Prob}\,\{\text{DOWN state}\} = q = \frac{\lambda}{\lambda + \mu} = \frac{r}{m+r} \tag{3.19}$$

so that

$$p + q = 1 \tag{3.20}$$

The traditional term for the unit unavailability is 'forced outage rate' (FOR), a misnomer in fact, since the concept is not a rate. An estimate for this important parameter may be given by

$$\text{FOR} = \frac{\text{forced outage hours}}{\text{forced outage hours + service hours}}$$

or,
$$\text{FOR} = \frac{\text{FOH}}{\text{FOH + SH}} \tag{3.21}$$

The usual method of accounting for partial outages is to increase the forced outage hours by an appropriate amount of time called 'equivalent force outage hours'(EFOH). This duration is obtained if the actual partial outage hours are multiplied by the corresponding fractional capacity reduction and these products are then totalled. Considering a single occurrence, for example, a unit operating at 60% capacity for 80 hours will have an equivalent forced outage duration of 80(0.4) = 32 hours. Based on this approach, an estimate of 'equivalent forced outage rate' (EFOR) may be defined as

$$EFOR = \frac{FOH + EFOH}{FOH + SH} \tag{3.22}$$

where the service hours (SH) include the actual partial outage times as well.

3.2.1 Probability Density Function of Available and Outage Capacity

For a generating unit of capacity C MW, FOR = q and availability p, the probability density functions (PDF) of available and forced outage capacity are given in Figure 3.3.

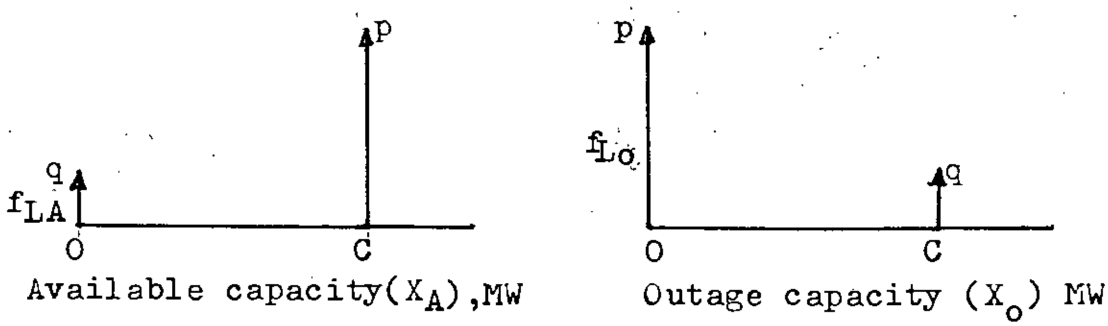


Figure 3.3: PDFs of available and forced outage capacity.

The PDF of forced outage capacity may be conventionally expressed as

$$f_{Lo}(X_o) = p\,\delta(X_o) + q\,\delta(X_o - C) \qquad (3.23)$$

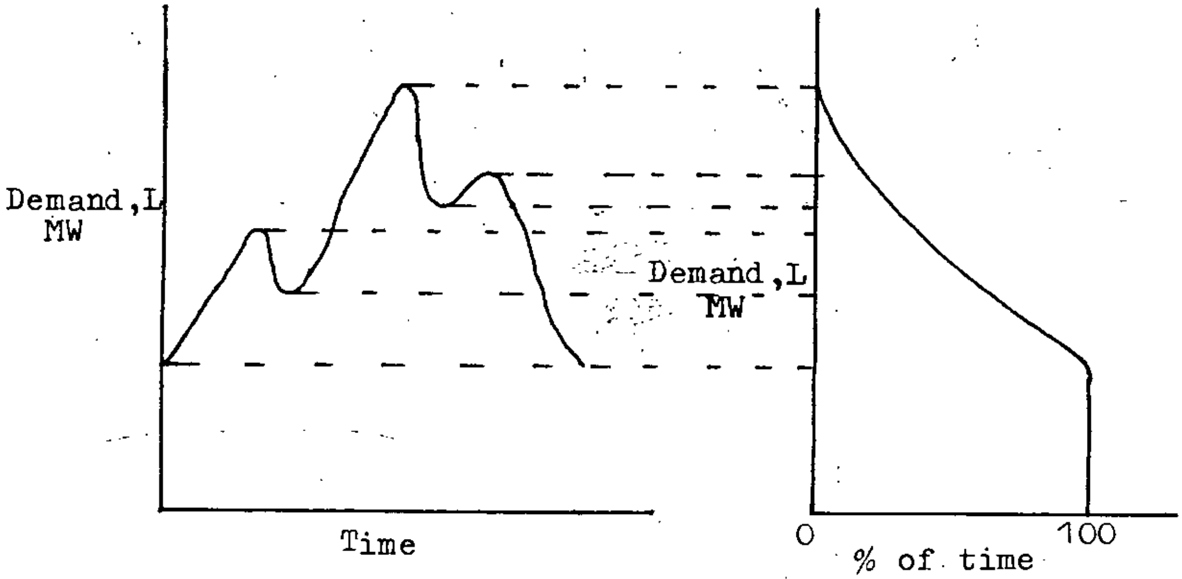
where

f_{Lo} = PDF of forced outage capacity

$\delta(.)$ = Dirac-delta function

3.3 PROBABILISTIC LOAD MODELS

Proper modelling of load is an important factor in the evaluation of LOLP and production cost. The probabilistic load model which is widely used describes the probability that load will exceed a certain value. The data required to develop such a model are readily available, since continuous readings of system demand and energy are usually obtained on a routine basis by electric utilities. If a recording of instantaneous demands were plotted for a particular period of time, a curve such as depicted in Figure 3.4(a) might result. This is known as the 'Chronological Load Curve' (CLC). From this curve the so called 'Load Duration Curve' (LDC) in Figure 3.4(b) is easily constructed. The load duration curve is created by determining what percentage of time the demand exceeded a particular level.



(a) Instantaneous demand vs. time (b) Load duration curve

Figure 3.4: Chronological load curve and load duration curve.

3.3.1 Load Probability Distribution

For generation system studies it is necessary to interchange the axis parameters in Fig. 3.4(b) and nomilize time, producing 'load probability distribution' in Figure 3.5. This curve is also called 'inverted load duration curve'. This load distribution will be denoted generally by $F_k(l)$, where k indicates the time period for which the distribution is applicable.

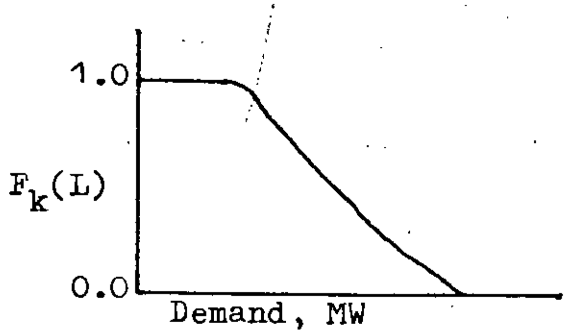


Figure 3.5: Load probability distribution for week k.

3.3.2 Hourly Load

Another load model which is often used in various probability methods for evaluating LOLP and production cost is the hourly load. It is derived from the chronological load curve (CLC). Figure 3.6 shows a CLC, the time axis being divided into a number of small intervals between times $t_o, t_1, t_2, \ldots\ t_{r-1}, t_r, \ldots\ t_{n-1}, t_n$.

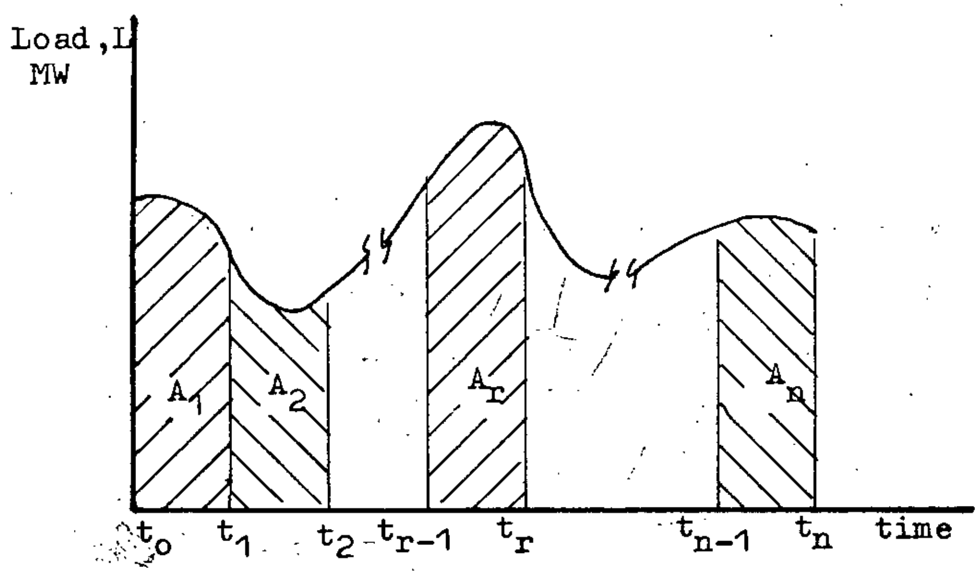


Figure 3.6: CLC with time axis divided into n small intervals.

In Figure 3.6, the energy demand during the period between t_{r-1} and t_r is given by the area A_r under the CLC between t_{r-1} and t_r. Hence

$$A_r = \int_{t_{r-1}}^{t_r} L\,dt \tag{3.24}$$

Dividing this area by the period of time $(t_r - t_{r-1})$, the average load during that period is obtained. Thus

$$L^r_{avg.} = \frac{A_r}{t_r - t_{r-1}} \qquad (3.25)$$

In this way the average load for all other time intervals are obtained. If the average load for each time interval is assumed to remain constant for the corresponding interval, then a distribution of load as shown in Figure 3.7 will result. Note that by such construction of load curve, the energy demand for each interval remains unchanged.

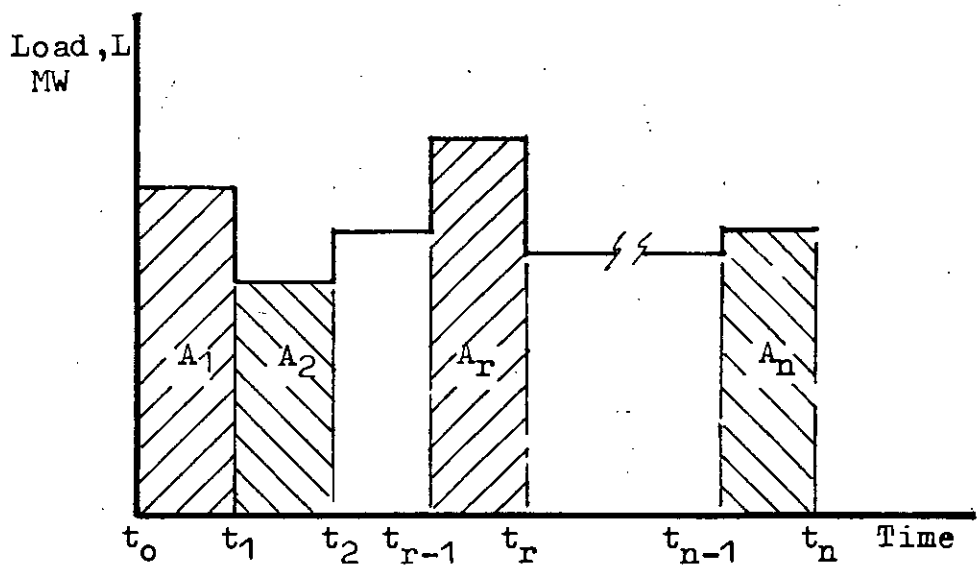


Figure 3.7: Load distribution assuming constant load for each small interval.

If each of the time intervals into which the time axis is divided equals to one hour then the resulting distribution is called 'hourly load curve'.

3.3.3 Equivalent Load

The randomness in the availability of generation capacity is taken into consideration by defining a fictitious load, known as 'equivalent load'(Le)[36]. Figure 3.8 depicts the relationship between the system load and generating units, where actual units have been replaced by fictitious perfectly reliable (100% reliable) units and fictitious random loads; whose probability density functions are the outage capacity density functions of the units.

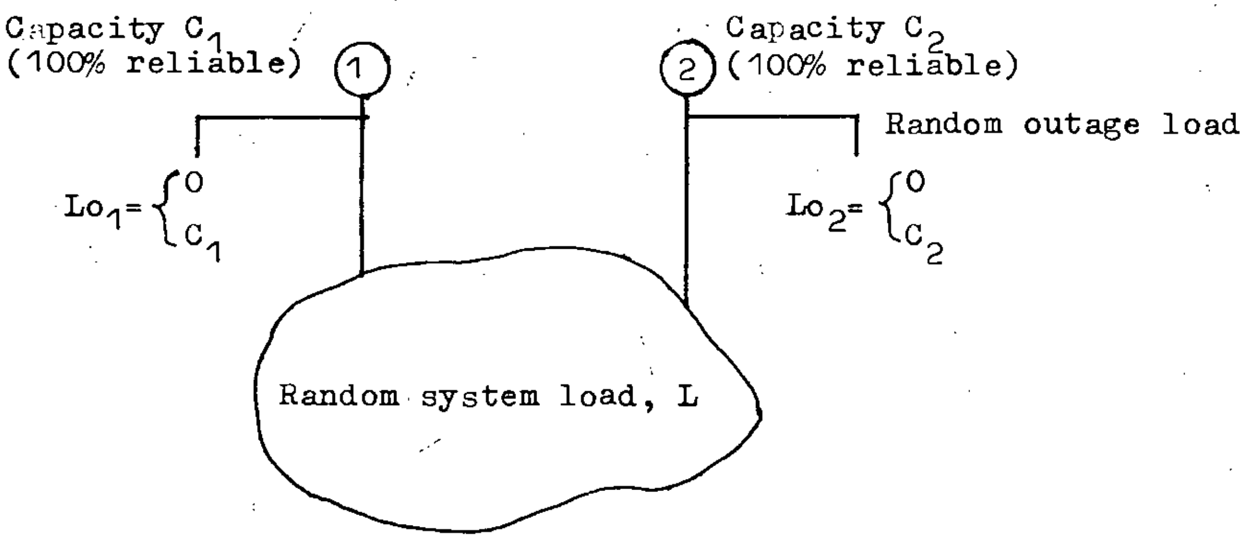


Figure 3.8: Fictitious generating units and system load model.

If Lo_i represents the random outage load corresponding to the i-th unit, the equivalent load (Le) may be expressed as

$$Le = L + \sum_{n=1}^{n} Lo_i \tag{3.26}$$

where n is the total number generating units. When $Lo_i = C_i$, the net demand injected into the system is zero for the i-th unit, just as it would be if the actual unit of capacity C_i were forced off-line. Note that the installed capacity of the system is given by

$$IC = \sum_{i=1}^{n} C_i \tag{3.27}$$

The outages of the generating units may be assumed independent of the system load. Then the distribution of the equivalent load will be the outcome of convolution of two distributions: f_{Lo} and f_L representing the PDFs of the outage capacity and the system load, respectively. For the discrete case the PDFs, f_L and f_{Lo}, respectively, may be written as

$$f_L(l) = \sum_i P_{L_i}\,\delta(l-l_i) \tag{3.28}$$

$$f_{Lo}(l_o) = \sum_j P_{Lo_j}\,\delta(lo-lo_j) \tag{3.29}$$

Then the PDF of equivalent load f_{Le} may be given as

$$f_{Le}(le) = f_L(l) * f_{Lo}(lo)$$

$$= \sum_{i,j} P_{L_i}\,P_{Lo_j}\,\delta(le-(l_i+lo_j)) \tag{3.30}$$

where * indicates the convolution and P_L and P_{Lo} are the probabilities of load and outages of machine, respectively. The small case letters within bracket of Equation (3.30) are the values of the corresponding random variables (RVs).

Recall that LOLP has been defined in terms of random terms ~~of random~~ system load (L) and available capacity (AC) by Equation (2.4). LOLP can also be expressed in terms of equivalent load (Le) as

$$\text{LOLP} = \text{Prob.}\left\{ \text{Le} > \text{IC} \right\} \tag{3.31}$$

CHAPTER 4

PROBABILISTIC SIMULATION TECHNIQUES

4.1 INTRODUCTION

Probabilistic simulation may be defined as a method for obtaining the expected energy generation, loss of load probability (LOLP) and production cost of a system of generating units meeting a demand by taking into consideration the random nature of generation and demand[37]. Probabilistic simulation method finds wide use throughout the power industry as a useful tool in generation expansion planning. Since the introduction of this method a number of different techniques have been developed with an ultimate target to improve its computational efficiency and flexibility. The probabilistic techniques that have been developed can be classified into two categories, exact and approximate.

This chapter presents a brief description of the techniques of probabilistic simulation. Before describing these techniques, the economic commitment procedure of the generating units is discussed briefly.

4.2 ECONOMIC COMMITMENT PROCEDURE

The generating unit with lowest incremental cost should be committed first. But it is seldom economical to commit one unit completely before calling on another. To simulate these facts the generating unit capacities are segmented into several capacity blocks. The reason for segmenting the unit capacities is the basic shape of the heat rate (HR) curve. A typical HR curve is shown in Figure 4.1. Clearly on this curve the second segment corresponds to higher efficiency, since fewer Btus are required for each MWh of energy produced. In Economic Commitment Schedule (ECS), the segments with lowest incremental cost are committed first. But lower capacity blocks of any unit should be committed before any higher block.

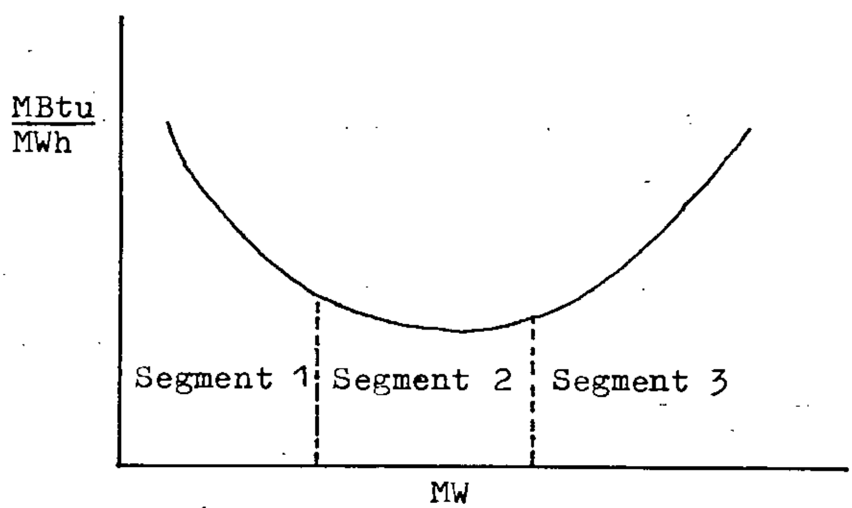


Figure 4.1: Typical heat rate curve.

From the basic HR curve of Figure 4.1 the input/output (I/O) curve can be obtained by multiplying every y-axis value by its corresponding x-axis value. A typical I/O curve is depicted in Figure 4.2. Differentiating the I/O curve, the incremental heat rate or simply IHR curve is obtained as shown in Figure 4.3. The IHR curve is used for calculating the incremental fuel costs of the generating units.

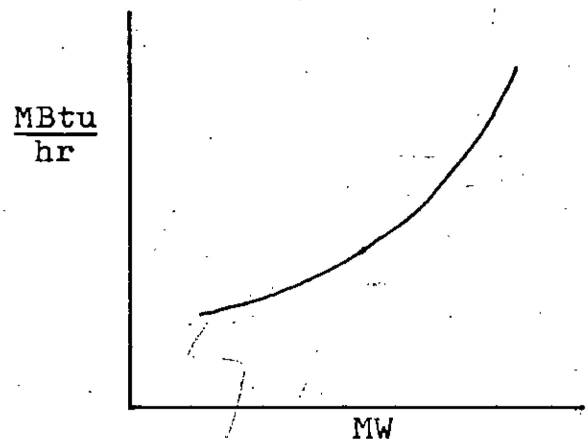


Figure 4.2: Typical input/output curve.

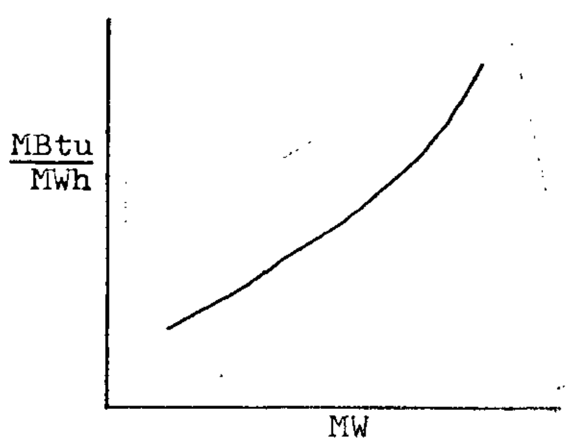


Figure 4.3: Typical incremental heat rate curve.

To quantity these relations, we have for the k-th unit (or segment)

$$I/O_k = L\ HR(L) \tag{4.1}$$

$$IHR_k(L) = \frac{d\ I/O_k}{dL} \tag{4.2}$$

In the special case when HR curve is assumed to be constant, $HR_k(L) = HR_k$, then

$$IHR_k(L) = HR_k \frac{dL}{dL} = HR_k \tag{4.3}$$

This special case is important, because in economic analysis the assumption that $HR_k(L)$ is constant makes computation simpler. For the k-th unit (or segment)

$$IFC_k = \frac{IHR(L) \times UFC_k}{HV_k} \tag{4.4}$$

where IFC_k = Incremental fuel cost for k-th unit (Tk./MWh)

UFC_k = Unit fuel cost for k-th unit (Tk./bbl or Tk./ton)

HV_k = Heat value for k-th unit (MBtu/bbl. or MBtu/ton)

If $HR_k(L)$ is constant then, for the k-th unit (or segment)

$$IFC_k = \frac{HR_k \times UFC_k}{HV_k} \tag{4.5}$$

4.3 EXACT TECHNIQUES OF PROBABILISTIC SIMULATION

Two exact techniques for probabilistic simulation have so far been developed: one is the 'Baleriaux-Booth' technique more commonly known as the 'recursive' method and the other is the 'segmentation' method.

4.3.1 Baleriaux-Booth Technique

The starting point of this method is the load probability distribution, F(L) and the generation system with the associated FOR of each unit. The probability distribution of equivalent load, F(Le), is obtained by convolving F(L) and the PDF of machine outages using Equation (3.30). In F(Le), the MW axis represents a fictitious load called 'equivalent load'. The units are convolved into F(L) in their economic merit order of loading in order to simulate the way units are actually loaded in a practical system. In a n unit system, when r units are convolved, the probability distribution of equivalent load is represented as $F^r(Le)$ and is shown in Figure 4.4. In this figure, PL denotes peak load.

The expected energy generation (E_{r+1}) by the (r+1)-th unit, assuming single block for each unit, is represented by the area it occupies under $F^r(Le)$ given as

$$E_{r+1} = T\, p_{r+1} \int_{k_1}^{k_2} F^r(Le)\, dLe \qquad (4.6)$$

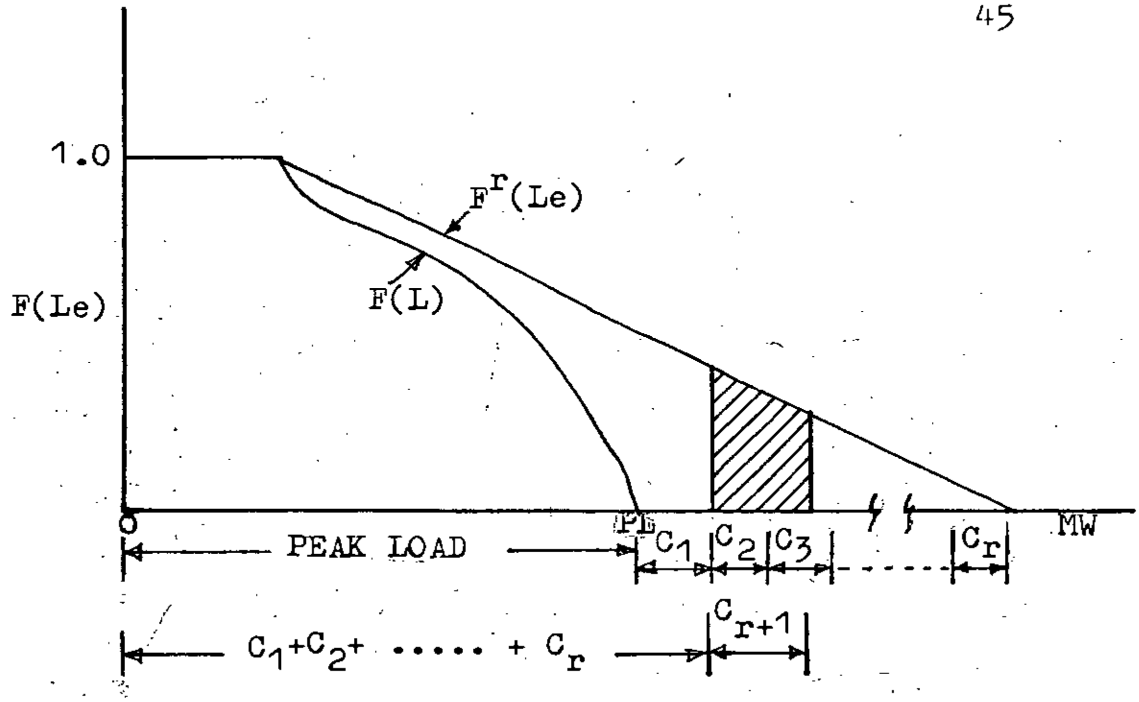


Figure 4.4: F(L) and $F^r(Le)$.

where T = period of hours considered,

p_{r+1} = availability of capacity C_{r+1} of the (r+1)-th unit

$= (1 - FOR_{r+1})$

$$k_1 = \sum_{i=1}^{r} C_i \text{ and } k_2 = \sum_{i=1}^{r+1} C_i$$

The cost of energy produced by the (r+1)-th unit, assuming single block for each unit, is obtained by multiplying E_{r+1} by its average incremental fuel cost.

When all the n units are convolved, the final equivalent load probability distribution $F^n(Le)$ is shown in Figure 4.5. In this figure IC denotes installed capacity and is given by

$$IC = \sum_{i=1}^{n} C_i \qquad (4.7)$$

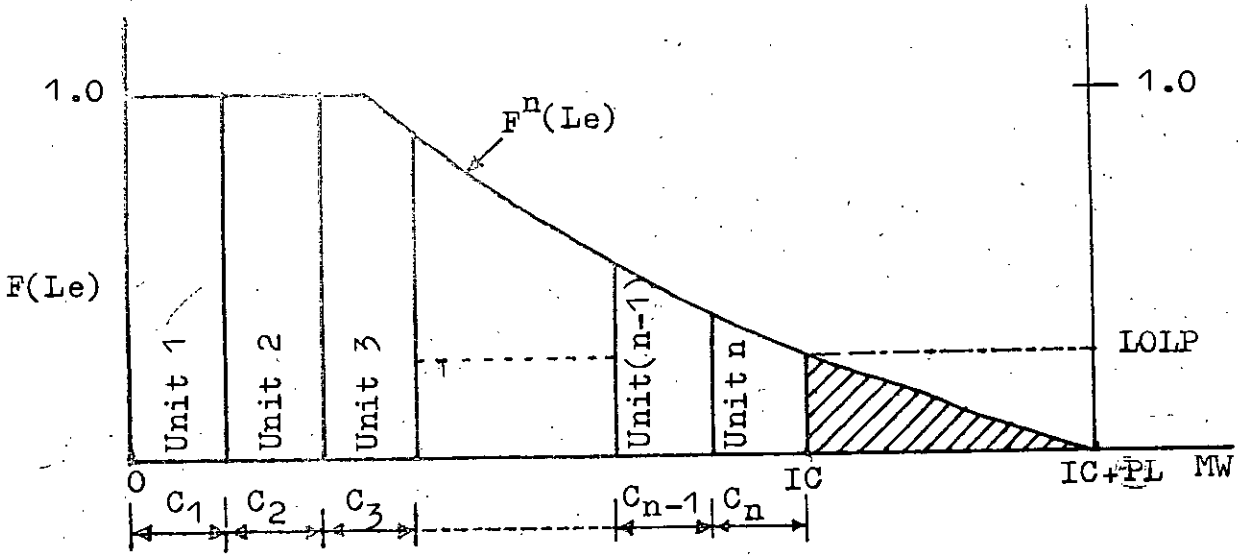


Figure 4.5: Final load probability distribution, $F^n(Le)$.

The loss of load probability is simply the probability obtained from the curve $F^n(Le)$ at the point corresponding to IC. The expected demand not served is obtained from the area under $F^n(Le)$ between the ordinates at IC and (IC+PL). This area is shown hatched in Figure 4.5 and is given by

$$\epsilon(DNS) = \int_{IC}^{IC+PL} F^n(Le)\ dLe \tag{4.8}$$

Hence, the expected energy not served is given by

$$\epsilon(ENS) = T \int_{IC}^{IC+PL} F^n(Le)\ dLe \tag{4.9}$$

This technique is also capable of incorporating the multiblock loading of generating units. The capacity blocks of a unit may occupy non-adjacent positions in the merit order of loading. The basic consideration in the simulation of multiblock loading is that an upper block of a unit cannot be loaded unless the corresponding lower blocks have been already loaded. In order to correctly carry out the probilistic simulation procedure, lower blocks must be deconvolved before the joint lower and upper blocks are convolved.

4.3.2 Segmentation Method

The segmentation method is an exact and computationally efficient method. It provides accurate results as compared to the Baleriaux-Booth method on LOLP and production cost, and simultaneously, is computationally very efficient[32,33,34].

This technique is based on obtaining the probability density function (PDF) of demand by sampling the daily chronological demand curve every hour or any other suitable interval. The demand is subdivided into equal capacity segments where capacity of each segment is equal to a common factor of capacity of all units and/or the capacity of the smallest unit, and the zeroeth and first order moments of each segment is obtained. As generating units are convolved in a merit order of loading, the zeroeth and first order moments for each segment are re-evaluated. From the first and zeroeth moments of the expected unserved demand after each convolution, the unserved energy is calculated. The expected energy generated by a unit k is the difference of unserved energies (UE) before and after loading unit k as:

$$E_k = UE_{k^-} - UE_k \qquad (4.10)$$

where E_k = Expected energy generation of the k-th unit,

$UE_{\bar{k}}$ = Unserved energy before convolving the k-th unit,

UE_k = Unserved energy after convolving the k-th unit.

LOLP of the system is the probability of the zeroeth moment of the last segment after convolving all units.

The segmentation method for evaluating LOLP and production cost of both single area system as well as two area interconnected systems will be discussed in detail in Chapter 6 and Chapter 7 respectively.

4.4 APPROXIMATE TECHNIQUES OF PROBABILISTIC SIMULATION

All the approximate techniques developed so far are based on the Gram-Charlier series expansion. These approximate techniques are much faster than the conventional Booth-Baleriaux technique; but the accuracy of the results in computing expected energy generation is highly system dependent (No. of units, FOR, size of units, load shape). Only one of approximate techniques, commonly known as 'cumulant method' is described here.

4.4.1 Cumulant Method

The 'cumulant method', also called the 'method of moments' approximates the discrete distribution of load (equivalent load) through Gram-Charlier series expansion as a continuous function. The convolution of generating unit outages with the LDC is performed in the merit order of loading. However, this convolution is obtained by a very fast method called the moment method. Also, the energy calculation, that is the area under the convolution curve, is not obtained by a numerical integration but is obtained from the normal probability table built into the program.

A successive convolution f(z) of several density functions can be expressed by the Gram Charlier series(27)

$$f(z) = N(z) - G_1 N^{(3)}(z)/3! + G_2 N^{(4)}(z)/4!$$
$$- G_3 N^{(5)}(z)/5! + (G_4 + 10G_1^2) N^{(6)}(z)/6! \qquad (4.11)$$

where the normal PDF N(z) and its derivatives are given by

$$N(z) = \frac{1}{\sqrt{2\pi}} \exp(-z^2/2) \qquad (4.12)$$

$$N^r(z) = \frac{d^r}{dz^r} N(z); \quad r = 1,2,\ldots. \qquad (4.13)$$

The normal PDF and its derivative are related by the recursive relations

$$N^{(1)}(z) = -zN(z) \qquad (4.14)$$

$$N^{(2)}(z) = (z^2-1)\, N(z) \qquad (4.15)$$

and $$N^r(z) = -(r-1)N^{(r-2)}(z) - ZN^{(r-1)}(z); r=3,4,.. \qquad (4.16)$$

Using these recursive relations, Equation (4.11) can be expressed in terms of N(z) and powers of z, the normalized variable, normalized capacity in MW in this case. In Equation (4.11), G_1, G_2, ... etc. are expansion factors expressed in terms of the moments of individual distributions. The n-th moment, m_n, of any PDF p(x) is defined as

$$m_n = \int_{-\infty}^{\infty} x^n \, p(x) \, dx \tag{4.17}$$

To obtain the expansion in (4.11) from the data of machines and their FOR and the LDC, six moments about the origin (n = 1 to 6) for the normalized LDC (f(x)) are calculated as

$$m_{nL} = \frac{1}{A} \int_{0}^{PL} x^n \, f(x) \, dx \tag{4.18}$$

where A = Area under the LDC

PL = Peak load

Let us consider a two-state representation of the generating units as described in Section 3.2. For the i-th machine in a system, the failure PDF consists of just two impulses, one of magnitude p_i at 0 MW and one of magnitude q_i(FOR) at C_i MW and $p_i+q_i = 1$. The moments (about the origin) of such two-state failure PDF are given by

$$m_n(i) = C_i^n \, q_i \, ; \; n = 1,2,\ldots \tag{4.19}$$

At any stage where r machines are convolved with the LDC, for each machine (1 to r), the following six moments about the origin are calculated using Equation (4.19)

$$m_1(i) = C_i \; q_i \tag{4.20}$$

$$m_2(i) = C_i^2 \; q_i \tag{4.21}$$

$$m_3(i) = C_i^3 \; q_i \tag{4.22}$$

and $m_4(i)$, $m_5(i)$, $m_6(i)$ similarly.

For each of the r machines the central moments (moments about the mean) are calculated using the following relations.

$$M_2(i) = V_i^2 = m_2(i) - m_1^2(i) \tag{4.23}$$

$$M_3(i) = m_3(i) - 3\, m_1(i)\, m_2(i) + 2\, m_1^3(i) \tag{4.24}$$

$$M_4(i) = m_4(i) - 4\, m_1(i)\, m_3(i) + 6 m_1^2(i) m_2(i) - 3\, m_1^4(i) \tag{4.25}$$

$$M_5(i) = m_5(i) - 5 m_4(i)\, m_1(i) + 10 m_3(i) m_1^2(i) - 10\, m_2(i) m_1^3(i) + 4\, m_1^5(i) \tag{4.26}$$

$$M_6(i) = m_6(i) - 6\, m_5(i)\, m_1(i) + 15\, m_4(i) m_1^2(i) - 20 m_3(i) m_1^3(i) + 15 m_2(i) m_1^4(i) - 5 m_1^6(i) \tag{4.27}$$

For each of the r machines the cumulants are calculated using the following expressions.

$$K_1(i) = m_1(i) \tag{4.28}$$

$$K_2(i) = M_2(i) = V_i^2 \tag{4.29}$$

$$K_3(i) = M_3(i) \tag{4.30}$$

$$K_4(i) = M_4(i) - 3\, M_2^2(i) \tag{4.31}$$

$$K_5(i) = M_5(i) - 10\, M_3(i)\, M_2(i) \tag{4.32}$$

$$K_6(i) = M_6(i) - 15\, M_4(i)\, M_2(i) - 10\, M_3^2(i) + 30\, M_2^3(i) \tag{4.33}$$

From the six moments of LDC obtained from Equation (4.18), the central moments for the normalized LDC $M_2(L)$ or V_L^2, $M_3(L)$, $M_4(L)$, $M_5(L)$ and $M_6(L)$ are calculated as indicated by Equations (4.23) to (4.27) by using moments of LDC instead of machine moments. Then the cumulants for the normalized LDC are calculated as indicated by Equations (4.28) to (4.33).

For the complete system of r units and the LDC, the cumulants of equivalent load are calculated using the following relation.

$$K_k(EL_r) = K_k(L) + \sum_{i=1}^{r} K_k(i), \quad i = 1,2,3 \ldots \tag{4.34}$$

where $K_k(EL_r)$ = k-th cumulant of equivalent load curve when r units have been convolved.

$K_k(L)$ = k-th cumulant of LDC.

$K_k(i)$ = k-th cumulant of the ith generating unit.

Note that the first cumulant of equivalent load curve is the mean (M) and the second cumulant is the square of standard deviation (V^2) of the distribution.

The G-coefficients are now calculated by

$$G_i = K_{(i+2)}(EL_r)/V^{i+2} \; ; \; i = 1,2,3,... \qquad (4.35)$$

The values upto Equation (4.33) are considered to be fundamental parameters and are stored. Convolution of additional machines will mean that each time Equations (4.34) and (4.35) are to be computed. This is done by keeping a running total of the quantities represented by these equations and by adding corresponding incremental quantities due to the addition (convolution) of each machine.

Having obtained the G-coefficients as outlined above, the Gram Charlier series describing the convolution of LDC with the machine outages is obtained. Now, the area 'a' under the equivalent load curve between values z_1 and z_2 may be calculated as

$$a = \int_{z_1}^{\infty} f(z)dx - \int_{z_2}^{\infty} f(z)\,dz \qquad (4.36)$$

where $f(z)$ = Equivalent load distribution

z_i = Standardized random variables (RVs)

$$= (X_i - M_i)/V_i \qquad (4.37)$$

in which X_i is any capacity (MW), and M_i and V_i are the mean and standard deviation of the equivalent load distribution.

The integral in equation (4.37) is calculated as follows

$$I = \int_{z_i}^{\infty} f(z)dz = \int_{z_i}^{\infty} N(z)\, dz + F(z_i) \qquad (4.38)$$

where $F(z_i) = G_1N^{(2)}(z_i)/3! - G_2N^{(3)}(z_i)/4!$

$$+ G_3N^{(4)}(z_i)/5! - (G_4+10G_1^2)N^{(5)}(z_i)/5! \qquad (4.39)$$

Equation (4.38) consists of areas under the normal probability density function and factor $F(z_i)$ which can be readily calculated. By building a normal table of areas in the program, a numerical integration is avoided.

The expected energy generation of a particular unit is obtained by multiplying the area under the equivalent load curve between the appropriate limits by the availability of the unit and the time period.

LOLP of the system is the value of the ordinate of the final equivalent load distribution (after convolving all the machines in the system) at the installed capacity.

CHAPTER 5

INTERCONNECTED SYSTEMS

5.1 INTRODUCTION

Interconnections between systems (power companies/utilities) is an effective means of improving the system reliability as well as decreasing the production cost. The simplest way to evaluate interconnected systems would be to consider them as a single system where the number of generating units is the sum of the units in the constituent systems, and the load is the total of the loads in these systems. There are reasons, however, for keeping the identifies of the constituent systems separate and evaluating their reliabilities and production costs individually. The reasons are the following:[5,6]

(i) A utility is primarily interested in the benefits that its own system can obtain from interconnections.

(ii) The ties forming the interconnections are usually limited in capacity and, in addition, are subjected to failures.

(iii) The load characteristics in the various interconnected systems may be different and in addition the loads of interconnected systems may be independent or dependent on each other.

These features can not be accounted for if the entire interconnected system is considered as a single system. Also, single system treatment can not accommodate the correlation between the loads.

5.2 BENEFITS OF INTERCONNECTION

The rationale of interconnections between power systems is well understood. Subject to the capacities of the tie line between such connected systems and to possible contractual limitations, a participating system will be able to receive additional generation from the others should its own generation be unable to meet the demand. It may happen, of course, that all the connected systems are experiencing loss of load due to low available generation at the same time; however, on many occations assistance will be available because of

(i) time-zone differences,

(ii) the diversity of loads and unit failures

As a result, the reliability of the global system as well as the individual systems will improve and so the production cost. To achieve a certain level of reliability, less reserve capacity is required if assistance from interconnected systems can be relied upon. The benefits in installed capacity due to interconnection are mainly dependant on

(i) the tie line capacity,

(ii) the type of agreement between the two systems.

The cost of energy production in one system may be much higher than the other. Interconnection between the systems allows transport of cheaper electrical energy to the system in which energy production cost is higher. The benefits of interconnection may be summarized as follows:

(i) increased reliability,

(ii) less reserve capacity requirement for a certain level of reliability,

(iii) lower cost of energy production.

5.3 TWO INTERCONNECTED SYSTEMS

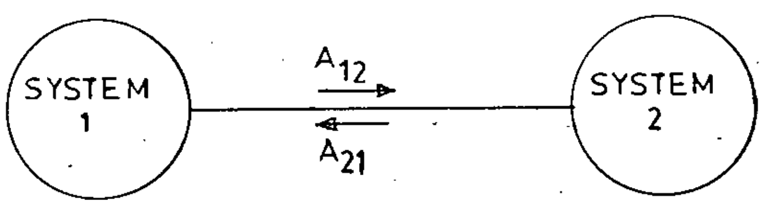


Figure 5.1: Two area interconnected system.

Let us consider the two-area system as depicted in Figure 5.1. Let

T_{12} = transfer limit of tie line from 1 to 2

T_{21} = transfer limit of tie line from 2 to 1

Operating Policy

Reserves are transferred only upto the limit of the tie line or reserve margin, whichever is minimum.

Let the possible assistance be, therefore,

$$\begin{aligned} A_{12} &= \min\,(RM_1,\ T_{12}) \\ A_{21} &= \min\,(RM_2,\ T_{21}) \end{aligned} \tag{5.1}$$

where,

A_{12} = Assistance from system 1 to system 2

A_{21} = Assistance from system 2 to system 1

RM_1 and RM_2 are the reserve margins in system 1 and 2 respectively.

For system 1 being assisted by system 2, the relevant quantities may be schematically shown in Figure 5.2.

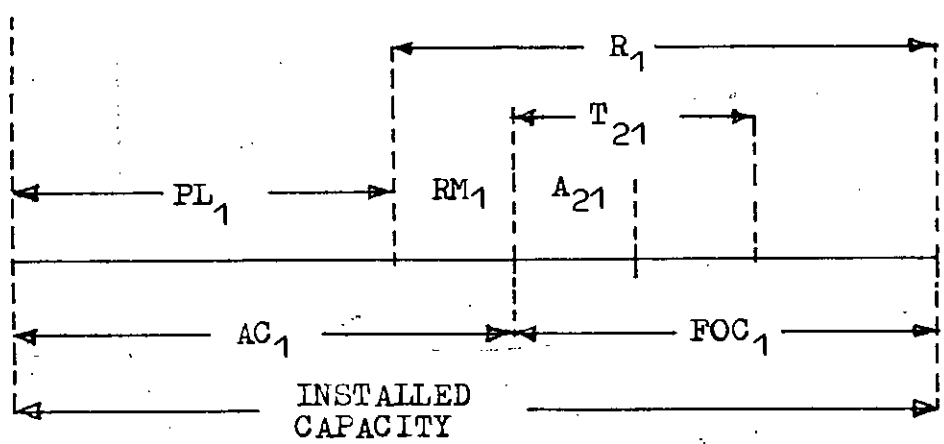


Figure 5.2: Schematic representation of assistance and relating quantities

To study the effect of interconnection on the loss of load probability (LOLP), the capacity outage tables for each system are first constructed. Note that a capacity outage table is a table expressing the probability that various amounts of generating capacity will be unavailable. The table is usually given in terms of exact and cumulative probabilities. The outage tables for the two systems are combined to form an array containing the probabilities of various capacity levels in the two systems. The procedure is explained in detail in the next section.

5.3.1 Effects of Interconnection on LOLP

To study the effects of interconnection on LOLPs, an example is considered in what follows. The generation data of two systems in given in Table 5.1.

Table 5.1: Generating system description

System	No. of units	Unit capacity MW	FOR	Peak load MW	Total capacity MW
1	2	10	0.20	30	50
	1	30	0.10		
2	2	15	0.10	40	55
	1	25	0.30		

Tie line capacity : $T_{12} = T_{21} = 10$ MW

Reserve capacity in system 1 : $R_1 = 50 - 30 = 20$ MW

Reserve capacity in system 2 : $R_2 = 55 - 40 = 15$ MW

The capacity outage probability tables (exact probabilities) are given in Table 5.2.

Table 5.2: Capacity outage tables

Capacity on outage MW	Exact probabilities	
	System 1	System 2
0	0.576	0.567
5	-	-
10	0.288	-
15	-	0.126
20	0.036	-
25	-	0.243
30	0.064	0.007
35	-	-
40	0.032	0.054
45	-	-
50	0.004	-
55	-	0.003

By multiplying the exact probabilities in both systems a two dimensional array showing the probilities of simultaneous capacity outages in the two systems is obtained(3)

This two dimensional array is shown in Figure 5.3. This graphical representation of joint probabilities may be referred to as the Venn Diagram. The array is divided into different sections. These sections are shown in Figure 5.4.

The LOLPs for the global system as well as for the individual systems may be computed from the joint probilities shown in Figure 5.3. In what follows the LOLPs for different conditions are computed.

i) Without tie line

In the absence of an interconnection between the two systems there will be no assistance from one system to the other. Hence, each system will experience loss of load when the outage capacity in a system exceeds its own reserve capacity. In this case, the LOLPs of individual systems and the global LOLP are calculated as follows:

LOLP of system 1,

$$LOLP_1 = Z + X + X' + X'' = 0.1$$

LOLP of system 2,

$$LOLP_2 = Z + Y + Y' + Y'' = 0.30700$$

O_1	0	5	10	15	20	25	30	35	40	45	50
P_1	0.576	0	0.288	0	0.036	0	0.064	0	0.032	0	0.004

O_2	P_2
0	0.567
5	0
10	0
15	0.126
20	0
25	0.243
30	0.007
35	0
40	0.054
45	0
50	0
55	0.003

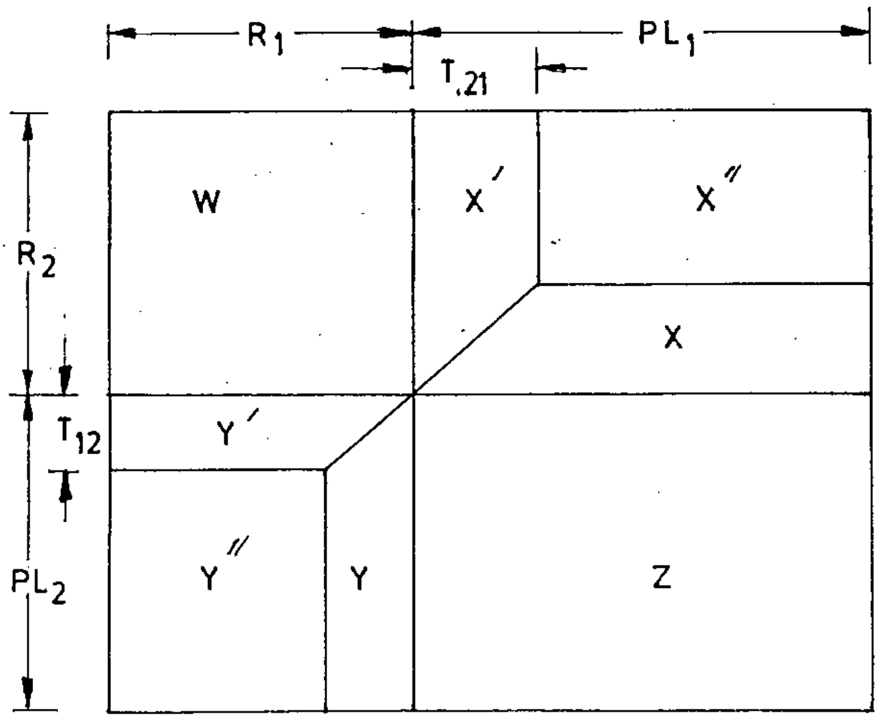
$R_1 = 20$ MW $\quad T_{21}$

$R_2 = 15$ MW $\quad T_{12}$

0.32659		0.16330		0.02041		0.036288		0.018144		0.002268
0.07258		0.03628		0.00454		0.008064		0.004032		0.000504
0.139968		0.069984		0.008748		0.015552		0.007776		0.000972
0.004032		0.002016		0.000252		0.000448		0.000224		0.000028
0.031104		0.015552		0.001944		0.003456		0.001728		0.000216
0.001728		0.000864		0.000108		0.000192		0.000096		0.000012

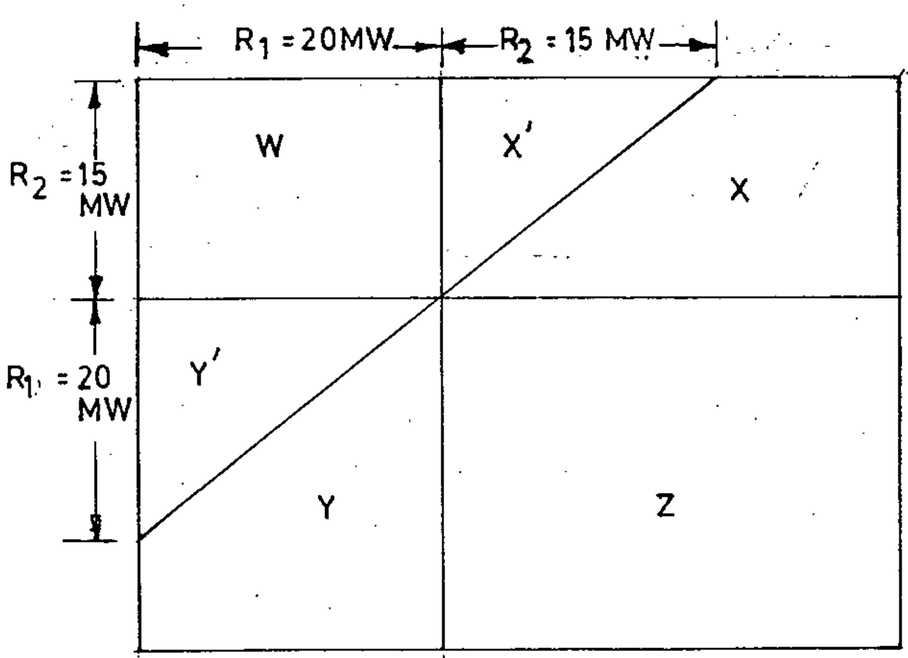
O_1, O_2 are the outage capacities in system 1 and 2 respectively.
P_1, P_2 are the corresponding exact probabilities.

Figure 5.3: Venn diagram for two area system.



W = 0.6237
X = 0.0126
X'= 0.036288
X"= 0.020412
Y = 0.011052
Y' = 0.209952
Y"= 0.055296
Z = 0.03070

Fig. 5.4 : Venn diagram for two systems with limited tie line capacity.



W = 0.6237
X = 0.033012
X'= 0.036288
Y = 0.062316
Y'= 0.213984
Z = 0.03070

Fig. 5.5 : Venn diagram for two systems with infinite tie line capacity.

Global LOLP,

$$LOLP_s = Z + X + X' + X'' + Y + Y' + Y''$$

$$= LOLP_1 + LOLP_2 - Z$$

$$= 0.3763$$

ii) <u>With limited tie line capacity</u>

In this case, the assistance available to each system is limited by the tie line capacity and the reserve margins of the participating systems and this can be evaluated by using Equation (5.1). The LOLPs of each system assisted by the other and the LOLP of the global system are obtained from Figure 5.4. These are given below.

LOLP of system 1 assisted by system 2 is

$$LOLP_{12} = Z + X + X'' = 0.063712$$

LOLP of system 2 assisted by system 1 is

$$LOLP_{21} = Z + Y + Y'' = 0.097048$$

LOLP of the Global system is

$$LOLP_s = Z + X + X'' + Y + Y''$$

$$= LOLP_{12} + LOLP_{21} - Z$$

$$= 0.13006$$

Note that LOLPs have decreased when assistance between the interconnected systems is considered.

iii) Infinite tie line capacity

In this case, the line capacity is considered to be infinity. That is the amount of assistance given by one system to the other is not limited by the tie line capacity. Therefore, Equation (5.1) becomes

$$\begin{aligned} A_{12} &= RM_1 \\ A_{21} &= RM_2 \end{aligned} \tag{5.2}$$

In this case, the internal structure of the Venn diagram mainly depends on the reserve margin. The Venn diagram for two interconnected systems with infinite tie line capacity is shown in Figure 5.5.

Now, LOLPs can be computed as follows

$$LOLP_{12} = Z + X = 0.063712$$

$$LOLP_{21} = Z + Y = 0.093016$$

$$\begin{aligned} LOLP_s &= Z + X + Y \\ &= LOLP_{12} + LOLP_{21} - Z \\ &= 0.126028 \end{aligned}$$

This small example reveals that

i) increasing the tie line capacity T_{21}, from 10 to 15 MW does not improve the reliability of system 1,

ii) increasing the tie line capacity T_{12}, from 10 to 20 MW improves the reliability of system 2,

iii) there is a limit beyond which the increase of tie line capacity is ineffective in improving the reliability of a system,

iv) If the capacity of the tie line between two interconnected systems is considered to be infinite then the two systems are merged into one pool (single area) and loose their identity. This is known as pooling operation[34]. Obviously, the value of LOLP obtained by pooling operation (single area evaluation) of two interconnected systems is different from the value obtained considering the tie line constraint.

CHAPTER 6

EVALUATION OF LOLP USING SEGMENTATION METHOD

6.1 INTRODUCTION

In generation expansion planning, reliability evaluation is essentially the first step to compare between alternative plans. Reliability evaluation is also important to an utility since reliability index is a measure of the standard of service to its consumer. The simplest and most common of all the reliability indices is the loss of load probability (LOLP)[2,3].

In this chapter, the methodology based on segmentation method for evaluating LOLP of a single area system is presented. The method is then fully described with a simple example. The segmentation method for evaluating the LOLP of two interconnected systems is also presented in this chapter. The computational procedure is described step by step considering correlated load.

6.2 EVALUATION OF LOLP OF A SINGLE AREA SYSTEM

Recall that the LOLP is defined in terms of installed capacity and the equivalent load as

$$\text{LOLP} = \text{Prob.}\{\text{Le} > \text{IC}\} \tag{6.1}$$

Thus in order to evaluate LOLP the distribution of the equivalent load (Le) incorporating the outages of all the generating units in the system is required.

The starting point of the segmentation method is the formation of segments of equal sizes by dividing the demand axis. The size of the segments depends on the largest common factor of the generating unit capacities. To each segment a probability value is attached which is equal to the sum of the probabilities (zeroeth moments) of the load impulses (in the PDF of load) lying in the range of the particular segment. One segment beyond the installed capacity (IC) is considered. It should be noted that the LOLP is obtained when the equivalent load is larger than the installed capacity. Hence, the probability (zeroeth moment) attached to the last segment in the final distribution is the LOLP. Since the probability of occurrence of any load lower than the base load is zero, the formation of segments starts from the base load. Clearly it shows that the numerous number of impulses have been reduced to a few number of segments.

In order to account for the random outages of units it is necessary to get a new distribution of segments incorporating the outages of all units. Considering the k-th segment and assuming a generating unit of capacity C MW and FOR=q, to be convolved, the probability of the k-th segment, after convolution may be expressed as

$$\tilde{P}_k = P_k\,(1-q) + \hat{P}_k\,q \tag{6.2}$$

where,

$\tilde{P}_k$ = Probability of the k-th segment after the convolution.

$\hat{P}_k$ = Probability of the k-th segment after the shift.

P_k = Probability of the k-th segment before convolving the unit.

The procedure for convolving a generating unit may be described as follows:

i) The original distribution of segments is multiplied by the availability of the units (1-q).

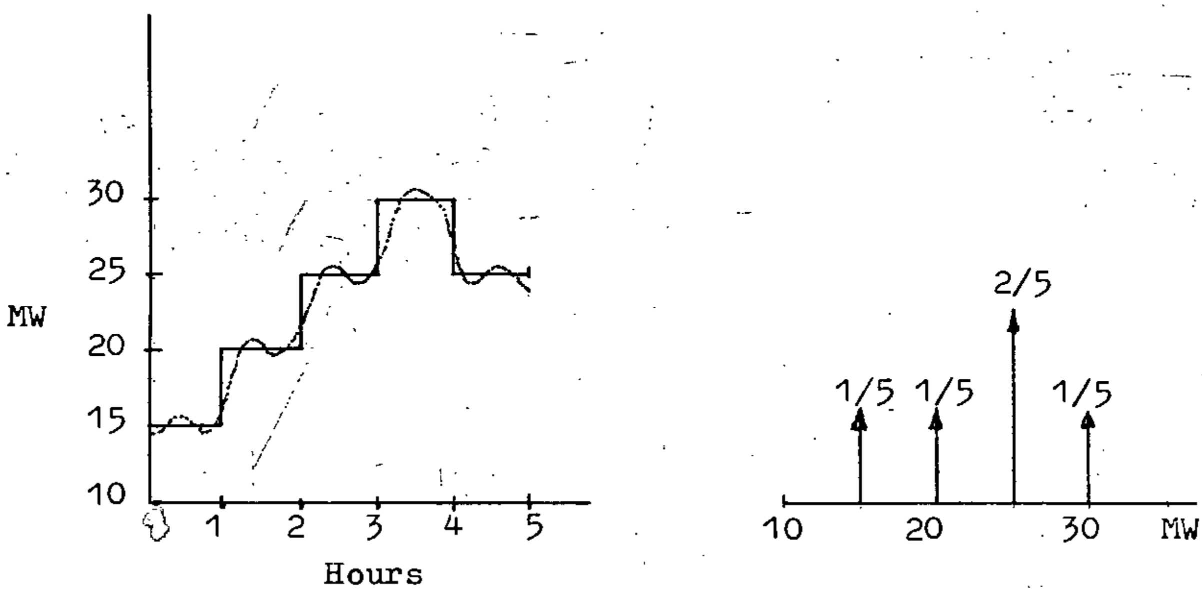
ii) The original distribution is then shifted by the unit capacity and multiplied by the FOR of the unit q.

iii) The values of the corresponding segments, obtained in (i) and (ii) above, are added.

It should be noted the probability value of the last segment is the sum of the probabilities of all the segments exceeding the installed capacity. Also, the segments below the already committed capacity can be deleted, since the probability values of these segments will not further contribute to the value of the last segment. Therefore, as the convolution process proceeds, the number of segments decrease.

In what follows an example will be presented to clarify the method.

Let us consider the hourly load as shown in Figure 6.1. The dotted line represents the chronological load while the firm line represents the hourly load. The hourly load is obtained from the chronological load assuming that the average load for an hour exists for that particular hour.



(a) -Chronological and hourly load profile

(b) - PDF of load

Figure 6.1: Load representation.

The hourly load of Figure 6.1(a) is sampled at an interval of one hour (may be sampled at any equal interval) and by assigning to each sampled hourly load an equal probability, i.e., 1/5 in this case, the PDF of load shown is Figure 6.1(b) is obtained.

Let us now consider the generating system as shown in Table 6.1.

Table 6.1: Generating system description

No. of units	Capacity MW	FOR	Installed capacity MW
2	10	0.2	45
1	25	0.1	

The segment size is chosen to be 5 MW using the largest common factor of the generating unit capacities of Table 6.1. Thus the demand axis upto 45 MW is divided into 9 segments each of 5 MW size. Out of these 9 segments two initial segments are omitted since there is no impulse before 15 MW (base load) and one additional segment is considered at the end which is shown in Figure 6.2(a). The probability value of each segment corresponding to the respective impulse of Figure 6.1(b), lying in the range of the particular segment is also shown in Figure 6.2(a). The numbers shown in the boxes of Figure 6.2 should be divided by 5 to get the actual value of PDF.

The different steps of convolution of load and the generating units of Table 6.1 are depicted in Figure 6.2. To convolve the first 10 MW unit the segments of Figure 6.2(a) are shifted towards right in Figure 6.2(b) by the unit

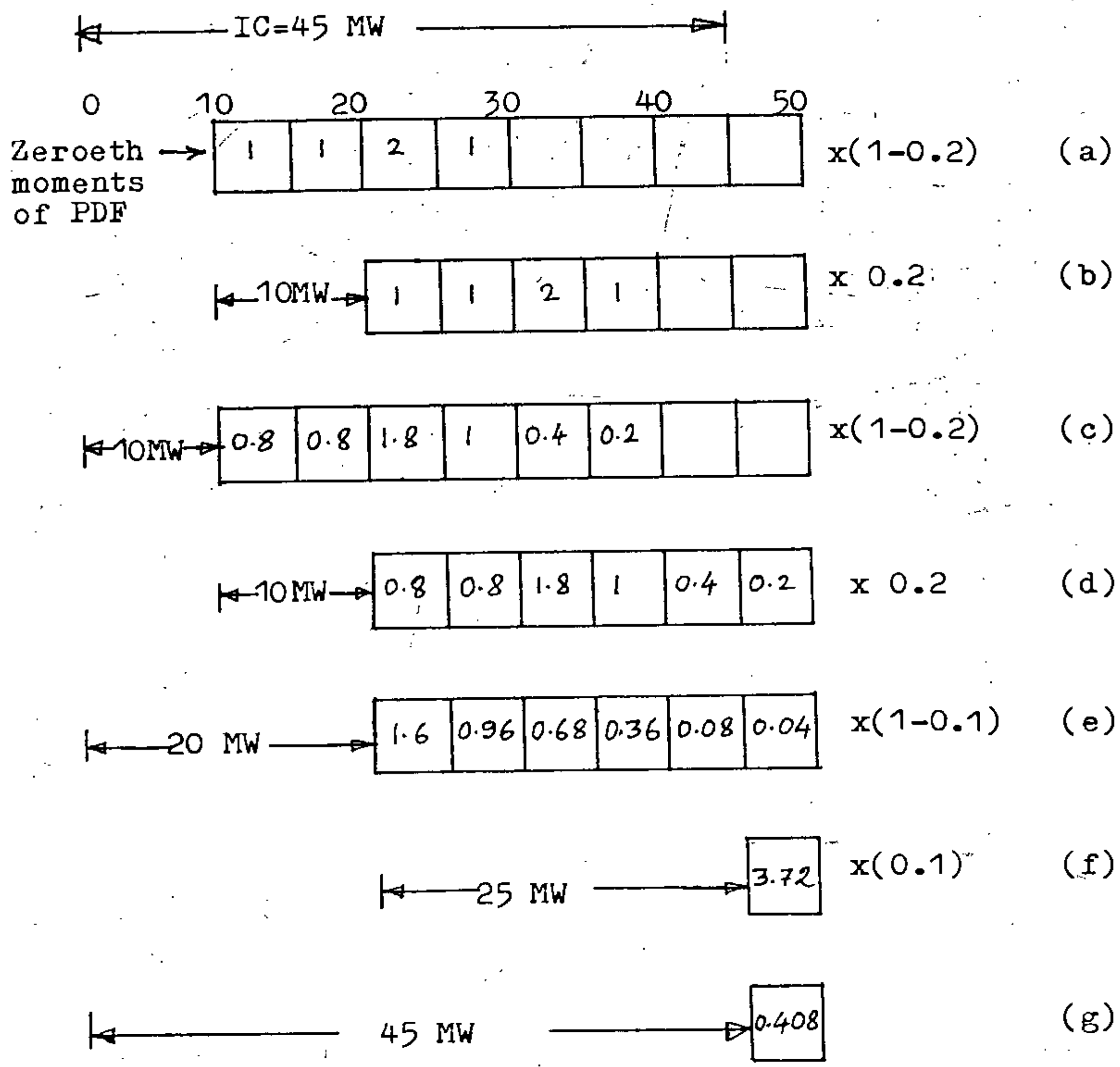


Figure 6.2 : Schematic of convolution procedure (All numbers in the boxes should be divided by 5).

capacity, i.e., 10 MW. The original distribution in Figure 6.2(a) is multiplied by the availability of the unit, 0.8 and the shifted distribution of Figure 6.2(b) is multiplied by the FOR of the unit, 0.2. The distribution after convolution is obtained by adding the probability values of the corresponding segments of Figure 6.2(a) and Figure 6.2(b). This is shown in Figure 6.2(c). The same procedure is followed for the rest of the units.

It should be noted that the segments below the convolved capacity are deleted during the convolution process since the probability values of these segments will not contribute further in the evaluation of LOLP. Also, the probability values are shifted toward the last segment and a number of them may be accumulated in this special segment. Thus, the last segment of Figure 6.2(f) is the sum of the last six segments of 6.2(e).

Now the LOLP is simply the probability value of the last segment of Figure 6.2(g), since LOLP is obtained when the equivalent load is larger than the installed capacity. Thus,

$$\text{LOLP} = \frac{0.408}{5} = 0.0816$$

6.2.1 <u>Computational Steps</u>

The different computational steps to evaluate LOLP by segmentation method are listed below.

Step 1: The hourly load (or any average load at equal interval) is obtained from the chronological load for the period under study (this may be predicted demand in case of planning).

Step 2: The hourly load (or any average load) is sampled at every hour or any other suitable interval and by assigning equal probability to each sample the distribution of load is obtained.

Step 3: The FORs of the generating units are obtained from the past history of the generating units as mentioned in Section 3.2. (In some cases, FOR is provided by the manufacturer).

Step 4: The distribution of segments is then obtained by dividing the demand axis and assigning a probability to each segment equal to the sum of the probabilities of the load impulses lying in the range of that particular segment.

Step 5: The units are then convolved one by one. For LOLP evaluation only, convolution of the units in the merit order of loading is not required.

Now LOLP is obtained from the final distribution of segments.

6.3 EVALUATION OF LOLP OF TWO AREA INTERCONNECTED SYSTEM

The segmentation method for the evaluation of LOLP of two interconnected system is based on the calculation of the PDF of load obtained from the chronological load curves of the two systems. It utilizes the segmentation of unit capacities as described in Section 6.2.

For the case of independent loads the PDF of equivalent load of each system is obtained by convolving the units with its own distribution of load. The joint probabilities of the equivalent loads of the two systems are obtained by properly multiplying the probabilities (zeroeth order moments) of the corresponding segments of the individual system. The LOLPs are obtained by summing the joint probability values of the segments under appropriate limits.

For correlated loads two dimensional segments are utilized corresponding to a joint load distribution. The generating units of each system are convolved to each system seperately. Summing the joint probabilities under appropriate limits the LOLPs for the two interconnected systems are obtained.

It is more realistic that there exists some correlation between the loads of the two interconnected systems. In case of correlated loads the computational steps for evaluating LOLPs of two interconnected systems are fully described with a simple example below.

Let us consider the hourly loads for the two interconnected systems as shown in Figure 6.3 and the generating units shown in Table 6.2. The two systems are interconnected by 10 MW tie line.

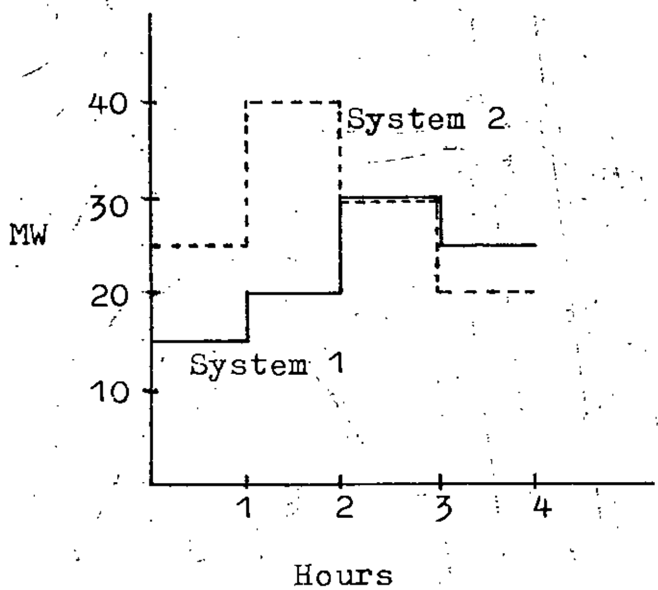


Figure 6.3: Hourly loads for the two systems.

Table 6.2: Generating system description

SYSTEM 1				SYSTEM 2			
No. of units	Capacity MW	FOR	Installed capacity MW	No. of units	Capacity MW	FOR	Installed capacity MW
2	10	0.2	50	2	15	0.1	55
1	30	0.1		1	25	0.3	

First a two dimensional array of segments of equal size is constructed. The segment size is chosen to be 5 MW using the largest common factor of the generating unit capacities and the tie line capacity. As in the case of single area system, there is no need of constructing segments before the base load. In this example, the segment construction starts with 15 MW load in system 1 and 20 MW load in system 2 as shown in Figure 6.4. The x-axis is attributed to system 1 and y-axis is attributed to system 2.

Assigning to each sampled hourly load equal probability (1/4 in this case), the joint probabilities of the loads of the two systems are obtained. Thus, the joint probability of 15 MW load in system 1 and the corresponding 25 MW load in system 2 is 1/4. In the same manner the rest of the joint probabilities are obtained. The segments are then filled up with the joint probabilities of loads as shown in Fig. 6.4.

The process of convolution requires the shifting of each segment as it is described for the case of single area system in Section 6.2. However, in this case the direction of shift depends on the system. The convolution of generating units from system 1 will shift the segments of Figure 6.4 in the direction of the x-axis while the convolution of the generating units from system 2 will shift the segments in the direction of y-axis. In this process of convolution, it is found to be convenient to convolve all the units of

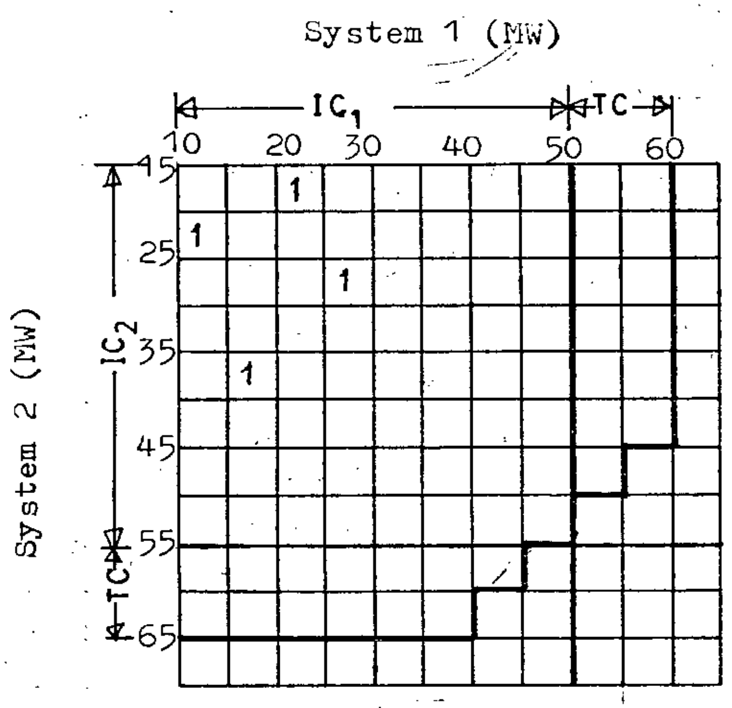


Figure 6.4: Joint probability matrix for systems with correlated load (all numbers in the boxes to be divided by 4).

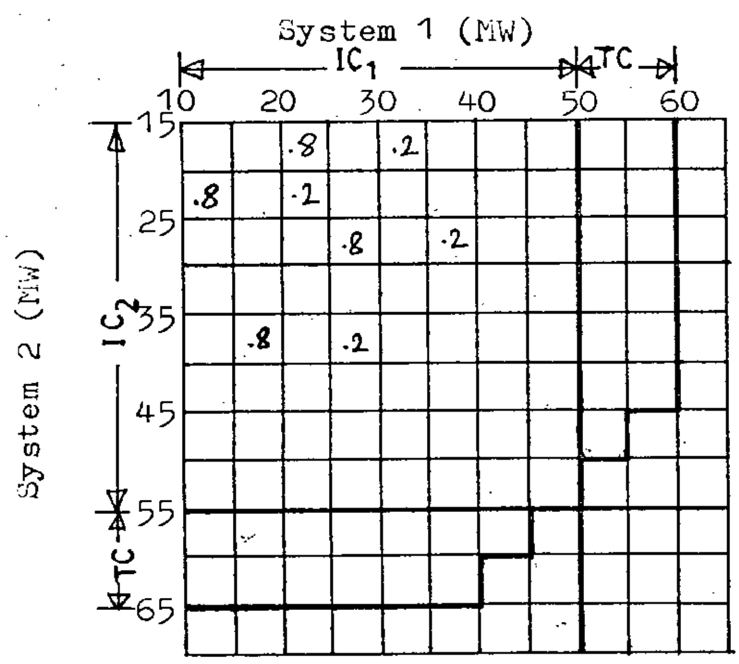


Figure 6.5: Joint probability matrix after convolving one 10 MW unit of system 1 (all numbers to be divided by 4).

one system first. Deletion of segments starts when the units of the second system are convolved, i.e., the segments below the total capacity of the committed units of the second system are deleted and the limits of the deletion zones are the installed capacities of either system.

Figure 6.5 shows the joint probability matrix after the convolution of one 10 MW unit of system 1 and Figure 6.6 shows the joint probability matrix after convolving all the units of the two systems. All the segments below the installed capacity of either system are deleted in the process of convolution. Also, the probability values in the last segments are simply the sum of the probabilities above installed capacity plus tie line capacity. Summation of the joint probabilities above the installed capacity of each system will result in subtotal joint probabilities spanning only the area of interest which is above the installed capacity for each system. Now, LOLP is obtained when the equivalent load is larger than the installed capacity.

The LOLPs of the system are obtained as follows:

$$LOLP_1 = (.025204+.074188+.036288+\ldots+.019584)/4 = 0.068$$

$$LOLP_2 = (.025204+.118588+.031104+\ldots+.015552)/4 = 0.12125$$

$$LOLP_{12} = (.025204+.074188+.000224+.019584)/4 = 0.0298$$

$$LOLP_{21} = (.025204+.118588+.003456+.015552+.000252)/4 = 0.040763$$

$$LOLP_s = LOLP_{12} + LOLP_{21} - 0.025204 = 0.045359$$

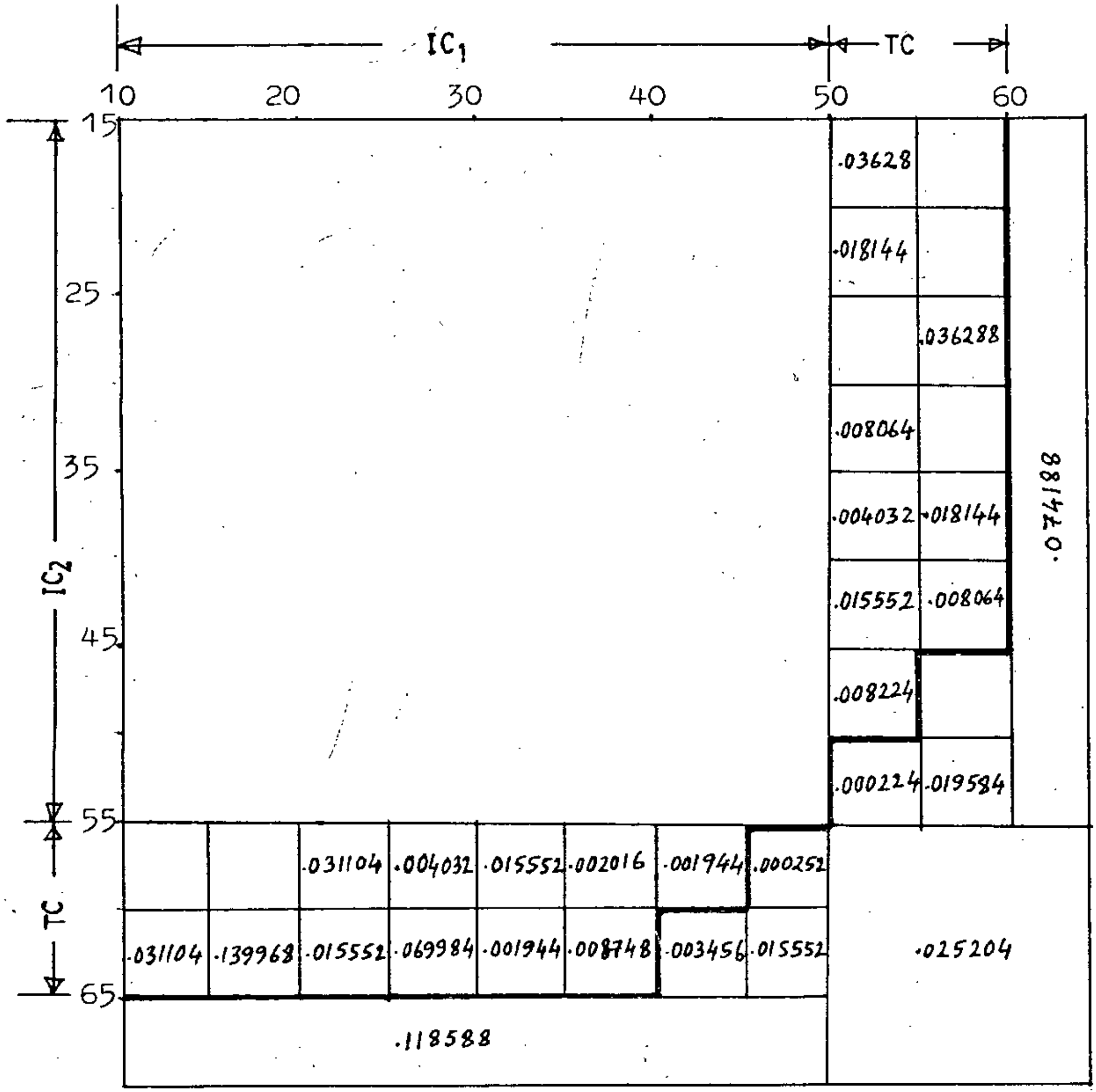


Figure 6.6: Joint probability matrix after convolving all the units of two systems (all numbers to be divided by 4).

6.4 MULTISTATE REPRESENTATION OF GENERATING UNITS

Multistate representation of generating units can be considered for evaluating LOLP using segmentation method. Consider the hourly load of Figure 6.1 and let the system have a generating unit of 45 MW. Consider a three-state model of the unit as shown in Figure 6.7. In what follows the method to convolve this unit in the system load is described. The steps are shown in Figure 6.8.

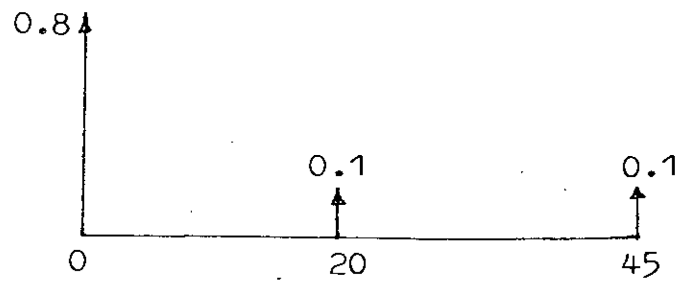


Figure 6.7: Multistate representation of generator.

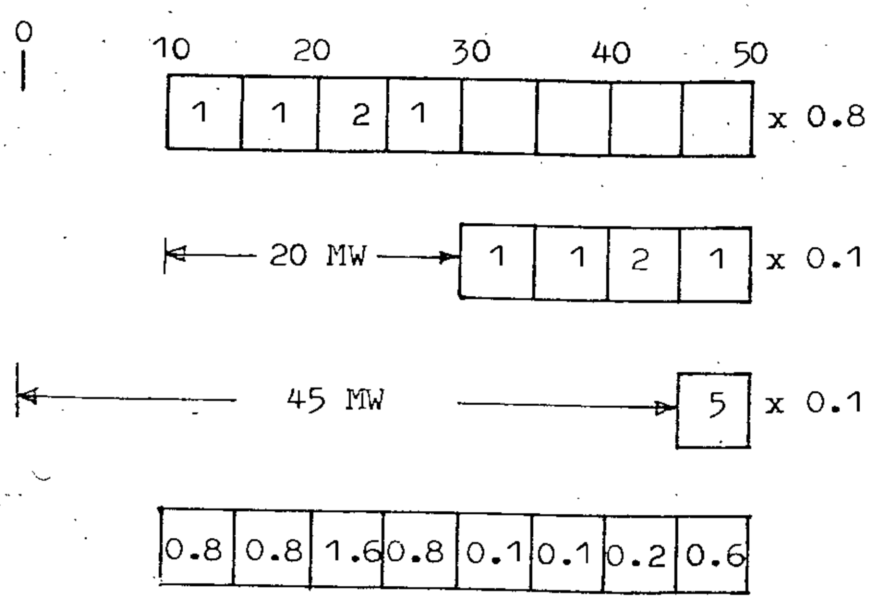


Figure 6.8: Convolution of multistate unit.

In this case the shifting of segments for a multistate unit is done corresponding to each state of the unit. The zeroeth moments for this shifted segments are calculated using the same technique as discussed in Section 6.2.However, it may be noted that this requires only a few more computations.

The segmentation method is also capable of considering multiblock loading of generating units.

CHAPTER 7

EVALUATION OF PRODUCTION COST USING SEGMENTATION METHOD

7.1 INTRODUCTION

The evaluation of the production cost of expected energy generation requires the calculation of expected energy generated by each unit first. The expected energy generated by a unit is obtained from the difference of unserved energies before and after the convolution of the particular unit. This is the basis of the segmentation method. Further, in this method the demand plane is divided to form an one dimensional array for single area system and two dimensional array for two area interconnected system. The distribution of demand is obtained by sampling the chronological load and in turn the distribution of segments is derived from the distribution of demand.

In this chapter, the segmentation method for evaluating the production cost of both single area and two area systems is presented. For clarification of the method, simple examples are also presented in this chapter.

7.2 PRODUCTION COSTING FOR SINGLE AREA SYSTEM

The evaluation of production cost of a single system utilizing segmentation method requires the formation of segments in exactly the same way as described in Section 6.2.

A probability value is attached to each segment which is obtained from the probability values (zeroeth moments) of the load impulses in the corresponding range of the segment. Each segment is also filled up with the sum of the first order moments of the load impulses lying in the range of the particular segment. The first moment is given by the expression

$$m_1 = \int_{-\infty}^{\infty} x f_X(x) dx \tag{7.1}$$

where x is the random variable and $f_X(x)$ is the probability density function of x. In discrete case,

$$m_1 = \sum_i x_i p_i \tag{7.2}$$

where x_i = value of the random variable

p_i = probability of the distribution corresponding to x_i

Sum of the first moments of all the segments gives the initial expected unserved demand. Generating units are then convolved one by one in the economic merit order of loading. Convolution of the units are carried in a way similar to that described in Section 6.2. The only difference is that in this case each segment contains two quantities, viz., the zeroeth moment and the first moment of load impulses. The shifted first moment of any segment may be obtained by the expression

$$m_1^{new} = m_1^{old} + \text{shift} \times m_0 \tag{7.3}$$

where m_0 is the zeroeth moment.

Unserved demands are calculated before and after the convolution of each unit. The unserved demands multiplied by the period under study gives the expected unserved energies. The expected energy generation of a particular machine is the difference between unserved energies before and after the convolution of the machine. Thus for unit k, expected generation is given by

$$E_k = UE_{k^-} - UE_k \qquad (7.4)$$

where E_k = Expected energy generated by the k-th unit,

UE_{k^-} = Unserved energy before convolving the k-th unit,

UE_k = Unserved energy after convolving the k-th unit.

The fuel cost for the unit is obtained by multiplying the expected generation with the average incremental cost of the unit.

$$EC_k = \lambda_k \; E_k \qquad (7.5)$$

where EC_k = Production cost for the k-th unit,

λ_k = Average incremental cost of k-th unit.

The segments below the already committed capacity are not required to be considered in calculated the unserved demand. Therefore, it is not necessary to keep track of these segments. Thus, as convolution of units proceeds, the number of segments decreases. It should be noted that the moment of the last segment is the sum of the moments of all segments exceeding the limit. The moments of the last segment in the final distribution gives the expected energy not served, ϵ(ENS). An example is given for clarification of the method.

Consider the generating system and the load model of the example given in Section 6.2. The PDF of load and the generating system are rewritten below.

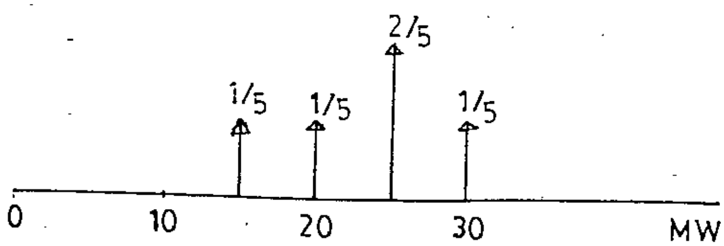


Figure 7.1: PDF of load.

Table 7.1: Generating system description

No. of units	Capacity MW	FOR	Average incremental fuel cost Tk./MWHR	Installed capacity MW
2	10	0.2	300	45
1	25	0.1	500	

Since the average incremental fuel cost of the two 10 MW units are lower than the single 25 MW unit, they are convolved first. The entire convolution procedure is illustrated in Figure 7.2. The upper number in each segment represents the zeroeth moment of load, and the other one represent the first moment. The unserved energy and the expected generation by each unit may be calculated as follows.

Unserved energy before convolving the first 10 MW unit

$$UE_{1}- = \text{1st moment of all segments} \times \text{time}$$

$$= 5x(15+20+50+30)/5 = 115 \text{ MWh}$$

Unserved energy after convolving the 1st 10 MW unit

$$UE_1 = 5x((12+16+45+30+14+8)-10(.8+.8+1.8+1+.4+.2))/5$$
$$= 75 \text{ MWh}$$

Expected energy generation of 1st 10 MW unit

$$E_1 = 115 - 75 = 40 \text{ MWh}$$

Cost of energy generated by 1st unit,

$$EC_1 = 40x300 = 12{,}000 \text{ Taka}$$

Unserved energy after convolving the second 10 MW unit

$$UE_2 = 5x((40+28.8+23.8+14.4+3.6+2)$$
$$-20(1.6+.96+.68+.36+.08+.04))/5$$
$$= 38.2 \text{ MWh}$$

Expected generation by the second unit

$$E_2 = 75-38.2 = 36.8 \text{ MWh}$$

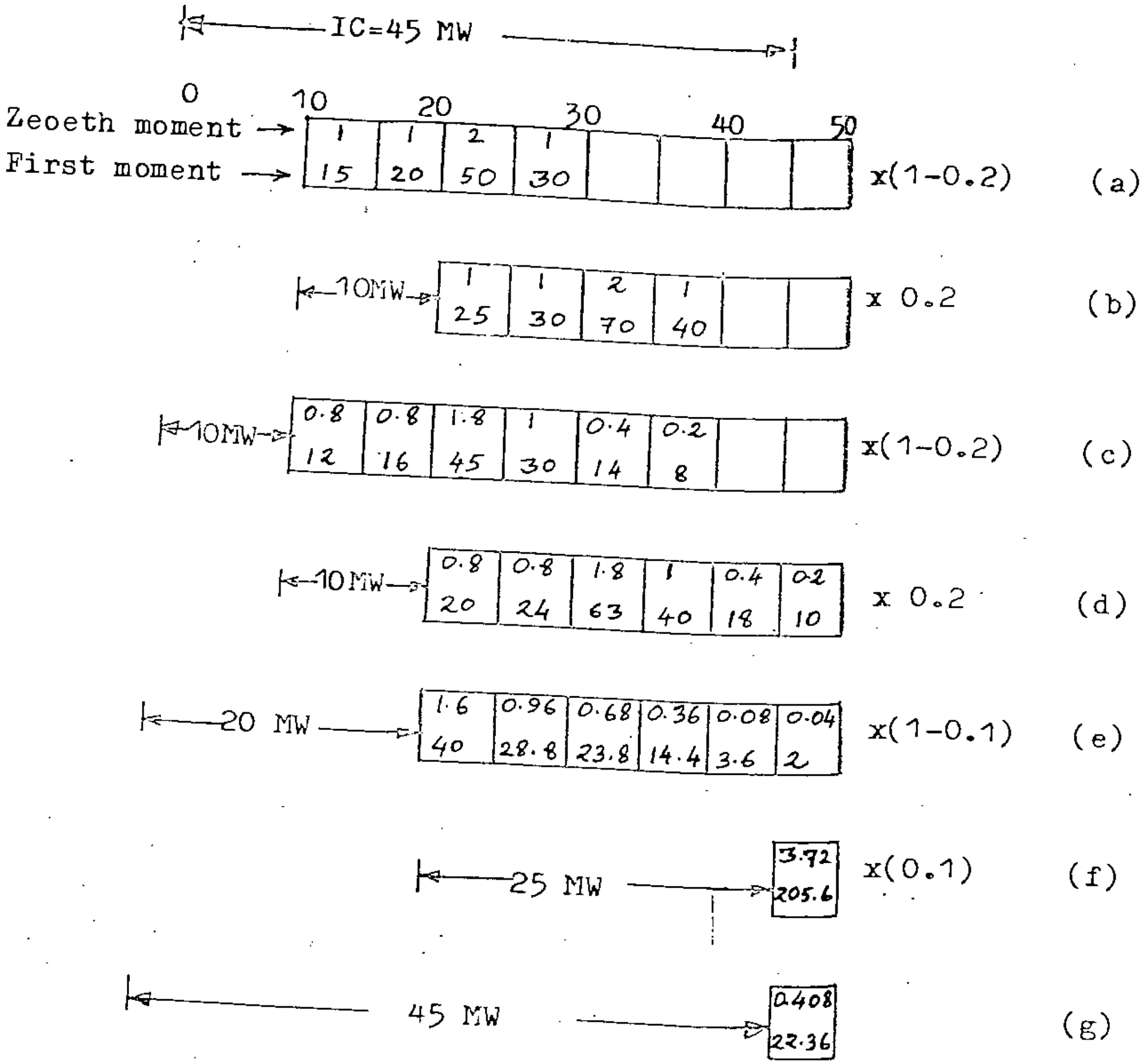


Figure 7.2 : Schematic of convolution procedure (All numbers in the boxes to be divided by 5).

Cost of energy generated by the second unit,

$$EC_2 = 36.8x300 = 11,040 \text{ Taka}$$

Similarly for the third (25 MW) unit

$$UE_3 = 5x(22.36-45x0.408)/5 = 4 \text{ MWh}$$

$$E_3 = 38.2-4 = 34.2 \text{ MWh}$$

$$EC_3 = 34.2x500 = 17,100 \text{ Taka}$$

Energy demand

$$ED = \text{initial unserved energy} = 115 \text{ MWh}$$

Total expected energy generation

$$EG = E_1+E_2+E_3 = 111 \text{ MWh}$$

Expected energy not served

$$\epsilon(ENS) = UE_3 = 4 \text{ MWh}$$

Total energy production cost

$$EC = EC_1 + EC_2 + EC_3 = 40,140 \text{ Taka}$$

For a given system and for the period under study the energy balance (EB) is the difference between the energy demand (ED) and the sum of total expected energy generation (EG) and expected energy not served, ϵ(ENS) as:

$$EB = ED -((EG + \epsilon(ENS)) \qquad (7.6)$$

For the present problem, energy balance is

$$EB = 115 - (111+4) = 0.0$$

7.3 TWO AREA PRODUCTION COSTING

First, the chronological loads for the two interconnected systems are sampled at any appropriate interval. The joint occurrence of each sampled load point is assigned equal probability. The demand plane is divided into a grid structure, or segments, of equal size. Each segment contains the joint probability of the load in the range of the selected segment as well as the first moment of load, or equivalent load, and residual tie line capacity for each system. The generating units are then convolved one by one in the economic merit order of loading. Before convolving any unit the possible expport or import are evaluated and the first moments are modified accordingly. Unserved energies are calculated before and after the convolution of each unit. The expected energy generated by a unit is obtained from the difference of the unserved energies before and after convolving the unit. Multiplying the expected energy generated by the average incremental cost the cost of energy generated is obtained.

The computational steps involved in evaluating the production cost of two interconnected systems using segmentation method is described in detail below.

Step 1:

The chronological loads of the two interconnected systems are sampled every hour (or any other appropriate time interval) and each sample is assigned equal probability of occurrence. Thus the joint probabilities of the sampled loads are obtained.

Step 2:

A two dimensional array of segments is constructed, the number of segments being given by

$$t_1 = \frac{\sum_{k=1}^{n_1} C_k^{(1)} + TC}{\Delta C} + 1 \tag{7.7}$$

$$t_2 = \frac{\sum_{k=1}^{n_2} C_k^{(2)} + TC}{\Delta C} + 1 \tag{7.8}$$

where

C_k is the capacity of the k-th unit. The superscript represents the system.

n_1 = total number of units in system 1.

n_2 = total number of units in system 2.

TC = tie line capacity

ΔC = largest common factor of the generating unit capacities of both systems as well as the tie line capacity.

Each segment contains the following parameters:

i) The zeroeth moment of load which corresponds to the joint occurrence of load sample; this corresponds to the joint segment probability.

ii) The first moments of load for each system corresponding to load samples in the range of the particular segment.

iii) The first moments of residual tie line capacity (RTC) for each system.

The residual tie line capacity (RTC) for a system is that capacity of the tie line that remains at any stage of the loading process after having been utilized by the previously committed generating unit or units from the system. Initially the first moment of RTC for each system is set equal to the product of the corresponding tie line capacity (TC) and the joint probability of the particular segment.

Step 3:

The loading order of the units of the two systems is deduced from the knowledge of the average incremental cost of the units. In this order the unit with the lowest average incremental cost comes first, then the unit with second lowest incremental cost and so on.

Before convolving any unit, in the loading order, the possible export or import must be evaluated. The fundamental strategy subsumed in the evaluation of export is that each system must keep its own interest paramount. That is, a utility will only export power to another as long as it has excess capacity after having met its own load. A system which exports power to another is known as an exporting system and a system which receives power from another is known as an importing system.

The principal factors which affect the capacity transactions between two interconnected system are:

i) the unserved demand of the exporting system,

ii) the unserved demand of the importing system,

iii) the capacity of the committed generating unit,

iv) the RTC of the exporting system.

The possible export $e_{i,j}$, at any segment (i,j), may be calculated by the relation

$$e_{i,j} = \mathrm{Min}(Z_1, Z_2, Z_3) \tag{7.9}$$

But $e_{i,j} \geq 0$.

The expected values (RVs) Z_1, Z_2 and Z_3 represent expected excess generation of the exporting system, expected RTC of the exporting system, and expected unserved demand of the importing system, respectively. These may be calculated for any segment (i,j) as follows.

$$Z_1 = \sum_{k=1}^{S^E+1} C_k^E \times p_{i,j} - m_{i,j}^E(EL) \tag{7.10}$$

$$Z_2 = m_{i,j}^E \text{ (RTC)} \tag{7.11}$$

$$Z_3 = m^I_{i,j}\,(EL) - \sum_{k=1}^{S^I} C^I_k \times p_{i,j} \tag{7.12}$$

where superscripts E and I refers to the exporting and importing systems respectively and EL refers to as the RV of equivalent load. In Equation (7.10) to (7.12) the notation m represents the first moment and S represents the total number of committed units.

Step 4:

The first moments of load are modified. The modified first moments of load (equivalent load) for the exporting and importing systems, $\hat{m}^E_{i,j}$ (EL) and $\hat{m}^I_{i,j}$ (EL), respectively, are given by

$$\hat{m}^E_{i,j}(EL) = m^E_{i,j}(EL) + e_{i,j} \tag{7.13}$$

$$\hat{m}^I_{i,j}\,(EL) = m^I_{i,j}(EL) - e_{i,j} \tag{7.14}$$

Step 5:

The first moments of RTC are also modified in those segments where transactions take place. The modification of the first moments of RTC is necessary to carry the information to the corresponding segment of equivalent load. The modified first moments of RTC are

$$\hat{m}^E_{i,j}(RTC) = m^E_{i,j}(RTC) - e_{i,j} \tag{7.15}$$

$$\hat{m}^{I}_{i,j}\ (RTC) = m^{I}_{i,j}(RTC) + e_{i,j} \tag{7.16}$$

where it is assumed that simultaneous transactions in both directions cannot occur.

Step 6:

The expected unserved energy of the exporting system before committing the k-th generating unit is calculated. This is given by

$$UE_k = T \sum_{i,j=k_1}^{i=t_2,\, j=t_1} (\hat{m}^{E}_{i,j}(EL) - C^{E}_{t} \times p_{i,j}) \tag{7.17}$$

where C^E_t is the total capacity of the already committed generating units of the exporting system and is given by

$$C^{E}_{t} = \sum_{k=1}^{S^E} C^{E}_{k} \tag{7.18}$$

The lower limit k_1 in (7.17) is given by

$$k_1 = \min\ (w^E,\ w^I),\ \text{but}\ k_1 \geq 1 \tag{7.19}$$

where

$$w^E = \sum_{k=1}^{S^E} C^{E}_{k}/\Delta C \tag{7.20}$$

$$w^I = \sum_{k=1}^{S^I} C^{I}_{k}/\Delta C \tag{7.21}$$

Note that the unserved demand for any segment (i,j) must be positive. That is

$$(\hat{m}^{E}_{i,j}(EL) - C^{E}_{t} \times p_{i,j}) \geq 0 \tag{7.22}$$

Step 7:

The unit is then convolved to the two dimensional distribution of segments. The process of convolution is simply effected by shifting each segment appropriately as each generating unit, in the loading order, is committed to meet the equivalent load. Assuming that x-direction of segments is attributed to system 1 and y-direction to system 2, then a generating unit in system 1 will shift the corresponding moments along the x-axis and conversely for a unit in system 2.

Considering the (i,j)th segment and assuming a unit of capacity C MW belonging to system 1 to be committed, the shifted first moment of load (or equivalent load) of system 1 of the $(i,j+w_1)$th segment may be expressed as

$$m^{new}_{i,j+w_1} = m^{old}_{i,j} + C \times p_{i,j} \tag{7.23}$$

where

$$w_1 = C/\Delta C \tag{7.24}$$

Clearly, the first moments of load of system 2 remain unchanged by commitment of a unit belonging to system 1. Also the segments probability stays unchanged by the shift since the zeroeth order moments are not affected by the shift.

To obtain the final distribution of segments after convolving the k-th unit, the original distribution (before convolving k-th unit) is multiplied by the availability $(1-q_k)$ and the shifted distribution is multiplied by the FOR (q_k) of the unit, and these two results are added.

Step 8:

The unserved energy, after commitment of the k-th unit, UE_k is then evaluated by using Equation (7.17) with the capacity of the k-th unit added to C_t^E given by Equation (7.18).

Step 9:

The expected energy generation by the k-th unit is given by

$$E_k = UE_{k-} - UE_k \tag{7.25}$$

Global expected energy generation in both systems is

$$GES = \sum_{k=1}^{n_1+n_2} E_k \tag{7.26}$$

Step 10:

The production cost for the k-th generating unit is given by

$$EC_k = \lambda_k \times E_k \tag{7.27}$$

The global production cost is then as follows

$$GEC = \sum_{k=1}^{n_1+n_2} \lambda_k \times E_k \tag{7.28}$$

In order to clarify the methodology presented above, it is exemplified through a simple example.

Consider two systems interconnected by a 10 MW tie line. The hourly loads for the two systems are considered to be the same as that given in Figure 6.3. It is redrawn in Figure 7.3 for convenience.

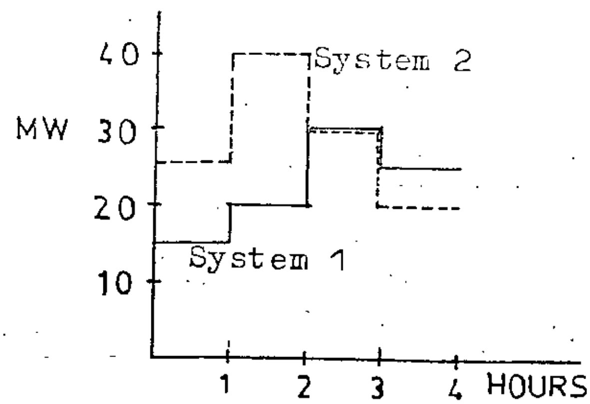


Figure 7.3: Hourly load profile.

The generation systems are shown in Table 7.2.

Table 7.2: Generation system description

SYSTEM 1				SYSTEM 2			
No. of units	Capacity MW	FOR	Average incremental cost Tk./MWh	No. of units	Capacity MW	FOR	Average incremental cost Tk./MWh
1	20	0.2	300	1	30	0.1	400
1	30	0.1	500	1	25	0.3	700

For these two systems interconnected by a 10 MW tie line, the segment size is $\Delta C = 5$ MW. The segments are filled up with the joint probabilities of load and the first moments of load and of the line capacity as shown in Figure 7.4. The first, second and third rows of each segment contain the following: first row, the segments probability, second row, the first moments of load for both systems (system 1 shown first) and third row, the first moments of RTC for both systems (system 1 shown first). The first moments are obtained by multiplying the probability with the numerical values of the RVs.

From Table 7.2 the loading order can be easily deduced. The 20 MW unit of system 1 is loaded first. This is followed by the 30 MW units of system 2; then the 30 MW unit of system 1 and finally the 25 MW unit of system 2.

Before the 20 MW unit is commited, the possible export must be evaluated using Equation (7.9). The only segment for which export is possible is the one which corresponds to the 15 MW of load in system 1: first segment in second row. For this segment, 5 MW can be exported from system 1 to system 2. Using Equation (7.13) and (7.14), the modified first moments of load are, therefore, $(15+5)/4 = 20/4$ for system 1 and $(25-5)/4 = 20/4$ for system 2. Since system 1 is exporting 5 MW over the tie line, its modified first

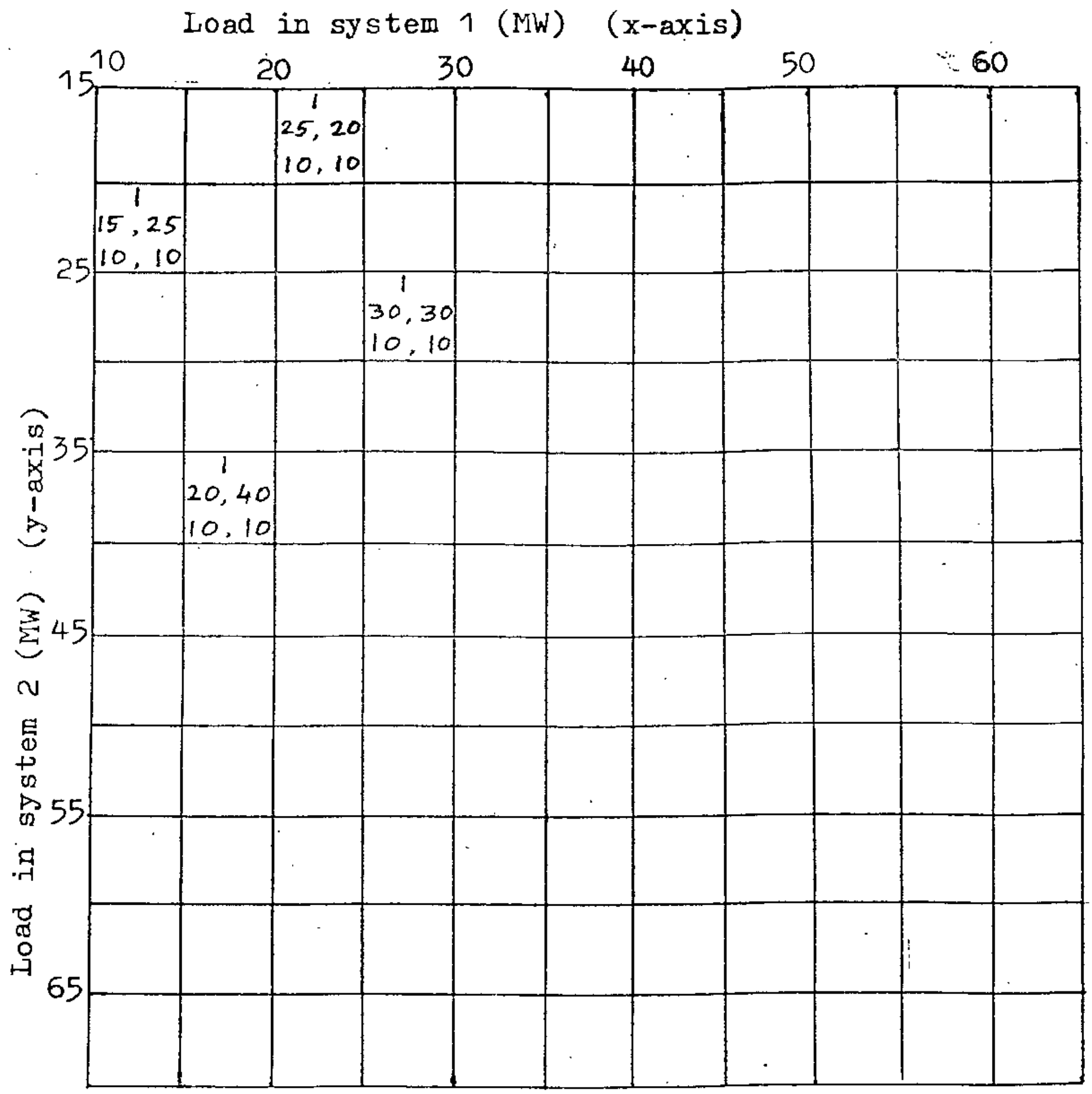


Figure 7.4: Schematic representation of joint probabilities and corresponding first moments (all numbers in the boxes to be divided by 4).

moment of RTC is (10-5)/4 = 5/4, in accordance with equation (7.15). Similarly, from Equation (7.16) for system 2 the modified first moment of RTC is (10+5)/4 = 15/4.

Using Equation (7.17), the expected unserved energy of system 1 before committing the 20 MW unit is

$$UE_{1^-} = 4(25+20+30+20)/4 = 95 \text{ MWh}$$

For convolving the 20 MW unit, the joint probabilities and first moments are shifted as shown in Figure 7.5. Only the first moments of load of system 1 are modified due to the shift.

In Figure 7.6 the distribution of load (equivalent load) and the corresponding first moments after the convolution of 20 MW unit are shown. From Figure 7.6 the unserved energy is recalculated. Thus, the expected unserved energy, by Equation (7.17) is given by

$$\begin{aligned} UE_1 &= 4\{(20+9+16+8+24+10+16+8) \\ &\quad -20(0.8+0.2+0.8+0.2+0.8+0.2+0.8+0.2)\}/4 \\ &= 31 \text{ MWh} \end{aligned}$$

The expected energy generation of the 20 MW unit of system 1 is from Equation (7.25) equal to

$$\begin{aligned} E_1 &= UE_{1^-} - UE_1 \\ &= 95 - 31 \\ &= 64 \text{ MWh} \end{aligned}$$

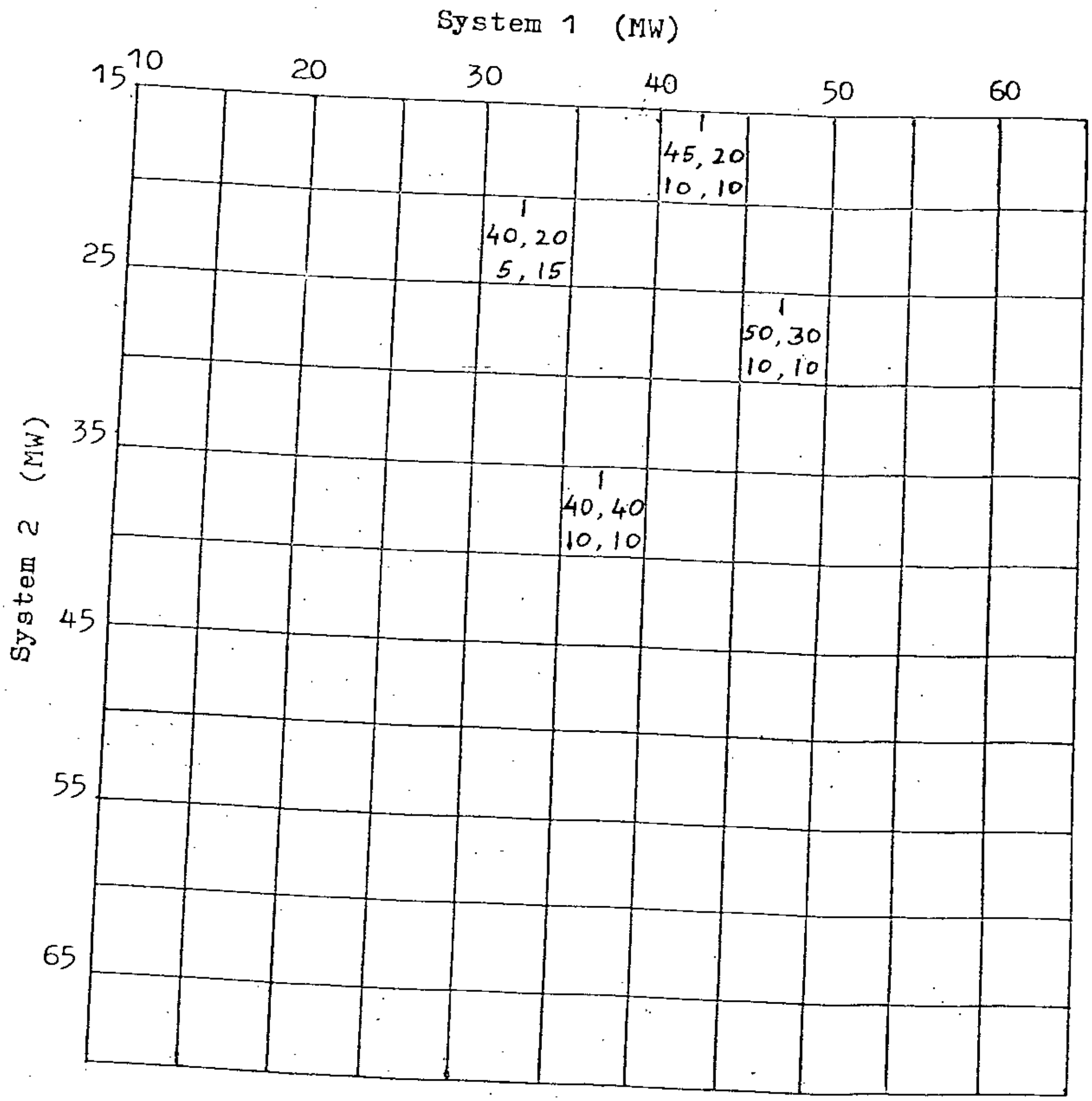


Figure 7.5: Shift of joint probability and first moments during the convolution of the 20 MW unit of system 1 (all numbers in the boxes to be divided by 4).

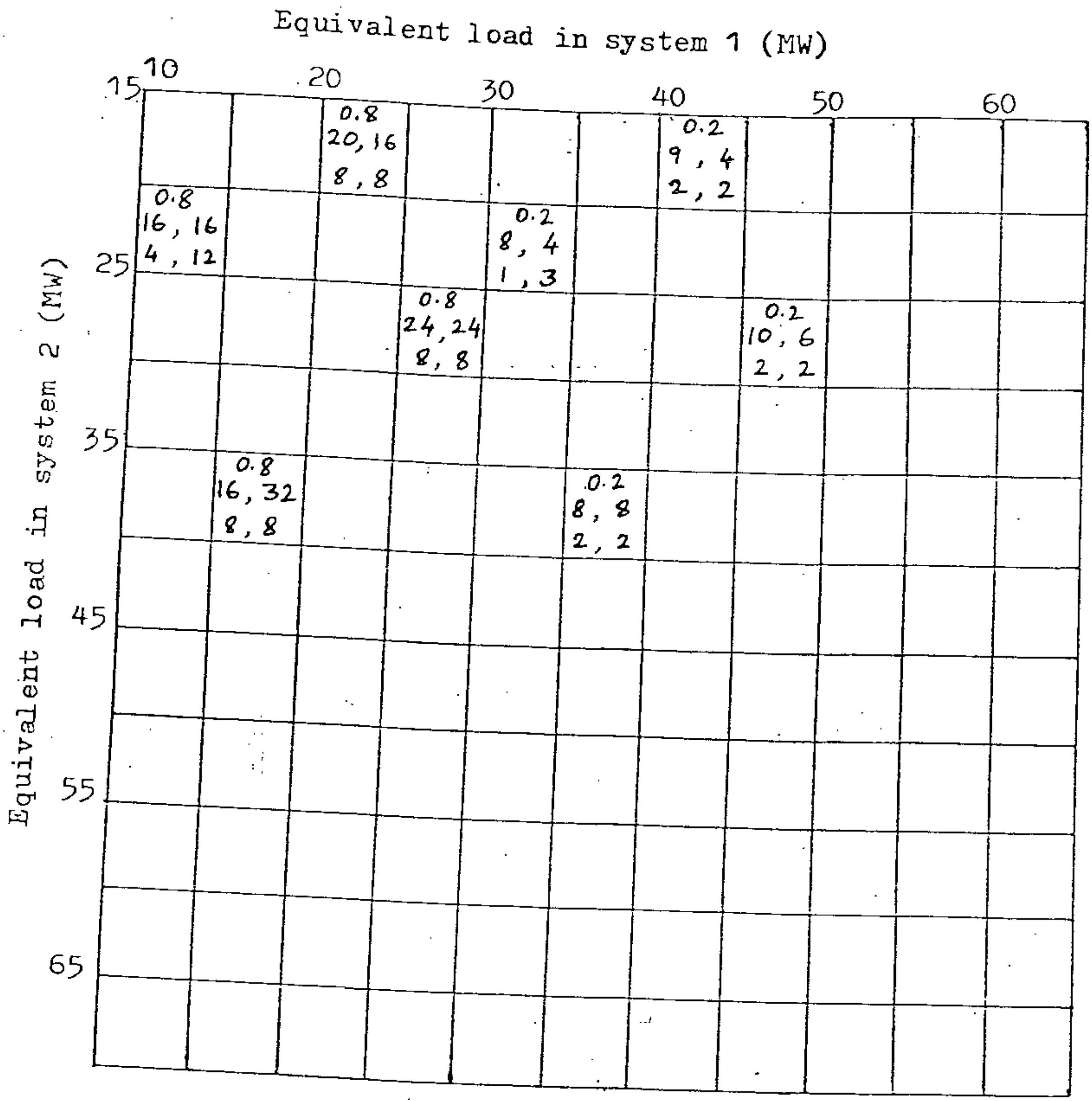


Figure 7.6: Distribution of load and resulting first moments after convolving the 20 MW unit (all numbers in the boxes to be divided by 4).

The cost of energy generated by this unit is given by Equation (7.27) and is equal to

$$EC_1 = \lambda_1 \times E_1$$

$$= 300 \times 64$$

$$= 19{,}200 \text{ Taka}$$

In a similar vien the rest of the units are loaded. The expected energies and production costs are given by

$$\left.\begin{aligned} E_2 &= 97.2 \text{ MWh} \\ EC_2 &= 38{,}800 \text{ Taka} \end{aligned}\right\} \text{(30 MW unit of system 2)}$$

$$\left.\begin{aligned} E_3 &= 32.4 \text{ MWh} \\ EC_3 &= 16{,}200 \text{ Taka} \end{aligned}\right\} \text{(30 MW unit of system 1)}$$

$$\left.\begin{aligned} E_4 &= 6.66 \text{ MWh} \\ EC_4 &= 4{,}662 \text{ Taka} \end{aligned}\right\} \text{(25 MW unit of system 2)}$$

7.4 SOME ADDITIONAL FEATURES OF SEGMENTATION METHOD

In segmentation method, the size of the segment has an influence on the accuracy of the method. Only when the segment size is a common factor of the unit capacities one can guarantee accurate results. But when dealing with a practical system, the individual generator capacities may not have a common factor and may not be multiples of the smallest generating unit. To avoid this inconsistency, one approach is to round-off unit capacities but making sure that the first moments stay unchanged. This requires corresponding change to the FORs. Another approach is to augment the size of the system by a factor 5, 10 or more until a segment size 1 MW may be utilized (equivalently fractional segment sizes may also be used). This last approach will increase the computational requirements. An approximation is to use a 5 to 10 MW step size if it is not a common factor. The errors are within possible tolerance. Unit aggregation is also possible. However, for this a multistate representation is required or an equivalent representation matching the first two or three moments.

The computational efficiency of the method depend on the size of the segment. A coarse segment size, not a common factor of unit capacities, will only produce approximate results but with high computational efficiency.

7.5 ALLOCATION OF PRODUCTION COST BETWEEN TWO INTERCONNECTED SYSTEMS

The economic benefits of interconnection between two separate systems, in terms of global production cost savings for a particular tie line capacity is calculated by subtracting the global production cost at that tie line capacity from the global production cost at zero MW tie line capacity. Thus

$$GS = GEC_o - GEC \tag{7.29}$$

where GS = Global savings,

GEC_o = Global production cost at zero MW tie line capacity

GEC = Global production cost at any tie line capacity greater than zero MW.

There are a number of methods for allocation of the production cost between two areas which are interconnected. One of these is called 'split-the-savings'. This method is popular among the utilities of North America. In this method, the actual cost shared by each utility (system) is obtained on the basis of individual production costs, global production cost and the global savings. The production cost shared by the exporting system at a particular tie line capacity is obtained by subtracting half of the global savings at that tie line capacity from its production cost at zero MW tie line capacity. That is

$$\widetilde{EC}_e = EC_o - \frac{1}{2} GS \tag{7.30}$$

where $\widetilde{EC}_e$ = Production cost shared by the exporting system,

EC_o = Production cost of the exporting system at zero MW tie line capacity,

GS = Global savings.

While the production cost shared by the importing system at any tie line capacity is obtained by subtracting the production cost shared by the exporting system from the global production cost at that tie line capacity. That is

$$\widetilde{EC}_i = GEC - \widetilde{EC}_e \tag{7.31}$$

where $\widetilde{EC}_i$ = Production cost shared by the importing system.

CHAPTER 8

NUMERICAL EVALUATION

8.1 INTRODUCTION

The methodologies of evaluating the reliability and the production costs have been developed in Chapter 6 and Chapter 7 respectively both for single area and for two area interconnected systems. In this chapter, the developed methodologies are utilized to evaluate the reliability and the production cost of Bangladesh power system. This numerical evaluation includes both single area approach and two are interconnected system approach. That is, the reliability and the production cost of Bangladesh electric power generation system are evaluated considering it as a single area system and also considering the Eastern and Western grids of the power system of Bangladesh as two separate systems interconnected by the East-West Interconnector (EWI). The results obtained for both the approaches are presented in this chapter. Some of the results are presented in the graphical form for quick observation of the difference between the two approaches. This chapter also includes a brief description of the power system of Bangladesh and the generation and the load data used in evaluating the system.

8.2 BANGLADESH ELECTRIC POWER GENERATION SYSTEM

The electric power generation system of Bangladesh may be divided into two zones : the East Zone and the West Zone seperated by the rivers Padma, Jamuna and Meghna. These two zones are interconnected by the East-West Interconnector (EWI) forming an integrated national grid. The EWI is a double circuit line presently operating at 132 KV, however, it has been designed for 230 KV. The power transmission capacity of the EWI is 180 MVA per circuit at 132 KV. The total installed capacity of BPDB is 1141 MW out of which 725 MW is located in the East Zone while 416 MW is located in the West Zone(38).

There are a number of Power Stations in the East and in the West Zones. The geographical locations of different Power Stations of BPDB are shown on the map of Bangladesh in Figure 8.1. The simplified single line diagram of the integrated power system of Bangladesh is shown in Figure 8.2. The large Power Stations are Karnafuli Hydro-Electric Station at Kaptai, Ashuganj Steam Power Station and Combined Cycle Plant, Ghorasal Steam Station, Siddhirganj Steam Station, Chittagong Steam Station, Shahjibazar Gas Turbine Power Station , Steam and Gas Turbine at Khulna, and Gas Turbine at Bheramara. Besides these there a number of small diesel stations which continue to play an important role in the northern areas of Bangladesh.

The power stations in the two zones have large variety of generating units, viz., Hydro,Steam, Gas Turbine, Diesel etc. Some of the units are old and their output are now lower

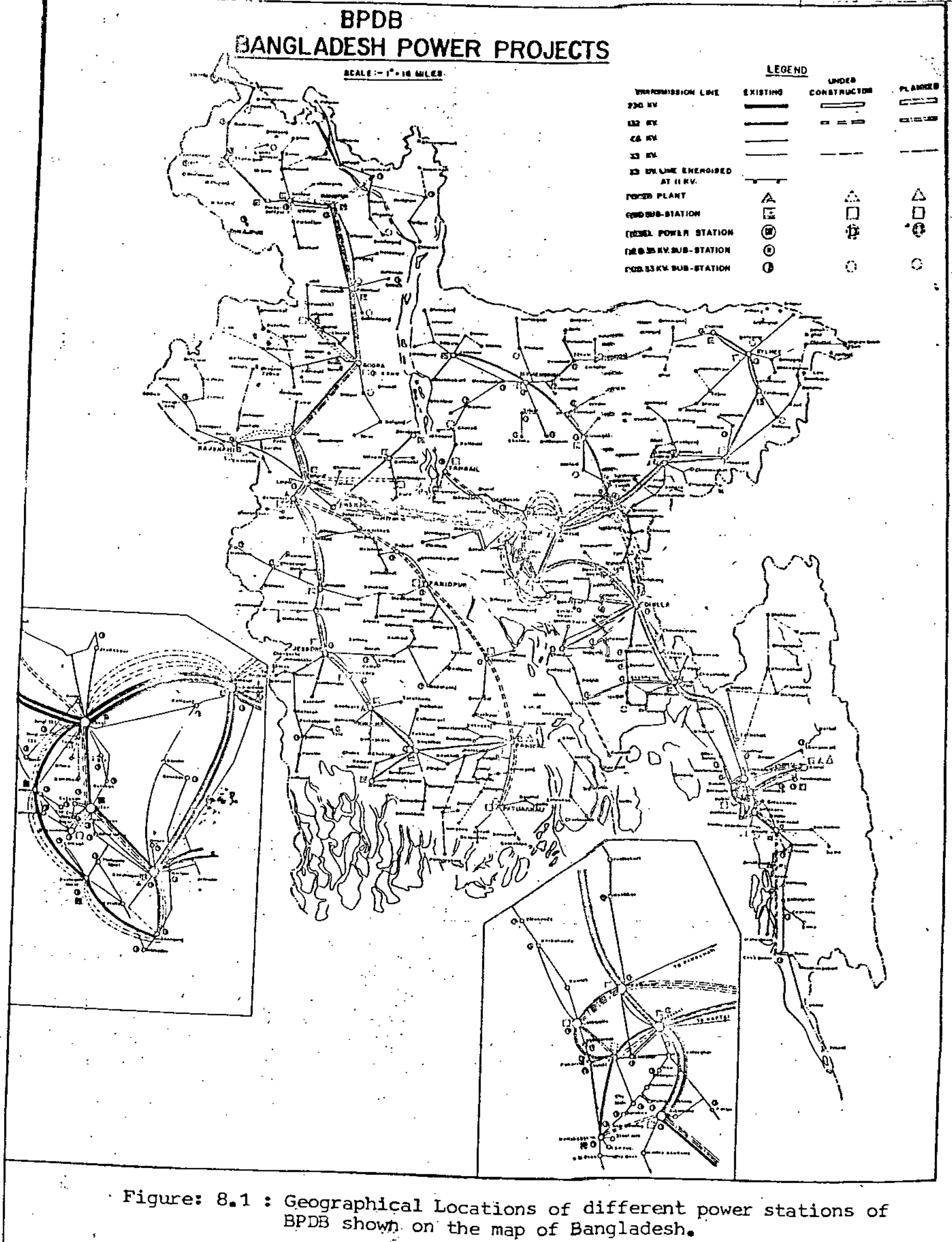


Figure: 8.1 : Geographical Locations of different power stations of BPDB shown on the map of Bangladesh.

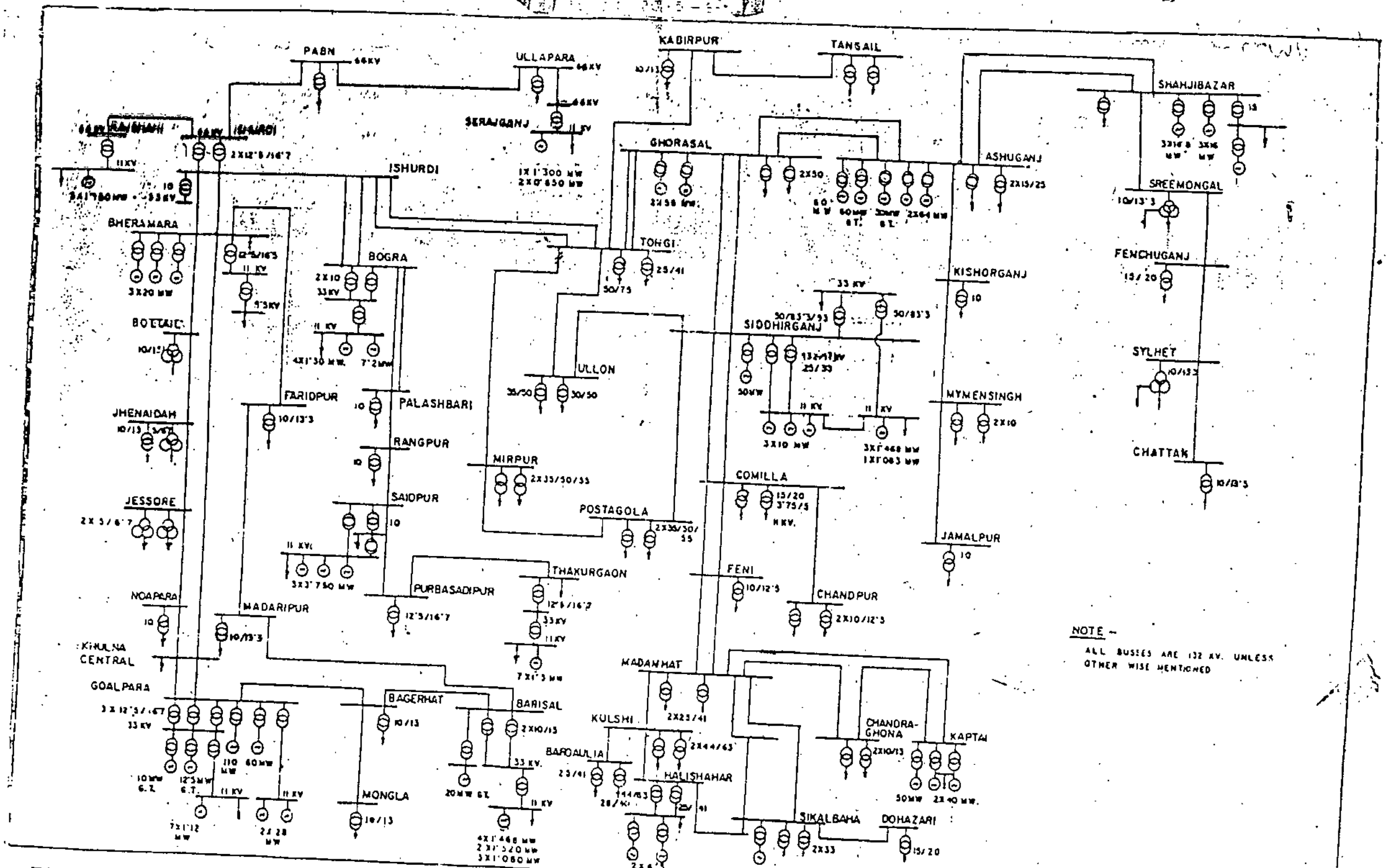


Figure: 8.2 : Single Line Diagram of the integrated power system of Bangladesh.

than the rated values. As a result, the total generating capability of BPDB is 1018 MW instead of 1141 MW. The maximum generating capability of the East Zone is 672 MW and that of the West Zone is 346 MW[38]. Most of the thermal stations in the East Zone use natural gas as fuel, while those in the West Zone generate electricity by burning costly liquid fuel. For this reason the average cost on account of fuel in the West Zone is much higher than that in the East Zone.

8.2.1 Generation Data

Generation data for the East and the West Zones that are used in this research are given in Appendix-A. The column showing the "Capacity" actually contains the maximum capabilities of different units in the two zones. Also some of the unit capacities are rounded off. For example, the capacity of each of the two 64 MW steam units at Ashuganj are rounded off to 65 MW. These changes are made in the unit capacities to decrease the computer time. However, note that the segmentation method is capable of accomodating any generating unit capacity. Also, in the West Zone the small diesel units with capacities less than 5 MW are aggregated to form units of 5 MW capacity and are shown in the appendix under the heading 'Small Diesel Stations'.

The East Zone has 23 generating units with an installed capacity of 675 MW. The generating units in this zone include 3 Hydro units, 10 Steam units and 10 Gas Turbine units. The FORs of the hydro units are very low compared to the FORs of the thermal units. The West Zone has 15 generating units with an installed capacity of 335 MW. Among these units 2 are Steam units, 6 are Gas Turbine units and 7 are Diesel units. The average incremental fuel costs of the generating units in the East Zone ranges from 0.14 to 0.28 Tk./KWh while those of the generating units in the West Zone ranges from 1.57 to 3.32 Tk./KWh.

8.3 LOAD DATA

Hourly load data for the month of August, 1985 are used in this research to get the distribution of demand and these hourly loads are given in Appendix-B. It is observed from the hourly load data that in both the East and the West Zones, the daily peak load occurs during 7:00 to 9:00 P.M. The peak loads are 539.19 and 229.23 MW in the East Zone and in the West Zone respectively. The global peak load for the integrated system is 765.05 MW. Usually the base load is observed to occur at around 4 A.M. in both the systems. The base load is 200 MW in the East Zone and 60 MW in the West Zone. The global base load for the integrated system is 287.09 MW.

8.4 COMPUTER PROGRAMS

Three computers programs in FORTRAN have been developed for the evaluation of reliability and production cost of the generating system of Bangladesh. The first program has been developed based on the segmentation method for evaluating the LOLP and production cost of a single area system. The whole Bangladesh power system is considered to be a single area system and the LOLP and production cost are evaluated using the first program.

The second program has been developed using also the segmentation method for the evaluation of LOLP of two interconnected systems. In this case, the loads of the two systems are assumed to be correlated. The East and West Zones are considered as two independent systems interconnected by the EWI. The LOLPs of the individual systems (East and West Zones) and the LOLP of the global system for various tie line capacities have been evaluated using the second program.

The third program has been developed utilizing the segmentation method for evaluating the production costs of two interconnected systems. In this program, the correlation between the loads of the two systems is incorporated. This program evaluates the production costs of the East and the West Zones of Bangladesh power generation system using a two area approach.

In all the three programs, two-state generating unit models and single block loading of the generating units are considered.

8.5 NUMERICAL RESULTS

In what follows the East Zone will be referred to as 'system 1' and the West Zone will be referred to as 'system 2'.

The LOLPs of the individual systems without considering assistance from the connected system ($LOLP_1$) and $LOLP_2$) as well as the LOLPs considering assistance from the connected system (LOP_{12} and $LOLP_{21}$) are given in Table 8.1 for different tie line capacities. The tie line capacity is varied from zero upto 200 MW. The LOLP for the global system at different tie line capacities are also presented in this Table. In the last row, the LOLP obtained considering the whole Bangladesh power system as a single area system is presented for comparative study. To consider the whole Bangladesh power system as a single area system the loads of the two zones are combined. The combined generating systems of the two zones is considered to be the generating system of single area in this case. In Figure 8.3, LOLPs are plotted against tie line capacity.

The expected energy generation of individual generators of the two systems at different tie line capacities are given

Table 8.1: LOLPs for different tie line capacities

Tie line capacity (MW)	LOLP(%)				
	$LOLP_1$	$LOLP_2$	$LOLP_{12}$	$LOLP_{21}$	$LOLP_s$
0.0	0.493890	1.175805	0.493890	1.175805	1.640265
5.0	"	"	0.428779	0.982429	1.381778
10.0	"	"	0.373332	0.817527	1.161430
20.0	"	"	0.284333	0.572198	0.827102
30.0	"	"	0.217372	0.389823	0.577766
40.0	"	"	0.167695	0.273996	0.412261
50.0	"	"	0.132582	0.193888	0.297040
75.0	"	"	0.087822	0.104923	0.163315
100.0	"	"	0.073535	0.082729	0.126834
125.0	"	"	0.070722	0.079014	0.120307
150.0	"	"	0.070493	0.078688	0.119751
175.0	"	"	0.070483	0.078678	0.119732
200.0	"	"	0.070483	0.078678	0.119732
⋮	⋮	⋮	⋮	⋮	⋮
∞*	---	---	---	---	0.113245

*Evaluation as a single area system.

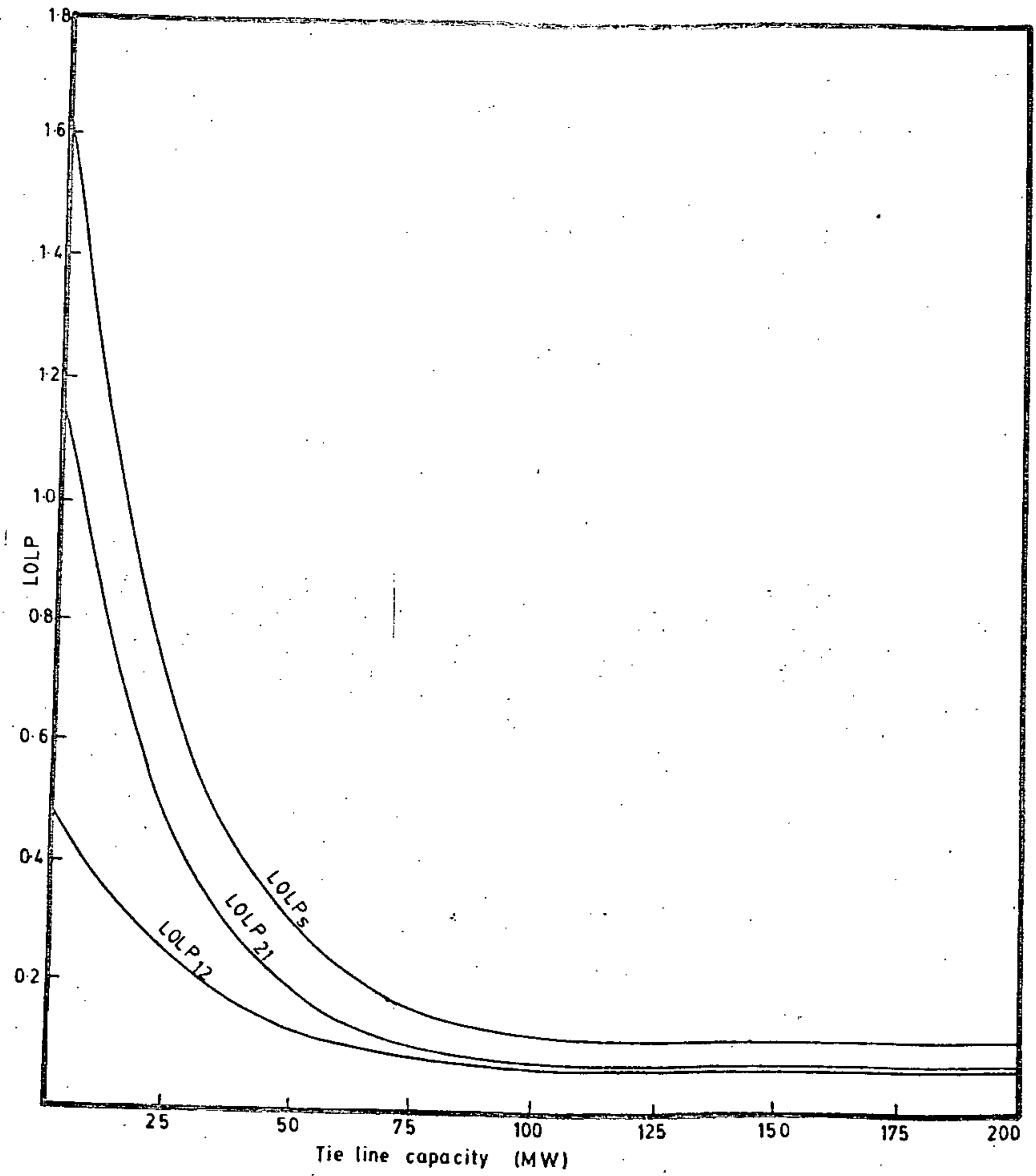


Fig. 8·3 LOLP vs. tie line capacity

in Table 8.2. The results for unlimited tie line capacity (last column of Table 8.2) corresponds to the case where the two systems are considered to be a single area system. The expected energy generation and the production costs of the two systems at different tie line capacities are shown in Table 8.3 and Table 8.4 respectively. In these two tables the results for infite tie line capacity (last row of Table 8.3 and Table 8.4) corresponds to the single area case. In Figure 8.4, the expected energy generation of both systems are depicted for different tie line capacities. The global expected production cost vs. tie line capacity is presented in Figure 8.5.

The variation of global savings with tie line capacity is shown in Table 8.5. The global benefits in terms of production cost savings and in terms of reliability improvement are depicted in Figure 8.6. In this figure, the lower dotted line represents minimum LOLP or the lower limit of LOLP and the upper dotted line represents maximum savings or the upper limit of savings. These limits are obtained by evaluating the two interconnected systems as a single area system. The allocation of production cost between the two systems using 'split-the-savings' principle is also shown in Table 8.5.

Table 8.2: Expected Energy Generation of individual generators for different tie line capacities

System	Capacity MW	FOR	Expected Energy Generation (GWh) at tie line capacity: 0 MW	10 MW	50 MW	∞*
1	50	0.01	36.8281	36.8281	36.8281	36.8281
	40	0.01	29.4625	29.4625	29.4625	29.4625
	40	0.01	29.4624	29.4624	29.4624	29.4624
	65	0.10	43.5240	43.5240	43.5240	43.5240
	65	0.10	42.5921	42.9954	43.5064	43.5240
	50	0.10	29.0578	30.1184	32.6571	33.3937
	60	0.10	26.3980	28.0503	34.4370	38.8327
	55	0.10	15.2257	17.0403	23.9796	32.0419
	55	0.10	8.3534	9.5227	15.3202	26.4603
	55	0.19	3.5560	4.2458	7.7095	18.5499
	30	0.19	1.0978	1.3203	2.6975	8.1839
	10	0.15	0.2939	0.3635	0.7498	2.5549
	10	0.15	0.2379	0.3043	0.6459	2.3695
	10	0.15	0.1939	0.2479	0.5540	2.2006
	10	0.18	0.1533	0.1949	0.4584	1.9730
	10	0.18	0.1268	0.1608	0.3963	1.8327
	10	0.18	0.1048	0.1329	0.3389	1.7004
	10	0.18	0.0856	0.1099	0.2843	1.5746
	10	0.18	0.0687	0.0900	0.2357	1.4548
	10	0.18	0.0543	0.0725	0.1946	1.3407
	10	0.18	0.0426	0.0576	0.1607	1.2317
	5	0.18	0.0180	0.0244	0.0702	0.5800
	5	0.18	0.0159	0.0216	0.0639	0.5559
2	110	0.10	71.9434	69.9987	54.8598	7.4316
	60	0.10	19.9202	16.4599	7.2938	1.4014
	5	0.12	0.9321	0.7702	0.3547	0.0720
	5	0.12	0.8621	0.7278	0.3150	0.0662
	5	0.12	0.7883	0.6804	0.2840	0.0608
	5	0.12	0.7389	0.6336	0.2604	0.0557
	5	0.12	0.6909	0.5893	0.2385	0.0511
	25	0.18	2.4754	1.9786	0.8472	0.1803
	25	0.18	1.5270	1.2272	0.4907	0.1195
	20	0.15	0.8710	0.6922	0.2477	0.0673
	20	0.18	0.5603	0.4316	0.1409	0.0442
	20	0.18	0.3654	0.2757	0.0809	0.0302
	20	0.18	0.2304	0.1685	0.0454	0.0202
	5	0.15	0.0454	0.0326	0.0086	0.0041
	5	0.15	0.0395	0.0279	0.0073	0.0037

* Evaluation as a single area system.

Table 8.3 : Expected Energy Generation of the two systems for different tie line capacities

Tie line capacity (MW)	Expected Energy Generation (GWh)			Global expected energy not served (MWh)
	System 1	System 2	Global	
0.0	266.9536	101.9902	368.9438	325.6
5.0	270.6535	98.3452	368.9987	270.6
10.0	274.3503	94.6944	369.0446	224.7
20.0	281.7317	87.3826	369.1143	155.1
30.0	289.0932	80.0680	369.1612	108.2
40.0	296.4299	72.7621	369.1920	77.3
50.0	303.7368	65.4749	369.2117	57.6
75.0	321.7588	47.4752	369.2340	35.4
100.0	338.7178	30.5217	369.2395	29.8
125.0	351.1033	18.1317	369.2404	29.0
150.0	357.5226	11.7172	369.2398	29.5
175.0	359.4558	9.7831	369.2390	30.4
200.0	359.6318	9.6070	369.2389	30.5
⋮	⋮	⋮	⋮	⋮
∞*	---	---	369.2409	28.4

*Evaluation as a single area system.

Table 8.4: Production Cost for different tie line capacities

Tie line capacity (MW)	Production Cost (10^4 Tk.)		
	System 1	System 2	Global
0.0	2550.4031	17445.7578	19996.1609
5.0	2610.2600	16730.9961	19341.2561
10.0	2670.3635	16027.7812	18698.1447
20.0	2791.3005	14652.0078	17443.3083
30.0	2913.1260	13314.1094	16227.2354
40.0	3035.7168	12013.1211	15048.8379
50.0	3159.0378	10750.0039	13909.0417
75.0	3469.5874	7734.1484	11203.7358
100.0	3772.0974	4970.7109	8742.8083
125.0	4009.2273	2880.1121	6989.3394
150.0	4148.2305	1952.6138	6100.8443
175.0	4195.4453	1643.8120	5839.2573
200.0	4200.1914	1615.7092	5815.9006
⋮	⋮	⋮	⋮
∞*	---	---	5815.3415

* Evaluation as a single area system.

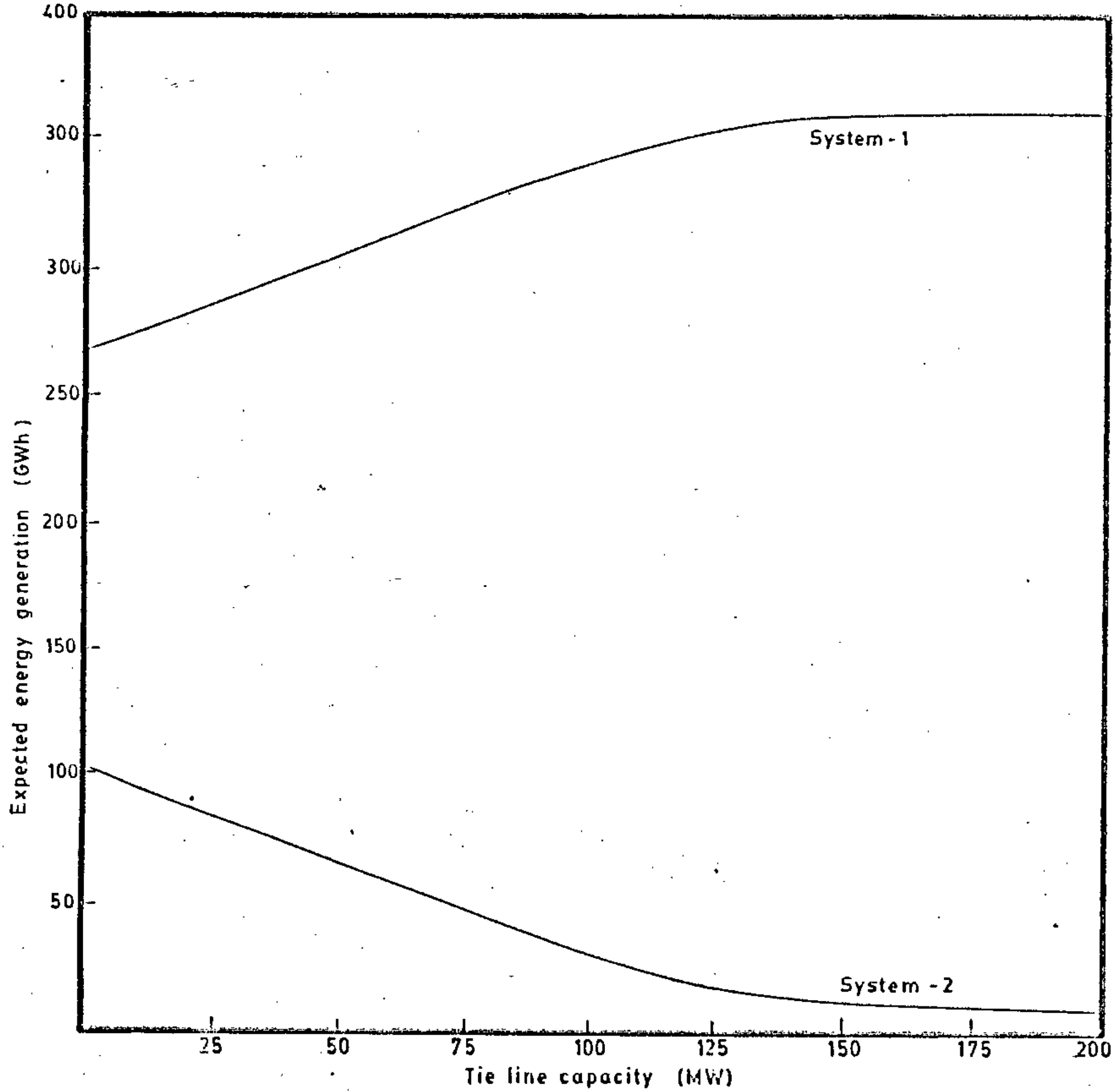


Fig. 8·4 Expected energy generation vs. tie line capacity

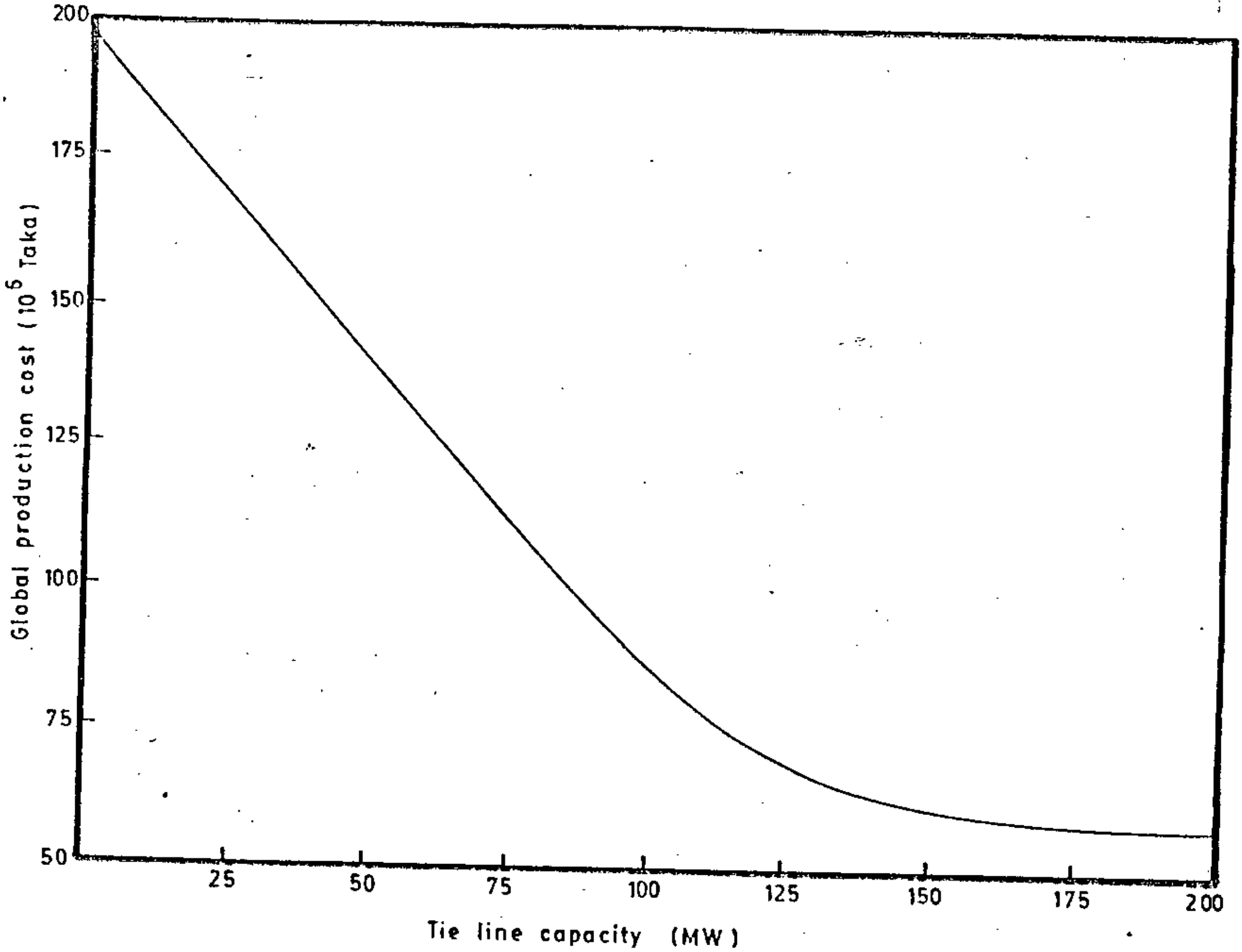


Fig. 8·5 Global production cost vs. tie line capacity

Table 8.5 : Expected Global Savings and Production Cost Shared by each system for different tie line capacities

Tie line capacity (MW)	Global savings (10^4 Tk.)	Production Cost Shared (10^4 Tk.)	
		System 1	System 2
0.0	0.0	2550.4031	17445.7578
5.0	654.9048	2222.9507	17118.3054
10.0	1298.0162	1901.3950	16796.7497
20.0	2552.8526	1273.9768	16169.3315
30.0	3768.9255	665.94035	15561.29505
40.0	4947.3230	76.7416	14972.0963
50.0	6087.1192	-493.1565	14402.1982
75.0	8792.4251	-1845.80945	13049.54525
100.0	11253.3526	-3076.2732	11819.0815
125.0	13006.8215	-3953.00765	10942.34705
150.0	13895.3166	-4397.2552	10498.0995
175.0	14156.9036	-4528.0487	10367.3060
200.0	14180.2603	-4539.72705	10355.62765
⋮	⋮	⋮	⋮
∞*	14180.8194	-4540.0066	10355.3481

* Evaluation as a single area system.

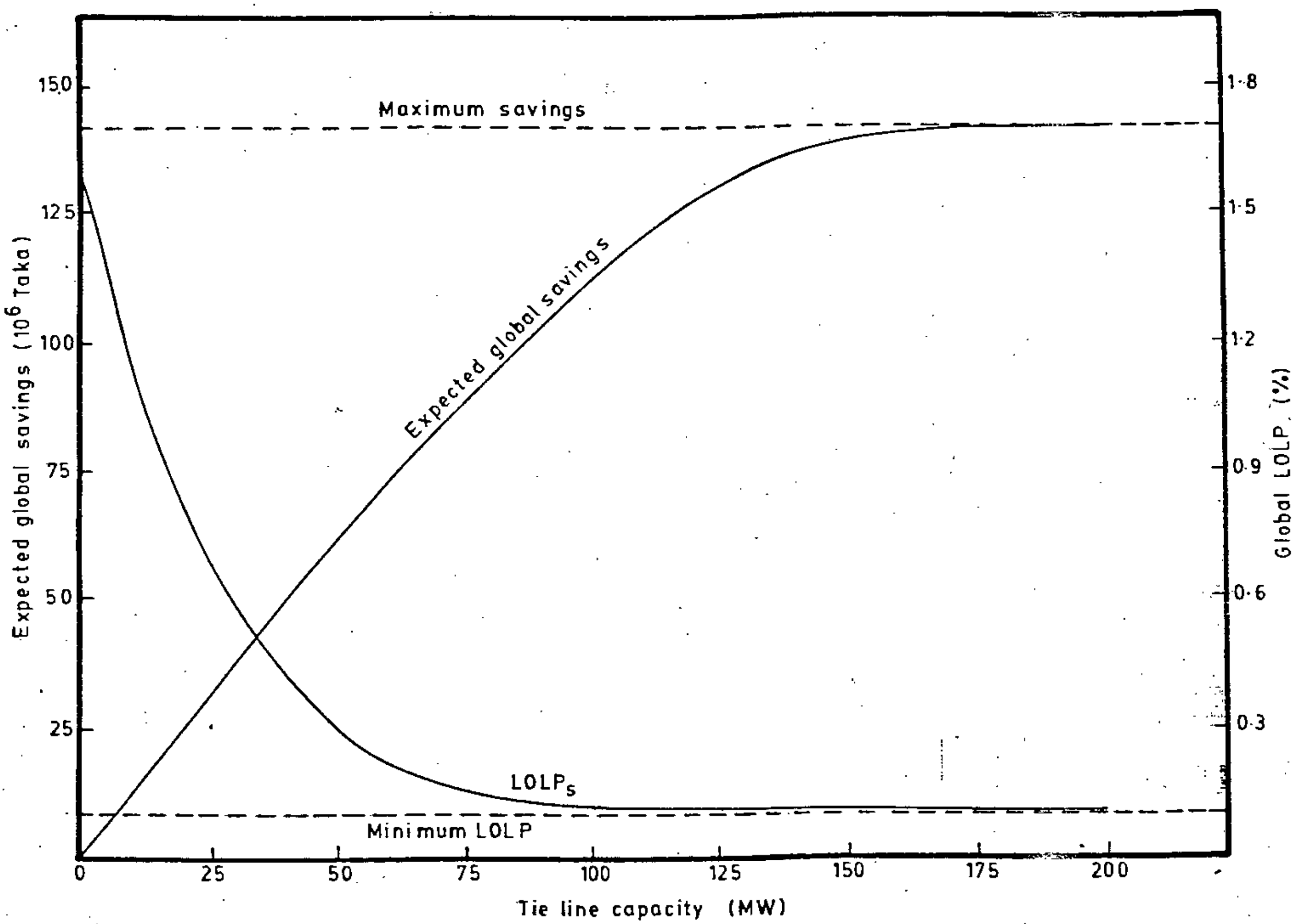


Fig. 8·6 Expected global savings and global LOLP vs. tie line capacity

CHAPTER 9

OBSERVATION AND CONCLUSION

9.1 OBSERVATION

It is clearly observed from Table 8.1 that the LOLPs of the individual systems considering assistance from the connected system as well as the LOLP of the global system decreases with the increase of tie line capacity. The same observation is also made from Figure 8.3. However, the decrease in LOLP with increasing tie line capacity is not linear. The saturation effect, as the tie line capacity is increased, can be clearly observed from Table 8.1. The saturation effect is pronounced at 175 MW tie line capacity. This means that for the existing generation of the two systems considered and the load data used, the increase of tie line capacity above 175 MW does not improve the reliability further. Note that the global LOLP ($LOLP_s$) at 175 MW tie line capacity is approximately equal to the value obtained using single area approach.

The generating units of system 1 are of much lower incremental cost than those of system 2. Therefore, it is expected that system 1 would export major part of the time. This is confirmed by Table 8.2 and Table 8.3. It is observed from Table 8.2 that the expected energy generation of the generating units of system 1 increase while those of the units of system 2 decrease with the increase of tie line capacity. As a result, the total expected energy generation of system 1 increases while that of system 2 decreases, as tie line capacity is increased which is observed from Table 8.3. This is also clearly observed from Figure 8.4. Table 8.3 also shows that the global expected energy generation increases and the global expected unserved energy decreases with the increase of tie line capacity. The saturation effect is pronounced at 175 MW tie line capacity. That is, the expected energy generation of the individual systems and global system as well as the global expected unserved energy remains almost constant for tie line capacities above 175 MW. The slight decrease in the global expected energy generation and the corresponding small increase in the expected unserved energy at tie line capacities above 125 MW are due to round-off error. It may also be observed from Table 8.3 that the global expected energy generation at 175 MW tie line capacity is very close to the expected energy generation of the integrated system obtained using the single area approach. A similar observation may be made from this table in case of expected unserved energy.

In Table 8.4, it is clearly observed that the production cost of system 1 increases while that of system 2 decreases with the increase of tie line capacity. However, as the tie line capacity is increased, the global production cost decreases. The decrease of global production cost with the increase of tie line is also clearly observed from Figure 8.5. The saturation effect on the global production cost at tie line capacities above 175 MW may be observed from Table 8.4 and also from Figure 8.5.

Table 8.5 shows that the global expected savings increases with the increase of tie line capacity. The saturation effect is also pronounced in case of global expected savings over 175 MW tie line capacity. The global benefits in terms of production cost savings and also in terms of reliability improvement as a result of interconnection are clearly observed in Figure 8.6. Near the saturation point, the global savings almost reaches the upper limit (upper dotted line) and the global LOLP almost reaches the lower limit (lower dotted line).

As mentioned earlier, while the global production cost decreases as the tie line capacity is increased, the production cost of system 1 increases. Since both system 1 and system 2 are parts of the same company (BPDB) and both lie in the same regulatory jurisdiction, only the global production cost is of interest. But if it is assumed that the two systems considered are independent companies then system 2 should pay system 1 for the energy it receives. Table 8.5 shows that if the two systems are independent and if there is no interconnection then the production cost shared by each system is equal to the individual production cost at zero MW tie line capacity. However, for interconnection, the production cost shared by each system decreases with the increase of tie line capacity. The negative values of production cost shared by system 1 at 50 MW tie line capacity and above implies that system 1 does not have to incur any expenses for meeting its demand; moreover, it earns some money by exporting energy to system 2. Also for these cases, the production cost shared by system 2 is less than the amount at zero MW tie line capacity.

9.2 CONCLUSIONS

On the basis of the discussions the following conclusions are put forward.

1. If it is necessary to interconnect two separate power systems, then the exact capacity of the tie line at which maximum benefits in terms of reliability improvement and production cost savings are obtained can be accurately determined using only the 'two area' approach.

2. If the capacity of the tie line between two interconnected systems is limited, in that case a 'single area' approach provides wrong information regarding reliability and production cost.

3. In case of tie line constraint (limited capacity), the 'two area' approach gives the actual optimum generation by each generating unit while the 'single area' approach does not, because in 'single area' approach, the tie line capacity is always considered to be infinite.

9.3 RECOMMENDATIONS FOR FURTHER RESEARCH

It has already been established that the evaluation of two interconnected systems with finite tie line capacity using a 'two area' approach is the most appropriate way of evaluation of such systems. In this research, the existing generation system and demand of BPDB has been used. But for a realistic long-term generation expansion planning, the demand for the planning period must be forecasted. Also, the planned generating capacity additions for that period must be taken into consideration. A number of alternative plants may be evaluated in terms of reliability and production costs using the methodologies presented in this thesis. For a more realistic analysis, the multistate representation of generating units as well as multiblock loading of units may be taken into consideration. The idea of 'load management' may also be incorporated. The impacts of load management on reliability and production costs of two interconnected systems may also be investigated using a 'two area' approach. Thus, the possibility of the use of load management strategy as an alternative to new plants may be investigated.

APPENDIX-A

GENERATION DATA

Table A-1: Generation Data for East Zone (System 1)

Name of power station	Type of fuel	No. of units	Capacity (MW)	FOR	Avg. inc. fuel cost Tk./KWh
Karnafuli Hydro	Hydro	1	50	0.01	0.0
		2	40	0.01	0.0
Ashuganj Steam Turbine	Gas	2	65	0.10	0.14
Siddhirganj Steam Turbine	Gas	1	50	0.10	0.15
		3	10	0.15	0.23
Chittagong Steam Turbine	Gas	1	60	0.10	0.16
Ghorasal Steam Turbine	Gas	2	55	0.10	0.16
Ashuganj Combined Cycle	Gas	1(GT)	55	0.19	0.16
		1(ST)	30	0.19	0.16
Shahjibazar Gas Turbine	Gas	7	10	0.18	0.27
Chittagong Gas Turbine	Gas	2	5	0.18	0.28

Table A-2: Generation Data for West Zone (System 2)

Name of power station	Type of fuel	No. of units	Capacity (MW)	FOR	Avg. inc. fuel cost Tk./KWh
Khulna Steam Turbine	F. oil	1	110	0.10	1.57
		1	60	0.10	1.79
		2	5	0.15	3.32
Khulna Gas Turbine (Barge)	SKO	2	25	0.18	2.62
Barisal Gas Turbine	HSD	1	20	0.15	3.01
Bheramara Gas Turbine	HSD	3	20	0.18	3.24
Small Diesel stations*	LDO/ HSD	1	5	0.12	1.93
		1	5	0.12	2.00
		1	5	0.12	2.20
		1	5	0.12	2.35
		1	5	0.12	2.49

* These are small diesel stations located at Thakurgaon, Bogra, Goalpara, Barisal, Rajshahi and Serajganj. Several small diesel units of these stations have been aggregated to form 5 units of 5 MW size.

APPENDIX - B

TABLE-B-1 : HOURLY DEMAND IN EAST ZONE FOR AUGUST, 1986

(MW)

TIME	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00
a.m.	317.48	303.66	294.47	289.61	297.04	318.86	353.43	378.50	400.69	408.58	427.32	412.38
p.m.	379.35	337.77	334.11	348.38	365.40	388.28	502.75	512.53	488.04	457.92	424.46	345.99
a.m.	336.60	303.83	297.97	290.68	284.26	279.26	285.47	290.96	301.46	285.53	305.95	296.55
p.m.	262.02	250.69	245.83	265.86	288.89	328.70	464.78	484.31	463.61	436.12	378.66	326.57
a.m.	291.58	273.67	266.32	258.35	262.33	284.97	324.37	344.41	361.10	351.95	395.48	385.27
p.m.	367.66	354.60	358.30	366.42	376.36	450.53	519.20	516.74	518.77	479.50	424.50	366.78
a.m.	332.32	322.01	300.60	300.84	301.42	316.73	383.62	362.71	399.87	396.27	416.02	403.16
p.m.	382.72	362.45	365.71	368.58	382.23	385.88	529.62	513.13	513.81	477.20	420.94	352.30
a.m.	335.16	318.27	309.90	299.32	297.98	317.27	360.03	379.01	389.84	393.89	396.13	394.98
p.m.	377.52	361.29	360.80	370.33	383.06	403.93	501.07	539.19	529.35	482.17	429.03	368.80
a.m.	331.78	311.29	303.03	297.83	297.16	315.86	350.64	373.11	388.83	401.04	412.36	407.50
p.m.	388.95	368.65	350.75	359.00	379.40	401.30	521.55	536.13	515.78	463.71	417.78	356.93
a.m.	327.21	308.58	288.86	286.93	296.12	304.45	340.01	346.21	378.02	380.61	406.43	392.59
p.m.	370.85	361.38	364.99	365.86	371.37	431.21	479.51	501.74	484.76	435.72	402.35	317.27
a.m.	314.26	298.59	276.18	289.84	288.52	313.40	352.02	354.97	405.50	390.98	398.83	400.62
p.m.	374.18	350.59	346.16	341.85	367.84	385.49	519.45	523.12	504.29	479.96	379.84	355.87
a.m.	315.94	304.12	301.01	293.08	271.50	263.60	304.13	304.02	310.29	315.55	317.54	313.57
p.m.	279.44	269.32	274.84	293.06	308.01	335.43	452.64	450.81	455.32	425.79	384.06	346.31
a.m.	316.44	303.21	289.81	282.16	276.10	309.17	352.64	376.34	388.69	407.46	420.33	413.09
p.m.	393.36	361.97	387.96	377.29	407.60	407.62	530.26	521.84	507.86	484.02	427.56	359.60

TIME →	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00
a.m.	327.04	312.18	306.95	305.39	308.62	311.24	357.93	366.37	390.06	409.55	416.92	414.29
p.m.	387.33	370.52	358.00	364.28	384.61	409.77	521.76	519.30	522.21	478.47	437.13	376.77
a.m.	340.21	325.44	318.46	305.65	311.27	333.88	378.35	397.69	417.39	415.61	494.15	424.43
p.m.	401.35	373.03	377.80	363.08	341.38	434.45	504.39	524.61	512.01	467.81	412.47	383.96
a.m.	319.21	302.75	295.46	290.74	292.26	316.32	336.00	371.12	395.39	412.60	415.24	409.45
p.m.	391.37	378.26	379.93	381.49	406.93	435.51	505.05	500.50	484.93	487.42	429.87	388.21
a.m.	341.39	321.03	333.85	310.13	304.43	322.52	350.21	387.52	382.57	414.90	406.40	401.78
p.m.	383.58	368.96	374.51	368.24	385.84	382.61	478.36	499.05	490.58	485.72	420.87	376.76
a.m.	340.06	325.67	317.58	305.09	312.75	324.02	368.10	390.44	411.91	406.05	421.04	421.07
p.m.	389.98	361.06	365.33	360.58	387.78	421.35	509.76	509.40	509.22	492.06	422.21	390.42
a.m.	357.93	339.52	322.13	307.52	295.95	276.52	299.24	307.13	313.23	310.00	314.30	307.66
p.m.	276.31	258.80	268.72	281.30	306.17	327.15	442.41	439.00	436.69	435.12	374.62	342.21
a.m.	320.66	306.09	306.54	291.52	287.32	299.63	373.33	365.47	385.37	400.24	403.44	396.04
p.m.	376.77	355.56	373.94	381.24	405.07	421.14	429.62	433.10	439.94	450.05	406.06	376.08
a.m.	329.04	312.23	300.40	293.77	299.92	317.70	372.80	387.62	401.59	403.17	414.31	405.15
p.m.	392.69	353.42	354.66	356.27	373.36	408.60	459.06	457.60	485.33	468.52	423.72	370.27
a.m.	349.72	330.23	311.81	311.26	314.47	322.91	362.95	393.27	398.61	405.42	413.34	410.30
p.m.	385.92	361.63	369.74	362.00	374.29	422.81	457.99	471.13	463.51	469.97	412.58	352.53
a.m.	323.16	311.88	391.55	297.56	299.04	314.63	358.65	375.54	389.37	398.31	417.37	410.46
p.m.	389.61	368.82	363.39	371.81	388.98	420.16	455.19	476.73	467.86	399.12	372.23	374.77

TIME →	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00
a.m.	304.35	315.34	307.01	307.01	306.78	317.06	373.15	382.81	401.07	401.10	401.87	396.92
p.m.	401.78	359.04	353.96	370.93	381.74	415.04	399.15	426.07	488.92	459.30	403.75	345.12
a.m.	333.25	315.83	308.52	303.34	300.95	315.77	366.78	383.53	400.99	397.65	427.96	424.09
p.m.	409.17	376.92	375.71	369.13	391.76	414.87	506.23	520.54	511.47	479.24	410.14	364.68
a.m.	328.89	316.51	308.06	302.23	308.63	294.60	340.03	345.76	350.36	357.65	350.52	322.07
p.m.	297.32	290.06	297.70	320.16	341.36	404.76	491.99	499.25	468.55	446.26	416.07	366.38
a.m.	340.86	323.32	310.24	295.19	296.06	307.50	346.38	364.13	378.95	390.91	405.70	393.98
p.m.	396.86	357.32	337.68	346.60	368.94	414.56	469.32	504.62	506.82	463.21	399.22	342.78
a.m.	333.33	318.25	299.04	290.25	289.42	293.59	316.87	337.94	364.68	369.08	378.25	365.60
p.m.	339.15	318.60	313.19	317.38	330.16	400.75	480.39	466.86	457.46	431.89	377.12	331.13
a.m.	300.71	285.59	274.42	263.89	264.89	263.51	280.39	282.12	289.11	273.87	298.51	304.45
p.m.	292.10	267.46	269.20	265.18	285.93	322.35	410.79	403.70	412.73	420.41	371.49	327.97
a.m.	294.31	281.92	264.05	257.69	261.62	267.43	258.36	228.25	211.04	205.67	203.53	200.00
p.m.	209.32	209.11	224.48	234.25	246.58	294.53	419.82	422.82	446.79	390.76	341.98	300.73
a.m.	276.39	257.90	252.67	249.59	241.69	237.04	240.11	252.21	236.47	232.54	237.62	245.41
p.m.	238.59	226.09	228.83	228.84	246.19	253.77	420.31	421.35	396.58	380.71	320.65	300.96
a.m.	281.01	264.27	254.08	247.10	239.90	234.55	239.90	256.42	253.16	257.75	255.62	276.29
p.m.	277.47	243.06	232.31	233.94	262.93	299.98	445.09	423.65	410.46	382.09	326.82	285.51
a.m.	270.58	261.20	253.43	249.65	247.70	246.96	247.40	253.16	258.90	259.14	268.53	261.07
p.m.	248.71	228.42	219.83	235.80	262.95	328.16	453.63	453.65	425.93	389.61	333.03	289.65
a.m.	262.98	247.26	240.11	236.96	244.79	248.43	276.88	297.09	305.45	321.39	329.18	324.84
p.m.	310.56	301.93	291.74	290.12	307.57	354.86	486.09	486.63	451.18	423.80	358.08	308.58

TABLE G-2 : HOURLY DEMAND IN WEST ZONE FOR AUGUST, 1985
(MW)

TIME →	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00
a.m.	115.63	107.87	106.36	103.23	103.48	120.75	147.58	143.15	141.62	120.26	144.18	148.27
p.m.	134.22	115.23	106.84	112.07	124.79	143.27	201.98	209.62	179.81	156.61	131.04	106.59
a.m.	107.50	100.05	95.10	90.75	90.75	89.55	118.56	121.58	106.29	112.59	120.26	118.63
p.m.	103.36	87.95	79.15	86.95	101.59	123.54	181.06	188.76	180.03	164.47	142.49	122.96
a.m.	114.23	106.14	103.83	86.18	91.78	107.92	142.65	132.77	144.51	151.60	157.70	155.77
p.m.	148.69	124.21	117.87	124.72	140.70	161.26	207.21	217.54	204.38	176.18	146.56	127.91
a.m.	119.34	113.89	111.23	107.83	109.03	122.62	146.69	147.32	147.11	153.67	161.11	156.85
p.m.	142.68	123.18	113.54	118.13	137.60	166.61	213.59	216.47	202.10	175.17	149.28	131.39
a.m.	117.95	113.87	110.55	106.32	112.73	122.70	154.65	150.47	157.09	160.19	169.59	163.02
p.m.	138.45	122.53	115.10	127.86	135.99	164.96	219.22	225.86	209.06	172.37	144.27	127.26
a.m.	118.30	111.50	107.89	101.73	103.13	116.70	148.12	144.48	139.56	136.87	154.85	150.32
p.m.	136.65	115.61	108.56	116.41	135.19	163.43	214.51	220.38	190.22	131.31	111.71	94.99
a.m.	112.18	105.36	102.42	98.64	104.64	114.78	148.73	152.65	145.53	149.77	151.88	151.78
p.m.	140.51	120.95	113.95	114.89	141.46	169.09	199.30	210.76	196.89	171.01	144.46	114.04
a.m.	116.91	111.91	107.31	104.39	106.59	122.56	152.03	155.94	147.13	153.29	162.99	160.59
p.m.	142.11	101.76	140.53	150.32	163.30	162.01	207.36	210.86	195.64	167.81	138.50	124.96
a.m.	110.58	104.59	102.23	101.14	102.68	106.22	136.66	139.88	110.91	108.18	113.35	114.58
p.m.	102.69	95.56	88.58	99.18	108.83	150.31	187.78	197.03	185.68	160.27	144.44	137.87
a.m.	114.82	108.21	109.32	101.36	103.10	119.63	157.71	156.88	154.65	155.15	164.38	148.63
p.m.	138.45	118.01	115.77	119.48	132.61	156.05	204.86	204.21	179.89	166.32	144.12	135.64

TIME →	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00
a.m.	124.03	113.87	111.83	110.34	113.54	127.23	151.63	154.41	147.33	151.27	149.93	160.39
p.m.	133.27	126.36	119.94	124.40	140.83	165.73	205.99	201.20	195.17	174.58	150.15	135.18
a.m.	121.45	117.18	112.07	111.69	114.38	130.04	150.59	152.80	161.14	158.42	164.82	154.41
p.m.	141.78	133.42	120.27	121.95	139.23	155.00	212.12	229.23	194.46	171.87	147.84	132.95
a.m.	115.20	111.54	106.57	112.40	114.04	123.07	130.53	142.26	150.14	158.68	163.62	169.08
p.m.	153.51	137.07	127.81	129.95	145.83	164.88	208.56	218.65	194.60	186.74	157.95	130.67
a.m.	120.07	118.02	103.90	104.10	109.28	118.76	160.13	146.30	145.88	149.35	167.12	157.60
p.m.	142.41	120.11	117.50	125.07	149.63	164.45	201.14	207.86	198.81	179.76	154.33	134.63
a.m.	116.79	117.17	112.08	110.79	114.01	128.75	161.58	162.20	157.90	164.47	172.62	169.26
p.m.	152.47	130.50	126.65	129.89	140.10	161.98	212.90	193.60	200.82	188.69	150.80	131.25
a.m.	121.97	116.81	112.71	111.72	110.92	121.16	141.96	141.09	93.35	100.72	95.32	107.68
p.m.	101.58	95.86	90.35	98.53	116.81	142.09	180.14	180.09	178.18	166.18	143.08	131.27
a.m.	119.95	116.60	111.02	110.21	113.05	132.76	174.58	162.66	165.00	164.23	178.76	172.84
p.m.	158.61	134.59	129.31	131.50	148.29	180.51	168.20	194.62	182.15	176.34	158.33	140.58
a.m.	63.80	61.70	61.10	60.00	65.80	73.00	159.74	157.34	153.39	165.82	173.73	156.12
p.m.	145.50	123.53	132.51	130.61	152.57	160.05	196.40	203.04	193.97	177.90	145.51	128.30
a.m.	128.80	121.96	116.62	109.52	123.30	127.55	163.53	163.73	162.01	168.72	168.60	166.36
p.m.	162.41	124.66	122.77	130.97	148.06	173.27	217.99	188.67	189.37	179.65	155.78	133.00
a.m.	125.27	118.70	112.32	112.10	118.34	127.42	156.55	160.98	156.42	154.76	169.07	161.20
p.m.	150.86	129.01	126.55	134.37	150.22	169.32	189.86	186.20	181.40	147.15	126.46	123.58

TIME →	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00
a.m.	114.71	110.83	108.75	107.32	110.96	116.48	154.31	158.82	155.51	154.40	155.37	161.10
p.m.	147.61	134.04	126.05	132.34	146.63	171.61	176.82	182.96	189.60	173.78	149.94	133.36
a.m.	123.46	116.30	113.48	107.69	113.42	125.79	165.91	157.84	149.84	160.55	171.87	169.41
p.m.	155.32	137.61	132.81	136.86	155.15	185.74	225.67	206.45	191.80	182.10	148.58	131.98
a.m.	118.84	113.26	105.67	106.53	112.26	91.79	119.42	123.72	119.29	115.05	123.66	128.73
p.m.	107.69	100.59	96.95	105.81	143.95	165.46	204.48	204.40	168.92	156.50	132.75	123.29
a.m.	122.62	116.63	112.30	110.83	112.72	120.65	143.62	160.19	155.44	156.96	172.40	167.98
p.m.	135.38	132.58	129.52	133.00	156.61	179.12	206.74	196.32	190.58	165.66	129.47	117.73
a.m.	117.81	113.31	109.01	106.01	107.63	114.16	144.46	156.45	151.81	151.48	166.21	164.32
p.m.	145.77	132.82	126.81	128.74	145.94	172.28	207.63	208.25	178.18	161.74	141.49	122.07
a.m.	111.63	107.95	104.25	97.47	99.73	102.91	123.63	132.65	123.58	130.10	134.64	133.02
p.m.	129.87	115.70	104.73	110.49	126.23	145.06	174.08	183.80	171.87	157.29	128.08	116.72
a.m.	106.00	98.40	95.88	93.04	96.83	98.37	110.06	105.40	92.55	84.54	83.56	87.30
p.m.	85.34	84.62	92.97	100.64	106.30	120.96	159.20	164.07	154.21	140.49	112.52	95.20
a.m.	90.49	87.10	83.84	82.65	85.10	84.91	100.73	113.14	108.48	105.53	104.46	112.43
p.m.	110.25	98.00	86.26	88.66	98.03	121.79	188.49	175.06	156.86	139.48	125.23	115.84
a.m.	100.77	83.11	92.16	86.86	90.66	88.10	112.82	118.88	114.64	115.28	123.78	120.38
p.m.	114.47	98.06	91.30	89.72	104.85	123.22	197.17	180.77	161.65	144.81	121.14	108.45
a.m.	103.17	96.50	93.91	90.44	96.69	100.31	114.84	119.49	103.39	111.75	118.80	105.46
p.m.	92.10	79.05	74.15	75.75	100.82	144.94	202.42	203.73	177.21	156.16	135.80	117.03
a.m.	110.39	117.83	99.51	98.70	97.26	107.75	130.62	131.03	133.42	136.65	148.89	158.37
p.m.	143.40	124.01	114.23	121.12	138.90	159.96	221.53	220.31	180.65	151.82	127.76	95.14

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