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Reliability Constrained Multi-Commodity Dispatch in Restructured Power Systems

Liu Yong (G3504420K)

School of Electrical & Electronic Engineering

A thesis submitted to the Nanyang Technological University
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Summary

For more than one hundred years, the power industries across the world had been operating as regulated utilities. Each electric utility ran as a local monopoly. In one area, there was only one utility that was in charge of all functions, including generating, transmitting, distributing and selling electricity and other services. Any customer had to buy the electricity from the local utility. Electricity price was set according to government regulatory rules. And the utility was assured a fix monetary return on its investment.

Nowadays, significant changes have occurred in power industries in some industry countries. In these countries, the traditional vertically integrated electric utility structure has been unbundled and economically separated into generation companies, transmission companies and distribution companies. This process is called restructuring or deregulation. Electric utility restructuring has brought forth significant changes in power system operation, planning, and trading process. In this new environment, many new topics are brought forward for academic researchers. Particularly, maintaining and/or enhancing power system reliability in the new environment has become one of the most important topics, which is the subject of this thesis.

This thesis is to investigate the technique to settle the energy and ancillary services to keep the system reliability at the required and appropriate level. A bi-fold approach is adopted to achieve this goal. On one hand, interruptible load (IL) is introduced as a source of operational reserve for the reliable operation of a restructured power system. On the other hand, the reliability-constrained system reserve criterion is proposed and used as the reliability constraint in the day-ahead electricity market settlement, which can more accurately assess the system operational risk and set the system reserve requirement accordingly. Furthermore, the impact of interruptible load, different system reserve criteria, and the transmission system failures on electricity market settlement has been investigated.

The arrangement of this thesis is as follows. Firstly, basic concepts about deregulation of power industry and its trading process are briefly reviewed. Especially, ancillary services including interruptible load are introduced as an important issue in new environment. Then, preliminary knowledge about economic dispatch (ED), security management and reliability assessment are presented. These techniques are adopted in this thesis to solve the multi-commodity dispatch problem. The reliability-constrained system reserve criterion is proposed and the effect of interruptible load bidding on system reliability enhancement is evaluated. Moreover, a more comprehensive model of the proposed technique is developed, which takes into account the impact of transmission system failures on electricity market clearing. The conclusion and recommendations for further research are given to end this thesis.

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1 Introduction

The restructuring of power industries is taking place in many countries throughout the world. This revolutionary process has brought forth significant changes in power system operation, planning, and trading [1, 2]. It also brings forward many new topics for academic researchers. In this new environment, reliability issues become more complicated and more important due to more economic concerns from market participants. In this chapter, motivation for this thesis is firstly described. Then, objectives and main contributions of this thesis are listed. In the end, the organization structure of this thesis is given.

1.1 Motivation

Deregulation of Electricity Industry

For over one hundred years, power industries across the world had been operating as regulated utilities. Each electric utility ran as a local monopoly. In one area, there was only one utility that was in charge of all functions including generating, transmitting, distributing and selling electricity and other services. Any customer had to buy the electricity from the local utility. Power price was set according to government regulatory rules. And the utility was assured a fixed monetary return on its investment.

Since 1980s drastic changes in power industries have occurred. With the traditional vertically integrated electric utility being unbundled, the utility is separated into different companies with different functions. Meanwhile, competition is introduced among these market entities. This process of commercial rearrangement of electric utility operation is called restructuring or deregulation [1]. The forces that lead to the deregulation are not all same in different countries [3]. While, the essential reason is to introduce competition and incentive in power industries to make the current utilities operate more efficiently.

Deregulation of electric industries is occurring in many countries around the world, such as Nordic countries, UK, South America, Singapore and US [4-10]. Different market models are developed in different countries in accordance with their own need. However, the usually adopted method is to open access to power delivery.

That means all the qualified market participants have equal rights to access to transmission network. Competition is introduced among power producers as well as among power buyers, such as retail companies and consumers. Besides these, independent system operator (ISO) is established to operate the transmission system and coordinate the various trades in the market. The power market is responsible for accepting the bids from the generation companies (Gencos) and customers and determining the market clearing price (MCP). In some cases, a power exchange (PX) is set up for market trading. The PX submits the balanced schedules to ISO and ISO is accountable for system operation. The framework of the wholesale electricity market is shown in Figure 1.1. This is a simplified structure of the market. The introduction of the electricity market will be given with more details in Chapter 2.

Figure 1.1 Framework of the Wholesale Electricity Market Structure

Generally, the operation of the wholesale electricity market is as follows:

- Power producers submit bids (prices and quantities) to ISO or PX.
- In a similar way, electricity buyers submit bids with prices and quantities to ISO or PX.
- Market clearing price (MCP) is determined as the intersection point of the aggregated producers' bidding curves and the aggregated buyers' bidding curves.
- All power producers are paid the market-clearing price (Note: There are other methodologies to determine the MCP).

In addition, in most electricity markets, power producers are allowed to directly make transactions with buyers. In deregulation environment, all market participants want to maximize their own profits. It is very important for government regulators to provide a fair field so as to send proper market signal to the market participants and thus to achieve better efficiency goal.

Deregulation has brought forth significant changes in power system operation, planning, and trading [3]. This brings forward many new topics for academic researchers. The components in deregulated power systems are operated closer to their capacity limits. This could put system operation at risk. The ISO has to manage to make power generation and load consumption in balance in normal and contingent cases. In deregulation environment, new technologies and products have to be developed, such as innovative control system, communication network, and metering products. Particularly, the study of maintaining and/or enhancing system reliability has become one of the most important topics, which is the subject of this thesis. In following subsections, the concept of power system reliability and the relevant issues in new environment are presented.

System Reliability

North American Electric Reliability Council (NERC) defines reliability as “the degree to which the performance of the elements of [the electrical] system results in power being delivered to customers within accepted standards and in the amount desired.” NERC’s definition of reliability includes two concepts, *adequacy* and *security*. *Adequacy* is defined as “the ability of the system to supply the aggregate electric power and energy requirements of the consumers at all times.” NERC defines *security* as “the ability of the system to withstand sudden disturbance.”

In other words, *adequacy* means that sufficient system resources are available to meet predicted load consumption with reserve for contingencies. *Security* means that the system operation remains reliable even in contingent cases. Obviously, both of them are complementary. Without system security, the generators output cannot be delivered to customers even though there is adequate power output. In turn, a high degree of security is no meaningfulness if there are no sufficient resources to meet customer need. On the other hand, the sufficiency of resources is

helpful to maintain a high degree of security. Likely, high level of system security can effectively reduce the redundancy of system recourses. Thus, the system opponents can be operated approaching their capacity limits. And the expensive infrastructure investment can be avoided.

Reliability issues should be paid more attentions in deregulation environment. It's obligatory that the competitive market mechanism be used to maintain reasonable level of system reliability at lower cost. The brief introduction about power system reliability evaluation technique is described in Chapter 3.

Reliability Issues in New Environment

As the result of restructuring, the traditional vertically integrated power system is unbundled. The different functions of power generation, transmission and distribution are managed by different companies respectively. In the new environment, power system reliability has been gaining more and more attentions due to the reduction of system operational margin with increasing competition among market participants. In restructured power systems, the objective of each market participant is to maximize its own profit in various trading. In some cases, this could result in insufficient system reserve and put system operation at risk. The normal operation of a power system requires that total power generation equals to total load consumption plus necessary reserve in case of emergent cases. In a practical power system, load changes and system components failure occurs randomly. In order to keep the system in balance, reserve is usually required to keep system operate safely and reliably.

How to guarantee the necessary and appropriate reliability level in deregulation environment? To solve the problem, one bi-fold approach could be used as proposed in this thesis. On one hand, interruptible load (IL) is introduced as an additional source of system reserve for the reliable operation of a restructured power system. In a conventional power system, the reserve dispatching is centrally managed by system operator. And operator mainly relies on controlling generators output to keep power generation and consumption in balance. This also could be achieved by changing load consumption. Interruptible load not only can reduce the reserve provided by generators, which is usually expensive, also provides a

mechanism to incorporate the demand-side participation into electricity market operation. In such way, customers can more flexibly control their load consumption according to their own reliability requirements.

On the other hand, the reliability-constrained system reserve criterion is proposed and used as one constraint in the day-ahead electricity market settlement, which can more accurately assess the system operational risk and set the system reserve requirement accordingly. In conventional power systems, deterministic methodologies are usually used to decide the system reserve requirement. They cannot assess the real risk the system is exposed to because they do not recognize the stochastic nature of system component failure. In deregulation environment, considering the fact that more uncertainty is emerging, probabilistic technique could be used to determine the system reserve requirement. More details about the proposed technique are elaborated in Chapter 4 and 5.

1.2 Objectives

This thesis is to investigate how to guarantee necessary and appropriate reliability level in the simultaneous settlement of energy and reserve market. As mentioned above, one bi-fold approach is proposed. On one hand, interruptible load is introduced as a source of operational reserve for the reliable system operation. On the other hand, the probabilistic method is adopted to determine the system reserve requirement. Specifically, the objectives of this thesis are listed as follows:

- To investigate the trading and pricing mechanism of a restructured power system.
- To incorporate interruptible load bidding in electricity market settlement to enhance system reliability.
- To introduce reliability-constrained system reserve criterion, which can more accurately assess the operational risk of a restructured power system and set the required system reserve accordingly.
- To investigate the impact of interruptible load, different system reserve criteria on electricity market settlement.
- To investigate the application of new optimization technique in electricity market settlement.

1.3 Major Contributions of This Thesis

The major contributions of this thesis are listed as follows:

- An AC OPF-based simultaneous auction design for energy and ancillary services is proposed.
- The impact of interruptible load on energy and spinning reserve market clearing has been investigated.
- A reliability-constrained system reserve criterion is proposed and used as one constraint in day-ahead spot market settlement.
- A more comprehensive model of the proposed technique is developed, which takes into account the impact of transmission system failure on electricity market clearing.
- The sequential quadratic programming (SQP) is used to solve the multi-commodity joint dispatch problem, which is a complex nonlinear constrained optimization problem.

1.4 Organization of This Thesis

Following the introduction chapter, the deregulation of power industry, the power trading process, and the relevant concepts are briefly introduced in Chapter 2. Especially, ancillary services including interruptible load are introduced as an important issue in new environment. The brief introduction of economic dispatch (ED), security management, and reliability evaluation in electricity market is provided in Chapter 3. These techniques are adopted in this thesis to solve the multi-commodity joint dispatch problem. In Chapter 4, the simultaneous dispatch of multi-commodity is formulated as one nonlinear constrained optimization problem and the proposed solution technique is presented in details. A more comprehensive model of the proposed technique is developed in Chapter 5 and the impact of transmission system failure on electricity market settlement is studied. Finally, the conclusion and recommendations for further research are given in Chapter 6.

2 Deregulated Electricity Market

In this chapter, firstly the deregulation of power industry, the trading process, and the related concepts are briefly introduced. Following, ancillary services including interruptible load are introduced as an important issue in deregulation environment. Moreover, overview of different electricity market models and different ancillary services management schemes in countries worldwide is presented.

2.1 Deregulation of Power Industry

Traditionally, the power industries across the world were being operated as regulated utilities. Every electric utility ran as a local monopoly. In one area, there was only one utility that was in charge of all functions including generating, transmitting and distributing and selling electricity and other services. Any customer had to buy the electricity from the local utility. Power price was set according to government regulatory rules. And the utility was assured a fixed monetary return on its investment.

Since 1980s drastic changes in power industries have occurred. With the traditional vertically integrated electric utility being unbundled, the utility is separated into different companies with different functions, such as generation companies, transmission companies, retail companies and other new emerging market participants. Meanwhile, the competition is introduced in power industry and participants are given more choice. Among the different functions, generation and retailing are to be competitive and transmission and distribution are commonly still regulated. The revenues for different services are also separated. This process of commercial rearrangements of electric utility operation is called restructuring or deregulation [1].

The forces that lead to the deregulation are not all same in different countries. As [3] points out, these forces behind the deregulation include: the pressure to privatize, the request from customers to buy cheaper energy, the demand for improving service quality, the demand for providing customers more choice, and the need to introduce incentive in current inefficient utility. By restructuring the power industries, it is expected that the competition can reduce power price,

encourage investment, improve decision, better use the existing facilities and provide more choice for customers.

Deregulation of the power industries is occurring in many nations around the world. Different market models are developed in different countries in accordance with their own need. However, the usually adopted method is to open access to power delivery. That means all the qualified market participants have rights to access to delivery network with equality. Undoubtedly, restructuring process makes the traditional vertically integrated electric utility replaced by an unbundled one, which is more complicated. For better understanding of this revolutionary process, some basic concepts of it are briefly reviewed as follows¹:

Open Access: As mentioned earlier, different market models are developed in different countries. The common method to achieve competition is to open access to power delivery. That means all the qualified participants have rights to access to delivery network with equality. In market environment, all participants want to maximize their own profit. It is very important for system operator to provide a fair field so as to send proper market signal to the market participants and thus to achieve better efficiency goal.

Competition among Power Producers and Retailers: In deregulation environment, competition is introduced among power producers as well as among power buyers. In one geographical area, there are a number of generation companies (Gencos). These power producers submit bids to compete for generation. Thus these producers must struggle to survive on the revenue obtained from selling electric power. Additionally, in some countries' markets the competition is also introduced among power buyers, such as retail companies and big load consumers. These power buyers also submit bids to compete to buy electric power. This is called retail market.

ISO and PX: Independent system operator (ISO) is established to operate the transmission system and coordinate the various trading in the market. The power market (spot market) is responsible for accepting the bids from the generation companies (Gencos) and from demand-side and determining the market clearing

price (MCP). In some cases, power exchange (PX) is set up for market trading, which operates like a stock exchange. Power sellers and buyers submit their bids to PX. PX determines the MCP and submits the balanced schedules to ISO. And ISO is accountable for the reliable operation of the power system.

Bilateral Contract: In most electricity markets, participants are allowed to directly make transactions each other so as to avoid price risk in spot market. Actually, there is also a hybrid model, which combines features of the two models mentioned above. This model provides power buyers with more flexibility to purchase electricity from either power pool or directly from power sellers.

2.1.1 Review of Deregulation around the World

In this section, reviewing of deregulation in countries around the world is presented. The focus is on the power trading process at the wholesale level. The different market models in different nations are introduced.

South America

In many ways, South America was the forerunner in driving restructuring spread to other countries [2]. Chile started its deregulation process in 1978 and Argentina followed in 1991 [11]. The wholesale electricity markets of both Argentina and Chile are hybrid ones, which include a spot market and a long-term market. An ISO or Poolco independently operates this market. Functionally, both models started with economic dispatch (ED). In Chile, Gencos are dispatched depending on generation cost and water availability (hydro Genco). The global load demand is forecast and values are updated monthly. The cost of the last unit selected to satisfy the load demand determines the short term marginal cost (STMC). Unit commitment is not important in Chile because of its predominant hydro system.

In Argentina, variable costs of the thermal generators are quoted and declared twice a year on a weekly basis. The price of Hydro Gencos is declared as a function of the reservoir's level. Discos submit their predicted load demand on a seasonal basis and set a maximum load that is not to be exceeded. The cost of the last unit dispatched to fulfill the load demand determines the market clearing price (MCP). In addition, large users (more than 1MW in Argentina and 2MW in Chile)

may contract directly with Gencos in the long-term market or buy in the spot market.

Deregulation in UK

The UK electric industry is an exemplary one in terms of deregulation [2]. The privatization process in UK began in February 1988 and a wholesale electricity market national wide was established in March 1990. The ISO in UK is the National Grid Company (NGC). It operates the power pool as well as owns and operates the transmission grid. In UK there are future, day-ahead, hour-ahead and real-time markets. In day-ahead market, the Regional Electricity Companies (RECs), as power buyers, submit load forecast and Gencos submit a 24-hour bid schedule [12-13] for next day to the pool. On this base, an unconstrained schedule is firstly derived, which minimizes the cost. The offer price of the marginal generator determines the system marginal price (SMP) for every half hour. On the operation day, when there is a deviation of the actual output from the unconstrained schedule, the change of the generator output is bought or sold in terms of its offer price. After all the transactions have been completed, power selling price (PSP) is calculated by adding an uplift related to the ancillary services cost. Consumers buy the energy in terms of PSP. The optional bilateral agreement can be made outside the pool through contract for the difference (CFD).

Scandinavian Island

The Norwegian market operated in May 1992 [14-15]. Sweden joined it in 1996. Finland became part of them in 1998 and Denmark in 1999. Today, the Nordic electricity market is recognized as most liquid and best-functioning market in the world [16]. ISOs in Nordic markets operate the transmission systems. Nord Pool operates spot market and future market. The spot market accepts bids for 24 hours of each day. Different from that in UK, the generating units take self-scheduling. In Norwegian market, the majority of electric sale (about 70%) is made through bilateral contracts between power sellers and buyers.

New Zealand and Australia

The deregulation of electric industry in New Zealand began in late 1980s [17]. During 1990s, extensive reform was implemented in New Zealand's electric

industry, which resulted massive change. The wholesale electricity market, New Zealand electricity market (NZEM), was established and operated by Marketplace Company Ltd (M-co) in 1996. The national transmission grid was owned and operated by Transpower. By adopting a nodal pricing model, M-co published the wholesale price of electricity at each grid point for each half-hour period. The spot market is supplemented by a range of forward contracts.

Since 1991, Australian government has reformed its electricity industry [18-19]. The national electricity market (NEM) started operation in December 1998, which is operated by the National Electricity Market Management Company (NEMMCO). Its responsibility is to manage the operation of the wholesale electricity market. In NEM generators can self-commit [20]. NEMMCO dispatches the scheduled generation and demand with the objective of minimizing the cost. A spot price for each half hour interval for the wholesale electricity is calculated independently of all the other intervals. In NEM, market participants can hedge risk by means of various financial instruments trading. NEM has permitted customers to choose their retailer, which is being introduced in stages [21].

North America

The power pool of Alberta began operation in 1996 [22]. Besides the responsibility for the safe and reliable system operation, the pool administrator is also responsible for making sure that all market participants comply with the related rules. On a day-ahead basis, both generating companies and electricity buyers submit offers to supply/purchase hourly blocks of energy at specific prices. Offers are submitted for a seven-day period and offer prices for the first trading day can't be altered. The pool administrator ranks offers and bids from the least expensive to the most expensive, and publishes a schedule for the next trading day. In real time, the hourly pool price is calculated from the actual dispatch and the pool settles with sellers and buyers monthly.

In USA, The Federal Energy Regulation Commission (FERC) deregulated the wholesale generation and bulk transmission with Order 888 in April 1996 [2, 23]. According to FERC's guidelines, the states are individually responsible for operating the electric industries in their own territories. The California electricity

market opened on May 31, 1998. The California Power Exchange (CPX) is a wholesale spot market. Except CPX, other power exchanges (also named scheduling coordinators) have been established. These scheduling coordinators can operate a market over a longer forward period. Bilateral trading of power is allowed in California. The California ISO manages the reliability issues, procures ancillary services, controls power dispatch, performs real time balancing of supply and demand, and administers congestion management. While, after the 2000 energy crisis CPX stopped operation and now CAISO is doing its functions. In New England, the ISO was in place in July 1997 [24]. It performs both ISO and PX functions. In New England Poolco bilateral trading is permitted. The New York ISO (NYISO) was formed in 1998. The Pennsylvania-Jersey-Maryland Pool (PJM) is Poolco type system. It runs both ISO and PX functions.

Asian Deregulation

In Asia, many countries are taking different ways to deregulate their electric industries. Japan opened the generation market for independent power providers (IPPs) in 1995 and in 2000 the retail sale of electricity took place partially and transmission access became open. In Thailand, IPP bidding commenced in 1995. Korea started liberation of generation market in 1995. In China, the Power Utility Law was in force in 1995 and Taiwan endorsed its first IPP in 1996. In Malaysia, TNB (electric utility company) was rearranged and its generation function shifted to Tenaga National Generation Company in 1997. In Singapore, the government corporatized the power and gas sections of Public Utility Board (PUB) on October 1, 1995.

2.2 Ancillary Services

In conventional electric utilities, all functions were centrally controlled. Some services, which are now commonly referred as ancillary services, such as frequency regulation, voltage control, and generation reserve had all been part of the electricity supply. With traditional power industry restructured, the functions of electric utility are unbundled. In new environment, system operator has to purchase ancillary services from their respective providers to ensure the required power quality and reliability of power system. Thus, ancillary services are very important issues in electricity market and much research has been done in this field.

Ancillary services are defined as all those activities that are necessary to support the transmission of electric power while maintaining reliable system operation and ensuring the required degree of quality. Ancillary services are also referred to as Interconnected Operation Services by North American Electric Reliability Council (NERC).

2.2.1 Ancillary Services Seen by Customers, Power Producers and Operator

As mentioned above, ancillary services are unbundled and priced separately in deregulation environment. While, from perspectives of different market participants and market administrator, the perceptions are different [25]. For customers, ancillary services are integrated to electricity supply. Any customer connected to the network is implicitly a consumer of ancillary services. For power producers, ancillary services are mainly defined by their contributions to system functions. Besides supplying active power, they supply or absorb reactive power and control the voltage as well as maintaining the system frequency. Finally, the system operator ensures the link between the power producers and customers. It purchases services from power producers to assure continuous supply to customers. Consequently, this raises the problem of evaluating relevant system cost, compensation of services suppliers and the allocation of cost to customers.

2.2.2 Ancillary Services' Classification and Definition

In this section, the NERC definitions of ten ancillary services are briefly introduced [26].

Category 1: Services required for normal operation

1. System Control

The control area operator function that schedule generation and transactions and control generation in real-time to maintain generation/load balance.

2. Voltage Control

Voltage Control entails the injection and/or absorption of reactive power, from generators and other reactive power compensation equipments, to maintain system voltages within required range.

3. Regulation

Regulation is the use of on-line generation units equipped with automatic generation control (AGC) or load to maintain minute-to-minute generation/load balance within the control area. This kind of units can change output quickly to track moment-to-moment fluctuation in load consumption and unintended fluctuation in generation output. Regulation also helps to maintain interconnection frequency, minimize difference between actual and scheduled power flow between control areas.

4. Load Following/Energy Imbalance

Load following refers to the use of on-line generation units to track the hour-to-hour and daily changes in customer load. Load following differs from regulation in three important respects: 1) It takes place over longer time interval (10 minutes or more). So different generators can provide this service; 2) The load-following patterns of customers are highly correlated with each other, in contrast to regulation patterns, which are largely uncorrelated; 3) Load-following changes are often predictable (e.g. the weather dependence of loads) and have similar day-to-day patterns.

Category 2: Services needed to prevent outages

1. Spinning Reserve

Spinning reserve is unloaded generating capacity that is synchronized to the power grid and can immediately (within 10 second) respond to generation/load imbalance and is fully available within several minutes. Federal Energy Regulatory Commission (FERC) of US has defines spinning reserve as the service provided by generating units that are on line and loaded at less than maximum output. This kind of units is available to serve load immediately in an unexpected contingency, such as unplanned outages of generating units. Spinning reserve must respond immediately to the contingency for short period (e.g. 10 minutes) until supplemental reserve comes on line.

2. Supplemental Reserve

The provision of generating capacity and curtailable load to generation/load imbalance and that is fully available within several minutes. However, unlike spinning reserve, supplemental reserve is not required to respond immediately.

Supplemental reserve can respond to system contingency within a short period of time – usually 10 minutes. Supplemental reserve must be maintained for 20 minutes after it responds to a contingency. Supplemental reserve usually are provided by: 1) generating units that are on-line but unloaded; 2) quick-start generating units; 3) interruptible load from demand-side, which is curtailable load based on an agreement between customers and electric utility.

3. Network Stability Service

Maintenance and use of special equipments (power-system stabilizer and dynamic-braking resistor) to maintain transmission system security.

In addition to the three services above, voltage control in *Category 1* can also acts like *Category 2* services and prevents voltage from decaying so far that voltage collapse occurs. And system control is required to manage these services.

Category 3: Services needed to restore the system after a blackout

1. System Blackstart Capability

The ability of a generating unit to start from a shutdown condition to an operation condition without assistance from the electrical grid and then to energize the grid to help other units start after a system-wide blackout occurs. Only generation unit can provide this kind of start-up service.

2.2.3 Global Overview of Ancillary Services Management

In this section, how ancillary services are managed in electricity markets around the world is briefly introduced [27].

New York ISO

In New York control area, ancillary services are provided by New York ISO (NYISO) or procured by the customers and suppliers themselves. NYISO coordinates the provision of all ancillary services and directly arranges for those services that are not self-supplied. According to the characteristics of these services, either market-based or embedded cost-based prices are used to price these services. In Table 2.1, the service provider and pricing method for each service are listed.

Table 2.1 NYISO Ancillary Services

Ancillary Service	Service Provider (SS: Self-Supplied)	Pricing Method
Scheduling, System Control and Dispatch	NYISO	Embedded Cost Based
Voltage Support	NYISO	Embedded Cost Based
Regulation and Frequency Respond	NYISO or SS	Market-based
Energy Imbalance	NYISO	Market-based
Operating Reserve	NYISO or SS	Market-based
Black Start Capability	NYISO	Embedded Cost Based

California ISO (CAISO)

In the California system, CAISO procures reactive power support service by long-term contract with must-run generating units [28]. After the day-ahead energy market is settled and the schedule is known, CAISO determines the required location-related amount of reactive power based on system power flow analysis. Then daily voltage schedules are issued to contracted generators and the transmission operators within the region.

JM Interconnection

The Pennsylvania-New Jersey-Maryland (PJM) interconnection restructured its operation in 1997. According to the reports of [29-30], reactive power is recognized as an ancillary service by PJM and its two components are separated. One component of it is the reactive capability at rated capacity of a generator and the other is the reactive capability at reduced generator output levels. It is mandatory that reactive power supply and voltage control services are provided directly by the individual provider. The provider defines the tariff rate for its customers. For the first component, the customer pays a charge in proportion to the total generation owner's monthly revenue and the amount of monthly use of the network. For the second component, generator is paid for the opportunity cost incurred as a result of increasing the reactive power production by lowering active power output.

United Kingdom

In UK, National Grid Company (NGC) operates the transmission system while maintaining a reliable supply. As the ISO, NGC is also responsible for making arrangement for ancillary services. NGC contracts for ancillary services with Gencos, regional electricity company, large consumer or even external entities. The Grid Code details the operational requirements of NGC and defines two categories of ancillary services, system ancillary services and commercial ancillary services [31]. They are briefly described as follows:

System Ancillary Services

System ancillary services are fundamental to system operation and all generating units must be able to provide this kind of services. System ancillary services are classified into two groups:

Group-1: Those services that all generators are obliged to provide.

- Reactive Energy: Other than that supplied by synchronous or static voltage compensator.
- Operating Margin (for frequency control): Capability of a generating unit to provide additional output with a short advanced notice.

Group -2: Services that NGC buys based on specific contracts

- Operating Margin (for frequency control): Capability of a gas turbine or pumped storage unit to fast start.
- Black Start Capability

Commercial Ancillary Services

Commercial Ancillary Services are the services that the generator is not obliged to provide and hence is subject to commercial agreements. Such services are as follows:

- Reactive energy: supplied by synchronous or static voltage compensator.
- Operating margin: provided by pumped storage unit, load reduction, stand-by generation, etc.

Sweden

The Swedish electricity market is dominated by bilateral contracts between power suppliers and customers. After the transaction is finalized and the daily

spot-market trading is settled, the suppliers and customers send information of the trades and generation schedules to Svenska Kraftnät. As the ISO, Svenska Kraftnät is responsible for the satisfactory system operation and procures the required ancillary services. Both reserve and regulation services are secured by Svenska Kraftnät through the regulating market.

In order to maintain the electricity supply/demand balance on a minute-by-minute basis, a two-tier approach is adopted. The primary regulation is implemented by generators in suitable power stations based on automatic frequency control. Svenska Kraftnät purchases this service from generating companies by long-term contracts. The secondary regulation is carried out by activating the most favorable bids from generators or consumers. Presently, no compensation is paid to generators for reactive power. Load shedding is recognized as an ancillary service, but not compensated. And no other ancillary services are recognized.

Finland

Fingrid, the Finnish ISO, is responsible for maintaining system voltage and thereby supplies reactive power. This is done through the use of its own resources and also by acquiring reactive power reserve from independent parties [32]. And now the provision of reactive power reserve is a mandatory service, i.e., generators of more than 10MVA rating are required to provide this service: 1) For generators connected to the 400KV power grid, their entire reactive power capacity should be available as reserve; 2) For generators connected to the 220/110KV grid, the mandatory reserve should not be less than half of the calculated reactive capacity corresponding to a power factor of 0.9; 3) For generators connected to the grid of less than 110KV, the reactive reserve should be half of their reactive intake capacity at the generators' voltage level. It is likely that a tariff mechanism for financial compensation will be in place for this service in the near future.

Australia

In Australia the National Electricity Market Management Company (NEMMCO) is responsible for procuring and scheduling various ancillary services. Seven services are recognized, which are classified in five system control activities as follows [33]:

Frequency Control Services

- Automatic generation control: This service is required from generators within five minutes as the ISO requests.
- Governor control: This service is based on the generators' governor droop characteristics and aids in frequency control, acting in from one-second to one-minute time frame.
- Rapid generator unit loading: This service requires generators not in operation to synchronize with the system within a five-minute time frame.
- Load shedding: This service requires curtailment of load following extreme frequency variations. The load is expected to automatically respond and disconnect with the system within a one-minute time frame.

Voltage Control Services

- Reactive power: This service is provided to keep system voltage at desired level by injection/absorption of reactive power at different nodes in the system. The financial compensation is only provided to generators and synchronous compensators.

Stability Control Service

- Rapid generator unit unloading: This service requires generators to unload rapidly from their normal operating conditions in order to preserve system stability. This may be demanded under some circumstances and is recognized as a system stability service.

Network Loading Control Services

- Automatic generation control
- Load shedding

These have been discussed above in the section of frequency control service. These two services are also recognized as network loading control services.

System Restart Service

- System restart is similar to the black start service defined by NERC. This service requires that the generators are able to energize the system after a

complete system failure.

Payment Mechanism

The payment to the ancillary service providers has been arranged in the Australian market based on the types of provided services and the providers' cost, including opportunity cost if applicable. Four categories of payment mechanisms are recognized and a particular service may fall in one or more of them for compensation.

- Availability payment: This payment is made to those services that require the providers' preparedness for providing the services when called for. This payment is applicable to system restart service and reactive power service from generating units.
- Enabling payment: This payment is made if a service has been activated by the ISO for use. This payment applies to all the ancillary services except for system restart and *reactive power* from generators while reactive power services from synchronous compensators are eligible for this payment.
- Usage payment: This payment is based on actual use of the ancillary services by the ISO and applies only to the rapid loading and rapid unloading service provided by generating units.
- Compensation payment: This payment is based on the providers' opportunity costs and is paid when the providers have been constrained from operating based on its market decision. This payment is applicable to all categories of services except reactive power service from synchronous compensators and system restart service.

Notes:

1. This part is as a summary of many references. Although the reference details are not listed here, the author of this thesis sure appreciates the contributions of those authors.

3 Adopted Techniques

As mentioned in Chapter 1, this thesis proposes a joint multi-commodity auction design to simultaneously settle the day-ahead energy and reserve markets, which is a complex nonlinear constrained optimization problem. The proposed technique mainly involves economic dispatch (ED), security management and reliability evaluation. In this chapter, these issues are briefly introduced. The details of problem formulation and solution process are given in Chapter 4.

3.1 Economic Dispatch in a Restructured Power System

Electric utilities are experiencing restructuring across the world. The objective of deregulation is to introduce competition in power industry and to reduce relevant cost [34-36]. The restructuring process has created many new problems regarding reliability issue, security management, pricing mechanism, system operation and planning. The conventional uniform electricity price is replaced by nodal price in a restructured power system. The market-driven economic dispatch (ED) takes the place of the conventional ED. In this section, firstly the conventional economic dispatch in a traditional power system is briefly reviewed [37]. Then, nodal price and its application in economic bidding in deregulation environment are introduced.

3.1.1 Economic Dispatch in a Conventional Power System

Economic dispatch in a conventional power system entails allocating the total system load among the available generating units with the least cost [37]. In the conventional vertically integrated power system, all the operation tasks, such as meeting the forecast demand, compensating for transmission loss, satisfying various operating constraints, balancing demand deviation in real-time and providing reserve for contingency, are integral services provided by electricity utility. The implementation of all these tasks is centrally controlled by power dispatching center. All the resources in one geographical area are belonged to a single utility. The electricity price is predefined. Utility can only make the maximum profit by minimizing system operation cost. The economic dispatch for inelastic (fixed) demand is different from that for elastic demand (demand sensitive to the price). For simplicity, the former is firstly reviewed without

considering transmission loss. For the same reason, 1) only the active power output of generators and the active power consumption of consumers are taken into account; 2) the transmission line capacity limit is not considered.

Economic Dispatch for Inelastic Demand

In a conventional power system, the objective of economic dispatch for inelastic demand without considering transmission loss is to minimize the total system cost subject to the constraint that the sum of generated power equals system load. Mathematically, this problem is formulated as:

$$\text{Min} \left(C_{\text{sys}} = \sum_{g=1}^{NG} C(P_g) \right) \dots \dots \dots (3.1)$$

$$\text{S.t. } H = \sum_{d=1}^{ND} P_d - \sum_{g=1}^{NG} P_g = 0 \dots \dots \dots (3.2)$$

Where C_{sys} is the total system cost and $C(P_g)$ is the cost function of generator g . P_g is the active power output of generator g and P_d is the active power consumption of consumer d . NG is the number of generators and ND is the number of consumers.

This is a nonlinear optimization problem with equality constraint, which can be solved by using *Lagrange* function as follows [37]:

$$L = C_{\text{sys}} + \lambda \cdot H \dots \dots \dots (3.3)$$

Where λ is *Lagrange multiplier*, which is an unknown constant.

The necessary condition for the existence of the optimum value is that the first derivatives of this function with respect to each independent variable P_g equal zero, which is as follows:

$$\frac{\partial L}{\partial P_g} = \frac{\partial C_{\text{sys}}}{\partial P_g} - \lambda = 0 \dots \dots \dots (3.4)$$

λ is also known as marginal cost. The above equation shows that only when the incremental cost rates of all generators are equal to λ , a minimum total system cost exists.

In addition to the equality constraint that the sum of the generators output equals the sum of the load consumption, there are two inequality constraints that must be satisfied by each generator. That is, the active power output of each generator must be greater than or equal to the minimum active power permitted and must also be less than or equal to the maximum active power permitted.

Summarily, the conventional economic dispatch for inelastic demand without considering transmission loss is formulated as follows:

$$\text{Min} \left(C_{\text{sys}} = \sum_{g=1}^{NG} C(P_g) \right) \dots\dots\dots (3.5)$$

$$\text{S.t. } P_g^{\min} \leq P_g \leq P_g^{\max} \dots\dots\dots (3.6)$$

$$\sum_{g=1}^{NG} P_g = \sum_{d=1}^{ND} P_d \dots\dots\dots (3.7)$$

Where $P_g^{\max}$ and $P_g^{\min}$ is the maximum and minimum active power output of generator g respectively.

Thus, the necessary condition for this optimization problem may be expanded as follows:

$$\frac{\partial C_{\text{sys}}}{\partial P_g} = \lambda \dots\dots\dots \text{for } P_g^{\min} \leq P_g \leq P_g^{\max} \dots\dots\dots (3.8)$$

$$\frac{\partial C_{\text{sys}}}{\partial P_g} \leq \lambda \dots\dots\dots \text{for } P_g = P_g^{\max} \dots\dots\dots (3.9)$$

$$\frac{\partial C_{\text{sys}}}{\partial P_g} \geq \lambda \dots\dots\dots \text{for } P_g = P_g^{\min} \dots\dots\dots (3.10)$$

The expanded necessary condition shows that due to the practical active power output constraints, the incremental cost rates of generators may be different when the minimum total system cost is reached.

Economic Dispatch for Elastic Demand

For elastic demand, the objective function of economic dispatch without regarding transmission loss becomes as:

$$\text{Min} \left(\sum_{g=1}^{NG} C(P_g) - \sum_{d=1}^{ND} B(P_d) \right) \dots\dots\dots (3.11)$$

Where $B(P_d)$ is the benefit function of customer d .

Subjects to the system power balance constraint of Equa. 3.7. For simplicity, the inequality constraints are not considered.

This optimization problem also can be solved by using *Lagrange Multiplier*. And the necessary condition for the optimum solution is as follows:

$$\frac{dC(P_g)}{dP_g} = \frac{dB(P_d)}{dP_d} = \lambda \dots\dots\dots(3.12)$$

Economic Dispatch Considering Transmission Loss

Practically, the active and reactive power loss inside the transmission system and equipments are inevitable. The active power loss is typical between 2% and 5% of total generation injection into the grid [37]. In this part, the effect of transmission loss on conventional economic dispatch is described. The objective function is as:

$$\text{Min} \left(C_{\text{sys}} = \sum_{g=1}^{NG} C(P_g) - \sum_{d=1}^{ND} B(P_d) \right) \dots\dots\dots(3.13)$$

Subjects to the following power balance constraint considering the effect of transmission loss:

$$H = \sum_{d=1}^{ND} P_d + P_{\text{sys}}^{\text{loss}} - \sum_{g=1}^{NG} P_g = 0 \dots\dots\dots(3.14)$$

Where $P_{\text{sys}}^{\text{loss}}$ is system active power loss. For simplicity, the inequality constraints are not considered.

By using the same Lagrange function as Equa. 3.3, the following result is obtained:

$$\frac{\partial L}{\partial P_g} = \frac{\partial C_{\text{sys}}}{\partial P_g} - \lambda \left(1 - \frac{\partial P_{\text{sys}}^{\text{loss}}}{\partial P_g} \right) = 0 \dots\dots\dots(3.15)$$

The system active power loss $P_{\text{sys}}^{\text{loss}}$ is a function of the independent variables P_g and system active power load $P_{\text{sys}}^{\text{load}}$. It can be seen that the transmission network's incremental power loss may cause a bias in the optimal economic scheduling of the generators.

Another useful set of data that are obtainable when the transmission network is incorporated in the scheduling process is the incremental costs of power at various points in the network [37], i.e. nodal price. Without considering transmission loss,

the incremental costs of power at all points in the grid are equal to λ , which is as follows:

$$\frac{\partial C_i}{\partial P_i} = \lambda \dots\dots\dots(3.16)$$

Where P_i is the active power injection into bus i . Bus i might be a load bus or a point where active power is injected into the network. C_i is the cost function of P_i .

Considering the effect of incremental transmission loss, the incremental costs of power at various spots differ throughout the network. Let the “penalty factor” of bus i be defined as follows:

$$pf_i = \frac{1}{1 - \frac{\partial P_{sys}^{loss}}{\partial P_i}} \dots\dots\dots(3.17)$$

Then the incremental costs at any two buses i and j satisfy the following equation:

$$pf_i C'_i = pf_j C'_j \dots\dots\dots(3.18)$$

Where $C'_k = dC_k/dP_k$ is the incremental cost of active power injection at bus k .

Thus, the incremental cost of active power at bus i is as:

$$C'_i = \left(\frac{pf_j}{pf_i} \right) C'_j \dots\dots\dots(3.19)$$

Where bus j is any real generator bus where the incremental cost of production is known. So Equa. 3.19 can be used to compute the incremental cost of active power at any point of the grid. This is the conceptual basis for spot price in electricity market, which is introduced in details in following part.

3.1.2 Nodal Price in an Electricity Market

In deregulation environment, traditional vertically integrated electric utility is unbundled and the distinct functions of power generation, transmission, distribution and selling are managed by different companies respectively. Customers are free to select electricity suppliers based on price and their reliability requirements. Electricity price is no longer fixed and determined by the regulatory

body. Power prices will be different at different nodes in the grid due to transmission loss and various system constraints, which can provide useful economic information regarding the usage of resources in a deregulated power system. This information can be used for system operator to make optimal operating decision, for power suppliers and users to make right choice on bidding, and for investors to select right time and location to do transmission and generation expansion.

Basic theory of spot price of electricity was developed by Schweppe, *et. al.*, [35]. As set forth by [35], the price for electricity is differentiated in space and time and accounts for the variable costs of production. The spot price at bus j at time t can be expressed mathematically as follows:

$$p_j = \theta(1 + \partial L / \partial D_j) + \sum_k \frac{\partial P_k}{\partial D_j} (\eta_{k,\max} - \eta_{k,\min}) \dots \dots \dots (3.20)$$

Where θ = the system marginal generating cost λ plus any required generating curtailment premium μ , i.e. $\theta = \lambda + \mu$.

L = a scalar representing system transmission loss

D_j = active power load at bus j

P_k = active power flow over transmission line k

$\eta_{k,\max} - \eta_{k,\min}$ = congestion charge for transmission line k (nonzero only if the line is fully loaded)

A lot of research work has been done to evaluate nodal price. Schweppe, *et. al.*, introduced the concept of essential part of spot price by using a DC load flow model. Baughman, *et. al.*, further developed the real-time price model by setting forth a comprehensive model for spot price with considering different constraints that often influence the operation of a power system [36]. Ray and Alvarado first utilized an optimal power flow (OPF) model to calculate the spot price and analyze its effect in [38]. Marginal costs of node power injection (nodal price) were represented as the Lagrangian multipliers corresponding to the power flow equations in [39] and it showed that OPF could be a very promising model for calculating the nodal price. Marginal cost in economics as shadow price was approved in [40]. However, Lagrangian multipliers cannot give full description of

components of nodal price. [41] decomposed the nodal price into various components corresponding to the important independent parts, such as generation, transmission congestion, voltage limitation etc, from the economic point of view. Recently the cost of supplying ancillary services becomes a hot research topic. Reactive power cost was taken into account in [42]. Power quality and environmental factor combined with the load-frequency control with the static equations were considered in [28]. Power market oriented OPF was discussed in [43], which can handle various inequality constraints via nonlinear interior point method. [44] calculated the distance of specific operating point to the system security limits and translated this distance into the security value. [45] presented the basic idea of the reliability differentiated pricing based on the customers' options of reliability and applied it into the spot pricing mechanism.

3.1.3 Economic Bidding in a Deregulated Power System

In a deregulated power system, resources are owned and managed by different entities. Electricity price varies with time and location and is not predetermined [35]. Each participant in electricity market wants to maximize its own benefit. On the conceptual basis of nodal price mentioned above, the market-oriented economic bidding is introduced. Firstly, the simple model without considering transmission loss is presented. For simplicity, system reactive power balance, transmission line capacity limit, and generator capacity constraint are not considered.

Economic Bidding without Transmission Loss

In the new environment, unit dispatch is determined by market bidding process [34]. The individual Genco bids into a power market. The objective of this bidding is to maximize the Genco's profit. The objective function is as follows:

$$\text{Max}(p \cdot P_g - C(P_g)) \dots \dots \dots (3.21)$$

Where p is the market clearing price.

A customer also wants to make the maximum benefit. For customer, the objective function becomes as follows:

$$\text{Max}(-(p \cdot P_d - B(P_d))) \dots \dots \dots (3.22)$$

Both above equations are subject to the system power balance Equa. 3.7.

When the incremental benefit converges to a single value p for all market participants, each of them can maximize its own profit:

$$\frac{dC(P_g)}{dP_g} = \frac{dB(P_d)}{dP_d} = p \dots\dots\dots(3.23)$$

This equation is almost same as Equa. 3.12. This shows that both the economic dispatch used in the conventional power system and the market-oriented one lead to the same power quantity traded with the same price in a perfect market. However, market participant may implement market power to maximize its own profit in some cases. If without considering the transmission loss, the market will converge to a single price based on the system economical dispatch no matter the market is perfect or not. But some of the social welfare may be lost [39].

Economic Bidding Considering Transmission Loss

Under perfect market condition (no market power exists), the necessary condition of the economic operation for each market participant considering transmission loss will be as follows:

$$\frac{\frac{dC(P_g)}{dP_g}}{1 - \frac{dP_{sys}^{loss}}{dP_g}} = \frac{\frac{dB(P_d)}{dP_d}}{1 - \frac{dP_{sys}^{loss}}{dP_d}} = p \dots\dots\dots(3.24)$$

$$p_i = \frac{dC(P_i)}{dP_i} = p \left(1 - \frac{dP_{sys}^{loss}}{dP_i} \right) \dots\dots\dots(3.25)$$

Where p_i is nodal price.

It can be seen that different node has different price due to the transmission loss. It is straightforward to see that the different price created by transmission loss at each bus is reflected by the ratio $1/(1 - dP_{sys}^{loss}/dP_i)$. Without the transmission loss, the marginal price of each market participant is identical and equal to the ideal market price p as defined in Equa. 3.23.

3.2 Security Management in Deregulation Environment

This section examines two of the most important ancillary services in a deregulated power system, namely spinning reserve (SP) and interruptible load (IL). The responsibility of ISO is to provide security constrained transmission service in an

open-market environment that is fair and equitable. In the new environment, the transmission network is heavily loaded due to the various trading. And the operational margin of power system is reduced with the increasing market competition. Therefore, security management is still an important issue in deregulation environment [27].

In a restructured power system, the basic problem is to maintain the reliable and safe operation. In pool type of market, system security constraints are often incorporated within the market settlement process. For example, in the New York and PJM (Pennsylvania, Jersey, Maryland) power pools, the ISOs implement a security constrained economic dispatch based on energy price offers, start-up cost offers, and minimum and maximum generation levels [46]. In the New Zealand Electricity Market (NZEM), various security constraints are simultaneously incorporated within the market clearing process [7]. The scheduling, pricing and dispatch (SPD) model adopted by NZEM considers branch flow limit, generator ramp rate, fast acting reserve (6 seconds), sustained reserve (acting within 60 seconds), and other various restrictions. The reserve scheduling also includes scheduling of interruptible load. In Nordic countries, the ISO is not in charge of either the market settlement or the bilateral contract settlement. Therefore, system security is carried out by the ISO through the balance market and counter-trade.

3.2.1 Dispatching of Spinning Reserve

The scheduling of spinning reserves is very important in the daily operation of power system. In the conventional power system, the most used approach is to set the reserve margin equal to the installed capacity of the largest generating unit or some percentage of the peak load. Such method is still applicable in deregulated environment. The only difference is that the reserve costs of units are replaced by the price bids for reserve.

However, it is pointed out that the deterministic approach cannot accurately assess the actual system risk. They do not recognize the stochastic nature of system components failure. In competitive market, probabilistic technique could be used to reflect the actual risk that the system is exposed to and set the system reserve accordingly. The proposed technique is given in details in next chapter.

The objective of dispatching spinning reserve is to minimize the total system cost subject to various constraints. Mathematically, this problem is formulated as follows:

$$\text{Min} \left(C_{\text{sys}} = \sum_{g=1}^{NG} C_g^{SR} \right) \dots\dots\dots (3.26)$$

$$\text{S.t. } P_g^{\min} \leq P_g^E + P_g^{SR} \leq P_g^{\max} \dots\dots\dots (3.27)$$

$$\sum_{g=1}^{NG} P_g^{SR} \geq RES_{\text{sys}}^{\text{req}} \dots\dots\dots (3.28)$$

Where C_g^{SR} is the spinning reserve (SR) bidding cost function of generator g . P_g^E is the active power and P_g^{SR} is the spinning reserve provided by the same generator g , respectively. $RES_{\text{sys}}^{\text{req}}$ is the required system reserve. The definitions of C_{sys} , NG , $P_g^{\min}$ and $P_g^{\max}$ are same as those in section 3.1.

Equa. 3.27 is called as generator capacity limit constraint. Due to the coupling effect between the active power and spinning reserve provided by one same generator, the sum of them must be greater than or equal to the minimum active power permitted and must also be less than or equal to the maximum active power permitted. It is the coupling effect that makes the market settlement economically inefficient in certain circumstances.

3.2.2 Interruptible Load Option

A number of demand-side management programs involve interruptible load. Their common characteristic is that they entail the utility to control the load directly or indirectly. Interruptible load scheme offer the customers a range of rate-reliability choices. In this kind of scheme, the customers sign interruptible load contracts with the utility to reduce their consumption as requested. The utility benefits from reducing its peak load to restoring voltage profile and ensuring system reliability. The customers benefit from reducing their energy charges. A market for interruptible load (callable forward) contract is proposed in [47], which is continuously tradable until the time of use. In UK large industrial customers are permitted to bid into the pool to reduce load, which is referred to as demand-side bidding (DSB) [48-49].

The settlement of interruptible load market is similar to that of spinning reserve market. However, as a source of operational reserve, interruptible load is more flexible than spinning reserve. This is because that interruptible load bidding comes from demand-side and there is no coupling effect between it and energy bidding. Mathematically, this problem is formulated as follows:

$$\text{Min} \left(C_{\text{sys}} = \sum_{d=1}^{ND} C_d^{IL} \right) \dots \dots \dots (3.29)$$

$$\text{S.t. } P_d^{\min} \leq P_d^{IL} \leq P_d^{\max} \dots \dots \dots (3.30)$$

$$\sum_{d=1}^{ND} P_d^{IL} \geq RES_{\text{sys}}^{\text{req}} \dots \dots \dots (3.31)$$

Where C_d^{IL} is the interruptible load (IL) bidding cost function of consumer d . ND is the number of IL bidding participants. P_d^{IL} is the actual IL bidding of consumer d . $P_d^{\min}$ and $P_d^{\max}$ is the lower and upper of IL limit, respectively.

3.2.3 International Practice of Interruptible Load Management

Demand-side Bidding Mechanism in UK

Within the UK power pool, demand-side bidding (DSB) was introduced in December 1993 [27]. As and when requested, the demand-side bidders will reduce a pre-defined amount of demand. The participants must offer at least 10 MW of their load for curtailment and should be prepared for 50 GWH demand reduction over a year.

The payment structure for demand-side bidding in UK is as follows:

- Demand-side bidders pay at *Pool Selling Price* for all actual consumption, no matter whether it was selected as being reducible or not.
- Demand-side bidders are paid an *Availability Payment* when they are selected to offer demand reduction.

This implies that the selected demand-side bidding is scheduled in a similar way as generating unit. The schedule is implemented as follows: The demand-side bidders bid in their reducible demand for each half-hour of the next day. Then the demand bids are scheduled in the unconstrained manner same as that of generating units. Within one hour of publishing the system marginal price, the demand-side bidders

will receive notification of demand reduction scheduled for the next day. In the event that there is no demand scheduled for reduction, then whenever the marginal price equals or exceeds the bid price, participants are required to reduce demand.

New York ISO (NYISO)

In NYISO, customers can offer interruptible load service via Load Serving Entity (LSE). But customers must contract with NYISO directly in order to bid in the day-ahead operating reserve market. The bids must be larger than 1MW, the response time 10 minutes and the interruption duration can be up to 1 hour. In NYISO, interruptible load is classified into two types:

- With non-price capped fixed energy: a fixed energy level with no price cap
- With price-capped energy: price-sensitive energy

There are 10-minute and 30-minute spinning reserve markets in NYISO. Interruptible load bidders can participate in these reserve markets. The bid can be 2MW or 1MW at each hour. The 2MW load is paid the day-ahead energy price while the 1MW load is paid the 10-minute spinning reserve market-clearing price [50-51].

Demand Relief Program of California ISO (CAISO)

CAISO has initiated a demand relief program to motivate customers to reduce their consumption during times of resource shortage. The payment is based on the monthly capacity reservation, which is preset by ISO. The customer must be able to reduce at least 1MW load when requested. When the emergency reserve falls below 5%, the loads without back-up generation are called first for interruption. These loads can be curtailed up to four hours and need to respond to curtailment signal within thirty minutes. When the emergency reserve falls below 2%, the loads with back-up generation are called second for interruption. These load needs to respond within fifteen minutes [52].

Alberta Power Pool

The Alberta power pool in Canada has a curtailable-load program to uplift the system security. Customers participating in this program need to offer at least 1MW load. Based on the submitted curtailable bids, the pool operator determines

the contracted bidders and categorizes these contracts into Type-1 or Type-2. The Type-1 contract is for a one-month period. The interruption duration is up to four hour. The response time is within one hour. And the maximum number of interruption requests is five per month. The financial compensation for Type-1 contract is based on a fixed price per MW per month. The Type-2 contract is for a one-week period requiring the customer to reduce its load within one hour up to a four-hour duration. The financial compensation for Type-2 contract is based on a price per MWh and is paid only when curtailment is activated [53]. In Alberta power pool, curtailable-load bids are ranked in order of the price, from highest to lowest. The pool operator selects the bids starting from the lowest price ones till meeting the curtailment quantity requirement.

NEMMCO Australia

The National Electricity Market Management Company (NEMMCO), the ISO in Australia, allows for demand side bidding in the market. So far, only a few large customers and pump-storage hydro power plants are participating and they are centrally dispatched [54].

3.3 Power System Reliability Evaluation

As the result of restructuring, the traditional vertically integrated power system is unbundled. In the new environment, system reliability has been gaining more and more attention due to the reduction of system operational margin with increasing market competition. In this section, the basic concepts of power system reliability evaluation are reviewed [55].

Power system reliability evaluation has been extensively developed and a wide range of indices has been determined. Reliability means the overall ability of the system to perform its functions. Power system reliability assessment can be divided into two basic aspects: *adequacy* and *security*. *Adequacy* means that there are sufficient system facilities to satisfy the load demand and system operational constraints. *Security* means that the system can withstand various disturbances. It is important to point out that most probabilistic techniques presently developed for reliability evaluation are in the domain of *adequacy* assessment. The available

probabilistic techniques to assess *security* are very limited. It also needs to point out that most reliability indices used at the present time are adequacy indices and not overall reliability indices.

3.3.1 Functional Zone and Hierarchical Level

The basic techniques for reliability assessment can be classified in terms of their application to segments of a complete power system. These segments shown in Figure 3.1 are defined as functional zones [55].

Figure 3.1 Functional Zones

Reliability evaluation can be implemented in each of these three functional zones as well as the combinations of them, which shapes the hierarchical levels shown in Figure 3.2.

Figure 3.2 Hierarchical Levels

These hierarchical levels can also be used in reliability assessment [55]. Hierarchical Level I (HLI) is only concerned with the generation facilities. Hierarchical Level II (HLII) comprises both generation and transmission facilities while Hierarchical Level III (HLIII) includes all these three functional zones.

3.3.2 Reliability Assessment

Generation System (HLI) Study

HLI reliability assessment determines the ability of all generating units within the system to meet the total load demand. This is usually termed “generation capacity reliability evaluation” [55]. The system model used at HLI level is shown in Figure 3.3.

Figure 3.3 HLI Model

In this model the transmission system is ignored. The basic concern is to assess that whether or not there is adequate generating capacity to meet the system demand in normal or contingent states.

Composite System (HLII) Study

In HLII, the simple generation-load model is extended to include transmission system. Reliability analysis at this level is usually termed composite system or bulk transmission system evaluation [55]. The extended model is illustrated in Figure 3.4.

Figure 3.4 HLII Model

This model is used to examine the ability of the composite system to perform its functions. The HLII model is much complex than that used in HLI considering the effect of load flow, contingency analysis, overload alleviation, generation rescheduling, and load shedding, etc.. Besides, the various types of outages, such as dependent, common-cause, and station-related ones, make composite system reliability evaluation more sophisticated.

Distribution System Study

The HLIII reliability assessment becomes very complex as this level involves all three functional zones. Therefore, the distribution functional zone is usually analyzed as a separate part.

3.3.3 Reliability Indices

This section presents some widely used reliability indices at different hierarchical levels [55]. These indices are basically expected values of random variables, which are the long-run average of the variables studied. These expectation indices provide valid reliability information and reflect the effects of various factors on reliability evaluation. It is important to point out that there are two sets of reliability indices: nodal/bus indices and overall system indices, which are complementary and not alternatives.

Reliability Indices in HLI

The basic indices in generating system reliability assessment are loss of load expectation (*LOLE*) and loss of energy expectation (*LOEE*). Mathematically, these indices can be calculated using the following equations:

LOLE (days/yr or hrs/yr)

$$LOLE = \sum_{i \in S} p_i \cdot T \dots\dots\dots (3.32)$$

Where p_i is the probability of system state i and S is the set of all system states with load curtailment. T is the days/hours number. *LOLE* means the average number of days or hours in a given period (usually one year) in which the daily peak load or hourly load exceeds the available generating capacity. This index does not indicate the severity of the deficiency nor the frequency nor the duration of load curtailment. But it is at present the most widely used probabilistic criterion in generating capacity planning study.

LOEE (MWh/yr)

$$LOEE = \sum_{i \in S} 8760 \cdot C_i p_i \dots\dots\dots (3.33)$$

Where C_i is the load curtailment for system state i . *LOEE* means the expected energy not supplied by the generating system due to the load demand exceeding

the available generating capacity. This index incorporates the severity of deficiencies with the duration and likelihood of them.

Reliability Indices in HLII

The reliability indices in HLI can be extended to composite system reliability assessment.

EDNS -Expected Demand Not Supplied (MW)

$$EDNS = \sum_{i \in S} C_i p_i \dots\dots\dots(3.34)$$

EENS -Expected Energy Not Supplied (MWh/yr)

$$EENS = \sum_{i \in S} 8760 \cdot C_i p_i \dots\dots\dots(3.35)$$

Where all definitions are same as those in HLI. Specifically, *EENS* is similar to *LOEE* in HLI. And it is an important index in composite system reliability assessment.

Frequency and Duration

A power system may operate in different system states. The system states and the transitions among them can be represented by a state space diagram [55]. The state space diagram for a single component is shown in Figure 3.5. The system has two states and can move from *up* state to *down* state, and in turn also can move from *down* state to *up* state. In Figure 3.5, λ and μ is failure rate and repair rate of one component respectively. The time between two failures is also called the cycle time (T) and the reciprocal of T is defined as failure frequency f .

Figure 3.5 State Space Diagram

A power system usually operates in the stable state. Thus, the frequency of entering a system state will equal the frequency of leaving that state. This is expressed as:

$$f = \lambda \cdot A = \mu \cdot U \dots\dots\dots(3.36)$$

Where A and U is the availability and unavailability of the component respectively. Mean durations of the up state and down state are designated as mean time to failure (MTTF) and mean time to repair (MTTR) respectively.

$$MTTF = \frac{1}{\lambda} \dots\dots\dots(3.37)$$

$$MTTR = \frac{1}{\mu} \dots\dots\dots(3.38)$$

A and U can be calculated as follows:

$$A = \frac{\mu}{\lambda + \mu} = \frac{MTTF}{MTTF + MTTR} \dots\dots\dots(3.39)$$

$$U = \frac{\lambda}{\lambda + \mu} = \frac{MTTR}{MTTF + MTTR} \dots\dots\dots(3.40)$$

And they satisfy the following equation:

$$A + U = 1 \dots\dots\dots(3.41)$$

A power system usually consists of many components such as generators and transmission lines. Definitions above can be applied to any size of power system. Considering a power system with a independent components, for contingency state j with exactly b failed components, the state probability p_j , the departure rate D_j of leaving this state and the mean outage duration d_j can be determined as follows:

$$p_j = \prod_{i=1}^b U_i \cdot \prod_{i=b+1}^a A_i \dots\dots\dots(3.42)$$

$$D_j = \sum_{i=1}^b \mu_i + \sum_{i=b+1}^a \lambda_i \dots\dots\dots(3.43)$$

$$d_j = \frac{1}{D_j} \dots\dots\dots(3.44)$$

4 Multi-Commodity Dispatch in Restructured Power System

In this chapter, an AC OPF-based simultaneous auction design for energy and ancillary services including interruptible load is proposed. The reliability-constrained system reserve criterion is introduced and used as one constraint in the day-ahead spot market settlement. The impact of interruptible load on energy and spinning reserve market clearing is investigated. The sequential quadratic programming (SQP) is used to solve the multi-commodity joint dispatch problem, which is a complex nonlinear constrained optimization problem.

4.1 Problem Formulation

In deregulation environment, the system operational margin is reduced due to the increased competition among market participants. The main objective of this thesis is to investigate how to guarantee the necessary and appropriate reliability level while the energy and reserve market are simultaneously settled. To solve the problem, one two-tier approach is proposed. On one hand, interruptible load is introduced as a source of operational reserve for the reliable system operation. On the other hand, the probabilistic method is adopted to determine the system operational reserve.

Conceptually, the basic problem is to simultaneously dispatch energy and ancillary services including interruptible load in a day-ahead spot market. The market settlement interval is assumed to be one hour. The objective function (OF) is as follows (Note: Under perfect market condition, i.e. that no market power exists, the OF to minimize the total system cost and that to maximize the total social welfare lead to the same result. In this thesis, the former is adopted.):

$$\text{Min} \left(C_{\text{sys}} = \sum_{g=1}^{NG} (C_g^E + C_g^{SR}) + \sum_{d=1}^{ND} C_d^{IL} \right) \dots\dots\dots (4.1)$$

Where C_{sys} is the total system cost. C_g^E , C_g^{SR} and C_d^{IL} is the bidding cost function of energy, spinning reserve (SR), and interruptible load (IL), respectively. NG is the number of generating units and ND is the number of IL bidders.

The above objective function is subject to the following constraints:

System power flow balance:

$$\sum_{g=1}^{NG} P_g^E - P_{sys}^{load} = P_{sys}^{loss} \dots\dots\dots(4.2)$$

Where P_g^E is the active power output of generator g . P_{sys}^{load} is the system active power load demand and P_{sys}^{loss} is the system active power loss.

$$\sum_{g=1}^{NG} Q_g^E - Q_{sys}^{load} = Q_{sys}^{loss} \dots\dots\dots(4.3)$$

Where Q_g^E is the reactive power output of generator g , Q_{sys}^{load} is the system reactive power load demand and Q_{sys}^{loss} is the system reactive power loss.

Transmission line capacity limit:

$$P_{i,j} \leq P_{i,j}^{max} \dots\dots\dots(4.4)$$

Where $P_{i,j}$ and $P_{i,j}^{max}$ is the actual active power flow and active power flow limit for the transmission line between bus i and j .

Bus voltage magnitude limit:

$$|V_i|_{min} \leq |V_i| \leq |V_i|_{max} \dots\dots\dots(4.5)$$

Where $|V_i|_{min}$ and $|V_i|_{max}$ is the lower and upper limit for bus voltage magnitude $|V_i|$ at bus i respectively.

Generator capacity limit:

$$P_g^{min} \leq P_g^E + P_g^{SR} \leq P_g^{max} \dots\dots\dots(4.6)$$

Where P_g^{min} and P_g^{max} is the minimum and maximum active power output of generator g respectively. P_g^E is the actual active power output and P_g^{SR} is the spinning reserve provided by the same generator g .

Load curtailment limit:

$$P_d^{min} \leq P_d^{IL} \leq P_d^{max} \dots\dots\dots(4.7)$$

Where P_d^{IL} is the actual curtailed load of IL bidder d . P_d^{min} and P_d^{max} is the lower and upper IL limit, respectively.

System reserve requirement:

$$\sum_{g=1}^{NG} P_g^{SR} + \sum_{d=1}^{ND} P_d^{IL} \geq RES_{sys}^{req} \dots\dots\dots(4.8)$$

Where RES_{sys}^{req} is the required system reserve.

4.2 Deterministic System Reserve Criterion

In a conventional power system, deterministic methods are usually used to determine system reserve requirement: reserve margin is either the portion of system load or the installed capacity of largest online generator. The essential weakness of deterministic methods is that they ignore the stochastic nature of system behavior and component failure and cannot assess the actual system risk [56]. For example, the outage of the largest online generator, usually much undesirable, is of little consequence if its occurrence is unlikely. Contrarily, if the failure probabilities of some relatively small generators are high, their outages would put the system in a dangerous state or even lead to the system blackout. Probabilistic techniques, however, can provide a realistic evaluation of the system risk by recognizing the stochastic nature of system component failure. The advantage of the probabilistic approaches is that they not only consider the severity of a system event and its impact on system operation but also the likelihood or probability of its occurrence [56]. The first major probabilistic technique for operating reserve assessment, known as the PJM method, was proposed in 1963. This method evaluates the probability of the committed generation of just satisfying or failing to satisfy the expected demand during a specified time into the future, known as the lead time.

Furthermore, due to the fact that the deterministic system reserve criterion is fixed once determined, the cost of the system reserve is usually recovered from customers on the basis of hourly electricity use. Thus, it does nothing to encourage customers to reduce the cost. On the other hand, this method cannot reflect the impact of the reliability performance of generating unit on system operation. It is likely that the monetary return of unreliable generator is still high. Therefore, the conventional deterministic method is economically inefficient and inequitable. Adopting probabilistic system reserve criterion can make it possible to assign system reserve cost to all market participants appropriately. With this approach used, those unreliable generators get less profits, which motivates those generators

owners to optimize the tradeoff between higher equipment and maintenance expenses and lower return.

4.3 Reliability-Constrained System Reserve Criterion

As mentioned above, the deterministic system reserve criterion cannot reflect the impact of the reliability performance of generating unit on system reserve margin determination. Due to the stochastic nature of power system component failure, the reliability-constrained system reserve criterion could be used instead. The derivation process is presented as follows.

In power system, availability (A) and unavailability (U) of system component are used to determine the relevant reliability indices. Unavailability (U) is usually termed as forced outage rate (FOR) in reliability evaluation. Availability/Unavailability of each component can be calculated using the average history data, which can be expressed as follows:

$$A = \frac{\mu_y}{\lambda_y + \mu_y} \dots\dots\dots(4.9)$$

$$U = \frac{\lambda_y}{\lambda_y + \mu_y} \dots\dots\dots(4.10)$$

Where λ_y and μ_y is the yearly failure rate and repair rate of one component respectively. Usually the above equations are used to determine A and U in power system planning in terms of years. Therefore, the A and U calculated using above equations are the yearly A and U of one component. While as supposed in section 4.1, the market settlement interval is 1 hour. Thus, the hourly A_h and U_h should be used instead and the outage replacement rate (ORR) should be used to replace FOR (U). ORR is defined as the probability that the generating unit fails and cannot be replaced by other units during the lead time (T) of this generator. The ORR of one generating unit with the hourly failure rate of λ_h can be calculated as:

$$ORR = 1 - e^{-\lambda_h T} \dots\dots\dots(4.11)$$

Considering the fact that the lead time of one generator is usually several hours,

and $T' = \text{market settlement interval} = 1\text{hour} < T$, the following derivation is obtained:

$\lambda_h T' < \lambda_h T \ll 1$, then

$$ORR \approx \lambda_h T' = \lambda_h \dots \dots \dots (4.12)$$

Summarily, the hourly A_h and U_h of one component can be calculated using the following equations:

$$A_h = 1 - U_h = 1 - \lambda_h \dots \dots \dots (4.13)$$

$$U_h = \lambda_h \dots \dots \dots (4.14)$$

Computation of EDNS in HLI

In this section, the system reliability is evaluated at HLI level and the HLI model is used. In a NG-unit-system, for system contingency state i , the probability of M generators being unavailable can be calculated as:

$$p_i = \prod_{j=1}^M U_j \cdot \prod_{j=M+1}^{NG} A_j = \prod_{j=1}^M \lambda_j \cdot \prod_{j=M+1}^{NG} (1 - \lambda_j) \dots \dots \dots (4.15)$$

Where A_j , U_j , and λ_j is the hourly availability, unavailability and failure rate of generator j respectively.

Expected demand not supplied ($EDNS$) considering the effect of interruptible load can be calculated as follows:

$$EDNS = \sum_{i=1}^K p_i \cdot C_i$$

$$= \sum_{i=1}^K p_i \cdot \left(P_{sys}^{load} - \sum_{j=M+1}^{NG} (P_j^E + P_j^{SR}) - \sum_{d=1}^{ND} P_d^{IL} \right) \dots \dots \dots (4.16)$$

Where C_i is the curtailed load in system contingency state i and K is the total number of system contingency states. And all other definitions are same as those in section 4.1. In order to relate the $EDNS$ with the required system reserve, the above equation is modified as follows:

$$EDNS = \sum_{i=1}^K p_i \cdot \left(P_{sys}^{load} - \sum_{j=M+1}^{NG} (P_j^E + P_j^{SR}) + \sum_{j=1}^M (P_j^E + P_j^{SR}) - \sum_{j=1}^M (P_j^E + P_j^{SR}) - \sum_{d=1}^{ND} P_d^{IL} \right)$$

$$= \sum_{i=1}^K p_i \cdot \left(P_{sys}^{load} - \sum_{j=1}^{NG} (P_j^E + P_j^{SR}) + \sum_{j=1}^M (P_j^E + P_j^{SR}) - \sum_{d=1}^{ND} P_d^{IL} \right)$$

At HLI level, $\sum_{j=1}^{NG} P_j^E = P_{sys}^{load}$, then

$$\begin{aligned} EDNS &= \sum_{i=1}^K p_i \cdot \left(-\sum_{j=1}^{NG} P_j^{SR} + \sum_{j=1}^M (P_j^E + P_j^{SR}) - \sum_{d=1}^{ND} P_d^{IL} \right) \\ &\leq \sum_{i=1}^K p_i \cdot \left(-\sum_{j=1}^{NG} P_j^{SR} + \sum_{j=1}^M P_j^{CAP} - \sum_{d=1}^{ND} P_d^{IL} \right) \\ &= \sum_{i=1}^K p_i \cdot \sum_{j=1}^M P_j^{CAP} - \sum_{i=1}^K p_i \cdot \left(\sum_{j=1}^{NG} P_j^{SR} + \sum_{d=1}^{ND} P_d^{IL} \right) \dots\dots\dots (4.17) \end{aligned}$$

Where P_j^{CAP} is the installed capacity of unavailable generator j .

Suppose that the allowed maximum $EDNS$ is $EDNS_{max}$, then $EDNS \leq EDNS_{max}$

$$\begin{aligned} \sum_{i=1}^K p_i \cdot \sum_{j=1}^M P_j^{CAP} - \sum_{i=1}^K p_i \cdot \left(\sum_{j=1}^{NG} P_j^{SR} + \sum_{d=1}^{ND} P_d^{IL} \right) &\leq EDNS_{max}, \text{ and} \\ \sum_j^{NG} P_j^{SR} + \sum_{d=1}^{ND} P_d^{IL} &\geq \frac{\sum_{i=1}^K p_i \cdot \sum_{j=1}^M P_j^{CAP} - EDNS_{max}}{\sum_{i=1}^K p_i} \dots\dots\dots (4.18) \end{aligned}$$

Now, the right-hand item of Equa. 4.8 becomes as:

$$RES_{sys}^{req} = \frac{\sum_{i=1}^K p_i \cdot \sum_{j=1}^M P_j^{CAP} - EDNS_{max}}{\sum_{i=1}^K p_i} \dots\dots\dots (4.19)$$

With different reliability performance, the unavailabilities of different generator are different. Using the reliability-constrained system reserve criterion, the reliability performance of generators in market settlement interval can be reflected and the system reserve can be determined accordingly. When the committed generators are very reliable, the value of required system reserve is relatively small. When the committed generators are less reliable, the value of required system reserve increases correspondingly. The correlation between both of them is shown and analyzed in details in section 4.5.

4.4 Solution Technique

A program has been developed using the proposed technique to demonstrate its effectiveness. This program is developed on the basis of MATPOWER 2.0 in the

environment of MATLAB 6.5. In this part, the solution procedure, the brief introduction of programming development and input data are presented.

4.4.1 Solution Procedure

Generally speaking, the solution process for multi-commodity dispatch is divided into two steps: 1) to do system reliability assessment so as to determine the required system reserve; 2) to dispatch multi-commodity simultaneously in day-ahead spot market. The whole process can be described as following diagram.

Figure 4.1 Solution Process

4.4.1.1 Reliability Assessment

In the first stage, system reliability evaluation can be implemented at different hierarchical levels (HL) and the relevant models are used. In this chapter, the HLI model is used and the HLII model is adopted in Chapter 5. In both models, the contingency enumeration method is used to do the reliability evaluation at different HLs. There are two main categories of reliability evaluation techniques: analytical and simulation [56]. Analytical techniques represent the system by analytical models and evaluate the indices from these models using mathematical solutions. Simulation methods estimate the indices by simulating the actual process and random behavior of the system. The contingency enumeration method falls into the former category, which involves selection and evaluation of contingencies,

classification of each contingency according to specified failure criteria, and computation of reliability indices.

Mathematically, the reliability evaluation algorithm is as follows:

1. Pre-specify one set of single and multiple system failures.
2. For one failure, determine the unsupplied loads and the possibility of its occurrence while system constraints are taken into account.
3. Check if all the pre-specified failures are examined. If not, go to step 1. Otherwise, terminate the reliability evaluation.

4.4.1.2 Multi-Commodity Dispatch

In the second stage, joint multi-commodity dispatch in spot market is a nonlinear constrained optimization problem. In this stage, the sequential quadratic programming (SQP) [57] is adopted to solve this problem. The solution process includes: 1) the solution of a set of nonlinear equation using Newton's method and 2) the derivation of simultaneous nonlinear equations using Kuhn-Tucker conditions to the Lagrangian of the constrained optimization problem. This algorithm uses a line search process based on Quasi-Newton method and the Broyden-Fletcher-Goldfarb-Shanno (BFGS) formula for the Hessian matrix update. Solutions of the joint multi-commodity dispatch include the dispatch schemes for energy, spinning reserve and interruptible load (IL), system active power loss, nodal energy price, spinning reserve price for each Genco, and interruptible load price for each IL bidder. The simulation results in different case studies are given in next section.

Sequential Quadratic Programming

Sequential Quadratic Programming (SQP) is the most efficient gradient-based algorithm for constrained nonlinear optimization problem. In this part, the SQP algorithm is briefly described [58].

The SQP makes a quadratic model of the objective function and linear models of the constraints, and solves them at each iteration. The problem approximated in this way is called quadratic program (QP) or QP sub-problem.

Generally, the constrained nonlinear optimization problem is formulated as follows:

$$\min f(x) \dots\dots\dots (4.20)$$

$$\text{S.t. } h(x)=0 \dots\dots\dots (4.21)$$

$$g(x) \leq 0 \dots\dots\dots (4.22)$$

Firstly, the objective function $f(x)$ is quadratically approximated as in the Newton method or Guasi-Newton method for unconstrained minimization problem:

$$f(x^k) + \nabla f(x^k)^T (x - x^k) + \frac{1}{2} (x - x^k)^T B_k (x - x^k) \dots\dots\dots (4.23)$$

Where B_k is an n-by-n symmetric matrix and x_k is the current point. Moreover, the constraints are approximated as follows:

$$h(x^k) + \nabla h(x^k)^T (x - x^k) = 0 \dots\dots\dots (4.24)$$

$$g(x^k) + \nabla g(x^k)^T (x - x^k) \leq 0 \dots\dots\dots (4.25)$$

The Lagrangian function $L(x)$ is defined as:

$$L(x) = f(x) + \lambda^T h(x) + \mu^T g(x) \dots\dots\dots (4.26)$$

Where λ is a vector of approximate Lagrange multipliers and μ is a vector of approximate KKT (Karush-Kuhn-Tucker) multipliers.

Instead of using the true Hessian of the Lagrangian, the BFGS approximation of the Hessian is used:

$$H_{k+1} = H_k + \frac{q_k q_k^T}{q_k^T p_k} - \frac{H_k p_k p_k^T H_k}{p_k^T H_k p_k} \dots\dots\dots (4.27)$$

$$p_k = x_{k+1} - x_k \dots\dots\dots (4.28)$$

$$q_k = \nabla f(x_{k+1}) + \lambda^T \nabla h(x_{k+1}) - (\nabla f(x_k) + \lambda^T \nabla h(x_k)) \dots \dots \dots (4.29)$$

The solution of the QP sub-problem provides a search direction d_k , which is used to generate a new point x_{k+1} :

$$x_{k+1} = x_k + \alpha d_k \dots \dots \dots (4.30)$$

A line search is executed such that the following penalty function is minimized:

$$\Psi(x) = f(x) + \rho \left[\sum_{i=1}^p |h_i(x)| + \sum_{i=1}^m \max\{0, g_i(x)\} \right] \dots \dots \dots (4.31)$$

Where ρ is a penalty parameter.

The SQP algorithm is defined as follows:

1. Solve the QP sub-problem and obtain the search direction d_k .
2. Execute line search to minimize the penalty function $\Psi(x)$ and then generate the next point x_{k+1} .
3. Update the Hessian approximation H_{k+1} using the BFGS formula.
4. Check the convergence. If it is converged, terminate the search. Otherwise set $k = k + 1$ and go back to 1.

4.4.2 MATLAB

MATLAB® [59] is a high-performance language for technical computing. It integrates computation, visualization, and programming in an easy-to-use environment where problems and solutions are expressed in familiar mathematical notation. Using MATLAB, computationally intensive tasks can be performed faster than with traditional programming languages, such as C, C++, and Fortran. MATLAB can be used in a wide range of applications, including signal and image processing, communications, control design, test and measurement, financial modeling and analysis, and computational biology. Add-on toolboxes (collections

of special-purpose MATLAB functions) extend the MATLAB environment to solve particular classes of problems in these application areas.

4.4.3 MATPOWER

MATPOWER is a package of MATLAB m-files for solving power flow and optimal power flow problems. It is intended as a simulation tool for researchers and educators which will be easy to use and modify. MATPOWER is designed to give the best performance possible while keeping the code simple to understand and modify. It is developed by Ray Zimmerman and Deqiang Gan of Power Systems Engineering Research Center (PSERC) at Cornell University [60]. According to the terms of use, MATPOWER is a free program. And anyone may use and modify it for his own use.

MATPOWER includes two solvers for the optimal power flow (OPF) problem. The first is based on the *constr* function included in MATLAB's Optimization Toolbox, which uses a SQP technique with a Quasi-Newton approximation for the Hessian matrix. The second approach is based on linear programming (LP). It can use the LP solver in the Optimization Toolbox or other MATLAB LP solvers available from third parties. The OPF problem solved by MATPOWER is a "smooth" OPF with no discrete variables or controls. The objective function is the total cost of real and/or reactive generation. These costs may be defined as polynomials or as piecewise-linear functions of generator output. The problem is formulated as follows:

$$\min f(x)$$

$$\text{Such that } g(x) \leq 0$$

Where $f(x)$ and $g(x)$ are nonlinear functions.

As mentioned above, the first of the two OPF solvers in MATPOWER is based on the *constr* nonlinear constrained optimization function in MATLAB's Optimization Toolbox. MATPOWER provides *constr* with two m-files which it uses during for the optimization. One computes the objective function $f(x)$, and the constraint violations $g(x)$ at a given point x . And the other computes their

gradients $\partial f(x)/\partial x$ and $\partial g(x)/\partial x$. MATPOWER has two versions of these m-files. One set is used to solve systems with polynomial cost functions. In this formulation, the cost functions are included in a straightforward way into the objective function. The other set is used to solve systems with piecewise-linear costs. Piecewise-linear cost functions are handled by introducing a cost variable for each piecewise-linear cost function. The objective function is simply the sum of these cost variables which are then constrained to lie above each of the linear functions which make up the piecewise-linear cost function. Clearly, this method works only for convex cost functions. In this thesis, the *constr* solver is used for the OPF problem and the objective function is defined as polynomial.

4.4.4 Input Data

A test system, named RBTS [61], is used to illustrate the effect of the proposed technique. In this part, firstly the brief description of RBTS is given. Then, the basic RBTS generation system data is presented, which is used as the input data of the developed program. The transmission network data are given in next chapter.

This system has 2 generator (PV) buses, 4 load (PQ) buses, 9 transmission lines and 11 generating units. The voltage level of the transmission system is 230KV. The system peak load is 185MW and the total installed generating units capacity is 240MW.

Table 4.1 Generating Unit Reliability Data

Unit Size (MW)	Type	No. of Units	Forced Outage Rate	MTTF (hr)	Failure Rate per Year	MTTR (hr)	Repair Rate per Year	Scheduled Maintenance (wk/yr)
5	Hydro	2	0.01	4380	2.0	45	198	2
10	Thermal	1	0.02	2190	4.0	45	196	2
20	Hydro	4	0.015	3650	2.4	55	157	2
20	Thermal	1	0.025	1752	5.0	45	195	2
40	Hydro	1	0.02	2920	3.0	60	147	2
40	thermal	2	0.03	1460	6.0	45	194	2

Generating System

The generating unit ratings and reliability data for RBTS are shown in Table 4.1. The locations of the generating units are shown in Table 4.2. The bus load data at the time of system peak in MW are shown in Table 4.3.

Table 4.2 Generating Unit Locations

Unit No.	Bus	Rating	Type
1	1	40	thermal
2	1	40	thermal
3	1	10	thermal
4	1	20	thermal
5	2	5	hydro
6	2	5	hydro
7	2	40	hydro
8	2	20	hydro
9	2	20	hydro
10	2	20	hydro
11	2	20	hydro

Table 4.3 Bus Load Data

Bus	Load (MW)
2	20
3	85
4	40
5	20
6	20
Total	185

4.5 Case Studies

The RBTS is modified to illustrate the effect of the proposed technique. The single line diagram of RBTS is shown in Figure 4.2. The generators connected to bus 1 and bus 2 are represented by Genco 1 and Genco 2 respectively. The generator failures up to the second order are considered in the reliability evaluation. 20% of

the load at each bus is assumed as the curtailable part, i.e. this part of load can be bid as interruptible load. The total system load is 185 MW. The allowed maximum $EDNS$ is assumed to be 0.2 MW (i.e. $EDNS_{\max} = 0.2MW$). The coefficients of all bidding cost functions are shown in Table 4.4. The bidding cost functions of all commodities are assumed to be quadratic as the follows:

$$C(x) = A \cdot x^2 + B \cdot x + C \dots\dots\dots(4.21)$$

Where x represents any commodity and A , B , C are corresponding coefficients.

In this section, different cases are studied and the simulation results are discussed in details.

Figure 4.2: Single Line Diagram of RBTS

Case 1:

In this case, the deterministic system reserve criterion is used and the reserve margin is set as 25% of total system load. Spinning reserve (SR) is the only

ancillary service commodity. The dispatch schemes for energy and spinning reserve are listed in Table 4.5. The system loss is 4.62 MW. The nodal energy price and spinning reserve price for each Genco are shown in Table 4.6.

Table 4.4 Coefficients of Bidding Functions

Cost functions	A	B	C
C_{Genco1}^E	0.02	12.45	10
C_{Genco2}^E	0.0175	10.75	10
C_{Genco1}^{SR}	0.002	1.245	1
C_{Genco2}^{SR}	0.00175	1.075	1
C_{d2}^{IL}	0.00255	1.46	5.0
C_{d3}^{IL}	0.00155	1.0	0.5
C_{d4}^{IL}	0.00195	1.2	4.0
C_{d5}^{IL}	0.00254	1.46	5.0
C_{d6}^{IL}	0.00254	1.46	5.0

Table 4.5: Dispatch Schemes (Case 1)

Power(MW)		SR(MW)	
Genco1	Genco2	Genco1	Genco2
76.42	113.2	29.46	16.79
189.62		46.25	

Case 2:

In this case, the same deterministic system reserve criterion is used as that in case 1. Both spinning reserve and interruptible load (IL) are ancillary service commodities. In case 2, the impact of interruptible load on energy and spinning reserve clearing price is analyzed. The dispatch schemes for energy, spinning reserve and interruptible load are listed in Table 4.7. The system loss is 4.66 MW. The nodal energy price, spinning reserve price for each Genco and interruptible load price for each IL bidder are shown in Table 4.8.

Table 4.6 Commodity Prices (Case 1)

Bus	Energy(\$/MW)
1	15.505
2	14.712
3	16.015
4	15.994
5	16.141
6	16.285
Genco	SR(\$/MW)
1	1.36
2	1.13

Table 4.7: Dispatch Schemes (Case 2)

Power(MW)		SR(MW)		IL(MW)	
Genco1	Genco2	Genco1	Genco2	IL3	IL4
75.35	114.31	5.56	15.69	17	8
189.66		21.25		25	
		46.25			

Table 4.8: Commodity Prices (Case 2)

Bus	Energy(\$/MW)	IL(\$/MW)
1	15.464	N/A
2	14.751	1.46
3	15.968	1.05
4	15.945	1.23
5	16.093	1.46
6	16.237	1.46
Genco	SR((\$/MW)	
1	1.27	
2	1.13	

The comparison of nodal energy prices of case1 and case 2 are shown in Figure 4.3. It can be seen that all nodal energy prices (except that at bus 2) and spinning reserve price of Genco1 in case 2 are lower than those in case 1. Since the energy bidding price of Genco1 is more expensive than that of Genco2, energy market is re-dispatched. The output of Genco1 reduces 1MW while Genco2 output increases 1MW. Therefore, the energy price at bus 2 slightly rises. Although the spinning reserve price of Genco2 is cheaper than interruptible load price at bus 4, constrained by generator capacity, it cannot provide more reserve. Because the spinning reserve bidding price of Genco1 is most expensive among the selected reserve market bidders, the reserve provided by Genco1 is reduced dramatically with the introduction of interruptible load bidding.

Figure 4.3: Nodal Energy Price Comparison

Case 3:

In this case, the reliability-constrained system reserve criterion is determined and used as one constraint. Here RES_{sys}^{req} is calculated using the Equa. 4.19 and the result is $RES_{sys}^{req} = 11.65MW$. Both spinning reserve and interruptible load are ancillary services commodities. Energy, spinning reserve and interruptible load dispatched in this case are listed in Table 4.9. The system loss is 4.72 MW.

Table 4.9: Dispatch Schemes (Case 3)

Power(MW)		IL(MW)
Genco1	Genco2	IL3
73.75	115.97	11.65
189.72		11.65

The nodal energy price, spinning reserve price for each Genco and interruptible load price for each IL bidder in case 3 are shown in Table 4.10.

Table 4.10: Commodity Prices (Case 3)

Bus	Energy(\$/MW)	IL(\$/MW)
1	15.400	NA
2	14.809	1.46
3	15.898	1.04
4	15.872	1.20
5	16.021	1.46
6	16.164	1.46
Genco	SR(\$/MW)	
1	1.24	
2	1.07	

Compared the results in this case with those in case 2, all nodal energy prices (except that at bus 2) decrease. The increase of nodal energy price at bus 2 is due to the increase of energy output by Genco2.

Case 4:

In this case, the failure rates of all generators are set as two times as those used in case 3. The reliability-constrained system reserve criterion is determined. Here $RES_{sys}^{req} = 66.4MW$. Both the spinning reserve and interruptible load are ancillary services commodities. The dispatch schemes for energy, spinning reserve and interruptible load in case 4 are listed in Table 4.11. The system loss is 4.63 MW. The nodal energy price, spinning reserve price for each Genco and interruptible load price for each IL bidder in case 4 are shown in Table 4.12

Table 4.11: Dispatch Schemes (Case 4)

Power(MW)		SR(MW)		IL(MW)	
Genco1	Genco2	Genco1	Genco2	IL3	IL4
76.21	113.42	24.82	16.58	17	8
189.63		41.40		25	
		66.40			

Table 4.12: Commodity Prices (Case 4)

Bus	Energy(\$/MW)	IL(\$/MW)
1	15.498	NA
2	14.720	1.46
3	16.006	1.05
4	15.985	1.23
5	16.132	1.46
6	16.276	1.46
Genco	SR(\$/MW)	
1	1.34	
2	1.13

Figure 4.4: Nodal Energy Price Comparison

The comparison of nodal energy prices of case 3 and case 4 are shown in Figure 4.4. It can be seen that with less reliable generators, more system reserve are required and the energy and reserve prices are different. All nodal energy prices (except that at bus 2), spinning reserve and interruptible load prices in case 4 increase compared with those in case 3. Because Genco2 provides less energy and Genco1 provides more reserve, the energy price at bus 2 decreases while spinning reserve price of Genco1 increases.

The case studies show that the reliability-constrained system reserve criterion can reflect the impact of generators reliability performance on the system reserve requirement determination. With different value of $EDNS_{\max}$ and different reliability data of generators, the different system reserve is required. With more reliable generators, small system reserve margin is required. While with less reliable generators, more system reserve has to be procured to keep power system operate safely and reliably.

5 Extended Development of Proposed Technique

Although the functions of power generation, transmission and distribution are unbundled in deregulation environment, the physical connection among them is still unchanged and the impact of transmission system on system reserve margin determination and multi-commodities dispatch need to be studied. In the event that transmission line outage occurs, system congestion may result in generation resheduling, load-shedding and the dramatic variation of energy and ancillary services price. In this chapter, the impact of transmission system on system reliability evaluation and system operation is investigated.

5.1 Problem Formulation

The problem formulation in this section is same as that in last chapter. While the system reliability evaluation is implemented at HLII level and the HLII model is used to determine the required system reserve. The basic problem is still to simultaneously dispatch energy and ancillary services in a day-ahead spot market. The market settlement interval is still one hour. All variable definitions in this chapter are same as those in last chapter. The objective is same as to minimize the total system cost. For convenience, the objective function and constraints are rewritten as follows:

The objective function is as:

$$\text{Min} \left(C_{\text{sys}} = \sum_{g=1}^{NG} (C_g^E + C_g^{SR}) + \sum_{d=1}^{ND} C_d^{IL} \right) \dots\dots\dots (5.1)$$

The cost functions for all commodities are still assumed to be quadratic as:

$$C(x) = A \cdot x^2 + B \cdot x + C \dots\dots\dots (5.2)$$

The objective function is subject to the following constraints:

System power flow balance:

$$\sum_{g=1}^{NG} P_{\text{sys}}^E - P_{\text{sys}}^{\text{load}} = P_{\text{sys}}^{\text{loss}} \dots\dots\dots (5.3)$$

$$\sum_{g=1}^{NG} Q_g^E - Q_{\text{sys}}^{\text{load}} = Q_{\text{sys}}^{\text{loss}} \dots\dots\dots (5.4)$$

Transmission line capacity limit:

$$P_{i,j} \leq P_{i,j}^{\text{max}} \dots\dots\dots (5.5)$$

Bus voltage magnitude limit:

$$|V_i|_{\min} \leq |V_i| \leq |V_i|_{\max} \dots\dots\dots(5.6)$$

Generator capacity limit:

$$P_g^{\min} \leq P_g^E + P_g^{SR} \leq P_g^{\max} \dots\dots\dots(5.7)$$

Load curtailment limit:

$$P_d^{\min} \leq P_d^{IL} \leq P_d^{\max} \dots\dots\dots(5.8)$$

System reserve requirement:

$$\sum_{g=1}^{NG} P_g^{SR} + \sum_{d=1}^{ND} P_d^{IL} \geq \overline{RES_{sys}^{req}} \dots\dots\dots(5.9)$$

Where $\overline{RES_{sys}^{req}}$ is the required system reserve determined using HLII model.

Apparently, $\overline{RES_{sys}^{req}} \geq RES_{sys}^{req} \Rightarrow \overline{RES_{sys}^{req}} - RES_{sys}^{req} = \Delta RES_{sys}^{req} \geq 0$. Here RES_{sys}^{req}

is the required system reserve determined using HLI model and ΔRES_{sys}^{req}

represents the increased system reserve requirement taking in account the impact

of transmission system. How to derive $\overline{RES_{sys}^{req}}$ and approximate ΔRES_{sys}^{req} is

presented in next section.

5. 2 Solution Procedure

Solution procedure in this chapter is same as that in last chapter. While in the first stage of reliability evaluation, the HLII model is adopted. Therefore, the reliability-constrained system reserve criterion derived in last chapter has to be modified. The derivation process is given in this section. All simulation results of different case studies are given in next section.

Extended Reliability-Constrained System Reserve Criterion

Considering the impact of transmission system on system operation, $EDNS$ adopted in last chapter is modified as follows:

$$\overline{EDNS} = \sum_{i=1}^K \overline{P_i} \cdot \left(\overline{P_{sys}^{load}} - \sum_{jg=MG+1}^{NG} \left(\overline{P_{jg}^E} + \overline{P_{jg}^{SR}} \right) - \sum_{d=1}^{ND} \overline{P_d^{IL}} \right) \dots\dots\dots(5.10)$$

$$\overline{P_i} = \prod_{jg=1}^{MG} \lambda_{jg} \cdot \prod_{jg=MG+1}^{NG} (1 - \lambda_{jg}) \cdot \prod_{jl=1}^{ML} \lambda_{jl} \cdot \prod_{jl=ML+1}^{NL} (1 - \lambda_{jl}) \dots\dots\dots(5.11)$$

Where $\overline{p_i}$ denotes the probability of MG units and ML transmission lines being unavailable in a N -Component-System ($N = NG + NL$) for system contingency state i . NL is the total number of transmission lines within the system. $\overline{K}$ is the total number of system contingency states, which is different from K in last chapter ($\overline{K} > K$). λ_{jg} , λ_{jl} is the hourly failure rate of generator jg and transmission line jl , respectively. $\overline{P_{jg}^E}$, $\overline{P_{jg}^{SR}}$, $\overline{P_d^{IL}}$ is the active power output and spinning reserve provided by generator jg , interruptible load of consumer d considering the impact of transmission system, respectively.

Constrained by the transmission system, if the contingency states occur at HLII level, generators/consumers cannot increase/decrease their active power output/consumption freely. Therefore, $\overline{P_{jg}^E} + \overline{P_{jg}^{SR}} \leq P_{jg}^E + P_{jg}^{SR}$ and $(P_{jg}^E + P_{jg}^{SR}) - (\overline{P_{jg}^E} + \overline{P_{jg}^{SR}}) = \Delta P_{jg} \geq 0$. Similarly, $\overline{P_d^{IL}} \leq P_d^{IL}$ and $P_d^{IL} - \overline{P_d^{IL}} = \Delta P_d^{IL} \geq 0$. Where P_{jg}^E , P_{jg}^{SR} , P_d^{IL} is the active power output and spinning reserve provided by generator jg , interruptible load of consumer d without considering the impact of transmission system, respectively.

In order to derive $\overline{RES_{sys}^{req}}$ and ΔRES_{sys}^{req} , Equa. 5.10 is modified as follows:

$$\begin{aligned} \overline{EDNS} &= \sum_{i=1}^{\overline{K}} \overline{p_i} \cdot \left(P_{sys}^{load} - \sum_{jg=MG+1}^{NG} (P_{jg}^E + P_{jg}^{SR} - \Delta P_{jg}) - \sum_{d=1}^{ND} (P_d^{IL} - \Delta P_d^{IL}) \right) \\ &= \sum_{i=1}^{\overline{K}} \overline{p_i} \cdot \left(P_{sys}^{load} + \sum_{jg=MG+1}^{NG} \Delta P_{jg} + \sum_{d=1}^{ND} \Delta P_d^{IL} - \sum_{jg=MG+1}^{NG} (P_{jg}^E + P_{jg}^{SR}) - \sum_{d=1}^{ND} P_d^{IL} \right) \\ &= \sum_{i=1}^{\overline{K}} \overline{p_i} \cdot \left(P_{sys}^{load} + \Delta P_{lost} - \sum_{jg=MG+1}^{NG} (P_{jg}^E + P_{jg}^{SR}) + \sum_{jg=1}^{MG} (P_{jg}^E + P_{jg}^{SR}) - \sum_{jg=1}^{MG} (P_{jg}^E + P_{jg}^{SR}) - \sum_{d=1}^{ND} P_d^{IL} \right) \\ &= \sum_{i=1}^{\overline{K}} \overline{p_i} \cdot \left(P_{sys}^{load} + \Delta P_{lost} - \sum_{jg=1}^{NG} (P_{jg}^E + P_{jg}^{SR}) + \sum_{jg=1}^{MG} (P_{jg}^E + P_{jg}^{SR}) - \sum_{d=1}^{ND} P_d^{IL} \right) \end{aligned}$$

Where $\Delta P_{lost} = \sum_{jg=MG+1}^{NG} \Delta P_{jg} + \sum_{d=1}^{ND} \Delta P_d^{IL}$. If P_{sys}^{loss} is ignored, $\sum_{jg=1}^{NG} P_{jg}^E = P_{sys}^{load}$.

$$\overline{EDNS} = \sum_{i=1}^{\overline{K}} \overline{p_i} \cdot \left(\Delta P_{lost} - \sum_{jg=1}^{NG} P_{jg}^{SR} + \sum_{jg=1}^{MG} (P_{jg}^E + P_{jg}^{SR}) - \sum_{d=1}^{ND} P_d^{IL} \right)$$

$$\begin{aligned}
 &\leq \sum_{i=1}^{\bar{K}} \bar{p}_i \cdot \left(\Delta P_{lost} - \sum_{jg=1}^{NG} P_{jg}^{SR} + \sum_{jg=1}^{MG} P_{jg}^{CAP} - \sum_{d=1}^{ND} P_d^{IL} \right) \\
 &= \sum_{i=1}^{\bar{K}} \bar{p}_i \cdot \left(\Delta P_{lost} + \sum_{jg=1}^{MG} P_{jg}^{CAP} \right) - \sum_{i=1}^{\bar{K}} \bar{p}_i \cdot \left(\sum_{jg=1}^{NG} P_{jg}^{SR} + \sum_{d=1}^{ND} P_d^{IL} \right) \dots\dots\dots(5.12)
 \end{aligned}$$

Where P_{jg}^{CAP} is the installed capacity of unavailable generator jg .

Suppose that the allowed maximum system $EDNS$ is still $EDNS_{sys}^{\max}$, then

$$\begin{aligned}
 &\sum_{i=1}^{\bar{K}} \bar{p}_i \cdot \left(\Delta P_{lost} + \sum_{jg=1}^{MG} P_{jg}^{CAP} \right) - \sum_{i=1}^{\bar{K}} \bar{p}_i \cdot \left(\sum_{jg=1}^{NG} P_{jg}^{SR} + \sum_{d=1}^{ND} P_d^{IL} \right) \leq EDNS_{sys}^{\max}, \text{ and} \\
 &\sum_{jg=1}^{NG} P_{jg}^{SR} + \sum_{d=1}^{ND} P_d^{IL} \geq \frac{\sum_{i=1}^{\bar{K}} \bar{p}_i \cdot \left(\Delta P_{lost} + \sum_{jg=1}^{MG} P_{jg}^{CAP} \right) - EDNS_{sys}^{\max}}{\sum_{i=1}^{\bar{K}} \bar{p}_i} \dots\dots\dots(5.13)
 \end{aligned}$$

Thus, the right-hand –side of Equa. 5.9 becomes as:

$$\overline{RES}_{sys}^{req} = \frac{\sum_{i=1}^{\bar{K}} \bar{p}_i \cdot \left(\Delta P_{lost} + \sum_{jg=1}^{MG} P_{jg}^{CAP} \right) - EDNS_{sys}^{\max}}{\sum_{i=1}^{\bar{K}} \bar{p}_i} \dots\dots\dots(5.14)$$

Comparing Equa. 5.14 with Equa. 4.19, $\sum_{jg=1}^{MG} P_{jg}^{CAP} = \sum_{j=1}^M P_j^{CAP}$ and $EDNS_{sys}^{\max}$ is

unchanged. Therefore the following approximate result is obtained:

$$\Delta RES_{sys}^{req} \cong \frac{\sum_{i=1}^{\bar{K}} \bar{p}_i \cdot \Delta P_{lost}}{\sum_{i=1}^{\bar{K}} \bar{p}_i} \dots\dots\dots(5.15)$$

The error analysis of above equation is given in next section. In addition, the impact of transmission system on market settlement results is analyzed.

5.3 Case Studies

The test system used in this chapter is same as that in last chapter. Generation and transmission system failures up to second order are considered in HLII reliability assessment. The allowed maximum system $EDNS$ is still assumed to be 0.2MW. The bidding cost functions of all commodities are same as those in previous

chapter. Taking in account the impact of transmission system, different cases are studied. The results are presented and analyzed in details in this section.

Additional Input Data

Transmission System

The transmission system consists of 6 buses and 9 transmission lines. The transmission voltage level is 230KV. Table 5.1 shows the basic transmission lines reliability data. Table 5.2 shows the load flow data for the transmission lines.

Table 5.1 Transmission Line Reliability Data

Line	Buses		Length (KM)	Permanent Outrage Rate (per year)	Outage Duration (hours)	Transient Outage Rate (per year)
	From	To				
1	1	3	75	1.5	10	3.75
2	2	4	250	5.0	10	12.5
3	1	2	200	4.0	10	10.0
4	3	4	50	1.0	10	2.5
5	3	5	50	1.0	10	2.5
6	1	3	75	1.5	10	3.75
7	2	4	250	5.0	10	12.5
8	4	5	50	1.0	10	2.5
9	5	6	50	1.0	10	2.5

Case 1:

In this case, the required system reserve is recomputed using the Equa. 5.14 considering the impact of transmission system. The computation result is $\overline{RES}_{sys}^{req} = 14.904 \text{ MW}$. Both spinning reserve and interruptible load are ancillary services commodities. All commodities dispatch outcomes in this case are listed in Table 5.3. The system loss is 4.72 MW. The nodal energy price, spinning reserve price for each Genco and interruptible load price for each IL bidder in case 1 are listed in Table 5.4.

Table 5.2 Line Data

Line	Buses		Impedance (p.u.)			Current Rating (p.u.)
	From	To	R	X	B/2	
1	1	3	0.0342	0.18	0.0106	0.85
2	2	4	0.114	0.6	0.0352	0.71
3	1	2	0.0912	0.48	0.0282	0.71
4	3	4	0.0228	0.12	0.0071	0.71
5	3	5	0.0228	0.12	0.0071	0.71
6	1	3	0.0342	0.18	0.0106	0.85
7	2	4	0.114	0.6	0.0352	0.71
8	4	5	0.0228	0.12	0.0071	0.71
9	5	6	0.0228	0.12	0.0071	0.71

Table 5.3: Dispatch Schemes (Case 1)

Power(MW)		IL(MW)
Genco1	Genco2	IL3
73.75	115.97	14.9
189.72		14.9

Table 5.4: Commodity Prices (Case 1)

Bus	Energy(\$/MW)	IL(\$/MW)
1	15.400	NA
2	14.809	1.46
3	15.898	1.05
4	15.872	1.20
5	16.021	1.46
6	16.164	1.46
Genco	SR(\$/MW)	
1	1.24	
2	1.07	

Compared the results in this case with those in case3 of last chapter, it can be seen that with the impact of transmission system, more system reserve are required. Meanwhile, the computation burden is much heavier than that in Chapter 4.

Case 2

In this case, the approximate increased system reserve requirement ΔRES_{sys}^{req} is computed using Equa. 5.15 and the error analysis is given. The computation result is $\Delta RES_{sys}^{req} = 3.252MW$, which is much close to $\overline{RES}_{sys}^{req} - RES_{sys}^{req} = 3.254MW$. Here $RES_{sys}^{req} = 11.65MW$, which is obtained in case 3 of last chapter. The error is
$$\left| \left(\overline{RES}_{sys}^{req} - RES_{sys}^{req} \right) - \Delta RES_{sys}^{req} \right| / \left(\overline{RES}_{sys}^{req} - RES_{sys}^{req} \right) = 0.1\% .$$

The case studies show that with the impact of transmission system, more system reserve is required. This is due to the reason: constrained by the transportation capacity limit of transmission system, when the contingency states occur at HLII level, generators and consumers cannot increase/decrease their active power output/consumption as they wish.

6 Conclusion and Recommendations

6.1 Conclusion

Restructuring in electricity industry has reshaped the traditional vertically integrated electric utilities, which are unbundled into different companies with different functions. This thesis investigates how to guarantee the necessary and appropriate reliability level while the energy and reserve market are simultaneously settled. As proposed in this thesis, a bi-fold approach is adopted to achieve this goal. On one hand, interruptible load (IL) is introduced as a source of operational reserve for the reliable operation of a restructured power system. On the other hand, the reliability-constrained system reserve criterion is proposed and used as one constraint in the day-ahead spot market settlement.

In summary, this thesis proposes an AC OPF-based simultaneous auction design for energy and ancillary services including interruptible load. The impact of interruptible load on energy and spinning reserve market clearing is investigated in details. Instead of using the deterministic system reserve criterion, the reliability-constrained criterion is used. In addition, the impact of transmission system failure on electricity market clearing is further developed.

Numerical results demonstrate that with interruptible load bidding the nodal price of energy and spinning reserve price are reduced, i.e. the system reliability is enhanced. The reliability-constrained system reserve criterion can more accurately assess the system operational risk and set the system reserve requirement accordingly. Moreover, considering the impact of transmission system, more system reserve is required.

6.2 Recommendations for Future Work

In current work, the system reserve requirement is calculated and used as one constraint of multi-commodity dispatch. While the diverse individual reliability requirements of customers are not taken into account. This will be studied in future work.

In this thesis, the nodal energy price, spinning reserve price for each Genco and

interruptible load price for each interruptible load bidder are calculated. The more advanced model to calculate nodal ancillary service price will be developed in future research.

In summary, the future work includes:

- Determine the nodal reliability indices and use them as constraints in multi-commodity joint dispatch.
- Evaluate the nodal ancillary service price in electricity market settlement.

Author's Publications

1 Peng Wang, **Yong Liu**, Yi Ding and Yu Xiao, “Determination of Interruptible Load as an Ancillary Service in a Coordinated Multi-Commodity Market”, Proceedings of the 15th Power System Computation Conference (PSCC), CDROM, Liege, Belgium, August 22-26, 2005.

2 Yong Liu, Peng Wang, and L. Goel, “Impact of Composite System Failures on Electricity Market Settlement”, accepted by 9th International Conference on Probabilistic Methods Applied to Power Systems (PMAPS), KTH, Sweden, June 11-15, 2006.

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