Reliability evaluation of deregulated power systems using Monte Carlo simulation

Viswanath Padmavati Aparna

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Reliability Evaluation of Deregulated Power Systems using Monte Carlo Simulation

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in fulfilment of the requirement for the degree of
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2007

This research work is dedicated to my parents
G. Nagalakshmi and G. Satyanarayana

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This research work has been a journey – of discovering academic excellence, personal strengths, lasting friendships and guidance, and, most importantly, the discovery of joy of learning itself. The contents of this thesis, of course, capture just a small portion of the discovery made during this journey. It is thus just appropriate that I take this opportunity to thank all those - starting with the divine Lord Balaji, whose resplendent grace lit the path all along - who made this journey possible.

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the journey goes on!

Summary

The research work described in this thesis is devoted to develop models and techniques to evaluate system and customer reliabilities based on the new system operating and reliability management policies in deregulated power markets. System and customer reliability indices calculated in this thesis will help customers to make better decisions in market trading and will also assist system planners and operators to operate electric power systems more economically and reliably.

Deregulation of the power industry has created new issues that must be addressed in reliability evaluation. With the deregulation of the power industry, the generation, transmission and distribution functions within a corporation are now segregated into individual companies. Services such as spinning reserve, interruptible loads, etc., are also segregated and sold at separate tariffs. These changes have created some fundamental changes in system operation and reliability management that can affect the system and customer reliabilities. The reliability evaluation techniques used in vertically integrated systems therefore need to be reviewed, updated and improved based on the new system operating and reliability management policies in order to suit the new environment.

This thesis investigates different market structures and proposes new methods to evaluate system reliability indices for spot markets, and customer reliability indices for bilateral and hybrid markets.

A Monte Carlo simulation technique is developed to evaluate the reliability of restructured power generation systems with a spot market structure. The proposed reliability model is developed by convolving the spot market based generation and load models. The proposed spot market based generation model is obtained from the operating history of the generating system and the spot market clearing mechanism. The proposed reliability model is further extended to incorporate the effects of uncertainties such as bid prices.

A Monte Carlo simulation technique is developed to evaluate the customer reliability of restructured power generation systems with a multi bilateral contracts market structure. The market related factors such as bilateral transactions, reserve agreements between Gencos and priority order of Gencos serving the customers are incorporated in the developed technique. The equivalent time varying multi-state generation (ETMG) is proposed and used to represent a bilateral contract. A procedure based on ETMG to evaluate the customer reliability is developed.

A non-time sequential Monte Carlo simulation technique is proposed to evaluate the customer reliability of restructured power generation systems with a hybrid market structure. Reliability management is more complex in deregulated power systems than in conventional systems because multiple transactions exist between Gencos and customers. These transactions are represented by a transactions matrix. A model for optimal transaction curtailment for a contingency state in a hybrid market is also developed in this project. The proposed model is utilized to evaluate the customer reliability which depends on the market related factors and the traditional reliability parameters.

A framework to implement supply and demand side contingency management in reliability assessment of restructured composite power generation and transmission systems with hybrid market structure is also proposed. In the proposed framework, the reliability cost and worth are balanced by the Independent System Operator (ISO) by coordinating the supply side “reserve offers” and the demand side “load curtailment offers” for a generation inadequacy state. The load curtailments and generation re-dispatch for a contingency state are determined by using an optimization technique. A Monte Carlo simulation technique based on this framework is proposed to evaluate the customer reliability. The evaluation domain for the technique involves the reliability problems of both generation and transmission systems.

Two test systems namely the Roy Billinton Test System (RBTS) and the IEEE Reliability Test System (RTS) are utilized to illustrate the proposed techniques.

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List of Symbols

General

h	index for Genco
k	index for customer
v	index for generating units
i	index for sampling state
j	index for system contingency state
m	number of Gencos
p	number of customers
λ	failure rate of a unit
μ	repair rate of a unit
U	Uniformly distributed random number
N	number of Monte Carlo samples
TTF	Time to failure
TTR	Time to repair
$LOLE$	Loss of load expectation
$EENS$	Expected energy not supplied

For sample i

LLD_i	Loss of load duration
ENS_i	Energy not supplied

Chapter 2

$LOLP$	Loss of load probability
$VOLL$	Value of lost load

SMP System marginal price of the pool

Chapter 3

M number of paths to save at each stage
L feasible states for hour *t*-1
I Generating units' state
LC_{cost} (t, I) Least cost to arrive at state (*t*, *I*)
MC_{cost} (t, I) Market Cost for state (*t*, *I*)
TC_{cost} (t, I) Transition cost from state (*t*-1, *L*) to state (*t*, *I*)
y index for scenario
Z number of scenarios
w weight of each scenario
SLOLE LOLE for a scenario
SEENS EENS for a scenario
WLOLE Weighted LOLE
WEENS Weighted EENS

Chapter 4

t time index
n the number of periods
T_n time at the end of *n*th period
GC_h^t Generating capacity (MW) of Genco *h*
PC_{hk}^t Priority commitments of Genco *h* prior to serving *BLP_k*
RA_h^t Reserve assistance (MW) to Genco *h* from other Gencos
AGC_{hk}^t Available generation capacity (MW) of Genco *h* at *BLP_k*
CC_{hk}^t Bilateral contract capacity (MW) by Genco *h* at *BLP_k*
ETMG_{hk} Equivalent time varying multi state generation, Genco *h* and *BLP_k*

Chapter 5

ψ^{gs}	Spot market clearing price
ψ^{gr}	Reserve market clearing price

$m \times 1$ **vectors**

T^{gs}	Spot market power transactions of Gencos
T^{gr}	Reserve market power transactions of Gencos
C^{gs}	Spot market curtailments of Gencos
C^{gr}	Reserve market curtailments of Gencos
T^g	Supply side transactions
e_m	Unit vector

$p \times 1$ **vectors**

T^{ds}	Spot market power transactions of customers
C^{ds}	Spot market curtailments of customers
T^d	Demand side transactions
e_p	Unit vector

$m \times p$ **matrix**

T^b	Bilateral power transactions
ψ^b	Prices for bilateral transactions
C^b	Bilateral curtailments

For Genco h with x units

B_h	vectors of unit variable operating costs
G_h^{max}	vectors of unit ratings
S_h	vector for sampling state of unit

Chapter 6

x	number of units in Genco to supply energy
y	number of units in Genco to provide primary reserve
z	number of units in Genco to provide secondary reserve

For unit v , Genco h and customer k

P_{hv}	Capacity of the unit
P_h	Total generation scheduled by Genco
R	Total reserve
$R_{hv}^{max pri}$	Capacity of primary reserve unit
$R_{hv}^{max sec}$	Capacity of secondary reserve unit
T_h^{gs}	Power sold by Genco in the spot market
T_k^{ds}	Power bought by customer in the spot market
T_{hk}^b	Power sold through bilateral contract
T_h^g	Total power sold by Genco
T_k^d	Total power bought by customer
$\mathcal{G}_{hk}^b$	Curtailment cost for the bilateral transaction
$\mathcal{G}_k^{ds}$	Curtailment bid of customer for spot market transaction
ORR_{hv}	Outage replacement rate
λ_{hv}	Failure rate

For sample i and contingency state j

S_{hvi}	Sampling state of unit
S_{hi}	Sampling state of Genco
P_{hi}	Total generation dispatched by Genco
$R_{hvi}^{\max pri}$	Available Capacity of primary reserve unit
$R_{hvi}^{\max sec}$	Available Capacity of secondary reserve unit
T_{hj}^{gs}	Power supplied by Genco in the spot market
T_{kj}^{ds}	Power supplied to customer in the spot market
T_{hkj}^b	Power supplied through bilateral contract
R_{hvj}^{pri}	Primary reserve dispatched
R_{hvj}^{sec}	Secondary reserve dispatched
C_{hj}^{gs}	Generation curtailed from Genco to the spot market
C_{kj}^{ds}	Load curtailed for customer in the spot market
C_{hkj}^b	Load curtailed for bilateral customer
F_l	Power flow in line l
$RMCP_1$	Primary reserve price
$RMCP_2$	Secondary reserve price
$EENS_k^d$	EENS of customer k
ERD	Expected reserve dispatch
$EMICOST$	Expected market interruption cost

List of Acronyms

Term	Definition
BLP	Bulk Load Point
CAISO	California Independent System Operator
COPT	Capacity Outage Probability Table
DLOL	Duration of Loss of Load
DPLVC	Daily Peak Load Variation Curve
Disco	Distribution Company
EMCP	Energy Market Clearing Price
EENS	Expected Energy Not Supplied
FLOL	Frequency of Loss of Load
Genco	Generation Company
HL	Hierarchical Level
ISO	Independent System Operator
LDC	Load Duration Curve
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MCS	Monte Carlo Simulation
MCQ	Market Clearing Quantity
MTTF	Mean Time to Failure
MTTR	Mean Time to Repair
NYISO	New York Independent System Operator
OPF	Optimal Power Flow
PX	Power Exchange
PJM	Pennsylvania-New Jersey-Maryland
RMCP	Reserve Market Clearing Price
RBTS	Roy Billinton Test System
RTS	Reliability Test System
Transco	Transmission Company

Chapter 1

Introduction

1.1 Motivation

The major focus of reliability evaluation in vertically integrated power systems has been to assess the redundancy requirements for reliable power generation, transmission, and distribution of electrical energy. Electric power utilities handle generation, transmission and distribution and are regulated by government agencies to ensure fair prices and adequate supplies. Regulators establish operating and planning standards for utilities to ensure system reliability. The major issue is how much redundancy should be provided to serve the customers economically and reliably. Well-established reliability criteria and reliability standards exist for such systems. Many reliability evaluation techniques and optimization techniques have been developed to address the traditional reliability issues. The focus thus far has been to enhance these techniques with an aim to obtain the best possible solutions for reliable operation of a system. In deregulated power systems, such conventional reliability techniques are no longer applicable. The major thrust of the research work reported in this thesis therefore is to perform reliability evaluation in deregulated power systems.

The electric power industry throughout the world is experiencing restructuring. The direct consequences of restructuring are the economic segregation of network functions such as generation, transmission and distribution into individual corporate bodies such as Generation Companies (Gencos), Transmission Companies (Transcos) and Distribution Companies (Discos) and also the unbundling of main and ancillary services such as capacity reserve provisions. A customer selects his own power providers that can satisfy his price and reliability expectations. The Gencos serve its customers with an objective to stay profitable.

Chapter 1 Introduction

Deregulation in the power market has created a new environment in which the contracts are no longer between a single electrical utility and multiple users, but between multiple suppliers and multiple users with the added complexity of differential pricing based on desired reliability needs.

Products such as real and reactive power, and reserve such as reserve generation or interruptible loads can be traded using separate tariffs in a power market or a power exchange (PX). The separation of ownership or “unbundling” has resulted in loss of control. An Independent System operator (ISO) may take up the responsibility for coordinating the activities of all the market participants for smooth and reliable operation of the system. Unlike a vertically integrated system, in the new environment, the system operator has to operate the system keeping in view the individual objectives of all market participants namely the Gencos and the customers. Accordingly, the system operation and reliability management policies are different and they can influence the system and customer reliabilities.

The reliability evaluation techniques used in vertically integrated systems need to be reviewed, updated and improved based on the new system operation and reliability management policies to suit the new environment.

1.2 Objectives

Power system reliability evaluation is generally performed using probabilistic techniques [1-3]. A bibliography on the applications of probability methods in power system reliability evaluation is given in [4-11]. Reliability evaluation techniques and applications reported in the literature are mostly suitable for vertically integrated power systems, which mainly deal with the redundancy requirements for a utility to serve the customers economically and reliably.

Increased efficiency, new technological drives, and increased choices motivated the deregulation of the electric power industry. Different countries adopted different

Chapter 1 Introduction

deregulation strategies. The deregulation of the power industry has given rise to some fundamental changes regarding system operation. The economics of system operation in the deregulated environment are highlighted in [12]. The reliability issues that have evolved due to the deregulation of the power industry are addressed in [13, 14].

A detailed literature review of the reliability evaluation of power systems both in the old and new environments is presented in Chapter 2.

The research described in this thesis focuses on the development of techniques to evaluate system and customer reliabilities in deregulated power systems based on the new system operation and reliability management policies. While the existing system-wide indices are mainly used by system planners and operators, customer reliability indices proposed in this thesis will help the customers to make better decisions with regards to price and reliability while trading for power.

The main objectives of this research work were as follows:

- to review the existing techniques used in conventional power system reliability evaluation
- to study the difference of system operation and reliability management between old and new system structures
- to investigate different power market structures and the corresponding reliability management
- to develop necessary models for reliability management associated with various markets
- to define and obtain necessary attributes for reliability evaluation
- to develop techniques to evaluate and manage system and customer reliabilities in the new environment
- to investigate the impact of reliability management (based on the individual objectives of the market participants) on system and customer reliabilities, and

- to incorporate the uncertainties in the operation of deregulated power markets for reliability evaluation.

1.3 Major Contributions

The main contributions and highlights of the thesis are summarized in the following.

1.3.1 Reliability Evaluation of Power Generation Systems with Spot Market Structure

A time sequential Monte Carlo simulation technique [2,3] is proposed for reliability evaluation of power generation systems with the spot market structure. The reliability model for the spot market is obtained by convolving the spot market based generation model with the load model. System-wide hourly reliability indices are obtained from the reliability model. The proposed reliability model is further extended to incorporate the effects of uncertainties such as bid prices.

1.3.2 Reliability Evaluation of Power Generation Systems with Multi-Bilateral Contracts Market Structure

A time sequential Monte Carlo simulation technique is proposed to evaluate the customer reliability of power generation systems with multi-bilateral contracts market structure. The reliability equivalent of a bilateral contract, defined as equivalent time varying multi state generation (ETMG) is developed. The reserve agreements between Gencos and the priority order of Gencos serving the customers are incorporated in modeling the ETMG. A reliability model for evaluating customer reliabilities is constructed by utilizing the ETMG. A procedure to determine the probability distributions of customer reliability indices is also proposed. The Roy Billinton Test System (RBTS) [15, 16] has been utilized to illustrate the procedure and also the factors that affect the customer reliability.

1.3.3 Reliability Evaluation of Power Generation Systems with Hybrid Market Structure

A non-time sequential MCS technique is proposed to evaluate the customer reliability of power generation systems with hybrid market structure. A model for optimal transaction curtailment for a contingency state in a hybrid market is developed to incorporate the changes brought about by deregulation. The objective of the contingency optimal transaction curtailment is based on minimizing the revenue loss for each individual Genco in serving its differentially priced customers. Customer load curtailment is determined using a load shedding philosophy that is based on the results of the optimal transaction curtailment by the Genco. Supply and demand transactions of the market participants are represented by a transaction matrix. The impacts of the firm and non-firm bilateral and reserve contracts on customer reliabilities have also been studied. The technique has been illustrated by application to the IEEE Reliability Test System (RTS) [17].

1.3.4 A Framework to Implement Supply and Demand Side Contingency Management in Reliability Assessment

A framework to implement supply and demand side participation in the contingency management of power systems with hybrid market structure is developed. A model for the ISO to coordinate the supply side “reserve offers” and the demand side “load curtailment offers” for a generation inadequacy state is introduced to balance reliability worth and cost. The load curtailments and generation re-dispatch for a contingency state are determined by using an optimization technique. The objective function for the optimization technique is to minimize the market interruption cost. A non-sequential Monte Carlo simulation technique based on this framework has been proposed to evaluate the customer reliability in restructured power systems with the hybrid market structure. The modified IEEE Reliability Test System is analyzed to illustrate the proposed technique.

1.4 Thesis Organization

In addition to the introductory chapter this dissertation is divided into the following chapters.

Chapter 2 presents a review of the literature on reliability evaluation of power systems in vertically integrated power systems, a brief description of the deregulation of the power industry, reliability issues in the deregulated environment and the available literature to address some of these issues.

Chapter 3 presents reliability evaluation of power generation systems with spot market structure. A market-based generation model is obtained based on the bidding and the market clearing mechanism. Uncertainties in bidding details are also incorporated in the reliability evaluation.

Chapter 4 presents reliability evaluation in a multi- bilateral contracts market by incorporating the reserve agreements between Gencos and the priority order of the Gencos serving the customers.

Chapter 5 presents reliability evaluation in a hybrid market. The power transactions in the hybrid market are represented by a transactions matrix. In case of contingencies the optimal transactions curtailments are considered for reliability evaluation.

Chapter 6 presents a framework to implement supply and demand side contingency management in the reliability assessment of power systems with hybrid market structure.

Chapter 7 presents the major conclusions and contributions of the thesis and also some recommendations for possible extensions of the research.

Chapter 2

Background Literature

2.1 Introduction

Reliability is a specific measure that describes the ability of a system to perform its intended function. The basic function of an electricity supply system is to supply electrical energy to its customers [2-3]. Reliability evaluation techniques progressed with increasing degrees of refinement from the days of vertically integrated markets and have become even more challenging in the present deregulated electricity supply environment. For assuring reliability, the challenges in a deregulated power industry are many and they are distinctly different from those faced in vertically integrated power systems.

This chapter presents an overview of reliability concepts and the existing techniques for reliability evaluation. Reliability issues starting from vertically integrated power systems to deregulated power systems are discussed. Finally, the need for the solution techniques proposed in this research work is presented.

2.2 Reliability Concepts in Power Systems

In order to provide reliable supply of power to the customers it is essential to have redundant generation, transmission and distribution facilities. Redundancy guarantees continuity of power supply in the event of forced outages and/or scheduled maintenance of the equipment. In the past, this redundancy was determined based on some deterministic criteria. For example, the generating reserve capacity was determined based on a fixed percentage of the maximum demand or the outage of the largest generating unit [2, 18]. Similarly for the transmission network, the number of circuits to the load was based on the N-1 contingency criterion [2]. These deterministic criteria cannot take into

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account the stochastic behavior of the system and for this reason many probabilistic reliability evaluation techniques have been developed to consider the forced outage rates, unit types and sizes, etc., of the generating units at the generation level, and failure rate, length, design, and location, etc. at the transmission level.

Reliability is defined as the probability of a system performing its required function for the period of time intended under the operating conditions encountered [1-3]. The term reliability is further classified into more specific terms such as system adequacy and system security. System adequacy is defined in [3] as the existence of sufficient facilities within the system to satisfy the customer load demand. System security is defined in [3] as the ability of the system to respond to disturbances arising within the system.

Power systems being very large and complex have been divided into subsystems based on their functions, for the purpose of reliability evaluation. The evaluation techniques used in reliability analysis of power systems can therefore be categorized into three basic functional zones of generation, transmission and distribution. In conducting reliability analyses, these functional zones can be combined to create hierarchical levels (HL) [3]. The hierarchical levels and the concerned functional zones for reliability assessment studies are as follows:

- HLI- Generation facilities
- HLII- Generation and Transmission facilities
- HLIII- Generation, Transmission and Distribution facilities

The research work described in this thesis focuses mainly on HLI evaluation in Chapters 3, 4 and 5, and both HLI and HLII evaluation in Chapter 6.

Reliability evaluation considering the generation facilities can be divided into two distinct categories namely static capacity assessment and operating reserve assessment. Static capacity assessments are made at the planning stage in order to decide on the “quantity” and “timing” of additional generating capacity installation. A large number of papers that apply probability techniques to static capacity reliability evaluation have been

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published in the last 50 years. These publications have been documented in three comprehensive bibliographies published in 1966 [4], 1972 [5] and 1978 [6] that include over 160 individual references.

Operating reserve reliability assessments are conducted to decide operating reserve requirements and associated operating costs. The basis for operating reserve reliability assessment is “to evaluate the probability of the committed generation just satisfying or failing to satisfy the expected demand during the period of time that generation cannot be replaced” [3]. The period of time that generation cannot be replaced is known as the lead-time.

Static capacity reliability assessment is discussed in Chapters 3, 4 and 5 of this thesis. The operating reserve reliability assessment is the main focus of Chapter 6.

2.3 Reliability Evaluation Techniques

The various techniques used in the reliability evaluation of power systems can be broadly classified into contingency enumeration (analytical) techniques [2] and Monte Carlo simulation techniques [2, 3]. In both these types of techniques, the generation and the load models of a system are convolved to obtain a risk model.

A base-load generating unit is generally represented as a two-state model. Units with derated states are represented by three state model and peaking units as four state model. Reliability evaluation techniques developed for two state models can also be extended for derated states and peaking units. The parameter used in the generating unit model is the probability of finding the unit on forced outage at some distant time in the future and is defined as the unit unavailability [3]. The probability of the unit residing in any of the states is evaluated using the Markov process [2], where the probabilities are developed in terms of the state transition rates.

There are a number of load models of which the two most important types are as follows:

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- 1) the annual load curve - the load model is obtained by scanning all the hourly points of the chronological load curve, and
- 2) (a) daily peak load variation curve (DPLVC) (b) the load duration curve (LDC) - in the DPLVC and LDC models the load levels from the chronological load curve are arranged in a descending order in order to form a cumulative load model.

Several reliability indices that can be obtained from the risk model [1-3] are as follows:

- Loss of Load Probability – LOLP
- Loss of Load Expectation – LOLE (hours or days or years per period)
- Expected Energy Not Supplied – EENS (MWh per period)
- Frequency of Loss of Load – FLOL (occurrences per period)
- Duration of Loss of Load – DLOL (hours per occurrence)

Among these reliability indices, LOLE and EENS are the most widely used as they provide a good measure of generation system reliability. LOLE is defined as the expected time period during which the system experiences a load loss. It is a simple index from the computational point of view and has been used by many utilities like Ontario Hydro, Hydro Quebec, BC Hydro and Power Authority, Alberta Interconnected System, Manitoba Hydro, Nova Scotia Power Corporation, etc., for reserve capacity planning [18]. EENS is the expected energy not supplied during the period the system experiences a load loss. EENS has been used by the Saskatchewan Power Corporation and Ontario Hydro, etc., for reserve capacity planning [18].

Even though the probabilistic reliability indices and their evaluation techniques are well developed some utilities are still utilizing deterministic criteria. In order to bridge the gap between the probabilistic and deterministic methods reliability indices based on the system well being framework were developed [19, 20]. In this framework the system states are categorized as healthy, marginal and risk states. The well being indices are P_h , P_r and P_m where they represent the probability of finding the system in healthy, risk and marginal states respectively, and can be expressed as follows:

$$P_h + P_r + P_m = 1 \quad (2.1)$$

2.3.1 Analytical Techniques [2-3]

Analytical techniques represent a system by a mathematical model and evaluate reliability indices from this model using direct numerical solutions [2]. In analytical techniques, the system states, i.e., zero outages, first order outages, etc., are selected only once and the indices are then calculated. The stopping criteria can be a particular contingency level or when the state probability becomes less than a pre-specified value.

In a conventional analytical technique, a generation model is constructed using a capacity outage probability table (COPT) and a recursive algorithm. A suitable load model can be convolved with the generation model to obtain a risk model. In [21] five different load models namely constant peak load model, straight line approximated load model, polynomial approximated load model, customized load model and annual load model are convolved with a generation model to evaluate LOLE and EENS.

In conventional analytical techniques, the COPT developed using the recursive algorithm consists of a number of discrete outage levels that requires huge computation time when applied to large power systems. In order to reduce the computing time, many approximate techniques were later developed. In most approximate techniques, the discrete distributions of the capacity outages are approximated by continuous distributions such as the normal distribution [22], folded normal distribution [23], modified distributions obtained by using Gram Charlier expansions [24] and Edgeworth expansions [25]. The computation time becomes much less when a continuous model for capacity outages is used but the results obtained by these methods are not as accurate as those obtained using a discrete model.

A capacity model with normal probability distribution gives sufficiently accurate results only when

- 1) the system has a large number of units with high forced outage rates (FOR), or
- 2) the system has a large number of small units.

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If the capacity model is assumed to be a normal distribution, the probabilities computed in the central part of the distribution are estimated accurately while the tail probabilities may be estimated inaccurately. Better estimates of the tail probabilities are obtained by using 1) folded normal distribution 2) expansions such as Gram Charlier and Edgeworth expansions 3) large deviation method [26], etc. Another approximate technique is the Fast Fourier Transform algorithm [27] proposed by R.N. Allan. In this method the convolution process is performed by multiplying the Fourier transforms of the density functions of generating units in the frequency domain.

In reference [28] approximate analytical techniques such as the Gram Charlier expansion, the high-order Edgeworth expansion, the large deviation method and the Fast Fourier transform algorithm were used to evaluate the marginal outage costs associated with the IEEE RTS [17] as a function of reserve levels and lead times. The accuracy of the results and the computing time for the approximate techniques are also compared with the corresponding values obtained by using the conventional technique. Among the approximate techniques the Fast Fourier Transform provided accurate results in reasonably low computing times for all operating reserves and for both high and low lead times. It was concluded in the paper that FFT was the most practical technique for evaluating marginal costs for the IEEE RTS. Although the large deviation method produced less accurate results than the FFT algorithm, the computation time for the large deviation method was shorter than that of the FFT when proper initial conditions were considered for the large deviation method. The accuracy of the Gram Charlier expansion and the high order Edgeworth expansion were found to be a function of the lead-time. They produced peculiar results such as negative probabilities when the lead-time was less.

2.3.2 Monte Carlo Simulation Techniques [2-3]

Monte Carlo Simulation techniques estimate the reliability indices by simulating the actual process and random behavior of the system. In this method the simulation process is treated like a series of real experiments. Unlike analytical techniques, the system states,

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i.e., zero outages, first order outages, etc., are simulated based on their probabilities of occurrence. States that have a greater probability of occurrence are simulated more times [3].

The basic concepts of Monte Carlo simulation are covered in [1] and extended to electric power systems in [2, 3]. A number of papers [29-34] have been published in the area of reliability evaluation of power systems utilizing Monte Carlo simulation techniques which can theoretically take into account virtually all aspects and contingencies inherent in the planning, design, and operation of a power system [3]. Reference [35] presents a Monte Carlo simulation based reliability evaluation technique by incorporating weather aspects including those situations where the transmission lines traverse several geographic regions that undergo different weather changes. In practical power systems, there exist bus load uncertainties. Further, the loads at different buses in a system are not completely dependent or independent but correlated. In [36], busload uncertainties and correlations are included in the Monte Carlo simulation based reliability evaluation technique. Monte Carlo simulation is a practical approach when complex operating conditions such as bus load uncertainty, weather conditions, etc., are to be incorporated in the reliability evaluation of large power systems.

Unlike the analytical techniques that provide only the average values, Monte Carlo Simulation techniques can provide both average values and the probability distributions of the reliability indices [2-3]. Probability distributions give a pictorial variation of the way the parameter varies, including important information on significant events, which although occur infrequently, can have very serious system effects.

Monte Carlo simulation can sometimes be more suitable in breaking down a complicated system into subsystems [2,3]. Each subsystem can be modeled separately and it is, therefore, easier to analyze the entire system and also the individual subsystems. In this research work, this technique is selected because of the ease in introducing many market players and market transactions that have evolved due to system restructuring.

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Monte Carlo simulation techniques can be further classified into random simulation and sequential simulation techniques. In random simulation, the basic intervals of time in the simulation period are chosen in a random manner. The state duration approach and the system state transition sampling approach are classified under the random simulation or the non-time sequential simulation technique. In sequential simulation, the basic interval of time of the simulated period is taken in a chronological order. State duration sampling approach is classified under the time sequential simulation technique.

State duration approach

Generation model building by this method is based on sampling [35, 36]. Sampling is relatively simple because only uniformly distributed random numbers between [0, 1] need to be generated. It is not necessary to generate a probability distribution function. This approach cannot be used to calculate the actual frequency indices (frequency of interruption indices).

System state transition sampling approach

This method needs only one random number to be generated for any number of system components to produce a system state [37]. This method can calculate the frequency index without the necessity to generate a distribution function, unlike the state duration sampling approach. However, it can be applied only to exponentially distributed component state durations.

State duration sampling approach

Generation model building by this method requires generation of a random variate from the uniformly generated random variable following a given distribution [3, 38]. This requires more computing time and memory than non-sequential simulation techniques. This method can be used to calculate the frequency indices. The probability distributions

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of the expected values of the indices can also be obtained. Chronological events such as time varying load can be easily handled by this technique.

In all the three types of Monte Carlo simulation techniques, the simulation process is stopped when the indices approach their real values. The stopping criterion is either a fixed number of simulations or statistical stopping rules. The purpose of the statistical stopping rules is to provide a compromise between the accuracy needed and the computation time. The coefficient of variation is used as the convergence criterion in statistical stopping rules. The variance reduction techniques that can be used are control variates, importance sampling, stratified sampling, antithetic variates [38] and dagger sampling [39].

For reliability evaluation of vertically integrated power systems considerable work has been done on the development of computer programs. Computer programs for reliability evaluation such as SYREL [40], RECS [41], GATOR [42], COMREL [43] and TRELSS [44] are based on state enumeration of system states (analytical methods) and programs such as MECORE [35-36], CREAM [45] and PROCOSSE [46] are based on Non-sequential Monte Carlo simulation techniques. Utilization of these programs in practice, however, is far from being widespread. The programs used in the research described in this thesis were developed in C and Matlab for the reliability evaluation of restructured power systems.

2.4 Reliability Evaluation in Conventional Power Systems

2.4.1 Features

Conventional vertically integrated power systems can be roughly divided into utilities, control areas and coordinating councils.

- Utilities are responsible for generation, transmission, and distribution of power over a region.

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- Control areas perform the task of regulating and dispatching power. Each Utility owns one or more control areas.
- Coordinating councils are responsible for establishing common reliability standards among its control area members [47].

2.4.2 Reliability Issues

In Reference [18] a survey was conducted in which utility system planners of Florida Power Corporation, Georgia Power Company, Ontario Hydro and others who were actively using probabilistic reliability assessment tools for power generation system planning participated. The utilities identified the following as the issues to be addressed by reliability assessment procedures/ reliability indices:

- to justify the addition of new facilities
- to identify system weaknesses
- to compare all possible expansion alternatives
- to modify deterministic criteria
- to communicate reliability issues
- to quantify reliability
- to develop reliability criteria and design standards
- to assess cost /benefit ratio of reliability

2.4.3 Reliability Assessment

Power system reliability evaluation in a vertically integrated utility has been extensively developed using probabilistic techniques [4-11]. In a contingency state, the objective of composite system operation in conventional systems is to minimize the total system load curtailment [48, 49] by considering the total system generation and the total system load. In [49], the load curtailment was performed in a contingency state according to the importance of individual loads by assigning weighting factors to the loads.

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Addition of generation facilities by a utility required the study of economic aspects such as the cost of reliability and its corresponding worth. The costs of reliability namely the capital costs and the operating costs are relatively easily known. However, the worth of reliability is difficult to be evaluated. The reliability worth can be measured in terms of the customers' interruption costs. The Power Systems Research Group of the University of Saskatchewan in Canada has conducted surveys of over 50,000 customers in Canada to evaluate customer interruption costs [50]. The methodology used to obtain service interruption cost information in government, institutions, and office-building sectors are presented in [51]. The interruption cost as a function of interruption duration is defined as the customer damage function. Customer damage functions for seven customer categories namely the large users, agriculture, industrial, residential, government, commercial buildings and offices in Canada were obtained by the research team. In [52], a minimum cost assessment method for composite generation and transmission system expansion planning for conventional systems is presented. During a contingency state, the objective in [52] was to minimize the sum of the system's operating costs and the damage costs (interruption costs) associated with the system unreliability.

For the utilities, a fundamental problem in system planning is the determination of reserve capacity for reliable operation of the system. If additional investment is made by the utility on reliability, then the decrease in outage cost should be outweighed by the increase in investment. On the other hand, if fewer investments are made by the utility on reliability, then the reduction in investment costs is outweighed by the increase in outage costs. The optimal reliability level is derived based on the least cost planning approach to be performed by the utility that considers both the costs of investments to improve reliability and the worth of reliability that is determined based on customer interruption costs. Thus, an important relation for optimal reliability is derived in [53] as:

Marginal costs of additional reserves at the margin = Marginal benefit of additional reserves at the margin.

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The optimal reliability derived in [53] can be used by utilities to incorporate the customers' choice (or customer interruption costs or outage costs) in reliability evaluation.

Due to lack of or complexity in obtaining the data of customer outage costs, the main objective of the utilities was cost minimization subject to accepted minimum reliability standards set by the coordinating councils. Independent regulatory bodies set rates charged to the customers by the utilities. Thus the only way utilities could maximize their profits was by minimizing their cost.

To summarize the reliability evaluation in conventional systems, the system representation considers the total system generation and the total system load. An overall adequacy assessment of the system is performed and system adequacy indices obtained. These indices provide a measure of the overall adequacy of the generation system and were used mainly by the utilities for power system planning purposes.

2.5 Deregulation of the Power Industry

2.5.1 Motivation

In the vertically integrated power market, the regulating bodies ensured that the rates for electricity were fair for both

- the utilities –they were assured a fair rate of return on their investment, and
- the customers –the rates were not subjected to a drastic increase.

When the vertically integrated structure is so fair to both the utilities and the customers, then it may be argued – “why is there a drive for deregulation”?

Some of the arguments and beliefs [54-57] that led to the deregulation process in the power industry can be summarized as follows:

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- Lower rates
- More choices for customer
- Additional customer services and products
- Improved reliability
- Efficient use of resources
- Diminished government procedures
- Incentives for innovation, etc.

With these beliefs the deregulation process started in different countries around the world. Each country adopted different deregulation strategies, but the common objectives [54-57] for the deregulation of the power industry were as follows:

- to increase efficiency through competition
- to deliver benefits to the customers
- to sustain future economic growth
- to encourage technological development, and
- to provide reliable supply of electricity.

Although increased efficiency, new technological drives, and increased choices are the main reasons for deregulation, the anticipated benefits of deregulation are yet to be realized. Thus we have both opponents as well as proponents of deregulation.

An opponent of deregulation, Coyle [58], argues that the power economists' idea of competition under deregulation is a failure. According to Lesser [59] the industry after deregulation is more complex but still requires the traditional oversights. He points out that this increase in the complexity of the market structure means more regulation to ensure competition and reliability, to provide risk management opportunities to utilities, etc.

However, the proponents of deregulation argue that competition in the generation sector can improve the efficiency compared with that in the regulated monopoly. Hunt et. al

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[60] argue that low prices, reliable services and fairly predictable bills can be obtained from a competitive market. In their opinion these expectations from the competitive electricity market have been achieved all around the world except in the case of California.

2.5.2 Market Features

In deregulated power systems, the various tasks that used to be performed in a conventional vertically integrated power system are segregated and open to competition. This is called “unbundling”. The tasks can be segregated based on the functions within a corporation i.e., “corporate unbundling” or based on the services i.e. “services unbundling”. The segregated tasks are coordinated by an independent entity for smooth operation of the power systems. The basic features of a deregulated power system are as follows:

1) Corporate unbundling

The generation, transmission, and distribution of power are managed by one or more Generating Companies (Gencos), Transmission Companies (Transcos), and Distribution Companies (Discos), respectively [47].

- Gencos: A Genco is an entity that operates and maintains generating plants. Gencos trade for real power, reactive power, spinning and non-spinning reserve. Power traded by Gencos will be delivered through the Transcos and Discos to the customers.
- Transcos: A Transco is an entity that owns transmission lines and transmits electricity from Gencos to Discos for delivery of power to consumers.
- Discos: A Disco is an entity that coordinates with the Transcos and the ISO to deliver power to customers. In some markets Disco is also a representative of customers in market trading.

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2) Service Unbundling

Services such as stand-by spinning, short term spinning reserve, interruptible loads, generation of real power, Var generation, load frequency control, etc., are unbundled for separate tariffs [47].

3) Market Coordinators

The task of coordinating the various activities of market participants is vital for the smooth operation of a power system. This has led to the establishment of the following entities whose functions are briefly described below:

- Scheduling Coordinators (SC): An entity that schedules the generation on behalf of a group of generators and customers.
- Power Exchange (PX): A non-profit corporation and competitive market place for all participants to trade energy and other related services.
- Independent System Operator (ISO): The main functions of the ISO are to schedule and dispatch power. It has responsibility for reliability. It markets ancillary services for a smooth and reliable operation of the system [47].

2.5.3 Market Models

The competitive market structure can be classified into three major market models [47] based on the trading of power - the spot market model, the bilateral contracts model and the hybrid market model.

In the spot market model, the Gencos and customers bid to the pool stating the price and quantity of power. A separate entity is responsible for establishing bidding procedures, administering the bid settlement process, scheduling and dispatching generation resources, procuring the necessary ancillary services to ensure system reliability, etc.

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In the bilateral contracts model, power is traded between two parties at a certain price, quantity and for a certain period such that it is acceptable to both. The ISO has no role in generation scheduling or dispatch and is only responsible for system operation and the maintenance of system security and reliability. In Nordic countries bulk power is mostly traded through bilateral contracts.

The hybrid model combines various features of the two models described above. In this structure, the customers can purchase from either the pool or through bilateral contracts [47].

2.5.4 Ancillary Services

The Federal Energy Regulatory Commission, FERC, in its open access order No. 888 [61], defined ancillary services as those “necessary to support the transmission of electric power from the seller to the purchaser given the obligation, to maintain reliable operations of the system”. Order 888 has six types of ancillary services: Scheduling, System Control and Dispatch Service, Reactive Supply and Voltage Control, Regulation and Frequency Response, Energy Imbalance Service, Operating Spinning Reserve and Operating Supplemental Reserve.

Operating reserve is an important ancillary service that contributes to the improvement in system reliability. Operating reserve consists of spinning reserve and non-spinning reserve. Spinning reserve is the reserve capacity that is synchronized and ready to take up load. The effective spinning reserve depends on the spinning reserves (supply side) and the interruptible loads (demand side). According to the North American Electricity Reliability council (NERC) Operating policy –10, interruptible load is one of the contingency reserve services [61].

Reserve

In a deregulated market, ancillary services are procured by the ISO through either auctions or contracts. The way spinning reserve is managed varies from one ISO to

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another. For example, California ISO has had an ancillary market operating since 1999. Midwest ISO, on the other hand, still does not have such a market.

In California, the ancillary service markets are separate and sequential, i.e., each market is treated individually and sequentially. The market is cleared sequentially starting from energy, spinning reserve, non-spinning reserve and then replacement reserves. In sequential markets for energy and ancillary services, the markets are cleared one at a time and the relationship among prices sometimes may not be rational. Ancillary prices were very high in the summer of 2000 in California. One part bidding and separate sequential energy and reserve markets led to the irrational price relationship. Even in New England, market is cleared sequentially [61].

The New York ISO also coordinates day ahead ancillary services markets but co-optimizes the scheduling of energy and ancillary services. The New Electricity market in Singapore also co-optimizes energy and reserve.

In real world markets, there is no hard and fast rule in minimum operating reserve requirements. For example, in the East Central Area Reliability Council (ECAR), the requirements for spinning and non-spinning reserve are 3% of daily peak. In the mid-Atlantic region, spinning reserve must be greater than 700 MW or the largest unit that is on line. In Florida, spinning reserve must be equal to 25% of the largest unit that is on line. The Western Systems Coordinated Council requires reserves equal to 5% of load supplied by hydroelectric resources plus 7% of the load supplied by thermal generation, with spinning reserves not less than one half of the total operating reserve [61, 62].

Interruptible Load Program

In this program the customers enter into a contract with the ISO to reduce their individual demand as and when requested, thereby reducing the system peak load [63], which benefits the ISO by saving on the costly reserves.

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It also benefits the customers

- by reducing their energy costs, and
- due to the incentives (payments) provided by the contract.

California ISO (CAISO) has implemented the DRP (demand relief program). In the year 2000, 269 MW of curtailable load offers were received under the demand relief program [63]. The average capacity price (curtailable) for accepted offers was U.S.\$ 36000 MW-month and average energy price (curtailable) was U.S. \$ 226/MWh. The interruptible load management practices adopted by the utilities/regulators in selected markets around the world are summarized in Table 2.1.

Table 2.1 Interruptible Load Programs in Selected Markets [63, 64]

Name	Advance Notification	Payment Structure
Alberta Type-I	1 hour	Fixed price per MW per month independent of the number of interruptions requested.
Alberta Type-2	1 hour	Price per MWh and loads are paid only when they are interrupted.
CAL-ISO Without back-up generation	30 minutes	Monthly capacity reservation payment -payment for energy actually delivered.
CAL-ISO With back-up Generation	15 minutes	
New York	10 minutes or 30 minutes	1 MW loads paid the 10-minute spinning reserve market price.
Singapore (secondary reserve)	10 minutes	Minimum curtailment is 0.1 MW, payment based on reserve market price.
Singapore (contingency reserve)	10-30 minutes	

2.5.5 System Operation

In the vertically integrated system minimizing the total system operating cost ensured fair prices to the customers. Under the new deregulated system, market trading and market participants' profitability should be considered in system operation. New methods for system operation and new tools to evaluate the impact of market trading are therefore required.

In Reference [12], the theoretical bases for benefit optimization in centralized (single control) and decentralized electric power systems with three independent utilities are examined. Even in the case of the centralized system, cost minimization is not necessarily equivalent to revenue maximization or profit maximization. The cost minimization, revenue maximization, and profit maximization are the same only if the marginal cost and the retail price of electricity are the same for the three utilities.

In [65], a matrix termed as the transaction matrix is proposed to represent the power transactions between suppliers and buyers (generators, customers and traders). Each row of the transaction matrix represents the quantity of power sold by the supplier to all possible buyers and each column represents the quantity of power purchased by a buyer from all possible suppliers. The transaction matrix can be used to represent the transactions in any type of market structure namely the Poolco, bilateral and hybrid markets. In [66] a lossless bilateral transaction matrix was developed from the matrix proposed in [65]. The bilateral transaction matrix can describe any combination of multi-bilateral transactions simultaneously. Some of the applications of these matrices are also reported in [66-67].

In [68-70], a one-step cost minimization based optimal power flow model that dispatches the combined pool and bilateral contracts is proposed. This model is developed to help the generators and load serving entities to choose appropriate relative levels of pool versus bilateral trade while considering risk, economic performance and physical constraints. In this model, the notations of pool/bilateral generation and demand and other

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technical and financial measures for each market participants are defined. This dissection of total power into individual pool and bilateral trading allows the market participants to evaluate the profitability of each individual pool and bilateral trade component.

Reference [71] describes a method for assessing the feasibility of simultaneous bilateral transactions ahead of their scheduling time, with regard to the economic dispatch and transmission system constraints by using the dc power flow based Ontario Hydro's PROCOSE (Probabilistic Composite Evaluation program) software. In Reference [72], uncertainties associated with peak load forecasting and component outages are included in assessing the feasibility of bilateral transactions. In Reference [73], the system well-being analysis has been used in the assessment of bilateral transactions.

2.6 Reliability Issues

In the conventional power systems the main reliability issues are:

- to assess the levels of redundancy requirements based on cost and worth analysis.
- to set reliability standards for the Utility based on past operating statistics of the systems.
- to supply all the customers with similar reliable power at similar price.

In the new environment the issues have changed. The corporate and functional unbundling of the power industry has led to an environment of many market players. The overall responsibility of supplying reliable power supply to a customer does not reside with a single utility but with all the market players [13-14]. Market players in the new regime perform their respective tasks with an objective to maximize their profits, rather than with the view to ensure a smooth and reliable operation of the system. Power system operation, reliability and security are still important in the new structure as they were in the traditional structure. In the new structure reliable operation of the system requires coordinating the activities of all the market participants, which has resulted in some

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fundamental changes in system planning, operation and reliability management. A major change is the shift from cost-based to price or profit-based operation and reliability management.

The presence of so many players in the new system has given rise to some questions such as “Who has the responsibility for reliability?”, “What is the role of the ISO and what are the responsibilities and commitments of the market players?” [13-14]. In a multi-player system, instead of setting up reliability standards, the desired reliability “performance” or reliability “received” should be achieved by appropriate economic incentives for the market participants and by regulatory norms for coordinating the activities of the market participants by an independent governing body such as the ISO. This has led ways to explore new possibilities for reliability management to be performed by the system operator to operate the system based on the economic signals given by the market participants.

In different markets different strategies are followed, making reliability management dependent on the market structure, the role of the various market participants and the rules and regulations in force. This has further given rise to more market structure-specific system operation and reliability issues.

Economic incentives or penalties will drive the supplier to achieve the desired reliability performance. In the new structure the suppliers pool their generation reserves in order to meet the energy obligations reliably and economically. Suppliers enter into various types of contracts with other entities to purchase power in case of failures. This has given rise to the “technical standards” being replaced by “contractual expectations”. Power suppliers see reliability as an issue of risk that they may not be able to supply at the required reliability level [13-14]. This has paved the way to develop different strategies for managing risks created by failures or due to unreliability.

Deregulation and competitive electricity pricing will make it possible for the customers to select their supplier based on cost-effectiveness and reliability [13-14]. Customers select their power suppliers that can satisfy their price and reliability expectations. Some

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customers may accept lower reliability of service for a lower price of electricity while the reliability needs of others may compel them to pay a higher price. This has created ways to explore the implementation of non-uniform reliability for customers.

A survey conducted in [74] shows that almost 70% of customers would switch their power suppliers to one with lower reliability for just a two percent reduction in price. The results illustrate how much customers' decision is sensitive to the price. Economic incentives can drive the customers in the new environment to manage their load by either reducing or rescheduling demand. Thus there is a need for exploring ways to implement customers' participation in reliability management- for example voluntary interruptible load services.

Ancillary services such as generation of real power, Var generation, operating reserve and interruptible load services, etc., are provided by different market players at different tariffs. There is therefore a need to explore new issues such as pricing, procuring and designing the ancillary services market.

In summary, deregulation of the power industry has modified the traditional reliability issues or has created new ones. The following subsections review the literature addressing the reliability issues in deregulated power systems.

2.6.1 Reliability and System Planning

To ensure adequate power supply, generation expansion planning and generation maintenance scheduling are important in the new structure, as they were in the past. In the new structure planning problems have to be handled in the context of multi-player participation.

In [75], an application of non-cooperative game theory to generation expansion planning in a competitive market is proposed. In the deregulated context, reliability is considered by a multi-player expansion rather than expansion by a traditional monopolist with an

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equivalent reserve margin requirement. In [76] a dynamic programming based generation expansion planning using expert systems is presented. Expert systems are used in this work to incorporate a number of rule-based procedures in the decision-making part of the dynamic programming algorithm. This work is expanded in [77] to include customer sensitive planning and pricing model to tie in with the ongoing changes brought about by the deregulation of the power industry.

Reference [78] proposes a method designated as the maintenance coordination technique (MCT) to coordinate composite system maintenance scheduling by an ISO in a deregulated utility system. The methods adopted by an ISO to coordinate planned outages are based on traditional load flow, stability analysis and deterministic operating criteria.

2.6.2 Reliability and System Operation

Maintaining the system security and reliable operation are very important in the new structure, as they were in the past. In deregulated power systems the system operation and reserve considerations should be based on the market structure, market prices and market participants' profitability.

In [79], a reliability-constrained market-clearing problem is formulated as a mixed integer linear programming problem that can be used in pool-based electricity markets to produce market-clearing results with the desired probabilistic characteristics. Reference [80] presents a technique for considering both the unit reliability and the price for reserve in competitive electricity market generation scheduling. The problem is formulated as an augmented Lagrangian dual problem and solved using a neural network.

The ISO's decisions on service identification and congestion management in order to maintain system security and reliability will affect the profit of individual market participants. A combined framework for service identification and congestion management based on an overall profit maximization of all the market participants is

proposed in [81]. This formulation gives non-discriminatory open access to all the market participants while maintaining system security and reliability.

2.6.3 Reliability and Uncertainty

In the present competitive environment, techniques incorporating high uncertainty in all the data concerned with reliability calculations are gaining importance. Reference [82] proposes a technique to evaluate the generation level reliability indices by considering uncertainties in the forecasted load. In this work the fuzzy set concepts in terms of fuzzy number are employed to model the uncertainties. In [83], fuzzy arithmetic is employed to model the customer damage function that is used to calculate the fuzzy interrupted energy assessment rate (FIEAR). The large deviation in the customer damage information is considered in the proposed FIEAR by using the FCCDF (fuzzy composite customer damage function) rather than the average CCDF (Composite customer damage function) that is used in the conventional IEAR [84-87].

The investment in new power generating capacity in the conventional system is based on the load growth and reliability standards. In the new deregulated scenario, investments by independent investors are based on returns from new investments. The exposure to risk and uncertainty has increased for participants in restructured power systems. A stochastic dynamic investment model that can determine optimal investment strategies in power generation under uncertainty is proposed in [88]. Both centralized social welfare maximization and decentralized profit maximization objectives can be evaluated from this model.

2.6.4 Reliability and Economic Incentives

In the past, reliability was based on cost and worth analysis of an entire power system. In deregulated power systems, the investment and maintenance costs for reliability improvement of an entity depend on the economic incentives or penalties for its reliability performance.

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Differentiated reliability based on customers' preferences is proposed in [89] by implementing insurance for reliability. In this insurance scheme the risk is taken /transferred to the Discos (who have control of the system) rather than consumers (who have no control over the system). To minimize risk or maximize profits the Discos have to make proper decisions in terms of reliability improvement costs/investments. The insurance scheme helps the consumers to give the Discos proper signals for their value of service thereby alleviating the risks the customers are currently forced to accept. The customers choose a type of insurance for reliability based on the value for the service and pay premiums accordingly. The customers will benefit from the insurance as long as the premiums are less than their reimbursements. If all the customers choose normal average reliability then by choosing the insurance scheme the premiums paid by the customers is equal to their reimbursements, and hence the customers do not lose by choosing an insurance scheme. The problem is formulated such that the customers' consumer surplus is maximized, so that they choose insurance coverage. In case of contingency the Disco has to pay reimbursements to the customers. The Disco's objective is to minimize the reimbursements. This can be achieved by investing on reliability improvement. If the cost of improving the reliability from low level to a higher level brings in a significant reduction in reimbursements then the Discos will consider reliability improvement. In addition to investment on reliability improvements, in case of contingencies, the Disco will minimize its reimbursements by giving higher priority of service to customers with higher reliability requirements (higher reimbursements) than to customers with lower reliability requirement. Differentiated reliability based on customer preference is thus achieved.

In [90], a scheme is proposed to operate the system under a pre-specified uniform reliability level and to reward the generators contributing more to system reliability by penalizing the generators who contribute less to system reliability. This motivates the generators to improve their performance by reducing their generators' outage rates through regular maintenance.

2.6.5 Reliability and Market Design

In the restructured electrical industry, in order to maintain and improve the reliability of the system, procuring adequate supply from Gencos and ensuring sufficient availability of reserve capacity are important tasks. Market designs that exist around the world are presented in [91-94] and are classified into three different categories, a brief summary of each of which is given below:

Leave it to the Market [91]

It is the simplest of all the designs as there is no regulatory intervention to procure adequate supply of power from producers. In simple terms this market is designed on the economic theory of supply and demand. If there is a scarcity in supply, the price will increase so as to attract more production from the existing plants and more investments to set up new plants. California and Australia are based on this market design. As of now generation shortages have been avoided and no measures are considered to keep surplus capacity.

Installed Capacity Obligation [91]

This market is designed based on an installed capacity obligation. In order to ensure sufficient available capacity, the market participants have an obligation to supply capacity (or buy the deficit from the market) equal to or greater than the monthly capability responsibility (*installed capacity obligation*) which is computed based on their installed capacity. This method in the long run ensures adequate capacity rather than relying on real time energy and reserve markets. This approach has been adopted in PJM and in parts of Eastern USA, e.g., New York.

Capacity Payments [91]

The pool designers have designed a scheme of payment to the generators for making their capacity available, called capacity payment. Capacity payment is made to the generators in addition to the market-clearing price for guaranteeing the availability of their capacity. This is an important source of revenue for the generators. Generators have earned capacity payments through participation in the British, Spanish and PJM power pools. The capacity payment price in the British pool is given by

$$\text{Capacity payment} = \text{LOLP} * (\text{VOLL} - \text{SMP})$$

where,

LOLP is the loss of load probability

VOLL is the value of lost load, and

SMP is the system marginal price of the pool at the time.

Issues related to adequacy and security as they are affected by market design are discussed in [91]. The uses and abuses of capacity payment are discussed in [93] - some market design recommendations that could better realize customers' preference for reliability are also presented. In [94], it is argued that capacity payments is the least desirable approach; a long term supply contracts in the form of call options with premiums that depend on the contracts strike prices is proposed to ensure adequate supply.

There is, therefore, no cut and dry solution to market design issues and in the future many changes are imminent based on the market participants' desire and the merits and demerits of different philosophies of market design.

2.6.6 Reliability and Ancillary Services

The concept of providing operating reserve requirements for system reliability in conventional vertically integrated power systems has turned into a question of "what kind

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of mechanisms should be devised to allocate and price this service in the new environment?" The provision of operating reserve in power systems is revisited in the context of deregulated power systems in [62], which proposes a mechanism to allocate and price the operating reserve in auction type capacity markets using a stochastic demand model.

In [95], various means for the provision of operating reserve (reserve generation and interruptible loads) in the new environment are examined and an optimal selling strategy is introduced so that the power producers can decide how much to sell in the spot and reserve market so that the expected profits are maximized. The reliability differentiated pricing in [96] is extended in [97] by including spinning reserve constraints and to obtain optimal prices for the real and reactive power components of spinning reserve.

The optimal procurement of interruptible load services model based on optimal power flow framework that can aid the ISO in real time selection of the interruptible load offers in the deregulated mechanism is proposed in [63]. In [98], demand relief contracts are designed such that customers are compensated sufficiently to participate voluntarily and at the same time ensuring that the utility's benefit is maximized while offering the demand relief contract. This model is further extended in [99] to have efficient demand relief contracts by having a good estimate of the customer outage cost function. In [100], significant economic gains are achieved by including demand side reserve offers in a market model where energy and reserve are dispatched in a joint auction through a mixed integer optimization program. In this model, the customers can submit offers to energy, up spinning, down spinning and stand-by reserve, with the model allowing continuous load curtailments all the way down to the curtailment limits set.

2.7 New Reliability Assessment Techniques

Restructuring of electric power industries has induced competition among generators and created choices for customers. The market participants are free to trade power through bilateral contracts or from a centralized spot market or a combination of both. In

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Reference [47], it is stated that in competitive electricity markets that are not entirely coordinated, reliability indices as single system-wide numbers begin to lose importance as they are deemed meaningless by all concerned. System reliability as in conventional power systems alone cannot give sufficient information to the market participants. Although many papers have proposed various methods, approaches and plans on reliability evaluation in deregulated power systems, none has proposed techniques to evaluate the customer reliability in deregulated power markets. Customer reliability as proposed in this thesis provides information on the reliability experienced by individual customers. Customer reliability is defined as the ability of the generating system of the power suppliers of a customer to meet the customer's demand.

Customer reliability evaluation techniques cannot be based entirely on the techniques developed for evaluating the system-wide indices in conventional systems, but should address the issue of changes brought about by deregulation in system operation and reliability management. In [101-104], a reliability evaluation technique for deregulated power markets based on the reliability network equivalent is proposed. A large composite power system is represented by reliability equivalents thereby providing a simplified network for reliability evaluation. Changes in the overall system affect the equivalents associated with the modified portion of the system and the remaining equivalents remain the same thus reducing the computational burden. In these references, the functional unbundling and different market players are considered. The power transactions for the pool and hybrid market models are not considered.

The reliability assessment techniques used in conventional systems are no longer applicable for customer reliability evaluation in the new environment. New techniques are needed to solve the problems caused by system restructuring. In this thesis an attempt is made to develop models and techniques to evaluate customer reliability in the deregulated environment. The models are based on the market structure, rules and regulations in force for system operation, the power transactions and agreements that exist among the various market participants, and also the economic aspects for the contingency state operation of the system.

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An appropriate reliability technique (time / non-time sequential MCS technique) is selected based on the requirement, complexity and flexibility in using the technique. Reliability evaluation procedures are developed based on the developed models and the technique selected. The customer reliability indices proposed in this thesis compliment the existing system-wide indices. Tools to evaluate customer reliability will help the customers to make better decisions with regards to price and reliability while trading for power. Additionally, the availability of customer reliability indices will help the customers in making decisions on scheduling their energy usage such that they participate in the market (such as interruptible loads) and on making use of the economic incentives provided.

Chapter 3

Reliability Evaluation of Power Generation Systems with Spot Market Structure

3.1 Introduction

In this chapter the main focus is on reliability evaluation of restructured power generation systems with the spot market structure. In a spot market, Gencos and customers participate in the market trading by submitting bids. The total generation capacity dispatched in the spot market is dependent on the aggregated customer demand bids. In the event of generating unit failures, reserve is called from the reserve units settled in the reserve market. The reliability of the system is determined by the total capacity of the units cleared in both capacity and reserve spot markets. Gencos are under no obligation to serve the demand and the participation of the Gencos solely depends on the market conditions. Therefore, the set of units participating changes on a continuous basis based on the market conditions. Based on the market clearing results in the capacity and reserve markets, the reliability will be different at different hours.

In the spot market the Gencos submit sealed bids to the market coordinator based on the forecasted price. In [105], it is suggested that in a perfectly competitive market the Gencos should bid at or very close to their marginal production costs to maximize the returns. However, the Gencos may bid higher than the marginal production cost to maximize their returns because electricity markets are not perfectly competitive. A number of papers addressing optimal bidding strategy for Gencos to maximize their returns based on their anticipated rivals' behavior and market predictions have been published. The bidding details of the market participants cannot be predicted with certainty. Therefore, the market settlement is also uncertain. A technique to evaluate the reliability indices in a spot market is required to incorporate the uncertainty. The

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fundamental changes in the system operation of a spot market structure from the traditional systems have to be incorporated while evaluating the spot market reliability.

In this Chapter, a time sequential Monte Carlo simulation technique [2,3] is proposed for reliability evaluation of power generation systems with the spot market structure. The reliability model for the spot market is obtained by convolving the spot market based generation model with the spot market demand. The aggregated customer demand is the spot market demand. Spot market demand is forecasted by the Market operator. The System-wide hourly reliability indices are obtained from the reliability model. The proposed reliability model is further extended to incorporate the effects of uncertainties such as bid prices.

3.2 Market Model and its Clearing Process

A spot market with energy and reserve is considered in this project. The Gencos and customers trade for power and the market operator coordinates the trading activities of the Gencos and the customers. A spot market that consists of m Gencos, p customers and a market operator is shown in Figure 3.1.

Figure 3.1 Spot market model

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The spot market accepts supply and demand bids to determine the market-clearing price and quantity for each hour in a trading day. The Market Operator requires a market clearing process to determine the market clearing price and quantity based on the bids submitted by the Gencos and customers. The market clearing process is an optimization problem. The objective of the optimization could be cost minimization, social welfare maximization, consumer payment minimization, etc. The optimization could be a single or multi (generally two)- objective optimization, and the bids submitted by Gencos and customers can be block bids or linear bid curves.

The spot and reserve market clearing price and quantities are determined in this research work based on the following assumptions.

- The unit characteristics such as the no-load cost, start-up cost, minimum up time and minimum down time are submitted to the market operator. It is assumed that the start-up cost is a fixed amount and that there are no costs for shutting down a unit.
- Gencos submit multiple block bids for each hour of the day stating the quantum of power available for sale and the expected price of each generating unit.
- The aggregated customer demand is the spot market demand. The spot market demand for a typical market-clearing hour is a constant but the market demand is different for different hours of the day. Therefore, the day ahead spot market demand is a time varying load model. The Market Coordinator forecasts the spot market demand. The day ahead forecasted demand is assumed to be the same as the actual demand.
- A reserve of 10% of the market demand is considered and the market clearing quantity (MCQ) is the sum of the spot market demand and the reserve.

The unit commitment for the 24-hour period to meet the forecasted demand is determined such that the total operational cost (bid cost, no-load cost and start-up cost) is the minimum while satisfying the operational constraints such as minimum up time, down time and generator limits. The day-ahead unit commitment problem is solved by using a

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forward dynamic programming approach. Strict priority–list schedule is imposed on the search range.

The recursive algorithm to compute the minimum cost in hour t and combination I is

$$LC_{\text{cost}}(t, I) = \text{Min}_{\{L\}} [MC_{\text{cost}}(t, I) + TC_{\text{cost}}(t-1, L: t, I) + LC_{\text{cost}}(t-1, L)]$$

where

$LC_{\text{cost}}(t, I)$ = Least cost to arrive at state (t, I)

$MC_{\text{cost}}(t, I)$ = Market Cost for state (t, I)

$TC_{\text{cost}}(t, I)$ = Transition cost from state $(t-1, L)$ to state (t, I)

M = number of paths to save at each stage

L = feasible states for hour $t-1$

The market cost consists of the no-load costs of all the committed units and the product of bid prices and quantities of all the dispatched units. Transition cost is the start-up cost for units that were “off” in hour $t-1$ and “on” for hour t .

The unit commitment using forward dynamic programming consists of the following steps:

Step 1: Input unit characteristics data, bidding data and priority list

Step 2: Hour $t=1$

Step 3: Array of unit state = I

Step 4: Compute $[MC_{\text{cost}}(t, I) + TC_{\text{cost}}(t-1, L: t, I)]$

Step 5: All combinations of unit states checked? If yes goto Step 6 else goto Step 3

Step 6: Find $LC_{\text{cost}}(t, I) = \text{Min}_{\{L\}} [MC_{\text{cost}}(t, I) + TC_{\text{cost}}(t-1, L: t, I)]$

Step 7: Hour $t=t+1$

Step 8: $\{L\}$ = “ M ” feasible states in hour $t-1$

Step 9: Array of unit state = I

Step 10: Compute $[MC_{\text{cost}}(t, I) + TC_{\text{cost}}(t-1, L: t, I) + LC_{\text{cost}}(t-1, L)]$

Step 11: All combinations of unit states checked? If yes goto Step 12 else goto Step 9

Step 12: Find $LC_{\text{cost}}(t, I) = \text{Min}_{\{L\}} [MC_{\text{cost}}(t, I) + TC_{\text{cost}}(t-1, L: t, I) + LC_{\text{cost}}(t-1, L)]$

Step 13: Save “ M ” lowest cost strategies

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Step 14: All hours checked? If yes goto Step 15 else goto Step 7

Step 15: Trace optimal schedule.

Once the unit commitment schedule is determined, Gencos' bids of the committed units are stacked starting with the lowest price. The point at which the stack of bids intersects the demand at that hour, is the market-clearing price that is awarded to all the Gencos. In this way, the most economical units that participate in the spot market are cleared as shown in Figure 3.2.

Figure 3.2 Market clearing process

3.3 Generating Unit Model

A two-state model of the generating unit is considered here such that the unit is either in the up state (operating state) or down state (repair state). The transition rate from the up state to the down state is the failure rate (λ) of the unit, and that from the down state to the up state is the repair rate (μ) of the unit. The state space diagram for the two state model of a unit is shown in Figure 3.3.

Figure 3.3 State space diagram of a generating unit

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The operating history for a two-state model unit has chronological up and down times. Transition from the up state to the down state is caused by the unit failure and from the down state to the up state by the repair of the unit. The time during which the unit remains in the operating or up state is called the time to failure (TTF). The time during which the generator is in the repair or down state is called the restoration time or time to repair (TTR).

The parameters TTF and TTR may follow different probability distributions such as Exponential, Normal, Lognormal and Beta distributions. The probability distribution functions (pdf) of exponential distribution, normal distribution and lognormal distribution are described in detail in Appendix A. Figure 3.4 shows the simulated operating history of a unit.

Figure 3.4 Generating unit operating/repair history

3.4 Simulation of Unit Operating History

The parameters TTF and TTR are random variables and are simulated by generating random numbers. Mathematical methods can be used to generate random numbers. Many computer programs based on these mathematical methods are widely used to generate random numbers. The random numbers that are used in this research are broadly classified into two, namely: uniformly distributed random numbers and random numbers following a probability distribution.

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3.4.1 Uniformly Distributed Random Numbers

A uniformly distributed random number generator should satisfy the following three statistical features [3]:

- 1) The random numbers generated should be uniformly distributed between [0,1].
- 2) The random numbers generated should be independent from one another i.e., there should be minimal correlation.
- 3) The repeat period for the generated number sequence should be very long.

3.4.2 Simulation of Probability Distributions

The state duration of a generating unit following different probability distributions is simulated using the uniformly distributed random number generator and mathematical methods. The procedure to generate exponential, normal and lognormal random variables [3] is described below:

Exponential Distribution

Exponentially distributed random variate is generated by the inverse transform method. The time to failure of a unit following exponential distribution is given by

$$TTF = -\frac{1}{\lambda} \ln U \quad (3.1)$$

The time to repair of a unit following exponential distribution is given by

$$TTR = -\frac{1}{\mu} \ln U \quad (3.2)$$

where U is a uniformly distributed random number between [0,1].

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Normal Distribution

In reliability evaluation, the time to repair of a generator is sometimes considered as a random variate from a normal distribution. The Box Muller method is used to generate random numbers following a normal distribution.

The two independent, normally distributed random variables X_1 and X_2 are generated from uniformly distributed random variables U_1 and U_2 respectively by:

$$X_1 = \sqrt{-2 \ln U_1} \cos(2\pi U_2) \quad (3.3)$$

$$X_2 = \sqrt{-2 \ln U_1} \sin(2\pi U_2) \quad (3.4)$$

The time to repair of a generating unit following the normal distribution is given by X_1 or X_2 .

Log-normal Distribution

In reliability evaluation, the time to repair of a generator is sometimes considered as a random variate from a lognormal distribution. The time to repair of a unit following lognormal distribution is given by

$$TTR = e^{\mu + \sigma z} \quad (3.5)$$

where z is the generated random variate following a standard normal distribution.

The mean μ and variance σ^2 of the normal distribution are determined from the specified mean E and variance V of the lognormal distribution by

$$\mu = \ln \left[\frac{E^2}{\sqrt{V + E^2}} \right] \quad (3.6)$$

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$$\sigma^2 = \ln\left[\frac{V + E^2}{E^2}\right] \quad (3.7)$$

In this research the standard deviation is assumed to be one-third of the mean time to repair (MTTR). In the case of the normal distribution, about 68% of the TTR values will fall within the range (MTTR - standard deviation, MTTR + standard deviation), while approximately 95% of the TTR values will fall within the range (MTTR - two standard deviations, MTTR + two standard deviations). When standard deviation is assumed to be one-third of the mean time to repair, the TTR values generated are positive.

3.5 Simulation Procedure

The procedure for reliability assessment of restructured power generation systems with the spot market structure using time sequential Monte Carlo simulation technique consists of the following steps:

Step 1: Read the system data, market data, reliability data and the initial state of the generating units from the input data file.

Step 2: Determine the unit commitment schedule for the day ahead market based on the unit characteristics, bidding data and the forecasted load as described in Section 3.2.

Step 3: Determine the market clearing results for each hour of the reliability study period as described in Section 3.2.

Step 4: Simulate TTF and TTR of the unit according to its distribution as described in Sections 3.3 and 3.4.

Step 5: Obtain the artificial operating history of each unit for the reliability study period by chronological up states and down states. If a committed unit is in upstate for the hour, then that hour is in the TTF period of Figure 3.2 .

Step 6: Obtain an artificial operating history of the spot market generating system from the operating history of each unit.

Step 7: Convolve the operating history of the spot market generating system and the load model.

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Step 8: Determine the reliability indices for each hour in the spot market.

Step 9: Determine the frequencies of occurrence of each reliability index for different class intervals.

Step 10: Go to Step 3 if the stopping criterion is not reached, else Go to Step 11.

Step11: Determine the mean and probability distributions of the reliability indices for each hour in the spot market.

3.6 Reliability Indices

Reliability evaluation using time sequential Monte Carlo simulation can provide the mathematical expectation of reliability indices. The Loss of Load Expectation (LOLE) & Expected Energy Not Served (EENS) which provide a consistent measure of the spot market generation system reliability are evaluated. The reliability indices obtained are system-wide hourly indices in the spot market and can be estimated using the following equations:

Loss of Load Expectation LOLE, (h/hour)

$$LOLE' = \sum_{i=1}^N \frac{LLD'_i}{N} \quad (3.8)$$

Expected Energy Not Served EENS, (MWh/hour)

$$EENS' = \sum_{i=1}^N \frac{ENS'_i}{N} \quad (3.9)$$

where i is the index for sampling, LLD is the Loss of Load Duration in hours, ENS is the Energy Not Supplied in MWh and N is the number of samples.

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3.7 Price Uncertainties in Reliability Evaluation

The bidding strategy of the Gencos in uniform price auctions is to bid the marginal production cost. But the bids are not always constant because the operational constraints of the units (ramp rate, minimum down time, inflow constraints) and the uncertainty in future prices (at the time of bidding the future price is uncertain) can have an impact on the bidding behaviour.

Competition among Gencos is so intense that the Gencos do not wish to reveal their actual bid data. The bidding details are uncertain rather than strictly deterministic. The uncertainty in bid data may show a large deviation in the data concerned with reliability calculations.

The procedure for reliability evaluation in a spot market described in Section 3.5 involves strictly deterministic data. In this section the uncertainty in bid details is included in the reliability evaluation. The uncertain data are represented as a set of deterministic data with associated probability as in Reference [106]. Each deterministic set is considered as a scenario. The uncertainty problem is handled by combining the Monte Carlo simulation technique with the scenario representation.

3.7.1 Simulation of Uncertainties

Let a deterministic bid set A consist of the bid data B_{hv} for each unit v in Genco h. The elements of Set A are given by

$$A = \{B_{11}, \dots, B_{1v}, \dots, B_{1x}, \dots, B_{h1}, \dots, B_{hv}, \dots, B_{hx}, \dots, B_{m1}, \dots, B_{mv}, \dots, B_{mx}\} \quad (3.10)$$

Let the uncertain bid price set UC consist of Z deterministic bid sets. The elements of Set UC are given by

$$UC = \{A_1, \dots, A_y, \dots, A_z\} \quad (3.11)$$

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such that

$$A_y = \{B_{11}^y, \dots, B_{1v}^y, \dots, B_{1x}^y, \dots, B_{h1}^y, \dots, B_{hv}^y, \dots, B_{hx}^y, \dots, B_{m1}^y, \dots, B_{mv}^y, \dots, B_{mx}^y\}$$

$$y=1, \dots, Z \quad (3.12)$$

The probability or weight for each element of UC is given by

$$W = \{W_1, \dots, W_y, \dots, W_Z\} \quad (3.13)$$

such that $\sum_{y=1}^Z W_y = 1$ (3.14)

Each deterministic bid set A_y is considered as a scenario. The uncertain bid prices are formulated as scenarios with the associated probabilities /weights.

For each scenario y , the scenario based loss of load expectation $SLOLE_y$ is given by

$$SLOLE = \{SLOLE_1, \dots, SLOLE_y, \dots, SLOLE_Z\} \quad (3.15)$$

For each scenario y , the scenario based expected energy not supplied $SEENS_y$ is given by

$$SEENS = \{SEENS_1, \dots, SEENS_y, \dots, SEENS_Z\} \quad (3.16)$$

A flow chart to evaluate the reliability considering bid price uncertainty rather than strictly deterministic data is shown in Figure 3.5. The limitation of this technique is the difficulty in obtaining the bid prices and their corresponding probability of occurrence data due to which modeling the bid price uncertainty as deterministic bids with weights becomes difficult. This problem can be overcome to some extent by obtaining the data based on Gencos historical bidding strategies.

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Figure 3.5 Reliability evaluation in the spot market considering bid price uncertainties

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3.7.2 Indices with Uncertainty

The reliability indices considering the bid price uncertainties are obtained as the weighted sum of the indices corresponding to all scenarios.

The weighted loss of load expectation WLOLE is determined by

$$WLOLE = \sum_{y=1}^Z W_y * SLOLE_y \quad (3.17)$$

The weighted expected energy not supplied WEENS is determined by

$$WEENS = \sum_{y=1}^Z W_y * SEENS_y \quad (3.18)$$

It is easy to incorporate in the developed model the uncertainty in bid details, which are described by probability distributions such as normally distributed variables with known mean and variance. Similarly the model can be extended to incorporate other input data uncertainties such as hourly load variations to study the influence of these factors on reliability indices. The number of scenarios is dependent on the model and type of the uncertainties considered. Another limitation of the proposed model is that the size of the problem increases with the number of scenarios. If the model and type of uncertainty considered leads to the formulation of a large number of scenarios then the model is computationally intensive.

3.8 System Studies

3.8.1 Test System and Market Data

The six-bus test system designated as the RBTS [15-16] has two generation buses, four load buses, nine transmission lines and eleven generating units, as shown in Figure 3.6. There are seven hydro generators at bus 2 and four thermal generators at bus 1. The seven hydro units at bus 2 with a total capacity of 130 MW are considered as Genco 1. The four

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thermal units with a total capacity of 110 MW at bus 1 are considered as Genco 2. The total installed capacity of the test system is 240 MW.

Figure 3.6 The single line diagram of the RBTS

The failure rates, repair rates and the two economical loading orders of the generators are given in Appendix-B. The priority schedule is taken as the first economical loading order. It is assumed that a two-part bid is submitted by the Gencos stating the quantity and price. Table 3.1 provides a quick reference of the generating system data and bid data. The up time for the units is taken as three hours and down time as one hour. Units G11 to G17 and G21 are in upstate for the past three hours.

The IEEE load model [17, Appendix B] with an annual system peak load of 185 MW is used as the annual hourly load model for the RBTS. The annual load model of the RBTS has 8736 points as shown in Figure 3.7. The annual peak load, weekly peak load in percentage of the annual peak, daily peak load in percent of the weekly peak, hourly peak load in percentage of the daily peak load data of the IEEE load model are given in Appendix B.

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Table 3.1 Generating unit data and bid data

Unit No	Unit Size (MW)	FOR	Min output (MW)	Start up cost (\$)	No load Cost (\$/h)	First part bid		Second part bid	
						Qty (MW)	Price \$/MWh	Qty (MW)	Price \$/MWh
G11	40	0.020	20	0.02	0.03	20	0.40	20	0.50
G12	20	0.015	10	0.02	0.03	10	0.35	10	0.55
G13	20	0.015	10	0.02	0.03	10	0.30	10	0.60
G14	20	0.015	10	0.02	0.03	10	0.25	10	0.65
G15	20	0.015	10	0.02	0.03	10	0.20	10	0.70
G16	5	0.010	2.5	0.02	0.03	2.5	0.45	2.5	0.45
G17	5	0.010	2.5	0.02	0.03	2.5	0.45	2.5	0.45
G21	40	0.030	20	0.5	2.0	20	9.5	20	9.5
G22	40	0.030	20	0.5	2.0	20	9.5	20	9.5
G23	20	0.025	10	0.5	2.0	10	9.75	10	9.75
G24	10	0.020	5	0.5	2.0	5	10.0	5	10.0

Figure 3.7 IEEE RBTS annual load model

The load model for the second day of week 51 is taken as the forecasted demand for the day ahead spot market. The demand for the 24-hour period is shown in Table 3.2. Market

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clearing quantity is taken as the sum of demand and reserve, with reserve as 10% of the load.

Table 3.2 Demand in the day ahead Spot market

Hour	1	2	3	4	5	6	7	8	9	10	11	12
Demand	124	117	111	109	109	111	137	159	176	177	177	176
MCQ	136	128	122	120	120	122	150	175	193	195	195	193
Hour	13	14	15	16	17	18	19	20	21	22	23	24
Demand	176	176	172	174	183	185	185	178	168	154	135	117
MCQ	193	193	189	191	201	203	203	195	185	168	148	128

The unit commitment schedule for the 24-hour period is as shown in Table 3.3. Unit state [1, 1, 1, 1, 1, 1, 1, 0, 0, 0, 0] for hours 3, 4, 5, 6 is more economical than unit state [1, 1, 1, 1, 1, 1, 1, 0, 0, 0, 0, 0] for hours 3, 6 and unit state [1, 1, 1, 1, 1, 1, 1, 0, 0, 0, 0, 0, 0] for hours 4, 5 because the bid price for units G16 and G17 is less.

Table 3.3 Unit commitment in the spot market

Gencos	Time Periods (1-24 Hours)
G11	1111111111111111111111111111
G12	1111111111111111111111111111
G13	1111111111111111111111111111
G14	1111111111111111111111111111
G15	1111111111111111111111111111
G16	1111111111111111111111111111
G17	1111111111111111111111111111
G21	1000001111111111111111111110
G22	00000001111111111111111000
G23	0000000000000000000000000000
G24	0000000000000000000000000000

Based on the unit commitment schedule the market clearing results for each hour are determined. At hour 1, the market clearing results are [40, 20, 20, 16, 10, 5, 5, 20, 0]. The first part bid of all the committed units and the second part bid of units G11, G12, G13, G16 and G17 are cleared. Only 6 MW of the second part bid of unit G14 is cleared. The

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second part bid of units G15 and G21 is not cleared. The market clearing results for the 24-hour period in the spot market are shown in Figure 3.8.

Figure 3.8 Market clearing results in the spot market

3.8.2 Reliability Indices

A reliability study for day ahead and week ahead spot market is presented in this section. In the day ahead market, the market clearing results shown in Figure 3.8 and their corresponding demand and reserve are considered for the study. LOLE and EENS for the day are presented in Figure 3.9 (a) and (b) respectively. The reliability indices show high values during the peak hours.

Figure 3.9(a) LOLE in the spot market

Figure 3.9(b) EENS in the spot market

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In the week ahead market the demand for each hour of the week is assumed as the load for the second week of the year i.e. from hour 168 to hour 336 of Figure 3.7. The market clearing results obtained are not based on the unit commitment solution technique of the day ahead market. The unit characteristics such as start-up cost, unit uptime and down time are not considered. The market clearing results for each hour are obtained based on the first economical loading order of the test system. Different percentage reserves are considered for the study. For example, in order to meet a demand of 144 MW in hour 183 a reserve of 16 MW is considered and to meet a demand of 146 MW for hour 184 a reserve of 34 MW is considered. The hourly demand in the spot market, the hourly percentage reserve considered and the market clearing quantity (MCQ) are shown in Figure 3.10.

Figure 3.10 Spot market results for the second week of the IEEE load model

Figures 3.11 and 3.12 show the LOLE & EENS respectively for each hour of the week in the spot market. The maximum LOLE is in the range of 0.13 hours/hour, which is likely to occur around the 235th hour of the year. Compared to the LOLE, the EENS shows wider variations, as it not only reflects the time but also the intensity with which the reliability has been affected. It can be seen from Figure 3.12 that at least for four hours in the week the expected energy not supplied has exceeded 2.0 MWh/hour.

Figure 3.11 LOLE for the second week of the IEEE RBTS load model

Figure 3.12 EENS for the second week of the IEEE RBTS load model.

3.8.3 Factors Affecting Reliability

The reliability in the spot market is dependent on several market factors in addition to the traditional reliability parameters. The effects of some of the traditional factors and market factors were investigated. Typical hours in the load model were selected for the studies.

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Effect of System Reserve on Reliability

The effect of system reserve on reliability was investigated. The LOLE and EENS for different reserves are presented in Figure 3.13(a) and 3.13(b). The reliability increases as the system reserve increases. The EENS is a smooth curve as compared to LOLE because EENS reflects the intensity with which the reliability is affected with increase in reserve.

Figure 3.13(a) LOLE at different reserves

Figure 3.13(b) EENS at different reserves

The provision of more reserve versus the improvement in reliability is generally based on financial gains. In order to make better decisions regarding reliability and reserve provisions, probability distributions of the reliability indices give a better picture about reliability than just the mean values. For example, consider hours 4354 and 2622. The demands for the two hours are different. The reserve for hour 4354 is 18% and for hour 2622 is 33% of the demand. The market clearing quantity (MCQ) and the generating units cleared are the same for both the hours. The mean value of the reliability indices for the two hours is presented in Table 3.4. The reliability indices at hour 4354 are higher than those at hour 2622 due to lower reserve margin at hour 4354.

Table 3.4 Reliability indices with different reserve margins

Typical Hour	Demand (MW)	Reserve (MW)	MCQ (MW)	LOLE (h/h)	EENS (MWh/h)
4354	102.74	17.26	120.0	0.0756	1.2218
2622	90.43	29.57	120.0	0.0498	0.5835

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The probability distributions of EENS for the two hours with different percentage reserves are shown in Figure 3.14. For the hour 4354, EENS in the range of 1.0-10.0 and in the range of 20.0-30.0 occur with significant larger probabilities than in other ranges. For the hour 2622, EENS may occur with significant probability only in the range of 10.0 – 20.0.

Figure 3.14 Probability distributions of EENS for two typical hours

Effect of Probability Distributions

The effects of the exponential distribution, normal distribution and lognormal distribution for generating unit restoration times on reliability were also investigated. The results are presented in Table 3.5. It is interesting to observe that the reliability indices do not show any significant differences when the generating unit restoration times are assumed to follow different distributions.

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Table 3.5 Reliability indices for various probability distributions of unit restoration times.

Demand (MW)	Committed Capacity (MW)	Probability Distribution	LOLE (h/h)	EENS (MWh/h)
102.74	120.0	Exponential	0.0855	1.2217
		Normal	0.0857	1.2212
		Log-normal	0.0853	1.2290
102.74	140.0	Exponential	0.0767	0.4227
		Normal	0.0761	0.4168
		Log-normal	0.0763	0.4582

3.8.4 Reliability Indices with Uncertainty

Reliability evaluation for an hour considering bid price uncertainties is presented in this section. The demand for a typical hour was assumed to be 126.36 MW. The units cleared in the market are determined based on the bid data. Four probable scenarios of market clearing results, as shown in Table 3.6, were assumed to illustrate the technique. Three cases of the four probable market-clearing scenarios and their corresponding weights are given in Table 3.7. The units indicated by “1” are cleared in the market and those underlined are the marginal units cleared.

Table 3.6 Market clearing scenarios

Scenario	G11	G12	G13	G14	G15	G16	G17	G21	G22	G23	G24
A	1	1	1	0	0	0	0	1	<u>1</u>	0	0
B	1	1	1	0	0	0	0	<u>1</u>	0	1	0
C	1	1	1	<u>1</u>	0	0	0	0	0	1	1
D	1	1	0	0	0	0	0	1	<u>1</u>	0	0

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Table 3.7 Market clearing scenarios and weights

Case	Scenario A	Scenario B	Scenario C	Scenario D
1	0.25	0.45	0.05	0.25
2	0.1	0.7	0.1	0.1
3	0.1	0.2	0.2	0.5

The probability distributions of EENS for Cases A to D of Table 3.6 are shown in Figure 3.15. Different market clearing scenarios show different probability distributions of EENS. Cases B and D show a high probability for EENS to be in the range of 10-20 MW whereas Cases A and D show a high probability for EENS to be in the range of 30-40 MW.

Figure 3.15a Scenario A

Figure 3.15b Scenario B

Figure 3.15c Scenario C

Figure 3.15d Scenario D

Figure3.15 Probability distributions of EENS for market-clearing scenarios A-D.

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The weighted probability distributions of reliability indices for the three cases of Table 3.7 are shown in Figure 3.16. The probability of EENS to be in the range of 10-20 MWh is very high in Scenarios B and C. The combined weight for Scenarios B and C is high in Case 2 and less in Case 3. The EENS to be in the range of 10-20 MWh, therefore, has the highest probability in Case 2 and the least probability in Case 3.

Figure 3.16 Weighted probability distributions of EENS in the spot market.

3.9 Conclusions

A time sequential Monte Carlo simulation based technique to evaluate the reliability in restructured power generation systems with spot market structure is proposed in this chapter. The proposed technique gives the probability distributions of the reliability indices, in addition to their mean values, thus providing detailed information to the market participants. The effects of factors such as system reserve, different probability distribution functions for unit restoration times, etc., were investigated and study results presented in this chapter. A methodology to incorporate uncertain bid prices in reliability evaluation is also presented.

Chapter 4

Reliability Evaluation of Power Generation Systems with Multi - Bilateral Contracts Market Structure

4.1 Introduction

In a multi-bilateral contracts market, the demand of a particular customer is served by multi-bilateral contracts with various Gencos. A Genco may have multi-reserve agreements with other Gencos to increase its supply reliabilities. In the event of a shortage of generation, Gencos would execute their various bilateral contracts in a selective manner that would minimize their financial burden. This selective manner of serving contracts, which may be termed priority commitment, by a Genco means that load is not served at a particular customer until the Gencos' other contractual commitments are met. Given such a scenario it is of interest to evaluate the reliability of power supply for customers served by these Gencos and affected by the Gencos' priority commitments.

Unlike the system overall reliability indices the customer reliability indices are dependent on the priority order of execution of contracts. The individual customer reliability depends on the bilateral contracts in force and the factors that can affect the execution of the contracts such as the priority order of execution of contracts and the reserve agreements among Gencos in the case of generator outages. The work presented in this chapter is aimed to evaluate the HL1 customer reliability indices in a multi bilateral contracts market considering the effects of bilateral transactions, reserve agreements, and the priority commitments.

Reliability is typically measured by a number of indices [2, 3]. Customer reliability indices show a wide distribution from their mean values with different probabilities due to random outages of generators. The probability distributions of reliability indices are

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used for monetary evaluation and risk assessment in the liberalized framework [107-108]. It is of utmost importance to obtain the probability distributions of the customer reliability indices in addition to their mean values.

Bilateral contracts are typically medium to long-term contracts. Bilateral transactions are established sequentially in time and for various desired durations. Bilateral transactions and associated strategies such as the reserve agreements and priority commitments are time varying in nature. In time sequential Monte Carlo Simulation (MCS), artificial operating histories of generating units are created. The chronological changes resulting from market activities and generation outages for a given time period can, therefore, be easily incorporated by using the time sequential MCS method. Probability distributions of the reliability indices can easily be obtained by this method. The time sequential MCS method has been selected for reliability evaluation in a multi bilateral contracts market.

The conventional reliability evaluation procedures for vertically integrated systems cannot be directly applied to customer reliability evaluation in a multi bilateral contracts market. In this chapter, a methodology is proposed to assist the system operator in a multi-bilateral contracts market to evaluate individual customer reliability indices for a given period. The effect of simultaneous bilateral transactions on the customer reliability is considered by representing a Genco with multi-bilateral contracts as an equivalent time varying multi-state generation (ETMG). The concept of assisting unit approach [2] has been used in the ETMG to incorporate the reserve agreements among the Gencos. The effects of bilateral transactions, reserve agreements, and the priority order for executing bilateral contracts are considered in modeling the ETMG. A procedure to construct an ETMG, and thereby to determine the customer reliability has been developed. The representation of bilateral contracts by its reliability equivalent provides a convenient and flexible way for evaluating the customer reliability. A procedure to determine the probability distributions of reliability indices based on the ETMG for various customers is proposed. The Roy Billinton Test System [15,16] is utilized to illustrate the application of the procedure. The factors that affect the customer reliability indices and the convergence of Monte Carlo simulation have also been investigated.

4.2 Reliability Equivalent of a Bilateral Contract

4.2.1 Market Model

In a bilateral contracts market, various contracts exist between Gencos and customers. Gencos are divided into reserve suppliers and reserve buyers. A Genco (reserve buyer) may have reserve agreements (RA) with another Genco (reserve supplier) to share their reserves in case of contingencies. A multiple bilateral contracts market, which consists of m Gencos and p customers or bulk load points (BLP) with multiple reserve agreements, is shown in Figure 4.1.

Figure 4.1 Multi-bilateral contracts market structure

4.2.2 Generating Unit Model

The generating units bid by a Genco are represented by the two-state model – units can be either in the operating state or in the repair state. The time during which the generator remains in the operating state is called the time to failure (TTF). The time during which the generator is in the repair state is called time to repair (TTR). The parameters TTF and TTR are sampled according to their respective probability distributions such as exponential, normal, lognormal, weibull, etc. An artificial operating history of a generating unit is created, as discussed in Chapter 3.

4.2.3 Equivalent Time Varying Multi State Generation

In power systems with multi bilateral contracts structure a contract between Genco h and BLP_k can be represented by an equivalent time varying multi state generation (ETMG_{hk}) as shown in Figure 4.2.

Figure 4.2 ETMGs for a multi-bilateral contracts market

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Power markets with multi-bilateral contracts are represented by ETMGs, where an ETMG represents the generation from a Genco and reserve supplier to a BLP. In case of generation shortage, BLPs are served based on the priority order. BLP with least priority order are curtailed first. The number of ETMGs for a power system depends on the number of Gencos and BLPs. ETMGs provide a simplified network for reliability evaluation. In case of contingencies in the power system, ETMGs associated with the affected portion of the system are affected but the ETMGs not associated with the affected portion of the power system remain the same. Therefore representing the power system with multi-bilateral contracts structure by ETMGs reduces the computational burden associated with reliability analysis.

ETMG_{hk} depends on the

- Generating capacity (GC_h^t) of Genco h
- Reserve assistance (RA_h^t) to Genco h from other Gencos
- Priority Commitments (PC_{hk}^t) of Genco h prior to serving BLP_k
- Available generation capacity (AGC_{hk}^t) of Genco h at BLP_k considering RA_h^t and PC_{hk}^t
- Bilateral contract capacity (CC_{hk}^t) by Genco h at BLP_k

The generating capacity of the Gencos, bilateral contracts and their associated strategies such as reserve agreements and priority commitments are known beforehand and are considered as system inputs.

The procedure used to determine the operating history of each ETMG consists of the following steps:

Step 1: The reliability study period i.e. T_0 to T_n is divided into n periods (which are usually unequal) as shown in Figure 4.3, such that GC_h^t , RA_h^t , PC_{hk}^t and CC_{hk}^t are all constants in the time period $T_n - T_{n-1}$. During a period they can be represented as GC_h , RA_h , PC_{hk} and CC_{hk} . Since all these are constant, the resultant ETMG_{hk}^t is also constant during the period and is denoted by ETMG_{hk}.

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Figure 4.3 Depiction of time periods.

Step 2: Consider the time period T_{n-1} to T_n , starting from $n=1$.

Step 3: $AGC_{hk} = 0$ if $GC_h + RA_h < PC_{hk}$

Step 4: $AGC_{hk} = GC_h + RA_h - PC_{hk}$ if $GC_h + RA_h > PC_{hk}$

Step 5: $ETMG_{hk} = AGC_{hk}$ if $AGC_{hk} \leq CC_{hk}$

Step 6: $ETMG_{hk} = CC_{hk}$ if $AGC_{hk} > CC_{hk}$

Step 7: If $t < n$ Go to Step 2

Step 8: Obtain the time varying $ETMG_{hk}$ of Genco h at BLP_k .

4.3 Evaluation Technique

The basic procedure for evaluating the customer reliability indices using the ETMG is as follows:

Step 1: Initialize $i=1$. Simulate the artificial generating history of all the Gencos for the reliability study period.

Step 2: Based on the operating history of the Gencos the reliability study period is divided into n periods. Initialize $n=1$.

Step 3: Reliability study periods are from T_{n-1} to T_n .

Step 4: Determine $ETMG_{hk}^t$ for $h= 1$ to m and $k= 1$ to p .

Step 5: $n=n+1$.

Step 6: All periods considered? If yes goto Step7 else goto Step3.

Step 7: Aggregate $ETMG_{hk}$ for $h= 1$ to m , to determine the total generation capacity model at BLP_k .

Step 8: Superimpose the generation and load models at BLP_k .

Step 9: Evaluate the loss of load duration (LLD) and energy not supplied (ENS) at BLP_k .

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Step 10: All customers considered? If yes goto Step 11 else goto Step 7.

Step 11: $i=i+1$.

Step 12: If $i=N$ goto Step 13 else goto Step 1.

Step 13: Obtain the mathematical expectation of the individual customer reliability indices.

The number of time periods for ETMGs depends on the time varying operating history of the generating units. The operating history of the units depends on the uniformly distributed random number generated, the probability distribution functions, failure rate and repair rate of the unit as described in Sections 3.3 and 3.4.

The time varying load model for a BLP is the time varying actual demand as per the bilateral contract (not the reduced demand). Customer reliability indices are evaluated by convolving the generation model and the load model at each BLP. Customer reliability can be expressed in terms of several reliability indices such as probability, frequency and duration of outages, load lost, energy lost, etc. [2, 3]. The customer reliability indices calculated in this project are the Loss of Load Expectation (LOLE) and the Expected Energy Not Served (EENS). The reliability indices for N Monte Carlo samples can be estimated using the following equations:

Loss of Load Expectation LOLE at BLP_k , (h/study period)

$$LOLE_k = \sum_{i=1}^N \frac{LLD_{ki}}{N} \quad k=1, \dots, p \quad (4.1)$$

Expected Energy Not Served EENS at BLP_k , (MWh/study period)

$$EENS_k = \sum_{i=1}^N \frac{ENS_{ki}}{N} \quad k=1, \dots, p \quad (4.2)$$

The study period can be in days, weeks, months or a year.

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4.4 Convergence Analysis

The number of samples N required in a Monte Carlo simulation technique is dependent on the rate of convergence of the reliability index. The convergence also varies for individual customer reliability indices and system level indices. Different reliability indices have different convergence rates. The EENS, which requires more samples for converging, is considered for determining the number of samples. The convergence characteristics of the EENS at various BLPs were determined before obtaining the mean and probability distributions of the indices.

4.5 Factors Affecting Customer Reliability

In a bilateral market model, the reliability experienced by customers depends on the following factors, which have been considered in the study.

- the number of contracts of customers with various Gencos.
- the contract quantity of customers with various Gencos.
- the priority order and capacity to be served by a Genco before serving customers.
- the reserve agreement policy among Gencos.
- generating capacities and load levels of the Gencos.

4.6 Evaluation of Probability Distributions of Indices

In a multi-bilateral contracts market, the procedure to determine the probability distributions of the customer reliability indices is shown in Figure 4.4. Based on the reliability indices, data classes are created which are mutually exclusive and of equal width. The frequency counter for the class interval is updated if the reliability indices obtained from each Monte Carlo sample falls within the intervals of the class. The probability distributions of the reliability indices are calculated based on the number in the frequency counter.

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Figure 4.4 Flow chart for evaluation of probability distributions of indices

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Discrete probability distributions of the reliability indices are obtained by the proposed method. The developed procedure can be used for any suitable statistical distribution of the generating unit restoration times such as the exponential distribution, normal distribution and lognormal distribution. The probability distributions of the indices depend on the factors described in Section 4.5 and also on the reliability data such as the failure rates and repair rates of the generating units.

4.7 System Studies

The six-bus test system designated as the RBTS [15, 16, Appendix B] was used for the study. The single line diagram of the test system, the generating unit data and the load model are described in detail in Chapter 3. Seven hydro units belong to Genco 1 and four thermal units belong to Genco 2. The time varying loads at various BLPs are shown in Figure 3.7 of Chapter 3. The peak load at each BLP is shown in the single line diagram of the Test System in Chapter 3. Table 4.1 gives the priority order of serving the customers’ bilateral contract capacity (CC).

Table 4.1 Priority order of execution of bilateral contracts

Priority Order	Genco1		Genco2	
	BLPs	CC (MW)	BLPs	CC (MW)
1	2	10	3	70
2	4	30	2	10
3	5	10	4	10
4	6	10	5	10
5	3	15	6	10

4.7.1 Reliability Equivalent for RBTS

The proposed methodology was used and ETMGs for BLPs were obtained for the test system with the bilateral contracts data shown in Table 4.1. The reliability equivalents of the test system are shown in Figure 4.5.

Figure 4.5 Reliability equivalent for the RBTS

4.7.2 Generation Model at BLP 6

The operating histories of the GC (generating capacities) of the two Gencos were obtained by simulating the parameters TTF and TTR according to their respective probability distributions. Figures 4.6(a) & 4.6(b) show the operating histories of Gencos 1 and 2 respectively.

Figure 4.6 (a) GC of Genco 1

Figure 4.6 (b) GC of Genco 2

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Genco 1 is only reserve provider and hence there is no reserve assistance for Genco 1. Based on the operating history of Genco 1 and the priority commitments of Genco 1 prior to serving BLP6, the AGC (available generation capacity) of Genco1 at BLP6 was obtained and is shown in Figure 4.7(a). Based on AGC_{16} , ETMG of Genco1 at BLP 6 was obtained, and is shown in Figure 4.7(b).

Figure 4.7(a) AGC of Genco 1 at BLP 6

Figure 4.7(b) ETMG of Genco 1 at BLP 6

Genco 2 has a reserve agreement of 20 MW with Genco 1. It is to be noted that Genco1 provides reserve only after it meets all its bilateral contracts. Based on GC_1 , the reserve assistance (RA) for Genco2 from Genco1 was obtained and is shown in Figure 4.8(a).

Figure 4.8 (a) RA for Genco 2 from Genco 1

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Based on GC_2 , RA_2 and the priority commitments of Genco 2 prior to serving BLP6, the AGC of Genco 2 at BLP6 was obtained and is shown in Figure 4.8(b). Based on AGC_{26} , ETMG of Genco2 at BLP 6 was obtained, and is shown in Figure 4.8(c).

Figure 4.8 (b) AGC of Genco 2 at BLP 6

Figure 4.8(c) ETMG of Genco 2 at BLP 6

$ETMG_{16}$ and $ETMG_{26}$ were aggregated to obtain the generation model for BLP 6. The generation model at BLP 6 with a reserve agreement of 20 MW between the Gencos is shown in Figure 4.9(a). The load model for BLP 6 with a peak load of 20 MW is shown in Figure 4.9(b). The generation model and the load model were convolved to obtain the risk model. The reliability indices are obtained from the risk model.

Figure 4.9(a) Generation model for BLP 6

Figure 4.9(b) Load model for BLP 6

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4.7.3 Reliability Indices

Reliability indices, LOLE and EENS, for the second week of the year (i.e. T_0 to T_n is 168 to 336 hours) were evaluated and are presented in Tables 4.2 and 4.3 respectively. It can be seen from these tables that BLP3 customer will be served with maximum reliability whereas BLP6 customer will be served with the lowest reliability.

Table 4.2 LOLE at the BLPs with different reserve agreements

BLP	LOLE (hrs/week)		
	RA=40MW	RA=20MW	No RA
2	0.0857	0.3543	7.9093
3	0.0007	0.0340	0.3196
4	0.1052	0.2520	4.1160
5	0.6420	8.8069	11.4595
6	0.7248	9.0725	15.1661

Table 4.3 EENS at the BLPs with different reserve agreements

BLP	EENS (MWhrs/week)		
	RA=40MW	RA=20MW	No RA
2	0.2787	1.3283	31.4739
3	0.0049	0.2234	4.3177
4	0.3206	0.7973	12.6643
5	2.4900	35.1355	46.2544
6	2.4653	36.3097	60.7955

The customer reliability indices, LOLE and EENS, at the BLPs for various reserve agreements (RA) between the Gencos are presented in Figure 4.10 & 4.11 respectively. The reserve agreements between the two Gencos significantly affect the reliabilities at all the BLPs for the above-considered scenario of multi-bilateral contracts. It can also be seen from the tables and figures that the reliabilities at BLP5 and BLP 6 become similar

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by increasing the RA to 40 MW, and the reliabilities at BLP2 and BLP 4 become similar by increasing the RA to 40 MW.

Figure 4.10 LOLE at the BLPs with different reserve agreements

Figure 4.11 EENS at the BLPs with different reserve agreements

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The probability distributions of EENS at BLP 6 for three different reserve agreements (RA) between the Gencos, namely RA=0 MW, RA= 20 MW and RA= 40 MW are presented in Figure 4.12. It can be clearly seen from the figure that the probability for EENS to occur in higher range is greatly reduced with the increase in RA.

Figure 4 .12 Probability distribution of EENS at BLP 6

4.7.4 Factors Influencing Customer Reliability Indices

BLP 6 is selected to illustrate the effects of factors described in Section 4.5 on customer reliability. Six different cases of bilateral contracts between the customers (BLPs) and the Gencos are considered. The bilateral contract capacity (CC) of Genco1 with the customers for all six cases is shown in Table 4.4. The bilateral contracts capacity of Genco2 with the customers for all six cases is shown in Table 4.5. TCC represents the total bilateral contract capacity. In Cases A to D the priority orders of serving the BLP 6 are different. In Case E the contract capacity of BLP 6 is different from that in the other cases. In Case F the TCC is different from that in the other cases.

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Table 4.4 Execution of Bilateral Contracts by Genco1

Priority Order →		1	2	3	4	5	TCC (MW)
Case A	BLP	2	4	5	6	3	75
	CC (MW)	10	30	10	10	15	
Case B	BLP	3	6	5	4	2	75
	CC (MW)	15	10	10	30	10	
Case C	BLP	2	4	5	6	3	75
	CC (MW)	10	30	10	10	15	
Case D	BLP	6	4	5	2	3	75
	CC (MW)	10	30	10	10	15	
Case E	BLP	2	4	5	6	3	75
	CC (MW)	15	35	15	5	5	
Case F	BLP	2	4	5	6	3	90
	CC (MW)	10	20	10	10	40	

Table 4.5 Execution of Bilateral Contracts by Genco2

Priority Order →		1	2	3	4	5	TCC (MW)
Case A	BLP	3	2	4	5	6	110
	CC (MW)	70	10	10	10	10	
Case B	BLP	6	5	4	2	3	110
	CC (MW)	10	10	10	10	70	
Case C	BLP	3	6	4	5	2	110
	CC (MW)	70	10	10	10	10	
Case D	BLP	3	2	4	5	6	110
	CC (MW)	70	10	10	10	10	
Case E	BLP	3	2	4	5	6	110
	CC (MW)	80	5	5	5	15	
Case F	BLP	3	2	4	5	6	95
	CC (MW)	45	10	20	10	10	

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Effect of priority order

The effect of priority order is investigated in this section. The bilateral contracts as in Cases A – E of Tables 4.4 and 4.5 are considered for the study. If the priority order is 1, 2 or 3 then it is indicated as high. If the priority order is 4 or 5 it is indicated as low. It is assumed that Genco 2 has no reserve agreements with Genco 1. The LOLE and EENS for Cases A- E are presented in Table 4.6. From the results it can be seen that the customer reliability is low if its bilateral contracts or a large portion of its bilateral contracts have a low priority.

Table 4.6 Reliability indices at BLP 6 for various priority orders

Case	Priority order of BLP6		LOLE (h/week)	EENS (MWh/week)
	Genco 1	Genco 2		
B	High	High	0	0
C	Low	High	9.1126	36.0956
D	High	Low	13.6303	58.6410
A	Low	Low	14.9991	60.4222
E	Low	Low	17.4915	137.5118

Effect of Reserve Agreement

The effect of reserve agreements between the Gencos is investigated in this section. The bilateral contracts as in Cases A and F of Table 4.4 and 4.5 are considered for the study. The EENS for Cases A and F for different reserve agreements are presented in Figure 4.13(a) and 4.13(b) respectively. It is noticed that the customer reliability increases with the increase of reserve agreements.

In deregulated market Gencos’ reserve not only depends on its installed capacity (which depends on installed generation and TCC) but also its reserve agreement with other gencos. From Figure 4.13 it can be seen that in order to provide the customer with similar reliability the reserve required for Genco 2 from Genco 1 is less in Case F than in Case A because the installed reserve of Genco 2 is high in Case F.

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Figure 4.13(a) EENS at BLP 6 for Case A

Figure 4.13(b) EENS at BLP 6 for Case F

4.8 Convergence

The convergence characteristics for the reliability indices at BLP 6, are shown in Figure 4.14. From this figure it is clear that the number of samples N can be taken as 6000 samples or beyond for the EENS to converge.

Figure 4.14 Convergence characteristics of EENS at BLP 6

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4.9 Conclusions

In a bilateral contracts market, the customer reliability depends on the various bilateral transactions and the associated strategies such as the priority order of execution of contracts and reserve agreements among the Gencos. A technique to evaluate customer reliability indices in a multi-bilateral contracts market by considering the reserve agreements between the Gencos and their preferences in serving these contracts is presented in this chapter. Representing each bilateral contract by an equivalent time varying multi-state generation (ETMG) provides flexibility in determining the customer reliability. The proposed technique is extremely easy for incorporating time sequential events of the bilateral contracts.

The RBTS has been utilized to illustrate the proposed technique. The effects of various factors on the customer reliability indices have been investigated. Generally speaking, the customer reliability is high if its bilateral contracts have a high priority order and also if the reserve of the Gencos with which the customer has bilateral contracts is high. However a Gencos' reserve depends on many factors such as the Gencos' installed reserve, its reserve providers' installed reserve and also the reserve agreement policy with its reserve providers. In cases when a customer does not have a high priority order with all the Gencos, then the customer reliability is high if a large portion of the customers' bilateral contracts has a high priority order and low reliability if a large portion of the customers' bilateral contracts has a low priority order.

In vertically integrated power systems, system planners and operators used system-wide indices in order to assess the generation adequacy of the system. The system-wide indices mainly depend on the total system installed capacity, the system load and the generating units reliability data. In deregulated power systems with complex multi-bilateral market structure, it is necessary to quantify the anticipated customer reliability in order to assist the customers in making judicious decisions to choose their suppliers. The customer reliability indices depend on the reserve agreements among the Gencos and the priority order of the customers in addition to the traditional reliability factors.

Chapter 5

Reliability Evaluation of Power Generation Systems with Hybrid Market Structure

5.1 Introduction

Reliability evaluation techniques for vertically integrated systems have been discussed in Chapter 2. The reliability assessment for vertically integrated systems using Monte Carlo simulation is presented in [2, 3, 29, 30]. These techniques are based on the system's ability to meet the system load and the obtained indices are usually system-wide values. In a contingency state, the objective of system operation is to minimize the total system load curtailment [48, 49]. In [49], the load curtailment was performed in a contingency state according to the importance of individual loads by assigning weighting factors to the loads. The addition of generation or transmission facilities required the study of the economic aspects such as the cost of reliability and its corresponding worth. In [52], a minimum cost assessment method for composite generation and transmission system expansion planning is presented. During a contingency state, the objective in [52] was to minimize the sum of the system's operating costs and the damage costs associated with the system unreliability.

Deregulation of electric power industries has induced competition among generators and created choices for customers. The market participants are free to trade power through bilateral contracts or from a centralized spot market or a combination of both. In a hybrid power market transactions between multiple Gencos and multiple customers take place with the added complexity of differential pricing based on desired reliability needs. Gencos in this new environment are concerned with their economic benefits rather than with the system and individual customers' reliabilities unless they are paid for it. In a contingency state curtailment, Gencos want to minimize their revenue losses from transactions and customers who pay more would be expected to have less load

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curtailments. The centralized decision-making in system operation should be replaced by the decentralized decision-making by different parties based on various power transactions that exist. Reliability assessment, therefore, becomes more complicated in restructured power systems than in conventional systems.

In competitive markets, there exist power transactions between various buying and selling entities. These transactions have been represented as a bilateral power transaction matrix in [65]. The generation and demand side pool and bilateral power transaction vectors have been defined in [68]. In this chapter, the notations of the power transaction matrices in [65, 68] have been used and the price and curtailment vectors for the above transactions have been defined. Use of power transaction matrices makes it easier to determine transaction curtailments of Gencos for contingency state operation.

This chapter presents a non-time sequential Monte Carlo simulation technique to evaluate the customer reliability indices of restructured power generation systems with a hybrid market structure. A model for contingency state operation of hybrid markets is developed based on supply side curtailments. The supply side curtailment is formulated as a linear programming problem to minimize the revenue loss of Gencos in a contingency state. The load curtailments for customers are determined using a load shedding philosophy based on the results from the supply side optimal generation curtailment. The impacts of firm and non-firm type of bilateral and reserve contracts on the customer reliabilities have also been studied. The simulation results for the IEEE RTS [17] illustrate the effects of bilateral, spot and reserve transactions on the customer reliabilities.

5.2 Hybrid Market Model and Transactions

A hybrid market model with m Gencos and p customers is considered. For a typical hour in the hybrid market there exist many power transactions between the generators and customers. Gencos sell power/reserve either to spot markets or to customers through bilateral contracts. A Genco negotiates directly with customers regarding the quantities

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and prices for power sale in terms of bilateral contracts. The spot and reserve market transactions for Gencos are determined through the market clearing process. The price awarded to the Gencos for the sale of power is the market-clearing price.

The power transactions of Gencos are represented as supply side matrices. The power transactions of customers are represented as demand side matrices. The power transactions of Gencos from the spot market and reserve market are represented by the $m \times 1$ vectors $\mathbf{T}^{gs}$ and $\mathbf{T}^{gr}$, respectively:

$$\mathbf{T}^{gs} = \{T_1^{gs}, \dots, T_h^{gs}, \dots, T_m^{gs}\}^T \quad (5.1)$$

$$\mathbf{T}^{gr} = \{T_1^{gr}, \dots, T_h^{gr}, \dots, T_m^{gr}\}^T \quad (5.2)$$

where T_h^{gs} and T_h^{gr} , respectively, are the energy and reserve transactions of Genco h in the spot market.

The power transactions of customers from the spot market are represented by the $p \times 1$ vectors $\mathbf{T}^{ds}$:

$$\mathbf{T}^{ds} = \{T_1^{ds}, \dots, T_k^{ds}, \dots, T_p^{ds}\}^T \quad (5.3)$$

where T_k^{ds} is the power transaction of customer k from the spot market.

The bilateral contracts between Gencos and customers are represented by an $m \times p$ matrix $\mathbf{T}^b$:

$$\mathbf{T}^b = \begin{bmatrix} T_{11}^b & \dots & T_{1p}^b \\ \vdots & \ddots & \vdots \\ T_{m1}^b & \dots & T_{mp}^b \end{bmatrix} \quad (5.4)$$

where T_{hk}^b is the bilateral transaction between Genco h and customer k .

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The supply side transactions can be represented by Equation (5.5):

$$T^s = T^{ss} + T^{sr} + T^b * e_p \quad (5.5)$$

where e_p is a unit vector of size $p \times 1$.

The demand side transactions can be represented by Equation (5.6):

$$T^d = T^{ds} + [T^b]^T * e_m \quad (5.6)$$

where e_m is a unit vector of size $m \times 1$.

The market clearing prices to be awarded to the Gencos for spot and reserve transactions are ψ^{gs} and ψ^{gr} , respectively. The prices for bilateral transactions are ψ^b .

$$\psi^b = \begin{bmatrix} \psi_{11}^b & \cdots & \psi_{1p}^b \\ \vdots & \ddots & \vdots \\ \psi_{m1}^b & \cdots & \psi_{mp}^b \end{bmatrix} \quad (5.7)$$

where ψ_{hk}^b is the price for the bilateral transactions between Genco h and customer k .

5.3 Supply-side Transaction Curtailment

Under normal operating conditions, a Genco supplies power based on its transactions. In case of contingency states due to generator failures, Gencos may have to curtail their transactions. A model based on optimal transaction curtailment by Gencos for a contingency state is shown in Figure 5.1. For Gencos the optimal curtailment to the transactions in a contingency state is based on the minimization of revenue loss.

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Gencos schedule their least cost units to supply their transactions in order to minimize the operating costs. When one or more of economical units fail, a Genco schedules units from its generating capacity reserve. Scheduling these reserve generating units, despite their higher operating costs, is economically justified when revenue obtained from serving the transactions is more than the operating costs. When there is insufficient generating capacity reserve, or when the higher operating cost reserve generating units scheduling are not economically justified, the Genco has to curtail some of its transactions (non-firm type of transactions, described in detail in section 5.3.1).

Figure 5.1: A model for optimal transaction curtailment in a hybrid market for a contingency state.

The revenue loss of a Genco during a contingency state includes the loss due to curtailment of transactions and the additional cost of operating these reserve generating units. The operating cost consists of a variable cost component and a fixed cost component as in Reference [3]. The fixed cost is a constant value to be recovered by a Genco and is not dependent on the system contingency state. For Genco h with x units,

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let $\mathbf{B}_h = \{B_{h1}, \dots, B_{hx}\}$ and $\mathbf{G}_h^{\max} = \{G_{h1}^{\max}, \dots, G_{hx}^{\max}\}$ be the vectors of unit variable operating costs (in \$/MWh) and the unit ratings (in MW), respectively.

Let $\mathbf{S}_h = \{S_{h1}, \dots, S_{hx}\}$ where $S_{hv} = \begin{cases} 1 & \text{when unit is available} \\ 0 & \text{when unit is unavailable} \end{cases}$.

The problem determines the optimal curtailment of spot, bilateral and reserve transactions represented as $C_h^{gs}, C_{hk}^b, C_h^{gr}$ for Genco h as shown in Figure 5.1.

The optimal curtailment of transactions for Genco h is as follows:

$$\text{Min} \left\{ \psi^{gs} C_h^{gs} + \psi^{gr} C_h^{gr} + \sum_{k=1}^p \psi_{hk}^b C_{hk}^b + \sum_{v=1}^x B_{hv} G_{hv} S_{hv} \right\} \quad (5.8)$$

Subject to the following constraints:

$$\sum_{v=1}^x G_{hv} S_{hv} + \sum_{k=1}^p C_{hk}^b + C_h^{gs} + C_h^{gr} = \sum_{k=1}^p T_{hk}^b + T_h^{gs} + T_h^{gr} \quad (5.9)$$

$$G_{hv}^{\min} S_{hv} \leq G_{hv} \leq G_{hv}^{\max} S_{hv} \quad v=1, \dots, x \quad (5.10)$$

$$0 \leq C_{hk}^b \leq T_{hk}^b \quad k=1, \dots, p \quad (5.11)$$

$$0 \leq C_h^{gs} \leq T_h^{gs} \quad (5.12)$$

$$0 \leq C_h^{gr} \leq T_h^{gr} \quad (5.13)$$

Similarly the optimal supply side curtailment of transactions can be obtained from all Gencos.

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5.3.1 Curtailment of Firm and Non-firm Transactions

Two types of transactions served by Gencos are defined: firm and non-firm. A firm transaction is one that cannot be curtailed in a contingency state, although it may be in the Genco's economic interest to do so. The transaction must be, however, be curtailed when reserve generating capacity is not sufficient.

A non-firm transaction is one that can be curtailed in a contingency state if it is in the economic interest of Genco, i.e., the transaction will be curtailed if revenue obtained from serving the transactions is less than the operating costs. Four different combinations of firm and non-firm transactions are considered. Each combination of firm and non-firm transactions will affect the results of the optimization problem. This requires corresponding changes in the objective function and constraints (5.8) to (5.13) for obtaining the optimal supply side curtailment of transactions from Gencos.

These changes are closely related to the total generation available for Genco h , G_h^{avail} , according to Equation (5.14).

$$G_h^{avail} = \sum_{v=1}^x G_{hv}^{max} \times S_{hv} \quad (5.14)$$

Case 1: Non-Firm Transactions

In this case the transactions during a contingency state are curtailed based on the minimum revenue losses determined using Equations (5.8)-(5.13). The transaction with the lowest price will be cut first followed by the more expensive one.

Case 2: Firm Bilateral Transactions

The firm bilateral transactions will be served and then the non-firm transactions will be served or curtailed based on the loss of revenue in a contingency state. In this case, the following changes are incorporated in the objective function and constraints for obtaining

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the optimal supply side curtailment of transactions from Gencos with firm bilateral contracts.

If

$$G_h^{avail} \geq \sum_{k=1}^p T_{hk}^b \text{ then } C_{hk}^b = 0 \quad k=1, \dots, p \quad (5.15)$$

$$\text{If } G_h^{avail} < \sum_{k=1}^p T_{hk}^b, \text{ then } C_h^{gs} = T_h^{gs} \text{ and } C_h^{gr} = T_h^{gr} \quad (5.16)$$

Case 3: Firm Reserve for Spot Transactions

During a contingency state, Gencos must provide reserve to the spot market and then the non-firm transactions are served or curtailed to minimize the loss of revenue. The following changes are incorporated in the objective function and constraints for obtaining the optimal supply side curtailment of transactions from Gencos with firm reserve supply to the pool:

$$\text{If } G_h^{avail} \geq T_h^{gr}, \text{ then } C_h^{gr} = 0 \quad (5.17)$$

$$\text{If } G_h^{avail} < T_h^{gr}, \text{ then } C_h^{gs} = T_h^{gs} \text{ and } C_{hk}^b = T_{hk}^b \quad (5.18)$$

Case 4: Firm Spot Market Reserve Followed by Firm Bilateral Transactions

During a contingency state, the Gencos must first provide reserve to the spot transactions, then to firm bilateral transactions and then the non-firm transactions are served or curtailed so as to minimize the loss of revenue. The following changes are incorporated in the objective function and constraints for obtaining the optimal supply side curtailment of transactions from Gencos with firm reserve supply to the pool followed by firm bilateral contracts.

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$$\text{If } G_h^{avail} \geq T_h^{gr} + \sum_{k=1}^p T_{hk}^b \text{ then } C_h^{gr} = 0 \text{ and } C_{hk}^b = 0 \quad k=1, \dots, p \quad (5.19)$$

$$\text{If } T_h^{gr} + \sum_{k=1}^p T_{hk}^b > G_h^{avail} \geq T_h^{gr} \text{ then } C_h^{gr} = 0 \text{ and } C_h^{gs} = T_h^{gs} \quad (5.20)$$

$$\text{If } G_h^{avail} < T_h^{gr} \text{ then } C_h^{gs} = T_h^{gs} \text{ and } C_{hk}^b = T_{hk}^b \quad (5.21)$$

5.4 Demand-Side Transaction Curtailments

Customer curtailments are essentially based on the supply curtailments determined in Section 5.3 and the curtailment philosophy for customers. In order to emphasize more on the procedure for reliability evaluation of the Power System with hybrid market structure, some assumptions for the market operation were made. In case of shortage of energy for the spot market even after considering the assistance from the reserve market, the load curtailment for customers in the spot market is based on the proportional curtailment philosophy, wherein the curtailments are divided in proportion to their demands in the spot market.

The curtailment of all the spot market customers C^{ds} which is derived from supply side curtailment is given by Equation (5.22).

$$C^{ds} = \text{Max}[0, (\sum_{h=1}^m C_h^{gs} - (\sum_{h=1}^m (T_h^{gr} - C_h^{gr})))] \quad (5.22)$$

where C^{ds} is zero if the reserve supply is more than the supply side curtailment to the spot transactions, and C^{ds} is equal to the difference between the supply side curtailment and reserve supply if the reserve supply is less than the supply side curtailment to the spot transactions.

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The curtailment of individual customers based on the proportional curtailment philosophy is given by Equation (5.23).

$$C_k^{ds} = \frac{T_k^{ds}}{\sum_{j=1}^p T_j^{ds}} \times C^{ds} \quad (5.23)$$

The curtailment for the customers in the bilateral market is the same as determined for the supply side curtailment variables for the Genco with which it has contracts.

5.5 Reliability Evaluation Using MCS

This section describes a Monte Carlo simulation based customer reliability evaluation procedure by incorporating the model for contingency state operation of the hybrid market based on supply side curtailments. A two-state model of generating units is used. The unit availability in a Genco is determined using a non-sequential Monte Carlo simulation technique based on the sampling process. A uniformly distributed random number U_{hv} between $[0, 1]$ is generated and the sample state of the unit, which is dependent on the Forced Outage Rate FOR_{hv} , is given by

$$S_{hv} = 1 \quad (\text{Operating state}) \quad \text{if} \quad U_{hv} \geq FOR_{hv} \quad (5.24)$$

$$S_{hv} = 0 \quad (\text{Repair state}) \quad \text{if} \quad 0 \leq U_{hv} < FOR_{hv} \quad (5.25)$$

The states of Genco h having x units is given by

$$S_h^g = (S_{h1}, S_{h2}, \dots, S_{hv}, \dots, S_{hx}) \quad (5.26)$$

Similarly the state of the system having m Gencos for Monte Carlo sample set i is given by

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$$S_i = (S_1^g, S_2^g, \dots, S_h^g, \dots, S_m^g) \quad (5.27)$$

The procedure to evaluate the customer reliability is as follows:

Step 1: The power and price transactions matrices, the operating cost and reliability data of the Gencos are the system inputs.

Step 2: Monte Carlo sample set is drawn for all units of all Gencos.

Step 3: If $S_i = 1$ then go to Step 10 with all supply and demand side curtailments set to zero.

Step 4: If $S_i \neq 1$ then for $h=1$ to m

Step 5: If $S_h^g = 1$ then Genco h curtailments are set to zero.

Step 6: If $S_h^g \neq 1$ then its elements are taken for S_{hv} described in Section 5.3.

Step 7: Determine Genco h curtailments based on whether the contracts are firm or non-firm.

Step 8: Return to Step 4 until all Gencos are considered.

Step 9: Determine customer curtailments as in Section 5.4.

Step 10: The Curtailments C_k^{ds} and C_{hk}^b are converted to energy unit ENS_k^{ds} and ENS_{hk}^b for the sample set i .

Step 11: Step 2 is repeated for a large number of samples.

Step 12: Calculate the mathematical expectations of the customer reliability indices.

The expected customer reliability indices for a typical hour in the hybrid market are obtained as

$$EENS_k^d = \frac{\sum_{i=1}^N [ENS_k^{ds}(S_i) + \sum_{h=1}^m ENS_{hk}^b(S_i)]}{N} \quad (5.28)$$

where ENS_k^{ds} and ENS_{hk}^b represent the energies not supplied to customer k in spot and bilateral markets respectively.

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The customer reliability indices for the hybrid market are represented in the $p \times 1$ vector form as shown in Equation (5.29).

$$EENS^d = \{EENS_1^d, \dots, EENS_p^d\} \quad (5.29)$$

5.6 System Analysis

The IEEE reliability test system (RTS) was utilized to illustrate the proposed technique. The single line diagram of the test system is shown in Figure 5.2.

Figure 5.2 IEEE Reliability Test System

The system configuration data and the generating unit reliability parameters are given in [17, Appendix B]. The generating unit operating costs are provided in [Table B.7 of the thesis]. The test system is assumed to have three Gencos G1, G2 and G3 and four bulk

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customers D1, D2, D3 and D4. The generators at buses 1, 2 and 7 belong to G1, generators at buses 13, 15, 16 & 23 belong to G2 and generators at buses 18, 21 and 22 belong to G3. The loads at buses 1-6 belong to D1, at buses 7-10 to D2, at buses 13-15 to D3 and at buses 16, and 18-20 to D4. Two sets of market transactions are given in Table 5.1. The impacts of hybrid transactions and prices on customer reliability are studied in this section.

Table 5.1 Two transactions sets in the hybrid market

Transactions - Set1	Transactions - Set2
$T^b = \begin{bmatrix} 100 & 100 & 100 & 100 \\ 200 & 100 & 200 & 342 \\ 200 & 166 & 376 & 100 \end{bmatrix}$ MW	$T^b = \begin{bmatrix} 100 & 100 & 100 & 100 \\ 200 & 100 & 200 & 142 \\ 200 & 166 & 176 & 100 \end{bmatrix}$ MW
$T^{gs} = \begin{bmatrix} 100 \\ 466 \\ 200 \end{bmatrix}$ MW	$T^{gs} = \begin{bmatrix} 100 \\ 666 \\ 400 \end{bmatrix}$ MW
$T^{gr} = \begin{bmatrix} 20 \\ 30 \\ 30 \end{bmatrix}$ MW	$T^{gr} = \begin{bmatrix} 20 \\ 30 \\ 30 \end{bmatrix}$ MW
$T^{ds} = \begin{bmatrix} 166 \\ 300 \\ 100 \\ 200 \end{bmatrix}$ MW	$T^{ds} = \begin{bmatrix} 166 \\ 300 \\ 300 \\ 400 \end{bmatrix}$ MW
$\psi^b = \begin{bmatrix} 62 & 64 & 60 & 58 \\ 65 & 52 & 54 & 62 \\ 40 & 45 & 50 & 52 \end{bmatrix}$ \$/MWh	$\psi^b = \begin{bmatrix} 72 & 75 & 73 & 74 \\ 69 & 70 & 73 & 72 \\ 72 & 70 & 69 & 66 \end{bmatrix}$ \$/MWh
$\psi^{gs} = [55]$ \$/MWh	$\psi^{gs} = [70]$ \$/MWh
$\psi^{gr} = [54]$ \$/MWh	$\psi^{gr} = [54]$ \$/MWh

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5.6.1 Effects of Firm/Non-firm Bilateral Transactions on Customer Reliability

The market transaction Set 1 was used for this study. All the reserve and spot market transactions were assumed to be non-firm contracts. The impacts of firm and non-firm bilateral transactions on customer reliability indices were investigated using 8 cases. Table 5.2 shows the EENS of customers for different cases.

It can be seen from Table 5.2 that the type of bilateral contract will have significant effect on the customer reliability when the quantity of the transactions is fixed. The reliability for D4 decreases when the type of bilateral transaction changes from Case 1 to Case 4. The reliability for D3 increases when the type of bilateral transaction changes from Case 1 to Case 4. These can be explained by investigating the installed capacity of Gencos, the transaction structure for the system and the associated prices.

In this power system with hybrid market structure, G1 has 684 MW installed capacity, 520 MW transactions and 164 MW of generating reserve capacity. G2 has 1621 MW installed capacity, 1338 MW transactions and 283 MW generating reserve capacity. G3 has 1100 MW installed capacity, 1072 MW transactions and 28 MW of generating reserve capacity. It can be seen from the above that G3 is operating with a very low reserve margin – even the loss of a single small unit will lead to curtailment of transactions. Therefore, the reliability of the load points will be mainly determined by G3. The energy and reserve prices of the spot market are also higher than the bilateral transaction prices for G3. The bilateral transaction price of G3 with D4 is higher than those with other loads. D4 also buys more capacity from the spot market (200 MW) than that from bilateral transactions (100MW).

If there is capacity shortage from G3 due to generating unit failures, the following curtailment process will take place.

For Case 1, G3 will curtail bilateral transactions first because the spot market price is higher than the bilateral transaction prices. For the bilateral transactions, D1 will be

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curtailed first due to its lowest bilateral transaction price followed by D2 and D3 in that order. D4 will be curtailed last due to its highest bilateral transaction price in all loads. Therefore the reliability of D4 is the highest (the smallest EENS) followed by D3, D1 and D2. The EENS of D2 is higher than that of D1 because of unit failures from other Gencos. In case of a capacity shortage from G2, the bilateral transaction of D2 is curtailed first. In case of a capacity shortage from G1, the spot transactions of G1 are curtailed first, D2 is curtailed the most because 40 % of the spot market demand is by D2.

For Case 4, G3 will curtail spot transactions first because G3 has firm bilateral transactions with loads. The portion of D4 supplied by the spot market is over 26% of its total load. Therefore, the reliability of D4 decreases compared to that from Case 1. The reliability of D3 increases compared to that from Case 1 because a large portion of its load is supplied by bilateral transactions and only 13% load is supplied by the spot market.

It can be seen from the analysis that the reliability of each load point changes with the firm and non-firm transactions.

Table 5.2 EENS of customers for different Gencos' firm bilateral contracts.

Cases	Firm Bilateral Contracts	Non-Firm Bilateral Contracts	EENS for customers (MWh/h)			
			D1	D2	D3	D4
1	None	G1, G2, G3	46.91	49.61	14.4	0.71
2	G1	G2, G3	46.03	48.44	13.95	0.64
3	G2	G1, G3	48.52	41.79	8.61	3.37
4	G3	G1, G2	40.71	26.72	13.31	9.19
5	G1, G2	G3	46.31	39.85	8.26	3.24
6	G2, G3	G1	43.12	26.67	8.64	12.67
7	G1, G3	G2	41.66	27.83	14.26	9.37
8	G1, G2, G3	None	43.12	20.68	8.64	12.22

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5.6.2 Effect of Transaction Structure on Customer Reliability

The impacts of different transaction and price structures on customer reliability indices were investigated using two different transaction sets. Customer reliability indices for Sets 1 and 2 with non-firm transactions are shown in Table 5.3.

Table 5.3 EENS of customers for two sets of market transactions

Sets	EENS for customers (MWh/h)			
	D1	D2	D3	D4
1	46.91	49.61	14.40	0.71
2	08.98	10.71	39.04	23.17

The average price paid by a customer is computed based on the spot and bilateral price and demand of the customers. In Set 1, the average price paid by D3 is the highest followed by D2, D1 and D4 respectively. However, D2 has the highest reliability index (least reliability) followed by D1, D3 and D4. In Set 2, the average prices paid by customers in an ascending order are D4, D1, D2 and D3. The reliability indices in a descending order are D3, D4, D2 and D1. The analysis shows that paying a high average price does not guarantee higher reliability in a hybrid power market. Customer reliability depends on many factors. Customers have to conduct a detailed study regarding the price and reliability to make decisions while trading for power.

The impacts of firm bilateral and firm reserve transactions for the two sets of market transactions were also investigated. The customer reliability indices for Set 1 when Gencos G1, G2 & G3 have firm bilateral and firm reserve transactions are shown in Table 5.4. In market transaction Set 1, the case of “all the transactions are non-firm” is compared to the case of “only the bilateral transactions are firm”. The reliabilities of D1, D2 and D3 have increased whereas D4 has poorer reliability.

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Table 5.4 EENS of customers for market transactions Set 1

Transactions of G1, G2 & G3	EENS for customers (MWh/h)			
	D1	D2	D3	D4
Non-firm	46.91	49.61	14.4	0.71
Firm Bilateral	43.12	20.68	8.64	12.22
Firm Reserve	44.12	47.21	14.1	0.72
Firm Reserve & Bilateral	48.24	18.43	8.31	10.51

The customer reliability indices for Set 2 when Gencos G1, G2 & G3 have firm bilateral and firm reserve transactions are shown in Table 5.5. In market transaction Set 2, the case of “all the transactions are non-firm” is compared to the case of “only the bilateral transactions are firm”. The reliability of D3 has increased whereas D1, D2 and D4 have poorer reliabilities.

Table 5.5 EENS of customers for market transactions Set 2

Transactions of G1, G2 & G3	EENS for customers (MWh/h)			
	D1	D2	D3	D4
Non-firm	08.98	10.71	39.04	23.17
Firm Bilateral	10.42	19.58	20.89	26.23
Firm Reserve	12.15	14.92	41.56	25.63
Firm Reserve & Bilateral	10.79	20.82	21.94	27.57

5.6.3 Effect of Spot Market Price on Customer Reliability

The impacts of spot market prices on customer reliability indices are presented in this section. The hybrid transaction Set 2 was used for the studies and all the transactions were assumed to be non-firm. In this case the load curtailment will mainly depend on the bilateral transaction prices and spot price. For the fixed bilateral transaction prices, the customer reliability indices at different spot market prices are shown in Table 5.6 and Figure 5.3.

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Table 5.6 EENS of customers at different spot market prices

Spot Price (\$/MWh)	EENS for customers (MWh/h)			
	D1	D2	D3	D4
65	10.91	20.59	22.15	27.58
68	7.68	14.82	16.38	40.96
70	8.98	10.71	39.04	23.17
75	12.14	17.46	39.52	22.81

The variation in EENS experienced by customers ranges from the minimum 7.68 MWh/h to the maximum 40.96 MWh/h when the spot market price changes from 65 \$/MWh to 75 \$/MWh. It can be seen from Table 5.6 and Figure 5.3 that the reliabilities of customers fluctuate with the spot prices. When the spot price is lower than the minimum bilateral transaction price (66\$/MWh), the spot transaction will be curtailed first during load curtailment. In this case the reliability of the load point will depend on the proportion of its transaction in the spot market. The larger the proportion of load is in the spot market, the lower is the reliability. Because the proportion of D4 from the spot market is the largest than that of other loads, it has the lowest reliability. Because the proportion of D1 from the spot market is the smallest than that of other loads, it has the highest reliability. When the spot price falls within the bilateral transaction prices, the reliabilities of load points depend on both spot price and transaction prices. In this case, the bilateral transactions with lower prices than the spot price will be curtailed first, followed by spot transactions and then bilateral transactions with higher prices than the spot price. The reliabilities of the load points will re-distribute based on the percentage of load in spot transactions and the associated prices. When the spot price is higher than the maximum bilateral transaction price (75\$/MWh), the bilateral transactions will be curtailed based on the relative bilateral prices. The bilateral transaction with the lowest price will be curtailed first and the highest price last. The bilateral contract prices for G3 with D1, D2, D3 and D4 are 72, 70, 69 and 66 \$/MWh respectively. For the non-firm transactions the curtailment will start from the cheapest transaction to the the most expensive transaction. If the spot price is 74 \$/MWh, D4 followed by D3 are curtailed first when outages occur. In this case D3 has the lowest reliability because it has a larger proportion of the bilateral

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load than D4. Therefore, the EENS for D4 and D3 are higher when the spot price is higher than the bilateral prices.

Figure 5.3 EENS of customers at different spot market prices

5.7 Conclusions

Deregulation in the electric power industry has created a new environment in which transactions are no longer between a single electrical utility and multiple customers, but between multiple Gencos and multiple customers. This has led to additional complexities for reliability management. A Monte Carlo simulation technique to evaluate customer reliability indices addressing the changes brought about by deregulation is proposed in this chapter. In this technique, the generation rescheduling and load curtailments for contingency states are obtained based on the optimization technique.

The IEEE-RTS has been analyzed to illustrate the technique. The effects of various market transactions, prices and types of transactions on customer reliability have been investigated. Generally speaking, when the spot price is lower than the bilateral transaction prices for non-firm contract, Gencos usually curtail the load portion supplied by the spot market followed by that supplied by bilateral transactions. In this case customers with large portion of spot transaction will have lower reliability. When the spot price is higher than all the bilateral transaction prices, the bilateral transaction will be

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curtailed first, which will cause a lower reliability for the customers with more bilateral transactions. However, this is not always true because the reliability also depends on other factors such as the reliability of suppliers and transaction structure. The impacts of various factors on the reliability therefore need to be investigated in a new market operation.

In vertically integrated systems reliability evaluation for assessing generation adequacy mainly depends on the total system installed capacity with respect to the total system load and the component reliability data. In competitive markets, however, in addition to the traditional reliability parameters, market operation and the other market participants' strategies also contribute to the variations in customer reliability. It can be concluded that the customer reliability in a deregulated power system is more difficult to determine. It is, therefore, necessary for the ISO, Gencos and customers to evaluate both prices and related reliability before making transaction contracts.

Although the proposed technique is applied to the IEEE-RTS, it can be extended to large practical power systems with a high accuracy because of the advantages offered by Monte Carlo simulation.

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Chapter 6

A Framework to Implement Supply and Demand Side Contingency Management in Reliability Assessment

6.1 Introduction

Restructuring of the electric power industry has resulted in the unbundling of main and ancillary services (AS) such as real power, reactive power and reserve provision. Unlike centralized reliability management used in conventional vertically integrated power systems, these main and ancillary services are traded as products in a power market to provide an opportunity for both Gencos and customers to participate in system reliability management. In the process of realization of self-desired reliability, the participants' objective in this competitive environment is to maximize their individual benefits. For the smooth functioning of a power system as a whole, and for coordinating the activities of all the market participants, the ISO plays an important role in reliability management [104].

In restructured power systems, the ISO or power exchange (PX) has the overall responsibility to manage system reserves and load curtailment bids to fulfill the reliability commitments of Gencos and the reliability requirements of customers. For example, in the New Electricity Market of Singapore (NEMS), there are three levels of reserves namely primary, secondary and contingency reserves [64]. In real-time operation, when generating resources are lost, the ISO will utilize the reserves or activate the load curtailments. Such a role by the ISO is very useful in reducing the cost of the expensive reserves and in including customer preferences for reliability needs in the decision-making process. Customers submit load curtailment bids based on their willingness to reduce demand when requested. Financial incentive programs that reward the customers for reducing their demand have been initiated in many power markets such as the

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interruptible load program in Singapore [64], NYISO, Alberta power pool in Canada and demand relief program in California [63].

Reserve provisions from both supply side and demand side has gained importance in the new environment. In Reference [95], various means for the provision of supply and demand side reserves in restructured power systems are examined. Reference [63] presents the design of a market for interruptible load services within the secondary reserve ancillary services market by addressing various issues associated with the procurement of load curtailment offers. Designing of load curtailment contracts such that customers are compensated sufficiently to participate voluntarily and at the same time ensuring the benefit maximization of a utility while offering load curtailment is proposed in [98, 99]. To increase significant gains in economic efficiency, joint dispatch of energy and reserve offers (both supply and demand side reserves) is proposed in [100].

Reliability evaluation techniques developed in the past were more suited for vertically integrated power systems [2, 3]. The objective during a contingency state then was to minimize the system interruption cost [52]. The minimum system interruptions cost was based on the estimated damage cost [50] of the load and the cost of utilizing the system-wide reserve for the system-wide supply shortage. This was a valid concept then because customers had no role to play in selecting their power supplier and reliability requirements.

In the new environment, the customers are provided an opportunity to participate in the reliability management. A contingency state may arise due to generation inadequacy (unit failures) in one or many Gencos or due to transmission line outages. In this case, both Gencos and customers can be activated by the ISO to release the system unbalance. This has changed the mechanism of reliability management. The reliability evaluation techniques developed for conventional systems have to be reviewed or modified for suitability of application in the reliability evaluation of restructured power systems.

A framework to implement supply and demand side contingency management in the reliability assessment of hybrid power markets is presented in this chapter. A model for

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the ISO to coordinate the curtailment and reserve costs for a contingency state is introduced in order to balance reliability worth and reliability cost. The load curtailments and generation re-dispatch for a contingency state are determined based on minimizing the market interruption cost using an optimization technique. A non-sequential Monte Carlo simulation technique based on this framework has been proposed to evaluate the reliability of restructured power systems in a hybrid market structure. A spot market with bilateral and reserve transactions are considered in the simulation. The modified IEEE Reliability Test System (RTS) [17] is used to illustrate the proposed technique.

6.2 Energy and Ancillary Service Dispatch In Hybrid Market

In a power system with hybrid market structure, energy can be traded either in an electricity spot market or through bilateral contracts, spinning reserve is traded in an ancillary service market and load curtailment bids are traded in ancillary service market or through bilateral contracts. In an electricity spot market Gencos and customers bid the quantity and prices. The energy market clearing price (EMCP), and sales and purchases of energy for the Gencos and customers are determined after the market clearing process. All the Gencos scheduled to supply energy are paid at the EMCP. All the customers who buy energy from the spot market pay at the EMCP. The energy price and quantity through a bilateral contract will be determined by the corresponding Genco and customer. The variables and the notations defined in Chapter 5 are also used in this Chapter. A hybrid market with m Gencos and p customers is shown in Figure 6.1.

The total power sold by Genco h through the spot market and bilateral contracts is:

$$T_h^g = T_h^{gs} + \sum_{k=1}^p T_{hk}^b \quad (6.1)$$

A Genco will schedule its units to meet the aggregated spot and bilateral demand T_h^g . The total power supplied by Genco h with x scheduled units to meet the spot and bilateral demand is:

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$$P_h = \sum_{v=1}^x P_{hv} = T_h^g \quad (6.2)$$

The total power bought by customer k from the hybrid market is:

$$T_k^d = T_k^{ds} + \sum_{h=1}^m T_{hk}^b \quad (6.3)$$

There is also an ancillary services (AS) market for reserve and load curtailment bidding in a hybrid market. Gencos submit their reserve bids to the primary and secondary reserve markets and the reserve market-clearing price (RMCP₁ and RMCP₂) and reserve schedule for the primary and secondary markets respectively are determined. It is assumed that the reserve units cannot participate in the energy market and they are available to take up load when requested. The reserve prices RMCP₁ and RMCP₂ respectively are awarded when the primary reserve units and secondary reserve units are called to supply in case of contingencies. It is assumed that the reserve units can be brought online and can immediately respond to meet the additional load demand. The total reserve in the AS market is given by Equation (6.4)

$$R = \sum_{h=1}^m \sum_{v=1}^y R_{hv}^{\max pri} + \sum_{h=1}^m \sum_{v=1}^z R_{hv}^{\max sec} \quad (6.4)$$

Customers bid for load curtailment in the AS spot market and through bilateral contracts. A customer submits price $\mathcal{G}_k^{ds}$ for per MW load curtailed in the spot AS market. Similarly for bilateral contracts, a flat rate of $\mathcal{G}_{hk}^b$ is used as the curtailment cost for per MW load curtailed. Customers are paid based on their curtailment bids when they are called to interrupt in case of contingencies.

After the market settlement, the total number of units scheduled for providing energy and reserves from each Genco, the associated reliability data and installed capacity for each unit, and the load curtailment cost data from customers are provided to the ISO for contingency management of the system.

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6.3 Contingency Management in Restructured Power Systems

The generation and reserve dispatched by an individual Genco may or may not be adequate to meet its demand in the different system states caused by random failures of generating units. These system states can be divided into two states namely the normal state and contingency state. In a normal state, all the Gencos have adequate generation to meet their demands. In a contingency state, one or more Gencos may have inadequate supply to meet their demands or one or more transmission lines are out. In this case, loads have to be shed and generation has to be re-dispatched. In restructured power systems, Gencos and customers have their own preferences for the activation of reserve and curtailment of contracts to execute their transactions. The ISO plays an important role for reliable system operation during a contingency state by coordinating activities such as the activation of reserve and curtailment of contracts in the interest of all the market participants.

The procedure for contingency management as shown in Figure 6.1 includes the following steps:

- obtain the transaction and reliability data from the hybrid market.
- identify the contingency state using the contingency enumeration program based on the reliability and capacity data.
- determine the re-dispatched generation, the reserves and load curtailments called under the minimization of market interruption cost using an optimization technique based on reserve and curtailment costs.
- inform all the market participants to curtail their individual spot market and bilateral transactions, and commit the reserve.

The objective of contingency management is to minimize the market interruption cost, which consists of the curtailment cost for the customers interrupted and reserve costs for the reserve units dispatched. The Genco that has caused the interruption has to pay the interruption cost. A detailed formulation for minimizing the market interruption cost during a contingency state for a hybrid market structure is presented in the next section.

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Figure 6.1 A framework for contingency management of the Hybrid Power Market

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6.4 Optimal Dispatch of Reserves and Load Curtailments

In conventional power systems, the minimum system interruption cost is determined based on the system-wide curtailment cost due to system-wide supply shortage and reserve cost. In restructured power systems, reserves supplied by Gencos and activation of customers' load curtailment bids are determined by market forces. During contingency state j , the ISO has to determine which reserve units have to be dispatched and which customers have to be interrupted under the minimum market interruption cost. The contingency management problem by the ISO is formulated as a linear programming problem with an objective to minimize the market interruption cost.

Problem Formulation

$$\text{Min} \left(\sum_{k=1}^p \sum_{h=1}^m C_{hkj}^b \times g_{hk}^b + \sum_{k=1}^p C_{kj}^{ds} \times g_k^{ds} + \sum_{h=1}^m \sum_{v=1}^y R_{hvj}^{pri} \times RMCP_1 + \sum_{h=1}^m \sum_{v=1}^z R_{hvj}^{sec} \times RMCP_2 \right) \quad (6.5)$$

Subject to the following constraints:

The power balance constraints

$$\sum_{k=1}^p C_{hkj}^b + C_{hj}^{gs} + P_{hj} = \sum_{k=1}^p T_{hk}^b + T_h^{gs} \quad h=1, \dots, m \quad (6.6)$$

The reserve constraint of the spot market

$$\sum_{h=1}^m C_{hj}^{gs} - \sum_{h=1}^m \sum_{v=1}^y R_{hvj}^{pri} - \sum_{h=1}^m \sum_{v=1}^z R_{hvj}^{sec} = \sum_{k=1}^p C_{kj}^{ds} \quad (6.7)$$

The curtailment limits for bilateral transactions

$$0 \leq C_{hkj}^b \leq T_{hk}^b \quad h=1, \dots, m \quad k=1, \dots, p \quad (6.8)$$

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The curtailment limits for the Gencos in the spot market

$$0 \leq C_{hj}^{gs} \leq T_h^{gs} \quad h=1, \dots, m \quad (6.9)$$

The curtailment limits for the Customers in the spot market

$$0 \leq C_{kj}^{ds} \leq T_k^{ds} \quad k=1, \dots, p \quad (6.10)$$

The limits for the available generation from the Gencos

$$0 \leq P_{hj} \leq P_{hj}^{\max} \quad h=1, \dots, m \quad (6.11)$$

The limits for primary reserve

$$0 \leq R_{hvj}^{pri} \leq R_{hvj}^{\max, pri} \quad h=1, \dots, m \quad v=1, \dots, y \quad (6.12)$$

The limits for secondary reserve

$$0 \leq R_{hvj}^{\sec} \leq R_{hvj}^{\max, sec} \quad h=1, \dots, m \quad v=1, \dots, z \quad (6.13)$$

The problem (Equations 6.5 - 6.13) is solved by using a linear programming technique. The variables (or output) for this optimization problem for the contingency state j are the bilateral contracts curtailments $C_{h kj}^b$, customers spot transactions curtailment C_{kj}^{ds} , Gencos spot transactions curtailment C_{hj}^{gs} , and the dispatch from primary and secondary reserve units R_{hvj}^{pri} and $R_{hvj}^{\sec}$. The contingency state transactions $T_{h kj}^b, T_{kj}^{ds}, T_{hj}^{gs}$ are determined by subtracting the curtailments $C_{h kj}^b, C_{kj}^{ds}, C_{hj}^{gs}$ from the original transactions $T_{hk}^b, T_k^{ds}, T_h^{gs}$.

The transmission limits

The above formulation can be extended to include transmission constraints. The formulation becomes an Optimal DC power flow problem when transmission line flows are considered.

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For transmission line l

$$|F_l| \leq F_l^{\max} \quad (6.14)$$

where F_l is the power flow and $F_l^{\max}$ is the upper limit of F_l .

6.5 Reliability Evaluation Procedure Using Non-sequential Monte Carlo Simulation

A non-sequential Monte Carlo simulation (MCS) technique for the reliability evaluation of restructured power systems in hybrid market models is developed based on the proposed framework for contingency management. A two-state model of generating units is used in the simulation. Exponentially distributed times to failure are assumed for each unit, and the outage replacement rate (ORR) [2] is used to decide on the supply and demand side operating reserve requirement.

The procedure to determine the system state for sample i is as follows:

A uniformly distributed random number, $U_{hvi} = \{0,1\}$ is generated for each unit scheduled in the energy and reserve market to determine the state of the unit.

$$S_{hvi} = \begin{cases} 1 & \text{(Operating state) if } U_{hvi} \geq ORR_{hv} \\ 0 & \text{(Failure state) if } 0 \leq U_{hvi} < ORR_{hv} \end{cases} \quad (6.15)$$

The state of Genco h with $x+y+z$ units is determined based on the state of each unit of the Genco

$$S_{hi} = (S_{h1i}, \dots, S_{hvi}, \dots, S_{hxi}, \dots, S_{h(x+y)i}, \dots, S_{h(x+y+z)i}) \quad (6.16)$$

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The total available generation from Genco h is determined by

$$P_{hi} = \sum_{v=1}^x P_{hv} \times S_{hvi} \quad (6.17)$$

The available reserve from each unit in the primary reserve market is determined by

$$R_{hvi}^{\max pri} = R_{hv}^{\max pri} \times S_{h(v+x)i} \quad (6.18)$$

The available reserve from each unit in the secondary reserve market is determined by

$$R_{hvi}^{\max sec} = R_{hv}^{\max sec} \times S_{h(v+x+y)i} \quad (6.19)$$

The procedure to evaluate the customer reliability is as follows:

Step 1: Input transactions, reserve and curtailment bids and the reliability data determined from the hybrid market.

Step 2: Generate the sample state of all the units scheduled in the market by using Equation (6.15).

Step 3: Determine the states of each Genco using Equations (6.15) and (6.16).

Step 4: Evaluate P_{hi} , $R_{hvi}^{\max pri}$ and $R_{hvi}^{\max sec}$ using Equations (6.17), (6.18) and (6.19), respectively.

Step 5: Check all generating units and transmission lines to determine the system contingency state. If $P_{hi} < T_h^g$ or if any transmission line is on outage, system is in the contingency state so go to Step 6 otherwise system is in the normal state so go to Step 9.

Step 6: Determine C_{ki}^{ds} , C_{hki}^b , C_{hi}^{gs} , R_{hvi}^{pri} and R_{hvi}^{sec} using the optimization technique for the contingency state.

Step 7: Inform the Gencos about the reserve units dispatch and contingency state transactions.

Step 8: Inform the customers about the load curtailments and contingency state transactions.

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Step 9: If $i < N$, go to Step 2 else go to Step 10.

Step10: Calculate the customer reliability indices, reserve dispatched and market interruption cost.

The expected load not supplied (ELNS) for customer k is:

$$ELNS_k^d = \frac{1}{N} \times \sum_{i=1}^N [C_{ki}^{ds} + \sum_{h=1}^m C_{hki}^b] \quad k=1, \dots, p \quad (6.20)$$

The expected reserve dispatched (ERD) from the reserve market is:

$$ERD = \frac{1}{N} \times \sum_{i=1}^N [\sum_{h=1}^m \sum_{v=1}^y R_{hvi}^{pri} + \sum_{h=1}^m \sum_{v=1}^z R_{hvi}^{sec}] \quad (6.21)$$

The expected market interruption cost (EMICOST) is:

$$EMICOST = \frac{1}{N} \times \sum_{i=1}^N \left(\begin{aligned} &\sum_{h=1}^m \sum_{v=1}^y R_{hvi}^{pri} \times RMCP_1 \\ &+ \sum_{h=1}^m \sum_{v=1}^z R_{hvi}^{sec} \times RMCP_2 \\ &+ \sum_{k=1}^p C_{ki}^{ds} \times g_k^{ds} + \sum_{k=1}^p \sum_{h=1}^m C_{hki}^b \times g_{hk}^b \end{aligned} \right) \quad (6.22)$$

6.6 System Analysis at Hierarchical Level - I

The IEEE reliability test system (RTS) was analyzed at the HL I level to illustrate the proposed technique. The single line diagram of the test system and the system configuration data are given in [17, Appendix B]. The modified failure rate data of the generating units are given in Table 6.1

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Table 6.1 Failure rate data of the generating units

Unit size (MW)	Failure rate (f/h)	Unit size (MW)	Failure rate (f/h)
12	0.0034	155	0.01042
20	0.0222	197	0.01053
50	0.00505	350	0.0087
76	0.0051	400	0.00909
100	0.00833	-	-

The test system is modified into a restructured power system with three Gencos (G1, G2 and G3) and four bulk customers (D1, D2, D3 and D4). The generators at buses 1, 2 and 7 belong to G1, generators at buses 13, 15, 16 & 23 belong to G2 and generators at buses 18, 21 and 22 belong to G3. The load at buses 1 to 6 is D1, at buses 7 to 10 is D2, at buses 13 to 15 is D3 and at buses 16 and 18 to 20 is D4. Two sets of peak load transactions (Set 1 and Set 2) are given in Tables 6.2 and 6.3 respectively.

Table 6.2 Market Transactions (MW) - Set 1

Set1	D1	D2	D3	D4	Spot
G1	75	50	75	100	200
G2	225	150	200	267	466
G3	166	200	151	225	300
Spot	200	266	350	150	-

Table 6.3 Market Transactions (MW) - Set 2

Set2	D1	D2	D3	D4	Spot
G1	100	100	100	100	100
G2	200	100	200	142	666
G3	200	166	176	100	400
Spot	166	300	300	400	-

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The time varying market transactions for each hour of the day are taken as a percentage of the peak load transactions. The second day of week 51 of the IEEE load model is considered as a typical day of a hybrid market for the study. The unit commitment for the day is shown in Table 6.4.

Table 6.4 Unit commitment schedule for the hybrid market

[illegible]

The three reserve units are the 76-MW unit of G1, 155-MW unit of G2 and 50-MW unit of G3. The curtailment bids and the reserve price are shown in Table 6.5.

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Table 6.5 Curtailment bids and reserve price data

Curtailment bids & Reserve price in \$/MW				
D1	D2	D3	D4	Reserve price
100	500	1000	5000	80

In contingency states, customer spot transactions are given higher priority than their bilateral transactions. The ORR of a unit depends on the lead-time and the failure rate. The lead-time is assumed to be 4 hours and the market transactions are assumed to be as in Set 1.

6.6.1 Customer Reliability Indices and Market Interruption Cost

The customer reliability indices and the expected reserve dispatch for different hours of the day are presented in Table 6.6. The solutions converged after 2500 Monte Carlo samples.

Table 6.6: ELNS and ERD in a hybrid market

Hour	ELNS (MW)				ERD (MW)
	D1	D2	D3	D4	
1	8.6905	3.7273	0.0182	0.0000	49.5260
3	8.1131	3.7972	0.0419	0.0000	43.0310
5	8.4639	3.9686	0.1975	0.0183	45.1010
9	17.6080	0.4810	0.2144	0.0000	73.6690
11	18.3280	0.0922	0.0444	0.0000	75.6720
15	17.2790	0.3754	0.1265	0.0000	74.7930
18	20.9610	0.3216	0.1008	0.0000	78.2210
22	14.0220	1.0224	0.0761	0.0000	66.6920
23	9.2184	2.2311	0.0196	0.0000	55.5250
24	7.4892	3.6316	0.1686	0.0000	46.3100

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The effect of non-peak load at hour 5 and peak load at hour 18 on the ELNS of customers can be observed from Table 6.6. The ELNS for D2 is higher during the non-peak hour than that at peak hour. In general, reliability depends on the number, ratings and the failure rate of the units committed to meet the load. In addition, customer reliability indices also depend on the demand of the individual customers. The demand of all the customers as a percentage of the total load demand is the same for all the hours but the absolute demand of D1, whose curtailment price is the lowest, is less in hour 5 than in hour 18. When a large unit is out for both the hours, the load not supplied will be restricted only to D1 in the peak load case whereas in the non-peak load case even D2 has to be curtailed.

The market interruption costs for 24 hours are shown in Figure 6.2. The components of the market interruption cost consist of the reserve cost and the customers' D1, D2, D3 & D4 curtailment costs.

Figure 6.2: Components of Market interruption costs

The customer curtailment cost in the market is the interruption revenue for the customers. The interruption revenue for a customer can be from the curtailment of its spot transactions and bilateral transactions. The interruption revenue for customer D1 for the

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curtailment of its spot market transactions and the bilateral transactions with G1, G2 and G3 are shown in Figure 6.3.

Figure 6.3: Expected Interruption revenue for customer D1

6.6.2 Factors Affecting Customer Reliability Indices

Reserve market price

The effect of reserve market price on customer reliability was investigated. Three different reserve price cases were considered as shown in Table 6.7.

Table 6.7 Different reserve price cases

Gencos	Unit rating (MW)	Price 1 (\$/MW)	Price 2 (\$/MW)	Price 3 (\$/MW)
G1	76	80	80	120
G2	155	80	120	120
G3	50	80	120	120

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The lead-time was assumed to be one hour. The ELNS of D1 for the three cases of reserve price are presented in Figure 6.4. Customer reliability indices depend on the relative ranking of the reserve price and the load curtailment costs.

Figure 6.4: ELNS of D1 for different reserve prices

Lead time

The effect of different lead-times on customer reliability was also investigated. The ELNS of D1 for different lead-times are presented in Table 6.8. The ELNS of D1 consists of the ELNS for its spot market transactions and for its bilateral transactions with G1, G2 & G3. The results presented are for hour 18 of the day. The probability that a unit fails is a time dependent quantity affected by the lead-time considered. Reliability indices show a higher value for higher lead-time.

Table 6.8 ELNS (MW) of D1

Transactions	Lead time		
	1 hour	2 hours	4 hours
Hybrid market	3.0236	7.6080	20.9610
Spot market	0.0288	0.1818	1.1637
Bilateral - G1	0.0129	0.1514	1.0340
Bilateral - G2	0.9391	2.9161	9.6013
Bilateral - G3	2.0428	4.3586	9.1618

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Transactions

The ELNS of D1 for Set 1 and Set 2 market transactions are presented in Table 6.9. The mix of spot market and bilateral contracts are different for both Sets, but the total demand and supply quantities of the individual customers and Gencos are the same. The unit commitment schedule considered is shown in Table 6.4 and the curtailment bids and reserve price considered are shown in Table 6.5 for both market transaction Sets. The results presented are for hour 18 of the day and the lead-time is assumed to be four hours.

The ELNS for a customer also depends on the quantities it negotiates with different Gencos. The quantity bought by D1 from G2 is more in Set 1 than in Set 2, and from G3 is less in Set 1 than in Set 2. The ELNS for D1 in Set 1 is lower than that in Set 2 because the reliability provided by G2 is better than that provided by G3. The reliability performance of G2 and G3 can be explained from Table 6.9. In Set 2, customer D1 has bought 200 MW from G2 and G3. The reliability index for D1 is higher for the bilateral contract with G3 than with G2.

Table 6.9 ELNS (MW) of D1

Transactions	Hybrid market	Spot market	Bilateral market		
			G1	G2	G3
Set 1	20.961	1.1637	1.034	9.6013	9.1618
Set 2	21.732	1.2052	1.8693	7.7433	10.915

6.7 System Analysis at Hierarchical Level - II

The IEEE reliability test system (RTS) was utilized at the HL-II level to illustrate the proposed technique. The test system is modified into a restructured power system with ten Gencos and seventeen customers. The generators at buses 1, 2, 7, 13, 16, 18, 21, 22 & 23 belong to G1, G2, G8, G9 and the generator at bus15 belongs to G10 and it participates only in the reserve market. The loads at buses 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 13,

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14, 15, 16, 18, 19, 20 belong to customers L1, L2,, L16 and L17 respectively. The hour 18 of the second day of Week 51 of the IEEE load model is considered for the study. The transactions between the Gencos and customers are given in Table 6.10.

Table 6.10(a) Market Transactions (MW)

Gencos\Customers	L1	L2	L3	L4	L5	L6	L7	L8	L9
G1	1.85	1.66	3.08	1.27	1.22	2.33	1.43	1.95	1.99
G2	3.70	3.32	6.16	2.54	2.43	4.66	2.85	3.91	3.99
G3	6.61	5.94	11.04	4.53	4.35	8.33	5.11	6.98	7.16
G4	13.75	12.40	22.92	9.42	9.04	17.32	10.61	14.52	14.87
G5	4.33	3.89	7.21	2.96	2.84	5.45	3.34	4.56	4.67
G6	18.41	16.5	30.68	12.61	12.10	23.18	14.22	19.44	19.89
G7	10.33	9.28	17.22	7.08	6.79	13.01	14.41	19.71	20.17
G8	10.13	9.09	16.88	6.94	6.66	12.75	14.11	19.31	19.76
G9	6.46	5.80	10.76	4.43	4.25	8.13	9.00	12.32	12.61
Spot	32.43	29.10	54.05	22.22	21.32	40.84	49.92	68.3	69.89

Table 6.10(b) Market Transactions (MW)

Gencos\Customers	L10	L11	L12	L13	L14	L15	L16	L17	Spot
G1	2.23	3.90	2.85	4.65	2.05	6.82	3.71	2.61	30.4
G2	4.45	7.80	5.70	9.31	4.09	13.64	7.42	5.23	60.8
G3	7.96	13.93	10.20	16.67	7.33	24.41	13.27	9.38	108.8
G4	16.55	25.76	18.85	30.8	13.56	45.16	24.55	17.37	175.6
G5	5.21	8.09	5.92	9.67	4.26	14.22	7.71	5.46	55.21
G6	22.17	34.47	25.23	41.23	18.16	60.46	32.86	23.25	235.1
G7	22.48	19.79	14.49	23.67	11.64	38.76	21.07	14.9	115.2
G8	22.02	19.40	14.20	23.21	11.41	37.98	20.65	14.6	112.9
G9	14.05	12.36	9.06	14.79	7.28	24.23	13.17	9.32	71.98
Spot	77.88	119.5	87.50	143	20.22	67.32	36.59	25.88	-

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The curtailment bids submitted by the customers and the reserve market price are shown in Table 6.11. The energy and reserve units participating in the market are shown in Table 6.12.

Table 6.11 Curtailment bids and reserve price data

Curtailment bids & Reserve price in \$/MW				
L1 to L6	L7 to L10	L11 to L13	L14 to L17	Reserve price
100	500	1000	5000	80

Table 6.12 Energy and reserve units participating in the hybrid market

Gencos	Energy Units					Reserve Units
G1	76	-	-	-	-	76
G2	76	76	-	-	-	
G3	100	100	<u>72</u>	-	-	
G4	197	197	<u>99</u>	-	-	
G5	155	-	-	-	-	
G6	155	155	350	-	-	
G7	400	-	-	-	-	
G8	<u>392</u>	-	-	-	-	
G9	50	50	50	50	50	50
G10	-	-	-	-	-	155

The ORR of a unit depends on the lead-time and the failure rate. The lead-time is assumed to be 4 hours. In contingency states customer spot transactions are given higher priority than their bilateral transactions.

6.7.1 Customer reliability indices

The customer reliability indices are presented in Table 6.13. The solutions converged after 2500 Monte Carlo samples.

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Table 6.13 ELNS of customers

Customers	Transactions		
	Spot	Bilateral	Hybrid
L1	0.434	3.373	3.807
L2	0.250	2.699	2.949
L3	0.192	3.948	4.140
L4	0.043	1.568	1.611
L5	0.029	1.424	1.453
L6	0.016	2.589	2.605
L7	1.32E-07	1.422	1.422
L8	1.22E-07	1.904	1.904
L9	1.21E-07	1.942	1.942
L10	1.18E-07	2.126	2.126
L11	6.38E-08	2.092	2.092
L12	5.94E-08	1.528	1.528
L13	6.43E-08	2.444	2.444
L14	1.48E-08	1.142	1.142
L15	1.58E-08	3.802	3.802
L16	1.52E-08	2.066	2.066
L17	1.48E-08	1.461	1.461

From Table 6.13 it can be observed that high curtailment bid customers have low reliability indices (or higher reliability). However high curtailment bid customers like L15 having 80% bilateral transactions and only 20% spot transactions have high reliability indices. This can be explained by considering the difference between the spot and bilateral transactions curtailment when large units of Gencos are on outage (for eg. G7 and G8 with only one large unit). When contingency occurs due to outage of units then from the supply side, all the spot and bilateral transactions of the Genco are curtailed. From the demand side, all the bilateral customers' of the Genco are curtailed. But when it comes to the curtailment of the spot market customers the supply side resources from all the Gencos are pooled and the shortage in the pool generation

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resources is reflected on the customers based on their curtailment bids. Thus in the spot market the customers’ reliability indices are mostly dependent on the curtailment bids. In the bilateral contracts market the customers should consider all the reliability parameters of the Gencos with which they have huge bilateral contracts.

The expected reserve dispatched (ERD) from G1, G9 and G10 is 65.45 MW. The components of the market interruption cost for Gencos G1, G9 and G10 and for customers L1 to L17 are shown in Figure 6.5.

Figure 6.5 Components of Market Interruption Cost

6.7.2 Factors Affecting Customer Reliability Indices

Effect of reserve market price

The impact of reserve market price on customer reliability was investigated. Three different reserve prices cases are shown in Table 6.14. The ELNS of customers for different reserve prices are presented in Table 6.15.

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Table 6.14 Different reserve price cases

Reserve price					
Price 1		Price 2		Price 3	
Genco	Price (\$/MW)	Genco	Price (\$/MW)	Genco	Price (\$/MW)
G1	80	G1	80	G1	120
G9	80	G9	120	G9	120
G10	80	G10	120	G10	120

Table 6.15 Effect of reserve price on ELNS (MW) of customers

Customers	Reserve Price		
	Price 1	Price 2	Price 3
L1	3.807	11.85	19.92
L2	2.949	7.908	14.69
L3	4.140	12.60	20.94
L4	1.611	4.590	6.278
L5	1.453	4.103	5.725
L6	2.605	5.760	10.21
L7	1.422	1.157	1.279
L8	1.904	1.552	1.711
L9	1.942	1.578	1.741
L10	2.126	1.707	1.901
L11	2.092	1.715	1.874
L12	1.528	1.253	1.369
L13	2.444	2.042	2.196
L14	1.142	0.939	1.028
L15	3.802	3.119	3.419
L16	2.066	1.695	1.858
L17	1.461	1.199	1.314

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When the reserve price is higher than the curtailment bids of customers' L1 to L6 the ELNS of these customers show a higher value. Similarly, when the reserve price is lower than the curtailment bids of customers L1 to L6 the ELNS of these customers show a lower value. The ELNS of customers L7 to L17 who have bid higher than the reserve price do not show any significant variations with the reserve price.

Effect of Lead-time

The impact of lead-time on customer reliability was investigated. The ELNS of customers for different lead-times are presented in Table 6.16. The ELNS of customers show a higher value for higher lead-times.

Table 6.16 Effect of lead-time on ELNS (MW) of customers

Customers	Lead Time		
	1 hour	2 hours	4 hours
L1	0.696	1.659	3.807
L2	0.524	1.261	2.949
L3	0.719	1.692	4.140
L4	0.294	0.675	1.611
L5	0.268	0.601	1.453
L6	0.503	1.117	2.605
L7	0.254	0.629	1.422
L8	0.332	0.836	1.904
L9	0.34	0.854	1.942
L10	0.378	0.942	2.126
L11	0.375	0.926	2.092
L12	0.275	0.676	1.528
L13	0.449	1.087	2.444
L14	0.21	0.513	1.142
L15	0.696	1.706	3.802
L16	0.378	0.927	2.066
L17	0.268	0.656	1.461

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Effect of transmission lines:

The impact of transmission lines on customer reliability was investigated. Three cases of transmission network are considered. In the first case no transmission network is considered i.e. HL1 level reliability evaluation. In the second case all the transmission lines are present, i.e., HL2 level reliability evaluation. In the third case three lines that exist between buses 13 and 23, buses 14 and 16 and buses 16 and 19 are removed. The ELNS of customers for the three cases are shown in Table 6.17.

Table 6.17 Effect of transmission lines on ELNS (MW) of customers

Customers	Transmission lines		
	HL1	HL2	HL2 (3 lines out)
L1	3.781	3.807	15.480
L2	2.935	2.949	10.330
L3	4.065	4.140	6.460
L4	1.587	1.611	7.062
L5	1.400	1.453	4.968
L6	2.552	2.605	10.22
L7	1.265	1.422	1.272
L8	1.717	1.904	1.735
L9	1.746	1.942	2.420
L10	1.905	2.126	1.991
L11	1.872	2.092	1.976
L12	1.364	1.528	1.472
L13	2.207	2.444	2.295
L14	1.029	1.142	1.227
L15	3.422	3.802	3.521
L16	1.860	2.066	1.861
L17	1.315	1.461	1.316

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From the results, it can be concluded that the HL-1 level and the HL-2 level reliability indices are similar if the transmission system is adequate. However, if the transmission system is inadequate or if there are transmission outages then the reliability indices show a higher value leading to higher interruption costs.

6.8 Conclusions

A non-time-sequential Monte Carlo simulation based reliability assessment in restructured power systems with hybrid market models is presented in this chapter. A framework to implement supply side “reserve offers” and demand side “voluntary load curtailment offers” for contingency management in reliability assessment of restructured power systems with hybrid market models is proposed. The IEEE RTS has been utilized to illustrate the proposed technique. Generally speaking, the customers with low curtailment bid have higher reliability than customers with high curtailment bids. However, many factors such as the spot and bilateral transactions of a customer, reserve price, transmission constraints, traditional reliability parameters, etc., can also influence the reliability indices. The framework for contingency management is based on features of a hybrid market structure described in this chapter. However the proposed technique can be extended for application to real power markets.

Chapter 7

Conclusions and Recommendations

7.1 Conclusions

Restructuring of the electric power industry has resulted in corporate and service unbundling. This has given rise to new system operational and reliability management policies that can influence the system and customer reliabilities. These changes have motivated this research to develop new techniques for reliability evaluation suitable for the new environment.

A time sequential Monte Carlo simulation technique for reliability evaluation of restructured power generation systems with the spot market structure is presented in Chapter 3. Special features of the spot market structure such as Gencos bidding into the pool to supply power and the market operator's market clearing mechanism for spot and reserve markets are incorporated in the proposed reliability evaluation technique. System-wide hourly indices that are obtained based on the operation of the power pool are more meaningful as they reflect the effect of both technical and market related factors on system reliability. The model is further extended to incorporate the effect of bid price uncertainty. Weighted mean and probability distributions of the reliability indices are defined and used to investigate the effect of uncertainty on system reliability. One of the merits of this model is that it can be used to incorporate any uncertainty such as variations in load. A major drawback of the model is the increase in computation time for incorporating more uncertainties.

A time sequential Monte Carlo simulation technique to evaluate customer reliability in power generation systems with multi-bilateral contracts market is presented in Chapter 4. Features such as reserve agreements between Gencos and priority order of Gencos serving the customers are incorporated for reliability evaluation. A reliability equivalent defined as ETMG is developed and utilized to evaluate the customer reliability. The

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ETMG is developed by blending traditional reliability parameters such as failure rate, repair rate, various probability distributions of the generating unit restoration times and market factors such as the bilateral transactions in force, the reserve agreements between Gencos, priority order of Gencos serving customers. Reliability evaluation considering the ETMG can easily handle chronological events such as time varying bilaterally agreed loads and reserve agreements. The method is, however, computationally more cumbersome but this is not a major issue with recent advances in computer technologies. In addition to the mean values, the probability distributions of the customer reliability indices are easily obtained by this method. Probability distributions of reliability indices provide additional information about the reliability to the customers and can be quite useful for reliability-related monetary evaluation and for considering reliability in economic risk management.

A non-time sequential Monte Carlo simulation technique to evaluate the customer reliability in power generation systems with hybrid market structure is proposed in Chapter 5. In a deregulated power market, the transactions are no longer between a utility and multiple customers but between multiple Gencos and multiple customers. This has led to additional complexity in reliability management. Customer reliability is more difficult to determine because it depends on the market operation and other market participants' strategy, in addition to the traditional reliability parameters. A model for optimal transaction curtailment for a contingency state in a hybrid market is developed to incorporate the changes brought about by deregulation. The supply and demand transactions of the Gencos and customers in the spot and bilateral market are represented by a transaction matrix. The proposed technique provides a useful tool for the customers to study the effects of market related factors on the reliability received by them and to help them make better decisions regarding price and reliability while trading for power. The effects of various market transactions, prices and types of transactions on customer reliability are illustrated by application to the IEEE RTS.

In deregulated power markets, Gencos can participate in the reserve market and the customers can participate in the voluntary load curtailment program for system reliability. A framework to implement supply and demand side participation in contingency

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management of hybrid power markets is presented in Chapter 6. A model for the ISO to coordinate the curtailment and reserve utilization contracts for a generation inadequacy state is introduced to balance reliability worth and cost. A non-sequential Monte Carlo simulation technique based on this framework has been proposed to evaluate the customer reliability of restructured power systems with a hybrid market model. The reliability indices obtained by this method provide useful information to the customers in making use of the economic incentives for participating in a voluntary load curtailment program by either reducing or shifting their demand. In addition to the customer reliability indices, the market interruption cost and the interruption revenue for the customers participating in the interruptible load programs are also evaluated. The effects of various market factors such as the spot and bilateral transactions in force, the reserve market price on the customer reliability indices are investigated. The technique is developed for HL1 evaluation i.e., the evaluation domain involves the reliability problems of generation system, as well as HL2 evaluation i.e., the evaluation domain involves the reliability problems of composite generation and transmission systems.

Although the proposed techniques are applied to two test systems in the thesis they can be easily extended to large practical power systems with a high accuracy. In practical power systems Gencos are not obliged to make their data such as failure rates public. Reliability techniques developed in Chapters 3 to 6 need data about the generating unit failure rates and also the market transactions in force. In the competitive electricity energy market environment the ISO, Gencos and customers have to participate in reliability management because it would be beneficial for all the market participants. It is strongly believed that with the maturity of power markets the ISO will eventually have the authority to obtain the reliability data from Gencos because its responsibility is to maintain the normal operation of the entire system.

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7.2 Recommendations

In this thesis several new ideas are introduced and developed. There is ample scope for extension of the work presented. A few recommendations are as follows:

- The generating unit model is considered as a two-state model throughout the thesis. The unit model selection should be based on whether the units are base load units (for example the units cleared in the energy market normally fall under this category) or peak load units (for example most units that participate in the primary, secondary or contingency reserve may fall under this category). The de-rated states that normally exist in real time for the base load units must also be considered in the unit model.
- The reliability indices are obtained by considering a large number of Monte Carlo samples. The number of samples is based on the convergence of the indices that has the most difficulty in converging. Although Monte Carlo simulation has many advantages compared to the analytical techniques, the computation time for Monte Carlo simulation is quite high. Using suitable variance reduction techniques rather than simulating for a large number of samples can reduce the computation time.
- The selection of a technique namely analytical, sequential and a non-sequential type of Monte Carlo simulation was based on the timeframe for reliability evaluation, the complexity in the operating conditions to be considered, the ease of incorporating the market situations. However, with suitable modifications other available techniques can also be used based on the ideas presented in the thesis.
- In Chapter 6, the reliability indices obtained are based on the argument that the ISO should minimize the market interruption cost for the benefit of both the Gencos and the customers. The developed framework can be applied to any strategy adopted by the ISO. The possibility of applying other formulations such as the social welfare maximization that can benefit all the market participants can

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be further explored. Reliability management policies in the deregulated environment are relatively new and newer management policies will continue to evolve that can be considered for reliability evaluation.

- The models and techniques developed in this thesis are applied to two test systems. The ideas proposed can be better appreciated by using the commercial software for energy and reserve market clearing, unit commitment and price forecasting for application in the real world markets.

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Appendix A

Elements of Probability and Statistics

Probability distribution and density function

A random event or phenomenon can be represented by a random variable. Given a continuous random variable X , the probability of X being not larger than a real number x is a function of x . This function is defined as the cumulative distribution function $F(x)$ of random variable X , i.e.

$$F(x) = P(X \leq x) \quad (-\infty < x < \infty) \quad (\text{A.1})$$

The cumulative distribution function indicates the probabilities of all possible values of X . Function $F(x)$ can be expressed as

$$F(x) = \int_{-\infty}^x f(x) dx \quad (\text{A.2})$$

where $f(x)$ is the probability density function, and

$$f(x) = \frac{dF(x)}{dx} \quad (\text{A.3})$$

The probability of X lying between a and b can be calculated by

$$P(a \leq X \leq b) = \int_a^b f(x) dx \quad (\text{A.4})$$

Distributions for reliability evaluation

The following three important distributions are used in this research work:

1. Exponential Distribution

The density function:

$$f(t) = \lambda \exp(-\lambda t) \quad (t \geq 0) \quad (\text{A.5})$$

The cumulative distribution function:

$$F(t) = 1 - \exp(-\lambda t) \quad (\text{A.6})$$

The mean and variance of the exponential distribution are $1/\lambda$ and $1/\lambda^2$.

2. Normal distribution

The density function:

$$f(t) = \frac{1}{\sigma\sqrt{2\pi}} \exp\left[-\frac{(t-\mu)^2}{2\sigma^2}\right] \quad (-\infty \leq t \leq \infty) \quad (\text{A.7})$$

where μ and σ^2 are the mean and variance of the normal distribution.

3. Log-normal distribution

The density function:

$$f(t) = \frac{1}{t\sigma\sqrt{2\pi}} \exp\left[-\frac{\ln(t-\mu)^2}{2\sigma^2}\right] \quad (t > 0) \quad (\text{A.8})$$

The μ and σ^2 in equation B.8 are not the mean and variance of the log-normal distribution.

The mean of the lognormal distribution is given by:

$$E(t) = \exp\left(\mu + \frac{\sigma^2}{2}\right) \quad (\text{A.9})$$

The variance of the lognormal distribution is given by:

$$V(t) = \exp(2\mu + \sigma^2)[\exp(\sigma^2) - 1] \quad (\text{A.10})$$

Parameter estimation

The calculation of a reliability index by using Monte Carlo simulation is a parameter estimation problem.

If quantities $X_1, X_2, \dots, X_N$ are samples of a population X . The sample mean is defined as

$$\bar{X} = \frac{1}{N} \sum_{i=1}^N X_i \quad (\text{A.11})$$

where $\bar{X}$ is an unbiased estimate of the population mean.

In Monte Carlo simulation, the sample mean are calculated repeatedly as the number of samples increases. The recursive equation for the sample mean is

$$\bar{X} = \frac{1}{N} [(N-1)\bar{X}_{N-1} + X_N] \quad (\text{A.12})$$

Appendix B

Reliability Test Systems

The proposed new models and techniques in this thesis are applied to two test systems namely the Roy Billinton test system (RBTS) and the IEEE reliability test system (IEEE RTS). The data for the test systems are the load model, generating system data and additional data.

Load model

Table B.1 gives a daily peak load cycle, in percentage of the weekly peak. Table B.2 gives data on weekly load in percentage of the annual peak load. Table B.3 gives weekday and weekend hourly load models. Tables B.1, B.2 and B.3 are same for both the test systems. The annual peak load for IEEE RTS is 2850 MW and for RBTS is 185 MW. Combination of Tables B.1, B.2 and B.3 with the annual peak defines an hourly load model of 8736 hours in a year.

Table B.1 Daily peak load as a percentage of weekly peak

Day	Peak load (%)
Monday	93
Tuesday	100
Wednesday	98
Thursday	96
Friday	94
Saturday	77
Sunday	75

Table B.2 Weekly peak load as a percentage of annual peak

Week	Peak load (%)	Week	Peak load (%)
1	86.2	27	75.5
2	90.0	28	81.6
3	87.8	29	80.1
4	83.4	30	88.0
5	88.0	31	72.2
6	84.1	32	77.6
7	83.2	33	80.0
8	80.6	34	72.9
9	74.0	35	72.6
10	73.7	36	70.5
11	71.5	37	78.0
12	72.7	38	69.5
13	70.4	39	72.4
14	75.0	40	72.4
15	72.1	41	74.3
16	80.0	42	74.4
17	75.4	43	80.0
18	83.7	44	88.1
19	87.0	45	88.5
20	88.0	46	90.9
21	85.6	47	94.0
22	81.1	48	89.0
23	90.0	49	94.2
24	88.7	50	97.0
25	89.6	51	100.0
26	86.1	52	95.2

Table B.3 Hourly peak load as a percentage of daily peaks

Hour	Winter weeks (1-8&44-52)		Summer weeks 18-30		Spring/Fall weeks (9-17&31-43)	
	Wkdy	Wknd	Wkdy	Wknd	Wkdy	Wknd
12-1 am	67	78	64	74	63	75
1-2	63	72	60	70	62	73
2-3	60	68	58	66	60	69
3-4	59	66	56	65	58	66
4-5	59	64	56	64	59	65
5-6	60	65	58	62	65	65
6-7	74	66	64	62	72	68
7-8	86	70	76	66	85	74
8-9	95	80	87	81	95	83
9-10	96	88	95	86	99	89
10-11	96	90	99	91	100	92
11-Noon	95	91	100	93	99	94
Noon-1pm	95	90	99	93	93	91
1-2	95	88	100	92	92	90
2-3	93	87	100	91	90	90
3-4	94	87	97	91	88	86
4-5	99	91	96	92	90	85
5-6	100	100	96	94	92	88
6-7	100	99	93	95	96	92
7-8	96	97	92	95	98	100
8-9	91	94	92	100	96	97
9-10	83	92	93	93	90	95
10-11	73	87	87	88	80	90
11-12	63	81	72	80	70	85

Generating system

The generating unit ratings and reliability data for the RBTS is shown in Table B.4 and for IEEE RTS is shown in Table B.5.

Table B.4 Generating Unit Reliability Data for RBTS

Unit size (MW)	Type	Number of Units	Forced outage rate	Failure rate (1/yr)	Repair rate (1/yr)
5	Hydro	2	0.01	2.0	198.0
10	Thermal	1	0.02	4.0	196.0
20	Hydro	4	0.015	2.4	157.6
20	Thermal	1	0.025	5.0	195.0
40	Hydro	1	0.02	3.0	147.0
40	Thermal	2	0.03	6.0	194.0

Table B.5 Generating Unit Reliability Data for IEEE RTS

Unit size (MW)	Number of Units	Forced outage rate	MTTF (hours)	MTTR (hours)
12	5	0.02	2940	60
20	4	0.10	450	50
50	6	0.01	1980	20
76	4	0.02	1960	40
100	3	0.04	1200	50
155	4	0.04	960	40
197	3	0.05	950	50
350	1	0.08	1150	100
400	2	0.12	1100	150

Table B.6 Transmission line data for IEEE RTS

From Bus	To Bus	X p.u.(100 MVA base)	Rating (MVA)
1	2	0.0139	175
1	3	0.2112	175
1	5	0.0845	175
2	4	0.1267	175
2	6	0.192	175
3	9	0.119	175
3	24	0.0839	400
4	9	0.1037	175
5	10	0.0883	175
6	10	0.0605	175
7	8	0.0614	175
8	9	0.1651	175
8	10	0.1651	175
9	11	0.0839	400
9	12	0.0839	400
10	11	0.0839	400
10	12	0.0839	400
11	13	0.0476	500
11	14	0.0418	500
12	13	0.0476	500
12	23	0.0966	500
13	23	0.0865	500
14	16	0.0389	500
15	16	0.0173	500
15	21	0.0245	500
15	24	0.0519	500
16	17	0.0259	500
16	19	0.0231	500
17	18	0.0144	500
17	22	0.1053	500

18	21	0.01295	500
19	20	0.0198	175
20	23	0.0108	175
21	22	0.0678	175

Additional data

The generating unit operating costs used in Chapter 5 are based on Table 7.8 of reference [3], shown below in Table B.7.

Table B.7 Generating Unit Operating cost for IEEE RTS

Unit size (MW)	Type	Fixed cost (\$/kW/yr)	Variable cost (\$/MWh)
12	Oil	10.0	63.3
20	Combus.Turbine	3.0	103.6
50	Hydro	2.5	0.50
76	Coal	10.0	15.30
100	Oil	8.5	52.80
155	Coal	7.0	12.44
197	Oil	5.0	50.62
350	Coal	4.5	12.10
400	Nuclear	5.0	6.30

Author's Publications

Portions of different sections of this research work have been reported in various publications.

Journal Papers:

1. L. Goel, **P. A. Viswanath** and P. Wang, "Monte Carlo Simulation based Reliability Evaluation in a multi-bilateral contracts market", IEE Proc. Gener. Transm. Distrib. , Vol. 151, No. 6, Nov 2004, pp. 728-734.
2. L. Goel, **P. A. Viswanath** and P. Wang, "Reliability Evaluation of Hybrid Power Markets based on Multiple Transaction Matrix and Optimal Transaction Curtailment", IET Proc. Gener. Transm. Distrib., Vol. 1, No. 1, Jan 2007, pp. 65-71.
3. L. Goel, **P. A. Viswanath** and P. Wang, "A Framework to Implement Supply and Demand Side Contingency Management in Reliability Assessment of Restructured Power Systems", IEEE Trans. on Power Systems, Vol. 22, No. 1, Feb 2007, pp. 205-212.

Conference Papers:

4. L. Goel, **P. A. Viswanath** and P. Wang, "Evaluation of Probability Distributions of Reliability Indices in a Multi-Bilateral contracts Market", Proceedings of the IEEE Power Technology Conference (POWERCON'2004), Singapore, 21 Nov – 24 Nov 2004.
5. **P. A. Viswanath**, L. Goel and P. Wang, "Generating System Reliability Evaluation in a Spot Market using Monte Carlo Simulation," Proceedings of the International Power Engineering Conference (IPEC' 2003), Singapore, 27 Nov – 29 Nov 2003.
6. **P. A. Viswanath**, L. Goel and P. Wang, "Generating System Reliability Evaluation in an Hourly Spot Market," Proceedings of the Australasian Universities Power Engineering Conference (AUPEC' 2003), ChristChurch, New Zealand, 28 Sep - 1 Oct 2003.