COMMON-MODE OUTAGE MODELLING FOR COMPOSITE SYSTEM RELIABILITY ASSESSMENT USING SEQUENTIAL MONTE CARLO SIMULATION TECHNIQUE

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A THESIS
SUBMITTED TO THE DEPARTMENT OF ELECTRICAL AND ELECTRONIC ENGINEERING, BANGLADESH UNIVERSITY OF ENGINEERING AND TECHNOLOGY (BUET),IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE
OF
MASTER OF SCIENCE IN ENGINEERING

DEPARTMENT OF ELECTRICAL AND ELECTRONIC ENGINEERING
BANGLADESH UNIVERSITY OF ENGINEERING AND TECHNOLOGY

SEPTEMBER 1998

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in partial fulfillment of the requirements for the degree of M.Sc. Engineering in Electrical and Electronic Engineering

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ACKNOWLEDGEMENT

It is a great pleasure of the author to acknowledge his sincere and heartiest gratitude to his supervisor, Dr. Mashiur Rahman Bhuiyan, Associate Professor, Department of electrical and Electronic Engineering, Bangladesh University of Engineering and Technology (BUET), Dhaka for his continued guidance, friendly supervision, kind co-operation, constant encouragement and valuable suggestions.

The author wishes to acknowledge his profound indentedness to Dr. Enamul Basher, Professor and Head, Department of electrical and Electronic Engineering, Bangladesh University of Engineering and Technology (BUET), Dhaka for his active co-operation in every conceivable way.

The author also wishes to express his thanks and sincerest gratitude to Dr. S. M. Lutful Kabir, Professor, Department of electrical and Electronic Engineering, Bangladesh University of Engineering and Technology (BUET), Dhaka for his help and co-operation to complete this work.

Sincere thanks to all colleagues and friends for their co-operation. The author is grateful to his parents, brother, sisters and wife for their encouragement.

ABSTRACT

The reliability assessment of composite generation and transmission systems now-a-days has drawn prime interest in the area of power system planning, designing and evaluation of reliability. As the demand of the modern society is to have electrical energy as economically as possible with a specified degree of reliability, therefore, there is a significant need to assess the reliability of the composite systems. To evaluate the specified reliability of the composite systems it is necessary to include all the operational factors. Power system reliability assessment can be divided into two basic aspects: adequacy and security. Most of the probabilistic techniques presently available for reliability evaluation are in the domain of adequacy assessment. There are two basic techniques available in the literature for reliability evaluation of composite systems: the analytical approach and simulation approach. Analytical approach represents the system by analytical models and evaluate the indices from these models using mathematical solutions. Monte Carlo simulation methods, however, estimate the indices by a simulating the actual process and random behaviour of the system. When complex operating conditions are involved and/ or the number of severe events is relatively large, Monte Carlo methods are often preferable. Power system reliability evaluation by simulation can be applied in two ways: non-sequential or randomly and sequential or chronological order.

The available technique for composite generation and transmission system normally consider only simultaneous independent outages because usually the common-mode failure rate is small i.e. typical values only of the order of 10% of independent failure rates. But such failures might have severe consequence on the system performance. Many utilities are, therefore now using common-mode representations for composite system adequacy analysis. Although the state space transition diagram for common-mode outages are well established. But they can only be utilized in random or non-sequential simulation not in sequential simulation. In case of common-mode outage, several departure transition may occur from each state, then it is difficult to predict the next transition. To overcome this difficulty a new approach has been developed in this research. This new algorithm is accommodated in the sequential simulation procedures to evaluate power system with common-mode failures.

Several common-mode outage groups are considered and their effect on reliability indices are shown in this thesis. So the inadequacies associated with common-mode outages in a composite power system are highlighted more accurately in this thesis. Therefore, the results of such a study are of great importance to the system planner and operator during the design and operation phases of a power system for more exhaustive analysis. In this research IEEE-RTS is evaluated using sequential Monte Carlo simulation technique for numerical evaluation.

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LIST OF ABBREVIATIONS

BDOI	Duration of Interruption at Buses
BENSI	Expected Energy not Served per Interruption at Buses
BNOI	Number of Interruption at Buses
BYDOI	Yearly duration of Interruption at Buses
BYENS	Yearly Energy not Served at Buses
BYNOI	Yearly Number of Interruption at Buses
CDF	Cumulative Density Function
CEA	Canadian Electrical Association
CIGRE	"Conference Internationale des Grands Reseaux Electriques a Haute Tension" (France)
DOI	Duration of Interruption
EDOIB	Expected Duration of Interruption at Buses
EDSYSE	Expected Duration of System Separation
ENSB	Expected Energy not Served at Buses
EFOIB	Expected Frequency of Interruption at Buses
EID	Expected Interruption Duration
EIR	Energy Index of Reliability
ELCI	Expected Load Curtailed Per Interruption
ENEL	"Ente Nazionate per L' Energia Elettrica" (Italy)
ERIS	Equipment Reliability Information System
EENSPI	Expected Energy not Served per Interruption
FOI	Frequency of Interruption
FSYSE	Frequency of System Separation
HL	Hierarchical Level
IEEE	Institute of Electrical and Electronics Engineers
LCY	Load Curtailed per Year
LOEE	Loss of Energy Expectation
LOLE	Loss of Load Expectation
MTTF	Mean Time to Failure

MTTR	Mean Time to Repair
NOI	Number of Interruptions
NY	Total Number of Simulation Year
PDF	Probability Density Function
RTS	Reliability Test System
TED	Total Energy Demand
TBTR	Time Between Transition
TTF	Time to Failure
TTR	Time to Repair
TTT	Time to Transition
YDOI	Yearly Duration of Interruption
YENS	Yearly Energy not Served
YNOI	Yearly Number of Interruption
λ	Failure Rate
μ	Repair Rate
λ_C	Common-mode Failure Rate
μ_C	Common-mode Repair Rate

CHAPTER-1

INTRODUCTION TO POWER SYSTEM RELIABILITY

1.1 INTRODUCTION

The primary objective of the techniques and criteria used for planning, designing and operating power systems is to supply electrical energy to the customers as economically as possible and with an acceptable degree of reliability and quality. Reliability assessments are therefore an integral part of power system studies in order to assist decisions regarding how much should be expanded on the system in order to improve or maintain the quality, adequacy and reliability of the system. With the over growing technological advancement and tremendous industrial automation during the past few decades, electricity has become an integral part and vital lifeline of present-day society. Even a most casual look at the modern civilization shows the important and crucial part played by electricity. The failure of electricity can often cause effects that range from inconvenience and irritation to a severe impact on society and on its environment. Almost every function of present day halts when the supply of electricity halts. A high degree of reliability of electricity is of utmost concern to the electricity supply industries. For this reason, reliability is, and always has been, one of the major factors in the planning, design, operation and maintenance of the electric power systems.

There are many variations on the definition of reliability, but a widely accepted form [1] is:

"Reliability is the probability of a device performing its purpose adequately for the period of time intended under the operating conditions encountered".

The concept of power system reliability, however is extremely broad, and covers all aspects of the ability of the system to satisfy the consumer requirements. Hence the term reliability can not be associated with a single specific definition such as that often used in the mission oriented sense. It is therefore necessary to recognize its extreme generality and use it to indicate, in a general rather than specific sense, the overall ability of the system to perform its function.

The term reliability has many interpretations. A simple classification of power system reliability has two basic aspects [2], adequacy and security, and these terms are now accepted in the industry. Adequacy relates to the existence of sufficient generating capacity within the system to provide sufficient energy and the associated transmission and distribution facilities required to transport the energy to the customers. Security relates to the ability of the system to respond to dynamic transient disturbances arising within the system. It is important to appreciate that most of the probabilistic techniques presently available for reliability evaluation are in the domain of adequacy assessment.

A power system consists of three functional zones: Generation, Transmission and Distribution. The functional zones can be combined for the purpose of reliability evaluation as illustrated in the hierarchical levels shown in Fig. 1.1. The composite system or bulk power system is defined as hierarchical level-II i.e. consisting of integrated generation and transmission facilities [3].

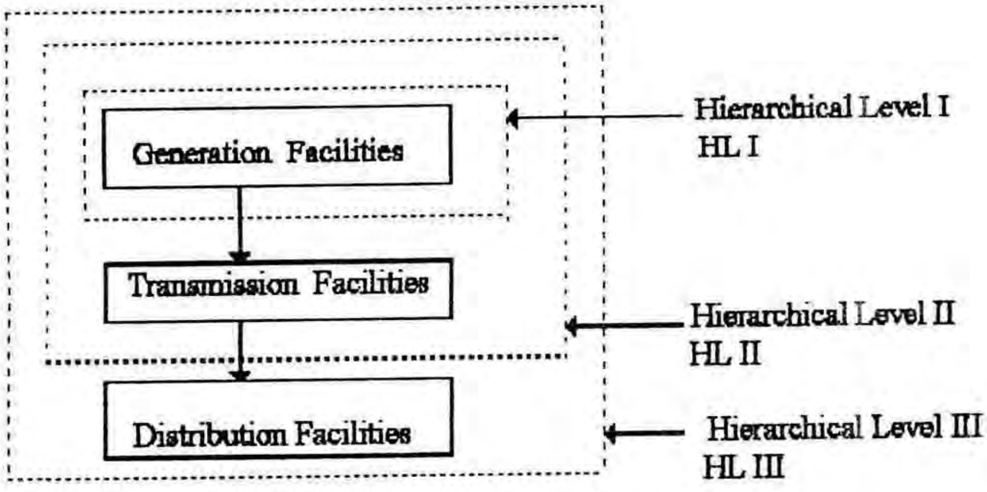

Fig. 1.1: Hierarchical Levels.

Composite system reliability performance is measured in terms of the amount of unreliability created by events in the bulk power system. Unreliability denotes the inability to provide the required electricity to all ultimate customers supplied by the bulk power system [3]. It involves the system failure events which consists of loss of load and system collapse arising from wide spread outages or islanding.

1.2 HISTORICAL BACKGROUND

Design, planning and operating criteria and techniques have been developed over many years in an attempt to resolve and satisfy the dilemma created by the economic, reliability, and operational constraints. The criteria and techniques first used in practical applications were all deterministically based. These include percentage reserves in generation capacity planning or N-1 contingency criteria in transmission planning. The basic weakness of deterministic criteria is that they do not and cannot account for the probabilistic or stochastic nature of system behaviours, of customer demands or of component failures.

The need for probabilistic evaluation of system behaviour has been recognized since at least the 1930's [4, 5], and first significant contributions in this area appeared in 1947 [6-9]. Although some utilities are still using deterministic criteria [10], probabilistic evaluation techniques are now-a-days universally accepted and are becoming more widely used. One of the most significant development in this area was the application of recursive techniques published in a series of five papers by Ringlee, Wood, et al [11-15]. These papers present reliability calculation methods for the generation system that incorporates the frequency and duration of unit outages. Another new method was the cumulant method to obtain the capacity outage probability by using Fourier transforms and Gram-charlier expansion was introduced by N. S. Rau and K. F. Schenk [16] in 1979. Another important technique was proposed by K. F. Schenk [17]. The method consists of obtaining the frequency distribution of equivalent load by convolving the generating units in a merit order of loading. The convolution process is achieved by appropriately shifting and combining the statistical moments of hourly loads and machine outages. Quantitative reliability evaluation using probability methods began with the evaluation of system adequacy at hierarchical level I.

Considerable effort has been expended during the last two decades in developing techniques and criteria for composite generation and transmission system assessment. The term composite refers to the consideration of both generation and transmission system contingencies, including the modelling of the operating policies necessary in order to dispatch generating units, assessment of power flows on transmission system components, alleviate network violations and load shedding if required. The analytical approach which have been applied to evaluate the composite system adequacy is called the contingency enumeration approach.

The contingency enumeration technique represents the system by simplified mathematical models and evaluates the reliability indices using analytical solutions. Billinton [18] illustrated the initial approach of the technique by applying a conditional probability approach in the determination of reliability index at any point in a composite system. Billinton and Bhavaraju [19] in 1970 proposed the use of the service quality standard as the reliability criterion rather than simple continuity between sources and load points of a composite system. They also present hypothetical system studies in which the reliability indices of each system load point are obtained. The utilization of the indices in system planning is illustrated in Reference 20. The proposed procedure used ac load flow solutions of the network to examine possible voltage and overload problems. Additional examples of alternative contingency enumeration approaches are presented in [21-24]. Reference 25 published in 1978 discusses the two aspects of reliability namely adequacy and security. This paper presents a classification and listing of indices in use. The fundamental definition of each index is given. Reference 26-27 present an overview of the major concepts debated by experts in the field of HLII adequacy assessment. These papers review the goals, the time frame and methods of reliability evaluation as well as the conflicting opinions sometimes occurring between American and European utility planners. Reference 28 describes the requirements for composite system reliability evaluation and concentrates on the philosophy and purpose rather than on modelling details. Billinton and Medicherla [29], describe a technique for evaluating the reliability of a composite generation and transmission system. The approach creates a set of busbar indices to assess the performance of the system after alleviating any overloads. The techniques mentioned above are based on analytical approaches in which models of the system are analyzed using mathematical equations and direct numerical solutions. It is worth mentioning that the application of contingency enumeration in HLII assessment appears to have been started in North America.

An alternative approach is simulation, generally known as Monte Carlo simulation. The name and the systematic development of Monte Carlo methods dates from about 1944. There are however a number of isolated and undeveloped instances on much earlier occasions [30-31]. In the beginning of the century the Monte Carlo method was used to examine the Boltzmann equation. In 1908 the famous statistician student used the Monte Carlo method for estimating the correlation coefficient in his t-distribution. The term "Monte Carlo" was introduced by Von Neumann and Ulam during World War II [32], as a code word for the secret work at Los Almos; it was suggested by the casinos at the city of Monte Carlo in Monaco. The real use of Monte Carlo methods as a research tool stems from work on the atomic bomb during the Second World War. Applications of Monte Carlo techniques can be found in many fields such as complex mathematical calculations, stochastic process simulation, medical statistics, Engineering system analysis, and reliability evaluation. In this research Monte Carlo methods have been applied for composite power system reliability evaluation. Application of this technique in power system reliability evaluation were initiated in Europe in the early 1970's [33-38]. Simulation technique is more popular in Europe and South America. Due to the recent development of computing power simulation techniques are gaining popularity in North America as well.

Monte Carlo simulation methods, estimate the indices by simulating the actual process and random behaviour of the system. The method therefore treats the problem as a series of real experiments. Many papers published on Monte Carlo simulation techniques. The first significant papers of simulation approach was found in [39]. This paper presented a new model for forced outages for use in general system simulation program. Monte Carlo methods were applied to the model to simulate random occurrence of force outages, random variations in daily peak load and others. This work has a significance of calculating the dispersion of actual performance about the average performance or about the effects of error in estimation of outage rates. In a more recent paper [40] it was proposed that load and generation should not be treated independently but should be considered in a correlated manner. It was found that simulation was appealing for this application. Other pioneers of simulation include ENEL (Italy) and FDF (France) papers from these organizations, including [41, 42] and others appear in many CIGRE publications and various European conference proceedings.

One of the most recent publication by Billinton and Ghajar [43] illustrated an overall approach in generating system adequacy evaluation using Monte Carlo simulation technique and this is widely used now-a-days. This paper is based on random simulation. Another paper [44] depicted a Monte Carlo simulation method used for generating capacity adequacy assessment. Monte Carlo simulation can be divided into two categories: non-sequential (random) and sequential. The application of Monte Carlo simulation in HLII assessment appears to have been initiated in Europe and particularly in Italy, although extensive work has also been done in France [45] and more recently in Brazil [46].

Reference 47 shows the use of a direct simulation methods for considering a vast number of random contingencies. Both random and sequential Monte Carlo approaches have also been applied in 1975 [48]. Salvaderi and Billinton [49] illustrated comparison of two conceptually different techniques for composite generation and transmission system evaluation. These comparison between simulation and contingency enumeration technique indicates the conceptual differences in modelling and problem perception and allows a better understanding of the merits and demerits of each approach. Reference 50 presents a recent application of the Monte Carlo simulation to the IEEE-RTS [51]. Reference 52 describes some of the basic modelling concepts based on hybrid approach of the Monte Carlo simulation and enumeration technique.

A new computational tool has been described in Reference 53 and 54 where the reliability evaluation methodology is based on Monte Carlo sampling with a variance reduction scheme. This latter technique allows the incorporation of analytical methods. Most of these papers have described the application of random and sequential simulation to the generation system only [48]. Ubeda and Allan [55] summarized the basic characteristics of sequential simulation and applied for the reliability evaluation of composite systems.

But, all the analysis carried out so far in simulation domain have considered only simulations independent outages. Because usually the common-cause or common-mode failure rate is small compared to independent failure rates. But such failures might have severe consequences on the system performance. Many utilities are therefore now using common-mode representation for composite system adequacy analysis.

In reference 56 gives the definition of common-mode outage. According to this papers a common-mode forced outage is an event having a single external cause with multiple failure effects, where the effects are not consequences of each other. This paper also shows from available common-mode data collection that the common-mode outage-events could be significant in transmission reliability calculations. Billinton, Medicherla and Sachdev [57] illustrates effects of the common-mode failure rate and repair rate on reliability indices. This papers also analyzed several possible common-mode outage models and described its impacts on individual load point and overall system reliability indices. Reference 58 present the transmission system models which include both common-mode failures and adverse weather conditions. Both of these factors have been considered as separate phenomenon in previously developed models. The models illustrated in [58] are used to examine the sensitivity of selected reliability indices to individual parameter variation in the composite model. The techniques mentioned above are all based on analytical technique.

Sequential Monte Carlo simulation techniques are well established for evaluating reliability of a composite system which containing only two state components. But if common-mode failure events exists in the composite system, then additional evaluation techniques are required. Due to the advantage of sequential Monte Carlo simulation, it is necessary to accommodate common-mode failures in sequential simulation technique. A new technique has been developed in this research for doing this additional evaluation and this new technique is easily accommodated into a sequential simulation algorithm. This new technique for common-mode failures can be applied to any composite system reliability evaluation using sequential Monte Carlo simulation technique. The system inadequacies associated with common-mode failures can be represented more accurately by this new technique. Therefore the results of such a study can be of great importance to the system planner and operators during design and operation phases of a power system. In this thesis IEEE-RTS [51] is used for numerical evaluation.

1.3 THESIS ORGANIZATION

This thesis consists of six chapters. As an introduction, chapter 1 draws an overview of power system reliability and the historical background of the reliability assessment of power systems. This chapter also points out the background of the sequential simulation. Chapter 2 describes elements of the Monte Carlo method. This description based on the mathematical fundamentals of Monte Carlo simulation places emphasis on the application aspects of Monte Carlo methods in system reliability evaluation. Chapter 3 deals with the composite system model i.e. description of generation system, transmission system and load models that are used in this research. Chapter 4 brings out the new approach which is used to evaluate the IEEE-RTS reliability indices. This chapter also describes the simulation procedure and the functional block diagram depicting the procedure. Using this new approach in sequential simulation methodology and taking data from IEEE-RTS different reliability indices for different single and multiple common-cause outage have been estimated and the numerical results are shown in chapter 5. In chapter 6 discussions and conclusions are presented on the basis of the results of chapter 5. Recommendations for further research are also provided in chapter 6.

CHAPTER-2

ELEMENTS OF MONTE CARLO SIMULATION

2.1 INTRODUCTION

This chapter describes the basic elements of Monte Carlo Simulation. In general, random number/variate generation and variance reduction techniques are the most basic and important aspects of the Monte Carlo simulation method. In this chapter Monte Carlo Methods are also discussed from a reliability point of view. This chapter provides the theoretical fundamentals required to apply Monte Carlo Methods in reliability assessment.

2.2 FEATURES OF MONTE CARLO METHODS IN RELIABILITY EVALUATION

A fundamental parameter in reliability evaluation is the mathematical expectation of a given reliability index. Salient features of the Monte Carlo method for reliability evaluation therefore can be discussed from an expectation point of view.

Let $\overline{Q}$ be the unavailability (failure probability) of a system and x_i be a zero-one indicator variable which states that

$x_i = 0$ if the system is in the up-state
$x_i = 1$ if the system is in the down-state

The estimate of the system unavailability is given by

$$\overline{Q} = \frac{1}{N}\sum_{i=1}^{N} x_i \qquad (2.1)$$

where N is the number of system state samples.
The unbiased sample variance is

$$V(x) = \frac{1}{N-1}\sum_{i=1}^{N}(x_i - \overline{Q})^2 \qquad (2.2)$$

When the sample size is large enough, equation (2.2) can be approximated by

$$V(x) = \frac{1}{N}\sum_{i=1}^{N}(x_i - \overline{Q})^2 \qquad (2.3)$$

Because x_i is a zero-one variable, it follows that

$$\sum_{i=1}^{N} x_i^2 = \sum_{i=1}^{N} x_i \tag{2.4}$$

Substituting equations (2.1) and (2.4) into equation (2.3) yields

$$\begin{aligned} V(x) &= \frac{1}{N}\sum_{i=1}^{N} x_i^2 - \frac{1}{N}\sum_{i=1}^{N} 2x_i\overline{Q} + \frac{1}{N}\sum_{i=1}^{N}\overline{Q}^2 \\ &= \overline{Q} - 2\overline{Q}^2 + \overline{Q}^2 \\ &= \overline{Q} - \overline{Q}^2 \end{aligned} \tag{2.5}$$

Equation 2.1 gives only an estimate of the system unavailability. The uncertainty around the estimate can be measured by the variance of the expectation estimate.

$$\begin{aligned} V(\overline{Q}) &= \frac{1}{N} V(x) \\ &= \frac{1}{N}\left(\overline{Q} - \overline{Q}^2\right) \end{aligned} \tag{2.6}$$

The accuracy level of Monte Carlo Simulation can be expressed by the coefficient of variation, which is defind as

$$\alpha = \sqrt{V(\overline{Q})} \,/\, (\overline{Q}) \tag{2.7}$$

Substitution of equation (2.6) into equation (2.7) gives

$$\alpha = \sqrt{\frac{1-\overline{Q}}{N\overline{Q}}} \tag{2.8}$$

Equation (2.8) can be rewritten as

$$N = \frac{1-\overline{Q}}{\alpha^2\overline{Q}} \tag{2.9}$$

This equation indicates two important points:

1. For a desired accuracy level α, the required number of samples N depends on the system unavailability but is independent of the size of the system. Monte Carlo methods are therefore suited to large-scale system reliability evaluation.

2. The unit unavailability (failure probability) in practical system reliability evaluation is usually much smaller than 1.0. Therefore,

$$N \approx \frac{1}{\alpha^2 \overline{Q}} \tag{2.10}$$

This means that the number of samples N is approximately inversely proportional to the unavailability of the system. In other words, in the case of a very reliable system, a large number of samples is required to satisfy the given accuracy level.

2.3 CONVERGENCE CHARACTERISTICS OF MONTE CARLO METHODS

(a) Convergence process:

Monte Carlo Simulation creates a fluctuating convergence process as shown in Fig. 2.1 and there is no guarantee that a few more samples will definitely lead to a small error. It is true, however, that the error bound or the confidence range decreases as the number of samples increases.

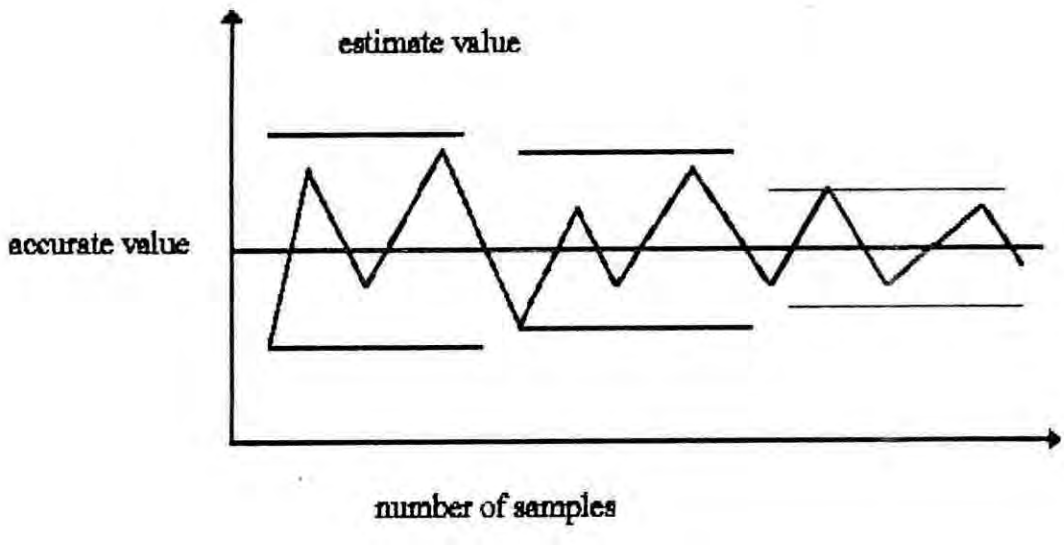

Figure-2.1: Convergence process in Monte Carlo simulation.

(b) Convergence Accuracy:

The variance of the expectation estimate is given by the following equation:

$$V(\overline{Q}) = \frac{1}{N} V(x) \tag{2.11}$$

where

$\overline{Q}$ unavailability of a system

x is the state variable

and N is the number of state samples

The standard deviation of the estimate can be obtained as follows:

$$\delta = \sqrt{V(\overline{Q})} = \frac{\sqrt{V(x)}}{\sqrt{N}} \tag{2.12}$$

This indicates that the measures can be utilized to reduce the standard deviation in a Monte Carlo Simulation: increasing the number of samples decreases the sample variance. Variance reduction techniques can be used to improve the effectiveness of Monte Carlo Simulation. The variance cannot be reduced to be zero therefore it is always necessary to utilize the reasonable and sufficiently large number of samples.

(c) Convergence Criteria:

The coefficient of variation shown in equation 2.7 is often used as the convergence criteria in Monte Carlo Simulation. In power system reliability evaluation, different reliability indices have different convergence speeds. It has been found that the coefficient of variation of the EENS index has the lowest rate of convergence [59]. This coefficient of variation should therefore be used as the convergence criterion in order to guarantee reasonable accuracy in a multi-index study.

2.4 RANDOM NUMBERS GENERATION

A random number can be generated either by using a physical or by a mathematical method. The mathematical method is most common as it can guarantee reproducibility and can be easily performed on a digital computer. A random number generated by a mathematical method is not really random and therefore is referred to a pseudorandom number [59].

The basic requirements of the generator are that the random numbers should possess the following characteristics-

i. **Uniformity:** The random numbers should be uniformly distributed between (0, 1). i.e. the number can take any value between zero and unity with equal likelihood.

ii. **Independence:** There should be minimal correlation between random numbers.

iii. **Long-Period:** The repeat period should be sufficiently long.

There is a wide range of random number generation methods. Two commonly used methods are:

a. Multiplicative Congruential Generator Method.

b. Mixed Congruential Generator Method.

2.4.1 Multiplicative Congruential Generator:

The multiplicative congruential generator method was presented in 1949 by D.H. Lehmer [60] and is based on a fundamental congruence relationship from which a new number x_{i+1} in a sequence is calculated from the previous value x_i using the expression.

$$x_{i+1} = Ax_i (\mathrm{mod}\, B) \tag{2.13}$$

Where A is a multiplier and B is the modulus; A and B have to be non-negative integers. The module notation (mod B) means that

$$x_{i+1} = Ax_i - Bk_i \tag{2.14}$$

where $k_i = [Ax_i/B]$ denotes the largest positive intiger in Ax_i/B. After deducing the sequence of random numbers, x_i, a uniformly distributed random number U_i in the range (0, 1) is found from the relation:

$$U_i = \frac{x_i}{B} \tag{2.15}$$

The process is started by choosing a value x_o known as the seed. The sequence is then produced automatically. However, the sequence will repeat itself after a number of steps which can be shown to be equal to a value not greater than B.

2.4.2 Mixed Congruential Generator:

In 1961, M. Greenberger generalized the multiplicative congruential generator to the mixed congruential generator, which is based on the following congruential relationship [61]:

$$x_{i+1} = (Ax_i + C) \pmod{B} \tag{2.16}$$

It is seen that, in addition to parameters A and B, a new parameter C is added into the multiplicative congruential generation. The quantity C is called the increment and it also to be a nonnegative integer.

The modulo notation (mod B) means that

$$x_{i+1} = Ax_i + C - Bk_i \tag{2.17}$$

where $k_i = (Ax_i + C)/B$ denotes the largest positive integer in $(Ax_i + C)/B$. After deducing the sequence of randon numbers, x_i a uniformly distributed random number U_i in the range (0,1) is found from the relation:

$$U_i = \frac{x_i}{B} \tag{2.18}$$

This process is started by choosing a seed value (x_o). The sequence is then produced automatically. Such a sequence will repeat itself in at most B steps and therefore it will be periodic. If the period of the sequence equals B, the random number generator is considered to have a full period.

Among these two methods, the multiplicative congruential generator is used in this research to generate random numbers. The constants A & B are chosen in this method to give optimal statistical properties. The multiplier and the modulus values used in this research are

$A = 16807$
$B = 2^{31} - 1$

After a sequence of random numbers has been created, they can be tested for independence and randomness using one of the standard statistical tests such as chi-squared and kolmogorov-smirnov goodness-of-fit tests [32].

2.5 RANDOM VARIATE GENERATION

A random variate refers to a random variable following a given distribution. The random number generation methods given in the previous sections are essentially ones which generate a random variable following a uniform distribution between (0, 1). Generators of random variates which follow other distributions are based on uniformly distributed random number between (0, 1).

The procedures for generating nonuniformly distributed random variates can be generally categorized into three techniques [59];

a. Inverse transform method.

b. Composition method.

c. Acceptance-rejection method.

Above these method, inverse transform method is most frequently used. The exponential and normal distributions are the most important ones in reliability evaluation. The exponential distribution is used in this research work. So techniques for generating exponentially distributed random variates are discussed in this chapter.

2.5.1 Exponentially Distributed Random Variates Generation (The inverse transform method):

An exponentially distributed random variate has the probability density function (PDF)

$$f(x) = \lambda e^{-\lambda x} \tag{2.19}$$

Its cumulative probability distribution function is

$$\begin{aligned} F(x) &= \int_o^x \lambda e^{-\lambda x} dx \\ &= 1 - e^{-\lambda x} \end{aligned} \tag{2.20}$$

By the inverse transform method

$U = F(x) = 1 - e^{-\lambda x}$

So that

$$X = F^{-1}(U) = -\frac{1}{\lambda}\ln(1 - U) \tag{2.21}$$

Since (1 - U) distributes uniformly in the same way as U in the interval (0, 1)

$$X = -\frac{1}{\lambda}\ln U \tag{2.22}$$

where U is a uniformly distributed randon number sequence and x follows an exponential distribution i.e. x is exponentially distributed random variates.

2.6 VARIANCE REDUCTION TECHNIQUES

The efficiency of Monte Carlo method depends on the computing time multiplied by the variance of the estimate. While evaluating reliability of power systems using Monte Carlo methods, the computing time and the variance are directly affected by the selected sampling techniques and system analysis requirements [59]. Sampling techniques include random number (or variate) generation methods, variance reduction techniques, and different sampling approaches. The purpose of system analysis is to judge if a system state is good or bad.

It has been already shown that the standard deviation of a estimate,

$$\delta = \frac{\sqrt{V(x)}}{\sqrt{N}}$$

From this equation it is concluded that standard deviation in a Monte Carlo Simulation can be reduced by increasing the number of samples and/or by decreasing the sample variance.

So the application of variance reduction techniques is an important concept in Monte Carlo Simulation. Five variance reduction techniques which are useful in power system reliability evaluation are control variates, importance sampling, stratified sampling, antethetic variates, and dagger sampling. In order to reduce the computational afford, the variance reduction technique can be used when the computing facilities is not sufficient and the system is very large. Although this technique is not used in this research but it is a very important concept in Monte Carlo simulation.

2.7 SIMULATION APPROACH IN RELIABILITY EVALUATION

Simulation techniques, generally known as Monte Carlo simulation estimate the indices by simulating the actual process and random behaviour of the system. The method therefore treats the problem as a series of real experiments [10]. Power system reliability evaluation by Monte Carlo Simulation can be applied in two ways [62, 63]; sequential and non-sequential (or random). Sequential approach simulates the basic intervals of the simulated period in chronological order and non-sequential approach simulates system life time at randomly chosen intervals of time.

Three sampling approach used in Monte Carlo simulation are state sampling approach, state duration sampling approach and system state transition sampling approach. The state sampling approach is based on sampling the probability of system state which depends on the combination of all component states and each component state can be determined by sampling the probability that the component appears in that state. The state duration sampling approach is based on sampling the probability distribution of the component state duration. In this approach, chronological component state transition processes for all components are first simulated by sampling. The chronological system state transition process is then created by combination of the chronological component state transition processes [59]. This approach uses the component state duration distribution functions. System State Transition Sampling approach focuses on state transition of the whole system instead of component states or component state transition processes.

If a system contains m components the transition rate of each component is λ_i ($i = 1,2, ... m$) and corresponding state duration of each component is T_i. System state transition depends randomly on the state duration of the component which departure earlist from its present state i.e. the duration T of present system state $S^{(k)}$ is a random variable which can be expressed by

$$T = \mathrm{Min}_i \{T_i\} \tag{2.23}$$

Since state duration of each component follows an exponential distribution, the random variable T also follows an exponential distribution and the probability density function

$$f(t) = \sum_{i=1}^{m} \lambda_i \exp\left(-\sum_{i=1}^{m} \lambda_i t\right) \tag{2.24}$$

If the system state $S^{(k)}$ starts at instant 0 and the system state change from $S^{(k)}$ to $S^{(k)}$ at instant to. This transition is caused by departure of the j-th component from its present state.

The probability of this transition is the following conditional probability

$P_j = P(T_j = \underline{to/T = to})$. $\frac{t_o}{T} = t_o$

The system contains m components and possible reached states of the system is m. The probability that the system reaches one of these possible states is expressed by the following equation

$$\sum_{j=1}^{m} P_j = 1 \tag{2.25}$$

Therefore, the next system state can be determined by the following simple sampling. The probabilities of m possible reached states are successively placed in the interval [0, 1] as shown in Figure 2.2.

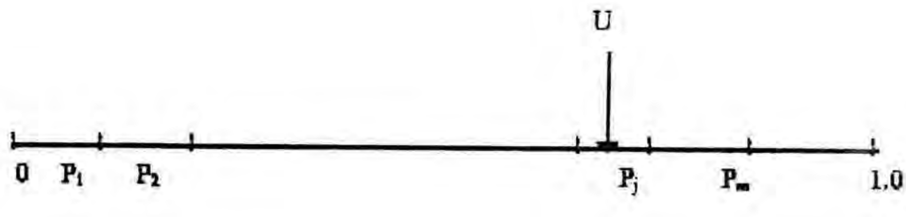

Figure-2.2: Explanation of System State Transition Sampling.

If U is the uniformly distributed random number between [0, 1] and the value of U falls into the segment corresponding to P_j, this means that the transition of the j-th component leads to the next system state. A long system state transition sequence can be obtained by a number of samples and the reliability of each system state can be evaluated.

The new approach which is used in this research has some similarities with system state transition sampling approach. System state transition sampling approach considers all the components of the system at the same time. In this approach many transition may occur at a time and random numbers are required to determine the next transition state. But, the new approach considers all the components individually and the total number of possible transition for each state together with correct transition rate are determined. The time to transition (TTT) are sampled for each possible transition from the state. The smallest value of TTT is the state residence time of this state. After elapsing the TTT time, the component moves from this state to another state (which is determined from the smallest value of TTTs). Similarly for every state the smallest value of TTT is determined which also gives the next state. If the state is known, then the individual status of the lines are determined from that state. After the individual component states have been determined, these states are combined to find the system performance state. This new approach is used in this research which is described in detail in chapter 4.

2.8 EVALUATING SYSTEM RELIABILITY BY MONTE CARLO SIMULATION

In order to illustrate the utilization of Monte Carlo techniques in reliability evaluation, a simple example is given in this section.

Two independent repairable components, A and B, operate in parallel and system operation requires at least one component in service. The state durations of both A and B follow Exponential distributions. Their failure rates are denoted by λ_A and λ_B and repair rates by μ_A and μ_B respectively. The reliability of the system without considering repair can be obtained using the following analytical expression

$$R_s = 1 - (1 - e^{-\lambda_A T})(1 - e^{-\lambda_B T}) \tag{2.26}$$

where T is the mission time.

If repairs are taken into consideration, the problem is relatively complex to solve by an analytical method. It can be solved easily by Monte Carlo Simulation. In this technique, the reliability of the system can be estimated by observing the results of random experiments. The first step is to simulate the transition processes of the two components. If there is no overlapping repair in the time interval [0, T], the experiment is said to be "success" (Fig. 2.2), otherwise, it is a "failure". By defining the following indicator variables:

$$X_i = \begin{cases} 0 & \text{if the i-th experiment is a "success"} \\ 1 & \text{if the i-th experiment is a "failure"} \end{cases}$$

the reliability of the system for a mission time of T can be obtained by

$$R_s = 1 - \frac{\sum_{i=1}^{N} X_i}{N} \tag{2.27}$$

where N is the number of experiments.

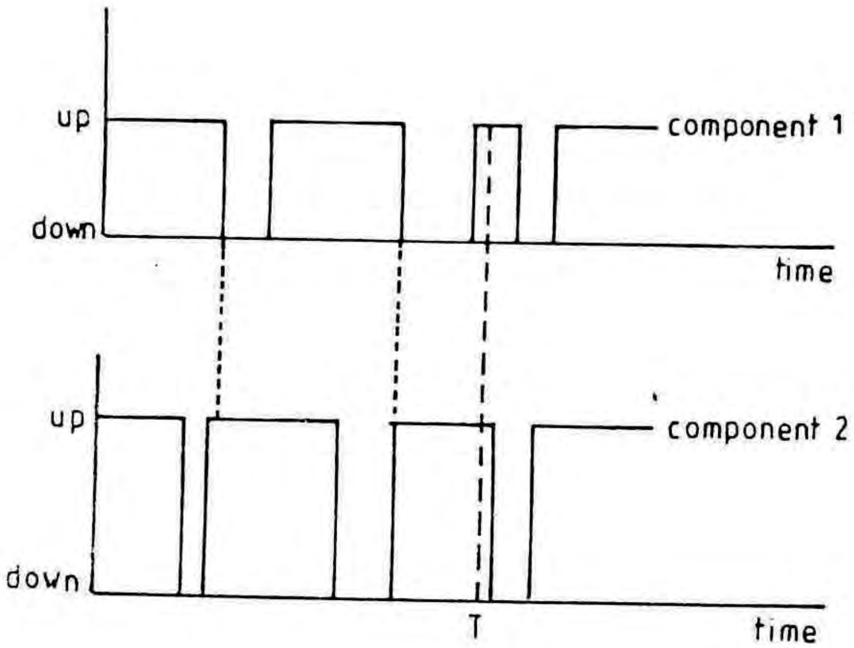

Fig.-2.3: Chronological Component State Transition Process.

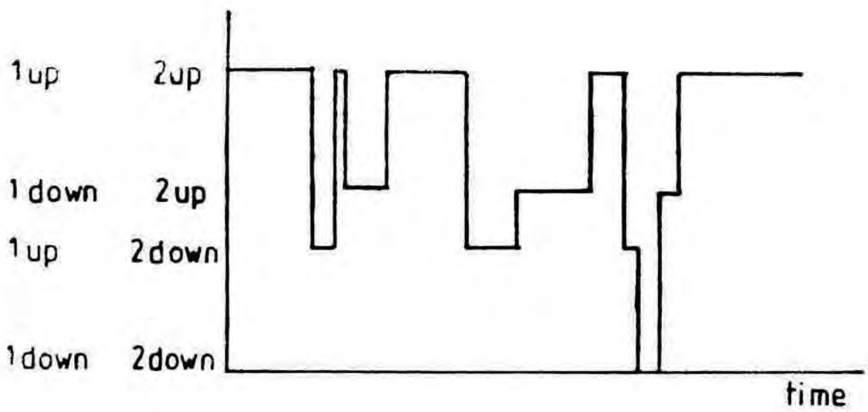

Fig.-2.4: Chronological System State Time Transition Process.

Similarly, the availability of the system can be calculated using the following analytical expression

$$A_s = 1 - \left(\frac{\lambda_A}{\lambda_A + \mu_A}\right)\left(\frac{\lambda_B}{\lambda_B + \mu_B}\right) \tag{2.28}$$

eq^n deduced or emperical ?

The availability of the system using Monte Carlo simulation can be estimated by observing the chronological system state transition process over a sufficiently long time as shown in Fig. 2.3. The value of A_S can be calculated using

$$A_S = \frac{\text{Total system up time}}{\text{Total simulation time}}$$

CHAPTER-3

GENERATION AND TRANSMISSION SYSTEM MODEL

3.1 INTRODUCTION

The basic objective of composite generation and transmission system adequacy assessment (HL2) is to evaluate the ability of the system to satisfy the load and energy requirements at the major load points. This evaluation domain involves the joint reliability problem of generating sources and transmission facilities.

Composite generation and transmission system modelling is essential for meaningful reliability assessment of a power system by Sequential Monte Carlo Simulation technique. For meaningful assessment using Monte Carlo simulation technique it is necessary to know the actual behaviour of each constituent components of the system, i.e. generating units and transmission lines. Because the actual behaviour of all its components i.e. generating units and transmission lines behaviour known is necessary for Monte Carlo Simulation technique. This is done by modelling each component of the system. These models represent actual behaviour of each type of component the system. Generating system model, transmission system model and the load model which are used in this study are described in the following section of this chapter. There are many possible indices which can be used to measure the inadequacy of composite system. The widely used power system adequacy indices which is used in the research are also discussed very briefly in this chapter.

3.2 GENERATION SYSTEM

The generating system is one of the major parts of a power system. In power system reliability analysis all the components of thermal plants (boiler, turbine, allernators etc.) are generally grouped into generating unit and represented by the availability model.

3.2.1 Availability Model:

The availability model of thermal generating units is concerned with forced outages and reparis. This assumes that [64]

(a) the time between forced outages and the outage duration are independent.

(b) a forced outage of any unit causes the loss of total capacity.

(c) the time to failure (TTF) is sampled from the corresponding underlying distribution using the mean time to failure (MTTF). A random value of TTF sampled every time the failed unit is repaired and restored to service.

(d) the outage duration is also assumed to be distributed obeying any underlying probability distribution having the mean value given by the mean time to repair (MTTR). A random value of TTR is sampled every time a component fails.

(e) the repair is undertaken as soon as any element fails, repair time is independent of any other repairs or failures and repair is always successful and restores the component to as-gòod-as-new.

3.2.2 Operating and Dispatch Policies

The operating policies determine what thermal generation and units should be committed. At HLII, transmission system constraints are taken into account and consequently redispatch and load shedding is needed if overloads appear in any line. These algorithms are also part of the operating policies.

An operating policy can be based on either a pure safety policy where only system reliability is interest or a mixed economy-safety policy when reliability as well as running costs are considered [49]. The mixed economy-safety policy is applied as an economic dispatch where the cost of generation is reduced.

3.2.2.1 Thermal Generation

The dispatch model used classifies the thermal generating units into four different types [65]:

THA - Base generation

THB - Economic generation

THC - Expensive generation

THD - Peaking generation

Each thermal unit is type-specified and this specification remains fixed for the entire simulation span. Within each type thermal units are dispatched according to their incremental fuel cost or a predetermined merit order.

3.2.3 Production Cost

Thermal units are associated with incremental fuel costs and these vary over a wide range depending on the type of the fuel used. The incremental fuel cost associated with a thermal unit usually represents the average behaviour of the corresponding heat rate curve.

In reliability assessment, it is the number of units, their capacities and their failure and repair PDF which account for the system reliability rather than the order in which the units are loaded. However, in cost analysis the loading order is also important. For the economic operation of the system, the schedule for the commitment of the units in order of their increasing average incremental cost called economic commitment schedule or merit order of loading, is used. The most economically efficient generating unit is the one with the lowest incremental cost among all the available units; and this generating unit is loaded first. Next in line will be the generating unit with again the lowest incremental cost among the remaining available units. After each hour of simulation, the total production cost during that hour is calculated using:

$$C(h) = \sum_{i=1}^{NT} IFC_i \quad P_i(h) \tag{3.1}$$

Where

$C(h)$	:	Generation cost during the h-th hour.
IFC_i	:	Incremental fuel cost of the i-th thermal unit.
$P_i(h)$	:	Power output of the i-th unit during the h-th hour.
NT	:	Total number of thermal units.

It is worth mentioning that in general the IFC of equation 3.1 is not a constant quantity rather it is a function of the output power of the unit. If the functional relation is known, then it can be accommodated easily during the simulation procedure. However this average representation is often used in reliability evaluation procedure to calculate the system production cost.

3.3 TRANSMISSION SYSTEM

In a composite system, the transmission network plays a very important role in determining the adequacy of the system as a whole. The generation system generates the power and this power is available at the bus connected to the generating station. Now the transmission network is needed to supply the electrical energy from the generating station to the major load centres or buses. In order to maintain a good quality of service, these transmission links must be adequately reliable as well as capable of carrying sufficient load. Major transmission components are the transmission lines and transformers. All these transmission elements are not only subjected to stochastic failure and repair processes but also they are limited in capacity. This latter constraint adds a new scenario to the adequacy evaluation procedure which is related to the overload of the transmission components.

In order to find the amount of load flowing through a line it is necessary to use the load flow algorithms. Various solution techniques, depending upon the adequacy criteria employed and the intent behind the studies, are available in order to analyze the transmission network. These techniques are complicated and require a good deal of computational effort. In composite system evaluation, load flow and its corrective measures account for the major share of the total simulation times.

If the continuity of supply i.e. overload of the transmission component is to be considered only, then a linearized or a DC load flow is sufficient. Linearized load flow is still favoured [66-68] in the simulation domain for composite system evaluation. In this study a linearized load flow technique is also used to perform the load flow and associated corrective measures. Also a new approach of linearized load flow "sequential load flow" is accommodated in simulation procedure. If the quality of power supply such as bus voltage level is an importnant adequacy criterion, then AC load flow methods such as Gauss-Seidel, Newton-Raphson or fast decoupled load flow techniques must be employed to assess the adequacy. The models used for the transmission systems are described under this section.

3.3.1 Availability Model

For the independent forced outages and repairs, transmission lines and transformers are represented by the same model. In the case of independent failures and repairs the availability model assumes that -

* the time between forced outages and the outage duration are independent.
* a forced outage of any branch causes the loss of total transmission capacity of that branch.
* the TTF is sampled from the underlying distribution of the branch using the MTTF. A random value of TTF is sampled every time the failed branch is repaired and restored to service.
* the outage duration can have any underlying distribution and the mean value of the distribution is designated as the MTTR. A randon value of TTR is sampled from the appropriate distribution every time a transmission branch fails.
* the repair is undertaken as soon as any element fails, repair time is independent of any other repairs or failures and repair is always successful and restores the branch to as-good-as-new.

3.3.2 Building Impedance Matrix

The linearized load flow algorithm uses the impedance matrix, therefore at the beginning of the simulation procedure it is necessary to build the impedance matrix. The procedure for building the impedance matrix is described in detail in Reference 69. A very brief description is included in this section. Assume that there are number of buses in the network and the n-th bus be the reference bus. The actual building process is carried out in the following four steps.

Step 1: All the elements of impedance matrix are initialized such that

$$Z_{ij} = 0 \tag{3.2}$$

where $i = 1$ to n and $j = 1$ to n

Z_{ij} is the element of the impedance matrix corresponding to the i-th row and j-th column.

Step 2: In this step only those branches having one end connected to the reference bus are included. If the L-th line is connected between the k-th bus and n-th bus (reference bus), then only one element of the matrix changes after inclusion of this line. The value of this element is given by,

$$Z_{kk} = X_L \tag{3.3}$$

where X_L is the L-th branch impedance.

After inclusion of all the branches similar to the type of L-th branch, it means that in addition to the reference bus some of the remaining buses are now included in the matrix. After this step, lines are selected one after another from the remaining lines and depending on the characteristics of a particular line, either step 3 or 4 is implemented. If the selected branch connects two buses neither of which has yet been considered, then this branch is temporarily ignored in the first iteration. These branches are considered and included in the matrix at the next or at a later iteration. At the first iteration, either step 3 or 4 is implemented only for those branches which have at least one end (bus) already included in the matrix. Step 3 or 4 is repeated iteratively until all branches are connected.

Step 3: If the selected branch connects a new bus to the network then this step is followed. This means that one end (bus) of the selected line is already on the network whereas the other end (bus) is not. Assume that the M-th line being selected. If this line is connected between the i-th and j-th buses where j-th bus is the new bus, then some of the elements of the impedance matrix must be recalculated using:

$$\begin{aligned} Z_{kj}^{new} &= Z_{ki}^{old} \\ Z_{jk}^{new} &= Z_{ik}^{old} \\ Z_{jj}^{new} &= Z_{ii}^{old} + X_M \end{aligned} \tag{3.4}$$

where $k = 1$ to $(n-1)$

Z^{new}, Z^{old} are the elements from the updated and from the old matrices respectively.
X_M is the impedance of the M-th branch.
All other elements of the impedance matrix remain unaltered.

Step 4: If the selected branch is between two already connected buses, then this step is followed. Assume that the P-th line is now selected. If this line is connected between the i-th and j-th buses, then:

$$Z_{mk}^{new} = Z_{mk}^{old} - \frac{\left(Z_{mi}^{old} - Z_{mj}^{old}\right)\left(Z_{ki}^{old} - Z_{kj}^{old}\right)}{X_p + Z_{ii}^{old} + Z_{jj}^{old} - 2Z_{ij}^{old}} \tag{3.5}$$

where $k = 1$ to $(n - 1)$
$m = k$ to $(n - 1)$
X_p impedance of the p-th branch.

It is important to note that Z is a symmetric matrix, therefore other elements of the matrix can be found accordingly.

3.3.3 Network Modification

During the course of the simulation, the network arrangement changes either due to a transmission branch forced outage or a branch being restored to service. As the state of a component (line or transformer) changes, the network impedance matrix must be modified accordingly. This modification can be realized by using equation 3.5 which is more commonly known as the kron's reduction formula [69].

3.3.3.1 Component Restoration

When a transmission component is restored to service the situation can be visualized as a new branch being added between the two already existing buses. Therefore, the situation is similar to that step 4 of section 3.3.2. Accordingly equation 3.5 is used where Xp is replaced by the impedance of the transmission component to be restored.

3.3.3.2 Component Disconnection

In this case equation 3.5 is also used to modify the network impedance matrix. The only difference is that now Xp is replaced by the negative value of the impedance of the component to be disconnected. Accordingly the component goes out of the network. A problem arises only when the denominator of equation 3.5 becomes zero. This implies that disconnection of a certain branch isolated a bus or a group of buses from the system network. In that case, the impedance matrix is not modified. No more transmission evaluation is carried out during that hour and the event is recorded as a "system separation". Accordingly system separation counters are updated. Full transmission evaluation is resumed only when system separation or islanding disappears. When failure of a branch creates an islanding situation, then the branch number is kept in a separate list and the network impedance matrix remain unaltered. If any already disconnected line is restored to service, then those lines remaining in the islanding list are again tried to be disconnected from the network one by one. If islanding still persists in the case of a particular line, then that line remains in the list. For any other line on the list if disconnection is possible without creating islanding, then that particular line is disconnected and subsequently the line number is removed from the islanding list. This process of checking the islanding list is carried out every time a line is restored to service. During the course of the simulation if a line is repaired while it is on the islanding list, then this line number is only removed from the list and there is no need to modify the impedance matrix for this restoration because the values of the network matrix elements already contain this line.

3.3.4 Linearized Load Flow

As mentioned earlier, the adequacy calculation of a composite system requires a detailed load flow analysis of the transmission network. In the sequential simulation, system evaluation is carried out chronologically hour by hour. As a system state can change at any hour, a load flow has to be performed for every simulated hour of the operation of the system. As said earlier, these load flow algorithms are quite time consuming. Therefore, modelling and programming of these alogrithms must be carried out carefully so that computational efforts can be reduced. A careful study of the individual component behaviour of most composite systems can reveal that, from a forced outage point of view, the transmission components are much more reliable than those of the generating systems. Although over a longer period of time many things can change, in the case of a transmission system, component states change very little from one time step to the next. Therefore, by using the information obtained from one time-step for the next, the computational efforts can be greatly reduced [55]. If a change does occur in the network in the next time-step, then little can be done to reduce the computational effort at this point. However if an event of interest then occurs, the extra efforts fully justified.

After a load flow is performed, the flow through the lines is calculated and remedial actions are performed if a transmission constraint is violated. The physical representation of DC load flow only takes into account active power flows, and voltage problems are not considered. The concept that small changes take place from one time-step to the next is applied using the approach described in section 3.3.4.2.

3.3.4.1 Distribution Factor

A linearized load flow is performed using the impedance matrix and the line flows obtained by multiplying the distribution factor matrix [70] by the vector of load and generation injections. Before going into the details of the load flow analysis, it is worth appreciating briefly the calculation process of distribution factors. If the i-th line is connected between buses i and j, then the distribution factor of the n-th bus to the i-th line along the direction from the i-th bus to the j-th bus can be given by [70]:

$$D_{nl} = \frac{Z_{ni} - Z_{nj}}{X_l} \tag{3.6}$$

where

D_{nl} : Distribution factor of the n-th bus to the l-th line.

Z_{ni} : Impedance matrix element corresponding to the n-th row and the i-th column.

Z_{nj} : Impedance matrix element corresponding to the n-th row and the j-th column.

X_l : Impedance of the l-th line.

It is important to note that if the value of D_{nl} calculated using equation (3.6) is positive, then it means that, for the positive injection (generation) at bus n, the flow through the l-th line will be along the direction from the i-th bus to the j-th bus. For a negative injection (load) at bus n, the actual flow through the l-th line will be along the direction from the j-th bus to the i-th bus.

3.3.4.2 Sequential Load Flow

After a load flow, the power flow through any line l for a given hour h is given by:

$$F_l(h) = \sum_i D_{il} G_i(h) - \sum_j D_{jl} L_j(h) - \sum_k D_{kl} PL_k(h) \tag{3.7}$$

where

$F_l(h)$: Power flow through line 1 for hour h

$G_i(h)$: Generation at busbar i for hour h

$L_j(h)$: Load at busbar j for hour h

$PL_k(h)$: Pump load at busbar k for hour h

Since only thermal generating unit considered in this research, so pump load is omitted from equation 3.7.

Hence the equation becomes,

$$F_l(h) = \sum_i D_{il} G_i(h) - \sum_j D_{jl} L_j(h) \tag{3.8}$$

In equation (3.8) the negative signs on the right hand side indicate that the flows through the line due to the generation and load are in opposite directions. Also i,j encompasses only those buses where generation and system load exist. Generation is allocated for every simulated hour according to the demand, available generating units and a merit order list.

It is assumed that the demand changes proportionally with time at all the load buses. This is reasonable for the buses in composite systems. Since these represent the bulk supply points at which a wide range of individual types of load are aggregated, including a general mix of industrial, commercial, residential and agricultural. Therefore the contribution of the loads to the flows can be expressed as:

$$\sum_j D_{jl} L_j(h) = k(h) \sum_j D_{jl} PK_j = k(h) CL_l \tag{3.9}$$

where

PK_j : Peak load at busbar j

$k(h)$: Load escalating factor for hour h

CL_l : Peak load contribution of loads to flow in line l.

Also, the contribution of generation to the flows is:

$$\sum_{i} D_{il} G_i(h) = CG_l(h) \tag{3.10}$$

where $CG_l(h)$: contribution of generation to flow in line l for hour h.

Therefore, equation 3.8 can be rewritten as:

$$F_l(h) = CG_l(h) - k(h)\, CL_l \tag{3.11}$$

Every time the network changes, i.e. a line enters a forced outage or is repaired, the impedance matrix changes, the D's also change, and equation 3.8 must be fully recalculated. Little can be done to save computational effort. However, if no network changes occur, the flow through line l for hour (h+1) will be:

$$F_l(h+1) = CG_l(h+1) - k(h+1)\, CL_l \tag{3.12}$$

The calculation of the actual load contribution is greatly simplified, since CL_l is already known. Also, since generating units are dispatched according to merit order, only a few units will vary their output from one simulated hour to the next. The calculation of $CG_l(h+1)$ is simplified to:

$$CG_l(h+1) = CG_l(h) + \sum_{m} D_{ml}\left[G_m(h+1) - G_m(h)\right] \tag{3.13}$$

Where m encompasses only those busbars where unit outputs have changed. The computational effort is again considerably reduced.

The flow through line l for hour (h+1) can then be rewritten as:

$$F_l(h+1) = CG_l(h) + \sum_{m} D_{ml}\left[G_m(h+1) - G_m(h)\right] - k(h+1)CL_l \tag{3.14}$$

Equation 3.14 reduces considerably [55] the number of calculations needed compared with a full load flow. This procedure of calculating the load flow is known as the sequential load flow. This technique is applied in this research and can be applied to any linearized load flow representation.

3.3.4.3 Bus Injections

If one or more overloaded branches exist in the transmission network, the resulting system state is defined as a system overload. In order to alleviate these overloads it is necessary to identify those buses contributing to the overloads. Each bus of the system in a linearized representation contributes to the flow in a line proportionally to its distribution factor and its net power injection. Similarly, if a line is overloaded, each bus contributes to that overload proportionally to its distribution factor and its net power injection. Therefore, the unitary contribution to the system overload by bus n is:

$$C_n = \sum_l D_{nl}(-1)^k \qquad 3.15)$$

where $k = 0$ if $F_l > 0$ or $= 1$ if $F_l < 0$

F_l : Power flow through line l

D_{nl} : Distribution factor of bus n for line l

C_n : Unitary contribution of bus n to global system overload.

l : Encompasses only overloaded lines

If C is positive, positive injections at bus n create overloads in the system and vice versa. However, if C is negative, positive injections reduce the overload of the system and vice versa. Therefore, there will be buses where a generation decrease will produce the same effect. The reverse occurs in the case of loads. Therefore, the value of C can be used to select the most sensitive buses for the generation redispatch or load shdding. A line is considered to be overloaded when its power flow is larger than its capacity limit. On the other hand, a certain margin (tolerance) of overload can be tolerated in each line and this is specified as input.

3.3.5 Overload Relief Algorithms

During the simulation of each simulated hour of a composite system, a generation dispatch is performed according to the demand, available generating units and finally a merit order list. This dispatch is done before any restrictions from the transmission system are considered. Therefore, overloaded lines may appear when the load flow is performed.

The simulation algorithms of a composite system must include models for relieving transmission overloads. The actual modelling procedure must be selected after thorough analysis of the system needs and priorities. These vary widely from one system to an other. Therefore, it is very difficult, if not impossible, to devise load shedding or redispatch algorithms that will work for any power system. The decision as to which philosophy of redispatch/shedding should be used must rest with the particular utility performing the analysis and this decision should be based on their accepted measures.

Generally these philosophies are based either on minimum change, minimum amount of load shed, minimum cost, proportional or localized.

The methods implemented in this study are based on the sensitivity of global system overload to busbar injections thus ensuring combination of the minimum change of original generation dispatch and minimum amount of load being shed. These algorithms are primarily based on those described in Reference 55. The basic concepts of these procedure are given in the following sections. In the case of an overload, generation redispatch is attempted first and it is carried out iteratively until it is infeasible to do so or the overload is eliminated completely, whichever comes first. If overload still persists, then load is shed at the most sensitive bus ensuring minimum shed necessary to change overload status of only one line at a time. After each load shed cycle, if overload continues, redispatch of generation is attempted again. These processes redispatch/load shedding, are repeated until the overload has finally been eliminated.

3.3.5.1 Generation Redispatch

The overload may be reduced by modifying the original generation dispatch. It is not always possible to reduce the overload of the system by redispatch, so it is important to know whether a redispatch will reduce the overload or not. The first condition for a redispatch is the existence of generation reserve, the second condition is that the generation reserve must exist at the buses where an increase of generation will produce a reduction of the system overload.

The method implemented consists of successively selecting pairs of buses according to their unitary contribution to the global system overload. The bus k_{re} with the largest positive injection, and the bus k_{in} with the largest negative contribution and positive generation reserve are selected. If the difference between the contribution of bus k_{in} and bus k_{re} is positive, then it is not possible to reduce the system overload by means of generation redispatch. If the difference is negative, then an increase of generation at k_{in} and a reduction at k_{re} will reduce the system overload.

If a redispatch is beneficial, the amount of generation to be exchanged is calculated. The maximum amount of generation exchanged between a pair of buses is given by the minimum value among the generation at bus k_{re} (for generation reduction), the reserve available at bus k_{in} (for generation increase) and the quantity that makes at least one line change its overloaded status, i.e.

$$GE = \min\left[G_{kre}, G_{kin}, d\right] \tag{3.16}$$

where

GE : amount of generation to be exchanged.

G_{kre} : amount of generation at bus k_{re}.

G_{kin} : generation reserve available at bus k_{in}.

d : quantity that overcomes overload of a line.

All lines must be checked to select d and this should be the minimum value found. After this exchange all lines will change their flow by the amount:

$$CHF_l = \left[D_{kinl} - D_{krel}\right]GE \tag{3.17}$$

where

CHF_l : Amount of change of flow through the i-th line.

D_{kinl} : Distribution factor of bus k_{in} to line l.

D_{krel} : Distribution factor of bus k_{re} to line l.

If equation (3.16) can select d as the value of GE, then after modifying line flows by equation (3.17) this will ensure one line has changed its overloaded status. Otherwise, it can not be guaranteed that after performing one generation redispatch cycle at least one line will change overload status.

Therefore, for every redispatch, the unitary contribution of buses must be calculated, a pair of buses selected, the feasibility of the redispatch checked, the amount of generation exchanged chosen and the new flows through the lines computed. This procedure continues until the system overload has been eliminated or the redispatch becomes infeasible.

3.3.5.2 Load Shedding

Load shedding procedures can be applied also in a similar manner to the redispatch. The k_{re} bus will reduce its generation while the k_{in} bus (which is now a load bus) will reduce its load (from a bus injection point of view, a reduction of load is equivalent to an increase of generation). The amount of load to be shed is chosen so that only one line at a time changes its overload status, ensuring minimum load shed. After each load cycle, if there is generation reserve, generation redispatch is attempted again only if it is feasible to do so, thus avoiding any unnecessary load curtailment. Load shedding procedures are always possible and certainly eliminated the overload of the system.

3.3.6 Cost of Generation After Redispatch

Cost of generation is calculated in section 3.2.3 before any transmission constraints are considered. After taking into account all transmission constraints, there can be line overloads. Appropriate corrections are then taken to alleviate these overloads using redispatch or if necessary by shedding loads.

During the redispatch and shedding procedures only the bus generations are either reduced or increased in order to eliminate the line overflows. These procedures therefore can modify the original unit generation dispatch following the procedure described in section 3.2.2.1. Therefore it is necessary to calculate the cost of generation after accommodating transmission constraints. To obtain the invididual unit energy production and hence the cost of generation, the modified bus generations are reallocated to specific generating units. During each simulation this cost is calculated using:

$$CC(h) = \sum_{i=1}^{NT} IFC_i PC_i(h) \tag{3.18}$$

where

$CC(h)$: generation cost after accommodating transmission constraints during the h-th hour.

IFC_i : incremental fuel cost of the i-th thermal unit.

$PC_i(h)$: power output of the i-th during the h-th hour after redispatch and load shedding

NT : total number of thermal units.

3.4 LOAD MODEL

Sequential simulation evaluates system performance hour by hour chronologically. In order to measure system adequacy during any hour it is necessary to know the system demand during that hour. Therefore in this research all load models are represented by a chronological hourly load. Now a chronological hourly load can be described in many ways, e.g. determining load levels for each hour from a yearly chronological load curve. But, the most common form of representation is that described in the IEEE-RTS [51] which is used in this research where weekly peaks are taken as a fraction of the system peak, daily and hourly peaks are taken as a fraction of the weekly and daily peaks respectively. A load model of this kind represents actual variations of the system load over the year. Now the system inadequacies calculated on the basis of such a load model are commonly known as annual inadequacies.

Specified load levels used for any study represent the forecasted levels for the period under consideration. Therefore, a degree of uncertainty can possibly remain within the forecasted load levels. The actual system load therefore may differ from the specified level for number of reasons. The uncertainty can be realized in the form of a probability distribution.

3.4.1 Load Forecast Uncertainty

It is extremely difficult to obtain sufficient historical data to determine the distribution describing the load forecast uncertainty. Published data [71], however, has suggested that the uncertainty can be reasonably described by a normal distribution. Uncertainty of the load can be simulated by multiplying the specified load by an uncertainty factor.This actually represents the deviation from the specified load level. This uncertainty factor is sampled from a normal distribution $N(1,\delta)$, with mean value of unity and standard deviation specified as input data. As the standard deviation (uncertainty level) increases, system unreliability also increases [71]. For a standard deviation equal to zero no uncertainty is considered. In these research, the standard deviation for load forecast uncertainty is assumed to be zero, although the algorithm and program used is able to accommodate any non-zero value.

3.5 QUANTITATIVE MEASUREMENT OF INADEQUACIES

Quantitative reliability measures their ability to serve as an absolute basis for determining an adequate level of system reliability.

In simulation technique, interruptions are encountered due to the inability of the system to meet the demand. These inadequacies could be caused by either the generation system, or the transmission system or combination of the both. For reinforcing the system it is necessary to determine which is responsible for the load curtailment. To obtain that information, system inadequacies are stored separately depdning on their sources of occurrence.

The evolution of supply deficiencies requires the collection of three basic quantities:

- energy not supplied per interruption, ENSPI
- duration of interruption, DOI
- number of interruption, NOI

Now for each deficiency or load curtailment, contributions from generation and transmission systems are also recorded using similar variables but subscripted by G and T respectively. ENSPI stores energy not supplied due to an interruption without considering its source of origin, thus it stores information from the overall system point of view. $ENSPI_G$ and $ENSPI_T$ store energies not supplied during an interruption due to generation-only and transmission-only deficiencies respectively.

As mentioned above, deficiencies are also grouped by simulated years in order to obtain annual reliability indices. To produce annual indices basic quantities are stored such that:

$$YENS_i = \sum_{j=1}^{YNOI_i} ENSPI_j$$

$$YDOI_i = \sum_{j=1}^{YNOI_i} DOI_j \tag{3.19}$$

where

$YENS_i$	:	yearly energy not served during the i-th year
$YDOI_i$	:	yearly duration of interruption during the i-th year
$YNOI_i$	:	total number of interruptions during the i-th year

Equation (3.19) represents quantities that are used to produce global annual indices. Similarly, quantities for generation-only and transmission-only annual indices can be stored.

In composite system evaluation, it is necessary to establish how the individual load points are affected by the system deficiencies. Load busbars are defined as load points of the bulk power system. These load point deficiencies are very important for the system planner because the distribution systems, which include individual customers, are affected by these deficiencies. Therefore, from an ultimate customer point of view, load point inadequacies have direct consequences. To calculate load point indices the following three quantities are recorded:

- BENSPI (bus energy not served per interruption)
- BDOI (duration of interruption at buses)
- BNOI (number of interruptions at buses)

To calculate annual load point indices, bus interruptions are grouped by year and the following informations are stored:

$$BYENS_i^k = \sum_{j=1}^{BYNOI_i^k} BENSPI_j^k$$

$$BYDOI_i^k = \sum_{j=1}^{BYNOI_i^k} BDOI_j^k \tag{3.20}$$

where

$BYENS_i^k$	:	yearly energy not served at the k-th bus during the i-th year
$YDOI_i^k$	:	yearly duration of interruption at the k-th bus during the i-th year
$YNOI_i^k$	:	total number of interruptions at the k-th bus during the i-th year

Equation 3.20 shows the global quantities. Similarly, quantities for generation-only and transmission-only annual indices can be stored.

Composite power system reliability indices are mainly grouped into three categories:

a. annual based
b. interruption based
c. load point based

Depending on the source of inadequacy all three categories can be divided into three more groups:

i. global indices
ii. generation-only indices
iii. transmission-only indices

3.5.1 System Annual Indices

The most commonly used annual indices are:

1. Loss of energy expectation (LOEE)
2. Loss of load expectation (LOLE)
3. Frequency of interruption (FOI)
4. Load curtailed per year (LCY)
5. Energy index of reliability (EIR)

Actual calculation procedure of these annual indices for the case of global indices are given below:

$$\text{LOEE} = \frac{1}{\text{NY}}\sum_{i=1}^{\text{NY}}\text{YENS}_i \quad ,\text{MWh / yr}$$

$$LOLE = \frac{1}{NY}\sum_{i=1}^{NY} YDOI_i \quad hr / yr$$

$$\text{FOI} = \frac{1}{\text{NY}}\sum_{i=1}^{\text{NY}}\text{YNOI}_i \quad \text{int / yr} \tag{3.21}$$

$$\text{LCY} = \frac{1}{\text{NY}}\sum_{i=1}^{\text{NY}}\left[\frac{\text{YENS}_i}{\text{YDOI}_i}\right] \quad \text{MW / yr}$$

$$\text{EIR} = 1 - \frac{\text{NY.LOEE}}{\text{TED}}$$

where

NY : total number of simulation year

TED : total energy demand of the system

Generation-only and transmission-only annual indices can be calculated using very similar equations.

3.5.1.1 System Separation Indices

When a busbar is isolated from the network due to the forced outages of one or more branches, then no transmission evaluations are performed. These types of incidents are recorded as system separation. Isolation of a part of a network is one of the major weakness of the transmission network design. Therefore reliability evaluation must highlight this shortcoming. This is reflected by two system separation indices. One deals with how frequent these isolations are and the other deals with how long these isolations continue. These indices are calculated from:

$$FSYSE = \frac{total\ number\ of\ bus\ isolations}{NY}, occ / yr \tag{3.22}$$

$$\text{EDSYSE} = \frac{\text{total duration of bus isolations}}{\text{NY}}, \text{hr / yr}$$

where

FSYSE : frequency of system separation.

EDSYSE: expected duration of system separation.

3.5.2 Interruption Indices

Interruption indices give inadequacies associated with individual load curtailment. Annual indices give the average behaviour of the system over a year whereas interruption indices measure system performance on an interruption basis. These indices can be grouped as global, generation-only and transmission-only. Calculation of global interruption indices are only included here. Interruption indices calculated in these studies are:

1. Expected energy not served per interruption (EENSPI)
2. Expected interruption duration (EID)
3. Expected load curtailed per interruption (ELCI)

These are calculated using

$$EENSPI = \frac{1}{TNOI}\sum_{i=1}^{TNOI} ENSPI_i \quad ,MWh / int$$

$$EID = \frac{1}{TNOI}\sum_{i=1}^{TNOI} DOI_i \quad ,hr / int \qquad (3.23)$$

$$ELCI = \frac{1}{TNOI}\sum_{i=1}^{TNOI}\left[\frac{ENSPI_i}{DOI_i}\right] \quad ,MW / int$$

where

TNOI : total number of interuptions during the entire simulation span.

Generation-only and transmission-only interruption indices can be calculated using very similar equations.

3.5.3 Load Point Indices

Annual and interruption indices of a composite system represents the inadequacies of the system as a whole. These indices can not reflect the weakness of certain sections of the network. More specifically, these indices can not show the load curtailments associated with the bus interruptions. Sometimes it can happen that the overall system performance is well within the adequate level but some specific load points behave inadequately. Therefore, some forms of requirements may be needed to improve the inadequacies associated with a particular load point. A comprehensive picture of load point inadequacies is represented by the load point indices.

These load point indices can be based either on an annual basis or on an interruption basis. Each of these indices again can be classified into three categories; global, generation-only and transmission-only depending on the sector responsible for the load curtailment. Calculations of only global annual and global interruption load point indices are included here.

3.5.3.1 Global Annual Load Point Indices

The following annual load point indices are calculated from:

$$
\begin{aligned}
EENSB^k &= \frac{1}{NY}\sum_{i=1}^{NY} BYENS_i^k \quad, MWh/yr \\
EDOIB^k &= \frac{1}{NY}\sum_{i=1}^{NY} BYDOI_i^k \quad, hr/yr \\
EFOIB^k &= \frac{1}{NY}\sum_{i=1}^{NY} BYNOI_i^k \quad, \text{int}/yr
\end{aligned}
\tag{3.24}
$$

where

$EENSB^k$	:	expected energy not served at the k-th load bus
$EDOIB^k$	:	expected duration of interruption at the k-th bus
$EFOIB^k$	:	expected frequency of interruption at the k-th bus.

Generation-only and transmission-only annual load point indices can be calculated using very similar equations.

3.5.3.2 Global Interruption Based Load Point Indices

The following interruption based load point indices are calculated:

$$
\begin{aligned}
EENSPIB^k &= \frac{1}{TNOIB^k}\sum_{i=1}^{TNOIB^k} BENSPI_i^k \quad, MWh/\text{int} \\
EIDB^k &= \frac{1}{TNOIB^k}\sum_{i=1}^{TNOIB^k} BDOI_i^k \quad, hr/\text{int} \\
ELCIB^k &= \frac{1}{TNOIB^k}\sum_{i=1}^{TNOIB^k} \left(\frac{BENSPI_i^k}{BDOI_i^k}\right) \quad, MW/\text{int}
\end{aligned}
\tag{3.25}
$$

where

$EENSPIB^k$	:	expected energy not served per interruption at the k-th bus
$EIDB^k$	:	expected interruption duration at the k-th bus
$ELCIB^k$	:	expected load curtailed per interruption at the k-th bus
TNOIBk	:	total number of interruptions at the k-th bus.

Generation-only and transmission-only interruption based load point indices are calculated using equation similar to 3.25.

CHAPTER-4

NEW APPROACH

4.1 INTRODUCTION

This chapter describes a new approach for taking into account common-cause or common-mode outage in sequential Monte Carlo simulation technique to evaluate reliability indices of composite system allthough the state space transition diagram for common-cause outages are well established they can only be utilized in random or non-sequential simulation and not in sequential simulation. The available technique for composite generation and transmission system normally consider only independent outages because usually the common-mode failure rate is small compared to independent failure rates. But such failures might have severe consequence on the system performance. Many utilities are, therefore, now using common-mode representation for composite system adequacy analysis. Therefore the new approach is necessary to accommodate into a sequential simulation algorithm. As the new approach is based on the system state transition sampling approach [59], the latter is also described in detail in the next section.

4.2 SYSTEM STATE TRANSITION SAMPLING APPROACH

Three basic sampling approaches are state sampling approach, state duration sampling approach and system state transition sampling approach which is used for reliability evaluation of a power system. These three sampling approach are discussed in chapter 2. As the new approach has some similarity with the system state transition sampling approach [59], this technique is elaborated here. Also, this has the following advantages compared to the other two approaches described in chapter 2.

(a) This approach can be used to calculate the exact frequency index without the need to sample the distribution function and storing chronological information as in the state duration sampling approach.

(b) This approach requires only a random number to produce a system state.

This approach focuses on state transition of the whole system instead of component states or component state transition process.

Assume that a system contains m components and that the state duration of each component follows an exponential distribution. The system can experience a system state transition sequence $\{S^{(1)}, \ldots\ldots, S^{(n)}\} = G$ where G is the system state space. If the present system state is $S^{(k)}$ and the transition rate of each component relating to $S^{(k)}$ is λ_i ($i = 1, \ldots, m$). The state duration T_i of the i-th component corresponding to system state $S^{(k)}$, therefore, has the probability density function; $f_i(t) = \lambda_i \exp(-\lambda_i t)$. Transition of the system state depends randomly on the state duration of the component which departs earliest from its present state, i.e., the duration T of the system state $S^{(k)}$ is a random variable which can be expressed by the following expression [59]

$$T = \min_i\{T_i\} \tag{4.1}$$

It can be proved that since the state duration of each component T_i follows an exponential distribution with parameter λ_i, the random variable T also follows an exponential distribution with parameter $\lambda = \sum_{i=1}^{m} \lambda_i$ i.e., T has the probability density function

$$f(t) = \sum_{i=1}^{m} \lambda_i \exp\left(-\sum_{i=1}^{m} \lambda_i t\right) \tag{4.2}$$

Assume that system state $S^{(k)}$ starts at instant 0 and the transition of the system state from $S^{(k)}$ to $S^{(k+1)}$ takes place at instant t_o. The probability that this transition is caused by departure of the j-th component from its present state is the following conditional probability: $P_j = P(T_j = t_o/T = t_o)$.

According to the definition of conditional probability and equation (4.1), it follows that

$$P_j = P(T_j = t_o/T = t_o)$$

$$= P(T_j = t_o \cap T = t_o) / P(T = t_o)$$

$$= P[T_j = t_o \cap (T_i \geq t_o, i = 1, \ldots, m)] / P(T = t_o)$$

$$= P(T_j = t_o) \prod_{i=1, i=j}^{m} P(T_i \geq t_o) / P(T = t_o) \tag{4.3}$$

Since T_i ($i = 1, ..., m$) and T follow exponential distributions,

$$P(T_i \geq t_o) = \int_{t_o}^{\alpha} \lambda_i e^{-\gamma_i t} dt = e^{-\gamma_i t_o} \tag{4.4}$$

$$P(T_j = t_o) = \lim_{\Delta t \to 0} (\lambda_j e^{-\lambda_j t_o}) \Delta t \tag{4.5}$$

$$P(T = t_o) = \lim_{\Delta t \to 0} \left(\sum_{i=1}^{m} \lambda_j e^{-\sum_{i=1}^{m} \lambda_j t_o} \right) \Delta t \tag{4.6}$$

Substituting equations (4.4), (4.5) and (4.6) into equation (4.3) yields

$$P_j = (P_j = t_o / T = t_o) = \lambda_i \bigg| \sum_{i=1}^{m} \lambda_i \tag{4.7}$$

State transition of any component in the system may lead to system state transition. Consequently, starting from state $S^{(k)}$, the system containing m components has m possible reached states. The probability that the system reaches one of these possible states is expressed by equation (2.26) and obviously [59]

$$\sum_{j=1}^{m} \mathrm{P}_j = 1 \tag{4.8}$$

Therefore, the next system state can be determined by the following simple sampling. The probabilities of m possible reached states are successively placed in the interval [0,1] as shown in Fig. 4.1.

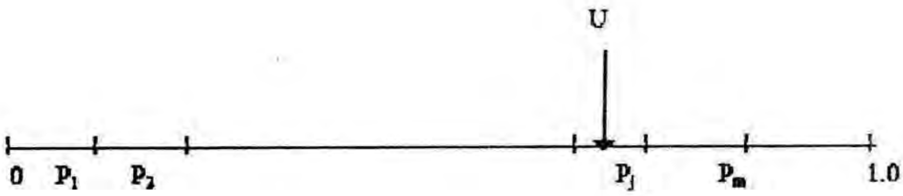

Figure 4.1: Explanation of System State Transition Sampling.

Generate a uniformly distributed random number U between [0,1]. If U falls into the segment corresponding to P_j, this means that transition of the j-th component leads to the next system state. A long system state transition sequence can be obtained by a number of samples and the reliability of each system state can be evaluated.

4.3 THE SEPARATE COMMON-CAUSE OUTAGE MODEL

A common-mode or common-cause outage is an event having a single external cause with multiple failure effects where the effects are not consequences of each other [57]. Economic and environmental constraints have led to the use of two or more transmission lines on the same tower or on the same right of way [57]. Outage of all lines of these arrangements can occur due to single causes such as floods, crashing of aircraft or collision of vehicle on the transmission tower or events initiating within the terminal facility. There are several possible common-cause outage models. These are the basic common-cause outage model, the IEEE model, the modified IEEE model and the separate common-cause repair process model [57]. The separate common-cause model is used in this research and this is discussed in detail.

In modified IEEE model, considers two possible repair phenomena when the system is in the down state due to a common-cause failure. These are the individual element and the joint common-cause repairs activities. But most of the common-cause failures occur due to terminal equipment failures and that both the lines are put into service simultaneously even if the repair of one of the lines is completed early, it is necessary to further modify the modified IEEE model to eliminate the individual repair phenomena when common-cause failures occur [57]. Such situations are suitably described by the separate common-cause repair process model.

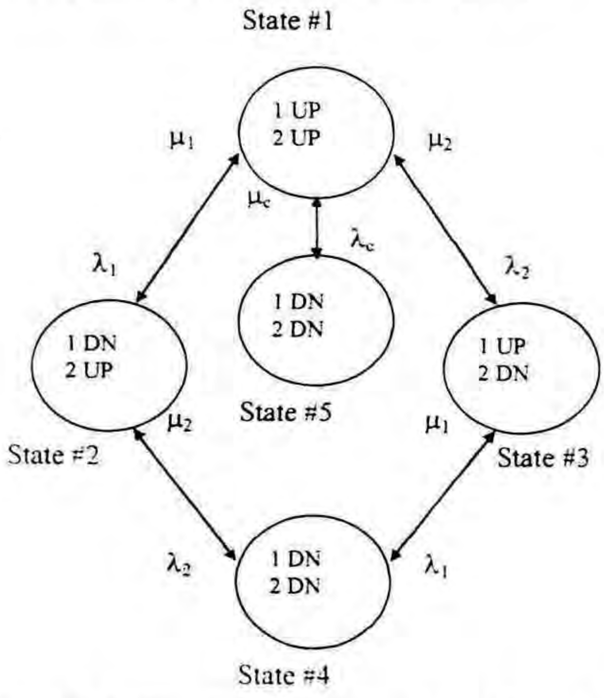

Figure 4.2: The Separate Common-Cause Outage Model.

Analytically the state probabilities of this model (Fig. 4.2) can be calculated from the following expressions [44]:

State probabilities of state 1, $P_1 = \mu_1\mu_2\mu_c/D$ (4.9)

State probabilities of state 2, $P_2 = \lambda_1\mu_2\mu_c/D$ (4.10)

State probabilities of state 3, $P_3 = \mu_1\lambda_2\mu_c/D$ (4.11)

State probabilities of state 4, $P_4 = \lambda_1\lambda_2\mu_c/D$ (4.12)

State probabilities of state 5, $P_5 = \mu_1\mu_2\lambda_c/D$ (4.13)

where $D = \mu_c(\lambda_1 + \mu_1)(\lambda_2 + \mu_2) + \mu_1\mu_2\mu_c$

λ_1 = Failure rate of component 1, frequency/yr

μ_1 = Repair rate of component 1, repair/yr

λ_2 = Failure rate of component 2, frequency/yr

μ_2 = Repair rate of component 2, repair/yr

λ_c = Common-mode failure rate, frequency/yr

μ_c = Common-mode repair rate, repair/yr

In sequential simulation techniques the time to failure (TTF) or time to repair (TTR) of a component sampled using uniformly distributed random number. After elapsing the TTF/TTR time, the component changes its state (up/down) from one state to another. In this way the transition cycles for two state component and is repeated for entire period of simulation. But if the composite system contains common-mode transmission line failure several departure transition can emanate from the state. After finishing the state residence time in one state, it is difficult to predict the next transition. In order to overcome this difficulty of knowing which transition occurs, a predetermined operating cycle is considered in [44]. However, this may not reflect correctly the stochastic nature of state transition of a component. In order to represent the actual transition process, a new approach is developed to accommodate common-mode failures in sequential simulation technique which is described in the section 4.4.

4.4 THE NEW APPROACH METHODOLOGY

The first step in this algorithm is to deduce the component state space diagram. The total number of possible transition are determined for each state together with the correct transition for each. Given an initial state i, the times to transition (TTT) are sampled for each possible transition from state i using the following equation:

$$TTT_{ij} = -\left[\frac{1}{TR_{ij}}\right]\ln(U_{ij}) \tag{4.14}$$

where j encompasses all the states of the component that can be reached directly from state i.

TR_{ij} is the transition from state i to j. After calculating all the TTTs from above equation, the smallest value and the corresponding state j are selected. This value is the residence time of the i-th state. After elapsing, the state of the component moves to the j-th state before any of the other transition are possible. This process is repeated for complete simulation period and can be applied to any number of components. This approach is applicable to any state space diagram.

Now in order to verify, the new approach is applied in separate common-cause outage model to determine the state probabilities of various state. Before applying the new approach for considering common-cause outage model, it is necessary to decide how long the simulation (i.e. simulation period) should be performed. However, after some initial runs it was decided to simulate for 2000 years to get steady value for the probabilities of each state.

Analytical and New Approach Result are given below:

Failure and Repair Rates	**Limiting State Probabilities**	
	Analytical Result	Simulation Result
$\lambda_1 = \lambda_2 = 2$ f/hr $\lambda_c = 0.2$ f/yr $\mu_1 = \mu_2 = 728$ r/yr $\mu_c = 364.0$ r/yr	$p_1 = 0.99398490$ $p_2 = 0.00273073$ $p_3 = 0.00273073$ $p_4 = 0.00000751$ $p_5 = 0.00054615$	$p_1 = 0.99384987$ $p_2 = 0.00277198$ $p_3 = 0.00281788$ $p_4 = 0.00000424$ $p_5 = 0.00055603$
$\lambda_1 = \lambda_2 = 0.5$ f/yr $\lambda_c = 0.05$ f/yr $\mu_1 = \mu_2 = 728.0$ r/yr $\mu_c = 364.0$ r/yr	$p_1 = 0.99849082$ $p_2 = 0.00068578$ $p_3 = 0.00068578$ $p_4 = 0.00000047$ $p_5 = 0.00013716$	$p_1 = 0.99848461$ $p_2 = 0.00068905$ $p_3 = 0.00070295$ $p_4 = 0.00000057$ $p_5 = 0.00012283$
$\lambda_1 = \lambda_2 = 0.2$ f/yr $\lambda_c = 0.02$ f/yr $\mu_1 = \mu_2 = 728.0$ r/yr $\mu_c = 364.0$ r/yr	$p_1 = 0.99939589$ $p_2 = 0.00027456$ $p_3 = 0.00027456$ $p_4 = 0.00000008$ $p_5 = 0.00005491$	$p_1 = 0.99939018$ $p_2 = 0.00028783$ $p_3 = 0.00028961$ $p_4 = 0.00000046$ $p_5 = 0.00003194$

It is seen from the calculated value that the simulation result is almost similar to analytical result. These results indicate that the new approach is acceptable and can be applied in composite system reliability evaluation for accommodating common-mode failures.

In this new approach first the total number of possible transition for each state with transition rate are determined from the state space diagram as shown in Fig. 4.2. The time to transition (TTT) are sampled for each possible transition from the state. The smallest value of TTT is the state residence time of this state. After TTT time has elapsed, the component moves from this state to another state (which is determined from the smallest value of TTTs). Similarly for every state the smallest value of TTT is determined which also indicates the next state. In this way if the state is known, then the individual status of the lines are determined from that state. After the individual component states have been determined, these states are combined to find the system performance state, e.g. how much generation is available from the generating units and the network impedance matrix after modifying it to account for the individual status of the lines. If any generation or transmission constraints are violated, standard corrective measures are taken as remedial actions and inadequacies are stored if there are any.

Now the new approach is included in sequential Monte Carlo simulation procedure and used to evaluate the reliability indices of IEEE-RTS with considering several common-cause outages. These results are given in details in chapter 5 ~~(Numerical evaluation)~~.

4.5 SEQUENTIAL SIMULATION PROCEDURE

The concepts of Monte Carlo simulation used in this research are based on:

(a) the multiplicative congruent method for generating pseudo-random numbers

(b) the appropriate transform method for converting these to relevant probability distributions in order to produce times-to-fail and times-to-repair for each component.

The system operation is simulated over a long period of time, which is subdivided into reference periods of one year. Each year is divided into basic time intervals during which the state of the system is assumed to be constant. In this research, time intervals considered on an hourly basis, which means that changes in the system are assumed to occur only at the beginning of every hour. For each component the times between forced outages and the outage durations are considered independent and exponentially distributed.

At hierarchical level II (HLII), major computational requirements are needed to perform load flow studies and to simulate corrective measures, i.e. redispatch and load shedding. Kron's reduction formula is used to modify the impedance matrix for network modifications. The load flow is performed using a linearised sequential load flow algorithm. The generation redispatch and load shedding algorithm 5 for relief of overloads are based on nodal contributions to system overload and are modeled using distribution factors. During the redispatch and load shedding procedures, the bus generation are rearranged, sometimes decreased and sometimes increased, to eliminate the overloads. In order to obtain the energy production of individual units and hence the cost of energy generation, these bus generations are reallocated to relevant generating units.

4.6 MAJOR STEPS IN SIMULATION

In sequential simulation procedures, the composite power system reliability evaluations are carried out following some main steps, briefly, these steps are:

1. At the beginning of the simulation all necessary system data are read. These include:
   (a) data about the thermal generating units. These include the number of states of the unit, capacity of each state, transition rate between states, incremental fuel cost, loading order position and dispatch group, and the bus to which the unit is connected .
   (b) transmission network data mainly include number of busbar and lines, their reliability data information regarding impedance matrix, capacity of transmission branches and tolerance, common-mode failure data etc.
   (c) load model data.
   (d) Monte Carlo simulation related data such as type of underlying probability distribution, seed for the random number generators etc.
2. Initialization of all component states.
3. For every simulated hour the availability of all system elements, such as generating units and lines, are checked.
4. New approach is used to calculate the time to transition i.e. state residence time of each state.
5. Time to transition (TTTR) are sampled from exponential probability distributions.
6. Other random conditions, such as uncertainty of the load, are also modeled by the random variates sampled from their associated probability distributions.

7. Component and their operations are represented by mathematical models.
8. When transmission system changes its state, the impedance matrix is modified accordingly. If islanding occurs, then the system state is recorded as system separation and transmission system evaluation remains suspended until islanding disappears.
9. The combined operation of the power system is then assessed.
10. If any system constraints are violated appropriate remedial actions are taken.
11. System deficiencies, if there are any, are recorded in magnitude and frequency in various formats. Each deficiency is stored as an independent sample. These deficiencies are also grouped by simulated years.
12. Reliability indices are obtained from the above records together with their frequency distributions.
13 The simulation steps 3-11 are repeated hour by hour for a period of simulated time long enough to include most of the events of interest.

It is worth mentioning that scheduled maintenance for any generating unit or transmission branch can be accommodated within the simulation procedure without any difficulty. The only required informations are the week to start maintenance and the number of weeks to remain under maintenance of the component.

4.7 SCHEMATIC DIAGRAM OF SIMULATION

Simulation Diagram

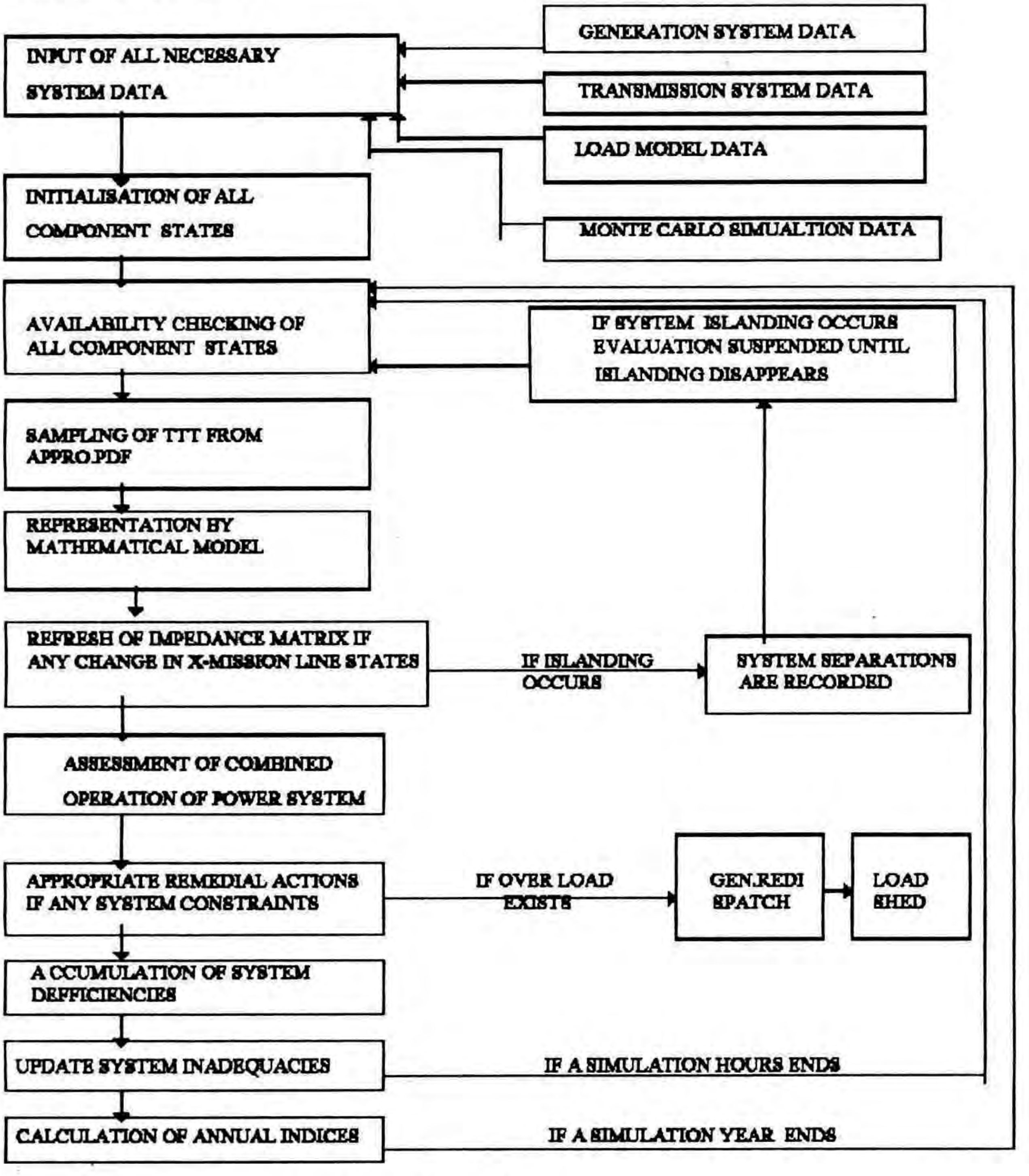

Figure 4.3: **Schematic Diagram of Simulation Methodology**

CHAPTER - 5
NUMERICAL EVALUATION

5.1 INTRODUCTION

For the simulation of composite power system with common-cause outage the methodology has been developed in chapter 4. This methodology is applied to evaluate the reliability of the IEEE-RTS. In the numerical evaluation the new approach for common-mode outages included in sequential Monte Carlo simulation is used for simulating different common-cause outages of transmission lines.

This chapter presents a brief description of IEEE-RTS. The simulation results are presented in this chapter for various common-cause outages of transmission lines. These results are given in the form of expected value of the reliability indices.

5.2 IEEE-RTS

There has been a continuing and increasing interest in methods for power system reliability evaluation. In order to provide a basis for comparison of results obtained from different methods it is desirable to have a reference or "test" system which incoporates the basic data needed in reliability evaluation. For this reason the IEEE subcommittee published the IEEE Reliability Test System (RTS) [51] in 1979. The IEEE-RTS is used in this research. The generation system, transmission network and load model of IEEE-RTS are described briefly in the following section.

5.2.1 IEEE-RTS Generation Data

Generation data of IEEE-RTS used in this research are given in Appendix-A. The generating system contains 32 units, ranging from 12 to 400 MW. The total installed capacity of the generating system is 3405 MW and the annual peak load for the test system is 2850 MW.

5.2.2 IEEE-RTS Transmission System Data

The IEEE-RTS composite system has 24 buses out of which 10 buses are generation buses. The transmission lines are at two voltages, 138 kV and 230 kV. Bus code, bus number and the percentage of the peak load connected to these buses are given in Appendix-B.

The IEEE-RTS system has 38 transmission lines which include overhead lines, underground cables and transformers. The test system contains a number of multiple circuit; some of them exist on the same right-of-way. The transmission line type, line number, bus number between which the line is connected and their voltage levels, impedance, capacity in MVA, tolerance in percentage are given in Appendix-C. Transmission reliability data, i.e. mean time to failure and mean time to repair, are also shown in Appendix-C.

5.2.3 IEEE-RTS Load Data

Hourly load data are used in this research for simulating IEEE-RTS. The hourly loads are given as percent of the daily peak and the daily peak load are given as percent of the weekly peak load. Similarly the weekly peak loads are also shown as percent of system annual peak. The daily peak load as percent of weekly peak are given in Table 5.1. The hourly peak load is found by multiplying the corresponding fraction of hourly load with the daily peak.

Table 5.1: Daily Peak Load in percent of weekly peak load.

Day	Peak Load
Monday	93
Tuesday	100
Wednesday	98
Thursday	96
Friday	94
Saturday	77
Sunday	75

The daily peak load for (7 x 52) = 364 days are given in Appendix-E.

5.3 NUMERICAL RESULTS

In order to show the applicability of the new approach the IEEE-RTS is evaluated. In addition to the data described in section 5.2. Some additional data are needed to represent common-mode failures. These are included in Table 5.2.

Table 5.2: Common-mode outage data for IEEE-RTS.

Buses From - To	Outage Rate (f/yr)	Outage Duration (hr)
15-21 15-21	0.041	20.0
18-21 18-21	0.035	20.0
19-20 19-20	0.038	20.0
20-23 20-23	0.034	20.0

As the sequential simulation algorithm is well established without these common-mode failures, the new approach is included in the sequential Monte Carlo simulation procedures and then used to evaluate the reliability of IEEE-RTS. After some initial runs it was decided to simulate the IEEE-RTS for 3000 years. At the end of each year the yearly values of reliability indices are stored. At the end of the simulation the expected values are calculated.

Three different cases are considered for the transmission system, namely:

Base Case:	Without any common-mode outage.
Case-I:	One common-mode group between buses 15-21.
Case-II:	Three common-mode groups between buses 18-21, 19-20 and 20-23.

Various annual adequacy indices, interruption indices and load point indices are evaluated and some of them are shown in tables. Each index is classified as: Composite (or global), generation-only (subscripted by G) and transmission-only (subscripted by T). In these studies simulation results include the following reliability indices:

Global annual indices:

LOEE (MWh/yr):	Loss of energy expectation.
LOLE (hr/yr):	Loss of load expectation.
FOI (int/yr):	Frequency of interruption per year.
LCY (MW/yr):	Load curtailed per year.

Global interruption based indices:

EENSPI (MWh/int): Expected energy not served per interruption.

EID (hr/int): Expected interruption duration.

ELCI (MW/int): Expected load curtailed per interruption.

Global annual load point indices:

ENSB (MWh/yr): Bus energy not served per year.

Global system separation indices:

FSYSE (freq./yr): Frequency of system separation.

EDSYSE (hr/yr): Expected duration of system separation.

Generation-only annual indices:

$LOEE_G$ (MWh/yr): Loss of energy expectation due to generation-only.

$LOLE_G$ (hr/yr): Loss of load expectation due to generation-only.

FOI_G (int/yr): Frequency of interruption per year due to generation-only.

LCY_G (MW/yr): Load curtailed per year due to generation-only.

Generation-only interruption based indices:

$EENSPI_G$ (MWh/int): Expected energy not served per interruption due to generation-only.

EID_G (hr/int): Expected interruption duration due to generation-only.

$ELCI_G$ (MW/int): Expected load curtailed per interruption due to generation-only.

Transmission-only annual indices:

$LOEE_T$ (MWh/yr): Loss of energy expectation due to transmission-only.

$LOLE_T$ (hr/yr): Loss of load expectation due to transmission-only.

FOI_T (int/yr): Frequency of interruption per year due to transmission-only.

LCY_T (MW/yr): Load curtailed per year due to transmission-only.

Transmission-only interruption based indices:

$EENSPI_T$ (MWh/int): Expected energy not served per interruption due to transmission-only.

EID_T (hr/int): Expected interruption duration due to transmission-only.

$ELCI_T$ (MW/int): Expected load curtailed per interruption due to transmission-only.

5.3.1 Base Case:

In order to realize the impact of common cause outages on reliability indices, first the IEEE-RTS evaluated considering without common-cause outage i.e. base case means no common-cause outage exists in the system. The simulation results for this case are presented in this section.

Table 5.3 depicts the annual indices for the global, generation and transmission systems. The LOEE, LOLE, FOI and LCY indices are shown in this table.

Table 5.3: Annual Indices.

Indices	Global Annual Indices	Generation-only Annual Indices	Transmission-only Annual Indices
LOEE, MWh/yr	1122.289	1103.365	18.925
LOLE, hr/yr	9.122	9.115	0.509
FOI, int/yr	1.892	1.890	0.089
LCY, MW/yr	47.948	47.208	1.855

Table 5.4 depicts the interruption indices. The indices shown include EENSPI, EID and ELCY for the global, generation and transmission systems.

Table 5.4: Interruption Indices.

Indices	Global Interruption Indices	Generation-only Interruption Indices	Transmission-only Interruption Indices
EENSPI, MWh/int	593.071	583.688	213.437
EID, hr/int	4.820	4.822	5.744
ELCI, MW/int	83.881	82.561	37.052

Frequency of the separation and the expected duration of the separation are presented in Table 5.5.

Table 5.5: Global System Separation Indices.

Frequency, Occurrance/yr	Duration, hr/yr
0.310	3.225

Yearly energy not supplied in load buses are presented in Table 5.6

Table 5.6: Annual Load Point Indices.

BUS Name	ENSB, MWh/yr
BUS-01 138	60.81
BUS-02 138	15.60
BUS-07 138	48.55
BUS-13 230	102.57
BUS-15 230	122.42
BUS-16 230	38.60
BUS-18 230	53.03
BUS-03 138	69.48
BUS-04 138	11.78
BUS-05 138	27.57
BUS-06 138	52.94
BUS-08 138	66.17
BUS-10 138	75.00
BUS-14 230	75.00
BUS-19 230	70.58
BUS-20 230	20.09
BUS-09 138	67.28

5.3.2 Case-I

The IEEE-RTS is evaluated considering single common-cause outage, which exists in between line 25 and 26. Both ends of these lines are connected to buses 15 and 21. The simulation results are presented in this section.

Table 5.7 depicts the annual indices for the global, generation and transmission systems. The LOEE, LOLE, FOI and LCY indices are shown in this table. Table 5.8 gives the interruption indices. The indices shown include EENSPI, EID and ELCI for global, generation and transmission systems.

Table 5.7: Annual Indices.

Indices	Global Annual Indices	Generation-only Annual Indices	Transmission-only Annual Indices
LOEE, MWh/yr	1167.457	1103.365	64.092
LOLE, hr/yr	9.368	9.115	0.778
FOI, int/yr	2.128	1.890	0.356
LCY, MW/yr	53.494	47.208	12.258

Table 5.8: Interruption Indices.

Indices	Global Interruption Indices	Generation-only Interruption Indices	Transmission-only Interruption Indices
EENSPI, MWh/int	548.701	583.688	180.203
EID, hr/int	4.403	4.822	2.187
ELCI, MW/int	92.695	82.561	135.664

Frequency of the separation and the expected duration of the separation are presented in Table 5.9.

Table 5.9: Global System Separation Indices.

Frequency, Occurrance/yr	Duration, hr/yr
0.916	3.831

Yearly energy not supplied in load buses are presented in Table 5.10

Table 5.10: Annual Load Point Indices.

BUS Name	ENSB, MWh/yr
BUS-01 138	85.82
BUS-02 138	30.53
BUS-07 138	49.38
BUS-13 230	106.77
BUS-15 230	122.55
BUS-16 230	38.59
BUS-18 230	53.01
BUS-03 138	69.41
BUS-04 138	11.78
BUS-05 138	27.57
BUS-06 138	52.93
BUS-08 138	66.16
BUS-10 138	74.98
BUS-14 230	74.98
BUS-19 230	70.57
BUS-20 230	20.08
BUS-09 138	67.26

5.3.3 Case-II

The IEEE-RTS is evaluated considering three common-cause outages group. Among these lines no. 32 and 33 are connected between buses 18 and 21, lines 34 and 35 are connected between buses 19 and 20 and lines 36 and 37 are connected between buses 20 and 23. The simulation results are presented in this section.

Table 5.11 shows the annual indices for the global, generation and transmission systems. Table 5.12 shows the interruption indices for the global, generation and transmission systems. Table 5.13 depicts the annual system separation indices.

Table 5.11: Annual Indices.

Indices	Global Annual Indices	Generation-only Annual Indices	Transmission-only Annual Indices
LOEE, MWh/yr	1211.264	1107.117	104.148
LOLE, hr/yr	10.180	9.143	2.015
FOI, int/yr	2.637	1.872	0.958
LCY, MW/yr	48.644	47.228	9.432

Table 5.12: Interruption Indices.

Indices	Global Interruption Indices	Generation-only Interruption Indices	Transmission-only Interruption Indices
EENSPI, MWh/int	459.331	591.409	108.752
EID, hr/int	3.860	4.884	2.104
ELCI, MW/int	64.560	81.989	20.763

Table 5.13: Global System Separation Indices.

Frequency, Occurrance/yr	Duration, hr/yr
0.511	5.118

Yearly energy not supplied in load buses are presented in Table 5.14

Table 5.14: Annual Load Point Indices.

BUS Name	ENSB, MWh/yr
BUS-01 138	60.85
BUS-02 138	37.62
BUS-07 138	48.72
BUS-13 230	102.91
BUS-15 230	122.88
BUS-16 230	38.73
BUS-18 230	133.02
BUS-03 138	69.72
BUS-04 138	28.77
BUS-05 138	27.66
BUS-06 138	53.12
BUS-08 138	66.40
BUS-10 138	75.25
BUS-14 230	75.25
BUS-19 230	104.92
BUS-20 230	97.47
BUS-09 138	67.50

CHAPTER - 6
DISCUSSIONS AND CONCLUSIONS

6.1 OBSERVATIONS AND DISCUSSIONS

Simulation techniques generally known as Monte Carlo simulation estimate the reliability indices by simulating or sampling the actual behaviour of the system. The values of output results of simulation study depend on a number of factors including the seed value i.e. starting value of the sequence of random numbers, the pseudo-random number generator, the number of samples and above all the system upon which the simulation study has been done. After performing a number of initial studies it was decided to simulate the IEEE-RTS for 3000 years in order to keep the uncertainties involved in the estimates of the indices in a tolerable limit and also to obtain the steady values for the reliability indices [55]. The accumulated average values of these samples are unbiased estimates of the mean values of the reliability indices. To obtain an exact estimation, the number of samples would have to be tend to infinity [55]. Since simulation uses a limited number of samples, the obtained average values are shown in Tables 5.3 - 5.6 for base case i.e. without common-mode outage case and in Tables 5.7 - 5.14 with common-mode outages, will usually differ from the true mean. Moreover this obtained mean value does not represent the actual true value for the real system but the true value for the model that is used to represent the system.

Tables 5.3, 5.5, 5.7, 5.9, 5.11 and 5.13 show the estimate of expected values of annual indices of the composite system. A closer look at the loss of energy expectation (LOEE) indices show that these are approximately of the similar value. LOEE for generation system is higher than that of the transmission system. This distinctly indicates that generation system is far less reliable than the transmission system. Another important aspect is that if the LOEE's for generation system and transmission system are added then these give the LOEE's for the overall composite system. The reason is that when there is an overlapping of interruptions of generation and transmission, the duration is overlapped but not the energies associated with the generation and transmission interruptions.

In the Tables 5.3, 5.7 and 5.11, the values of LOLEs are also of similar value. But in this case the summation of LOLEs for generation and transmission system does not show equality with that of the composite system, rather the LOLE for composite system is less than the sum. This is because of the fact that there are overlapping of generation and transmission interruptions. The value of LOLE for generation system is higher than that of the transmission system. This again indicates that generation system is less reliable than the transmission system, i.e. transmission system is much more reliable than the generation system in case of IEEE-RTS. The values of FOI in Tables 5.3, 5.7 and 5.11 are similar value for all cases. But the FOI for generation system is higher than that for the transmission system.

The values of LCY in Tables 5.3, 5.7 and 5.11 are similar for all cases. But LCY for generation system is higher than that of the transmission system. The overall composite system LCY does not show equality with that of the summation of LCY of generation and transmission system, rather the LCY for composite system is less than the sum. The reason is again that there are overlapping of generation and transmission interruptions.

In comparison to Table 5.3, Tables 5.7 and 5.11 show that annual indices increase with the inclusion of more and more common-mode outages. As expected this increase is mainly due to the increase of transmission system inadequacies as shown in the Tables. When common-mode outages are accommodated in the simulation procedure, the number of interruption due to transmission system increases significantly as given by FOI_T index in Tables 5.7 and 5.11. The interruption based indices also follow the same trend of annual indices.

Since common-cause outage events involve only transmission system of a composite system, therefore common-cause outages have no effect on generation system reliability indices. For this reason, generation system indices remain almost the same for all cases. But due to generation redispatch generation-only indices may change slightly as shown in Tables 5.11 and 5.12. Again for bus isolation generation from a particular bus may not be available. For this reason generation-only indices may also change. It is assumed that common-cause failure rate is only about 10% of the independent failure rate. That is if one independent failure occurs in 10 (ten) years than only one common-cause failure will occur in 100 years time. In this research the IEEE-RTS system is simulated for 3000 years. Therefore, it is expected that some of these transmission failures occurred during the simulation span. However, if the failure bunching effect occurs only then the values of transmission indices will increase significantly. It is well-known that transmission system of the IEEE-RTS is much more reliable than that of the generating system.

From the Tables 5.5, 5.9 and 5.13 show the estimate of expected values of annual system separation indices of the composite system. Table 5.5 show the frequency of system separation and duration of system separation for base case. Similarly Tables 5.9 and 5.13 show the frequency of system separation and duration of system separation for case-I and case-II respectively. Frequency of system separation and mean duration of system separation change significantly due to the common-cause outage. System separation and mean duration of system separation indicates higher value for common-cause failure events. Isolation of a transmission branch is one of the major weakness of the transmission network design. In fact a system separation arises when the failure of a single or multiple transmission branches cause isolation of atleast one bus from the network.

The Tables 5.6, 5.10 and 5.14 show the estimate of expected values of yearly energy not supplied in load buses. Yearly energy not supplied changes significantly in some lòad buses due to common-mode outages whereas for other buses YENS remain almost unchanged.

6.2 CONCLUSIONS

The function of reliability assessment is to establish the impact of any event in order to determine what actions are to be taken to minimize its effect. In this research work inadequacies associated with common-mode failures are accommodated in the sequential simulation procedures. From the observations and discussions given in this thesis, the following conclusions are made.

a. A new approach has been developed in this research to determine the actual stochastic nature of state transition of transmission components.

b. The models presented in this thesis extended the wider applicability of the sequential simulation for appreciating more accurate picture of transmission system inadequacies.

c. Inclusions of common-mode outages change the transmission reliability indices significantly. The system separation indices also change significantly with common-cause outage events. However, the actual impact of common-mode outages depend on the transmission system network configuration.

6.3 RECOMMENDATION FOR FURTHER RESEARCH WORK

In this research only two transmission lines are considered in the common-cause outage model on the same right of way or on the same transmission tower. But, practically more than two transmission lines may exist on the same right of way or on the same transmission tower. Hence these considerations can be taken into account in future research. Dependent outages are not considered in this research. Only independent and common-cause outages are included in the transmission system evaluations. Hence dependent failures may be taken into account in future research work.

APPENDIX - A

Table - A.1: IEEE-RTS GENERATION DATA

Unit No.	Rated Capacity (MW)	MTTF (hr)	MTTR (hr)	Cost $/MWh	Bus No.	Voltage Level (kV)
1	400.00	1100.00	150.00	00.3	BUS-18	230
2	400.00	1100.00	150.00	00.3	BUS-21	230
3	350.00	1150.00	100.00	00.7	BUS-23	230
4	197.00	950.00	50.00	00.7	BUS-13	230
5	197.00	950.00	50.00	00.7	BUS-13	230
6	197.00	950.00	50.00	00.7	BUS-13	230
7	155.00	960.00	40.00	00.8	BUS-16	230
8	155.00	960.00	40.00	00.8	BUS-15	230
9	155.00	960.00	40.00	00.8	BUS-23	230
10	155.00	960.00	40.00	00.8	BUS-23	230
11	100.00	1200.00	50.00	00.8	BUS-07	138
12	100.00	1200.00	50.00	00.8	BUS-07	138
13	100.00	1200.00	50.00	00.8	BUS-07	138
14	76.00	1960.00	40.00	00.9	BUS-01	138
15	76.00	1960.00	40.00	00.9	BUS-01	138
16	76.00	1960.00	40.00	00.9	BUS-02	138
17	76.00	1960.00	40.00	00.9	BUS-02	138
18	12.00	2940.00	60.00	00.9	BUS-15	230
19	12.00	2940.00	60.00	00.9	BUS-15	230
20	12.00	2940.00	60.00	00.9	BUS-15	230
21	12.00	2940.00	60.00	00.9	BUS-15	230
22	12.00	2940.00	60.00	00.9	BUS-15	230
23	20.00	450.00	50.00	05.0	BUS-01	138
24	20.00	450.00	50.00	05.0	BUS-01	138
25	20.00	450.00	50.00	05.0	BUS-02	138
26	20.00	450.00	50.00	05.0	BUS-02	138
27	50.00	1980.00	20.00	00.0	BUS-22	230
28	50.00	1980.00	20.00	00.0	BUS-22	230
29	50.00	1980.00	20.00	00.0	BUS-22	230
30	50.00	1980.00	20.00	00.0	BUS-22	230
31	50.00	1980.00	20.00	00.0	BUS-22	230
32	50.00	1980.00	20.00	00.0	BUS-22	230

Total No. of Units : 32

Total Installed Capacity: 3405 MW

MTTF : Main Time to Failure.

MTTR : Main Time to Repair.

APPENDIX - B

Table - B.1: IEEE-RTS BUS DATA

Sl. No.	BUS Code	BUS Name	Voltage Level (kV)	Fraction of load share
1	BG	BUS-01	138	0.0380
2	BG	BUS-02	138	0.0340
3	BG	BUS-07	138	0.0440
4	BG	BUS-13	230	0.0930
5	BG	BUS-15	230	0.1110
6	BG	BUS-16	230	0.0350
7	BG	BUS-18	230	0.1170
8	BG	BUS-21	230	0.0000
9	BG	BUS-22	230	0.0000
10	BG	BUS-23	230	0.0000
11	B	BUS-03	138	0.0630
12	B	BUS-04	138	0.0260
13	B	BUS-05	138	0.0250
14	B	BUS-06	138	0.0480
15	B	BUS-08	138	0.0600
16	B	BUS-10	138	0.0680
17	B	BUS-11	230	0.0000
18	B	BUS-12	230	0.0000
19	B	BUS-14	230	0.0680
20	B	BUS-17	230	0.0000
21	B	BUS-19	230	0.0640
22	B	BUS-20	230	0.0450
23	B	BUS-24	230	0.0000
24	B	BUS-09	138	0.0610

BG : **Generation Buse.**

APPENDIX - C

Table - C.1: IEEE-RTS TRANSMISSION SYSTEM DATA.

Sl. No.	X-Mission Line Type	From Bus	kV	To BUS	kV	Capacity (MVA)	TOL	X-Mission Line Impedance	FR	OD (hr.)
1	U	BUS-1	138	BUS-2	138	175	0.10	0.0139	00.24	16.
2	L	BUS-1	138	BUS-3	138	175	0.19	0.2112	00.51	10.
3	L	BUS-1	138	BUS-5	138	175	0.19	0.0845	00.33	10.
4	L	BUS-2	138	BUS-4	138	175	0.19	0.1267	00.39	10.
5	L	BUS-2	138	BUS-6	138	175	0.19	0.1920	00.48	10.
6	L	BUS-3	138	BUS-9	138	175	0.19	0.1190	00.38	10.
7	T	BUS-3	138	BUS-24	230	400	0.28	0.0839	00.02	768.
8	L	BUS-4	138	BUS-9	138	175	0.19	0.1037	00.36	10.
9	L	BUS-5	138	BUS-10	138	175	0.19	0.0883	00.34	10.
10	U	BUS-6	138	BUS-10	138	175	0.10	0.0705	00.33	35.
11	L	BUS-7	138	BUS-8	138	175	0.19	0.0614	00.30	10.
12	L	BUS-8	138	BUS-9	138	175	0.19	0.1651	00.44	10.
13	L	BUS-8	138	BUS-10	138	175	0.19	0.1651	00.44	10.
14	T	BUS-9	138	BUS-11	230	400	0.28	0.0839	00.02	768.
15	T	BUS-9	138	BUS-12	230	400	0.28	0.0839	00.02	768.
16	T	BUS-10	138	BUS-11	230	400	0.28	0.0839	00.02	768.
17	T	BUS-10	138	BUS-12	230	400	0.28	0.0839	00.02	768.
18	L	BUS-11	230	BUS-13	230	500	0.20	0.0476	00.40	11.
19	L	BUS-11	230	BUS-14	230	500	0.20	0.0418	00.39	11.
20	L	BUS-12	230	BUS-13	230	500	0.20	0.0476	00.40	11.

Table C.1 Contd..............

Sl. No.	X-Mission Line Type	From Bus	kV	To BUS	kV	Capacity (MVA)	TOL	X-Mission Line Impedance	FR	OD (hr.)
21	L	BUS-12	230	BUS-23	230	500	0.20	0.0966	00.52	11.
22	L	BUS-13	230	BUS-23	230	500	0.20	0.0865	00.49	11.
23	L	BUS-14	230	BUS-16	230	500	0.20	0.0389	00.38	11.
24	L	BUS-15	230	BUS-16	230	500	0.20	0.0173	00.33	11.
25	L	BUS-15	230	BUS-21	230	500	0.20	0.0490	00.41	11.
26	L	BUS-15	230	BUS-21	230	500	0.20	0.0490	00.41	11.
27	L	BUS-15	230	BUS-24	230	500	0.20	0.0519	00.41	11.
28	L	BUS-16	230	BUS-17	230	500	0.20	0.0259	00.35	11.
29	L	BUS-16	230	BUS-19	230	500	0.20	0.0231	00.34	11.
30	L	BUS-17	230	BUS-18	230	500	0.20	0.0144	00.32	11.
31	L	BUS-17	230	BUS-22	230	500	0.20	0.1053	00.54	11.
32	L	BUS-18	230	BUS-21	230	500	0.20	0.0259	00.35	11.
33	L	BUS-18	230	BUS-21	230	500	0.20	0.0259	00.35	11.
34	L	BUS-19	230	BUS-20	230	500	0.20	0.0369	00.38	11.
35	L	BUS-19	230	BUS-20	230	500	0.20	0.0369	00.38	11.
36	L	BUS-20	230	BUS-23	230	500	0.20	0.0216	00.34	11.
37	L	BUS-20	230	BUS-23	230	500	0.20	0.0216	00.34	11.
38	L	BUS-21	230	BUS-22	230	500	0.20	0.0678	00.45	11.

U : Underground Cable

T : Transformer

L : Overhead Transmission Line

TOL : Tolerance in Percentage of Capacity.

FR : Failure Rate, Frequency/year

OD : Outage Duration in Hour

APPENDIX - D

Table D.1: IEEE-RTS Load Data.
Hourly Peak Load as a Percentage of Daily Peak.

Hour	Winter Weeks		Summer Weeks		Spring/ Fall Weeks	
	Weekday	Weekend	Weekday	Weekend	Weekday	Weekend
12-1 am	0.67	0.78	0.64	0.74	0.63	0.75
1-2 am	0.63	0.72	0.60	0.70	0.62	0.73
2-3 am	0.60	0.68	0.58	0.66	0.60	0.69
3-4 am	0.59	0.66	0.56	0.65	0.58	0.66
4-5 am	0.59	0.64	0.56	0.64	0.59	0.65
5-6 am	0.60	0.65	0.58	0.62	0.65	0.65
6-7 am	0.74	0.66	0.64	0.62	0.72	0.68
7-8 am	0.86	0.70	0.76	0.66	0.85	0.74
8-9 am	0.95	0.80	0.87	0.81	0.95	0.83
9-10 am	0.96	0.88	0.96	0.86	0.99	0.89
10-11 am	0.96	0.90	0.99	0.91	1.00	0.92
11-noon	0.95	0.91	1.00	0.93	0.99	0.94
12-1pm	0.95	0.90	0.99	0.93	0.93	0.91
1-2	0.95	0.88	1.00	0.92	0.92	0.90
2-3	0.93	0.87	1.00	0.91	0.90	0.90
3-4	0.94	0.87	0.97	0.91	0.88	0.86
4-5	0.99	0.91	0.96	0.92	0.90	0.85
5-6	1.00	1.00	0.96	0.94	0.92	0.88
6-7	1.00	0.99	0.93	0.95	0.96	0.92
7-8	0.96	0.97	0.92	0.95	0.98	1.00
8-9	0.91	0.94	0.92	1.00	0.96	0.97
9-10	0.83	0.92	0.93	0.93	0.90	0.95
10-11	0.73	0.87	0.87	0.88	0.80	0.90
11-12	0.63	0.81	0.72	0.80	0.70	0.85

APPENDIX - E

Table - E.1: IEEE-RTS LOADS DATA.

Daily Peak load in MW.

Week No.	Day						
	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
01	2284.70	2407.60	2456.70	2358.40	2309.30	1891.70	1842.50
02	2385.50	2513.70	2565.00	2462.40	2411.10	1975.10	1923.80
03	2327.10	2402.20	2502.30	2452.30	2352.20	1926.80	1876.70
04	2210.50	2329.40	2376.90	2281.80	2234.30	1830.20	1782.70
05	2332.40	2457.80	2508.00	2407.70	2357.50	1931.20	1881.00
06	2229.10	2348.90	2396.80	2300.90	2253.10	1845.60	1797.60
07	2205.20	2323.80	2371.20	2276.50	2228.90	1825.80	1778.40
08	2136.30	2251.20	2297.10	2205.20	2159.30	1768.80	1722.80
09	1961.40	2066.80	2109.00	2024.60	1982.50	1623.90	1581.80
10	1953.40	2058.40	2100.50	2016.40	1974.40	1617.40	1575.30
11	1895.10	1997.00	2037.80	1956.20	1915.50	1569.10	1528.30
12	1926.90	2030.50	2071.90	1989.10	1947.60	1595.40	1553.90
13	1865.90	1966.30	2006.40	1926.10	1886.00	1544.90	1504.80
14	1987.90	2094.80	2137.50	2052.00	2009.30	1645.90	1603.10
15	1911.00	2013.80	2054.90	1972.70	1931.60	1582.20	1541.10
16	2120.40	2234.40	2280.00	2188.80	2143.20	1755.60	1710.00
17	1998.50	2105.90	2148.90	2062.90	2019.90	1654.70	1611.70
18	2218.50	2337.70	2385.50	2290.00	2242.30	1836.80	1789.10
19	2305.90	2429.90	2479.50	2380.30	2330.70	1909.20	1859.60
20	2332.40	2457.80	2508.00	2407.70	2357.50	1931.20	1881.00
21	2268.80	2390.80	2439.60	2342.00	2293.20	1878.50	1829.70
22	2149.60	2265.10	2311.40	2218.90	2172.70	1779.70	1733.50
23	2385.50	2513.70	2565.00	2462.40	2411.10	1975.10	1923.80
24	2351.00	2477.40	2527.90	2462.80	2376.30	1946.50	1895.90
25	2374.90	2502.50	2553.60	2451.50	2400.40	1966.30	1915.20

Table E.1 Contd..............

Week No.	Day						
	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
26	2282.10	2453.90	2355.70	2404.80	2306.60	1889.50	1840.40
27	2001.10	2151.80	2065.70	2108.70	2022.70	1656.90	1613.80
28	2162.80	2325.60	2232.60	2279.10	2186.10	1790.70	1744.20
29	2123.10	2282.90	2191.50	2237.20	2145.90	1757.80	1712.10
30	2332.40	2508.00	2407.70	2457.80	2357.50	1931.20	1881.00
31	1913.70	2057.70	1975.40	2016.60	1934.20	1584.40	1543.30
32	2056.80	2211.60	2123.10	2015.70	2078.90	1702.90	1658.70
33	2120.40	2280.00	2188.80	2234.40	2143.20	1755.60	1710.00
34	1932.20	2077.70	1994.50	2036.10	1953.00	1599.80	1558.20
35	1924.30	2069.10	1986.30	2027.70	1944.90	1593.20	1551.80
36	1868.60	2009.30	1928.90	1969.10	1888.70	1547.10	1506.90
37	2067.40	2223.00	2134.10	2178.50	2089.60	1711.70	1667.30
38	1842.10	1980.80	1901.50	1941.10	1861.90	1525.20	1845.60
39	1918.90	2063.40	1980.90	2022.10	1939.60	1588.80	1547.60
40	1918.90	2063.40	1980.90	2022.10	1939.60	1588.80	1547.60
41	1969.30	2117.60	2032.90	2075.20	1990.50	1630.50	1588.20
42	1971.90	2120.40	2035.60	2078.00	1993.20	1632.70	1590.30
43	2120.40	2280.00	2188.80	2234.40	2143.20	1755.60	1710.00
44	2335.10	2510.90	2410.40	2460.60	2360.20	1933.40	1883.10
45	2345.70	2522.30	2421.40	2471.00	2370.00	12.00	1891.70
46	2409.30	2590.60	2487.00	2538.80	2435.20	1994.00	1943.00
47	2491.50	2679.00	2571.80	2625.40	2518.30	2062.80	2009.20
48	2358.90	2536.50	2435.10	2485.80	2384.30	1953.10	1902.40
49	2496.80	2684.70	2577.30	2631.00	2523.60	2067.20	2013.50
50	2571.00	2764.50	2653.90	2709.20	2598.60	2128.70	2073.40
51	2650.50	2850.00	2736.00	2793.00	2679.00	2194.50	2137.50
52	2523.30	2713.20	2604.70	2658.90	2550.40	2089.20	2034.90

APPENDIX—F

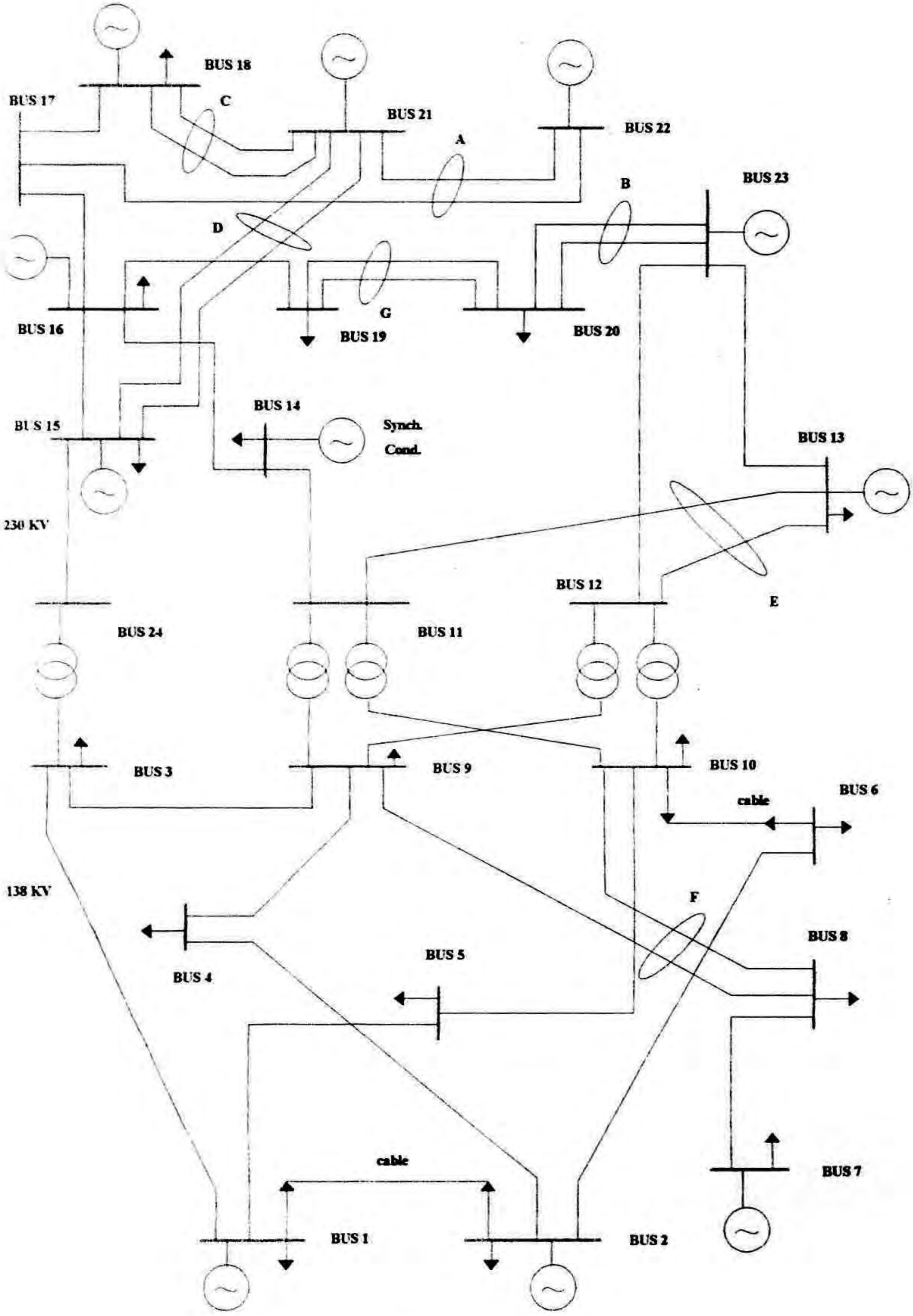

Figure 2: The IEEE-RTS network

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