SPINNING RESERVE MANAGEMENT IN DEREGULATED POWER MARKETS

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List of Abbreviations

AS	Ancillary Service
BLP	Bulk Load Point
CAISO	California Independent System Operator
CBSRAM	Cost-Based Spinning Reserve Allocation Method
CCDF	Composite Customer Damage Function
CDF	Customer Damage Function
DA	Day Ahead
Discos	Distribution Companies
Gencos	Generation Companies
Genbus	Generating Bus
HA	Hour Ahead
HL	Hierarchical Level
HSRAM	Hybrid Spinning Reserve Allocation Method
ISO	Independent System Operator
MO	Market Operator
PHBLP	Probability of Health for Bulk Load Point
PJM	Pennsylvania-New Jersey-Maryland Interconnected System Method

PMBLP	Probability of Marginal state for Bulk Load Point
PRBLP	Probability of Risk for Bulk Load Point
PX	Power Exchange
RBSRAM	Risk-Based Spinning Reserve Allocation Method
RBTS	Roy Billinton Test System
RTS	Reliability Test System
SC	Scheduling Coordinator
SCD	Security Constrained Dispatch
SR	Spinning Reserve
SRMCP	SR Market Clearing Price
TMSR	Ten-Minute SR
Transcos	Transmission Companies
UC	Unit Commitment
MUCR	Minimum UC risk
MSRC	Minimum SR cost
MTC	Minimum total cost

List of Notations

$p(down)$	The probability of a two-state unit on outage
λ	Failure rate
μ	Repair rate
T	Lead time
P_j	Probability of system in state j
$p_n(in\ service)$	The probability of nth component in service
$p_m(on\ outage)$	The probability of mth component on outage
N_s	The number of possible system states

$$u = \begin{cases} 1 & \text{when system demands are not satisfied} \\ 0 & \text{when system demands are satisfied} \end{cases}$$

P_h	Probability of the system being in the healthy state
P_m	Probability of the system being in the marginal state
P_r	Probability of the system being in the risk state
SP_r	The system pre-specified risk
SP_h	The system pre-specified healthy state probability
G_{sr}	The required SR capacity

G_p	The total capacity of the generating units committed to the system
L	The customer's load demand
C_{sr}	The cost of purchasing SR for each customer
g_g	SR generation purchased from Genco g
ρ_g	The bidding price of Genco g
N_g	The number of Gencos in a power market providing SR
$c(d_k)$	The cost for interruption duration d for the loss event k
C_{loss}	The cost of loss of load
R_k	The risk of load loss event k
L_{lossk}	The interruption load capacity for load loss event k
N_{loss}	The total number of load loss events
C_T	The total cost
G_{gmin}	The minimum generating output of Genco g
$G_{g\max}$	The maximum generating output of Genco g
A	The probability of all components being available
p_{gn}	The outage probability of the $gnth$ generating unit
p_{lm}	The outage probability of the $lmth$ transmission line
N_{gout}	The number of generating units on outage

M_{lout}	The number of transmission lines on outage
P_{out}	The probability of outage contingency
UCR_{iBLP}	The unit commitment risk of Bulk Load Point (BLP) in allocation i
R_i	The sum of BLP risk allocation i
N_p	The number of BLP

$$u_g = \begin{cases} 1 & \text{when there is load inadequacy caused by units outages} \\ 0 & \text{otherwise} \end{cases}$$

$$u_k = \begin{cases} 1 & \text{when there is line to bus b overload} \\ 0 & \text{otherwise} \end{cases}$$

P_{gj}	The state probability of the generators at state j
p_{kj}	The state probability of transmission lines at state k under state j
N_{si}	The number of generating unit outage states of SR allocation i
N_k	The number of transmission line outage states
N_b	The number of generating buses
g_{srgbi}	The SR capacity provided from Genco g at generating bus b in allocation i
$g_{srgb}^{\max}$	The maximum SR, which can be provided by Genco g at generating bus b
SRC_i	The total system SR cost for allocation i
T_{sr}	The required SR capacity for system reliability
$C_{gbi}(g_{srgbi})$	The SR bidding curve from Genco g at generating bus b for allocation i

f_{l0}	The power flow of line l for normal state
f_l^{max}	The transmission limitation of line l

Summary

An efficient electricity market is very important in a competitive and reliable environment. In reality, power producers are facing more uncertainties such as those of fuel price, load demand, electricity price, generation failure, etc, which will make it more difficult to carry out generation schedules and dispatch for preparing the offer bids. The physical system reliability may not be as easy to maintain in the new environment as in the conventional integrated power systems. The reliability issue especially the spinning reserve (SR) management under such new environment needs to be investigated from a new perspective. It is therefore necessary for the system regulators and policy makers to recognize the potential market unreliability factors and find ways to improve the market efficiency. Deregulation is also seen as a way of giving more choices to the customers. Not only the spinning reserve capacity but also the spinning reserve providers can be selected by customers, which means that customers not only decide the price of the commodity but also their reliability, leading to a trade-off between reliability and costs for SR. This trade-off determined by customers in a deregulated power system could lead to the reliability of a physical system being lower, equal or higher than that under the conventional regulated environment. SR management is therefore an essential factor for the evaluation of reliability in a deregulated power system. New reliability analysis techniques need to be developed to handle the new uncertainties introduced by the free market concept.

The broad objective of this research work was to study important aspects of spinning reserve management in the deregulated environment. Studies were carried out based on probabilistic evaluation techniques. One study investigates the spinning reserve requirements in generating systems, in which the transmission system failures are not considered. The other study develops SR allocation methods considering the effects of both generating unit and transmission line failures. These two categories of studies are based on risk evaluation approaches, which are also incorporated with the consideration of cost for reliability, in order to manage the spinning reserve in deregulated power systems.

The risk-based spinning reserve management in deregulated power systems is studied under a well-being analysis model to investigate the spinning reserve problems from the customer point of view based on the reliability risk and cost. In this model the reliability state of each customer can be presented by three levels, healthy state, marginal state and being at risk. Based on this model two methods of determining SR are proposed and studied in both bilateral market model and real-time market model. The spinning reserve capacity is represented by the load point risk indices. Customers determine their SR providers based on the reliability levels they require. The different levels are represented by the load point risk indices, the Probability of Healthy state for Bulk Load Point (PHBLP), the Probability of Marginal state for Bulk Load Point (PMBLP) and the Probability of Risk state for Bulk Load Point (PRBLP).

The objective of Risk/cost-based SR allocation method in deregulated generating systems is to find the SR allocation with minimum total cost, which includes the cost for purchasing spinning reserve and the reliability cost. It suggests that the optimum spinning reserve allocation determined by this method may result in the maximum benefit that customers can acquire from the purchase of spinning reserve.

Three methods of determining spinning reserve allocation for a deregulated composite (combined generation and transmission) system have been developed from a reliability point of view.

- The risk-based spinning reserve allocation method (RBSRAM) is developed to allocate SR based on the risk that the load cannot be complemented by spinning reserve when system failures occur. The hybrid spinning reserve allocation method (HSRAM), which considers both the reliability risk and cost, has been developed to determine the SR allocation in a real-time market model.
- When only the cost for SR allocation method (CBSRAM) is considered, the customer can choose the SR allocation with minimum cost of purchasing SR. It shows that under the same required capacity of spinning reserve the cost for purchasing may be different due to the SR purchased from different gencos. However, the corresponding unit commitment (UC) risk may be high.
- The hybrid model (HSRAM) considers both the reliability risk and reliability cost. It determines the SR allocation based on the minimum sum of reliability cost and cost of purchasing SR. The reliability cost is the worth of purchasing spinning reserve. It is also represented by the customer interruption cost. Moreover, a real-time spinning reserve market model, based on day-ahead bidding has been developed.

Chapter 1 Introduction

1.1 Deregulation of Electricity Industry

The electric power industry has over the years been dominated by large utilities that had an overall authority over all activities in generation, transmission and distribution of power within its domain of operation. Such utilities have often been referred to as *vertically integrated utilities* [1]. In some regions these utilities even served as the only electricity provider and were obliged to provide electricity to everyone with the same price, which was set in accordance with government regulatory rules and the utilities were assured a fair return on their investments.

Since the 1980s, drastic changes and restructuring in the electricity industry have occurred with the traditional vertically integrated electric utility structure being deregulated and replaced by a competitive market scheme [2].The traditional monopoly utility is now divided into generation, transmission, distribution and retail companies. Competition has been introduced in the power industry by separating or unbundling integrated industry structure, which also provides more choices on reliability and prices to customers. This process of commercial rearrangements for trading energy is called restructuring or deregulation. The motives that lead to the deregulation and restructuring are not uniform, which result in different power market structures across different countries and areas. However, the basic reason is to introduce competition and incentives in the electricity industry where the incumbent utilities have become inefficient [3].

Many countries have developed their own market models based on their specific society and political needs, traditions, physical situations, etc. such in Norway, Sweden, Finland, UK, Argentina, New Zealand, Australia and American California [4-10]. The basic principle used to achieve these goals is open access to power transmission and distribution. An independent entity called the Independent System Operator (ISO) is formed to operate the transmission system and to coordinate the various services settled in the open market: a place for electricity trading. This place is called the power market (PM) or power Exchange (PX). PM or PX accepts the bids from buyers and sellers and determines a market-clearing price in a way similar to that in a stock or commodity market. PM also schedules generation and submits the schedule to the ISO for system operation. When there is no PX, ISO may operate the electricity market as well as the electrical system. The skeletal structure of the wholesale electricity market is shown in Figure 1.1 [11]. It should be noted that this is a simplified structure of the electricity market. Details of the deregulated electricity market are presented in Section 2.1.

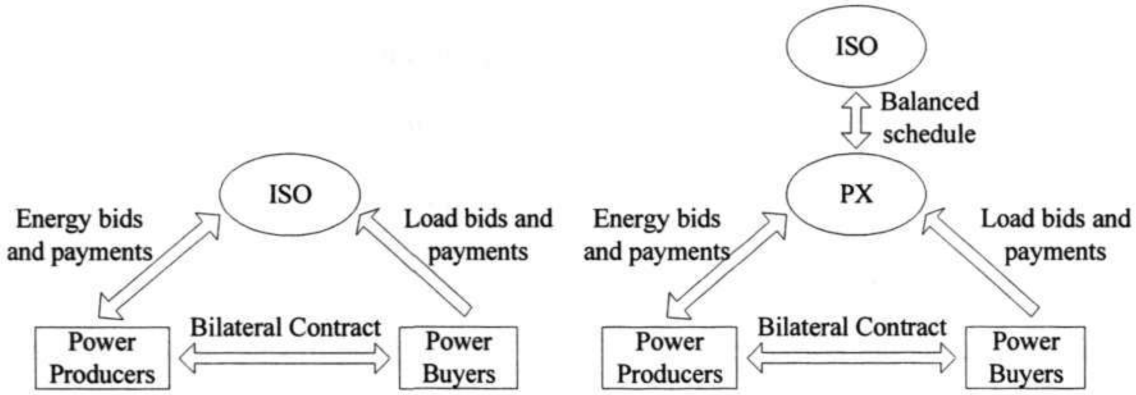

Figure 1.1 Skeleton of the wholesale electricity market structure

Deregulation and restructuring have brought forth an innovation in the electricity industry, which has led to very significant changes in power system operation, planning, transactions, etc [12]. Not only traditional products, but also new technologies and facilities such as control system, communication, metering technology etc. have to be developed in order to meet the requirements of deregulation. In particular, the existing techniques for reliability management have to be improved and new approaches have to be developed to incorporate these changes. The main focus of this research work is on the reliability management in the new environment.

1.2 Spinning Reserve Management in the Deregulated Environment

Opening up the electricity sector to competition may improve the efficiency of power generation and thereby benefit consumers. However, this may also lead to some difficulty in reliability management.

A perfect competitive power market is the basis for a fair competition among power producers. In a perfectly competitive power market, all the power producers bid the production costs (or short-run marginal costs) of their generating units. In this decentralized market, each power producer makes its own generation and reserve planning, and its financial decision is guided by the objective of maximizing its own benefits [13]. It is more difficult for power producers to bid for generation and reserve because with the competition introduced to the deregulated power system they are facing more uncertainties such as fuel price, load demand, electricity price, generation failure, etc. The fluctuating electricity price sometimes results in the shortage of reserve. It may not be as easy to maintain system reliability as in the conventional integrated power systems. The reliability issue under such new environment needs to be investigated from a new point of view.

Generating capacity that is spinning and synchronized with the system and available to serve load on a moment's notice is called *spinning reserve* [14]. Spinning reserve in a system is a measure of its ability to increase the generation in order to take care of contingencies such as generation outage or shortfall. The system reliability can be improved by increasing the system spinning reserve. In a power market the deregulation is seen as a way of giving more choices to the customers. Not only the SR capacity but also the SR providers can be selected by customers based on their reliability and price requirements. For customers the trade-off between reliability and costs for SR could lead to a lower, equal or higher reliability than in the regulated structure.

SR management is therefore an essential factor in the evaluation of reliability in a deregulated power system. New techniques for the spinning reserve management need to be developed to handle the new uncertainties introduced by the restructuring. Spinning reserve techniques should be more concerned with the customers' requirements and be able to assist customers to more easily arrive at equilibrium between the reliability and the cost.

1.3 Techniques for the spinning reserve management

1.3.1 Problems in existing techniques

Generally speaking the determination of the required amount of system generating capacity to ensure an adequate supply is an important aspect of power system operation. This problem can be divided into two conceptually different areas designated as static and operating capacity requirements [14]. The static capacity area relates to the long-term evaluation of the overall system requirement. The operating capacity area relates to the short-term evaluation of the actual capacity required to meet a given load level. A wide range of techniques has been developed to evaluate the long-term reserve capacity requirements [14-16]. However, due to the complexities involved in real-time system operation, relatively few techniques [17, 18] have been developed to investigate the short-term reserve determination.

SR requirements in most conventional power systems are determined by deterministic methods [14], which may result in a higher cost than necessary when committing excessive SR. It has been discussed in [19] that too low a value means excessive interruption while too high a value results in excessive costs. The greater the uncertainty regarding the actual reliability of any installation the greater the investment costs. Probabilistic methods are intended to complement this deficiency. System behavior is stochastic in nature, and therefore it is logical to consider that the assessment of such systems should be based on techniques that respond to this behavior, i.e., probabilistic techniques. The basic probabilistic method, Pennsylvania-New Jersey-Maryland Interconnected System Method (PJM) method, was the main approach used for short-term planning in traditional power systems. New techniques in conjunction with deregulated power systems were investigated in this project.

Besides the PJM method many methods based on the risk of unit contingencies in a generating system have been developed. Reference [20] proposes methods for SR studies under traditional regulated environment. It suggests that effective control of spinning reserve can provide substantial cost reductions in large power systems and this goal can be achieved by tightly integrating a probabilistic reserve assessment with the unit commitment (UC) function. References [21] and [22] investigate SR issues in deregulated power systems. Reference [21] proposes a method to consider generator reliability explicitly in the scheduling problem. The price for reserve is used, along with the unit reliability, to find a balance between the cost of reserve and the risk of not providing it. In [22] the authors derived the spinning reserve pricing policy implied by the reliability differentiated pricing model, and illustrate the importance of such a pricing policy.

However, transmission line failures can also have a significant effect on the SR determinations. Operating reserve evaluation involves two distinctly different aspects. The first is unit commitment, in which the system operator decides which units to commit and how many to commit to satisfy the operating criteria. The second aspect is associated with the dispatch decisions regarding those units that have been committed. In deregulated power markets, the SR providers may be chosen by customers such that the units providing SR capacity may be located in different parts of the system. When the generation and load are not balanced the scheduled SR may not be committed to the system due to transmission line failures. Hence the system reliability may be significantly affected.

A probabilistic technique has been developed for unit commitment and assessment of generating system operating health, margin and risk [23]. This health analysis technique has been developed in [24] using a well-being model for spinning reserve assessment in composite generation and transmission systems. However, this technique was originally proposed for traditional power systems. In this thesis new methods for SR determinations considering transmission line contingencies were developed under the deregulated environment.

Most existing techniques for the spinning reserve management are developed for conventional power systems. The spinning reserve is centrally managed by the system planner. The objective is to minimize the total system spinning reserve cost. Transmission effect on spinning reserve allocation is not the main problem due to the monopoly of generation. On the other hand, the price is not the issue in the spinning reserve management of conventional power systems and therefore has not been considered in the existing techniques.

1.3.2 SR Studies in Deregulated Power Markets

Firstly in the restructured power systems, the spinning reserve is not provided centrally by a single generation owner due to the separation of the generation system. Spinning reserve is provided by many power producers and is traded in an independent market, the SR market. SR providers have more options to provide spinning reserve to customers directly through bilateral contracts or/and to bid to the spinning reserve market. The SR can be determined simultaneously with energy or separately cleared from energy. Secondly, customers may have more chances to determine the SR providers and SR requirements for themselves, which results in more uncertainties and risks existing in the market than in the traditional regulated environment. Thirdly, market price will have significant impact on the spinning reserve management. The amount of the spinning reserve will be determined by both SR risk and price. Finally the spinning reserve allocation in the new environment becomes more important than in conventional system due to the separation of generation. Therefore, the task of system operators to maintain the physical system reliability after considering market optimized benefit and uncertainties will be more complex. Recently some new methods [21,25,26] have been reported to aid the evaluation of reliability in deregulated power systems and the determination of the SR requirements. In addition, many SR market models have also been developed [27]. Therefore, developing new techniques based on market models for SR determination is very important under the current deregulated environment. In the studies described in this thesis, the developed techniques are based on the bilateral model in generating system studies and real-time bidding when considering transmission lines.

1.4 Objectives

The broad objective of this research work was to study important aspects of the spinning reserve management in the deregulated environment. This research focuses on two aspects. One study investigates the spinning reserve determinations in generating systems, in which the transmission system failures are not considered. The other study develops SR allocation methods considering the effects of both generating unit and transmission line failures. These two aspects are based on risk evaluation approaches with considerations of cost for reliability, in order to manage the spinning reserve in deregulated power systems. The detailed objectives of the research work are stated in the following.

1.4.1 Spinning Reserve Allocation in Deregulated Generating Systems

As stated above, in deregulated power systems customers have the chance to determine the spinning reserve, which results in the complication of system and customer reliability evaluation. The customers' reliability requirements are not uniform anymore. Some customers may pay less for spinning reserve with low reliability requirements, while others with high reliability level requirements may pay more for SR. Hence it is necessary to develop new methods to balance the reliability levels and the associated cost. In summary, the specific objectives are

- Propose new indices and new reliability evaluation techniques for spinning reserve determination
- Propose risk-based method for spinning reserve determination in deregulated generating systems
- Propose risk/cost-based method for spinning reserve determination in deregulated generating systems
- Implement programs of the proposed methods in the determination of spinning reserve.

1.4.2 SR Allocations in Deregulated Composite Systems

In a deregulated power system customers can determine the SR providers located in different parts of a power network. Different allocations of SR may result in different reliability levels of the physical system. Practically, the SR units may not be able to commit to the system due to some failures of transmission lines. It is necessary for the ISO to consider the effect of transmission line contingencies in the determination of SR allocations. Hence, developing techniques considering transmission line contingencies to determine SR is the second major objective of this thesis. In summary, the specific objectives are:

- Develop risk-based SR allocation method in deregulated composite systems and
- Develop risk/cost-based SR allocation method in deregulated composite systems

The IEEE-Reliability Test System (RTS) [29] was used to investigate the spinning reserve determination from the viewpoint of ISO using the proposed methods. Bilateral and Real-time market models were used for these simulations.

1.5 Major Contributions

1.5.1 SR Management in Deregulated Generating Systems

In a deregulated generating system the transmission network is not considered. Under this condition a well-being analysis model has been developed that can investigate the spinning reserve problems from the customer point of view based on the reliability risk and cost. In this model the reliability state of each customer can be represented by three levels, healthy state, marginal state and being at risk. Based on this model two methods for determining SR are proposed and studied in both the bilateral market model and the real-time market model.

Risk-based SR allocation method

In this method the bulk load point indices have been introduced in deregulated generating power systems to replace the system indices in vertically integrated power systems. The spinning reserve capacity that customer requires is represented by load point risk indices.

Customers determine their SR providers based on the reliability levels they require. The different levels are presented by load point risk indices, the Probability of Health for Bulk Load Point (PHBLP), the Probability of Marginal state for Bulk Load Point (PMBLP) and Probability of Risk for Bulk Load Point (PRBLP). One major conclusion is that the concept of unified system reliability should be replaced by individual load point reliability in this new environment. Customers in a deregulated market tend to choose generation producers located in any part of the system by making bilateral contracts with SR providers. From the customers' perspective, the system reliability is not uniform any more.

Risk/cost-based SR allocation method

The objective of Risk/cost-based SR allocation method is to find the SR allocation with minimum total cost, which includes the cost for purchasing SR and reliability cost. It suggests that the optimum SR allocation determined by this method may result in the maximum benefit customers can acquire from the purchase of SR. The cost for purchasing SR is based on the bidding curve of each genco that provide SR to the SR market. The reliability cost is generally evaluated using the customer interruption cost. There are many methods for determining the interruption cost. The customer survey method is utilized in this thesis. In this method the customer damage function (CDF) and composite customer damage function (CCDF) from the Canadian surveys were used to obtain the 10-minute interruption cost. With this interruption cost the risk/cost based SR allocation method was investigated using the IEEE reliability test system. The numerical examples were evaluated under both bilateral market model and real-time market model.

1.5.2 SR Management in Deregulated Composite Systems

RBSRAM and HSRAM methods to determine SR allocation for a deregulated composite system have been developed from the reliability point of view. In the deregulated composite system SR capacity may not be delivered to the load point due to transmission line failures. These two methods investigate these issues when determining SR allocations. A model in conjunction with these methods based on real-time SR market is also proposed.

- **Market model for SR determination**

The real-time SR market model in this thesis is based on one-hour bidding. By applying the SR allocation methods to the time frame of an SR market structure, a market model is developed. In this market model after the SR biddings and customers offers for SR are submitted to the ISO, the SR allocation method is used by the ISO to evaluate all the possible SR allocations and to determine the optimized SR allocation.

- **Risk-based SR allocation method for composite systems**

The objective of cost-based SR allocation method is to select the optimal SR location with the minimum total system SR cost. In this method only the cost of purchasing SR is considered. When this method is used in a deregulated composite system the final SR allocation should not result in the violation of transmission line constraints.

- **Cost-based SR allocation method for composite systems**

The approach is developed to allocate SR based on the risk that the load cannot be complemented by SR when system failures occur. Generally this risk can also be called unit commitment (UC) risk. It is defined as the probability of the committed generation just satisfying or failing to satisfy the expected demand during the lead time. The optimum SR allocation is with the minimum UC risk.

- **Hybrid SR allocation method**

A hybrid method, which considers both the reliability risk and cost, has been developed to determine SR allocation in a real-time market model. When only considering the cost for SR, the customer can choose the SR allocation with minimum cost of purchasing SR. This shows that under the same required capacity of SR, the cost for purchasing may be different due to the SR purchased from different gencos. However, the corresponding UC risk may be high. The hybrid model considers both the reliability risk and cost. It determines the SR allocation based on minimum sum of reliability cost and cost of purchasing SR. The reliability cost is the worth of purchasing SR. This is also represented by the customer interruption cost.

1.6 Thesis Organization

This chapter describes the motivation for the study of spinning reserve in the deregulated environment. The basic concepts on deregulation in the electric power industry are briefly introduced. The significance of spinning reserve research and the objectives and the major contributions of this project are outlined. In Chapter 2, a brief introduction to the basic concepts of spinning reserve is presented and a review of the relevant literature on spinning reserve study is summarized. In addition, some topics related to the spinning reserve study in the competitive electricity markets are also outlined. In Chapters 3 and 4, spinning reserve determination in generating systems is investigated. In Chapter 3, the development of a well-being model for the evaluation of deregulated power system reliability is described, and some new indices are proposed. Based on this model, risk-based methods are developed. In the case studies the method is mainly simulated using a bilateral market model. In Chapter 4, the study is carried out with regard to the cost for reliability. The effect of reliability cost on SR determination is analyzed. The risk/cost-based SR determination method is proposed, the objective of which is to obtain a balance between cost and reliability when determining the SR for a customer. In Chapters 5 and 6, the SR allocation methods for deregulated composite systems are developed. In Chapter 5 the risk-based SR allocation method is proposed, and the procedure to implement this method is also illustrated. A SR market in conjunction with this method is illustrated. Based on this method the effect of transmission line failures on SR allocation are investigated and the method is applied on a reliability test system. Chapter 6 proposes a risk/cost-based SR allocation method. The program that can implement risk-based, cost-based and hybrid SR allocation methods is described. Finally, conclusions of the research work and the recommendations for further study are presented in Chapter 7.

The RBTS and RTS system data used in various studies and theoretical treatments of techniques used in the analysis are provided in the Appendices.

Chapter 2 Background Literature

In this Chapter, the background knowledge of reliability and spinning reserve are introduced. Deregulation of the electric power industry currently occurring all over the world is briefly reviewed. The reserve market, which is the essential component to ensure that the power markets operate reliably and economically, is then investigated. Some concepts and topics related to spinning reserve in electricity markets are also discussed.

2.1 Power System Reliability

Reliability can be defined as the probability of a system performing its required function for the period of time intended under the operating conditions encountered [30-32]. The concept of power system reliability is extremely broad and covers all aspects of the ability of the system to satisfy the consumer requirements. Due to the wide-ranging implications of the term reliability, it is necessary to subdivide it into more specific segments. A simple but reasonable subdivision of the term "system reliability" can be made by considering the two basic and fundamental aspects of system adequacy and security as shown in Figure 2.1 [14].

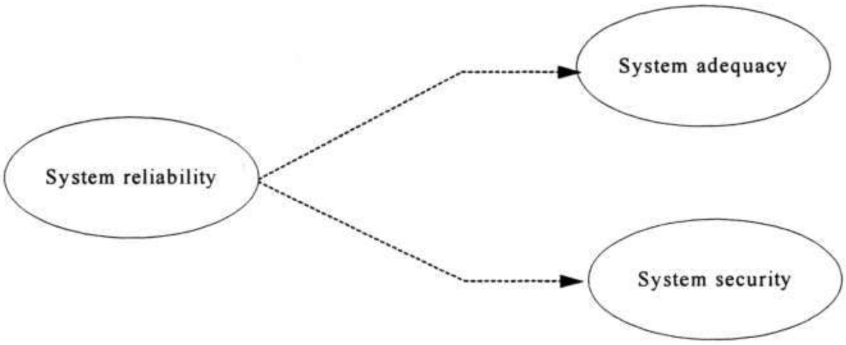

Figure 2.1 Adequacy and security concepts of reliability

2.2 Functional Zones and Hierarchical Levels

The evaluation techniques used in reliability analysis of power systems can be categorized in terms of their application to the three basic functional zones of generation, transmission and distribution. These functional zones can be combined to create Hierarchical Levels (HL) for the purpose of conducting system reliability analyses [33]. Reliability assessment at the different hierarchical levels and functional zones has undergone continuous development and application since the 1930s [34-38]. These functional zones and hierarchical levels are shown in Figure 2.2.

Hierarchical Level I (HLI) is concerned only with the generating facilities. Reliability evaluation at HLI provides a quantitative assessment of the ability of the generating system to satisfy the total system demand. The total problem of power system reliability evaluation at HLI can be divided into the two conceptually different areas of static and operating reserve assessment. The static capacity area relates to the long-term evaluation of the overall system requirements. Operating reserve assessment, on the other hand, is related to the short-term evaluation of the actual capacity required to meet a given load demand. Considerable efforts have been devoted to static capacity assessment [33-40]. There is however, relatively little published material in the area of operating reserve assessment. The research work described in this thesis is restricted to the area of operating reserve assessment.

Both generation and the associated transmission facilities are considered in HLII reliability evaluation. The combined generation and transmission system is known as a composite or bulk system. Composite system reliability evaluation techniques, therefore, include the ability of the transmission system to deliver the generated energy to the major load points.

HLIII studies are concerned with the overall assessment of the three functional zones in order to evaluate customer load point adequacy indices.

The reliability indices calculated at each hierarchical level are physically different. System reliability is usually predicted using one or more indices (which quantify expected system reliability performance) and implemented using criteria based on acceptable values of these indices. This research project is concerned with operating reserve assessment at HLI and HLII, which is in the domain of system security.

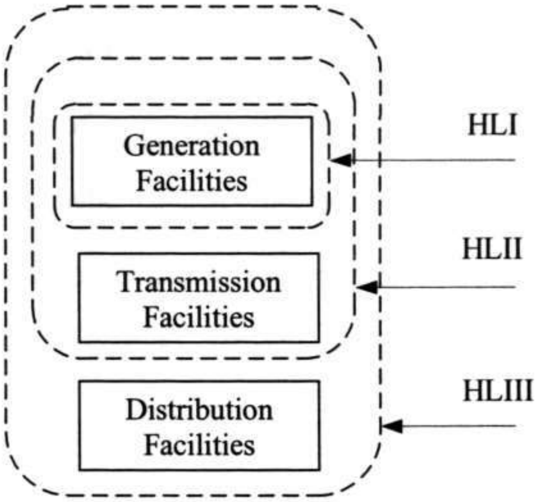

Figure 2.2 Hierarchical levels of a power system

2.2.1 Reliability Evaluation Techniques

The determination of the required amount of system generating capacity to ensure an adequate supply is an important aspect of power system planning and operation. The total problem can be divided into two conceptually different areas designated as static and operating capacity requirements. Therefore, reliability evaluation can be divided into static capacity assessment and operating reserve assessment. Different methods have been developed with regards to these two assessments.

Static capacity reliability assessment

Static capacity assessments are made at the planning stage in order to decide how much, and when, additional generating capacity needs to be installed. The static reserve must be sufficient to provide for the overhaul of generating equipment, outages that are not planned or scheduled and load growth requirements in excess of the estimates. A practice that has developed over many years is to measure the adequacy of both the planned and installed capacity in terms of a percentage reserve. However, the application of probability methods to the static capacity problem provides an analytical basis for capacity planning which can be extended to cover partial or complete integration of systems, capacity of interconnections, effects of unit size and design, effects of maintenance schedules and other system parameters [14]. The economic aspects associated with different standards of reliability can be compared only by using probability techniques.

A great number of technical papers have been published in applying probability techniques to generating capacity reliability evaluation. The first set of recognizable papers envisaging the application of probability techniques appeared in the 1930s [39]. These should be considered as pioneer papers. The first significant set of papers that added impetus to the application of probability theory to reliability assessments appeared in 1947 [40]. The "Calabrese" method, a recognized major contribution, forms the basis of the loss of load approach that is still the most widely used probabilistic technique in the reliability evaluation of generating capacity. This basic method was subsequently extended to include a loss of energy approach. Both these methods involve evaluations of expectation using basic probability methods. Another significant approach is the frequency and duration method [41].

Operating Reserve Reliability Assessment

The operating capacity area relates to the short-term evaluation of the actual capacity required to meet a given load level. When one or more factors, rapid start units such as gas turbines and hydro-plant, interruptible load, assistance from interconnected systems, voltage and/or frequency reductions are added to the effective spinning reserve, the total entity is known as operating reserve. As explained in Section 2.1 a simple but reasonable subdivision of the term "system reliability" can be made by considering the two basic and fundamental aspects of system adequacy and security. System adequacy [33] relates to the existence of sufficient facilities within the system to satisfy the consumer load demand. This includes the necessary facilities to generate sufficient electrical energy and the associated transmission and distribution facilities required to transfer the energy to the customer load points. Adequacy is used to describe a system state in which the actual entry to and departure from that state is ignored and is thus defined as a steady-state condition.

Security is considered [33] to relate to the ability of the system to respond to disturbances arising within that system. Security is therefore associated with the response of the system to whatever disturbances it is subjected. These are considered to include conditions causing local and widespread effects and the loss of major generation and transmission facilities. Power system engineers tend to relate security to the dynamic process that occurs when the system transits between one state and another. Both of these states may themselves be acceptable if viewed only from an adequacy perspective; i.e., they are both able to satisfy all system demands and all system constraints. More recently some techniques have been developed for security studies under the deregulated environment [42, 43]. Reference [42] introduces an efficient security-constrained unit commitment (SCUC) approach with ac constraints that obtains the minimum system operating cost while maintaining the security of power systems. An SCUC model with emphasizes on the simultaneous optimization of energy and ancillary services markets has been introduced in [43].

There are two basic existing techniques: the PJM method and the security function approach [14]. The basic PJM method evaluates 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, known as the lead time. The security function approach evaluates the probability of breaches of security including inadequate spinning reserve using the concepts of conditional probability. The constraints such as ramping, minimum up-down times, start-up cost, shut-down cost, etc., are considered in the security function studies.

The spinning reserve assessment, which is the subject of this thesis, is still relatively new with the problem of satisfying the load demand. Thus it falls in the domain of adequacy assessment. In adequacy evaluations it is assumed that after equipment outage the system always reaches a stable equilibrium state. Considerable effort has been expended by researchers in developing the techniques and criteria for adequacy evaluation. Two basic approaches: the contingency enumeration (analytical) technique and the Monte Carlo simulation techniques have been applied in the development of computing tools.

Analytical techniques

Analytical techniques represent the system by a mathematical model and evaluate the reliability indices from this model using direct numerical solutions [14]. These techniques generally provide average indices in a relatively short computing time. The analytical approach generally selects states in an increasing order of the contingency level, i.e., zero outages (all the system components are in service), first order outages (only one generating unit or transmission line failures), etc. The programming process based on this technique is usually stopped at a particular contingency level or when the state probability becomes less than a pre-specified value. A state is, therefore, assessed only once and the indexes are calculated mathematically from the statistical data defining each state, i.e., probability, frequency, duration, etc.

Simulation methods

Simulation methods estimate the reliability indices by simulating the actual process and random behavior of the system [14]. Theoretically all aspects and contingencies inherent in the planning, design, and operation of a power system can be considered in this method. Compared with the analytical method the system states which have a greater probability of occurrence are more likely to be simulated several times. After either a fixed number of simulations or on the basis of statistical stopping rules the simulation process will stop.

2.3 Spinning Reserve

2.3.1 Introduction

Generally speaking the determination of the required amount of system generating capacity to ensure an adequate supply is an important aspect of power system planning and operation. Spinning reserve in a system is a measure of its ability to increase the generation in order to take care of contingencies such as generation outage or shortfall. The system reliability can be improved by increasing the system generating reserve.

A wide range of techniques [19-22, 44-46] has been used to determine operating reserve requirements. These methods can be divided into two categories of deterministic and probabilistic approaches. The former do not incorporate any explicit recognition of the actual risk and subsequently probabilistic techniques were developed to incorporate this requirement (spinning reserve allocation using response health analysis). Operating reserve evaluation involves two distinctly different aspects. The first is unit commitment, in which the system operator decides how many and which units to commit to satisfy the operating criteria. The second aspect is associated with the dispatch decisions regarding the units that have been committed. The basic probabilistic methods are the Pennsylvania-New Jersey-Maryland Interconnected System Method (PJM) method and the security function approach [14]. Another probabilistic technique has been developed for unit commitment and assessment of generating system operating health, margin and risk [23]. This health analysis technique has been developed in [24] using a well-being model for spinning reserve assessment in composite generation and transmission systems.

2.3.2 Basic Technique for Spinning Reserve Management

Outage Replacement Rate (ORR)

It is shown in [47] that, if failures and repairs are exponentially distributed, the probability of finding a two-state unit (states of on outage or in service, see Figure 2.3) on outage at a time T [14], given that it was operating successfully at t=0, is

$$p(down) = \frac{\lambda}{\lambda+\mu} - \frac{\lambda}{\lambda+\mu} e^{-(\lambda+\mu)T} \tag{2.1}$$

Due to the short SR committed period (time T) the repair process can be neglected i.e., $\mu = 0$, then Equation (2.1) reduces to

$$p(down) = 1 - e^{-\lambda T} \tag{2.2}$$

If $\lambda T << 1$, which is generally true for short lead times of up to several hours, (Lead time is the period of time that generation cannot be replaced [14]), then we can rewrite Equation (2.2) as,

$$p(down) = \lambda T \tag{2.3}$$

Equation (2.3) is known as the outage replacement rate (ORR) and represents the probability that a unit fails and is not replaced during the lead time T.

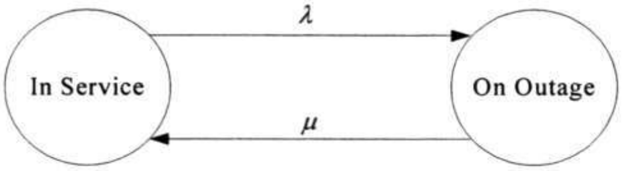

Figure 2.3 The states of a generating unit

Unit Commitment (UC) Risk

Unit commitment risk is the basis of the PJM method, which has been mentioned in Section 2.2.1. The PJM method evaluates 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. The UC risk therefore represents the risk of just supplying or not supplying the demand during the lead time.

Given a system in a state j where N components are in use and the remaining M components are on outage, the probability for this state can be calculated by Equation (2.4).

$$P_j = \prod_{n=1}^{N} p_n(in\ service) \prod_{m=1}^{M} p_m(on\ outage) \tag{2.4}$$

Hence the UC risk (UCR) can be calculated by Equation (2.5)

$$UCR = \sum_{j=1}^{N_s} uP_j \tag{2.5}$$

where

N_s the number of possible system states

$$u = \begin{cases} 1 & \text{when system demands are not satisfied} \\ 0 & \text{when system demands are satisfied} \end{cases}$$

2.4 Deregulation of Power Systems

Under deregulation, governments foster the competition through changing the utility environment and regulations. One of the principle characteristics of a competitive structure is the identification and separation of the various tasks which are normally carried out within the traditional organization so that these tasks can be open to competition whenever practical and profitable. This process is called "unbundling" or "deregulation". It can be described as follows.

Unbundling functions within a corporation

The generation, transmission and distribution are not belonging to one vertically integrated corporation. They are separated into three independent competitive commercial entities, generation companies, transmission companies and distribution companies.

Introducing competition in generation activities

If the original generation is large, its generation can be split into a sufficiently large number of smaller independent competing generating companies or gencos to which new independent producers are added. Competition can be introduced through the creation of power pools, provision for direct bilateral transactions or bidding in the spot market.

Service unbundling

Under deregulated environment the main service that provides generating power some of other system services can be unbundled for separate tariff. They are the generation of real power, real-time load and generation balancing, transmission loss compensation, ancillary services, etc. Out of all these services, the ancillary services are gaining more attention. Ancillary services are defined as those activities on the interconnected grid that are necessary to support the transmission of power while maintaining reliable operation and ensuring the required degree of quality and safety. They would thus include [1]:

- Regulation of frequency and tie-line power flows
- Voltage and reactive power control
- Ensuring system stability
- Maintenance of generation and transmission reserves,
- and many others.

In a vertically integrated utility ancillary services are an integral part of the electricity supply and are not separated. However, with the deregulation of the power industry, generation and transmission becoming separate businesses, the system operator often has no direct control over individual power stations and purchases ancillary services from the ancillary service provider. In such an environment, issues pertaining to pricing mechanisms for such services are extremely important for the functioning of the system. This thesis is mainly concerned with one of the ancillary services, spinning reserve.

Another most important difference resides in the pricing of the electricity energy. In deregulated electricity systems, the price will never be charged as described in the last section but charged separately. Figure 2.4 shows the details of that difference [3].

Then...
the electricity prices included
- generation, transmission and all other costs and were wholly charged to the customer

Now....
the electricity price includes
- price of electrical energy
- price of other services such as frequency regulation and voltage control(Ancillary services)
    - which are priced separately and charged independently
    - but may not be visible though in electricity bills

Figure 2.4 Traditional (then) and deregulated (now) electricity pricing

Figure 2.5 from [3] shows the typical structure of a deregulated electricity system with links of information and money (cash) flow between various players. This is the basic electricity power market structure, and it will vary in different countries under different power systems. Although the energy is still generated by generation and delivered to customers through transmission and distribution the trading rules have changed. The generation, transmission and distribution sectors are separated to generation companies, transmission companies and distribution companies, respectively. The system operator is independent of these three sets of companies. Customers purchase energy either directly from generation companies or through market traders.

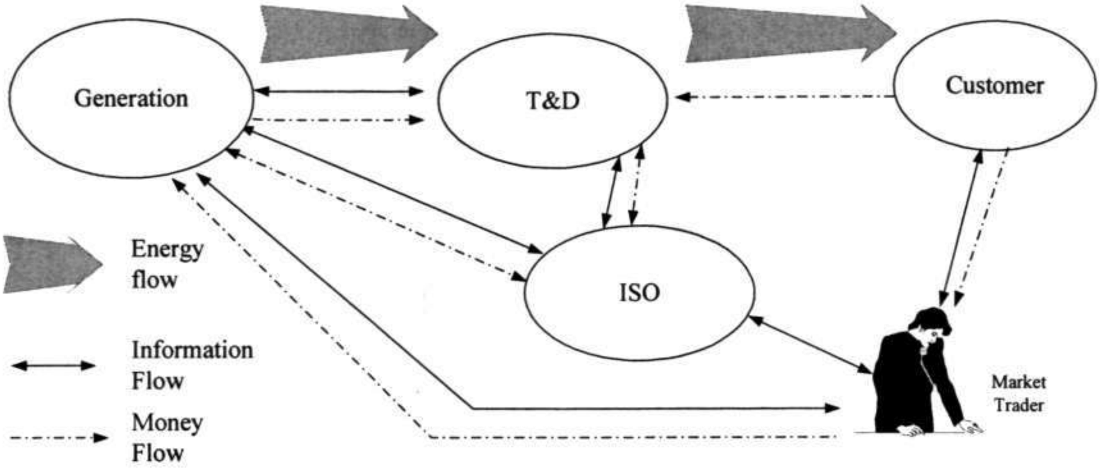

Figure 2.5 Typical structure of a deregulated electricity system

2.5 Market Structures and Trading Rules

As described in Section 2.4, each deregulated electricity market is structured differently and continues to go through different phases of restructuring in different nations. There is not one market structure and a set of trading rules that can represent the situations of all the countries and states. To better understand the features of the power trading processes, this section aims at classifying the categories of market structure or trading protocols according to different aspects. Based on the trading rule the electricity energy market consists of the (a) forward and (b) spot or real-time markets [53]. Based on the trading algorithm the electricity energy market can be divided into single energy and energy-reserve market.

Spot market

The spot market is in charge of accepting the offers from the generation companies and demands from customers, and determining the market price. In this market energy is traded in real time. Such an organization may or may not be operated by the ISO.

Forward market

The forward market may include bilateral contracts, futures, options, day-ahead and hour-ahead markets for energy, and, in some regions, ancillary service markets. In bilateral contracts small customers' aggregation is essential to ensure that they would benefit from the competition [3]. This model permits direct contracts between customers and generators. By establishing non-discriminatory access and pricing rules for transmission and distribution systems, direct sales of power over a utility's transmission and distribution systems are guaranteed. Wholesale suppliers would pay transmission charges to a transmission company to acquire access to the transmission grid and pay similar charges to a distribution company to acquire access to the local distribution grid. In this model, a distribution company may function as an aggregator for a large number of retail customers in supplying a long-term capacity. Also, the generation portion of a former integrated utility may function as a supplier or other independent generating companies, and transmission system would serve as a common carrier to contracted parties that would permit mutual benefits and customers' choices. Any two contracted parties would agree on contract terms such as price, quantity and locations, and generation providers would inform the ISO on how its hourly generators would be dispatched.

Single energy and energy-reserve market

In single energy market the only product in the market is energy, and power reserve that is necessary for maintaining the security of the power system is not paid but is mandatory, such as the electricity market in Australia [53]. In an energy-reserve market, both the requirements of the energy and reserve are considered simultaneously and paid, such as the electricity market in the UK. Another possibility is that energy and reserve are traded in two different markets, such as in the California Power Exchange. Energy is traded in a spot market (power exchange) while reserve is traded as a kind of ancillary service in an ancillary service auction [54].

2.6 Reserve Markets

The practical reserve markets around the world are first introduced in this section. Some discussions about these reserve markets are given after then. Finally the reserve market models are concluded.

2.6.1 Reserve Markets around the World

In this section a review of reserve markets around the world is presented focusing on the spinning reserve operation and settlement in countries where the electricity industries are deregulated.

Spinning reserve is one of the many services in ancillary markets. Ancillary services markets are necessary to ensure that an ISO is able to comply with reliability standards. The details of ancillary services are more complex and can vary considerably from markets to markets. South America was the pioneer in privatization to drive restructuring [1], Chile started its deregulation process in 1978 and Argentina followed with an aggressive process in 1991 [55]. Therefore, the ancillary market was not simultaneously configured until 1998 when it was firstly found by the California ISO (CAISO).

The California ISO also provides ancillary services introduced in Section 2.3.1. However, the other AS such as voltage support and black start are procured on a long-term basis by the ISO, primarily through the Reliability Must Run contracts. The CAISO is responsible for conducting a competitive market of the four "reserve" services, i.e., Regulation, Spinning, Non-spinning, and Replacement Reserves [56]. The spinning reserve is defined by CAISO as *Generation that is already up and running, or "spinning" with additional capacity that is capable of ramping over a specified range within 10 minutes and running for at least two hours.*

The market participants are the Scheduling Coordinators (SC). SCs can either self-provide their pro rata share of the total ISO grid reserve services or have the ISO arrange it for them in a competitive manner. Each SC is responsible for a pro rata share or AS obligation based upon its metered load and exports, consistent with the ISO Tariff [57]. The ISO determines the appropriate amount of required AS using load forecast and Preferred Schedule information, to assure compliance with minimum operating reliability criteria.

In CAISO, ancillary service self-provided schedules and market bids can only be submitted to the ISO through SCs. This forward market auction process takes place after the time when Preferred Schedules and AS bids are submitted to the ISO. The ISO purchases AS during the day-head (DA) forward market, and again each of 24 hour-ahead (HA) forward markets to account for any changes in load and generation schedules. In real time, the ISO dispatches these sources of balancing energy on an economic basis, using economic dispatch. Suppliers of AS are all paid the system-wide market-clearing capacity price for those services. If congestion exists, the requirements for each service are established on a zonal basis, and the procurement is carried out separately in each zone, resulting in different zonal market clearing prices [56].

In Europe all countries have reserves that can act in approximately 15 minutes (although the specific requirements and terminology vary). The procurement of reserves is based on a commercial basis using a variety of procurement mechanisms. These include full rolling market mechanisms (e.g. bids every half-hour or hour), periodic tenders (e.g. daily, monthly, 6 monthly or yearly) and bilateral agreements (negotiated when required) [62]. To meet the bilateral contracts, market players generally dispatch their generators (and possibly their loads), and notify the physical positions of these to the System Operator to allow imbalance to be forecast, and the system secured. First, they have to do so the day ahead, where the physical notification is only indicative (Except in Spain, where this day ahead physical notification is firm and cannot be changed). Then, they can update their notification until a point ahead of real time, "gate closure", which is rolling during the operation day. In Netherlands the gate closure can be rolling every fifteen minutes. In England and Wales it is every half-hour and in Sweden every hour. In France, Germany and Spain the rolling time is at fixed "windows" during the operation day. If an interconnector connects two systems that use different gate closure times, the earlier gate closure is usually used.

In real time if reserves are needed to balance the system, the ISO accepts some bids in the merit order. Accepted bids are paid their bid price, or the marginal price (the bid price of the last bid accepted in a given time interval). The marginal price is paid in the Netherlands, Sweden, Finland, Norway, Spain and Greece. In the other countries, the bid price is paid, such as in England and Wales, Poland, Italy and France. In Austria, Portugal and Ireland the payment is based on the bilateral contracted price.

In the East Pacific area Australia, New Zealand and Singapore have restructured their power systems in the early and mid 1990s. However, the reserve market was not configured at the same time. In Australia although the National Electricity Market (NEM) is based on the half-hourly spot market design [63], the providers of reserve service are not entitled to spot market revenue associated with the reserve services. The NEM Management Company Limited (NEMMCO) has produced a single contract for different types of reserve services and any market revenue arising from the dispatch or activation of reserve service will belong to NEMMCO [64]. The data relating to the reserve adequacy is produced periodically, which can be two years, seven days or to the end of next market day [64]. The reliability standard has been specified in terms of energy not supplied due to a capacity shortage. The criterion is that the expected level of energy not supplied should be no greater than 0.002% of total energy demanded in each NEM region having regard to the uncertainties of generation plant performance and peak load forecast uncertainty. This reserve margin is determined based on this criterion and the statistical methods used to quantify the unserved energy based upon Monte Carlo simulations [66].

In the New Zealand Electricity Market (NZEM) the SR providers offer their reserve into a market that is dispatched co-optimally with the energy market [67]. However, before any ancillary service agent makes a reserve offer, that ancillary service agent must have a valid and enforceable contract with the system operator to provide reserve offers in accordance with the rules. Each day, each ancillary service agent, which has a contract with system operator may submit to the system operator reserve offers for the trading periods of the following trading day. Reserve offers must be submitted so that the system operator receives them by 1300 hours on the day prior to the trading day for which the reserve offer applies. The price in each band of a reserve offer made by an ancillary service agent that is made on behalf of a generator will be expressed in dollars and whole cents per MW excluding GST. There will be no upper limit on the prices that may be specified and the lower limit will be $0.00 /MW [68]. The offers will be cleared according to the least overall cost outcomes as determined by the SPD (Scheduling, Pricing and Dispatch Software Package as currently specified in the NZEM market rules) software formulation [69].

Since 1995 the power system assets of Singapore have been structured to facilitate commercialization and subsequent privatization [70]. Singapore's New Electricity Market consists of a wholesale market and a retail market. The wholesale market actually comprises two markets:

- The real-time market or spot market for energy, regulation, and reserve, and
- The procurement market for other ancillary services.

Reserve is a significant factor in the Singapore power system since some generating units are large relative to the total load. Three levels of reserve are provided for in the system: 8 seconds, 30 seconds and 10 minutes. They are provided as an integrated part of the wholesale market clearing process. The quantity of reserve required by the Power System Operator is determined by the expected size of a contingency. It is calculated dynamically from:

- The size of the largest generating unit
- The stability of the unit under contingencies, and

- The correlation of unit failure with other contingencies.

Generators make offers to supply energy, reserve and regulation for each of their units in each half-hour dispatch period in which they want to operate. Offers can vary for each half-hour. Every half-hour a computer model, The Market Clearing Engine (MCE) is run to determine the dispatch schedule and the associated energy market prices for the upcoming dispatch period. In addition to the dispatch schedule and energy prices, MCE determines which plant is on reserve and regulation duty along with the market price for reserve and regulation. The spot market price for each class of reserve and regulation is cleared along with that of energy. In solving the market for each class of reserve and regulation, the MCE simultaneously finds the lowest cost solution (in terms of the offers made) that trades off among energy, reserve and regulation for the various facilities. The reserve prices are common throughout Singapore but may vary according to the reserve class.

2.6.2 Proposed Reserve market models

Based on the trading rule the reserve markets around the world can be divided into real-time market models and bilateral market models without ISO operation. The real time market model is a centralized market model where power producers provide the bidding curves and operational parameters of all its units to the Independent System Operator (ISO) and the unit commitment and dispatch is determined by the ISO, such as in the UK. It can be a day-ahead market, hour-ahead market or even 30-minute market. An hourly bidding model is used to explain this market model, the time frame of which can be shown in Figure 2.7 [27].

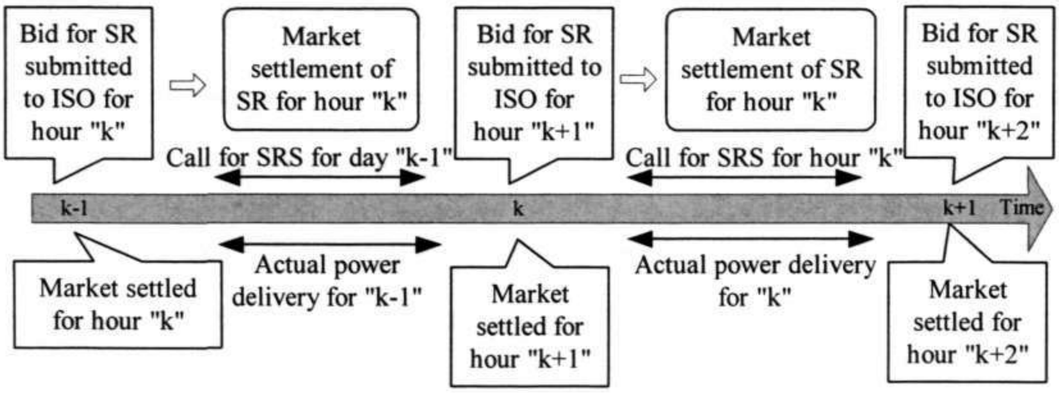

Figure 2.6 Time frame of the functioning of the SR service market

After the energy market settles down, the ISO offers its own auctions for SR, and SR providers submit their bids for hour “k” at hour “k-1”. The cleared SR will be dispatched between hour k to k+1. This is repeated for the next day and so on [27]. The payment for spinning reserve is normally based on the cleared price, for example in Figure 2.6, the generators responding to loading of spinning reserve are paid $ 50 premium above event local marginal price for MW delivered.

The bilateral market is a decentralized market. In a decentralized market, power producers have to make decisions about the unit commitment and dispatch of their generators themselves. They only provide their quantity-price bidding curve, such as in the California Power Exchange, Nordic Pool, etc. Customers make reserve bilateral contracts directly with the server providers. ISO would not operate any more in this market model. In this market there is a price denoted as the spinning reserve market clearing price.

The methods proposed in this thesis have been investigated under the day-ahead or the bilateral market model or both. The difference between these two reserve market models resides in the different reliability selections for different customers. In day-ahead market the reserve is managed by the ISO and customers cannot determine the reliability selection for themselves. However, customers can make their own reserve determination through the bilateral market with the assumption that the whole system reliable operation is not violated. This thesis focuses on the reserve allocation methods.

Based on the trading algorithm the market can be single-reserve or energy-reserve market. Sequential dispatch and simultaneous (joint) dispatch are two current alternatives for dispatching energy and reserve [71]. Simultaneous approach is based on formulating the dispatching problem in the context of energy and ancillary optimization coordination. In a sequential dispatch, the energy market is first cleared followed by the settlement of the reserve market. The optimization of energy and spinning reserve is done separately. This thesis investigates the SR allocation methods under a sequential dispatch market model.

2.7 Summary

In this chapter, the basic concepts of reliability and spinning reserve are presented. The restructuring of power systems is reviewed and the market structure and trading rules that are common to the power markets around the world are stated. As the deregulation is on the one hand seen as potentially leading to reduce reliability, and on the other hand often mentioned as one of the reasons for the increased interest in reliability, therefore the reliability issues under the new deregulated environment are more complex than under traditional regulated systems. The review of the practical structuring of reserve markets is summarized according to different ways of procurements. According to the definition of

SR, the reserve market can trade 10-minute SR, 15-minute SR or 30-minute SR and the SR can be called contingency reserve or primary reserve, too. SR can be provided by interruptible load or generating units. Based on the ways of SR trading, the SR can be purchased through bilateral contracts or in a real-time market. Based on the ways to settle the reserve market, there are two approaches to dispatch SR. One method is to clear reserve market and energy market separately and another is to simultaneously optimize the energy and SR dispatching. In order to determine the SR capacity, some research literature is reviewed in this chapter. Two categories of methods are proposed to determine the SR – deterministic techniques and probabilistic techniques. Generally most practical reserve markets use deterministic methods to determine the required SR capacity, such as the size of the largest generating unit or a percentage of the peak load.

Chapter 3 SR Assessment in Deregulated Generating Systems with Bilateral Contract Market

3.1 Introduction

Marketing gives customers a choice among products [71]. In a deregulated power system customers can select not only the energy and transmission providers but also their own reliability levels. This implies that the reliability levels at different bulk load points (BLPs) may be different. In vertically integrated power systems spinning reserve was centrally managed to meet the disturbance condition requirements of certain system performance standards, such as the NERC (North American Electric Reliability Council) Control Performance Standards [73]. The reliabilities of all customers therefore remained the same.

In a deregulated power system customers can purchase spinning reserve directly from generation providers in a reserve market. The forming of reserve market results from the unbundling of ancillary services from generation and transmission in a deregulated power market. A reserve market can operate concurrently with the energy market for power, while the reserve price can be different from the energy price; Gencos may contract with each other to provide reserve for each other's transactions [74], which implies that generators will make reserve agreements with each other to supply power to customers with the reserve service. Consequently new techniques and practical tools have to be developed to facilitate customers to choose the appropriate reliability level. Reference [44] describes major changes in the fundamental principles underlying reliable electric energy service as the power systems restructure. It also discusses the need to develop a powerful technique for achieving a desired level of reliability. Ref. [44] used the developed indices such as Loss of Load Probability (LOLP) to compare the results of operators' actions to their effect on the reliability as seen by the customers. Reference [45] proposes one probabilistic method combined with the deterministic consideration based on a well-being model, which provides some reliability indices to determine the required capacity of spinning reserve in traditional power systems.

This chapter investigates the impact of spinning reserve on customer load point reliability in generating systems by using a probabilistic method. The different reliability requirements for customers can be achieved by purchasing different capacities of reserve. Similarly, the capacity of spinning reserve in the agreements can be determined based on the reliability level required by customers. Some load point reliability indices are introduced in this chapter for customers to recognize their reliability levels. The well-being analysis technique used in vertically integrated power systems is extended to evaluate the customer load point reliability. A procedure for making transactions by customers using reliability indices is then presented and applied to a reliability test system.

3.2 Spinning Reserve Management in Conventional Generating Systems

3.2.1 Concept of traditional Well-being analysis technique

The well-being analysis method based on a well-being model combines deterministic considerations with probabilistic indices to monitor the system well-being, which has been developed in [45,23]. In a vertically integrated power system the system reliability is a major concern of the system operators. Spinning reserve is centrally determined by system operators to maintain the entire system reliability at a desired level. These reliability criteria are either deterministic or probabilistic. The well-being analysis technique recognizes that the entire system operating states created by incorporating the system deterministic criteria can be categorized as being healthy, marginal or at risk. A system operates in the healthy state when it has enough margins to withstand the deterministic criterion, i.e. any single unit outage. In the marginal state the system no longer has sufficient margin that it can withstand outages in excess of the specified deterministic criterion. In the risk state the system load is greater than or equal to the operating capacity. The healthy and marginal states both reside in the comfort domain. This concept is illustrated in Figure 3.1.

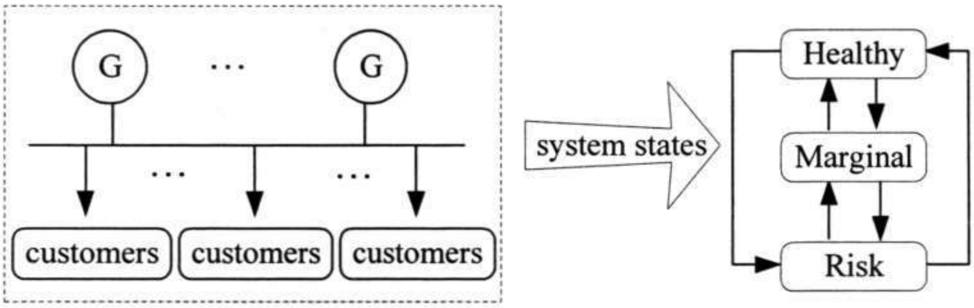

Figure 3.1 Well-being model for a conventional system

3.2.2 Calculation of the Well-being Risk

In the traditional generation system all the generators in one utility serve all customers in the system. The total system states are categorized into three groups of healthy, marginal and risk states based on deterministic criteria, which can be expressed by Equation (3.1). It means that in the well-being model a system sate can only be either in healthy, marginal or risk state.

$$P_h + P_m + P_r = 1 \tag{3.1}$$

where, P_h, P_m and P_r are the probabilities of the system being in the healthy, marginal and risk states respectively. The probability of each system state can be calculated using Equation (2.4) in Chapter 2. These states are categorized by a deterministic criterion, e.g. in a healthy state any unit outage is still within the reserve capacity margin. Which method should be used to determine the criterion depends on the required level of reliability. Once the probabilities of the system being in the healthy, marginal and risk states are calculated, the generating reserve capacity can be determined by the system operators to satisfy the single criterion or multiple criteria.

Single criterion

When the single criterion is used it means that the capacity of spinning reserve must be scheduled in such a way that the probability of the system being in the risk state cannot be greater than a pre-specified system risk that is determined by the system operators.

$$P_r \leq SP_r \tag{3.2}$$

where SP_r is the system pre-specified risk.

Multiple criteria

The operating criteria might be to operate the system such that the probabilities of the healthy state and the system risk state are both at acceptable levels. In this case, the capacity of spinning reserve should first be determined to meet the acceptable risk state probability followed by satisfying healthy state probability that exceeds or equals the pre-specified value. The required number of units therefore depends on the desired healthy state probability and the specified risk

$$P_h \geq SP_h \;\&\; P_r \leq SP_r \tag{3.3}$$

where SP_h is the system pre-specified healthy state probability.

In a vertically integrated power system, the required reliability level is determined by the system operator with the premise that customers connected to different load points share the same service reliability levels.

3.3 Well-being Model for a Bilateral Market

The well-being analysis technique for SR management of conventional systems alleviates the difficulty in interpreting the risk index and provides more applicable information for the system operator. However, the technique cannot be directly used in a bilateral market due to the customer's freedom to choose the reliability level. Some industry plants require more reliable electric power thus providing for any electricity breakdown that will cause huge profit shortage, whereas other customers would like to pay less money for lower reliability electricity service.

The bilateral power market provides customers more choices in selecting power producers, reserve providers and transmission providers. A system operator will provide a range of options for customers instead of a predefined fixed reliability criterion for operation. The bulk load point reliability is therefore more important for an individual customer. In order to provide customers more information on their reliability levels we extend the well-being analysis technique to the load point reliability analysis in the bilateral market.

System states are categorized as Healthy, Marginal and Risk states for each load point. New load point indices developed are the Probability of Healthy state for Bulk Load Point (PHBLP), the Probability of Marginal state for Bulk Load Point (PMBLP) and Probability of Risk state for Bulk Load Point (PRBLP). These indices are determined by using the state probability and load capacity. The well-being model for a bilateral power market is shown in Figure 3.2.

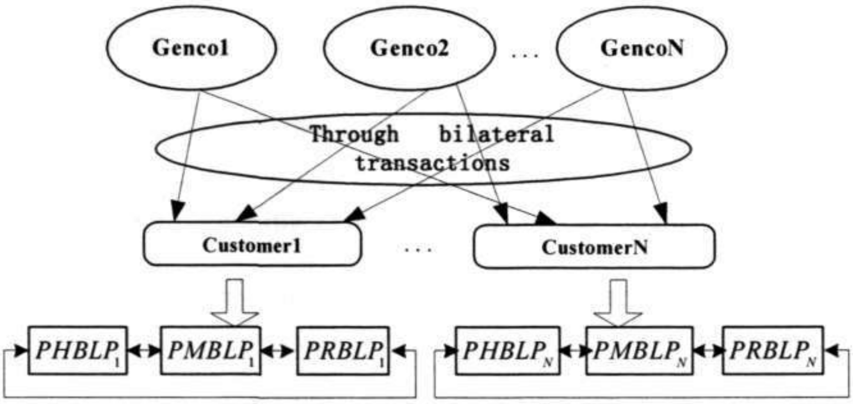

Figure 3.2 Well-being model for a bilateral power market

It can be seen from Figure 3.2 that customers can directly choose the energy and reserve providers through bilateral transactions. Their operating states can be determined by them by predefining the values of PHBLP, PMBLP and PRBLP. Different customers will obtain different values of these reliability indices subject to the spinning reserve capacity they purchased in the contracts.

3.4 Risk-based Reserve Management

In a bilateral market customers present their reliability requirements to the gencos. The customers can determine the SR capacity they require based on the well-being risk or considering both the risk and the SR cost. The risk-based method is illustrated in this chapter, and the risk/cost-based method is illustrated in the next chapter.

Gencos make Unit Commitment (UC) and reserve schedules based on the reliability requirements from customers. The data of all gencos that provide SR service are firstly bid in the bilateral market. Based on these data the reserve required by a customer can be determined by the customer himself using the following procedure:

1. Customers choose their potential energy providers.

2. Customers present their reliability levels required using the multiple criteria PHBLP and PRBLP, or the single criterion PRBLP.

3. The providers determine the reserve required based on the desired criteria.

4. The providers arrange spinning reserve based on the result. A genco can purchase spinning reserve through reserve agreements with other generation providers.

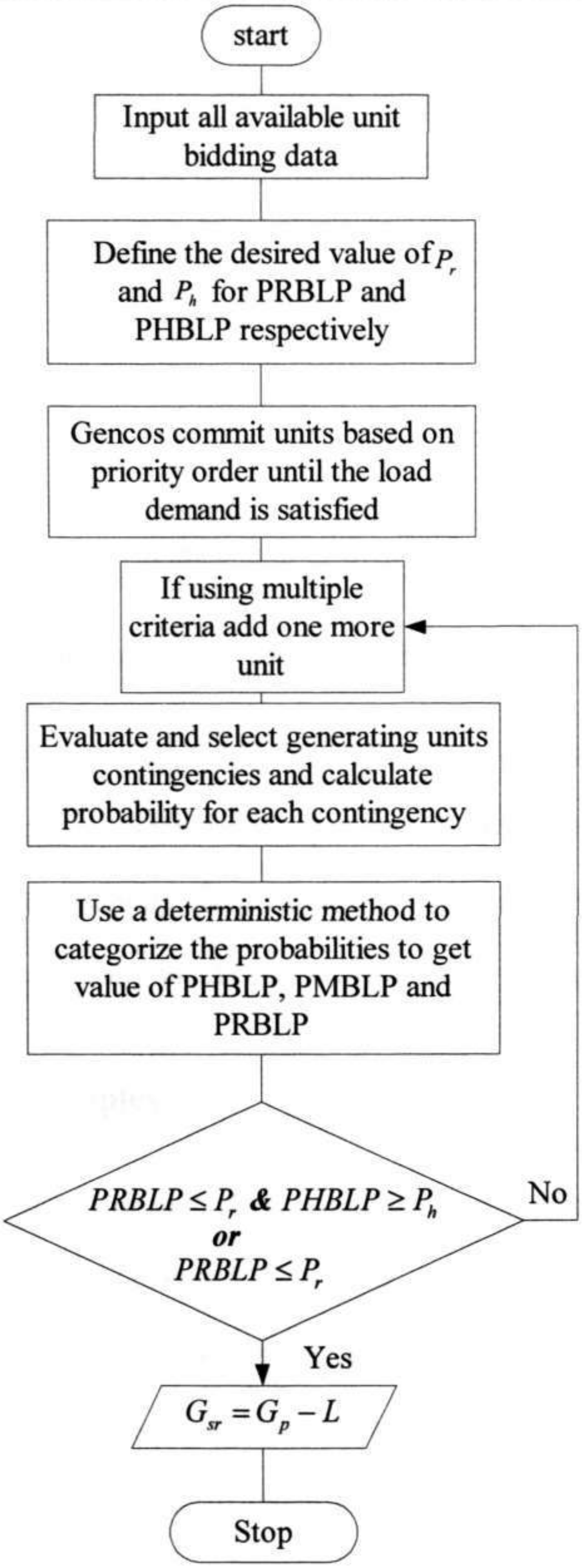

Figure 3.3 Flowchart for determining reserve capacity

The detailed procedure for determining the required spinning reserve is shown in Figure 3.3, in which G_{sr} is the capacity of required spinning reserve, G_p is the total capacity of the generating units committed to the system and L is the customer's load demand. For each generating unit the G_p can be:

$$G_{g\min} \le G_p \le G_{g\max} \tag{3.4}$$

where

G_{gmin} The minimum generating output of Genco g, and

$G_{g\max}$ The maximum generating output of Genco g.

This procedure renders customers to have the full right to choose the energy and reserve providers. After making transactions the generation providers have an obligation to satisfy the customers' reliability requirements. If the transactions are not completely fulfilled, any associated penalty should also be written into the transactions.

3.5 Illustrative Examples

In the first part of this section both the traditional well-being analysis method for vertically integrated power systems [24] and the developed method in this thesis for bilateral power market are applied to the Roy Billinton Test System (RBTS) [75, 28]. A comparison of the two methods is done to study the difference between these two methods under different operating environments. The generating units in the RBTS have also been grouped into two gencos to model the bilateral market environment. In the second part of this section only the newly developed method, an optimization method of

SR allocation based on well-being analysis, is applied to the bilateral market pertaining to the IEEE-Reliability Test System (RTS) [29].

3.5.1 Application to the RBTS

The single-line diagram of the RBTS is shown in Figure 3.4. The RBTS is an educational test system developed at the University of Saskatchewan. The basic objective in designing the RBTS was to make it sufficiently small to permit a large number of reliability studies with reasonable solution time but sufficiently detailed to reflect the actual complexities involved in practical reliability analyses. The detailed generating unit data are shown in Appendix A. Here we also assume that customers connected at the same load point have the same load type.

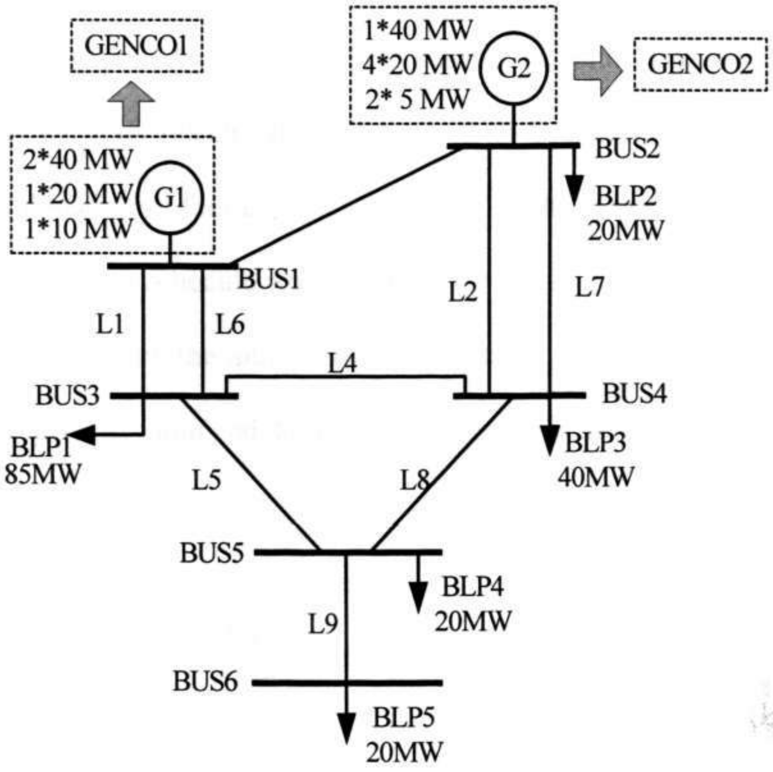

Figure 3.4 Single-line diagram of the RBTS

Case 1 RBTS as a vertically integrated power system

The generating units connected to buses 1 and 2 are combined as one generation to serve the entire system load. The well-being model for this system is shown in Figure 3.5. The spinning reserve capacity allocation among units in this case will be determined by both the single criterion and multiple criteria. The pre-specified system risk is assumed to be 0.001 and the pre-specified probability for healthy state is assumed to be 0.9. The lead time used for calculating the outage replacement rate (ORR) is assumed to be 10 minutes.

Table 3.1 shows the required number of committed units for four load levels and the corresponding probabilities of the different operating states when a pre-specified risk of 0.001 is selected as the unit commitment single criterion. Because the unit is selected according to the priority loading number if the number of committed units is 8, the first 8 units in the priority list are selected to provide generation capacity. It can be seen that in load level one and load level four the probabilities of health states are zero, which implies that this unit commitment schedule would not satisfy the system reliability requirement if the operating criterion were the multiple-criterion. In such regulated systems the system operators would give a command to generators to commit other units to satisfy this operating criterion.

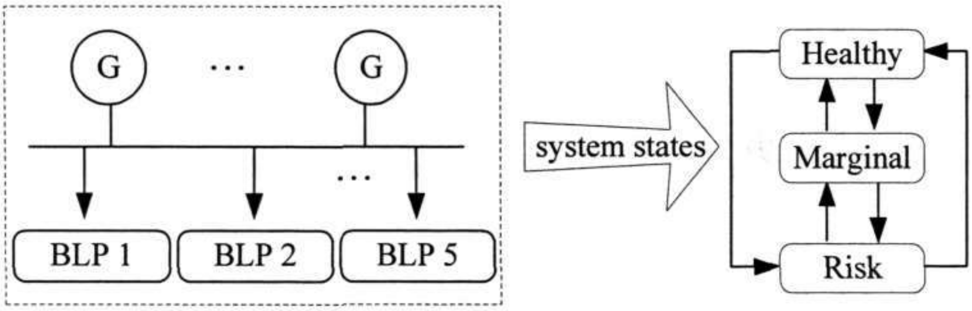

Figure 3.5 Well-being model of the vertically integrated RBTS

Table 3.1 System well-being indices and UC using single criterion

Load level (MW)	Number of Committed Units	Generating Capacity (MW)	Health	Margin	Risk
185(100%)	8	210	0.00000000	0.99971461	0.00028539
148(80%)	7	190	0.99948261	0.00051730	0.00000009
111(60%)	7	155	0.99955868	0.00044127	0.00000005
74(40%)	4	100	0.00000000	0.99982877	0.00017123

From Table 3.2 it can be seen that the reliability level of the entire system is highly improved for each load level due to the increase in the spinning reserve capacity. However, the price of electricity is also increased. For those who may not need such a high reliability level and also would not be willing to pay for such a high cost, they will have no other choice because the system reliability is determined and maintained by the system operators.

Case2: RBTS as a bilateral market without reserve agreement

In this case the purchasing of spinning reserve will be fulfilled through bilateral contracts under the deregulated environment. The generators connected to two buses are separated into two independent Gencos. Each load bus, also named bulk load point, can be seen as one customer and BLP1 selects Genco1 as its electricity provider while other BLPs select Genco2. It means that customers in BLP1 can be seen as customer group 1 and other customers in other BLPs can be seen as customer group 2. This concept is illustrated in Figure 3.6. The lead time used for calculating the ORR is assumed to be 10 minutes.

Table 3.2 System well-being indices and UC using multiple criteria

Load level (MW)	Number of Committed Units	Generating Capacity (MW)	Health	Margin	Risk
185	9	225	0.99945599	0.00054391	0.00000010
148	7	190	0.99948261	0.00051730	0.00000009
111	7	155	0.99955868	0.00044127	0.00000005
74	5	120	0.99973747	0.00026251	0.00000002

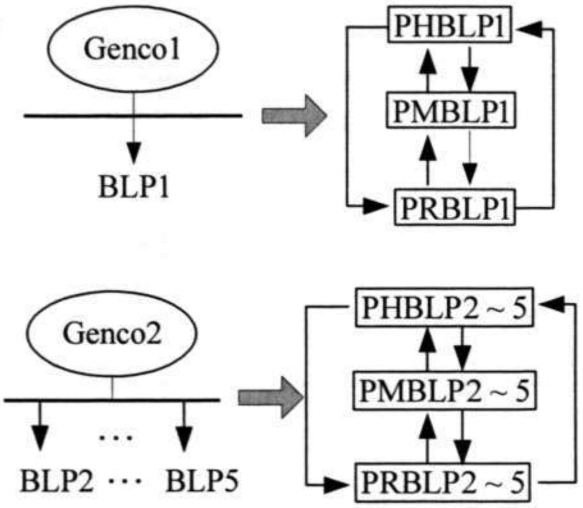

Figure 3.6 Well-being model of the deregulated RBTS

Assuming the load to be fixed at 85MW at BLP1 and the total generation to be 110MW at Genco 1, the PHBLP, PMBLP and PRBLP of BLP1 under different spinning reserve capacity and generation are shown in Table 3.3.

Table 3.3 BLP1 well-being indices and UC at Genco 1

Generation (MW)	Spinning reserve (MW)	PHBLP1	PMBLP1	PRBLP1
110	25	0	0.99977170	0.00022830
100	15	0	0.99973366	0.00026634
90	5	0	0.99967659	0.00032341

Table 3.4 shows the PHBLP, PMBLP and PRBLP of BLP 2-5 under different spinning reserve capacity and generation schedules. The load was assumed to be 100MW at the other four load points and the total generation was assumed to be 130MW. Tables 3.3 and 3.4 show that the probabilities for the risk state increase significantly with the reduction of reserve capacity. This implies that high reliability can be obtained by purchasing more spinning reserve.

Table 3.4 BLP 2-5 well-being indices and UC at Genco 2

Generation (MW)	Spinning reserve (MW)	PHBLP2~5	PMBLP2~5	PRBLP2~5
130	30	0	0.99994291	0.00005709
125	25	0	0.99994290	0.00005710
120	20	0	0.99994291	0.00005709
110	10	0	0.99980595	0.00019405
100	0	0	0.99980595	0.00019405

If the cost of unit commitment is not considered it can be seen from Tables 3.3 and 3.4 that customers can determine the spinning reserve with regards to the reliability level they require. Figure 3.7 shows the PRBLP of BLP 2-5 under different reserve capacities. The bulk load point reliability is more likely to be in the risk state when the reserve is not enough.

Customers at different bulk load points can determine different pre-specified risks. If the customers merely plan to use a pre-specified risk, e.g. 0.001, to make the unit commitment, then each genco has enough generating capacity to meet this requirement. However, if some customers, e.g. some important industrial customers, require higher reliability level such that they want a pre-specified probability of the system being in the healthy state e.g. 0.9, as the criterion to make unit commitment, it can be seen from Tables 3.3 and 3.4 that none of the gencos can satisfy this requirement.

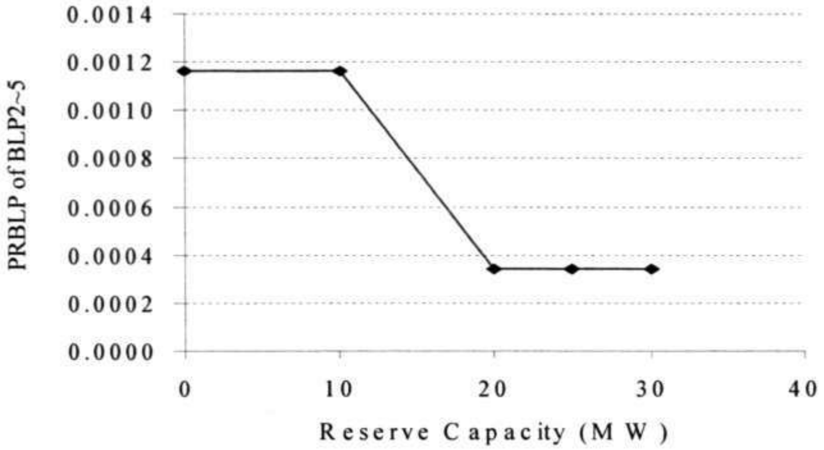

Figure 3.7 Effect of reserve capacity on the PRBLP of BLP2-5

This implies that deregulation may reduce the reliability level of each customer if the genco which provides it electrical power, does not have enough generating capacity. It is necessary for each genco to make a spinning reserve agreement or contract with other gencos.

Case 3: RBTS as bilateral market with reserve agreement

In this case the SR purchasing among gencos can be fulfilled through reserve agreements in a bilateral market. This agreement is firm that it does not consider flexible curtailments to reduce the loss from transmission congestions. Customers can choose to purchase SR from gencos that have SR agreement or not depending on whether the gencos can provide enough SR to satisfy their requirements. This concept can be explained using Figure 3.8. Assuming that Genco1 purchases 20MW from Genco2 and that Genco2 purchases 10MW from Genco1, then the probabilities of each bulk load point state are shown in Table 3.5 after the purchases.

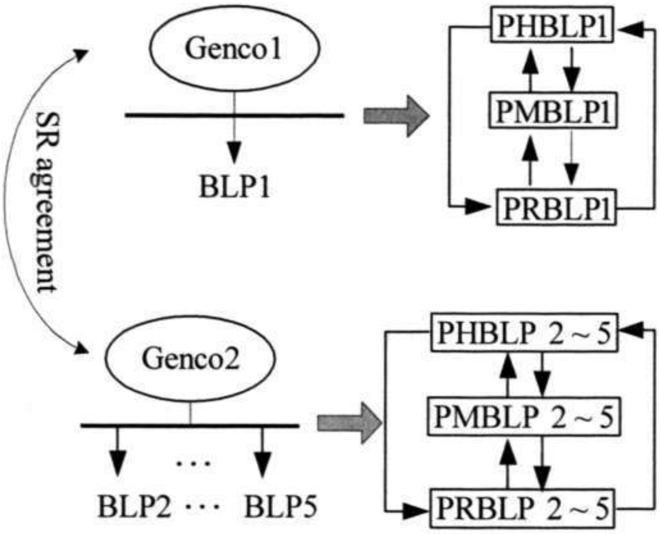

Figure 3.8 Well-being model of the deregulated RBTS with SR agreement

It can be seen from Table 3.5 that after the purchase of spinning reserve the reliability of each bulk load point is highly enhanced. However, in actual practice the high reliability level will increase the cost of spinning reserve. It is therefore necessary for the customers to find equilibrium between the reliability and the cost of spinning reserve. This issue is rather complex and needs extensive research.

Table 3.5 BLP well-being indices with spinning reserve agreements

Number of BLP	Purchased Capacity(MW)	PHBLP	PMBLP	PRBLP
1	0	0	0.99977170	0.00022830
	20	0.99959291	0.00040704	0.00000005
2~5	0	0	0.99994291	0.00005709
	10	0.99958911	0.00041087	0.00000002

3.5.2 Application to the IEEE-RTS

In this study we illustrate the evaluation of the load point well-being analysis technique to determine the capacity of spinning reserve in the deregulated market pertaining to the RTS. The single-line diagram of the 24-bus IEEE-RTS is shown in Figure 3.9. This 24-bus system was established by an IEEE Task Force in 1979. It is a relatively large power system in which sufficient complexity and detail have been included to make the test system representative of an actual utility system. This system has 11 generator buses, 13 load buses, 33 transmission-lines and 5 transformers. The total number of generating units is 32, ranging from 12 MW to 400 MW. The total system generation is 3405 MW and the annual peak load is 2850 MW. The generation data and the system priority loading order for the IEEE-RTS are given in Table B.3 of Appendix B. The detailed branch and bus data are shown in Appendix B.

The system is analyzed as a bilateral power market. By using the reliability equivalent technique [76] the generation system is restructured into three gencos. Genco1 owns the generation providers at buses 1, 2 and 7, which consists of 11 generating units. Six generating units connected to buses 13 and 23 belong to Genco2. A total of 15 generating units connected to Buses 15, 16, 18, 21 and 22, constitute Genco3. The 10 load points in the RTS can be seen as one independent customer each. Load points 7, 13 and 18 were selected as the study cases. The deterministic criterion is to withdraw 10% and 15% of the load. The predefined probability for healthy state (P_h) was assumed to be 0.9. The lead time assumed was 10 minutes. The computing time of the following applications was within seconds.

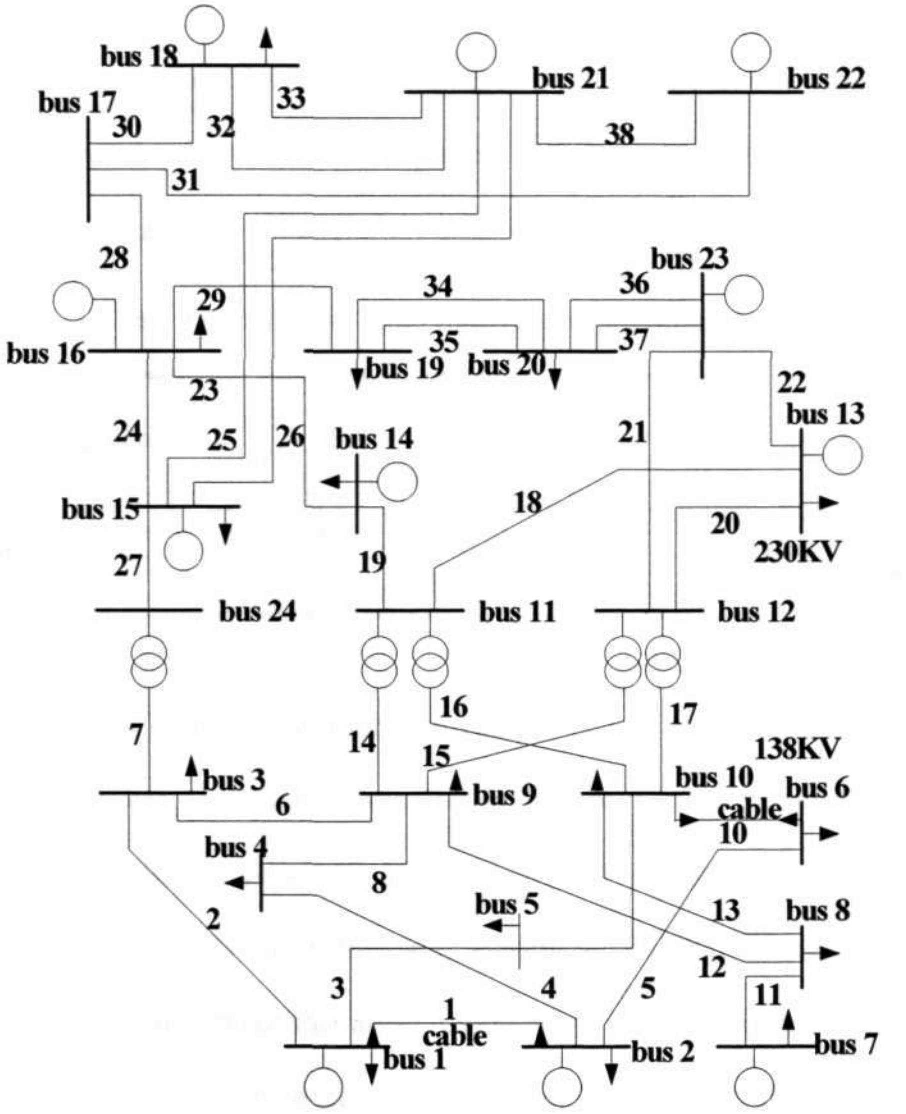

Figure 3.9 Single-line diagram of the IEEE-RTS

Load Point Indices without Spinning Reserve

In this case study the customers connected to these load points first choose the energy providers to satisfy their load demands. It is assumed that customers at BLP 1, 2, 5, 7 and 8 choose Genco1 as their load demand provider. Genco2 is assumed to provide energy supply to meet the load demand of customers at BLP 3, 4, 6, 9, 10, and 13, whereas Genco3 caters to BLP 14, 15, 16, 18, 19, and 20. The well-being reliability indices for each load point are shown in Table 3.6.

From Table 3.6 it can be seen that due to lack of reserve the PHBLP cannot satisfy the desired reliability and the risk is very high at each BLP. In order to maintain the reliability level at a desired level, customers connected to the BLPs should make SR bilateral contracts with generation providers.

Table 3.6 Bulk load point indices without SR agreement

BLP	Gencos	Load (MW)	Generation For load (MW)	Unit numbers	PHBLP	PMBLP	PRBLP
1,2,5,7,8	1	572	604	7	0.0000000	0.9954679	0.0045321
3,4,6,9,10,13	2	1025	1096	5	0.0000000	0.9949411	0.0050589
14-20	3	1253	1255	9	0.0000000	0.9941250	0.0030148

Load Point Indices with Bilateral SR Contracts

Customers can choose not only the same gencos that provide electric power for their load demands but also other SR providers. The method used for SR allocation is discussed in Section 3.4. Table 3.7 shows the values of load point reliability indices after the bulk load points choose the same gencos that also provide power for their load demands. It can be seen from Table 3.7 that each genco can also service as a SR provider. The deterministic criterion for healthy state is to withdraw 15% of the peak load. The state of BLP can be seen as healthy when the reserve margin is not less than 15% of the peak load.

Table 3.7 SR allocations

BLP	SR and energy Providers	Unit Numbers	Reserve Margin (MW)	15% of Load (MW)	PHBLP	PMBLP	PRBLP
1,2,5,7,8	Genco 1	10	92	86	0.9981336	0.0014494	0.000417
3,4,6,9,10,13	Genco 2	6	226	154	0.998982	0.0008728	0.0001452
14-20	Genco 3	13	193	188	0.998732	0.0009647	0.0003032

Table 3.8 Different SR allocations for same SR requirement

BLP	SR and Load Providers	Reserve Margin (MW)	10% of Load (MW)	PHBLP	PMBLP	PRBLP
1,2,5,7,8	Genco 3	128	57.2	0.9990871	0.0000038	0.0009091
1,2,5,7,8	Genco 2	132	57.2	0.9958180	0	0.0041820
1,2,5,7,8	Genco 1	72	57.2	0.9910485	0.0044194	0.0045321

Moreover, customers can purchase energy and SR from different gencos located at different places within a power grid. Table 3.8 shows the values of healthy indices when customers at BLP 1, 2, 5, 7 and 8 choose Genco 1, Genco 2 and Genco 3 as their energy and SR providers. The deterministic criterion for healthy state is to withdraw 10% of the peak load.

Figure 3.10 shows the PRBLP values of BLP 1,2,5,7,8 and different SR levels for different allocations, in which the deterministic criterion is to withdraw 10% of the peak load. It can be seen from Figure 3.10 that high reserve capacity may not result in low risk due to the different SR allocations, for example the second allocation. It is important to consider not only the SR capacity but also the SR allocation when determining the SR schedule.

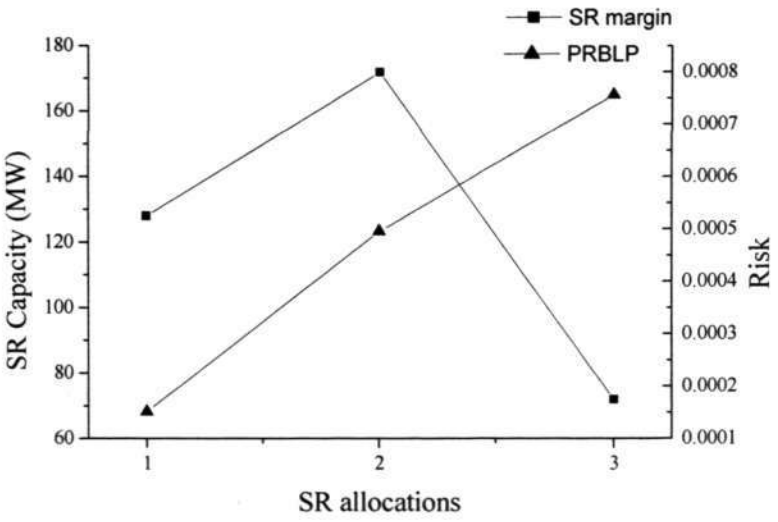

Figure 3.10 SR margin via risk for BLP 1,2,5,7,8

However, it is not necessary for a customer to choose a genco as both generation and reserve providers. A customer can choose one genco as SR provider and another genco as generation provider. In the previous case after Genco3 provides electric power to satisfy load demands of BLP 14,15,16,18,19,20 there are still 6 units left. These units can provide SR to BLP 1, 2, 5, 7, 8 whose load demands are satisfied by Genco1. This case is shown in Figure 3.11 and the corresponding load point indices are shown in Table 3.9. It can be seen that although the SR capacity is the same, the reliabilities for customers are different due to the different allocation of SR on different parts of the network. If the cost for SR is not considered, then customers may choose the SR allocation with the minimum risk. However, it is important to strike a balance between the cost and the risk when purchasing SR. This is investigated in detail in the next chapter.

Table 3.9 Different SR allocations with different energy providers

BLP	Energy Provider	SR Provider	Reserve Margin (MW)	15% of Load (MW)	PHBLP	PMBLP	PRBLP
1,2,5,7,8	genco 1	genco3	101	86	0.9989496	0.0010436	0.0000068
14-20	genco 3	genco 3	62	154	0.0000000	0.9971391	0.0028609

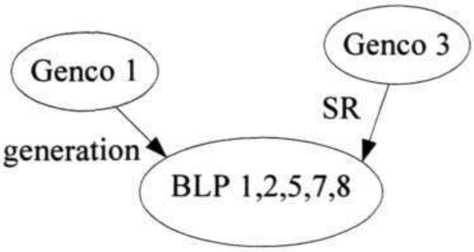

Figure 3.11 SR provided for BLP 1, 2, 5, 7 and 8

It can be seen from Table 3.9 that due to the existence of SR bilateral contracts the SR allocation is not unified within one system. However, the reliability levels of BLP 14, 15, 16, 18, 19 and 20 are affected, as they are not high enough to satisfy the predefined PHBLP of 0.9. In such a case customers at these load points should purchase more SR from other gencos. In the RTS system all the customers can also share SR within the entire system. This can be seen from Figure 3.12. The corresponding load point indices are shown in Table 3.10.

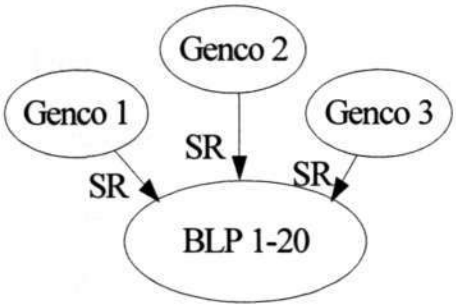

Figure 3.12 SR sharing within the three gencos

Table 3.10 SR allocations for all BLP

BLPs	Load (MW)	Power Providing (MW)	Reserve margin (MW)	15% of Load (MW)	PHBLP	PMBLP	PRBLP
1-20	2850	3285	435	427.5	0.9753522	0.0246117	0.0000361

From Tables 3.7, 3.8 and 3.9 we can see that different allocations of SR due to different bilateral contracts have much impact on the reliability level of not only the customers making these contracts but also on other load points within the system.

3.6 Summary

In this chapter the bulk load point indices have been introduced for deregulated generating power systems to replace the system indices in vertically integrated power systems. Spinning reserve capacity is represented by the load point risk indices. It is pointed out that the concept of unified system reliability should be replaced by individual load point reliability in the new environment. In a deregulated power system, spinning reserve is one part of the Ancillary Services (AS) and is provided by one or more generating companies. Customers can achieve the desired reliability level by making different reserve bilateral agreements. As a result, customers in a bilateral market tend to choose generation producers located in any part of the system by making bilateral contracts with SR providers. From the customers perspective the system reliability is not uniform any more. Different SR allocations will lead to different reliability levels at different customer load point. This is the main contribution of the work described in this chapter to quantify the impact due to various SR bilateral contracts on the bulk load points' reliabilities. This chapter introduces a technique that can be used to assist customers to make the right reserve purchase decisions. Incorporating and identifying this effect in a consideration of the SR cost will facilitate customers in making judicious decisions with regards to bilateral contracts. This is investigated further in the following chapter.

Chapter 4 Risk/Cost Based SR Allocations in Deregulated Generating Systems

4.1 Introduction

The cost is an important factor in the determination of SR allocations. In a deregulated power system customers have more choices not only in terms of the price of the commodity but also in terms of its reliability. A trade-off between reliability and cost is more important than a single cost or reliability. This trade-off could lead to a lower, equal or higher reliability than in regulated power systems. As a result the customers in a deregulated market tend to choose generation producers located in any part of the power system in regards to their optimization of the cost and reliability. It is necessary to investigate the SR determination issues in deregulated power systems based on both reliability risk and cost.

Generally in SR market the determination of the SR market clearing price and dispatch schedule are based on a proposed model with a certain optimization objective, such as to maximize the market benefit [71]. In [71] a hybrid dispatch method, which combines the sequential dispatch method with the joint dispatch method, is proposed to solve the energy and ancillary dispatch problem for ISO New England (ISO-NE). The focus of Ref. [71] is on a dispatch method for both energy and ancillary (including the SR) services. However, the reliability constraints are not generally considered during the optimization, or as with the method described in the previous chapter only reliability constraints are considered while the related costs are not considered. The reliability constraints include planning network capacity requirement and operating capacity requirement so that power systems provide a reliable and economic supply of electric energy to customers. In this chapter a risk/cost-based method is proposed to determine SR in deregulated generating systems. The main focus is on the determination of SR allocation considering the reliability constraints.

In this thesis the cost for reliability includes two aspects, the cost for purchasing the SR and the reliability worth obtained by purchasing SR. During the assessment of reliability worth the cost due to outage is a kind of security cost. The optimized result by comparing these two values will finally determine the required SR capacity and allocations. In [77-78] the ability to assess the costs associated with providing reliable service has been reasonably well established and accepted. In contrast it is rather complicated to assess the worth of providing reliable service. Reference [14] presents the various methodologies used for this issue under the system planning umbrella. The methods are introduced in detail in the next section of this chapter. The cost/risk-based method and the functions are then proposed. The proposed method is illustrated by application to the IEEE-RTS and conclusions are drawn from the studies.

4.2 Reliability Cost/Worth Evaluation

In the traditional system there are basically two approaches that are used in the evaluation of reliability worth [14,79,80], the implicit and explicit methods. In the implicit method the system reliability is determined by a deterministic criterion or by fixed quantitative indices selected on the basis of experience and judgment. This approach implies that an implicit socioeconomic cost is associated with the selection of the reliability criterion. The second approach, known as the explicit cost technique, incorporates reliability in the costing process by comparing the overall costs, including the societal costs of unreliability. This method uses subjective and objective measures of customer monetary losses arising from electric energy supply curtailments.

Basically these two approaches can also be applied to the reliability worth evaluation in a short term SR market. The deregulated markets enable customers to choose the SR suppliers and the reliability levels, which can be indicated in a bilateral contract. The implicit method is consistent with this kind of trading. It compares the costs for SR purchasing under the assumption that each alternative provides the same reliability level based on whatever deterministic or probabilistic technique is used. The final result should therefore reflect the optimum trade-off between the cost of achieving the required reliability and the benefits derived by society.

The explicit cost approach to reliability worth assessment can be used to provide valuable information in two major ways. Firstly, it can be used to quantify the fundamental electric utility requirement of what is a reasonable level of reliability at all three hierarchical levels. Secondly, it can also be used in a more direct and practical manner in a wide range of utility decision-making processes such as the determination of SR. The basic concepts associated with the explicit cost approach to reliability worth assessment are illustrated in Figure 4.1. The utility cost (cost for SR in our context) increases as the reliability level increases. The socioeconomic losses in the form of customer costs decrease as the reliability increases. The total societal cost is the sum of utility and customer costs. The optimum level of reliability therefore occurs at the point of minimum total cost. This can be used to determine the optimal SR allocation in a deregulated generating system.

In this chapter the second method is incorporated with the risk-based methods proposed in the previous chapter to determine the SR allocations in a deregulated generating market. In the studies the transmission system is assumed to be perfectly reliable, hence load flow is not considered. It is easier to predefine a reliability criterion in a generating system than in a composite system. The implicit method can therefore be used in deregulated generating systems. After the transmission lines are considered only the explicit method is used to determine the SR, which is illustrated in detail in Chapter 6.

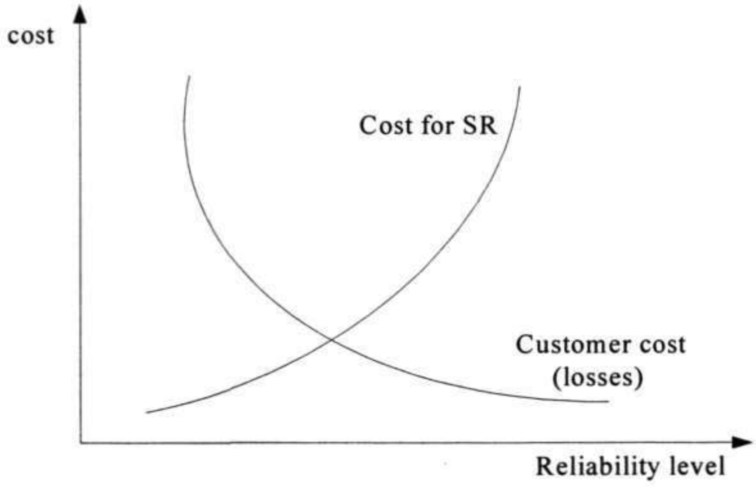

Figure 4.1 Cost curves in the explicit approach

4.3 Cost Functions for Purchasing SR

Generally the SR suppliers bid in a deregulated SR market and offer their bidding curves for the SR. Hence the cost for SR purchasing of each customer from gencos can be calculated using Equation 4.1.

$$C_{sr} = \sum_{g=1}^{N_g} \rho_g g_g \tag{4.1}$$

C_{sr}	The cost of purchasing SR for each customer
g_g	SR generation purchased from Genco g by customer
ρ_g	The bidding price of Genco g, and
N_g	The number of gencos that provide the SR.

Figure 4.2 shows the typical SR bidding curve in a deregulated power market. Each genco offers different price/quantity blocks. The blocks are arranged in an ascending order of price. In practice the offer price of each genco is varied with its different bidding time and bidding capacity. In this thesis it is assumed that the offer price of each genco is constant, in which case the price will not vary with the bidding time and capacity.

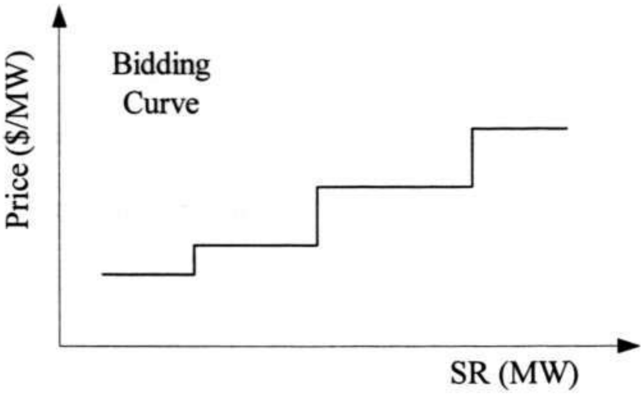

Figure 4.2 Typical bidding curve

4.4 Customer Loss of Load Evaluation

Due to certain interruption customers may have some loss when the load cannot be satisfied. The methods for customer interruption cost evaluation are first introduced in this section. However, the cost of reliability assessment is the customer loss of load cost due to certain interruptions. It can be defined as the loss of load during the period of electricity getting interrupted. Hence the calculation for loss of load based on the methods for customer interruption cost evaluation is given at the end of this section.

4.4.1 Existing Methods for Customer interruption evaluation

Broadly speaking, the cost of an interruption from the customer's perspective is related to the nature of the degree to which the activities interrupted are dependent on electrical supply [14]. In turn, this dependency is a function of both customer and interruption characteristics. Costumer characteristics include type of customer, demand, and energy requirements, energy dependency as a function of time of day, etc. Interruption characteristics include duration frequency, and time of occurrence of interruptions; whether an interruption is complete or partial; if advance warning or duration information is supplied by the utility; whether the area affected by the outage is localized or widespread, etc. Finally, the impact of an outage is partially dependent on the attitude and preparedness of customers, which in turn is related to existing reliability levels. The evaluation methods of interruption impacts on customers have been well developed [81-83]. These methods can be categorized into three categories: indirect analytical evaluations, case studies of blackouts, and customer surveys. The last method is used in this thesis.

With the customer surveys method [84-88] customers are asked to estimate their costs or losses due to possible supply outages of varying duration and frequency at different times of the day and even year. The strength of this method lies in the fact that the customer is probably in the best position to assess the losses. In this method the customer interruption costs are obtained in the form of customer damage functions (CDF). The CDF can be determined for a given customer type and aggregated to produce sector customer damage functions for the various classes of customers in the system. Generally the customers are categorized into large users, industrial users, commercial users, agricultural users, residential users, government and institutional users and office & building users.

4.4.2 Interruption Cost Data from Surveys

In this project the survey results from some Canadian surveys [89-93] were utilized to evaluate the costumer interruption costs, which results from the unavailability of SR capacity. The data are shown in Table 4.1.

Table 4.1 Sector interruption cost estimates (CDF) expressed in kilowatts of annual peak demand ($/kW)

	Interruption duration				
User sector	1 min	20 min	1 hr	4 hr	8 hr
Large users	1.005	1.508	2.225	3.968	8.24
Industrial	1.625	3.868	9.085	25.163	55.808
Commercial	0.381	2.969	8.552	31.317	83.008
Agricultural	0.06	0.343	0.649	2.064	4.12
Residential	0.001	0.093	0.482	4.914	15.69
Govt.&inst.	0.044	0.369	1.492	6.558	26.04
Office&building	4.778	9.878	21.065	68.83	119.16

Usually each load point serves not one customer category but combinations of customer categories. Hence the interruption cost for each category can be aggregated at any particular load point in the system to produce a composite customer damage function (CCDF) at that load point. The method to obtain the CCDF is described in Appendix C. The results are shown in Table 4.2 and are graphically described in Figure 4.3.

Table 4.2 System CCDF ($/kW) calculated from the sector CDFs

Interruption duration				
1 min	20 min	1 hr	4 hr	8 hr
0.67	1.56	3.85	12.14	29.41

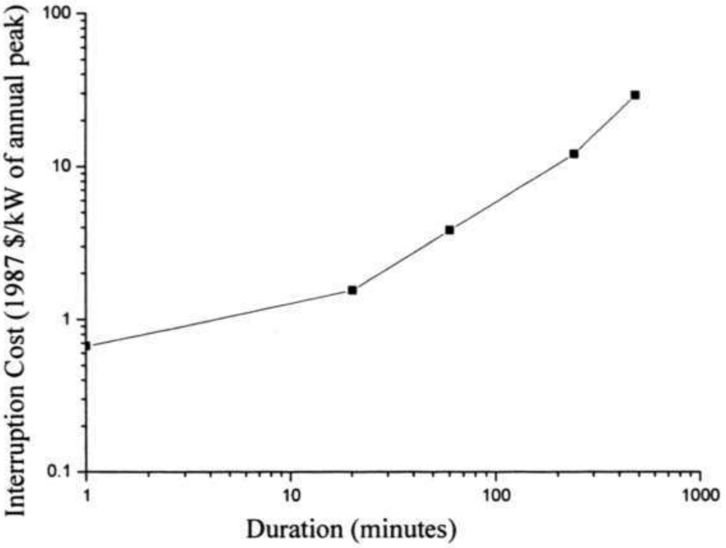

Figure 4.3 System composite customer damage function

4.4.3 Reliability Worth Evaluation Function

In a deregulated generating power system, either bilateral or real-time market, purchasing different capacities of SR or choosing different SR allocations exposes customers under different risks to lose load. The expected cost under each SR allocation for costumer loss of load due to the shortage of SR can be calculated by Equation (4.2).

$$C_{loss} = \sum_{k=1}^{N_{loss}} R_k L_{lossk} c(d_k) \tag{4.2}$$

where

$c(d_k)$ is the cost for interruption duration d for the loss event k

C_{loss} is the cost of loss of load

R_k is the risk of load loss event k, and

L_{lossk} is the interruption load capacity for load loss event k, and

N_{loss} is the total number of load loss events.

This index can be used to evaluate the benefit of purchasing the SR capacity. It is expected to be more reliable with more SR capacity. However, the objective is to obtain lower C_{loss} with lower SR cost. The method to determine SR allocation by solving this objective function is illustrated in the following section.

4.5 Risk/Cost Method for SR Allocation

4.5.1 Objective Function in bilateral market model

Under the bilateral market model each customer can purchase SR directly from gencos. Each genco can be seen as a potential SR provider to the customer. The different reliability level selections among customers can be fulfilled through bilateral contracts between customers and all gencos that provide SR services. In practice the genco can also be a customer when its capacity is not enough to provide SR service. However, the effect of this trading strategy on the objective function is not investigated in this thesis. The method in this thesis focuses on the optimum SR allocation for customers unable to provide SR services. The SR capacity requirement G_{sr} may be different in different contracts.

The objective of risk/cost method is to obtain the optimum SR selection from different gencos for each customer purchasing in a perfect market without market power. Based on this method, the customers identify the gencos with which they may be interested in entering into contracts. The objective function is,

$$\text{Min } C_T = C_{loss} + C_{sr} \tag{4.3}$$

subject to:

SR capacity requirement

$$\sum_{g=1}^{N_g} g_g = G_{sr}\text{, and} \tag{4.4}$$

Generating unit capacity limit

$$G_{gmin} \leq g_g \leq G_{g\max} \tag{4.5}$$

where,

C_T	is the total cost
G_{sr}	is the required SR capacity
G_{gmin}	is the minimum generating output of Genco g, and
$G_{g\max}$	is the maximum generating output of Genco g.

The final SR allocation is obtained by solving the objective function of Equation (4.3) under the constraints that the total SR capacity requirement of each customer is satisfied and each generating output is within generation limits.

4.5.2 Objective Function in day-ahead power market model

Customers can also choose to obtain SR service through the day-ahead power market, which would be settled by the ISO. Consequently the different reliability level selection in bilateral markets would be changed to the same reliability level among customers in the day-ahead power market. Under this market model the objective of risk/cost-based method is to obtain the optimum SR allocation for the entire system. The SR capacity required would be same for all the customers in this power market. The objective function and some constraints are same as in the bilateral power market. An additional constraint required is as follows:

$$G_{sr} \le G_{\max T} \tag{4.6}$$

where

$G_{\max T}$ is the maximum SR capacity available in the day-ahead power market.

The SR capacity required in this power market should not be more than the maximum SR capacity available.

4.5.3 Solution Procedure

A general computer program was developed based on the above-mentioned techniques for both the bilateral market and day-ahead market model. Under bilateral market model when customers choose to use this allocation method they will firstly compare the cost for purchasing SR with the damage cost which is due to not scheduling this SR. After then based on the output of this program, which is the optimal SR allocation with minimum total cost, customers can directly purchase undispatchable SR units from generation companies. The undispatchable units mean those generating units that are not involved the economic dispatch controlled by ISO. Under the day-ahead market model the ISO used this method because they will finally determine to purchase SR from which SR providers and purchase how much SR from these providers based on the objective of this method. Figure 4.4 shows the flowchart of this computer program.

Step 1: Input SR bids from SR providers.

Step 2: Determine all possible SR allocations based on the SR capacity requirements

Step 3: Input initial Minimum Total Cost (MTC) values of C_T , in which C_{loss0} and C_{sr0} are initial values of C_{loss} and C_{sr}, respectively.

Step 4: Select allocation i.

Step 5: Calculate C_{sri}.

Step 6: Calculate the risk of the loss of load considering unit outage contingencies only.

Step 7: $C_{Ti} = C_{lossi} + C_{sri}$

Step 8: If $C_{Ti} < MTC$, $MTC = C_{Ti}$ Otherwise go to Step 9.

Step 9: If all SR allocations are considered go to Step 10. Otherwise go to Step 4.

Step 10: Output the optimum SR allocation.

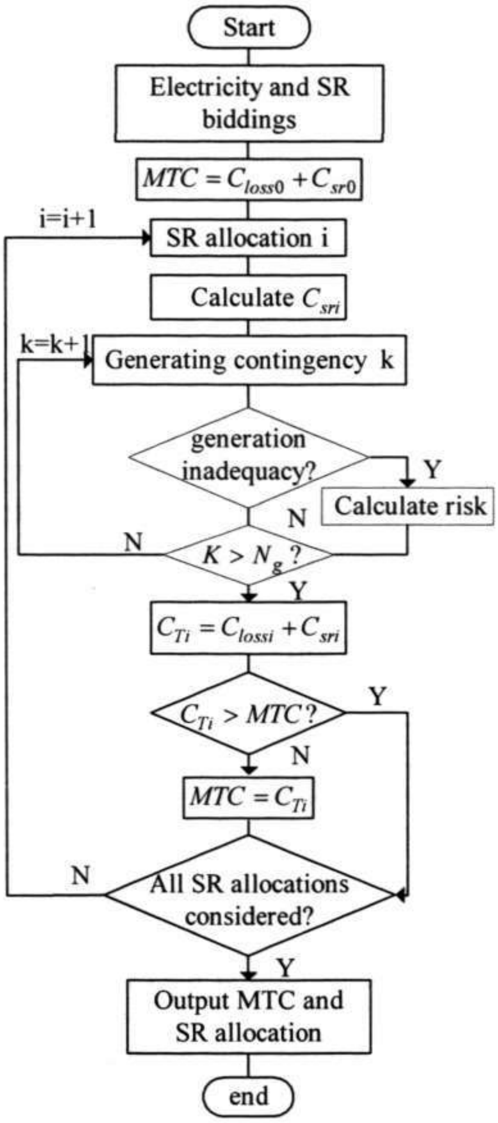

Figure 4.4 The flowchart of Risk/Cost method in a deregulated generating system

4.6 Illustrative Examples

In this section the RTS system [29] is utilized to illustrate the method described in Section 4.5. The system topology and data are introduced in Chapter 3. Genco1 owns the generation providers at buses 1, 2 and 7, which consists of 11 generating units. Eight generating units connected to buses 18, 21 and 22 belong to Genco3. A total of 13 generating units connected to Buses 13, 15, 16 and 23, constitute Genco2. Customers can be categorized into three groups. Agency 1 serves customers at load points 1,2,6,7 and 8.

Agency 2 serves customers at load points 3, 4, 5, 9, 10, 13 and 16. The remaining customers are served by Agency 3. Hence three groups of customers can be presented by three customer agencies to purchase electric power. The energy-clearing is shown in Table 4.3. The remaining generating units participate in SR market bidding. The bidding price of each genco is shown in Table 4.4.

Table 4.3 Energy-clearing for load demand

Load group	Peak load (MW)	Units committed	Genco
1	637	12,13,14,71,72,73	1
		151,156	2
2	1060	161,232,233	2
		181	3
3	1153	152,131,132,133	2
		221,222,223,211	3

Ten-minute SR is mainly considered in this thesis. The CCDF data in 10-minute interruption duration is 1.10$/kW, which is calculated based on data provided in Table 4.2. It is assumed that the CCDF between the 1-minute and 20-minute durations is linear

Table 4.4 Generating units left for bidding in the SR market

Unit number	Bus location	Genco	Capacity (MW)	Bidding Price ($/MWh)
224	22	3	50	30
225	22	3	50	30
226	22	3	50	30
153	15	2	12	45
154	15	2	12	45
155	15	2	12	45
11	1	1	20	50
21	2	1	20	50
22	2	1	20	50
23	2	1	76	50
24	2	1	76	50
231	23	2	155	45

4.6.1 Risk/cost SR Allocation Method under the Bilateral Market Model

In a bilateral power market each customer can directly purchase SR with gencos. Assume the SR capacity required by customers is 15% of their peak load. The SR allocations and the corresponding costs for three groups of load points are shown in Tables 4.5, 4.6 and 4.7, respectively. The SR capacities for each load group are 96 MW, 159 MW and 173 MW, respectively. The optimal result under each SR capacity is shown by bold fonts.

Table 4.5 SR allocations and the corresponding cost for load group 1

Allocation	Genbus	Capacity(MW)	C_{loss} (\$)	C_{sr} (\$)	C_T (\$)
1	**2**	**96**	**13.1359**	**1.3333**	**14.4692**

Table 4.6 SR allocations and the corresponding cost for load group 2

Allocation	Genbus	Capacity(MW)	C_{loss} (\$)	C_{sr} (\$)	C_T (\$)
1	**22**	**150**	**70.6469**	**1.4000**	**72.04689**
	15	**12**			
2	1	20	70.6619	1.6667	72.3286
	2	40			
	22	100			
3	2	76	70.7912	1.9222	72.7134
	15	36			
	22	50			
4	1	20	70.7550	2.1889	72.9439
	2	116			
	15	24			

Based on the minimum total cost the SR allocation for each load group is selected and marked in bold. Figure 4.5 displays the cost curves under different SR allocations for load group 3. It can be seen that although in SR allocation 3 the SR cost is the highest, the loss cost is not the lowest. Due to the different SR allocations high cost for reliability may not result in low risk of load loss. Optimum result is obtained by using the risk/cost SR allocation method to comprehensively consider the total cost. In the optimum result although the loss cost is not the minimum but the cost for purchasing the required SR is low enough for the total cost to be optimized

Table 4.7 SR allocations and the corresponding cost for load group 3

Allocation	Genbus	Capacity(MW)	C_{loss} ($)	C_{sr} ($)	C_T ($)
1	23	155	51.7943	2.2153	54.0096
	1	20			
2	2	76	51.8170	1.8889	53.7059
	22	100			
3	15	24	51.8404	2.4111	54.2515
	2	152			
4	**22**	**150**	**51.8096**	**1.5500**	**53.3596**
	15	**24**			
5	1	20	51.7757	1.8389	53.6146
	2	20			
	15	36			
	22	100			

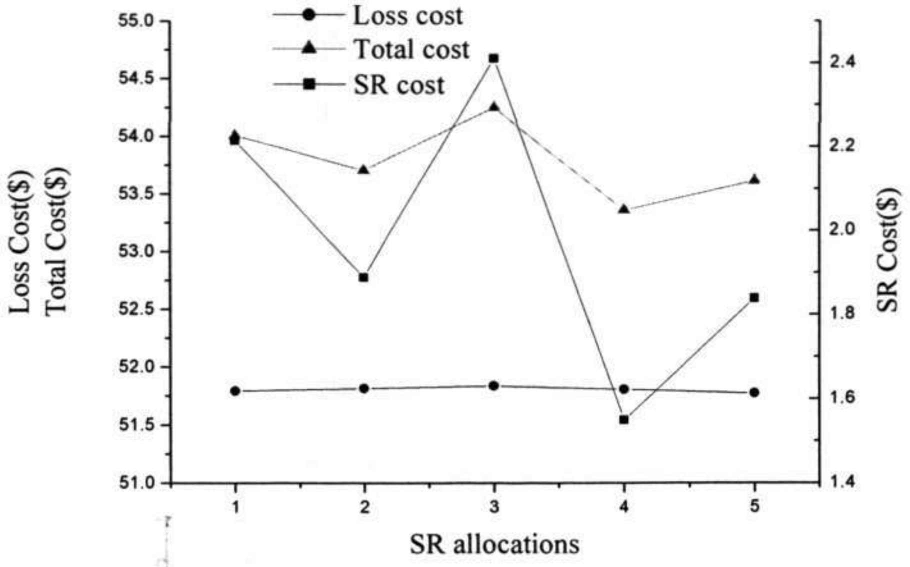

Figure 4.5 Cost curves under different SR allocations for load group 3

4.6.2 Risk/cost SR Allocation Method under the Day-ahead Market Model

In a day-ahead market both customers and gencos submit their offers for SR to the ISO. The total system SR capacity and providers are determined by the ISO. Tables 4.8, 4.9 and 4.10 show the SR allocations and the corresponding cost for the entire system under different SR capacity requirements, which are equal to 10% of the peak load, the largest unit capacity and 15% of the peak load, respectively. It should be noted here that all the SR allocations of the generating units are considered during the calculations. However, they are grouped based on the gencos that the generating units belong to. The optimum results are shown in bold.

Table 4.8 SR allocations and the corresponding costs under 285 MW SR

Allocation	Genco	Capacity(MW)	C_{loss} (\$)	C_{sr} (\$)	C_T (\$)
1	2	167	48.9020	3.1986	52.1006
	1	20			
	3	100			
2	1	96	48.9758	3.7208	52.6966
	2	191			
3	**1**	**136**	**48.9404**	**3.1389**	**52.0793**
	3	**150**			
4	1	152	49.0945	3.3944	52.4889
	2	36			
	3	100			
5	1	216	49.0909	3.6611	52.7520
	2	24			
	3	50			

Table 4.9 SR allocations and the corresponding costs under 400 MW SR

Allocation	Genbus	Capacity(MW)	C_{loss} ($)	C_{sr} ($)	C_T ($)
1	2	96	0.1590	4.5208	4.6798
	22	150			
	23	155			
2	2	152	0.2092	5.0431	5.2523
	1	20			
	15	24			
	22	50			
	23	155			
3	2	116	0.2011	4.8097	5.0108
	1	20			
	22	100			
	15	12			
	23	155			
4	1	20	0.2097	5.3319	5.5416
	2	192			
	15	36			
	23	155			
5	**2**	**40**	**0.2089**	**4.4708**	**4.6797**
	1	**20**			
	15	**36**			
	22	**150**			
	23	**155**			

Table 4.10 SR allocations and the corresponding costs under 428 MW SR

Allocation	Genbus	Capacity(MW)	C_{loss} ($)	C_{sr} ($)	C_T ($)
1	**2**	**152**	**12.2112**	**5.1819**	**5.3041**
	23	**155**			
	15	**24**			
	22	**100**			
2	1	20	12.8706	5.4486	5.5773
	2	196			
	15	12			
	22	50			
	23	155			

Compared with the loss cost of customers under bilateral market model, each customer in this model is expected to take the risk of high loss for cost. However, the customers have more choices on selecting SR providers in this model. In the real-time market model the loss cost of each customer is lower but the SR allocation shall be determined by the ISO. This is one feature of the power market that purchasing SR through real-time market or bilateral contract is determined by the customers.

4.7 Summary

A risk/cost based SR allocation method is proposed in this chapter. It realizes an optimum SR allocation with the least total cost, which considers both the cost for reliability and SR cost. Generally it is difficult to directly evaluate the worth of reliability. An interruption cost method is proposed to estimate the reliability worth. The customer survey method is selected from some existing methods to evaluate the reliability worth in this chapter. In this method the CDF and CCDF of customer surveys conducted in Canada were utilized to obtain the 10-minute interruption cost. With the obtained interruption cost the risk/cost based SR allocation method is illustrated by application to the IEEE reliability test system.

The numerical examples are illustrated under both bilateral market model and real-time market model. Under the bilateral market model, each customer is expected to take the risk of high cost of loss. However, the customers have more choices on selecting SR providers in this model. In the real-time market model the loss cost of each customer is lower but the SR allocation shall be determined by the ISO. It is shown from both the models that high SR cost may not result in low loss cost. The optimum result is the lowest total cost. The solution procedure and computer programs developed are also illustrated in this chapter.

Chapter 5 Risk Based SR Allocation in Deregulated Composite Systems

5.1 Introduction

In a deregulated power system SR units can be allocated to different locations of the physical system. This may have significant impact on customer reliability due to the line overloads caused by transmission line failures. Transmission system should therefore be considered when determining the SR allocation in a deregulated composite system. Hence the method to determine the SR allocation considering only the generating unit outages in the previous chapters (Chapters 3 and 4) needs to be modified to account for line outages. A new method to determine SR in conjunction with generating unit outages as well as transmission line failures is presented in this chapter.

In [71] a new method to determine the SR market clearing price and dispatch schedule is based on a proposed model with a certain optimization objective, such as to maximize market benefit. However, under certain unexpected situations such as transmission line failures, system congestions may occur. Consequently the cleared SR would not be able to get committed to the system. This will result in undesirable reliability problems.

New techniques should therefore be developed to solve this reliability problem in a deregulated power market. The risk of load being unsatisfied is a concern with customers located at bulk load points. Reference [94] points out that it is extremely helpful to think of reliability primarily as a risk-taking and management process. Actually in most practical power markets the responsibilities for risk-taking have been clearly defined through bilateral contracts among market participants. The bulk load point reliability for generating systems has been introduced in the previous chapters. Reference [24] proposed a well-being model which was used for the determination of SR in a traditional composite power system. However, the bulk load point risk in a composite system was not considered in this reference. This chapter aims to consider the bulk load point risk-based SR allocation in a composite system, which includes both generation and transmission system.

A risk based SR allocation method (RBSRAM) is proposed in this chapter. It uses the contingency enumeration technique under each possible SR allocation schedule to find the minimum sum of UC risk for each bulk load point. Unit Commitment (UC) risk was once used to evaluate the SR problem in a traditional power system [14]. The SR market model, which is combined with this method, is also illustrated in this paper. The details of this method are described in Sections 5.2 and 5.3 of this chapter. The SR market model involved with this allocation method is investigated in Section 5.4. Selected system studies using this method are shown in Section 5.5, and the conclusions are presented in Section 5.6.

5.2 Risk Based Spinning Reserve Allocation Method (RBSRAM)

In this method under certain contingencies when overload occurs- which may result in the load inadequacy for some bulk load points - the probabilities of these contingencies will be deemed as the risk of SR allocation for these bulk load points. The transmission constraints, load flow functions and objective functions are described in this section after introducing the contingency enumeration method. The proposed method is illustrated by application to the test systems.

5.2.1 Contingency Enumeration

The contingency enumeration method checks all the possible states of a physical system. The analytical technique [14], a probabilistic measure of the system reliability, is used in the contingency enumeration within the RBSRAM. Considering the computational requirements and low values of probabilities, not all the system contingencies are considered in practical power systems. Up to second-level contingencies were considered in this project in the RBSRAM. These include up to two units' outage, two transmission lines' outage and one unit with one transmission line outage. Assuming that all the units and transmission lines can exist in two states (up or down, the model is shown in Chapter 3, Figure 3-2, in which the corrective actions are not considered when a contingency results in system failure), the probability of a unit or a transmission line on outage at time T can be given by Equation (5.1) (the deduction process is shown in Chapter 3):

$$p = \lambda T \tag{5.1}$$

Considering a system with n generating units and m transmission lines, the probability of all components being available is

$$A = \prod_{gn=1}^{N_{gout}} (1 - p_{gn}) \prod_{lm=1}^{M_{lout}} (1 - p_{lm}) \tag{5.2}$$

where:

p_{gn} the outage probability of the gn^{th} generating unit.

p_{lm} the outage probability of the lm^{th} transmission line.

N_{gout} the number of generating units on outage, and

M_{lout} the number of transmission lines on outage.

When the failure of each component in this system is independent, the probability P_{out} when q components on outage can be expressed by Equation (5.3).

$$P_{out} = \frac{A\prod_{k=1}^{q} p_k}{\prod_{k=1}^{q}(1-p_k)} \tag{5.3}$$

where

p_k is the outage probability of the k^{th} component

5.2.2 Objective Function and Constraints

The RBSRAM is aimed to determine the SR allocation under which the sum of all the BLP risks is the minimum. In this thesis the BLP risk is defined as the probability that the bulk load point cannot be served power under system contingencies.

Objective function

When certain generating units in the system are out, the spinning reserve unit will be committed to the system. However, transmission line failures should be considered to evaluate the availability of these SR units. During the contingency when the composite network is reconfigured, line overload may occur. Once a certain line is overloaded the To-bus at the end of this line may lose power. The probability of this contingency state will then be added to the BLP risk. The BLP risk can be calculated as follows:

$$UCR_{iblp} = \sum_{j=1}^{N_{si}} \left[u_g p_{gji} + (1-u_g) \sum_{k=1}^{N_k} u_k p_{gji} p_{kj} \right] \tag{5.4}$$

Then the objective function will be

$$\mathbf{min}\ R_i = \sum_{blp=1}^{N_p} UCR_{iblp} \tag{5.5}$$

where, for the i^{th} possible SR allocation,

UCR_{iblp}	is the unit commitment risk of BLP p
R_i	is the sum of BLP risk
N_p	is the number of BLP

$$u_g = \begin{cases} 1 & \text{when there is load inadequacy caused by units outages} \\ 0 & \text{otherwise} \end{cases}$$

$$u_k = \begin{cases} 1 & \text{when there is line overload} \\ 0 & \text{otherwise} \end{cases}$$

P_{gj}	is the state probability of the generators at state j
p_{kj}	is the state probability of transmission lines at state k under state j
N_{si}	is the number of generating unit outage states of SR allocation i
N_k	is the number of transmission line outage states under state j

Generating capacity constraints

Generators have limited capacities to produce energy and at the same time to provide enough SR services. These are defined as capacity constraints as follows:

$$\sum_{b=1}^{N_b}\sum_{g=1}^{N_g} g_{srgbi} = G_{sr} \tag{5.6}$$

and

$$g_{srgbri} < g_{srgbr}^{\max} \tag{5.7}$$

where

N_g	is the number of gencos in a power market
N_b	is the number of generating buses
g_{srgbi}	is the SR capacity provided from Genco g at generating bus b for allocation i
R_{sr}	is the required SR capacity for system reliability
$g_{srgb}^{\max}$	is the maximum SR, which can be provided by Genco g at generating bus b

DC load flow constraint

System power flow will be calculated when considering transmission line contingencies. There are two methods to calculate the power flow; the AC power flow method and the DC power flow method. The power flow results are more realistic when using the AC power flow method. However, this method needs more time to converge and it is not necessary to use this method when only the real powers of lines are of concern. Hence the DC flow method is used in the calculation of power flow in this thesis.

The risk evaluation method is based on the DC load flow. This function is shown in Equation (5.8).

$$P^{sp} = B_0\theta \tag{5.8}$$

where

P^{sp} is the vector of injected power into each node, B_0 is the symmetric flow Jacobian matrix and θ is the vector of power angle of each node.

Then θ can be solved using Equation (5.9)

$$\theta = B_0^{-1}P^{sp} \tag{5.9}$$

The line power flow P_{ij} between nodes i and j can be calculated using Equation (5.10).

$$P_{ij} = \frac{\theta_i - \theta_j}{X_{ij}} \tag{5.10}$$

where

X_{ij} is the reactance between nodes i and j.

Transmission line constraints

Once the transmission congestion problem occurs, the SR will have a risk that cannot be committed to the system. Under system failure conditions the power flow has a probability that violates the transmission limitation, which can be expressed by Equation (5.11).

$$P_{fl} \leq F_l^{\max} \tag{5.11}$$

Equation (5.11) indicates that the power flow P_{fl} on line l cannot exceed the transmission limitation $F_l^{\max}$ on line l.

5.3 Solution Procedure and Flowchart

A computer program, illustrated by the flowchart of Figure 5.1, was developed to implement the RBSRAM. Due to the consideration of transmission lines the computer program for this method can be applied to the real time market to facilitate the ISO to determine the optimal SR allocation. Taking the BLP risk to evaluate the SR allocation enables the physical power system to be more reliable under system failures. In the proposed approach, the reliability required SR capacity would be allocated among the selected SR providers based on the minimum risk taken. The cost for each generating unit is assumed to be equal in the current version of this method. The solution procedure for the RBSRAM is as follows:

1. Input SR bids from SR providers.
2. Determine all possible SR allocations.
3. Select allocation i.
4. Run generating unit outage contingency enumeration. If generation is inadequate, calculate the BLP risk. Otherwise go to step 5.
5. Run transmission line contingency enumeration. If the line is overloaded, add the probability of this contingency to the BLP risk. Otherwise go to step 6.
6. If all the transmission line contingencies are considered, go to step 7. Otherwise to step 5.
7. If all the generating unit contingencies are considered, go to step 8. Otherwise go to step 4.
8. If all SR allocations are considered, go to step 9. Otherwise go to step 3.
9. Obtain the sum of the risk for all the BLPs and output the optimal SR allocation.

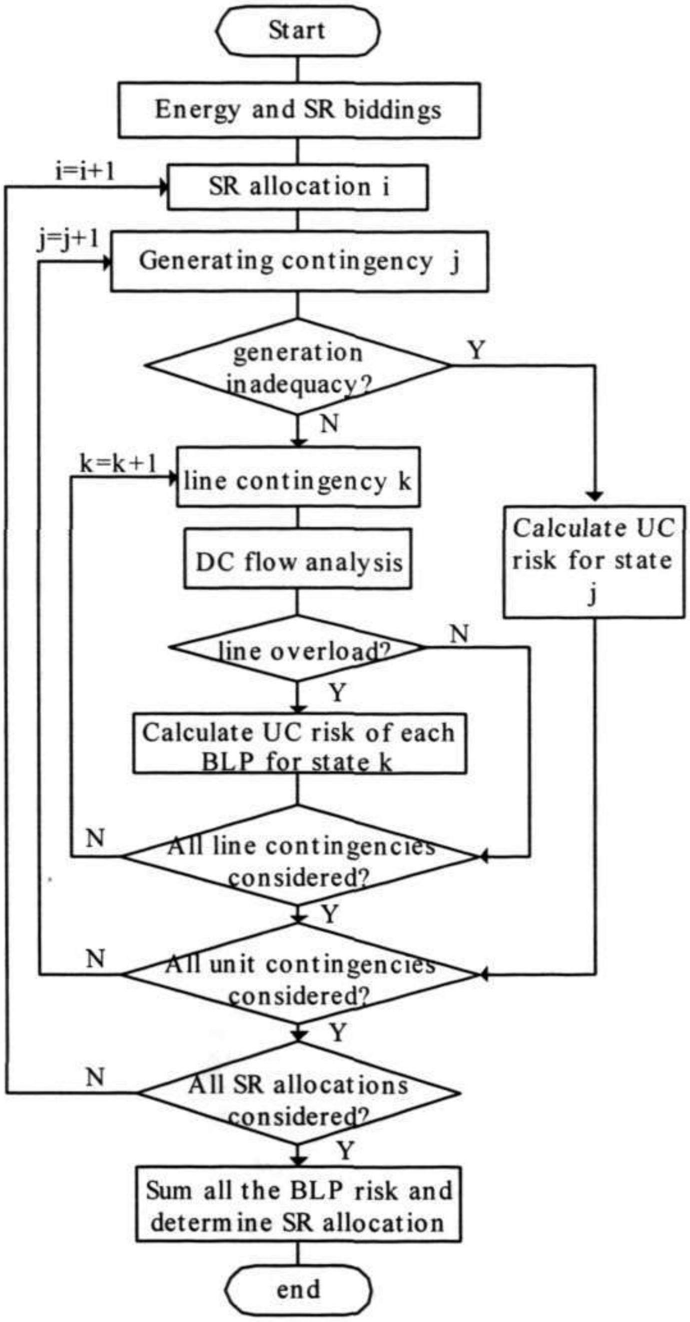

Figure 5.1 Flowchart of the RBSRAM method

5.4 Spinning Reserve Market Model with RBSRAM

In this section the RBRAM method combined with a sequential optimization model is applied to simulate a day-ahead SR market model.

The spinning reserve market (details in Chapter 2) is a market that is independent of the energy market. Like the energy market it can be fulfilled through real-time bidding or through bilateral contracts. Bilateral contracts are arranged between market participants. The ISO only acts as the manager of bilateral contracts. However, in day-ahead the ISO offers its own auctions for spinning reserve services, and the reserve will be allocated by the ISO.

This chapter investigates the risk of spinning reserve allocation in a day-ahead bidding market (in Figure 5.2) with sequential dispatching. In this market model after the SR biddings and customers' offers for SR are submitted to the ISO, the RBSRAM will be used by the ISO to run all the possible SR allocations and determine the optimized SR allocation.

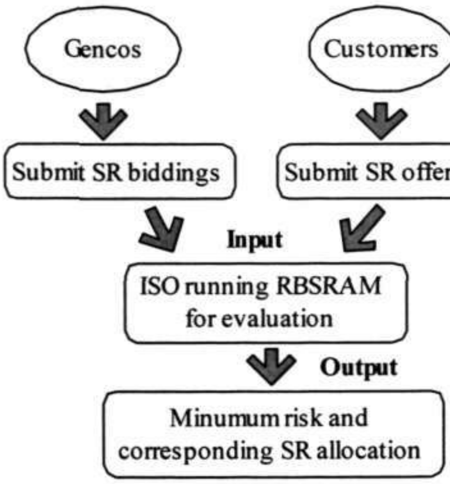

Figure 5.2 SR market model with RBSRAM

5.5 Illustrative Examples

The proposed technique was applied to the IEEE-Reliability Test System (RTS) [29]. The single-line diagram of the 24-bus IEEE-RTS with three gencos is shown in Figure 5.3. By using the reliability equivalent technique [76], the generation system is restructured into three Gencos. Genco1 owns the generation providers at buses 1, 2 and 7, which consists of 11 generating units. Eight generating units connected to buses 18, 21 and 22 belong to Genco3. A total of 13 generating units connected to Buses 13, 15, 16 and 23, constitute Genco2. We take the peak load hour as the consideration point in 24 hours.

The objective of the RBSRAM is to find the minimum commitment risk and the corresponding SR allocation. Since in the model of Section 5.3 the energy market is therefore cleared first, for which the commitment algorithm is not considered in this thesis, we assume two schedules of energy dispatch for simplicity. The SR allocation method is investigated under two different energy schedule environments. In both these assumptions after the energy market is cleared, there are 12 units left in this system, which can be bid to the SR market. The units left in the system are shown in Tables 5.1 and 5.2.

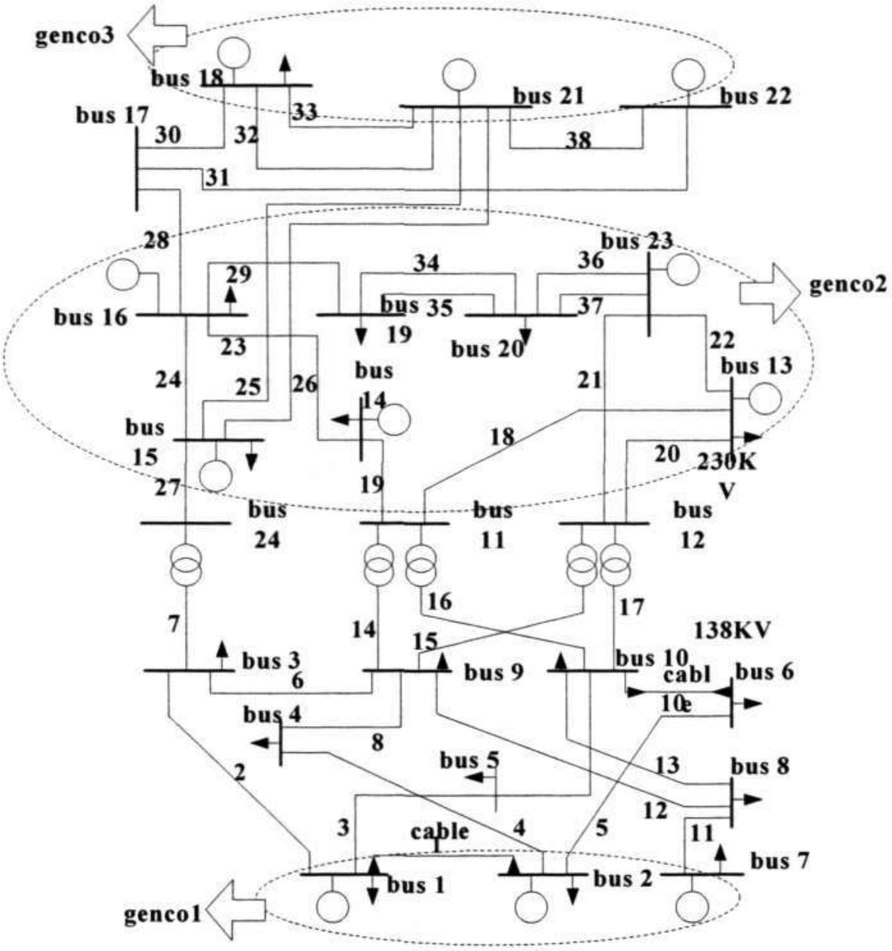

Figure 5.3 Single-line diagram of the IEEE-RTS with three gencos

A: Case studies under energy schedule 1

As described in Section 5.3 both the SR biddings from gencos and SR offers from customers are submitted to the ISO. The SR requirements of customers may be determined by them, hence the system SR requirement is the sum of customers' SR requirements. For simplicity the reserve requirement is set to 285 MW (10 percent of peak load). Because the sum of committed unit capacity may not be exactly equal to the reserve requirements (e.g. 285 MW) the calculation deviation in the computer program is limited to 3 MW.

Considering all the 12 units left for SR bidding, there are 47 unit combinations whose total capacity satisfies the SR capacity requirement. In addition, there are 7 SR allocation schedules after the unit combinations are categorized by Genbus. The UC risk and the corresponding SR allocations are shown in Table 5.3.

Table 5.1 Generating units for bidding in the SR market based on energy schedule 1

Unit Number	Bus location	Genco	Capacity (MW)	Bidding Price ($/MWh)
224	22	3	50	30
225	22	3	50	30
226	22	3	50	30
153	15	2	12	45
154	15	2	12	45
155	15	2	12	45
11	1	1	20	50
21	2	1	20	50
22	2	1	20	50
23	2	1	76	50
24	2	1	76	50
231	23	2	155	45

Table 5.2 Generating units for bidding in the SR market based on energy schedule 2

Unit Number	Bus location	Genco	Capacity (MW)	Bidding Price ($/MWh)
224	22	3	50	30
225	22	3	50	30
226	22	3	50	30
153	15	2	12	45
154	15	2	12	45
155	15	2	12	45
11	1	1	20	50
14	1	1	76	50
21	2	1	20	50
22	2	1	20	50
24	2	1	76	50
161	16	2	155	45

Table 5.3 Allocation of 285 MW SR and the corresponding UC risk

Allocation number	Risk	Genbus	Capacity(MW)
1	1.07535440E-02	23	155
		1	20
		15	12
		22	100
2	1.07537705E-02	23	155
		2	20
		15	12
		22	100
3	1.07540391E-02	23	155
		2	76
		1	20
		15	36
4	1.07542650E-02	23	155
		2	96
		15	36
5	1.07552746E-02	2	116
		1	20
		22	150
6	**1.07515518E-02**	**2**	**152**
		15	**36**
		22	**100**
7	1.07543110E-02	2	192
		1	20
		15	24
		22	50

Based on the minimum risk the sixth SR Allocation is selected as the final SR schedule, as shown in Figure 5.5. In this allocation, generators at Bus 2 provide 152 MW SR, generators at Bus 15 provide 36 MW SR and generators at Bus 22 provide 100 MW SR, which belong to Genco 1, Genco 2 and Genco 3, respectively.

It can also be seen from Figure 5.4 that the UC risk can be very different under different SR allocations although the SR capacity for each SR allocation is the same.

Considering the UC risks under different SR capacities, Tables 5.4, 5.5 and 5.6 show the results for 143 MW (5 percent of peak load) SR, 428 (15 percent of peak load) SR and 400 MW (largest generating unit capacity) SR, respectively.

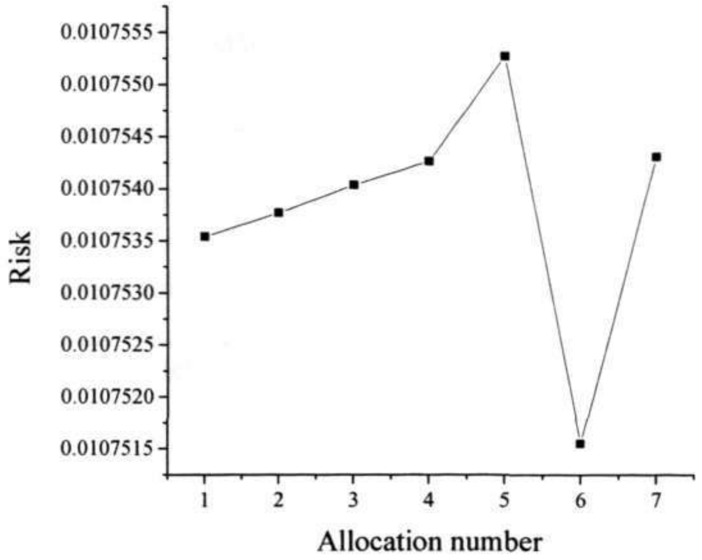

Figure 5.4 285MW SR allocations and risks

Table 5.4 Allocation of 143 MW SR and the corresponding UC risk

Allocation number	Risk	Genbus	Capacity(MW)
1	3.57833099E-02	2	76
		1	20
		22	50
2	3.57835312E-02	2	96
		22	50
3	3.57809303E-02	1	20
		15	24
		22	100
4	3.57811563E-02	1	20
		15	100
		22	24
5	**3.57656762E-02**	**2**	**40**
		1	**20**
		15	**36**
		22	**50**

Based on the minimum risk the SR allocation number 5, 3 and 1 are chosen as SR schedules when SR capacity requirements are 143 MW, 400 MW and 428 MW, respectively. For 143 MW SR requirement Genco 1 provides 60 MW, Genco 2 provides 36 MW and Genco 3 provides 50 MW. For 400 MW SR requirement Genco 1 provides 172 MW, Genco 2 provides 179 MW and Genco 3 provides 50 MW. For 428 MW SR requirement Genco 1 provides 152 MW, Genco 2 provides 179 MW and Genco 3 provides 100 MW.

Table 5.5 Allocation of 400 MW SR and the corresponding UC risk

Allocation number	Risk	Genbus	Capacity(MW)
1	4.91466110E-05	1	20
		2	76
		22	150
		23	155
2	4.95195581E-05	2	96
		22	150
		23	155
3	**4.87829963E-05**	**2**	**152**
		1	**20**
		15	**24**
		22	**50**
		23	**155**
4	4.90089147E-05	2	172
		15	24
		22	50
		23	155
5	5.80067582E-05	2	116
		1	20
		22	100
		15	12
		23	155
6	6.04821400E-05	1	20
		2	40
		15	36
		22	150
		23	155

Table 5.6 Allocation of 428 MW SR and the corresponding UC risk

Allocation number	Risk	Genbus	Capacity(MW)
1	**4.57203085E-05**	**2**	**152**
		15	**24**
		22	**100**
		23	**155**
2	5.82050593E-05	2	192
		1	20
		23	155
		22	50
		15	12

Figure 5.5 shows the different minimum risks for different SR capacity requirements. It shows clearly that with the increase of SR capacity the UC risk decreases significantly.

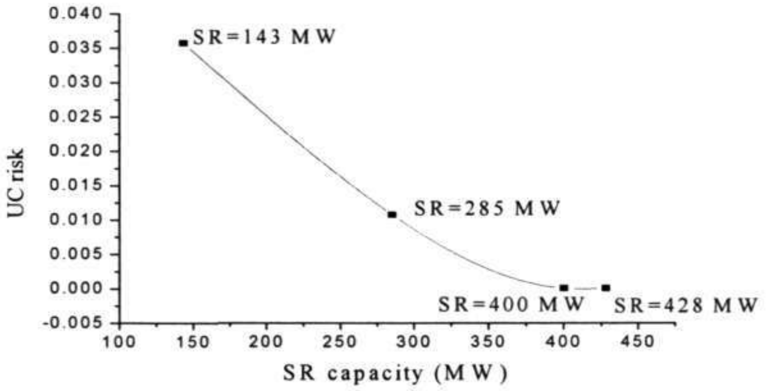

Figure 5.5 Minimum UC risk under different SR capacity requirements

B: Case studies under energy schedule 2

Under this schedule Tables 5.7, 5.8 and 5.9 show the SR allocations under SR capacities 143 MW, 285 MW and 400 MW, respectively. The optimal results are shown in bold.

With the same SR capacity, comparing the results under different energy schedules it can be seen that the risk increases. This implies that from a reliability point of review the SR market is strongly related to the energy market. As described in Chapter 2 there are two market models to dispatch energy and SR; single energy market and energy-reserve market. The former model was used in this project such that the SR and energy are cleared separately. It is recommended that further investigation of SR allocation under a combined energy-reserve market model could be done in future work.

Table 5.7 Allocation of 143 MW SR and the corresponding UC risk

Allocation number	Risk	Genbus	Capacity(MW)
1	3.99425829E-02	1	96
		22	50
2	3.57883090E-02	1	20
		2	76
		22	50
3	3.99426509E-02	1	76
		2	20
		22	50
4	3.57883519E-02	2	96
		22	50
5	3.57863318E-02	1	20
		15	24
		22	100
6	3.57862395E-02	2	20
		15	24
		22	100
7	**3.57721160E-02**	**1**	**20**
		2	**40**
		15	**36**
		22	**50**

Table 5.8 Allocation of 285 MW SR and the corresponding UC risk

Allocation number	Risk	Genbus	Capacity(MW)
1	1.07597106E-02	1	20
		15	12
		16	155
		22	100
2	1.07596918E-02	2	20
		15	12
		16	155
		22	100
3	1.07591584E-02	1	96
		15	36
		16	155
4	1.07593981E-02	1	20
		2	76
		15	36
		16	155
5	**1.07590661E-02**	**1**	**76**
		2	**20**
		15	**36**
		16	**155**
6	1.07593058E-02	2	96
		15	36
		16	155
7	1.07628721E-02	1	96
		2	40
		22	150
8	1.07631241E-02	1	20
		2	116
		22	150
9	1.07612472E-02	1	76
		2	76
		15	36
		22	100
10	1.07637140E-02	1	96
		2	116
		15	24
		22	50

Table 5.9 Allocation of 400 MW SR and the corresponding UC risk

Allocation number	Risk	Genbus	Capacity(MW)
1	5.50688318E-05	1	96
		16	155
		22	150
2	**5.44783765E-05**	**1**	**20**
		2	**76**
		16	**155**
		22	**150**
3	5.51849720E-05	1	76
		2	20
		16	155
		22	150
4	5.61022987E-05	2	96
		166	155
		22	150
5	5.61597452E-05	1	96
		2	76
		15	24
		16	155
		22	50
6	5.60673951E-05	1	76
		2	96
		15	24
		16	155
		22	50
7	6.66449457E-05	1	96
		2	40
		15	12
		16	155
		22	100
8	6.85725438E-05	1	20
		2	116
		15	12
		16	155
		22	100
9	6.66450228E-05	1	96
		2	40
		15	12
		16	155
		22	100
10	6.76711628E-05	1	96
		2	116
		15	36
		16	155
11	6.99714644E-05	1	20
		2	40
		15	36
		16	155
		22	150

5.6 Summary

This chapter has proposed a new risk evaluation method named the risk-based spinning reserve allocation method (RBSRAM) and illustrated a SR market model in conjunction with this method. It has been shown that under certain system failure conditions, the SR allocation can significantly affect the UC risk. The UC risk can differ significantly under different SR allocations although the SR capacity requirements may be the same. In such situations, the cleared SR has a high probability of not being dispatched to the system. The risk evaluation method becomes more feasible in such reliability assessment of deregulated power systems. Risk-taking should also be considered by the ISO in determining the SR allocation schedule. The RBSRAM is basically geared to determine the SR allocation with the objective to obtain the minimum UC risk.

A real-time SR market model in conjunction with the RBSRAM can help the ISOs to determine SR allocations among all the SR bidders based on the minimum unit commitment risk. The RBSRAM has not been applied to the hybrid market model in this project. In a hybrid market model the ISO can only dispatch part of SR generating units. In this model the bilateral contracts are also considered, in which the SR providers are chosen by customers first. Hence the dispatchable SR units are combined with the undispatchable SR units, which results in some complication while determining the UC risk. A new algorithm for this calculation may be formulated in future studies.

For the same SR requirement the minimum UC risk can be obtained by allocating SR to different generating units located at different generating buses, or for different SR requirements the decrease of UC risk can be obtained by increasing SR capacities. However, both these methods did not consider the SR cost. Considering the cost for SR may result in different UC risk and SR allocations. A new method to consider both the risk and the cost is proposed in Chapter 6. The effect of energy market on the SR market is expected to be investigated in future extensions of this work by other researchers.

Chapter 6 Hybrid SR Allocation in Deregulated Composite Systems

6.1 Introduction

Spinning Reserve (SR) management has evolved since the onset of power system deregulation. In a conventional system spinning reserve allocation among the generating units usually has an important bearing on the unit commitment and dispatch decisions, because it comes at some cost, which ideally should be kept minimal. As a result the SR can be adjusted on various generating units to keep the total start-up/back-down and operating cost at a minimum [96]. System reliability is centrally controlled and maintained by system operators – they have the authority to allocate spinning reserve among different generating units within the system in order to meet the overall system reliability criterion. Customers are thus provided with similar reliabilities, regardless of what they prefer.

In a deregulated power system, generating units are scheduled on offers and bids to buy and sell energy and ancillary services [97]. SR can be purchased through a bilateral contract or in a SR market. From the genco's point of view, the optimal SR allocation is to find the schedule of unit generating between energy and spinning reserve so that the expected benefit from selling both energy and spinning reserve to the market is maximized [98]. From the Independent System Operator (ISO) point of view, in a centralized SR market, the determination of the SR market clearing price and dispatch schedule are generally based on a certain model with a certain optimization objective, such as to maximize the social welfare [71].

However, a competitive retail market would be encouraged to provide the customer with more choices and competition in service and reliability [99]. Customer decisions on their reliabilities and costs can affect the capacity and the allocation of SR in a power system. Reference [21] indicates that customer choices on reliability and location of units are not considered at the scheduling stage. It is necessary to develop techniques to consider both the cost and the reliability when allocating the SR. Reference [16] describes the optimal scheduling of spinning reserve by using the Lagrangian Relaxation method in conjunction with probabilistic reserve assessment in a conventional power system. The trade-off between cost and reliability in a deregulated power system is not considered in [16]. Reference [100] discusses the spinning reserve allocation by using certain system probabilistic risks, such as system health indices. However, this reference does not involve the effects of cost for reliability on the SR allocation. A new methodology for allocating and pricing operating reserves is developed in [100]. It describes a modified security constrained economic dispatch formulation by considering the network constraints and line losses. The unit commitment risk and the related cost have not been considered in Reference [101].

In Chapter 5 a RBSRM is proposed to allocate SR units to different geographical locations of a deregulated composite system. Different UC risks from different allocations indirectly indicate the cost difference. However, it was realized that lower UC risk will reduce the cost for loss of load while increasing the cost for reliability. In order to obtain an optimal result, a trade-off between the cost and reliability is required through an effective risk evaluation algorithm. This chapter is a step forward in this direction.

In addition to the RBSRAM described in the previous chapter, the two other methods, a cost-based SR allocation method (CBSRAM), and a hybrid SR allocation method (HSRAM), are proposed in this chapter. The details of the proposed methods are presented in Sections 6.2 and 6.3. The solution procedures and developed computer programs of these methods are illustrated in Section 6.4. Selected system studies using the proposed methods are shown in Section 6.5, and the conclusions of the work described are presented in Section 6.6.

6.2 Cost-Based SR Allocation Method without Considering UC Risk

In this method only the cost of purchasing SR is considered. The objective of cost-based SR allocation method is to select the optimal SR location with the minimum total system SR cost. The objective function is as follows:

$$Min\ SRC_i = \sum_{b=1}^{N_{bi}} \sum_{g=1}^{N_{gi}} C_{gbi}(g_{srgbi}) \tag{6.1}$$

Subject to the following constraints:

SR capacity constraint

$$\sum_{b=1}^{N_{bi}} \sum_{g=1}^{N_{gi}} g_{srgbri} = G_{sr} \tag{6.2}$$

Generating unit constraint

$$g_{srgbri} < g_{srgbr}^{\max} \tag{6.3}$$

Transmission line constraint in normal state

$$f_{l0i} \le f_l^{\max} \qquad (6.4)$$

where:

SRC_i the total system SR cost for allocation i

g_{srgbi} the SR available from Genco g at generating bus b for allocation i

$C_{gbi}(g_{srgbi})$ the SR bidding curve from Genco g at generating bus b for allocation i

f_{l0i} the power flow of line l for normal state, and

f_l^{max} the transmission limitation of line l.

In this method the SR allocation is determined based on the minimum SR cost, which is subject to three constraints. The constraint expressed by Equation (6.2) indicates that the summation of SRs from all gencos in the system must be equal to the total SR capacity required by the ISO. Equation (6.3) illustrates the constraint that the SR capacity from each genco should be less than or equal to its maximum output. It is noted that the difference between the cost-based SR allocation method in deregulated generating systems and deregulated composite systems resides in the constraint described in Equation (6.4). It indicates that in a deregulated composite system the final SR allocation should not result in the violation of transmission line constraints.

6.3 Hybrid SR Allocation Method (HSRAM)

In a practical power market, the unit commitment risk can be related to the reliability cost. The objective of the hybrid method for SR allocation is to minimize both the reliability cost and the SR cost. The reliability cost can be evaluated using the customer interruption cost, introduced in Chapter 4. It is the cost of loss of load because the units cannot be committed to a system. For customers at each bulk load point the reliability cost is a function of UCR_{iblp}, which can be calculated by Equation (5.4). Hence the reliability cost for each SR allocation in a composite system can be evaluated as follows:

$$RC_i = \sum_{blp=1}^{Np} L_{ip} UCR_{iblp} c(d) + C_{iloss} \tag{6.5}$$

The optimization problem of this method is formulated as follows:

$$\boldsymbol{Min} \;\; TC_i = RC_i + SRC_i \tag{6.6}$$

Subject to

Transmission line constraint

$$f_{lki} \le f_l^{\max} \tag{6.7}$$

SR capacity constraint

Equation (6.2)

Generating unit constraint

Equation (6.3)

In Equations (6.5) to (6.7), for the SR allocation i

RC_i	the reliability cost
L_{ip}	the loss of load at bulk load bus p due to transmission line failures
$c(d)$	the customer damage function
N_p	the number of bulk load buses
TC_i	the total cost
f_{lki}	the power flow of line l at any contingency state k

In the objective function the index C_{loss} can be calculated using Equation (4.2). Besides the constraints illustrated by Equations (6.2) and (6.3), Equation (6.7) indicates that under line failures the other transmission line constraints should not be violated.

The hybrid method not only considers the UC risk of SR units but also evaluates the reliability values. Up to two line failures, two unit outages and one line and one unit outage were considered in the contingency enumeration used in the hybrid method in this project.

6.4 Solution Procedure

A computer program has been developed to implement the three methods namely RBSRAM, CBSRAM and HSRAM. The output of this program can be optimal SR allocation with minimum risk, minimum cost or minimum total cost depending on which SR allocation method the ISO used. With this result ISO can determine to purchase SR from which providers and how much SR purchased from these providers. Figure 6.1 shows the flowchart of the computer program. The notations of some of the indices in the flowchart are stated in Chapter 5 and previous sections of this chapter. The basic steps in the evaluation process are as follows:

1. Input SR bids from SR providers.
2. Determine all possible SR allocations based on the required SR capacity.
3. Input initial values of SRC, UCR and TC as *MSRC*, *MUCR* and *MTC*, respectively.
4. Select allocation i.
5. If both HSRAM and CBSRAM are not used, go to Step 11.
6. Calculate SRC_i.
7. If CBSRAM is not used go to Step 11.
8. Compare SRC_i with *MSRC*.
9. If $SRC_i < MSRC$, $MSRC = SRC_i$. Otherwise go to Step 10.
10. If SR allocations are considered, go to Step 19. Otherwise go to Step 4.
11. Calculate UCR_i.
12. If RBSRAM is not used go to Step 16.
13. Compare UCR_i with *MUCR*.
14. If $UCR_i < MUCR$, $MUCR = UCR_i$. Otherwise go to Step 15.
15. If all SR allocations are considered go to Step 19. Otherwise go to Step 4.
16. $TC_i = RC_i + SRC_i$
17. If $TC_i < MTC$, $MTC = TC_i$. Otherwise go to Step 18.
18. If all SR allocations are considered go to Step 19. Otherwise go to Step 4.
19. Output the optimum SR allocation.

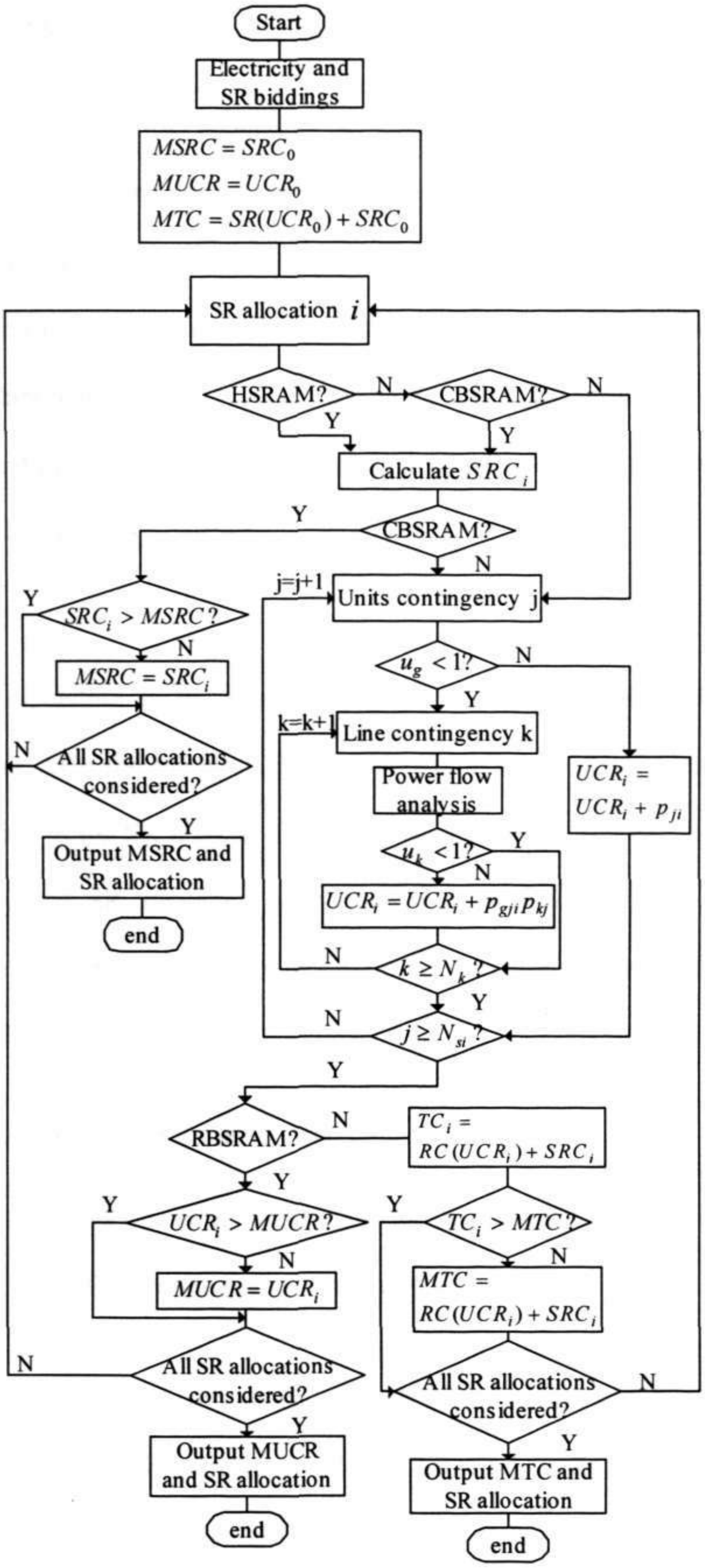

Figure 6.1 Flowchart of the three SR allocation methods

6.5 Illustrative Examples

The developed technique was applied to the IEEE-Reliability Test System (RTS) [29]. The single-line diagram and system data of the 24-bus IEEE-RTS with three gencos are shown in Figure 5.4. As illustrated in Figure 5.4 the generation system was restructured into three generating companies (gencos). Genco1 owns the generation providers at buses 1, 2 and 7, which consists of 11 generating units. Eight generating units connected to buses 18, 21 and 22 belong to genco3. A total of 13 generating units connected to buses 13, 15, 16 and 23, constitute genco2.

The hour corresponding to the peak load (2850 MW) has been used in the studies described below. After the energy market is cleared, there are 12 units left in this system, which can be bid in the SR market. The units left are shown in Table 4.4 of Chapter 4. The three proposed SR allocation techniques were applied, and selected results are presented here. All the studies are based on the real-time market model, which is illustrated in Chapter 5.

6.5.1 SR Allocation Using CBSRAM

Tables 6.1 and 6.2 show the SR allocations and the corresponding costs when the required SR is 10% and 15% of the peak load, respectively.

Based on the CBSRAM the fifth allocation with the minimum cost is chosen as the SR allocation schedule. The ISO purchases 136 MW SR from Genco1 and 150 MW SR from Genco3. It can be seen that although the UCR in allocation 6 (reserve schedule 6) is the minimum the cost of this schedule is very high. Moreover, although the SRC for allocations 1 and 2 are the same the UCR are different due to the SR units located at different generating buses. The risk and cost curves for 285 MW SR capacity are shown in Figure 6.2.

Table 6.1 SR allocations and the corresponding UC risk and cost with 285 MW SR

Allocation	SRC($)	Genbus	Capacity(MW)	UCR
1	3.198611	23	155	1.07535440E-02
		1	20	
		15	12	
		22	100	
2	3.198611	23	155	1.07537705E-02
		2	20	
		15	12	
		22	100	
3	3.720833	23	155	1.07540391E-02
		2	76	
		1	20	
		15	36	
4	3.720833	23	155	1.07542650E-02
		2	96	
		15	36	
5	**3.1388889**	**2**	**116**	**1.07552746E-02**
		1	**20**	
		22	**150**	
6	3.3944444	2	152	1.07515518E-02
		15	36	
		22	100	
7	3.661111	2	192	1.07543110E-02
		1	20	
		15	24	
		22	50	

Table 6.2 SR allocations and the corresponding UC risk and cost with 428 MW SR

Allocation	SRC ($)	UCR	Genbus	Capacity(MW)
1	**5.1819444**	**4.57203085E-05**	**2**	**152**
			15	**24**
			22	**100**
			23	**155**
2	5.4486111	5.82050593E-05	2	192
			1	20
			23	155
			22	50
			15	12

Generally, when the cost for SR decreases the UC risk increases. However in the second allocation both the UC risk and SR cost are high. It is obvious that this allocation is the worst choice. In other words selecting SR allocation with high cost may not decrease the UC risk. The optimal allocation is to minimize both, which is the objective of the HSRAM. The test studies using the HSRAM are discussed in the next subsection.

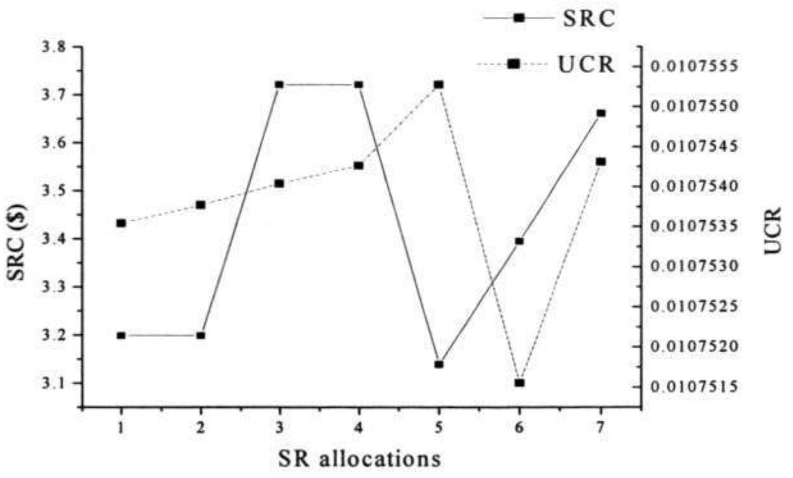

Figure 6.2 UC risk (UCR) and SR cost (SRC) curve

6.5.2 SR Allocation Using HSRAM

The objective of the hybrid method for SR allocation is to minimize both the reliability cost and the SR cost. In practice the reliability cost function related to the UC risk is different for different ISOs due to the different buildup of grid. This function mainly includes the cost of customers' loss of load. The 10-minute interruption load value is introduced in this section, which is about 1.10$/kW as calculated in Chapter 4.

Based on the UC risk calculated in Chapter 5 the RC and TC are shown in Tables 6.3 and 6.4 under the 285 MW (10% of peak load) and 428MW (15% of peak load) SR conditions, respectively.

Table 6.3 Total cost under 285MW SR

Allocation number	SRC($)	RC ($)	TC($)
1	3.1986	1402.7530	1405.9516
2	3.1986	1402.7980	1405.9966
3	3.7208	1402.7380	1406.4588
4	3.7208	1402.7830	1406.5038
5	**3.1389**	**1402.1640**	**1405.3029**
6	3.3944	1403.0110	1406.4054
7	3.6611	1402.1460	1405.8071

Table 6.4 Total cost under 428 MW SR

Allocation number	SRC ($)	RC($)	TC($)
1	**5.1819**	**1.3501**	**6.5320**
2	5.4486	1.8507	7.2993

Based on the minimum TC the results are shown in bold in Tables 6.3 and 6.4. Comparing the results it can be seen that the TC decreases significantly due to the decrease of RC while the cost for purchasing SR is not increased much. It implies that under this case choosing more capacity of SR is more economic.

If the assumption is changed to energy schedule 2 (details in Chapter 5) and the SR units bidding to the market are shown in Table 5.2, the costs for SR allocations are different. The results are shown in Tables 6.5, 6.6 and 6.7. The optimal results are shown in bold.

Table 6.5 Total cost under 143MW SR based on energy schedule 2

Allocation number	SRC($)	RC ($)	TC($)
1	1.7500	5223.8297	5225.5797
2	1.7500	4680.0821	4681.8321
3	1.7500	5223.8425	5225.5925
4	1.7500	4680.0902	4681.8402
5	1.4111	4679.6609	4681.0720
6	**1.4111**	**4679.6435**	**4681.0546**
7	1.7000	4676.6970	4678.3970

Table 6.6 Total cost under 285MW SR based on energy schedule 2

Allocation number	SRC($)	RC ($)	TC($)
1	3.1986	1403.2565	1406.4551
2	3.1986	1403.2227	1406.4213
3	3.7208	1403.3089	1407.0297
4	3.7208	1403.1959	1406.9168
5	3.7208	1403.2915	1407.0123
6	3.7208	1403.1786	1406.8994
7	3.7639	1402.4909	1406.2548
8	3.7639	1402.3807	1406.1446
9	3.3944	1403.4909	1406.8853
10	**3.6611**	**1402.5590**	**1406.2201**

Table 6.7 Total cost under 400MW SR based on energy schedule 2

Allocation number	SRC($)	RC ($)	TC($)
1	4.5208	1.8770	6.3979
2	**4.5208**	**1.6053**	**6.1261**
3	4.5208	1.8989	6.4197
4	4.5208	1.8630	6.3839
5	5.0431	1.9428	6.9858
6	5.0431	1.9254	6.9684
7	4.8097	2.2190	7.0287
8	4.8097	2.2938	7.1035
9	4.8097	2.2190	7.0288
10	5.3319	2.3235	7.6554
11	4.4708	2.2485	6.7193

A comparison of the results in Tables 6.5 to 6.7 with Tables 5.7 to 5.9, respectively, shows that the final SR allocations are different due to different determination methods used. Under reserve capacity 143 MW, 285 MW and 400 MW the final SR allocations are the 7th, 5th and 2nd respectively using the RBSRAM, whereas they are 6th, 10th and 2nd using the HSRAM. Hence both reliability requirement and cost affect on SR allocation significantly. In practice it is not necessary to use the hybrid method for determination of SR allocation. Customers can make a final determination after simulating with the three proposed methods.

6.6 Summary

This chapter has proposed two new methods of spinning reserve allocation, namely the cost-based SR allocation method (CBSRAM), and the hybrid SR allocation method (HSRAM). It has been shown that under certain system failure conditions SR allocation can significantly affect the UC risk. In such situations, the cleared SR has a high probability of not being dispatched to the system. The risk evaluation method becomes more feasible in such reliability assessment of deregulated power systems. Risk-taking should also be considered by the ISO in determining the SR allocation schedule(s). The CBSRAM simply determines the SR allocation based on the minimum cost for required SR capacity. The HSRAM method considers not only the cost for SR but also the reliability cost, which is directly related to the UC risk. The optimal result from the HSRAM can provide the maximum benefit for customers in purchasing SR. Hence the HSRAM can help the ISOs to determine optimal SR allocations among all the SR bidders.

Chapter 7 Conclusions and Recommendations

7.1 Conclusions

This thesis describes and illustrates three new methods that have been developed to determine spinning reserve allocation in deregulated power markets. Several aspects of spinning reserve management have also been studied in this thesis. Studies in spinning reserve management have been investigated for two different hierarchical systems: deregulated generating systems and deregulated composite systems.

7.1.1 SR Management in a Deregulated Generating System

In a deregulated generating system, the transmission system is assumed to be 100% reliable and is therefore not considered. Under this condition, a well-being analysis model has been developed that can investigate the spinning reserve problems from the customer point of view based on the reliability risk and cost. In this model, the reliability state of each customer can be identified as healthy state, marginal state and being at risk. Based on this model two methods of determining the spinning reserve (SR) are proposed and studied in both the bilateral market model and the real-time market model.

Risk-based SR allocation method

In this method the bulk load point indices have been introduced in deregulated generating power systems to replace system indices in vertically integrated power systems. Spinning reserve capacity is represented by the load point risk indices. Customers determine their SR providers based on the reliability levels they require. The different levels are presented by load point risk indices, such as PHBLP, PMBLP and PRBLP.

It is pointed out that the concept of unified system reliability should be replaced by individual load point reliability in this new environment. Customers in a deregulated market tend to choose generation producers located in any part of the system by making bilateral contracts with SR providers. From the customers perspective the system reliability is not uniform any more. For example some industrial customers may require a relatively higher reliability level such that the PHBLP is greater than 0.9, while other customers may only require the PRBLP to be lower than 0.001. Hence by quantifying these different reliability requirements the risk-based SR allocation method facilitates customers in making judicious decisions with regards to bilateral contracts. The numerical studies using the RBTS and RTS also show that high capacity of spinning reserve may not result in high reliability level. Allocating the required SR to the different SR gencos has a significant effect on the customer reliability. The risk-based SR allocation method therefore is an important technique for SR management.

Risk/cost-based SR allocation method

The optimum SR allocation shall be obtained based on the maximum benefit to customers acquired from the purchase of SR. Hence the objective of the Cost/risk-based SR allocation method is to find the SR allocation with minimum total cost, which includes the cost for purchasing SR and reliability cost. The cost for purchasing SR is based on the bidding curve of each genco that provide SR to the SR market. The reliability cost cannot be directly obtained. It is generally evaluated using the customer interruption costs. Interruption costs obtained from the customer survey methods are utilized in this thesis. In this method the CDF and CCDF of Canadian surveys are introduced to obtain the 10-minute interruption cost. Using the interruption costs the risk/cost based SR allocation method is investigated using the IEEE reliability test system. The numerical examples are studied under both bilateral market and real-time market models. Under the bilateral market model customers select optimum SR allocation with minimum cost for them. In a real-time market model customers submit their SR requirements to the ISO and their SR allocations are determined by the ISO. The ISO determines the SR allocations based on the minimum total cost of the entire system. The results show that high SR cost may not result in low loss cost due to different SR allocations. Customers who choose to purchase SR through bilateral contract may encounter high loss of load cost than that through the real-time market. However, they have more choices to select the SR providers. Therefore the required capacity of SR, the providers of SR and the purchasing method of SR are determined by customers. This is one of the benefits of the deregulated power market.

7.1.2 SR Management in a Deregulated Composite System

Three methods of determining SR allocation for a deregulated composite system have been developed from the reliability point of view. The deregulated composite system not only considers generating unit outages but also transmission line failures. It indicates that SR capacity may not be delivered to the load points due to line failures. The method for determining SR allocation also involves line failures. A model in conjunction with these methods based on real-time SR market is also proposed.

SR determination market model

The real-time SR market in this thesis is based on day-ahead bidding. By applying the SR allocation methods to this market model a SR market structure and a market model are developed. In this market model after the SR biddings and customers offers for SR are submitted to the ISO, the SR allocation method is used by the ISO to run all the possible SR allocations and determine the optimized SR allocation. In the numerical studies the hour with peak load is selected and the required SR is allocated among the units which did not provide energy for load demands.

Risk-based SR allocation method for composite systems (RBSRAM)

The approach is developed to allocate SR based on the risk that the load cannot be complemented by SR when system failures occur. Generally this risk can also be called the unit commitment (UC) risk. The optimal SR allocation is with the minimum UC risk.

It is shown that high capacity of SR may decrease the UC risk. Under the same required capacity of SR, the UC risks are different when SR is allocated to different generating buses in a network. The allocation with minimum UC risk is the optimized SR allocation.

Hybrid SR allocation method (HSRAM)

A hybrid method, which considers both the reliability risk and cost, has been developed to determine the SR allocation in a real-time market model. When only considering the cost for SR, customers can choose the SR allocation with minimum cost of purchasing SR. It shows that under the same required capacity of SR the cost for purchasing may be different due to the SR purchased from different gencos. However, the corresponding UC risk may be high.

The hybrid model considers both the reliability risk and cost. It determines the SR allocation based on minimum sum of reliability cost and cost of purchasing SR. The reliability cost is the worth of purchasing SR. It is also represented by the customer interruption cost. The results of numerical studies show that loss of load cost decreases due to increase of SR capacity. Under the same SR capacity high cost of purchasing SR may not result in low UC risk. Increasing cost of purchasing SR may not decrease the loss of load cost. The optimum SR allocation is located on the minimum sum of these two costs.

7.2 Comparison of the three methods

Risk-based, cost-based and hybrid SR allocation methods are proposed in this thesis. Risk-based SR allocation method focuses on the effect of reliability on SR allocation while cost-based method aims to obtain the most economic SR allocation without considering the reliability constraints. The hybrid technique is the most comprehensive method. However, the computing time for this method is more than that for risk-based and cost-based methods. The SR allocations are different using different allocation methods. Customers and ISOs can select among these three methods based on their operating conditions. In practice, market model, security constraints and other factors will also have great impact on SR allocation. This thesis has only focused on the effect of reliability constraints on SR allocation in a sequential SR market model. Other considerations on SR allocation were not implemented in the work, but are discussed in the next section.

7.3 Recommendations

Several new ideas are introduced and developed in this thesis. Therefore there is ample scope for extension of the research work and a few specific topics are suggested below.

The hybrid method by utilizing the real bidding curve may be developed. In practice, the bidding curve is not constant unlike what has been assumed in this thesis. The method in conjunction with this real bidding curve may be more complicated but feasible.

Currently the SR methods for the deregulated composite system have not been applied to the hybrid market model, because in a hybrid market model the ISO can only dispatch part of SR generating units. In this model the bilateral contracts are also considered, in which the SR providers are chosen by customers first. Hence the dispatchable SR units are combined with the undispatchable SR units, which makes the determination of UC risk quite complex. A new algorithm for this calculation may be formulated in future studies.

Market power may be considered in the methods proposed in this thesis. The methods in this thesis are developed by assuming that the power market is perfect. There are no undue advantages assumed in the SR biddings from gencos. Hence there is a generating constraint in the objective functions. However, in a market with market power gencos can bid SR capacity higher or lower than the real generating capacity. This makes the evaluation more complex and involved, and will possibly form a topic of future research interest.

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Appendices

Appendix A: The Roy Billinton Test System Data

The RBTS is a small power system developed by Professor Roy Billinton, which was firstly utilized extensively in reliability research work at the University of Saskatchewan, Canada. The system is described in Section 3.5.1 of Chapter 3. The detailed generating unit, bus and transmission line data are shown in the following tables.

Table A.1 Generating unit data of the RBTS

Priority loading order	Unit size [MW]	Cost parameters			Failure rate [f/yr]	Bus
		A	B	C		
1	40	0	0.5	0	3	2
2-3	20	0	0.5	0	2.4	2
4	40	26	12	0.01	6	1
5	40	28	12	0.01	6	1
6	20	16	12.25	0.02	5	1
7	10	14	12.5	0.02	4	1
8-9	20	0	0.5	0	2.4	2
10-11	5	0	0.5	0	2	2

Table A.2 Bus data of the RBTS

Bus No.	Load (p.u.)		P_g	Q_{max}	Q_{min}	V_0	V_{max}	V_{min}
	Active	Reactive						
1	0.00	0.00	1.0	0.50	0.40	1.05	1.05	0.97
2	0.20	0.00	1.2	0.75	0.40	1.05	1.05	0.97
3	0.85	0.00	0.0	0.00	0.00	1.00	1.05	0.97
4	0.40	0.00	0.0	0.00	0.00	1.00	1.05	0.97
5	0.20	0.00	0.0	0.00	0.00	1.00	1.05	0.97
6	0.20	0.00	0.0	0.00	0.00	1.00	1.05	0.97

Table A.3 Transmission line data of the RBTS

Line No.	Bus		R	X	B/2	Tap	Current Rating (p.u)	Failure Rate (occ/yr)
	From	To						
1	1	3	0.0342	0.18	0.0106	1.00	0.85	1.50
2	2	4	0.1140	0.60	0.0352	1.00	0.71	5.00
3	1	2	0.0912	0.48	0.0282	1.00	0.71	4.00
4	3	4	0.0228	0.12	0.0071	1.00	0.71	1.00
5	3	5	0.0228	0.12	0.0071	1.00	0.71	1.00
6	1	3	0.0342	0.18	0.0106	1.00	0.85	1.50
7	2	4	0.1140	0.60	0.0352	1.00	0.71	5.00
8	4	5	0.0228	0.12	0.0071	1.00	0.71	1.00
9	5	6	0.0228	0.12	0.0071	1.00	0.71	1.00

Appendix B: The IEEE Reliability Test System Data

The IEEE-RTS is a relatively large power system in which sufficient complexity and detail have been included to make the test system representative of an actual utility system.

Table B.1 Bus data of the RTS

Bus No.	Load (p.u)		P_g	Q_{max}	Q_{min}	V_0	V_{max}	V_{min}
	Active	Reactive						
1	1.080	0.220	1.720	1.20	-0.75	1.00	1.05	0.95
2	0.970	0.200	1.720	1.20	-0.75	1.00	1.05	0.95
3	1.800	1.370	0.000	0.00	0.00	1.00	1.05	0.95
4	0.740	0.150	0.000	0.00	0.00	1.00	1.05	0.95
5	0.710	0.140	0.000	0.00	0.00	1.00	1.05	0.95
6	1.360	0.280	0.000	0.00	0.00	1.00	1.05	0.95
7	1.250	0.250	3.000	2.70	0.00	1.00	1.05	0.95
8	1.710	0.350	0.000	0.00	0.00	1.00	1.05	0.95
9	1.750	0.360	0.000	0.00	0.00	1.00	1.05	0.95
10	1.950	0.400	0.000	0.00	0.00	1.00	1.05	0.95
11	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95
12	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95
13	2.650	0.540	5.500	3.60	0.00	1.00	1.05	0.95
14	1.940	0.390	0.000	3.00	-0.75	1.00	1.05	0.95
15	3.170	0.640	2.100	1.65	-0.75	1.00	1.05	0.95
16	1.000	0.200	1.450	1.20	-0.75	1.00	1.05	0.95
17	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95
18	3.330	0.680	4.000	3.00	-0.75	1.00	1.05	0.95
19	1.810	0.370	0.000	0.00	0.00	1.00	1.05	0.95
20	1.280	0.260	0.000	0.00	0.00	1.00	1.05	0.95
21	0.000	0.000	3.500	3.00	-0.75	1.00	1.05	0.95
22	0.000	0.000	2.500	1.45	-0.90	1.00	1.05	0.95
23	0.000	0.000	6.600	4.50	-1.75	1.00	1.05	0.95
24	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95

Table B.2 Line data of the RTS

Line No.	Bus		R	X	B/2	Current Rating (p.u)	Tap	Failure Rate (occ/yr)
	From	To						
1	1	2	0.0260	0.0139	0.2306	1.93	1.00	0.240
2	1	3	0.0546	0.2112	0.0286	2.08	1.00	0.510
3	1	5	0.0218	0.0845	0.0115	2.08	1.00	0.330
4	2	4	0.0328	0.1267	0.0172	2.08	1.00	0.390
5	2	6	0.0497	0.1920	0.0260	2.08	1.00	0.390
6	3	9	0.0308	0.1190	0.0161	2.08	1.00	0.180
7	3	24	0.0023	0.0839	0.0000	5.10	1.00	0.020
8	4	9	0.0268	0.1037	0.0141	2.08	1.00	0.360
9	5	10	0.0228	0.0883	0.0120	2.08	1.00	0.340
10	6	10	0.0139	0.0605	1.2295	1.93	1.00	0.330
11	7	8	0.0159	0.0614	0.0166	2.08	1.00	0.300
12	8	9	0.0427	0.1651	0.0224	2.08	1.00	0.440
13	8	10	0.0427	0.1651	0.0224	2.08	1.00	0.440
14	9	11	0.0023	0.0839	0.0000	6.00	1.00	0.020
15	9	12	0.0023	0.0839	0.0000	6.00	1.00	0.020
16	10	11	0.0023	0.0839	0.0000	6.00	1.00	0.020
17	10	12	0.0023	0.0839	0.0000	6.00	1.00	0.020
18	11	13	0.0061	0.0476	0.0500	6.00	1.00	0.020
19	11	14	0.0054	0.0418	0.0440	6.00	1.00	0.390
20	12	13	0.0061	0.0476	0.0500	6.00	1.00	0.400
21	12	23	0.0124	0.0966	0.1015	6.00	1.00	0.520
22	13	23	0.0111	0.0865	0.0909	6.00	1.00	0.490
23	14	16	0.0050	0.0389	0.0409	6.00	1.00	0.380
24	15	16	0.0022	0.0173	0.0364	6.00	1.00	0.330
25	15	21	0.0063	0.0490	0.0515	6.00	1.00	0.410
26	15	21	0.0063	0.0490	0.0515	6.00	1.00	0.410
27	15	24	0.0067	0.0519	0.0546	6.00	1.00	0.410
28	16	17	0.0033	0.0259	0.0273	6.00	1.00	0.350
29	16	19	0.0030	0.0231	0.0243	6.00	1.00	0.340
30	17	18	0.0018	0.0144	0.0152	6.00	1.00	0.320
31	17	22	0.0135	0.1053	0.1106	6.00	1.00	0.540
32	18	21	0.0033	0.0259	0.0273	6.00	1.00	0.350
33	18	21	0.0033	0.0259	0.0273	6.00	1.00	0.350
34	19	20	0.0051	0.0396	00417	6.00	1.00	0.380
35	19	20	0.0051	0.0396	00417	6.00	1.00	0.380
36	20	23	0.0028	0.0216	0.0228	6.00	1.00	0.340
37	20	23	0.0028	0.0216	0.0228	6.00	1.00	0.340
38	21	22	0.0087	0.0678	0.0712	6.00	1.00	0.450

Table B.3 Generation data of the RTS

Unit No.	Bus No.	Rating (MW)	Priority order	Failures per year
1	22	50	1	4.420
2	22	50	2	4.420
3	22	50	3	4.420
4	22	50	4	4.420
5	22	50	5	4.420
6	22	50	6	4.420
7	15	12	1	2.980
8	15	12	2	2.980
9	15	12	3	2.980
10	15	12	4	2.980
11	15	12	5	2.980
12	15	155	6	9.130
13	7	100.0	1	7.300
14	7	100.0	2	7.300
15	7	100.0	3	7.300
16	13	197.0	1	9.220
17	13	197.0	2	9.220
18	13	197.0	3	9.220
19	1	20.0	1	19.47
20	1	20.0	2	19.47
21	1	76	3	4.470
22	1	76	4	4.470
23	2	20.0	1	19.47
24	2	20.0	2	19.47
25	2	76	3	4.470
26	2	76	4	4.470
27	23	155	1	9.130
28	23	155	2	9.130
29	23	350	3	7.620
30	18	400	1	7.960
31	21	400	1	7.960
32	16	155	1	9.130

Appendix C: Calculation of CCDF

Assume that the load composition in terms of the annual peak demand and energy consumption is as shown in Table C.1. The system CCDF is obtained using the data in Tables 4.1 and Table C.1. The weighting procedure used to obtain the CCDF is as follows. The CCDF value at the 1-min duration is obtained using the 1-min values in Table 4.1 and the sector peak % values in Table C.1.

Table C.1 Load composition for the assumed service area, based on annual peak demand and annual energy consumption

User sector	Sector peak (MW)	Sector peak (%)	Sector energy (%)
Large users	55.5	30.0	31.0
Industrial	25.9	14.0	19.0
Commercial	18.5	10.0	9.0
Agricultural	7.4	4.0	2.5
Residential	62.9	34.0	31.0
Govt.&inst.	11.1	6.0	5.5
Office&building	3.7	2.0	2.0
Total	185.0	100.0	100.0

CCDF (1-min duration) = 0.30(1.005) + 0.14(1.625) + 0.10(0.381) + …(0.02)(4.778)

= 0.668040

= 0.67 $/kW

The CCDF (20-min duration) was also obtained using the sector peak % values. The 2-, 4- and 8-hr values were obtained using the sector energy % values. All the results are shown in Table 4.2.

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Portions of Research work from this dissertation have been reported in the following publications:

L. Goel, Z. Song and P. Wang, "Well-being Analysis of Spinning Reserve in a Bilateral Power Market", Electric Power Systems Research, Volume 69, Issue 1, April 2004, pp. 37-42.

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