The Hong Kong Polytechnic University

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INTERRUPTIBLE LOAD MANAGEMENT IN DEREGULATED POWER SYSTEMS

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A thesis submitted in partial fulfillment of the requirements for the Degree of Doctor of Philosophy

May 2008

CERTIFICATE OF ORIGINALITY

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SYNOPSIS

This thesis investigates interruptible load management (ILM) under deregulated market conditions, especially about the new market roles of interruptible loads as ancillary reserve suppliers and emergency control actions for security and stability improvement. A new reserve market operation procedure is first developed by considering interruptible loads and the optimal problem for Independent System Operator (ISO) to procure reserve service is then formulated. In this market, interruptible load customers compete with generators as reserve service suppliers by signing call option contracts with ISO. In order to maximize their benefits, the load customers can optimally dispatch their total load capacity in both the energy market and the reserve market. The optimal bidding strategy of load customers in the reserve market including bidding price and capacity is determined while taking their risks into account. Besides, the correlation analysis between the energy market and the reserve market for interruptible load customers is performed. It has confirmed that the introduction of interruptible loads as reserve suppliers can contribute to reduce the overall reserve cost.

In the reserve market, only those very large scale load customers can participate because of the characteristic of reserve service and requirement of supplementary equipments such as open access same time information system. Along with the deepening of the power market reform, the minimum capability of interruptible load which is allowed to participate in the management will decrease. Since more and more load customers participate in ILM, it is difficult

and complicated for ISO to organize all the load customers to bid.

Instead of organizing all load customers to bid, ISO can offer a set of contracts for load customers to sign according to their own private information. However, it is very difficult for ISO to estimate the private information of the load customers such as interruption costs and to provide the customers rational compensation. Therefore, cost-effective demand management programs that do not need to estimate the private information of each load customer are necessary. And how to prevent the abuse of market power of load customers because of incomplete market information is another very challenging problem faced by ISO.

Therefore, based on the concept of mechanism design with revelation principle, an interruptible load contract design is developed, by which the load customers are successfully stimulated to sign up for the contracts and reveal their true private information in order to receive maximum compensation fee. Besides, an equitable and effective control scheme is developed for ISO to shed the interruptible loads, according to the proposed contract design, as an alternative solution of generation rescheduling under some emergency market conditions when the generation rescheduling capability is insufficient or its price goes relatively high. Optimization problems with the objective of minimizing the total management costs for load curtailment and generation rescheduling are formulated with consideration of different security and stability limits such as transmission thermal limit, voltage stability limit and transient stability limit. The quadratic programming method is used to determine the optimal redispatch results. The effectiveness of the proposed method on the elimination of congestion and stability problems, and the alleviation of market power abuse by participants has been validated using numerical examples.

ACKOWLEDGEMENT

Earning the right to call yourself Doctor of Philosophy is a life changing experience. I honestly never thought it would be so frustrating, intellectually challenging, fun, satisfying, and wonderful. I have enjoyed my time at Electrical Engineering department more than I can say, and I would thank a number of people who made this thesis possible.

I would like to express my sincere gratitude and appreciation to my supervisor Dr. C. Y. Chung, for his invaluable guidance and constant encouragement throughout the progress of this thesis. His enthusiasm and innovatory approach were strong sources of inspiration. It has been an honor and a very fruitful experience to work under his direction.

I would like to acknowledge the guidance and encouragement that I received from my co-supervisor, Professor K. P. Wong and Dr. C. W. Yu throughout my PhD studies. They are always available for me in spite of their busy schedule and duties.

Thanks are due to staffs of the Department of Electrical Engineering and all my friends for their support and help during the course of my studies.

I reserve special thanks to my wife, my father, my mother and my brother who encourage me so much in life and helped me become the person I am today. They were always supportive of me pursuing my dreams whether in personal life or in PhD studies. They shower me with love, kindness and care, and I am so lucky to have been blessed with the family I have.

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List of abbreviations

ILM	Interruptible Load Management
ISO	Independent System Operator
VSM	Voltage Stability Margin
DSM	Demand Side Management
IRP	Integrated Resource Planning
DLC	Direct Load Control
ILC	Interruptible Load Control
OPF	Optimal Power Flow
DRP	Demand Relief Program
LSE	Load Serving Entity
IMC	Interruptible Management Console
GRTN	Gestore Rete Trasmissione Nazionale
RTU	Remote Terminal Unit
LSPU	Load Shedding Peripheral Units
ACC	Area Control Centers
NCC	National Control Centre
DMP	Direct Market Participant
UFR	Under Frequency Relay
PSO	Power System Operator
EMC	Energy Market Company
MRA	Measurement, Recoding and Activation

TPC	Taiwan Power Company
AGC	Automatic Generation Control
PAB	Pay As Bid
NERC	North America Electricity Reliability Council
IR	Individual Rationality
IC	Incentive Compatibility
FACTS	Flexible Alternative Current Transmission System
PCC	Post-contingency Corrective Capability
LI	Lerner Index
SNB	Saddle Node Bifurcation
HB	Hopf Bifurcation
SIB	Singularity Induced Bifurcation
TEF	Transient Energy Function
COI	Centre Of Inertia
CMG	Critical Machine Group
CCT	Critical Clearing Time
MC-TSCOPF	Multicontingency transient stability constrained optimal power flow
PJM	Pennsylvania-New Jersey-Maryland
KE	Kinetic energy
PE	Potential energy

CHAPTER 1 INTRODUCTION

1.1 Background and motivation

Along with the deepening of electricity market deregulation, demand side management (DSM), which is an important aspect of integrated resource planning (IRP), has aroused the interests of the participants of the electricity market [1, 2] for decades. On the one hand, in most instances, load customers have very little influence on the design of power markets and hope to act as a more active role in the market instead of just passively acceptation of the arrangement of power companies [3]. On the other hand, Independent System Operator (ISO) also hopes that load customers can make more rational decisions on their power consumption to shave peak and fill the valley of total load demands, so the system load shape can be more flexible and not so flexuous [4].

Utilities are increasingly devoting considerable attention to DSM and ILM to provide reliable and economical power system operation under normal and emergency conditions. DSM and ILM are always specifically used to peak demand shaving and prevent power system degradation under particular conditions. It can be predicted that controlling load will play an important role in the power market and can contribute significant economical improvement in the market operation [5-11].

Interruptible load customers can serve as competitors in the reserve service market. In the Alberta market, interruptible load customers can supply operating reserve. It has been found that this arrangement can improve the reliability of the

Alberta's electric power system [1].

ILM can offer ISO an alternative control action to cope with some phenomena which are harmful to the safe and reliable operation of the power system such as congestion and instability problems. New York ISO provides a mechanism for load reduction during emergency conditions (the emergency demand response program). Participants in the program are required to reduce their electricity consumption during a given period of time, and they are paid a fixed payment or the clearing price of electricity for the reduced consumption. PJM also designs an emergency load response program to provide a method by which customers may be compensated for voluntarily load reduction during emergencies [2].

Although it has been generally accepted that ILM plays an important role in the market, it has not been implemented widely. One of the key problems is how to sufficiently stimulate the load customers to take part in the management plan. At the same time, how to prevent the abuse of market power of load users because of incomplete market information is another difficult problem faced by utilities.

Revelation principle is the key concept used in mechanic design, especially in the market with incomplete information. Customized electricity exchange agreements are arranged between an electricity supply industry and its key customers to participate in the utility's demand side management [6]. These special agreements usually cannot provide sufficient financial incentives for the customers to participate and also the utility cannot get the sufficient revenue. The mechanism should be designed to make sure that the utility's benefit is guaranteed and that customers are compensated sufficiently to participate voluntarily. How to rationally calculate the interruptible load compensation fee weighs highly in the mechanism of ILM [7]. The interruption costs of load customers are difficult to evaluate partly due to the lack of availability of data. The mechanism should be designed so that load customers wishing to maximize their own total benefits are encouraged to reveal their true costs and valuation of power interruptions [8]. Also, the long-term benefits due to the reduction of power system and reserve capacity by the power companies should be taken into account when the pricing method is designed [9].

Besides the price of interruptible loads, how to select interruptible loads and determine the amount of them rationally is another very important problem facing to ISO. Ideally, ISO's objective while designing the optimal contracts and the operation scheme would be to seek those customers offering the lowest price. But such a selection would take the risk of transmission congestion, increased system losses, increased reactive support requirement, and increased chance of system instability, etc [10]. So when the management scheme is designed, these factors should also be considered and integrated into the optimization methodology to ensure the safe and reliable operation of system.

Furthermore, in the design of the ILM scheme, the policy about the advance notification, the contract type and some other limits should also be enacted clearly and logically based on the details about the market conditions and characteristics of market participants.

Therefore, there is a need to design a commercially transparent and technically justifiable mechanism which can direct the pricing of interruptible loads and develop a congestion management methodology in which interruptible loads can be considered.

1.2 Organization of this thesis

This thesis consists of eight chapters.

This chapter, Chapter 1, first states the background and motivation of this research. Organization of the thesis and a list of publications of this research works are provided.

In Chapter 2, a literature review about ILM is presented and the practical experience worldwide is highlighted.

In Chapter 3, the interruptible load customer is proposed as a competitor with generators in the reserve market. The key issues about the reserve market are first discussed. The market model and the bidding mechanism are developed for ISO in order to consider the interruptible load customers as reserve service suppliers. In the proposed mechanism, the option contract is employed so that the interruptible loads can participate in the bidding through signing the option contract with ISO. The optimal bidding capacity of interruptible load is studied with consideration of its risk.

In Chapter 4, the operation procedure of ILM is described and the profits of market participants in ILM are illustrated. The interruptible load contract design is proposed based on mechanism design with revelation principle, which encourages the participation of load customers by revealing their true curtailment costs and providing them sufficient compensation while preventing the abuse of market power of load customers induced by incomplete information.

In Chapter 5, a new congestion management scheme with consideration of

ILM is developed based on the proposed interruptible load design in Chapter 4. This scheme provides an equitable and effective way for ISO to shed the interruptible loads as an alternative to generation rescheduling to alleviate the congestion. The scheme aims at eliminating the congestion while minimizing the management cost with consideration of the static functional operating constraints and the transmission line capability limits with respect to normal condition and contingencies. The effectiveness of the proposed method has been verified using a modified IEEE 30-bus system.

Chapter 6 illustrates that the proposed congestion management with ILM can also be used to handle the voltage stability problem in deregulated power systems. The pattern of load increase is difficult to be predicted in the new market environment; therefore it is treated as uncertain and the locally closest bifurcation computed by an iterative method is used as the voltage stability margin (VSM). The management scheme with considering VSM is developed and its effectiveness on voltage stability improvement is then demonstrated.

Chapter 7 extends that the proposed congestion management to solve the transient stability problems in power markets. It is found that the ILM can provide an effective preventive control for enhancing power system transient stability performance.

In Chapter 8, the main contributions of this thesis are concluded and some possible directions for future research work are presented.

1.3 List of publications

Journal paper published:

G. Y. Wu, C. Y. Chung, K. P. Wong and C.W. Yu, “ Voltage Stability Constrained optimal Dispatch in Deregulated Power Systems,” *Proc. Inst. Eng. Tech. Gen. Transm. Distrib.*, vol. 1, no. 5, pp. 761–768, Sep. 2007.

Journal paper under review:

G. Y. Wu, C. Y. Chung and K. P. Wong, “A new congestion management scheme considering interruptible load contract design,” *Electric Power Systems Research*

Conference paper presented:

G. Y. Wu, C. Y. Chung, K. P. Wong, C. W. Yu and B. Dai, “Voltage stability enhancement by preventive control in power markets,” *International Conference on Electrical Engineering*, Korea, July 2006, (CDRom)

G. Y. Wu, C. Y. Chung, K. P. Wong and C. Rehtanz, “Interruptible load management to preserve voltage stability,” *Conf. Proc. 7th IEE International Conference "Advances in Power System Control, Operation and Management International Conference" (APSCOM2006)*, Hong Kong, Nov. 2006, (CDRom)

CHAPTER 2 LITERATURE REVIEW AND PRACTICE EXPERIENCE

2.1 Literature review

2.1.1 Load shedding under direct load control

Load shedding under direct load control (DLC) has been utilized by power systems as one of the main methods of direct load management and aroused great interests of researchers and scholars. Its applications for improving system security have been studied comprehensively. Jung [11] derived an appropriate convergence criterion and demonstrated an application of the method to load shedding. An approach to avoiding catastrophic failures in interconnected power systems was also proposed using the method of reinforcement learning with temporal differences. Feng [12] presented a new approach for determining the minimum load shedding to restore the solvability of a power system. Based on the equilibrium point associated with the system post-contingency boundary, the invariant subspace parametric sensitivity is used to determine the most effective control strategy so that a practical minimum load shedding can be derived. And the system adjustments that could further reduce the minimum load shedding, such as rescheduling of real power generations and changing of generator terminal voltages are also investigated. Ladhani [13] provided an introduction and an overview of the design and implementation considerations of an undervoltage load shedding scheme. An overview of the power system equipments, which affect undervoltage load shedding design and operation, is also provided. In [14], a technique for undervoltage load shedding in power systems is presented. The undervoltage load shedding criterion has been developed using a dynamic load model. Under a voltage unstable situation, the proposed undervoltage load shedding criterion can be used to calculate the minimum amount of load to be shed at any point in time to avoid voltage collapse. In [15], an undervoltage load shedding method to prevent voltage collapse is presented. This method is based on a global index which indicates voltage collapse proximity and voltage magnitudes on critical buses. Echavarren [16] presented an optimization load shedding algorithm to improve the load margin when the system load is very high, or there is a large generation-demand imbalance, and active and reactive power generation resources in the importing areas are exhausted. The objective function is the minimization of the total system demand reduction. First order sensitivities of the load margin with respect to the load demand to be shed are considered.

Load shedding under the power market environment has been studied in [17, 18]. The new approach of load modeling is recommended and undervoltage load shedding is proposed as a cost-effective corrective tool to overcome voltage instability and abnormal voltage conditions. In [18], a method for computing minimum load shedding in a power market is proposed. The idea is to determine individual load-shedding percentages for each bus bar to assure predefined security conditions.

2.1.2 Interruptible load management

Under interruptible load control (ILC), the utility provides advance notice and incentives to the customer for switching off loads or shifting loads from peak to off-peak by an appropriate tariff. In the deregulated power systems, ILC or ILM is more reasonable than DLC.

Load curtailment occurring under emergency conditions can have significant monetary impacts on the system participants. Satisfaction of customers is very important in the competitive environment, and the customers should receive monetary compensation for power supply interruption. Minimizing the overall interruption costs of customers is an important aspect for ISO in the implementation of ILM.

There are three major issues in ILM including implementation criteria, profit analysis, capability and tariff for load interruption. Implementation criteria are discussed in [10, 19-21]. Casamatta [10] analyzed the state of the art of the procedures to ensure the security of power system operation with respect to the introduction of interruptible loads. A new definition of security is discussed as a consequence of the use of interruptible loads not only into emergency conditions but also during normal and alert operation. Voumas [19] focused on voltage security analysis in a deregulated power market with alternative methods to alleviate congestion using generation rescheduling and/or interruptible load rejection. Wang and Billinton [20] presented an optimum load-shedding technique to improve the reliability of a local distribution system. Customer concerns regarding interruption costs are considered in the load-shedding procedure. The objective is to minimize the total system interruption cost with weighting factors used to determine the load-shedding priority among feeders. Wangdee [21] focused on incorporating interruption cost factors, such as the customer types which are interrupted, the actual load demand at the time of the outage, the duration of the outage, the time of day and the day in which the outage occurs, in a load-shedding strategy. The load-shedding algorithm is developed using an approximate event-based customer interruption cost evaluation technique to identify and determine the priority of the distribution feeders on a given bus during an emergency.

Economics is the first goal pursued by all the participants in the power market. Associated with the development of the power market, controlling load may play a new role in the new context set up by the open market and result in significant economical improvement. The profit of participants is analyzed in [5, 22]. Fahrioglu and Alvarado [5] believe that demand relief from customers can help a utility or any load serving entity (LSE) to solve a variety of problems. The utility has to design cost effective yet attractive demand management contracts to provide the incentive paid to the customer to participate in demand management programs. Mechanism design with revelation principle is adopted from game theory and applied to the interaction between a utility and its customers in order to design such contracts. During the mechanism design, contracts are designed based on Bayes equilibrium, which is difficult to be found by ISO. During the mechanism design, the utility solves the optimal problem to find the equilibrium point and maximize its benefits through interruptible load substituted for delivering power to certain locations. Wang [22] proposed that, on the premise of transmission open access, the grid company can have larger profits by shedding load and providing reasonable compensation for the supply energy companies and service energy companies based on the analysis of the power exchange and the requirement of reserve capacity. The relevant models for load-shedding in the power exchange and the confirmation of reserve capacity are developed.

Interruptible load capability and tariff are also discussed in [7, 23]. An optimal power flow (OPF) based framework is proposed to determine the incentive rates of an interruptible tariff mechanism on an hour-to-hour basis in [7]. The interaction between the utility and customers contracting interruptible load is demonstrated and then an interruptible tariff mechanism is formulated by incorporating customer response functions into the framework to reduce costs and aid in system operation during peak load periods. In [23], a probabilistic technique to evaluate the interruptible load carrying capability of isolated and interconnected systems was presented. The amount of interruptible load and the corresponding interruption time can be obtained by maximizing the expected energy supplied while satisfying the operating criteria.

2.2 Experience around the world

2.2.1 US

- ***California***

Among various markets in North America, California ISO has first initiated a demand relief program (DRP) in which the load customer signs a contract with ISO for demand reduction [24]. ISO implements the program by providing incentives for load customers to reduce their demand during times of power supply shortage. According to an evaluation of the DRP in 2000, 269 MW of interruptible load offers were received. The average capacity price (interruptible) for accepted offers was 36000 $/MW per month and average energy price (interruptible) was 226 $/MWh [25].

DLC accounted for 5352 MW of peak reduction and an incremental peak reduction of 572 MW in the US in 1995 [26-29]. A survey of DLC programs indicated that the most commonly controlled loads are electric water heaters, air conditioners and space heating systems. High voluntary participation rates (up to 40% of eligible customers) were achieved through innovative marketing and attractive rate rebates [26].

In the agricultural sector, a voluntary DLC project for irrigation pumps in California had 540 accounts with 15 MW of connected load (pumps ranged from 5-250 kW with an average of 28 kW). The program was modified to provide participants with an override option. A toll-free number was added to provide information about the likelihood of interruption during the day. Participation was limited to pumps with summer load factors higher than 20% [24].

- *New York*

Within New York ISO, there is also a provision for load customers to offer interruptible load services to a LSE which thereby provides additional operating reserve. The load customers can enter into contracts with the LSE and may also participate in the day-ahead or operating reserve market. There is a provision for 10-min and 30-min spinning reserve markets in New York ISO wherein interruptible and/or dispatchable load resources synchronized to the system can participate [30].

- *North Carolina*

In North Carolina, the interruptible load contracts have been developed and the main issues about the contracts are described as follows:

The duration of contract is at least 5 years and the load customers must give written applications to the power supply company 12 months before canceling the contract. When the power generation capacity is less than the demand, the interruptible loads are allowed to be shed but the load customers must be informed at least 30 minutes before interruption. The power supply company determines the beginning and end of the interruption, but the load customer must be informed the end time of all the interruptions. The total amount of the interruption time should be less than 150 hours a year and 10 hours a day for each power supply company. If a load customer is not required to interrupt its load, the company retains the right to suspend the load shedding contracts. As regards the compensation for the interruptible loads, the power supply company would determine the interrupted load capacity to calculate the compensation each month.

- *Connecticut*

Interruptible load contracts have been adopted in Connecticut for years. The power company signs the contracts with the load customers that agree to shed the load more than 300kW following the requirement of the power supply company. When there are any security problems (such as congestion in transmission lines or power supply reliability in the system) or economical reasons (the price of energy becomes very high), the interruptible loads will be curtailed according to the contracts. The load customers must be informed at least 4 hours before interruption and there will be no more than 5 times of interruption for one load customer per year. The duration of each interruption is less than 4 hours. The power supply company gives the compensation to the load customers through the electricity bills each month based on the interruptible load contract. During the contract period, the load customer must give the written application to the load supply company 30 days before it wants to increase the interruptible or fixed electricity demand, or 3 months before it wants to reduce the electricity demand, or 1 month before it wants to terminate the contract [25, 26].

- Oregon

The interruptible load contracts designed in Oregon have the following characteristics: The load customers who want to sign the contracts must be more than 1 MW and agree to shed the load more than 200kW. The regulated interruption starts from 6 am to 11 am and from 5 pm to 8 pm each Monday to Friday in winter (December in a year to February in the year after) and there should be not more than 10 days per month. The load customers must be informed one day before the interruption and the interrupted loads will be compensated as the average peak electricity price.

2.2.2 Italy

The Northern Italian border is where the interconnection between Italy and neighboring countries, France, Switzerland, Austria and Slovenia is located. The interconnection is constituted by 15 tie lines (6 of which are 380 kV lines and 9 are 220 kV lines), which bring a large amount of power to Italy [31].

Interruptible loads have been used by utilities for decades, and essentially aim to enhance the reliability of the interconnected system. Interruptible loads pay their energy at a lower price as the compensation for the possibility of being shed by the system operator when necessary. Characteristics of interruptible programs usually are: a) Large load reductions of at least 1 MW and usually including the entire facility; b) Short notification to comply such as just an hour and as short as ten minutes; c) Interruption could be required at any time of the day or day of the year; d) Mandatory compliance; d) Failure to perform resulted in huge penalties; e) Maximum number of interruptions allowed during any year; f) Permanent discounts on electric bills [31].

The new load-shedding system, named Interruptible Management Console (IMC), has been started in 2001. The IMC project is aimed at offering system operators a simple and efficient load shedding device to cope with emergency situations due to sudden failures in the generation sector or in interconnection tie lines. The main goals of the project were the following [31]:

- ✓ quick, simple and efficient shedding of interruptible loads in real time;
- ✓ coordinated and flexible shedding management between GRTN (Gestore Rete Trasmissione Nazionale-Italian transmission system operator) control rooms;
- ✓ separate management of the different types of shedding;
- ✓ interfacing of the new load shedding system with existing control system;
- ✓ allowing data exchange with GRTN Energy Management Systems;
- ✓ allowing data exchange with GRTN Settlement and Billing systems using *xml* format, providing (by site) single and total load shedding power amount,

unsupplied energy, unavailable power and single site power deviation from contractual power band.

GRTN developed a brand new device to meet these requirements. The new apparatus of the RTU (Remote Terminal Unit) category, named Load Shedding Peripheral Units (LSPU) has been commissioned to industry for installation at interruptible loads sites [31]. Also, a fast and reliable communication network between the GRTN Area Control Centers (ACC) and the GRTN National Control Centre (NCC) has been carried out. LSPU devices were installed, tested and maintained at the sites of each interruptible load customers.

2.2.3 Singapore

In the Singapore wholesale electricity market, the concept of interruptible load allows electricity consumers to compete in the reserve market. Interruptible load is a load which can be voluntarily interrupted for a limited duration to enable the power system to return to its normal operating state [32-34].

A load facility must be able to voluntarily reduce load of at least 0.1MW to be able to participate in the reserve market [32]. Interruptible load may be provided by a load facility of a direct market participant (DMP) or through a retailer who is also a market participant.

Retailers are required to have operational control over the load facility. If retailers have more than one load facility under their operational control, they must bid them as separate load offerings in the reserve market [33].

➢ *Activation*

When system frequency falls below 49.4Hz, load facilities participating in primary reserve market are required to trip. Likewise, when system frequency falls to or below 49.7Hz for 30 seconds, load facilities scheduled to provide secondary reserve are required to trip. A load facility offering primary and secondary reserve is to be activated by use of an under frequency relay (UFR) that automatically disconnects load when frequency drops below a specified level upon instructions from the Power System Operator (PSO) and a dispatch coordinator. Such facilities must reduce their load by the scheduled quantity within 10 minutes of being called upon [33].

➢ *Restoration*

When interruptible load is activated, the DMP or retailer will restore it individually upon publication of a PSO advisory notice on the EMC (Energy Market Company) trading website followed by message paging to the dispatch co-coordinators [32,33] to prevent the jeopardy to the system restoration process after a contingency event aroused by premature switching back of load from such facilities. And the DMP or retailer must submit MRA (Measurement, Recoding and Activation) device records to the PSO within 24 hours of activation to ensure compliance with these requirements [33].

➢ *Limits on interruptible load*

The following restrictions on the amount of reserve provided by load facilities should be laid [33]:

1) Zonal limit:

The entire system load in Singapore is divided in number of electrical zones and each load facility is assigned to a particular zone. A limit is set on the amount of reserve that can be provided by load facilities in each zone. These limits currently range from 23-100% of total load in a particular zone and the lowest quantum for a zone is currently 70MW.

2) Reserve class limit:

10% of total primary reserve required, 20% of total secondary reserve required and 30% of total contingency reserve required are capped currently from the load facilities.

- *Reserve payment*

Reserve payment is made to the retailer or DMP for interruptible load at the price of reserve multiplied by the quantity of reserve scheduled in a trading period [33].

- *Compliance and penalty*

If a load facility restored before receiving clearance from PSO or a DMP or retailer fails to curtail scheduled load when activated, it is considered to have been non-compliant with dispatch instructions and may face disciplinary action from the Market Surveillance and Compliance Panel [33].

2.2.4 Taiwan

An interruptible load control scheme was implemented by the Taiwan Power Company (TPC) in 1987 [35]. Participants, having an interruptible load of at least 5 MW, interrupted loads for 6 hours/day in the peak periods (10 to 12 a.m. and 1 to 6 p.m.) from June to September, except on Sundays and holidays. Customers reduced their demand regardless of the system requirement.

Twenty-eight industries participated in this scheme with a total interruptible load of 271 MW or 2.4% of the system peak demand [35].

Nowadays, the power company in Taiwan, Taipower, also has a load shedding scheme associated compensation when a large unit is tripped during the summer peak [35]. As illustrated in Table 2.1, the results showed that with strategy A, customers participated in the program and reduced the system peak-load significantly. The system peak was reduced by 2.5%. Through Strategy B, it was seen that there would be a dramatic increase of potential for interruptible load if the discount rate was increased from 30% to 50%, and more peak load reduction would be exercised if the advance notification time were increased.

Table 2.1 Interruptible load contracts in Taipower

Name	Contract type	Advance notification	Minimum curtailment	Payment structure
Strategy A	contract	1 day,1 week	5MW, 6 hours per day	Contracted demand is charged with 50% discounted price
Strategy B	contract	1 day,4 hours, 1hours	All industrial customers, up to 6 hours	Depending on the advance notification time

2.3 Summary

In this chapter, a literature review on ILM is presented. The main issues of ILM are introduced and the corresponding research works are reviewed. The practical experiences in several countries and regions including USA, Italy, Singapore and Taiwan are also highlighted.

CHAPTER 3 INTERRUPTIBLE LOAD AS A COMPETITOR IN THE RESERVE MARKET

3.1 Introduction

In order to produce stable and reliable electricity supply, ancillary services are required as additional services besides energy exchange in the power industry. Generally, these services include voltage support, black start capability, automatic generation control (AGC) and reserves with various levels of response time [36]. Reserve services are the services required for the control of system frequency within certain bounds in the presence of events. They are necessary in order to enable the system to intercept runaway frequency after an unexpected disturbance and are typically provided by spinning units within a very short time range. The terminology and definition of reserve services vary from region to region [37-39].

Most of the existing works for the reserve markets focus on the supply side only. However, under some circumstances, load customers may also have the capability to curtail their consumption in addition to their natural response to energy prices to react to the market condition. Utilities are increasingly devoting considerable attention to DSM and ILM to provide reliable and economical power system operation under normal and emergency conditions.

In this chapter, the key issues of reserve service are discussed and the operation procedure of the reserve market considering interruptible loads as the competitors is introduced. Through the proposed call option, interruptible loads offer their bids to ISO and compete with the other reserve service suppliers. As to the interruptible load customer, the optimal bidding capacity in the reserve market is calculated to optimally dispatch its load in the energy and reserve markets while maximizing its total benefit on both two markets considering risk management.

3.2 Past and current practices of the reserve market

There exist two thoughts for market design as deregulation in the power industry proceeds around the world, which are known as pool model and bilateral model [40, 41]. Accordingly, the reserve markets are sorted to these two models either. In a pool-based market, reserves are centrally and optimally allocated based on volunteer bids. Under two-settlement design, the allocation of reserves is implemented in day-ahead scheduling and real-time dispatch.

There exist different types of reserves. Reserve types are characterized in terms of response time and they are downward substitutable as faster responding reserves can replace slower ones. Faster response reserves can be regarded as high-quality resources and can be substituted for lower quality reserves [40]. The key issues of reserve services and some recent works are discussed in this section.

3.2.1 Assessment of total reserve capacity

A utility must have sufficient reserve generation available for immediate use at all times so that if one generator or one line fails, all loads can still be served without interruption. This reserve requirement is known as the N-1 criterion. The traditional criterion is that the total reserve capacity of a power system should be greater than or at least equal to the largest online generator or certain percentage of total system load. If the reserve capacity is more abundant, the probability of unprotected contingency would be reduced and also the overall operation risk will be lower. However, the operation cost will increase because additional generating units are committed and other units are not operating at their optimal output condition. So a lot of new criterions instead of the traditional N-1 criterion have been proposed.

Reference [42] proposes a new pool-based market-clearing algorithm for application in electricity markets with reliability-based reserve criteria that include the scheduling of spinning reserve according to a hybrid deterministic/probabilistic reliability criterion. Reference [43] presents a new probabilistic method designated as ‘System Well-being Analysis’ to be used in the assessment of system capacity reserve, which incorporates the accepted deterministic criteria in the definition of ‘healthy’ and ‘marginal’ system states by evaluating the system wellbeing indices of practical systems.

3.2.2 Bidding price and capacity of reserve suppliers

In the reserve market, all participants should offer their price and amount of different types of reserve they buy or sell. Some papers have investigated the pricing mechanism for reserve markets.

Reference [40] presents a methodology for the simultaneous market clearing of energy and reserve services. According to this approach, the pitfalls of the sequential procedures are avoided. Under marginal pricing, it yields a single price given by the nodal marginal cost of security for all reserve types scheduled at a bus. In [44], the development of an option market for spinning reserve considering power system security and reliability constraints is discussed and a three-phase computational method to derive the call option price and put option price for spinning reserve is proposed.

3.2.3 Optimal allocation of reserve services

Based on the bids of different reserve service providers, ISO should allocate the reserve among them to achieve the sufficient capacity. Two of the current existing techniques for reserve capacity allocation in competitive markets are widely used including sequential method and rational buyer’s method [41].

Sequential method was adopted by the California ISO in the initial market for ancillary services. The sequential method was used to procure ancillary services because of its strict consistence with the market rules and relatively easy implementation. The objective of this methodology is to satisfy the preset needs of four submarkets including regulation, spinning, non-spinning and replacement reserves. Each market was operated separately and cleared sequentially. It does not necessarily produce the minimum costs for the overall reserve amount. Each generator can offer capacity in each reserve market and its participation in different markets is a function of its bid price and its maximum limit of capacity. The last accepted bid in the specific service market is set as the market clearing price and all bids accepted are paid at this price. However, during the heat wave of July 1998, the ancillary service price was soaring up to 9999 $/MWh for a few hours, comparing with the normal price range from 5 to 10 $/MWh. The California ISO had to impose a price cap and embarked on an ambitious effort to redesign the ancillary service market, resulting in the rational buyer’s method [36].

The initial algorithm of rational buyer’s method started to be used by the California ISO on 18 August 1999 [36]. Each generator would submit a single bid for each ancillary service simultaneously, which should specify the type, the price, and the quantity of the service. The four submarkets are not operated separately and substituting higher quality lower cost services for lower quality higher cost services is allowed when it would reduce the total procurement cost. Noted that the market clearing price is a variable and the optimal problem cannot be solved as the sequential method does. An exhaustive search that evaluates all possible combinations of bid prices can be used as one option. For each of the four submarkets, an upper bound price can be found so that any price combination with a price higher than the upper bound can be excluded from the search process. For each case, the bids are evaluated in the sequence of regulation, spinning, non-spinning and replacement reserves. For each possible case, a linear programming technique is used to find the optimal allocation of capacity in different markets. The case with the overall minimum cost will be the solution of the rational buyer’s algorithm.

There are differences between the two techniques discussed above, and the main difference is that the rational buyer’s method treats the system as a whole market and not as submarkets, since it tries to overcome the possible offer shortage in a certain market in relation to the reserve requirements by using the surplus of higher quality reserves [36]. The practical operation results show that the rational buyer’s algorithm is practically feasible and has improved the market efficiency.

3.3 Proposed market model and trading mechanism

3.3.1 Interruptible load in the reserve market

In a fully competitive electricity market, both generators and load customers should be given the opportunity to participate in both energy and reserve markets. The participation of demand side in the energy market can reduce the market-clearing price. Similarly, the participation of interruptible loads in a reserve market can also reduce the price of reserve and directly benefit from the provision of reserve. Participation of demand side enhances the efficiency of the market operation and makes the markets more competitive in both energy and reserve markets. Furthermore, due to the incorporation of demand side in the market operation, system security and integrity will also be improved [10, 19, 45-52].

Interruptible load contracts have been used in reserve markets in many countries. These usually involve commercial and industrial consumers. In Alberta market, interruptible load customers can supply operating reserve. These are found to contribute to a more reliable operation of the Alberta's electric power system [1]. In Singapore's wholesale electricity market, there are three reserve classes, namely, primary, secondary, and contingency reserves, with response times of 8 s, 30 s, and 10 min, respectively and electricity consumers are allowed to compete in the reserve market [32]. The situation is similar in U.K although slightly different time scales are associated with the corresponding reserve/response services. Interruptible loads are actively encouraged to compete with generators in the provision of all types of reserve services [52]. Each interruptible load is allowed to offer in all or some of the three reserve markets if it meets the criteria for the respective reserve class. Interruptible loads compete with generators to provide reserve under the same time response requirement. Interruptible loads are considered to be tripped automatically within 10 min upon notification.

Generally, interruptible loads can lessen the reserve burden of generators significantly and can provide another source of reserve during emergency when their service is needed most. Hence, interruptible loads increase the diversity of supply of reserve services. Meanwhile, successful demand bidders are able to effectively compete with generators. As a result, the level of competition in the provision of reserve services is increased, and the prices and the overall cost of reserve are reduced.

3.3.2 Proposed market model

For impending emergency states, under which the system operator would have to rebalance power, some loads may be willing to curtail their consumption beyond their elasticity limits, albeit at a price. In this chapter, it is assumed that the load customers will provide such emergency reserve by offering to alter their consumption anywhere from a minimum of zero up to its maximum with certain price. A market model is proposed in which both generators and load customers are participants in a joint energy and reserve market.

Producers and consumers participate in this market by submitting offers to ISO. Reserve service producers can supply the following products:

- Regulation;
- Spinning reserve;

• Non-spinning reserve;

• Replacement.

Since there is advance notification needed, the load customers can bid to consume energy as well as offer to non-spinning reserve and replacement reserve in the reserve market. The rational buyer's method is used in this study. The main function of the market operator is to minimize the combined cost of the total generated energy and the reserve provided by producers and consumers. The mathematical function of rational buyer's method for ISO is as follows:

$$\min(\rho_{re}S_{re} + \rho_{sp}S_{sp} + \rho_{ns}S_{ns} + \rho_{rp}S_{rp}) \tag{3.1}$$

subject to:

$$S_{re} \geq D_{re} \tag{3.2}$$

$$S_{sp} + S_{re} \geq D_{sp} + D_{re} \tag{3.3}$$

$$S_{sp} + S_{re} + S_{ns} \geq D_{sp} + D_{re} + D_{ns} \tag{3.4}$$

$$S_{sp} + S_{re} + S_{ns} + S_{rp} \geq D_{sp} + D_{re} + D_{ns} + D_{rp} \tag{3.5}$$

where S_{re}, S_{sp}, S_{ns} and S_{rp} are the supply of regulation, spinning reserve, non-spinning reserve and replacement market respectively; D_{re}, D_{sp}, D_{ns} and D_{rp} are the demand of regulation, spinning reserve, non-spinning reserve and replacement market respectively; ρ_{re}, ρ_{sp}, ρ_{ns} and ρ_{rp} are the specific marginal clearing prices of different four submarkets.

3.3.3 Operation of the reserve market

The reserve market operation procedure is described as below:

Step 1: Based on market forecasting, ISO assesses the total reserve capacity and announces key information to market participants.

Step 2: Generators and interruptible load customers offer their bids to ISO while attempting to optimize their own benefits.

Step 3: According to the bids offered by all reserve service suppliers, ISO chooses the suppliers and allocates the reserve capacity among them through the rational buyer's method.

3.4 Optimal bidding strategy of interruptible load

3.4.1 Option contract

Since 1973, financial options had been developed in American stock markets and after then, it has been widely used and acted as an effective instrument for risk management or hedge. In order to mitigate market price risk, contracts similar to options on electricity are already being employed in Britain and there are also some discussions about the possibility of a commodity market for electricity in USA.

There are two types of options: put and call options. A call option is the right, but not the obligation, to purchase a unit of energy at time T for a price k \$, called the strike price, or exercise price. A put option is the right, but not the obligation, to sell a unit of energy at time T for a price k \$ [44].

In the reserve market, interruptible loads can offer their bids through signing a call option contract with ISO. ISO can allocate the reserve capacity among all the reserve service suppliers while minimizing the total reserve cost.

With the specific call option contract, ISO can pay certain amounts of money, which is called premium to keep its right for exerting the call option contract. ISO has the right to interrupt the load when it is needed and compensates the load at the strike price regulated in the option contract. If there is no need for the reserve capacity, ISO pays the premium only without exercising the option contracts [53].

As to the option contract price, there are a lot of researches and the most famous work is the Black-Scholes pricing model. Based on the research results of this model, a lot of extension models are also developed [54, 55].

3.4.2 Interruption cost of loads

In power systems, the curtailment cost of a load customer depends on not only the amount to be interrupted but also its load type, which is the load customer's private information. As discussed in [5, 56], the cost function of the customer with load type θ_i and amounts of curtailment x_i can be represented by:

$$c_i(\theta_i, x_i) = K_1 x_i^2 + K_2 x_i - K_2 x_i \theta_i \tag{3.6}$$

where load type θ_i, real load type parameter for load i, varying within the range of [0, 1] represents the characteristics of the customers and their willingness to be interrupted. And x_i is the curtailed quantity of load i and assumed to be continuous. K_1, K_2 are the constant coefficients of load curtailment cost. θ_i "sorts" the customers from "the least willing" to "the most willing" for load shedding. Then θ_i should has a linear relationship with x_i and the term "$x_i\theta_i$" is therefore included in (3.6) so that different values of θ_i lead to different values of $\partial c_i / \partial x_i$ (marginal cost for the customer).

3.4.3 Optimal bidding capacity

In the market, every rational market player aims at maximizing its own benefit. Based on the concept of economic theory, the utility of certain investment or assessment set, i.e. load, can be expressed as the function of the benefits and risk as follows:

$$U = E - \varpi\sigma^2 \tag{3.7}$$

where U is the utility of load; E represents the expectation of the benefit of load; σ^2 is the variant of the benefit; and ϖ is the absolute risk aversion coefficient, which can be used to evaluate the investor's risk partiality [25, 26]. When ϖ is positive, the investor's type is risk aversion. And the greater it is, the benefit of the utility function will be decreased more to elude the risk. If ϖ equals zero, the investor does not care about the risk and only focuses on the benefit. If ϖ is negative, the investor is risk preference and it will take more risk to increase its benefits. $\varpi\sigma^2$ represents the equivalence of risks.

For the load customer, its total load capacity is x_o. Its load can also be viewed as a set of assessment since it can get profits in the energy market and reserve market.

The load customer's benefits can be expressed as:

$$E = \rho_p x_i + p_{Prob}\left[\rho_e x_i - (K_1 x_i^2 + K_2 x_i - K_2\theta_i x_i)\right] + (Ax_r^2 + Bx_r + C) - \rho_r x_r \tag{3.8}$$

where ρ_p represents the premium of the option for the interruptible load as a competitor of the reserve market; x_i is the amount of interruptible load; ρ_e is the exercise price of the option. It is well known that two models are widely adopted to determine the price for bidding in the market: PAB (pay as bid) and the clearing pricing which is set as the highest one accepted in the market. Under the PAB model, ρ_e just depends on the bidding price of the load customer, and under the clearing pricing model, ρ_e should be forecasted based on the historical data and market condition. p_{Prob} is the probability of the execution of the option; $(K_1 x_i^2 + K_2 x_i - K_2 \theta_i x_i)$ is the interruptible load cost; x_r is the load amount submitted to the pool and $x_r + x_i = x_o$; $(Ax_r^2 + Bx_r + C)$ is the benefit of load x_r; ρ_r is the spot price on the energy market. The first part in (3.8), $\rho_p x_i + p_{Prob}\left[\rho_e x_i - (K_1 x_i^2 + K_2 x_i - K_2 \theta_i x_i)\right]$, represents the expectation of benefit in the reserve market of interruptible load bidding. And the second part in (3.8), $(Ax_r^2 + Bx_r + C) - \rho_r x_r$, represents the expectation of benefit in the energy market.

The variance of the benefit, σ^2, can be computed based on the variants of the related different variables. Assume that ρ_p, ρ_e, and ρ_r are all independent variables, which means there is no relationship among three variables and the prices will not affect each other in the market. When their variants are $\sigma_{\rho_p}^2, \sigma_{\rho_e}^2$, and $\sigma_{\rho_r}^2$ respectively, their relationships can be represented by

$$\sigma^2 = x_i^2 \sigma_{\rho_p}^2 + p_{Prob}^2 x_i^2 \sigma_{\rho_e}^2 + x_r^2 \sigma_{\rho_r}^2 \tag{3.9}$$

Since the load customer will try to maximize its benefit in (3.7), the optimal problem can be expressed as:

$$\begin{aligned}\max U &= E - \varpi\sigma^2 \\ &= \rho_p x_i + p_{Prob}\left[\rho_e x_i - (K_1 x_i^2 + K_2 x_i - K_2 \theta x_i)\right] \\ &\quad + (Ax_r^2 + Bx_r + C) - \rho_r x_r - \varpi(x_i^2 \sigma_{\rho_p}^2 + p_{Prob}^2 x_i^2 \sigma_{\rho_e}^2 + x_r^2 \sigma_{\rho_r}^2)\end{aligned} \tag{3.10}$$

subject to:

$$x_r + x_i = x_o \tag{3.11}$$

$$0 \le x_i \le x_{i\max} \tag{3.12}$$

Then, the optimal bidding capacity of the interruptible load customer in the reserve market will be:

$$x_i = \begin{cases} \min(x_{opt1}, x_{i\max}) & x_{opt1} > 0 \\ 0 & x_{opt1} \le 0 \end{cases} \tag{3.13}$$

$$x_{opt1} = \frac{2Ax_o - 2\varpi\sigma_{\rho_r}^2 x_o - \rho_P - p_{Prob}\rho_e + p_{Prob}K_2 - p_{Prob}K_2\theta + B - \rho_r}{2A - 2p_{Prob}K_1 - 2\varpi\sigma_{\rho_e}^2 - 2p_{Prob}\varpi\sigma_{\rho_e}^2 - 2\varpi\sigma_{\rho_r}^2} \tag{3.14}$$

In actual situation, the price of two markets will affect each other and jointly influence the load customers' strategy on the load dispatch in energy and reserve markets. That means there exists a correlation between ρ_e and ρ_r. Therefore, when ρ_p is an independent variable and the correlation coefficient of ρ_e, and ρ_r is represented by μ, (3.9) can be modified to:

$$\sigma^2 = x_i^2\sigma_{\rho_p}^2 + p_{Prob}^2 x_i^2\sigma_{\rho_e}^2 + x_r^2\sigma_{\rho_r}^2 - 2\mu x_i x_r \sigma_{\rho_e}^2\sigma_{\rho_r}^2 \tag{3.15}$$

According to (3.10), the optimal problem can be formulated as:

$$\begin{aligned} \max U &= E - \varpi\sigma^2 \\ &= \rho_p x_i + p_{Prob}\left[\rho_e x_i - (K_1 x_i^2 + K_2 x_i - K_2\theta x_i)\right] + (Ax_r^2 + Bx_r + C) \\ &\quad - \rho_r x_r - \varpi(x_i^2\sigma_{\rho_p}^2 + p_{Prob}^2 x_i^2\sigma_{\rho_e}^2 + x_r^2\sigma_{\rho_r}^2 - 2\mu x_i x_r \sigma_{\rho_e}^2\sigma_{\rho_r}^2) \end{aligned} \tag{3.16}$$

subject to constraints (3.11) and (3.12).

Therefore, the optimal bidding capacity of the interruptible load customer in the reserve market will be:

$$x_i = \begin{cases} \min(x_{opt2}, x_{i\max}) & x_{opt2} > 0 \\ 0 & x_{opt2} \le 0 \end{cases} \tag{3.17}$$

$$x_{opt2} = \frac{2Ax_o - 2\varpi\sigma_{\rho_r}^2 x_o - \rho_P - p_{Prob}\rho_e + \varpi K_2 - p_{Prob}K_2\theta + B - \rho_r - 2\mu\varpi x_o\sigma_{\rho_e}^2\sigma_{\rho_r}^2}{2A - 2p_{Prob}K_1 - 2\varpi\sigma_{\rho_e}^2 - 2\varpi p_{Prob}\sigma_{\rho_e}^2 - 2\varpi\sigma_{\rho_r}^2 - 4\mu\varpi\sigma_{\rho_e}^2\sigma_{\rho_r}^2} \quad (3.18)$$

3.5 Case study

Assume there is one 1000 MW load customer ($x_o = 1000\text{MW}$) and the values of other parameters are listed as follows:

A=0.025\$/(MW^{2}h); B=210\$/MWh; C=3200\$/h; θ =0.6; ϖ =0.05, K_1=0.018\$/(MW^{2}h); K_2=160\$/MWh; $x_{i\max} = 250\text{MW}$. For the market, ρ_P =0.5\$/MW; ρ_e =150\$/MWh; ρ_r =72\$/MWh; $\sigma_{\rho_e}^2$ =956.24; $\sigma_{\rho_r}^2$ =189.06; p_{Prob} =0.005.

According to (3.13) and (3.14), the optimal bidding amount in the reserve market can be calculated and equal to 163.81MW when the correlation is not considered. The load amounts in different markets and the benefits under different conditions are also calculated and shown in Table 3.1.

Table 3.1 Optimal bidding capability and benefits of interruptible load (Correlation is not considered)

Market type		Energy market	Reserve market
Option is not executed	Load amount (MW)	1000	0
	Benefit (\$/h)	166200	81.415
Option is executed	Load amount (MW)	837.17	162.83
	Benefit (\$/h)	136250.80	13607.55

In practice, when the option is executed, it usually means that there are some power transmission apparatus failures or sudden increase of total load since supply cannot meet the balance, which always accompany with the price spikes. The execution of such kind of option will greatly decrease the energy market price while ensuring the safe and economical operation of power system. Fig. 3.1 illustrates the different bidding capacities in the reserve market of the load customer with different risk preference. Along with the increase of risk aversion coefficient of the load customer, the load customer prefers to evade the risk and then submits more amounts of load in the reserve market.

When the correlation between ρ_e, and ρ_r is considered and set as 0.0005, the optimal bidding amount can be obtained based on (3.17) and (3.18) and equal to 175.79MW. The load amounts on different markets and the benefits under different conditions are listed in Table 3.2. Fig. 3.2 illustrates the different bidding capacities in the reserve market of the load customer with different values of correlation coefficient between ρ_e and ρ_r. The relationship is almost linear and along with the increase of correlation coefficient, the optimal bidding capacity also increases. It is consistent with the practical experience and the load customer prefers to offer more reserve when the clearing price of the energy market are more related to option exercise price (the correlation coefficient is greater) to release the price spikes. When the correlation coefficient increases, the higher the real-time energy price in the energy market is, the higher the exercise price of option contract in the reserve market will be. Under this case, the load customer prefers to offer more its load capacity in the reserve market to decrease the energy cost in the energy market and increase the benefit in the reserve market. The load consumed in the energy market is less and it will contribute to reduce the price in the energy market and the cost in the energy market of the load customer due to the decrease of load demand.

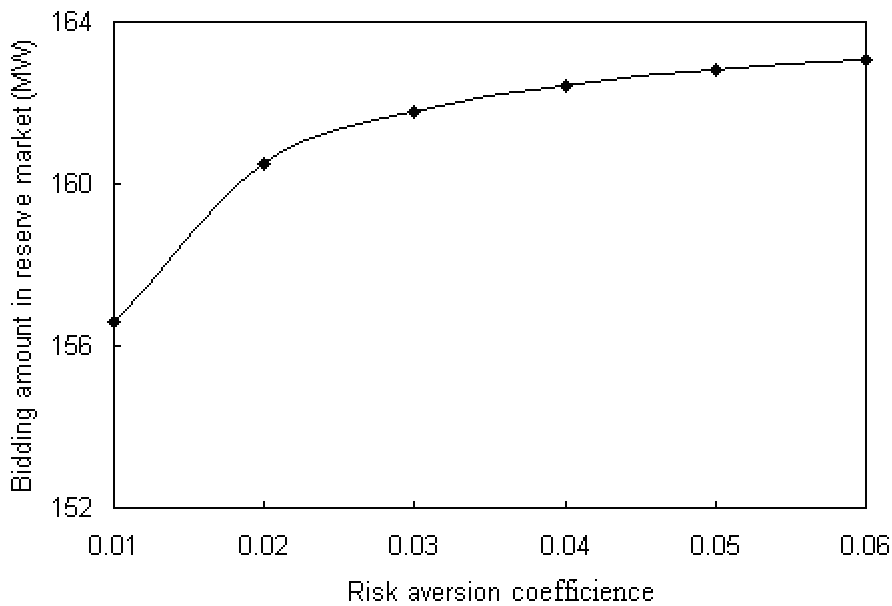


Fig. 3.1 Optimal bidding capability under different risk preference (Correlation is not considered)

Table 3.2 Optimal bidding capacity and benefits of interruptible load (Correlation is considered)

<table>
<tr><th colspan="2">Market type</th><th>Energy market</th><th>Reserve market</th></tr>
<tr><td rowspan="2">Option is not executed</td><td>Load amount (MW)</td><td>1000</td><td>0</td></tr>
<tr><td>Benefit ($/h)</td><td>166200</td><td>87.90</td></tr>
<tr><td rowspan="2">Option is executed</td><td>Load amount (MW)</td><td>824.21</td><td>175.79</td></tr>
<tr><td>Benefit ($/h)</td><td>133924.03</td><td>14649.56</td></tr>
</table>

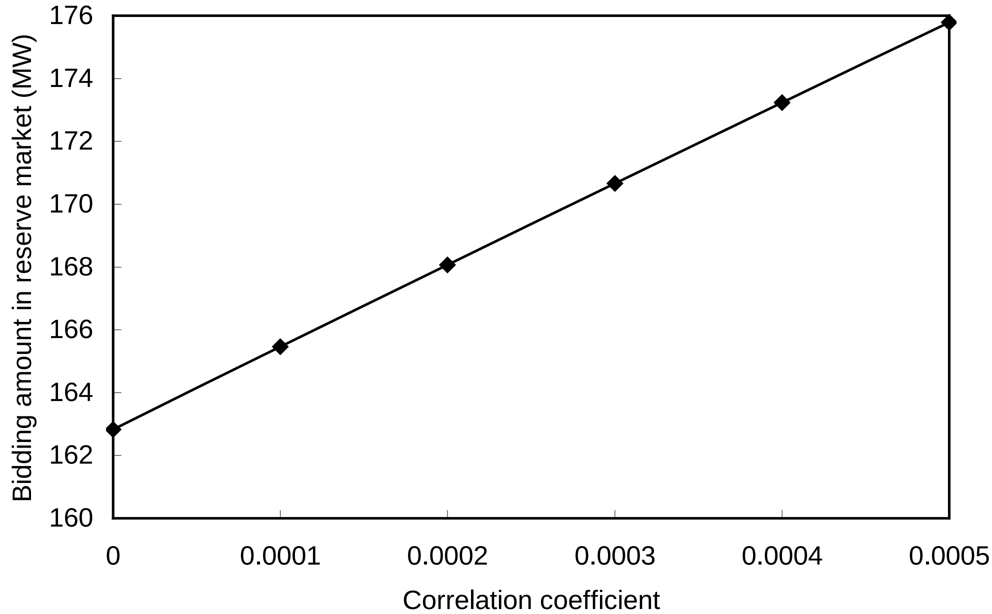


Fig. 3.2 Optimal bidding capability under different correlation coefficient

The hypothetical system is used to evaluate the performance of the proposed methods. Table 3.3 shows the reserve capacities and bidding prices offered by different generators in the submarkets. $C_{\max}$ is the maximum limit of the total capacity in the whole reserve market offered by the specific unit or load customer. According to the system data in Table 3.3, the results based on rational buyer's method without considering interruptible load are showed in Table 3.4.

When the interruptible loads are allowed to participate in the reserve market as competitors, Table 3.5 shows the resources of the reserve market. It is assumed that the load submits its bidding as 175.79 MW at the price of 150 $/MWh. The results when interruptible loads are considered are illustrated in Table 3.6. It shows that interruptible load will offer ISO an alternative in the reserve market and can help decrease the total cost to procure the reserve the systems needed.

Table 3.3 Bids and capacity requirements in the reserve market

Unit	Reserve types				C_{max} (MW)
	Regulation (MW, $/MWh)	Spinning (MW, $/MWh)	Non-spinning (MW, $/MWh)	Replacement (MW, $/MWh)	
1	60, 5	60, 10	60, 1	60, 5	90
2	100, 3	100, 6	100, 2	100, 10	160
3	120, 4	120, 4	120, 4	120, 4	160
4	80, 2	80, 3	80, 5	80, 2	100
Minimum capacity (MW)	200	100	100	100	

Table 3.4 Optimal results for each submarket

Unit	Reserve types			
	Regulation (MW)	Spinning (MW)	Non-spinning (MW)	Replacement (MW)
1	-	-	60	20
2	100	-	60	-
3	120	40	-	-
4	80	20	-	-
Clearing price ($/MWh)	400	400	200	500
Total cost ($/h)	178000			

Table 3.5 Bids and capacity requirements in the reserve market considering interruptible load

Unit	Reserve types				C_{max} (MW)
	Regulation (MW, $/MWh)	Spinning (MW, $/MWh)	Non-spinning (MW, $/MWh)	Replacement (MW, $/MWh)	
1	60, 5	60, 10	60, 1	60, 5	90
2	100, 3	100, 6	100, 2	100, 10	160
3	120, 4	120, 4	120, 4	120, 4	160
4	80, 2	80, 3	80, 5	80, 2	100
Load	-	-	175.79	175.79	175.79
Minimum Capacity (MW)	200	100	100	100	

Table 3.6 Optimal results for each submarket considering interruptible load

Unit	Reserve types			
	Regulation (MW)	Spinning (MW)	Non-spinning (MW)	Replacement (MW)
1	-	-	60	-
2	100	-	-	-
3	60	40	-	-
4	80	20	-	-
Load	-	-	140	-
Clearing price ($/MWh)	400	400	150	0
Total cost ($/h)	150000			

3.6 Summary

The key issues of the reserve market are discussed in this chapter. Interruptible load customers are introduced into the reserve market as competitors of reserve suppliers with generators. The optimal bidding strategy is also developed to maximize the load customer's benefits on energy and reserve markets by taking their risks into account. A case study has illustrated that the introduction of interruptible loads as reserve suppliers can greatly contribute to reduce the overall reserve cost.

CHAPTER 4 INTERRUPTIBLE LOAD CONTRACT DESIGN

4.1 Introduction

In the reserve market, only those very large scale load customers can participate because of the characteristic of reserve service and requirement of supplementary equipments such as open access same time information system. When the market condition is more mature and the operation experience is accumulated, the minimum capability of interruptible load which is allowed to participate will decrease. Since more and more load customers participate in the reserve market, it is so complicated for ISO to arrange the real-time bidding for all the load customers. In this situation, instead of organizing all the load customers to bid, ISO can offer a set of contracts for load customers to sign according to their conditions.

When some operation constraints cannot be satisfied, rescheduling strategy always is taken first to ensure the system security [57]. However, under some situations, the threat may not be eliminated due to the limits of power plants output or network transfer. According to the North America Electricity Reliability Council (NERC) Operating Policy-10 [58], ILM is recognized as one of the contingency reserve services and also able to provide ISO an alternative solution to solve the congestion problems.

Deregulation of the electric power industry is aimed at increasing competition and efficiency and therefore decreasing the energy costs of customers. However, because of the rapid development of economic and difficulty of building new power plants and transmission networks, generators can take advantage of the reduced competition and market power to bid up the power prices because of the distorted market situation, such as emerged in California. In this case, interruptible load can offer ISO an efficient way to reduce its costs. Also, abnormally high clearing prices related to high demand and generation shortage might be avoided if sufficient load elasticity is available.

Although the significance of ILM in the market has been generally accepted, it is not implemented widely. One of the key problems is how to sufficiently stimulate the load customers to take part in the management plan. However, it is very difficult for ISO to estimate the private information of the load customers such as curtailment costs and to provide the customers sufficient compensation. Therefore, cost-effective demand management programs that do not need to estimate the private information of customers are necessary. At the same time, how to prevent the market power abuse by load customers due to incomplete market information is another challenging problem faced by ISO. Therefore, this chapter will develop an interruptible load contract design based on mechanism design with revelation principle to tackle these problems.

4.2 Operation of ILM

ILM involves analysis of load variations, identification of controllable loads, selection of control option and implementation strategy. The procedure of ILM is described as below:

Step 1: ISO should investigate the types of all load customers. At the primeval stage of the market, only the large customers, which are evaluated by certain criteria such as amount of demand, are selected and allowed to participate in the ILM. Along with the development of the market and operational experience of ILM, the criteria should be modified so more load customers can take part in.

Step 2: ISO designs the management contract based on the load type margin for the selected load customers to choose.

Step 3: Load customers choose and sign the contracts which are suitable for them according to their willingness.

Step 4: ISO analyzes the operation condition and market circumstance, and then decides whether the ILM should be implemented or not.

Step 5: If ILM is needed, ISO will determine the amount of load curtailment and the corresponding price for the compensation of the load customers who have signed the contracts.

4.3 Profit analysis

In the pool of the energy market, generators offer their bids to ISO and ISO designs the final exchange scheme and market clearing price for customer loads.

For ILM, ISO designs a set of contracts for the load customers to sign. Then according to the specific market operation circumstance, ISO chooses the corresponding contract to ensure the smooth operation of the market. Since ISO is not-for-profit, the compensation fee for interruptible loads should be allocated among all the market players.

The cash flow among market participants and ISO can be illustrated in Fig. 4.1. There are 9 main cash flows among them:

(1) Cost of energy production for generators in the energy market

(2) Cost of service production for ancillary service provider

(3) Revenue of generators in the energy market

(4) Cost of service for generators in the energy market

(5) Cost of service for ancillary service providers

(6) Revenue of ancillary service providers

(7) Compensation for interruptible load

(8) Cost of energy service for customer loads

(9) Revenue of customer loads

This research focuses on the implementation of ILM involved generation rescheduling and load curtailment to alleviate the transmission congestion aroused by overload or to preserve stability problems so the cash flow (3) and (7) will be affected. It is aroused by generation rescheduling cost and compensation fee for the interruptible loads. ISO should minimize the management cost aroused by changes of cash flow (3) and (7).

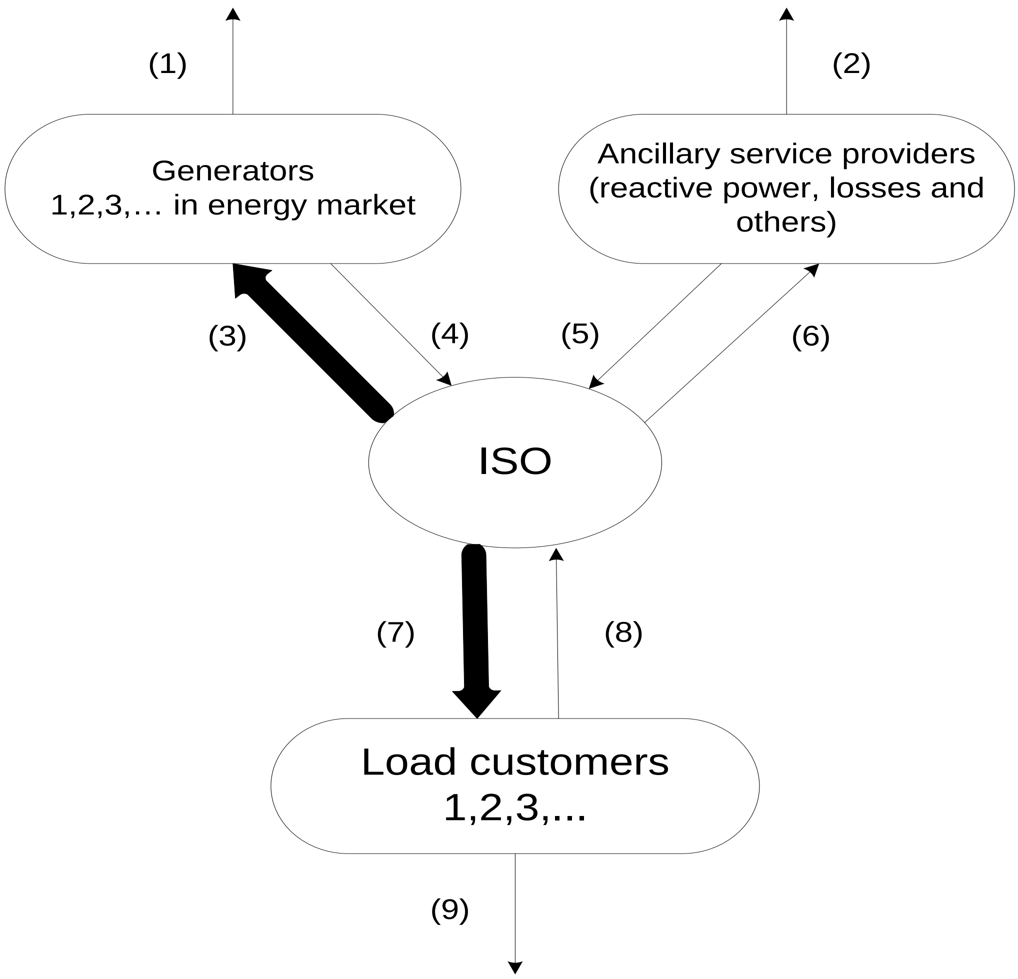


Fig. 4.1 Cash flow among market participants and ISO

4.4 Contract design

4.4.1 Mechanism design with revelation principle

Mechanism design and revelation principle are developed by economists and used in nonlinear pricing problems [59, 60]. The purpose of mechanism design is to establish a set of playing rules used in a game among a group of participants, and to achieve certain specified market outcomes by providing appropriate incentives to all the participants. Since most of the realistic markets are under asymmetric and incomplete information of participants, the mechanism design becomes very difficult and therefore the revelation principle is used to solve the problem. This idea is to design a mechanism in which all the participants can maximize their own benefits by revealing their true private information. To achieve this objective, the mechanism should be incentive compatible and also individual rational. Incentive compatibility (IC) of a mechanism means that each participant can get the maximum benefit by submitting their true private information assuming that all other participants also submit their true private information. Individual rationality (IR) means that all the participants should not gain less profit when they submit the true information. The concept of mechanism design with revelation principle is applied to contract design for interruptible loads in the following section.

4.4.2 Individual rationality and incentive compatibility constraints

As discussed in Chapter 3, the cost of the customer with load type θ_i and amounts of curtailment x_i can be represented by (3.6).

To make the mechanism individual rational, the compensation from ISO to the load customers should always be larger than their curtailment costs in order to offer them incentive to sign the contracts. To ensure the mechanism incentive compatible, the compensation from ISO to the customers should be maximized if they submit their true load type. Therefore, the IR constraint and the IC constraint for the contract design are formulated in (4.1) and (4.2) respectively.

IR constraint:

$$y_i(\theta_i, x_i) \geq c_i(\theta_i, x_i) \tag{4.1}$$

IC constraint:

$$y_i(\theta_i, x_i) - c_i(\theta_i, x_i) \geq y_i(\overline{\theta}_i, \overline{x}_i) - c_i(\theta_i, \overline{x}_i) \tag{4.2}$$

where x_i, $\overline{x}_i$ are curtailed quantities of load i with reported load types θ_i and $\overline{\theta}_i$ respectively; $\overline{\theta}_i$ is any load type parameter except θ_i ; $y_i(\theta_i, x_i)$ is the compensation fee function for load i with load type θ_i and amounts of curtailment x_i.

The IR constraint in (4.1) shows that the compensation fee should be larger than the interruptible cost if the customer signs the designated contract for its true type, which encourages the load customers participate in ILM. The IC constraint in (4.2) ensures that the customer will gain the maximum benefit through signing the contract based on its true private information. By this way, the load customers are encouraged to report their real information hence removes the market power aroused by the incomplete market information.

The profit function, $u_i(\theta_i, x_i)$, of load i with load type θ_i and amounts of curtailment x_i to participate in ILM is expressed as:

$$\begin{aligned} u_i(\theta_i, x_i) &= y_i(\theta_i, x_i) - c_i(\theta_i, x_i) \\ &= y_i(\theta_i, x_i) - K_1 x_i^2 - K_2 x_i + K_2 x_i \theta_i \end{aligned} \tag{4.3}$$

To make a mechanism design efficient [61-69], the sorting condition (also called single crossing condition or Spence-Mirrlees condition [60]) has to be satisfied. If the customers are sorted by the increase of willingness, the sorting condition dictates:

$$\frac{\partial}{\partial \theta_i}\left(\frac{\partial u_i / \partial x_i}{\partial u_i / \partial y_i}\right) > 0 \tag{4.4}$$

From (4.3), ${\partial u_i}/{\partial y_i} = 1$ can be obtained and the sorting condition for the contract design can be also simplified as:

$$\frac{\partial}{\partial \theta_i}\left(\frac{\partial c_i}{\partial x_i}\right) < 0 \tag{4.5}$$

It is clear that the load curtailment cost in (3.6) satisfies the sorting condition in (4.5). Indeed, the sorting condition can be illustrated by Fig. 4.2, where the x-axis represents the amount of load curtailment and the y-axis represents the compensation fee for the load curtailment. Suppose Point A (x_1, y_1) is the allocation of a load customer with type θ_1 and with profit u_1. For each load type, the locus of the allocation with the same profit can be represented by an indifference curve so that there are infinite indifference curves with different profits and they are parallel to each other. Here, Line ℓ_1 is the indifference curve of the customer with load type θ_1 and profit u_1.

When the load type of this customer increases to θ_2 or another customer is with a higher load type θ_2 (i.e. $\theta_1 < \theta_2$), ${\partial c_i}/{\partial x_i}$ under the same load curtailment will decrease with the increase of load type according to the sorting condition in (4.5). It means that the slope of the indifference curve decreases with the increase of the load type. Therefore, the indifference curve for θ_2 and with profit u_2 can be illustrated by Line ℓ_2 in Fig 4.2. It means a feasible region, which lies below ℓ_1 and above ℓ_2 (i.e. the shadow region in Fig. 4.2), will exist for the allocation of the load customer with type θ_2. Suppose a point within the region, say Point B(x_2, y_2), to be the allocation of the load customer with type

θ_2. Two indifference curves (Lines ℓ_1' and ℓ_2') passing through Point B and paralleling Lines ℓ_1 and ℓ_2 respectively can be obtained and represent the profit for load type θ_1 (u_1') and load type θ_2 (u_2') respectively. $u_2 \geq u_1$ because θ_2 > θ_1, $u_1 \geq u_1'$ because the compensation fee of Line ℓ_1' is lower than that of ℓ_1 for same curtailment. Similarly, $u_2' \geq u_2$ because compensation fee of Line ℓ_2 is lower than that of Line ℓ_2' for same curtailment. $u_2' \geq u_1'$ can be obtained so that the customer will report its true load type θ_2 and operate at Line ℓ_2' to maximize its profit. The concept can be extended to multi customers. It is also explained why the sorting condition in (4.4) can ensure a mechanism design efficient.

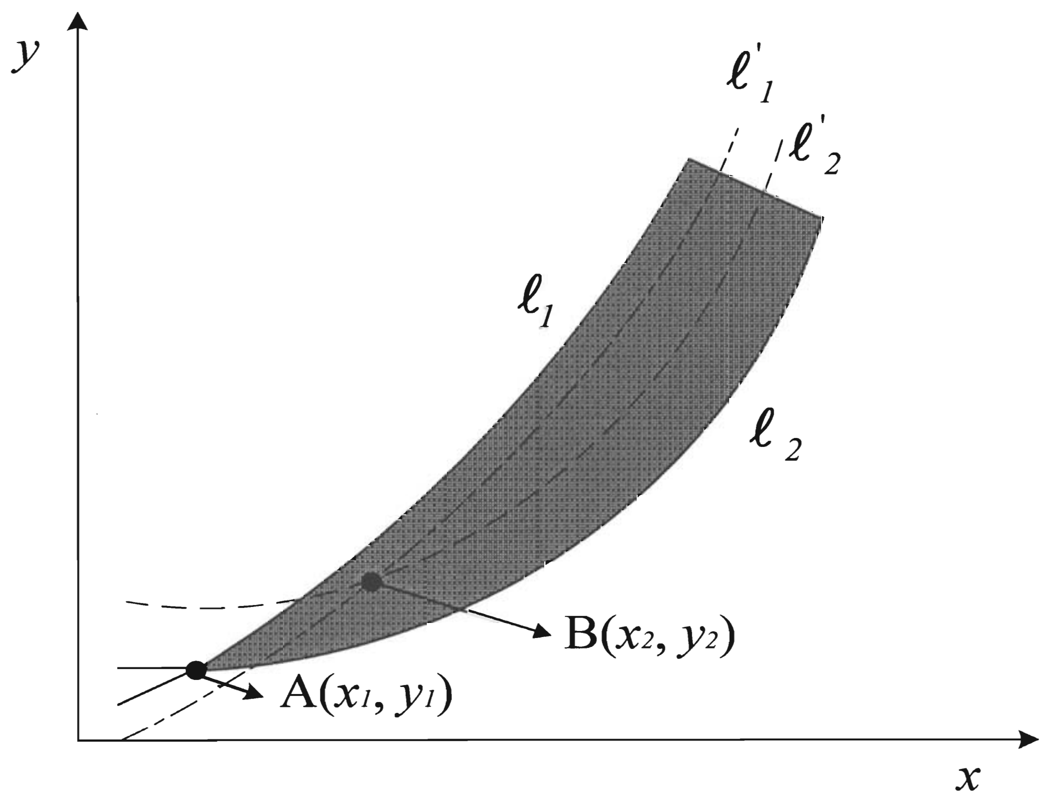


Fig. 4.2 Illustration on the sorting condition

4.4.3 Interruptible load contract design

Under stressed conditions, it may become very difficult or too expensive to deliver power to certain locations and serve the customers. In order to select the customers for ILM, ISO should evaluate the cost to purchase additional power and deliver it to serve the customers through the OPF computation in a pool market [70]; and then compare the obtained results with the curtailment cost of different types of loads. Therefore, the marginal load type θ_s can be determined when the obtained cost is equal to the curtailment cost. It can be observed that the curtailment cost for a load decreases along with the increase of its type. When θ_i is greater than θ_s, it means ISO prefers to shed this load rather than keeping its supply due to its low curtailment cost. On the contrary, if θ_i is smaller than θ_s, this load will not be considered in ILM. Therefore, θ_s is used to evaluate the effectiveness of load curtailment. It is noted that when θ_i is equal to θ_s, the IR constraint in (4.1) becomes binding , i.e. $y_s(\theta_s, x_s) = c_s(\theta_s, x_s)$.

Under some market conditions with violation of operational constraints, if there is no more generation supply and generation rescheduling is impossible, load shedding becomes the last resort and θ_s will then become 0, and all the load customers will be considered in ILM. Then the regulatory scheme and the compensation fee function will not depend upon θ_s. The loads will be interrupted based only on their true types and the impacts (i.e. sensitivities) on the alleviation of congestion.

Based on the IR and IC constraints, the cost of the load customer and the market circumstance, ISO can design the contracts for interruptible loads. Assuming that the load type θ_i is distributed between 0 and 1, the compensation fee function is:

$$y_i(\theta_i, x_i) = c_i(\theta_i, x_i) + \varepsilon(\theta_i) \tag{4.6}$$

where $\varepsilon(\theta_i)$ is the information compensation fee in order to stimulate the customer to tell the truth by ensuring the satisfaction of the IR constraint.

The load type parameters are first assumed as continuum of infinitesimal. By substituting (4.6) into (4.3), the profit of the customer becomes:

$$\begin{aligned} u_i &= K_1\overline{x}_i^2 + K_2\overline{x}_i - K_2\overline{x}_i\overline{\theta}_i + \varepsilon(\overline{\theta}_i) - K_1\overline{x}_i^2 - K_2\overline{x}_i + K_2\overline{x}_i\,\theta_i \\ &= K_2\overline{x}_i\,(\theta_i - \overline{\theta}_i) + \varepsilon(\overline{\theta}_i) \end{aligned} \tag{4.7}$$

The IC constraint ensures that the customer can achieve maximum benefit when their true types are reported so that $\partial u_i / \partial \overline{\theta}_i = 0$ when $\overline{\theta}_i = \theta_i$ as below:

$$\partial u_i / \partial \overline{\theta}_i = [-K_2\overline{x}_i + K_2\overline{x}_i^{'}(\theta_i - \overline{\theta}_i) + \varepsilon^{'}(\overline{\theta}_i)]_{\overline{\theta}_i = \theta_i} = 0 \tag{4.8}$$

Then (4.9) and (4.10) can be obtained as follows:

$$\varepsilon^{'}(\theta_i) = K_2 x_i \tag{4.9}$$

$$\varepsilon(\theta_i) - \varepsilon(\theta_s) = K_2 \int_{\theta_s}^{\theta_i} x d\theta \tag{4.10}$$

where *x* is the corresponding amount of load curtailment for load type θ.

Since the IR constraint for the customer with load type θ_s turns out to be a binding condition, i.e. $y_s(\theta_s, x_s) = c_s(\theta_s, x_s)$, we have $\varepsilon(\theta_s) = 0$ and (4.10) becomes

$$\varepsilon(\theta_i) = K_2 \int_{\theta_s}^{\theta_i} x d\theta \tag{4.11}$$

Therefore, the compensation fee function is:

$$y_i(\theta_i, x_i) = K_1 x_i^2 + K_2 x_i(1-\theta_i) + K_2 \int_{\theta_s}^{\theta_i} x d\theta \tag{4.12}$$

In real power systems, the distribution of load type is indeed discrete because only certain customers should be invited to participate in ILM in order to simplify the management flow and relieve the pressure caused by the utility's lack of experience. Large customers are generally more cost-effective and have greater impacts. Therefore, ISO can determine some typical load types for contract design based on the market investigation and then offer the customers a catalog of contracts to choose from rather than receiving the load type offered by the customers.

Based on (4.12), and assuming that the system has K customers with load type θ_i greater than or equal to θ_s ,the corresponding marginal compensation cost (i.e. the case with $i=1$) and the compensation function with discrete load types in (9) can be obtained:

$$y_s(\theta_s, x_s) = K_1 x_s^2 + K_2 x_s(1-\theta_s) \qquad i=1 \tag{4.13}$$

$$\begin{aligned} y_i(\theta_i, x_i) = & K_1 x_i^2 + K_2 x_i(1-\theta_i) \\ & + K_2 \sum_{t=1}^{i-1} (\theta_{t+1} - \theta_t) x_t \end{aligned} \qquad i=2,\dots,K \tag{4.14}$$

The first part of y_i , $K_1 x_i^2 + K_2 x_i(1-\theta_i)$, is the cost compensation fee for the loss of interruptible loads and it will decrease along with the increase of load type. And the second part of y_i , $K_2 \sum_{t=1}^{i-1} (\theta_{t+1} - \theta_t) x_t$, is the information compensation fee, which increases with the load type. For a customer with a large value of load type, its cost compensation fee will be small. However, if this customer wants to get more cost compensation fee by reporting a smaller load type value, its information compensation fee will then decrease. The designed mechanism can ensure the customers to tell the truth to maximize their profits and also prevent their abuse of market power due to incomplete market information.

4.5 Summary

This chapter introduces the procedure of ILM. The cash flow of the market is illustrated when ILM is involved. Based on the mechanism design with revelation principle, an interruptible load contract design is developed to encourage the participation of load customers into ILM while avoiding the market power aroused by the private information of load customers. The contracts can offer interruptible load customers sufficient compensation for their interruption. The benefit of the interruptible load customer for participation in ILM can be maximized when it signs the contract designated for its true private information.

CHAPTER 5 CONGESTION MANAGEMENT WITH CONSIDERATION OF INTERRUPTIBLE LOAD

5.1 Introduction

Congestion in power systems is a consequence of network constraints and some of desired power transfer cannot be accommodated. In the traditional vertical bundled power systems, congestion can be released by regulating the power flow patterns. Owing to more intensive use of available transmission facilities and less regulation in power flow patterns in deregulated power systems, congestion management has become one of the most important and challenging tasks faced by ISO [71-75].

There are several ways to eliminate congestion including cost-free and non-cost-free means [74].

Congestion can be relieved, sometimes, by cost-free means such as:

- outage of congested branches (lines or transformers)
- operation of FACTS (flexible ac transmission systems) devices
- operation of transformer taps

It is not always possible to eliminate the congestion by cost-free means, and in most cases, some non-cost-free congestion control methods have to be exercised:

- re-dispatch of generation

- curtailment of pool loads and/or bilateral contracts

It is a great importance to find a commercially transparent and technically justifiable congestion management in deregulated systems. Generation rescheduling among the scheduled generators or using a costlier generator which has not been considered in the original schedule is commonly viewed as an effective way to be taken for solving congestion problems. In [71], a sensitivity-based generation rescheduling approach is proposed to prevent congestion under normal condition and contingencies. Reference [72] introduces a method to alleviate line overloads by generation rescheduling and load shedding with the help of a local optimization concept which can determine the proper sequence of control actions. However, in some situations, generators are able to make use of their market power to bid up the market price; and the effectiveness of generation rescheduling may be limited. Market power is the antithesis of competition and undesirable as it is a symptom of an uncompetitive industry and can lower economic efficiency. The potential for market power abuse appears in two main forms: market dominance and transmission constraints. There are various definitions of market power [76-78]. In general, market power is referred as the ability of a market participant to profitably maintain prices above a competitive level for a significant period of time. As pointed out in [79], during June–November 1998, the actual price of electricity was 22% above the competitive level in the California wholesale electricity market. In June 1998, wholesale electricity prices briefly rose to 7000 $/MWh in the Midwest US market [80]. Market abuse may affect seriously on the effectiveness of congestion management.

In this chapter, a new congestion management scheme with consideration of both generation rescheduling and load curtailment contract scheme based on the interruptible load contract design of Chapter 4 will be proposed. The optimal problem is formulated to minimize the management cost for alleviation of the congestion with consideration of both preventive and post-contingency corrective capabilities.

5.2 Optimization methodology of congestion management

The pool model is considered in this study. Generators offer their bids to ISO. ISO designs the power dispatch and determines market clearing price for load customers in the ILM. The congestion management scheme is formulated as a three-step game with incomplete information, where load types are private information of load customers. In the first step, ISO needs to design a contract scheme for load customers and to encourage their participation based on the proposed method in Chapter 4. In the second step, the customers make their own decision to accept or reject the contracts based on their willingness. The customers, who accept the contracts offered by ISO, will get the corresponding incentives. In the last step, when congestion occurs, ISO will determine the redispatch results by eliminating the congestion while minimizing the management costs. The minimization of the management cost with the consideration of both generation rescheduling and load curtailment under normal state and contingencies [81-84] is an optimization problem which can be solved by the quadratic programming technique [82]. The ability of preventive and post-contingency corrections based on the contracts can be considered in the problem. The formulation of the problem is given in the following sections.

5.2.1 Objective function

The objective function of the optimization problem can be formulated as follows:

$$Min \sum_{n\in[0,N]} [\omega_n (\sum_{j\in BG} \rho_{G_j}^n \left|\Delta P_{G_j}^n\right| + \sum_{i\in K} y_i^n (x_i^n))] \tag{5.1}$$

where n is the contingency number and N is the total number of contingencies. The contingency number (n) is 0 when it represents the normal state and the preventive aspect. When n is non-zero, i.e. any value from 1 to N, it represents one of the contingencies and the post-contingency aspect. ω_n is the weight attached to contingency n. j is the generation bus number and BG is the total generation bus number. $\rho_{G_j}^n$ is the generation rescheduling clearing price of generator j under contingency n. $\Delta P_{G_j}^n$ is the change of active power output of generator j under contingency n and $\sum_{j\in BG} \Delta P_{G_j}^n = 0$. x_i^n is the curtailed quantity of load i under contingency n and $y_i^n(x_i^n)$ is the compensation fee for load i with the corresponding curtailment quantity under contingency n. Besides, the values of ω_n are determined by ISO based on the knowledge of the contingencies. Usually, $\omega_0 >> \sum_{n\neq 0, n\in N} \omega_n$ and $\sum_{n\in N} \omega_n = 1$.

The first term in the above objective function ($\sum_{j\in BG} \rho_{G_j}^n \left|\Delta P_{G_j}^n\right|$) represents the total generation rescheduling cost while the second term ($\sum_{i\in K} y_i^n (x_i^n)$) represents the total load curtailment cost.

5.2.2 Constraints of transmission limits

Congestion will occur when the flow of current in the transmission line *l* under different contingencies exceeds the transmission limit. In practice, the square of the line current is adopted in this constraint for convenient, that is:

$$(I_l^n)^2 \le (I_{l,\max})^2 \qquad l \in L, n \in [0, N] \tag{5.2}$$

where L is the total number of lines; I_l^n is the current in line *l* under contingency *n* and $I_{l,\max}$ is the maximum value of the current in line *l*.

To alleviate the congestion under contingency *n*, $\Delta(I_l^n)^2$, which is the changes of the square of current in line *l* due to the control of ISO, should satisfy the following inequality:

$$\Delta(I_l^n)^2 \ge (I_l^n)^2 - (I_{l,\max})^2 \qquad l \in L, n \in [0, N] \tag{5.3}$$

$\Delta(I_l^n)^2$ can be expressed as a linear relationship with control variables ($\Delta P_{G_j}^n$ and x_i^n) as follows:

$$\Delta(I_l^0)^2 = \sum_{j \ne m, j \in BG} S_{P_{G_j}}^0 \Delta P_{G_j}^0 + \sum_{i \in K} S_{D_i}^0 x_i^0 \qquad l \in L \tag{5.4}$$

$$\Delta(I_l^n)^2 = \sum_{j \ne m, j \in BG} S_{P_{G_j}}^n (\Delta P_{G_j} + \Delta P_{G_j}^n) + \sum_{i \in K} S_{D_i}^n (x_i + x_i^n) \qquad l \in L, n \in N \tag{5.5}$$

where $S_{P_{G_j}}^n$ and $S_{D_i}^n$ are the sensitivities of square of the current in line *l* with respect to active power output of generator *j* and demand of load *i* under contingency *n* respectively.

When n=0, $S^0_{P_{G_j}}$ and $S^0_{D_i}$ are calculated based on the normal state of the system. And when n equals 1 to N, $S^n_{P_{G_j}}$ and $S^n_{D_i}$ are computed based on the operating state under the corresponding contingency. And all these sensitivities can be computed as follows.

The power flow equations can be expressed as:

$$\boldsymbol{g}(\boldsymbol{v},\boldsymbol{u},\boldsymbol{p}) = 0 \tag{5.6}$$

where $\boldsymbol{v}$ represents a vector including magnitude and phase angle of load bus voltage; $\boldsymbol{u}$ represents a vector of active power at buses; $\boldsymbol{p}$ is a vector of other independent variables of load flow calculation except for $\boldsymbol{v}$.

By holding $\boldsymbol{p}$ as constant and expanding (5.6) into first-order Taylor series,

$$\frac{\partial \boldsymbol{g}}{\partial \boldsymbol{v}}\Delta\boldsymbol{v} + \frac{\partial \boldsymbol{g}}{\partial \boldsymbol{u}}\Delta\boldsymbol{u} = 0 \tag{5.7}$$

For slack bus m, we have

$$\Delta u_m = -\left(\frac{\partial g_m}{\partial u_m}\right)^{-1}\frac{\partial g_m}{\partial \boldsymbol{v}}\Delta\boldsymbol{v} \tag{5.8}$$

$$\Delta\boldsymbol{v} = -\left(\frac{\partial \boldsymbol{g}_{\neq m}}{\partial \boldsymbol{v}}\right)^{-1}\frac{\partial \boldsymbol{g}_{\neq m}}{\partial \boldsymbol{u}_{\neq m}}\Delta\boldsymbol{u}_{\neq m} \tag{5.9}$$

where subscript ,$_{\neq m}$, means excluding slack bus.

Also, the line flow vector ($\boldsymbol{I}$) can be expressed as a function of the voltage at both ends ($\boldsymbol{v}$) and the sensitivity relationship between is:

$$\Delta\boldsymbol{I}^2 = \frac{\partial \boldsymbol{I}^2}{\partial \boldsymbol{v}}\Delta\boldsymbol{v} \tag{5.10}$$

Then the sensitivities of square of the current in line l with respect to control variables under normal state and different contingencies n in (5.5) can be determined from (5.9) and (5.10).

5.2.3 Constraints on control actions

For preventive and post-contingency corrections, there are bounds placed on their ranges:

$$P_{G_{j,\min}} - P_{G_j} \le \Delta P_{G_j}^0 \le P_{G_{j,\max}} - P_{G_j} \qquad j \in BG \tag{5.11}$$

$$\left|\Delta P_{G_j}^n\right| \le \Delta \hat{P}_{G_{j,\max}} \qquad j \in BG, n \in N \tag{5.12}$$

$$P_{G_{j,\min}} - P_{G_j} \le \Delta P_{G_j}^0 + \Delta P_{G_j}^n \le P_{G_{j,\max}} - P_{G_j} \qquad j \in BG, n \in N \tag{5.13}$$

$$x_i^0 \le x_{i,\max} \qquad i \in K \tag{5.14}$$

$$x_i^0 + x_i^n \le x_{i,\max} \qquad i \in K, n \in N \tag{5.15}$$

$$x_i^n \le \hat{x}_{i,\max} \qquad i \in K, n \in N \tag{5.16}$$

where $x_{i,\max}$ and $\hat{x}_{i,\max}$ is the corrective capabilities of load i under normal state and contingency respectively. $P_{G_{j,\min}}$ and $P_{G_{j,\max}}$ is the active power output limits of generator j. The post-contingency corrective capabilities (PCC) of generation rescheduling ($\Delta \hat{P}_{G_{j,\max}}$) and load curtailment ($\hat{x}_{i,\max}$) occupies certain percentage of the full ranges of generation rescheduling ($min[(P_{G_{j,max}}^n - P_{G_j}^n),(P_{G_j}^n - P_{G_{j,min}}^n)]$) and load capacity ($x_i$) respectively.

5.2.4 Constraints on power balance

Assuming that generator attached to the slack bus m is designated to balance generator and load power changes with due regard for transmission losses, the power balance equation is formulated as

$$\Delta P_m^n - \sum_{i\in K}\gamma_i^n x_i^n - \sum_{j\neq m, j\in BG}\gamma_{G_j}^n \Delta P_{G_j}^n = 0 \qquad n\in[0,N] \tag{5.17}$$

where ΔP_m^n is the adjustment of generator at the slack bus under normal state and different contingencies; γ_i^n and $\gamma_{G_j}^n$ are the sensitivities of active power output of the slack bus with respect to active power output of generator *j* and demand of load *i* under contingency *n* respectively.

5.2.5 Optimal problem

In order to use the quadratic programming technique, the control variables should be non-negative. In the generation rescheduling, the output of some generators will be increased, but some of generators will be decreased. $\Delta P_{G_j}^n$ may not fulfill this requirement. So $\Delta P_{G_j}^n$ should be divided into two parts as:

$$\Delta P_{G_j}^n = \Delta P_{G_j}^{n+} - \Delta P_{G_j}^{n-} \qquad n\in[0,N] \tag{5.18}$$

where $\Delta P_{G_j}^{n+}$ and $\Delta P_{G_j}^{n-}$ represent the increase and decrease amounts of generation output. They are all positive and one of them must be zero.

Then the minimization of the objective function of the congestion management problem can be rewritten as:

$$Min \sum_{n\in[0,N]}[\omega_n(\sum_{j\in BG}\rho_{G_j}^n\left|\Delta P_{G_j}^{n+} - \Delta P_{G_j}^{n-}\right| + \sum_{i\in K} y_i^n(x_i^n)] \tag{5.19}$$

subject to constraints (5.3)-(5.5) and (5.11)-(5.17).

The above optimization problem can be solved by the iterative procedure and illustrated in Fig. 5.1. Even if the relationship between square of the current in line l with respect to active power load of the customer is not exact linear but close to a linear or quadratic form, we can iterate this process until a satisfied result is obtained.

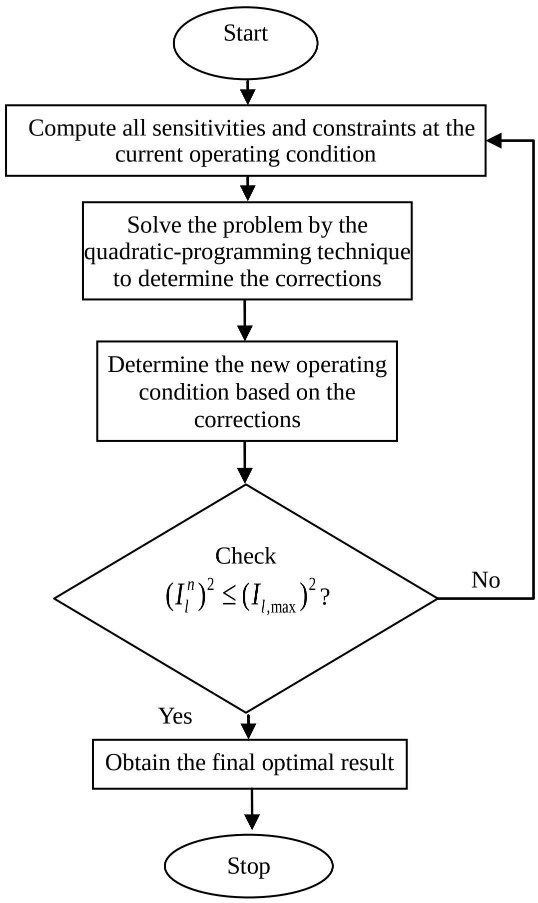


Fig. 5.1 Flowchart of the proposed method

5.3 Case study

The proposed method is tested on a modified IEEE 30-bus system. The data of the system and network figure can be obtained in Appendix I. Load types, which are not provided in the standard system, are assumed. The modified data of generators including the output of generators and generating cost function ($bP_{G_j} + cP_{G_j}^2$) are also provided in Appendix I. Besides, there are 18 typical load types in the system including 0.1, 0.15, 0.2, 0.25, 0.3, 0.35, 0.4, 0.45, 0.5, 0.55, 0.6, 0.65, 0.7, 0.75, 0.8, 0.85, 0.9 and 0.95 based on the investigation of ISO. Power factor of the loads is assumed to be constant when the load at each bus is being curtailed. The parameters K_1 and K_2 of the compensation function in (4.13) and (4.14) are set to \$0.0025/MW^{2}h and \$23/MWh. The marginal load type parameter in this study is assumed to be 0.4 so ISO considers those contracts signed by the customers with load type greater than 0.4 only. Bus 1 is designated as slack bus arbitrarily. It is noted that the selection of slack bus will not affect the effectiveness of the proposed design.

All the N-1 contingencies are tested and considered in this study. It is found that congestion does not occur under the normal state, and totally three contingency cases arouse the overloads of certain lines as shown in Table 5.1. It is assumed that $\omega_1 = \omega_2 = \omega_3$ =0.05, i.e. ω_0 =0.85 obtained from (5.1), and $\rho_{G_j}^n$ in (5.1) is same for all generators under different contingencies in this study. The maximum amount of load curtailment under normal state is set as 0.4 of the total load capacity. And PCC of generation rescheduling and load curtailment is also set as 0.4.

Table 5.1 Insecure line outage cases

Contingency (n)	Line outage	Overloaded line	$I_{l,\max}$ (p.u.)	I_l^n (p.u.)
1	1-3	1-2	1.30	1.339
2	3-4	1-2	1.30	1.314
3	2-5	2-6	0.65	0.835
		4-6	0.90	0.952
		5-7	0.70	1.133
		6-7	1.30	1.375

5.3.1 Preventive control

The simulation results for considering preventive control only are shown in Table 5.2 when $\rho_{G_j}^n$ is set as low and high values (i.e. 2$/MWh and 10$/MWh). When the generation rescheduling price is high, load curtailment is more economical than generation rescheduling. The customer loads will be interrupted when contingency occurs. When the generation rescheduling price is low, generation rescheduling becomes more economical and preferred. However, after certain amount of generation rescheduling, generation rescheduling becomes less effective because the sensitivities of line current flow corresponding to generation rescheduling in (5.4) and (5.5) becomes smaller and load curtailment is then taken. It is noted that in Table 5.2, the maximum limits of the curtailment of Load 3, 0.4 of total load or 0.96MW has reached. Load 5 has to be curtailed to release the congestion although the curtailment of Load 3 is more effective. This shows that interruptible load can provide an effective mean to solve the congestion problem especially under the high generation rescheduling price. The rest of study in this section will focus on the case of high generation rescheduling price (i.e. $\rho_{G_j}^n$ = 10$/MWh).

5.3.2 Post-contingency control

Table 5.3 shows different control actions for the cases of generation rescheduling only or both generation rescheduling and ILM under post-contingency aspects. It is noted the congestion cannot be fully alleviated by generation rescheduling alone under Contingency 3. Also, due to the high generation rescheduling price, interruptible load will offer ISO a more commercial alternative solution even both ways can handle the problem, such as under Contingencies 1 and 2. The lower management costs with the control of interruptible loads under these two cases have illustrated this conclusion. Therefore when the generator uses the distorted market condition to bid up the price, interruptible loads can help ISO reduce the management cost and to alleviate the abuse of market power of generators.

Table 5.2 Redispatch results for preventive control

$\rho_{G_j}^{n}$			Low		High	
Generation rescheduling (MW)			Generator 13	+5.27	-	-
			Generator 1	-5.27	-	-
Load curtailment (MW)			Load 3	0.96	Load 3	0.96
			Load 5	32.16	Load 5	36.15
I_l^n	n = 1	Line 1-2	0.8868		0.9409	
	n = 2	Line 1-2	0.8720		0.9259	
	n = 3	Line 2-6	0.6322		0.6500	
		Line 4-6	0.6875		0.6920	
		Line 5-7	0.6997		0.6957	
		Line 6-7	0.9037		0.9061	
Management cost ($/h)			313.251		340.070	

Table 5.3 Redispatch results for post-contingency control

Contingency	Control actions (MW)			Cost ($/h)
1	Only generation rescheduling	Generator 11	+3.80	76.00
		Generator 1	-3.80	
	With ILM	Load 3	0.96	26.79
		Load 5	2.67	
2	Only generation rescheduling	Generator 11	+1.28	25.60
		Generator 1	-1.28	
	With ILM	Load 4	1.28	5.89
3	Only generation rescheduling	-	-	-
	With ILM	Load 5	36.33	212.20

5.3.3 Preventive and post-contingency control

If there exists enough PCC of interruptible loads, preventive control will not be taken and all cases can be solved by post-contingency corrective actions since the cost of post-contingency corrective actions is compared small because of the low occurrence probability of the contingency. When the PCC is insufficient to fulfill the need, the preventive control will be taken after the maximum allowable corrective interruptible load curtailment is reached, which will greatly increase the total management costs. Fig. 5.2 shows the management cost curves under different values of PCC. Note that the intersection of the solid line on the vertical axis lies below the broken line because the multiplier ω_0 is less than one (0.85 in this case).

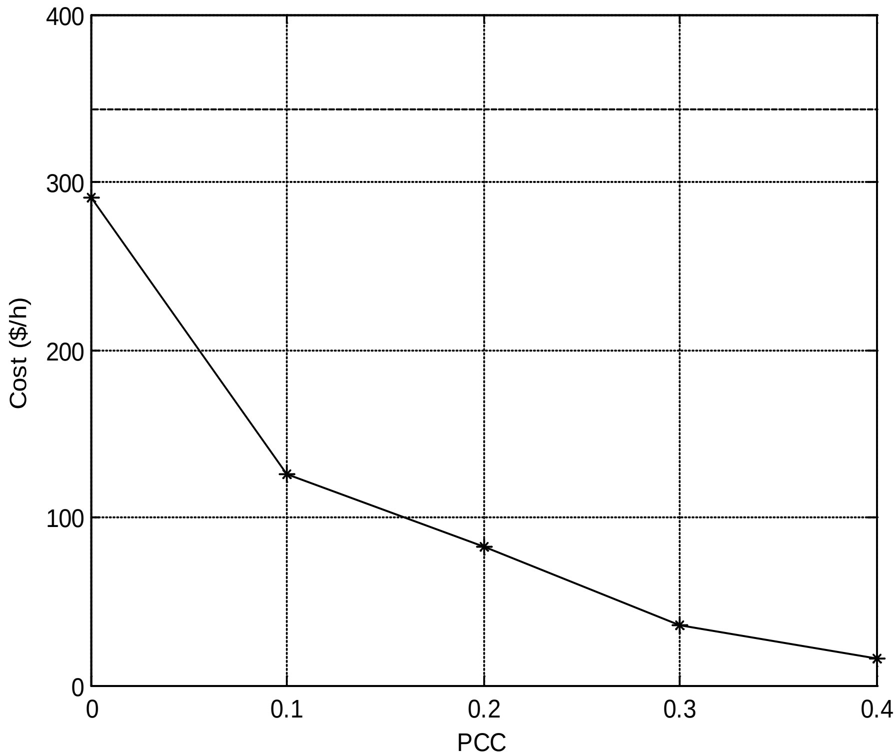


Fig. 5.2 Congestion management costs for different PCC
---- pure preventive control
—— preventive and post-contingency control

5.3.4 Validation of interruptible load contract design

Fig. 5.3 shows the profit of Load 3 for choosing the contracts with different load types in the ILM when the preventive control is considered. The bar chart illustrates that Load 3 can maximize its benefit through submitting ISO its real load type 0.9. Similar observations are found for other loads. It is noted that there is no profit for other values except 0.9 and 0.95 in Fig. 5.3 because if Load 3 reports the load type parameter other than 0.9 and 0.95, it will not be chosen to be interrupted by ISO in this case. It can validate that the proposed method using the theory of mechanism design with revelation principle can successfully help ISO reveal the private information of load customers so that an effective congestion management can be achieved.

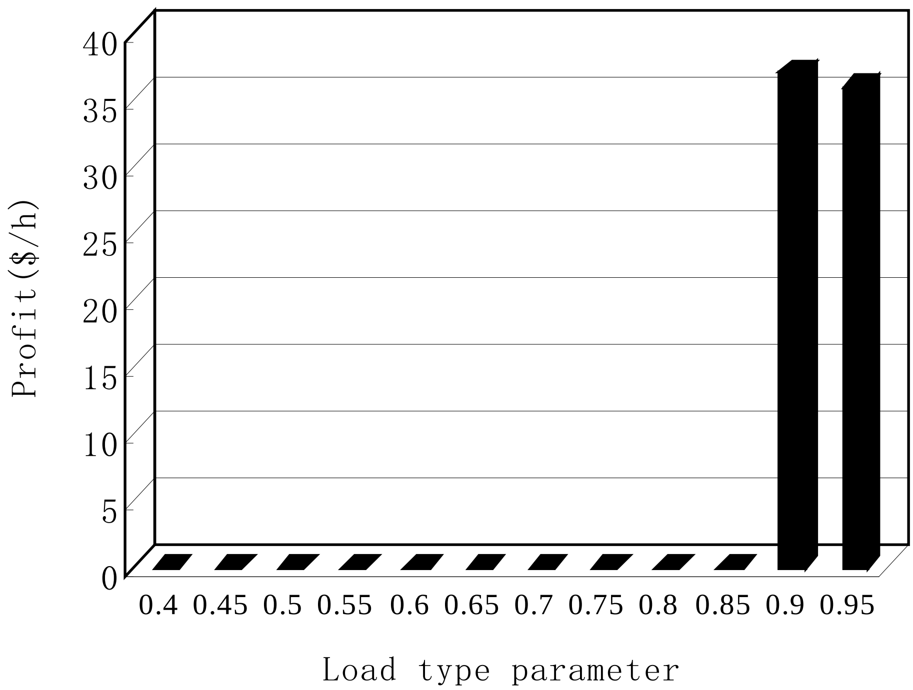


Fig. 5.3 Profit of Load 3 under different contracts

5.3.5 Market power analysis

Various indexes have been developed for market power analysis [76-78]. The Lerner Index (LI) is one of the most widely used indicators and is employed in this study. Instead of analyzing market shares and market concentration, this index focuses on individual price behavior of market players so the impacts of load variation and transmission constraints on market power can be reflected. The LI is defined as $LI= (P-MC)/P$. Here, P represents actual market price and MC marginal cost of the system. Fig. 5.4 shows the change of LI along with different generation rescheduling price when only generation rescheduling or both generation rescheduling and interruptible loads are considered as post-contingency control to release the congestion under Contingency 1. It is noted that along with increase of the rescheduling price, LI of Generators 1 and 11 becomes intolerably high when only generation rescheduling is considered. When interruptible loads are considered, it shows LIs of generators greatly decrease, which illustrates that the introduction of ILM can alleviate the market power of generators. It should be noted that the prevention of the market power abuse of interruptible loads due to incomplete market information has been considered in the proposed contract design.

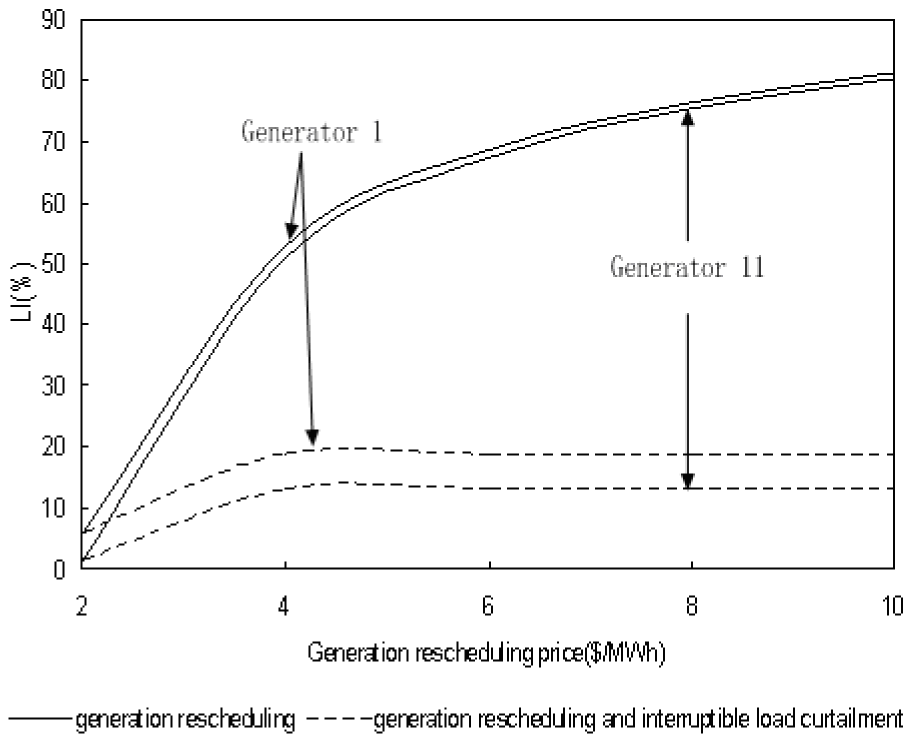


Fig. 5.4 LI under different clearing prices of generation rescheduling

5.4 Summary

This chapter introduces a new congestion management for ISO considering ILM based on the contract design proposed in Chapter 4. It is found the contract design can successfully encourage the load customers to participate in the ILM by reporting their true load types. The new congestion management scheme is proposed to eliminate the congestion while minimizing the management cost while considering the static functional operating constraints. The modified IEEE 30-bus test system has been used to demonstrate the effectiveness of the proposed method and the introduction of ILM is efficient to release the transmission line thermal limit. Beside, the advantages of the proposed contract design on alleviation of the market power abuse by participants have also been discussed and illustrated.

CHAPTER 6 INTERRUPTIBLE LOAD MANAGEMENT TO PERSERVE VOLTAGE STABILITY

6.1 Introduction

Voltage stability is defined as the ability of a power system to maintain steady acceptable voltages at all buses in the system under normal operating conditions and after being subjected to a disturbance. It includes large-disturbance voltage stability (system faults, loss of generation, or circuit contingencies) and small-disturbance voltage stability (small perturbations such as incremental changes in system load) [85-87].

Voltage instability or voltage collapse occurs when a disturbance, increase in load demand, or change in system condition causes a progressive and uncontrollable decline in voltage. Voltage stability problems normally occur in heavily stressed systems. While the disturbance leading to voltage collapse may be initiated by a variety of causes, the principal factors contributing to voltage collapse in addition to the strength of transmission network and power transfer levels are the generator reactive power, voltage control limits, load characteristics, characteristics of reactive compensation devices and the action of voltage control devices such as transformer under-load tap changers [87].

A criterion for a stable system is that, at a given operating condition for every bus in the system, the bus voltage magnitude increases as the reactive power injection at the same bus is increased. A system is voltage unstable if, for at least one bus in the system, the bus magnitude decreases as the reactive power injection at the same bus is increased. In other words, a system is voltage stable if the sensitivity of bus voltage magnitude responding to the reactive power injection is positive for every bus and voltage unstable if the sensitivity of bus voltage magnitude responding to the reactive power injection is negative for at least one bus [87].

In the world, there are several blackouts of power system which mainly aroused by voltage collapse [87]:

- New York power poll disturbances (1970)
- Florida system disturbance (1982)
- French system disturbances (1978,1987)
- Northern Belgium system disturbance (1982)
- Swedish system disturbance (1983)
- Japanese system disturbance (1987)

As power systems become more complex and more heavily loaded, voltage collapse becomes an increasingly serious problem. Fortunately, practical analytical tools will soon be making their ways from researchers to system designers and operators.

Generally, the following questions should be answered during voltage stability analysis:

- ✓ How close is the system to voltage instability?
- ✓ How and why does voltage instability occur?

✓ What should be considered to improve voltage stability and prevent voltage instability?

Basically, there are two fundamental measures about voltage stability analysis: static analysis and dynamic analysis [87].

The static analysis approach firstly model the system condition to approximate the operating point along the time domain trajectory by solving a set of system steady state algebraic equations with appropriate models for controls and limits including network, steady state generator, and load power voltage characteristic equations. Given the specific controls, limits and active power dispatch, we can obtain 'snapshots' which represent various stages along the time domain trajectory [87]. Several methods have been widely used including continuation power flow analysis, V-Q sensitivity analysis and modal analysis.

As to dynamic analysis, the following methods are commonly used:

A. Real time simulation method: The curve that voltage and other state variables vary along the time can be obtained using the integration, which retains the dynamics characteristics of devices and nonlinear characteristics of system.

B. Energy function method: It computes out the difference between system energy after fault and critical energy to judge the system stability. The two main challenges: 1) development of energy function fulfilling the standards of Lyapunov rules; 2) computation of critical energy.

C. Load bifurcation analysis method: In bifurcation theory, voltage collapse occurrences are associated with bifurcation problems. Generally, there are 3 kinds of local bifurcations which determine the system stability margin: SNB

(Saddle node bifurcation), HB (Hopf bifurcation) and SIB (Singularity induced bifurcation).

Voltage stability is an important aspect of security analyses in power system planning and operation. It can be contained or avoided normally by preventive or post-contingency control corrections [71, 83]. The post-contingency corrective control attempts to improve the voltage stability performance by directing the system into a new and more stable equilibrium condition shortly after a severe contingency, such as tripping of a heavily loaded transmission line [71, 84]. The preventive control is carried out before contingency actually occurs. Many works have been done on the problem formulation and optimization technique development for optimal control of voltage stability improvement, in which maximization of a load power margin [74, 84] or minimization of an objective function with voltage stability constraints [71,75] are the aims of the optimization problems. Available control actions include adjustment of transformer taps and reactive power injections etc.

ISO needs to take appropriate actions to deal with the voltage instability problem in power systems. Usually, voltage collapse involves heavily stressed system conditions. When the available reactive power resources cannot meet the requirement, a new optimal dispatch method considering generation rescheduling and ILM may be necessary to change the power flow pattern to limit power transfers and start up additional generating units to provide voltage support at critical areas and offer an alternative to prevent voltage collapse [84-87].

6.2 Voltage stability assessment

VSM commonly uses to indicate the maximum loadability of a system, which is how much the system can be further stressed before becoming unstable. To provide a reliable system, ISO is required to maintain the voltage within allowable limits and also ensure that adequate VSM is provided under different system operating situations. Many indices have been proposed for measuring the VSM and for predicting voltage collapse [88-91].

The VSM can be defined as the MW load distance between the current operating condition and the critical operating condition corresponding to the network maximum loadability of the saddle node bifurcation as shown in Fig. 6.1.

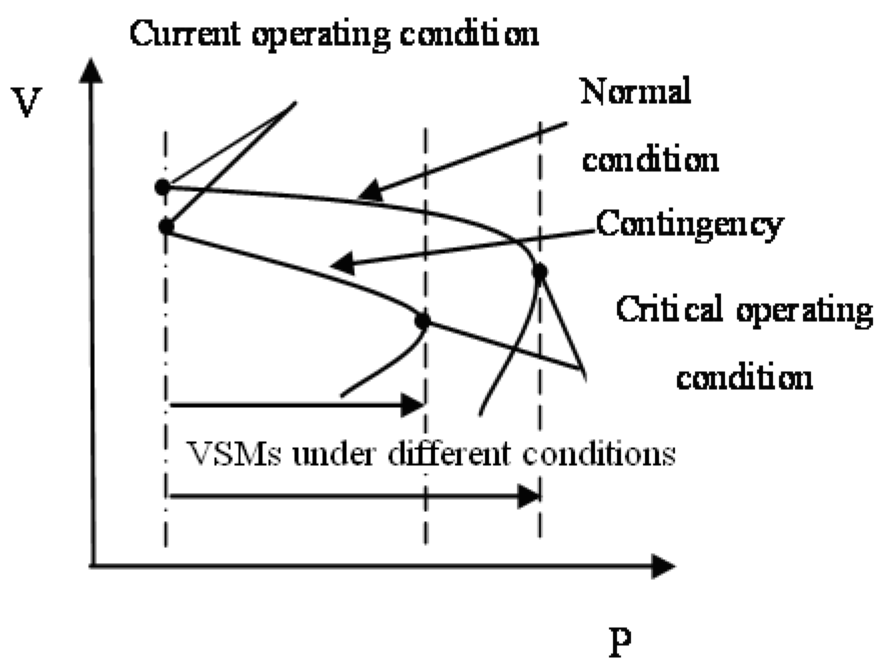


Fig. 6.1 PV curves and VSM

Sufficient stability margin in power markets is necessary to ensure that the operation will be unaffected when contingencies occur. However, the increase of the load in power markets depends on the electricity price so it is difficult to predict the pattern of the load increase and how the system network is stressed by the loads. When loads increase in different patterns or the network is stressed in different directions, different VSMs will be obtained. Therefore, to ensure the system stability, the pattern of the load increase should be assumed to be uncertain. The minimum load increase for system instability should be considered as the VSM of the systems. The iterative method proposed in [88] is used to compute the direction of load increase for the closest bifurcation. This section will introduce the methodology and procedure in detail.

A power system can be represented as the following static model:

$$f(\boldsymbol{X},\boldsymbol{\lambda})=0 \qquad (6.1)$$

where the state vector $\boldsymbol{X}$ includes all the bus voltage phasors; $\boldsymbol{\lambda}$ is a vector which includs active power and reactive power loads and nodes with zero-injection are ignored. For a critical loading $\boldsymbol{\lambda}_i$ with the corresponding state vector $\boldsymbol{X}_i$ at hypersurface Σ as shown in Fig. 6.2, the Jacobian of f in (6.1) with respect to $\boldsymbol{X}$ at $\left(\boldsymbol{X}_i,\boldsymbol{\lambda}_i\right)$, $\boldsymbol{J}_X\big|_{(X_i,\lambda_i)}$, has a zero eigenvalue with the corresponding left eigenvetor $\boldsymbol{\omega}_i$. At bifurcation point, $\boldsymbol{J}_X\big|_{(X_i,\lambda_i)}\Delta\boldsymbol{X}+\boldsymbol{J}_\lambda\big|_{(X_i,\lambda_i)}\Delta\boldsymbol{\lambda}=0$ and $\boldsymbol{\omega}_i^T\boldsymbol{J}_X\big|_{(X_i,\lambda_i)}=0$, where $\boldsymbol{J}_\lambda$ is the Jacobian of f with respect to $\boldsymbol{\lambda}$, then $\boldsymbol{\omega}_i^T\boldsymbol{J}_\lambda\big|_{(X_i,\lambda_i)}\Delta\boldsymbol{\lambda}=0$. Since $\Delta\boldsymbol{\lambda}$ is determined arbitrarily, $\boldsymbol{\omega}_i^T\boldsymbol{J}_\lambda\big|_{(X_i,\lambda_i)}$ must be equal to zero. Therefore the corresponding normal vector can be obtained by $\boldsymbol{N}_i=\boldsymbol{\omega}_i^T\boldsymbol{J}_\lambda\big|_{(X_i,\lambda_i)}$. Assume that the hypersurface is continuous and convex. The normal vector can be used as the direction of the load increase to determine the closest bifurcation by the following procedures:

Step 1: Set the iteration number i =0 and assume the initial direction of load increase $\boldsymbol{N}_0$. Here $\boldsymbol{N}_0 = \left(P_1 \Big/ \sum_{i=1}^{m} P_i , \; P_2 \Big/ \sum_{i=1}^{m} P_i , \ldots, \; P_m \Big/ \sum_{i=1}^{m} P_i \right)$, where m is the total number of loads; and P_i is the active power of the ith load. It is assumed that power factor of each load keeps constant along the load increase.

Step 2: Set $i = i + 1$ and increase the load along the direction $\boldsymbol{N}_{i-1}$ until the bifurcation occurs. Determine the VSM_i and the corresponding active load power vector by $\boldsymbol{P_i} = \boldsymbol{P_0} + \boldsymbol{N_{i-1}} VSM_i$, where $\boldsymbol{P_0}$ is the load condition of the current operating point;

Step 3: Compute the left eigenvector $\boldsymbol{\omega}_i$ of $\boldsymbol{J_X} \big|_{(X_i,\lambda_i)}$ corresponding to the zero eigenvalue;

Step 4: Set $\boldsymbol{N_i} = \boldsymbol{\omega_i^T} \boldsymbol{J}_\lambda \big|_{(X_i,\lambda_i)}$;

Step 5: Repeat Steps 2-4 until the change of $\boldsymbol{N_i}$ is within the specified tolerance. The final normal vector $\boldsymbol{N}^*$ (i.e. direction of load stress for closest bifurcation) and the corresponding $\boldsymbol{\lambda}$ vector ($\boldsymbol{\lambda}^*$) are obtained as shown in Fig. 6.2.

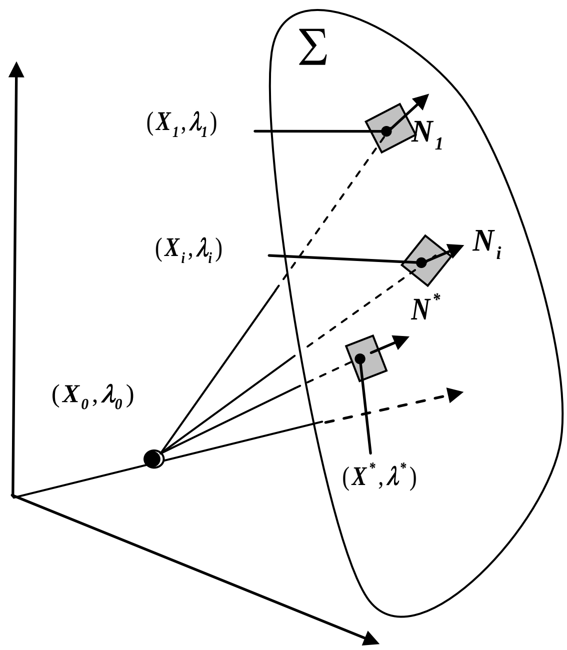


Fig. 6.2 Load increase direction for closest bifurcation

6.3 Mathematical model of optimal methodology

6.3.1 Optimal problem

The formulation of this optimal problem is similar to the congestion management problem in Section 5.2, but the VSM requirement should be considered.

The objective function can be formulated as (5.1):

$$Min \sum_{n\in[0,N]} [\omega_n (\sum_{j\in BG} \rho^n_{G_j} \left|\Delta P^n_{G_j}\right| + \sum_{i\in K} y^n_i (x^n_i))] \tag{5.1}$$

Also the constraints of control action limits and constraints of power balance have been illustrated in Sections 5.2.3 and 5.2.4.

$$P_{G_{j,\min}} - P_{G_j} \le \Delta P_{G_j}^0 \le P_{G_{j,\max}} - P_{G_j} \qquad j \in BG \tag{5.11}$$

$$\left| \Delta P_{G_j}^n \right| \le \Delta P_{G_{j,\max}}^{\wedge} \qquad j \in BG, n \in N \tag{5.12}$$

$$P_{G_{j,\min}} - P_{G_j} \le \Delta P_{G_j}^0 + \Delta P_{G_j}^n \le P_{G_{j,\max}} - P_{G_j} \qquad j \in BG, n \in N \tag{5.13}$$

$$x_i^0 \le x_{i,\max} \qquad i \in K \tag{5.14}$$

$$x_i^0 + x_i^n \le x_{i,\max} \qquad i \in K, n \in N \tag{5.15}$$

$$x_i^n \le x_{i,\max}^{\wedge} \qquad i \in K, n \in N \tag{5.16}$$

$$\Delta P_m^n - \sum_{i \in K} \gamma_i^n x_i^n - \sum_{j \ne m, j \in BG} \gamma_{G_j}^n \Delta P_{G_j}^n = 0 \qquad n \in [0, N] \tag{5.17}$$

The constraint of VSM requirement will be discussed in next section and should be integrated into the above optimal problem.

6.3.2 Constraints of VSM requirement

VSM under normal condition (n = 0) and different contingencies n are computed as discussed in Section 6.2. The following inequality constraints are formulated and included in the optimization to ensure the voltage stability performance of the system [92-93]:

$$\sum_{j \ne m, j \in BG} S_{G_j}^0 \Delta P_{G_j}^0 + \sum_{i \in K} S_{DV_i} x_i^0 \ge VSM_r - VSM \tag{6.2}$$

$$\sum_{j \ne m, j \in BG} S_{G_j}^n (\Delta P_{G_j} + \Delta P_{G_j}^n) + \sum_{i \in K} S_{DV_i}^n (x_i + x_i^n) \ge VSM_r^n - VSM^n \qquad n \in N \tag{6.3}$$

where VSM^n and VSM_r^n are the actual VSM and required VSM under the contingency n, $S_{G_j}^n$ and $S_{DV_i}^n$ are the sensitivities of VSM responding to changes of generator j's output and the curtailment of load i respectively. They can be obtained by the following method.

For the dynamic power system, at the equilibrium operating point, the dynamic system can be written as follows:

$$f(\boldsymbol{u}, \boldsymbol{v}, \boldsymbol{w}) = 0 \tag{6.4}$$

where $\boldsymbol{w}$ denotes the control parameters. Here, it represents adjustment of generator's active power output.

When bifurcation occurs, the load level is:

$$\boldsymbol{v} = \boldsymbol{v_0} + \hat{\boldsymbol{k}}VSM \tag{6.5}$$

where $\boldsymbol{v_0}$ is the real load powers at initial operating condition, vector $\hat{\boldsymbol{k}}$ denotes the load increase pattern while VSM denotes the load margin.

The following equation can be obtained by linearizing (6.4) at bifurcation point t,

$$\boldsymbol{J_u}\Big|_{(u_t,v_t,w_t)} \Delta\boldsymbol{u} + \boldsymbol{J_v}\Big|_{(u_t,v_t,w_t)} \Delta\boldsymbol{v} + \boldsymbol{J_w}\Big|_{(u_t,v_t,w_t)} \Delta\boldsymbol{w} = 0 \tag{6.6}$$

Since $\boldsymbol{\omega_t^T J_u}\Big|_{(u_t,v_t,w_t)} = 0$, pre-multiplication of (6.6) by the real part of the left eigenvector associated with the eigenvalue with zero real part produces:

$$\boldsymbol{\omega_t^T J_v}\Big|_{(u_t,v_t,w_t)} \Delta\boldsymbol{v} + \boldsymbol{\omega_t^T J_w}\Big|_{(u_t,v_t,w_t)} \Delta\boldsymbol{w} = 0 \tag{6.7}$$

From (6.5), the $\Delta\boldsymbol{v}$ can be expressed as

$$\Delta\boldsymbol{v} = \hat{\boldsymbol{k}}\Delta VSM \tag{6.8}$$

Thus from (6.7) and (6.8), the sensitivity of VSM with respect to the control parameters can be obtained and $S_{G_j}^n$ in (6.2) and (6.3) can be computed:

$$\boldsymbol{S} = -\frac{\boldsymbol{\omega_t^T J_w}\Big|_{(u_t,v_t,w_t)}}{\boldsymbol{\omega_t^T J_v}\Big|_{(u_t,v_t,w_t)} \hat{\boldsymbol{k}}} \tag{6.9}$$

As to $S^n_{DV_i}$, the changes of load can be separated into two parts. One part is aroused by system load increase, which is the set of uncontrollable parameters represented by $\boldsymbol{v}$. The other part is aroused by load shedding, which can be viewed as control parameters. So the sensitivities of VSM with respect to active power load of the customer (x_i) under different condition can also be deduced by the above method.

From (6.7), when all the other control parameters except Δx_i equal to zero, $\boldsymbol{\omega}_t^T \boldsymbol{J}_{\boldsymbol{v}}\big|_{(u_t,v_t,w_t)} \Delta \boldsymbol{v} + \boldsymbol{\omega}_t^T \boldsymbol{J}_{v_i}\big|_{(u_t,v_t,w_t)} \Delta x_i = 0$ and then:

$$\boldsymbol{S}^n_{DV_i} = -\frac{\boldsymbol{\omega}_t^T \boldsymbol{J}_{v_i}\big|_{(u_t,v_t,w_t)}}{\boldsymbol{\omega}_t^T \boldsymbol{J}_{\boldsymbol{v}}\big|_{(u_t,v_t,w_t)} \hat{\boldsymbol{k}}} \tag{6.10}$$

where $\boldsymbol{J}_{v_i}\big|_{(u_t,v_t,w_t)}$ is the ith column *of* $\boldsymbol{J}_{\boldsymbol{v}}\big|_{(u_t,v_t,w_t)}$ corresponding to x_i.

6.4 Case study

In this section, the proposed method is tested based on the modified 39-bus New England system. The data of the test system and network figure are provided in Appendix II respectively. $I_{l,\max}$, load type and reactive power limits of generators, which are not provided in the standard system, are assumed in this study.

It is assumed that based on the investigation of ISO, there are 19 typical load types in the system including θ = 0.05, 0.1, 0.15, 0.2, 0.25, 0.3, 0.35, 0.4, 0.45, 0.5, 0.55, 0.6, 0.65, 0.7, 0.75, 0.8, 0.85, 0.9, and 0.95. $\rho^n_{G_j}$ is assumed to be same for all generators under different contingencies when generation rescheduling is considered and only Generators 31, 32, and 33 have the rescheduling capability. Power factor of the load is assumed to be kept constant when the load at each bus is curtailed. The parameters K_1 and K_2 of the compensation function are set to \$0.0025/MW^{2}h and \$23/MWh. And the maximum available curtailment capacity of all loads occupies 0.25 of their total load and the limits of allowed generation rescheduling are set as their output limits. In this case we assume the probability of the occurrence of a N-1 contingency as 0.02.

Power factor keeps constant when the load at each bus is curtailed. Assuming that the marginal load type parameter in this study is 0.4, ISO only considers those contracts signed by the customers with load type greater than 0.4.

6.4.1 Consideration of transmission limits only

When the thermal transmission limits are considered only, the insecure cases are listed in Table 6.1.

Table 6.1 Insecure line outage

Contingency	Line outage	Overloaded line	$(I_{l,\max})^2$ (p.u.)	$(I_l^n)^2$ (p.u.)
1	Line 6-7	Line 5-6	81.0000	82.2978
2	Line 13-14	Line 4-5	14.4400	15.4553

When $\rho_{G_i}^n$ is set as 5\$/MWh and 15\$/MWh, the final redispatch results considering preventive control only are shown in Table 6.2. When the generation rescheduling price is equal to 15\$/MWh, ILM is more economical than generation rescheduling. The load customers will be interrupted when the corresponding contingency occurs as shown in Table 6.2 a. When the generation rescheduling price is equal to 5$/MWh, generation rescheduling becomes more economical and preferred as showed in Table 6.2 b.

Table 6.2 Redispatch results of ILM scheme only considering preventive control

a) $\rho^{n}_{G_j}$ =15$/MW

Curtailment (MW)	Load 4	107.8	
$(I^{n}_{l})^2$ (p.u.)	n =1	Line 5-6	80.1533
	n = 2	Line 4-5	14.4048

b) $\rho^{n}_{G_j}$ =5$/MW

Rescheduling (MW)	Generator 31	-14.9	
	Generator 33	+14.9	
$(I^{n}_{l})^2$ (p.u.)	n =1	Line 5-6	80.5736
	n = 2	Line 4-5	14.4173

Table 6.3 shows different control actions for the cases of generation rescheduling only or both generation rescheduling and ILM under different post-contingency aspects. Also, when the generation rescheduling price is high (15$/MWh in the case), interruptible load will offer ISO a more commercial alternative solution even through both ways can handle the problem, which the different costs under these two cases have illustrated this point. So when the generators take advantage of the distorted market condition to bid up the price (from 5$/h to 15$/h in this case), interruptible load can help ISO reduce the

management cost. Fig. 6.3 shows the comparison of different costs between generation rescheduling and interruptible load under different generation rescheduling price when preventive aspect is considered. Fig. 6.4 illustrates the management cost curves under different post-contingency corrective capacity. Along the decrease of the post-contingency corrective capability, the requirement cannot be fulfilled only by post-contingency changes since the corrective capacity limits are hit, so preventive actions must be taken and the benefit loss increases remarkably. Note that the intersection of the solid line on the vertical axis lies below the broken line because the multiplier ω_0 is less than one (0.96 in this case).

Table 6.3 Final control actions considering post-contingency control (PCC=0.25, $\rho_{G_j}^{n}$ =15$/MW)

<table>
<tr><th>Contingency (n)</th><th colspan="3">Control actions (MW)</th><th>Cost ($/h)</th></tr>
<tr><td rowspan="3">1</td><td rowspan="2">Only generation rescheduling</td><td>Generator 31</td><td>-11.9</td><td rowspan="2">357</td></tr>
<tr><td>Generator 33</td><td>+11.9</td></tr>
<tr><td>With ILM</td><td>Load 7</td><td>-19.6</td><td>68.58</td></tr>
<tr><td rowspan="3">2</td><td rowspan="2">Only generation rescheduling</td><td>Generator 31</td><td>-14.9</td><td rowspan="2">447</td></tr>
<tr><td>Generator 33</td><td>+14.9</td></tr>
<tr><td>With ILM</td><td>Load 4</td><td>107.8</td><td>276.99</td></tr>
</table>

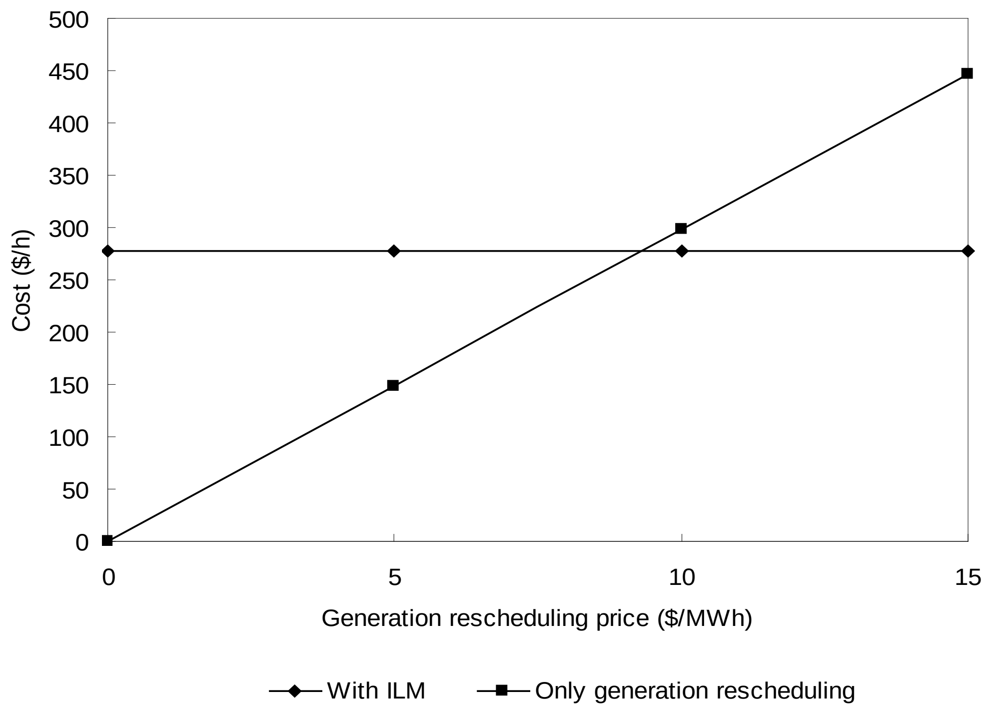


Fig. 6.3 Cost of different preventive control actions

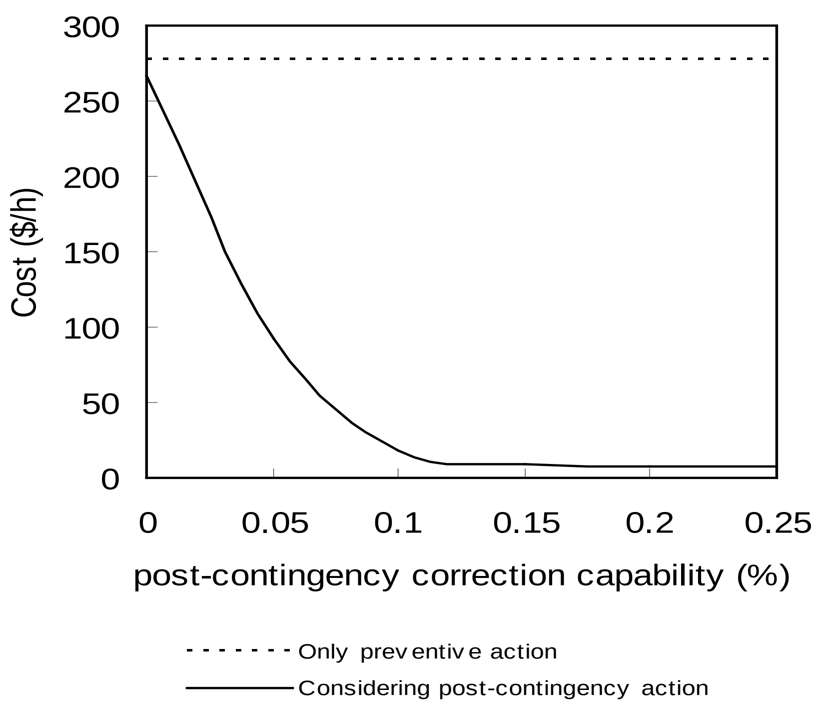


Fig. 6.4 Cost under different post-contingency corrective capacity

6.4.2 Consideration of VSM requirement

When VSM requirement (8% of the total load amount) is also considered, all the insecure cases except thermal overloaded cases are listed in Table 6.4. It is noted the VSM under normal condition (9.452%) fulfills the requirement.

Table 6.4 Insecure line-outage case（ VSM_r^n=8%）

Contingency (n)	Line outage	VSM^n
3	Line 3-4	6.042%
4	Line 4-5	6.573%
5	Line 8-9	6.095%
6	Line 9-39	6.516%
7	Line 15-16	5.112%

Table 6.5 shows different preventive control actions for the cases of generation rescheduling only or both generation rescheduling and ILM when both thermal limits and VSM requirement are considered. Fig. 6.5 shows the different management results under different VSM requirement. With the increase of the VSM requirement, the management cost also increases.

Fig. 6.6 shows the benefits of Load 4 (θ=0.9) for choosing different contracts when participating in the ILM scheme. The curve illustrates the load customer can maximize its benefit through submitting ISO the true private information because Load 4 can get the maximum benefit when signing the contract designed for load type 0.9, i.e. its real load type parameter. Noted that Load 4 can only be chosen in ILM when it reports its load type as 0.9 and 0.95. When it reports its load type as 0.95, the compensation fee cannot cover its interruptible cost so the value of its benefit is negative. This proves that the proposed method can encourage the load customers to submit their true load types. So even the load type is the private information, the contract designed using the theory of mechanism design with revelation principle can help ISO reveal them and prevents that the load customers abuse them.

Table 6.5 Final control actions of ILM (VSM_r^n =8%, $\rho_{G_j}^n$ =15$/MW)

a) Consider generation rescheduling only

Generation rescheduling (MW)	Generator 31	-221	
	Generator 33	+221	
VSM^n (%)	n=0	11.267	
	n=3	9.213	
	n=4	9.803	
	n=5	9.128	
	n=6	9.550	
	n=7	8.061	
$(I_l^n)^2$	n=1	Line 5-6	58.8570
	n=2	Line 4-5	3.8899

b) With ILM

Interruptible load (MW)	Load 3	-10.24	
	Load 4	-125.00	
VSM^n (%)	n=0	11.220	
	n=3	8.929	
	n=4	9.216	
	n=5	8.871	
	n=6	9.273	
	n=7	8.047	
$(I_l^n)^2$	n=1	Line 5-6	79.7734
	n=2	Line 4-5	14.2405

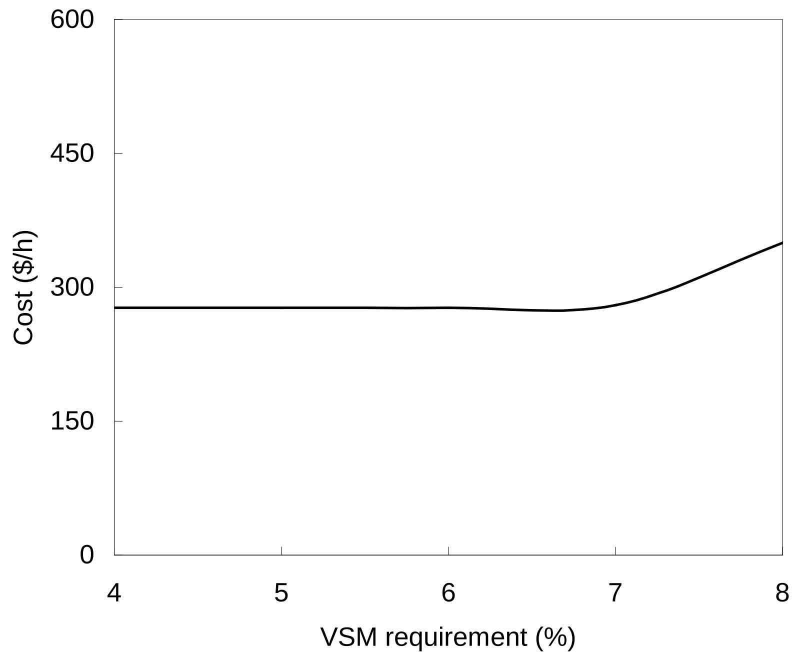


Fig. 6.5 ILM cost under different VSM requirement

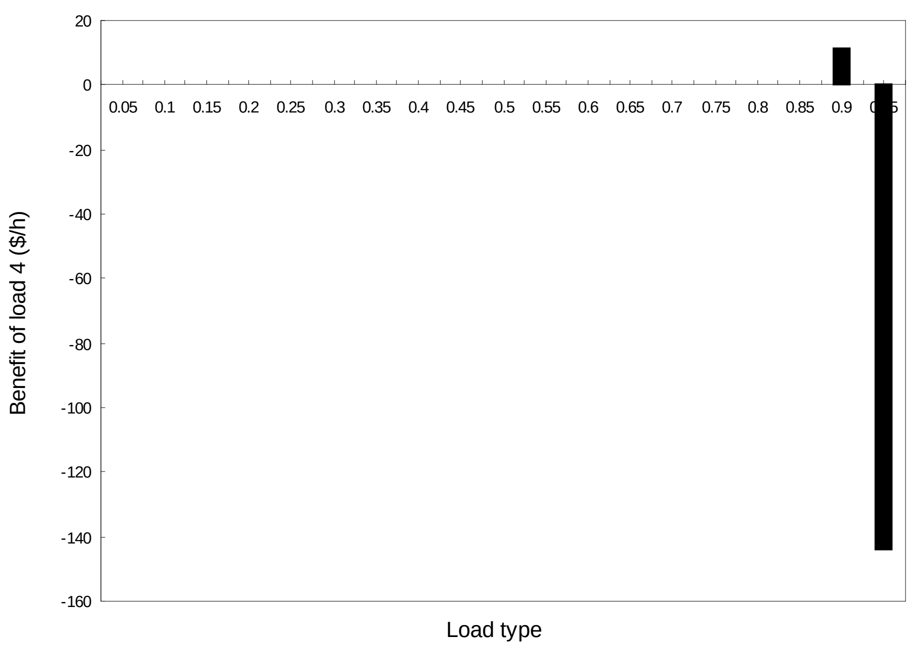


Fig. 6.6 Benefit of load 4 by signing different contracts

6.5 Summary

This chapter extends the congestion management scheme with ILM in Chapter 5 to solve the voltage instability problem in power systems. It is found that ILM can greatly contribute to the voltage ability of system by offering the adequate VSM. An optimal management procedure is developed and VSM requirements of the normal and contingency conditions are also considered under both preventive and post-contingency aspects. Also, the economical benefit of introduction of ILM is validated. The modified 39-bus New England test system has been used to demonstrate the effectiveness of the proposed method when VSM is considered.

CHAPTER 7 PREVENTIVE CONTROL WITH INTERRUPTIBLE LOAD TO SOLVE TRANSIENT STABILITY PROBLEMS

7.1 Introduction

Power system transient stability has long been recognized as an important and problematic issue. From a physical viewpoint, transient stability is the ability of the power system to maintain synchronism when subjected to a severe transient disturbance such as a fault on transmission facilities, loss of generation, or loss of a large load [94-97]. The system response to such disturbances involves large excursion of generator rotor angles, power flows, bus voltages, and other system variables. If a system can regain a new stable state after the contingency, relative angular velocities of all generators in the system keep in an acceptable value. If a system tends to go unstable by the loss of synchronism, relative angular velocities of some generators with respect to the rest system machines goes on increasing.

For transient stability analysis, there exist different models [98]:

1. Classical Model: The generator is represented by a constant electric potential behind the direct axis, and the load is represented by a constant reactance.
2. Structure Conservation Model: The salient pole effects, flux linkage decay, and excitation control etc. are considered. The load will depend on the bus voltage.
3. Reduced Network Model: The large system is decoupled into several lower

order sub-systems.

Up to now, methods for transient stability analysis can be categorized into three main kinds of analysis methods: time-domain simulation, direct transient energy function method and hybrid method, i.e. the combination of the above two methods [98].

1. Time-domain simulation

Time domain simulation is to analyze the nonlinear dynamic responses of the state variables of a power system via the solution of a set of differential-algebraic equations describing the electromechanical transients. Step-by-step numerical integration methods are used to solve the nonlinear ordinary differential equations with known initial values obtained by static power flow solution before the transients. It integrates the differential equations of fault and post-fault system periods, to get the approximate solution of these equations.

2. Direct method

Direct methods are capable of determining the system stability directly without solving the complex differential-algebraic dynamic equation set. A function describing the system transient energy is computed at the end of the disturbance and compared with a critical value of the energy for transient stability assessment. The difference between them is the energy margin, which is an indication of stability and of great interest in transient stability assessment [98].

Up to now, direct methods for transient stability analysis of power system are classified into two categories. One is based on transient stability energy function, including relevant or controlling instability equilibrium point method, potential energy boundary surface method, boundary of stability region based controlling unstable equilibrium point method; the other is based on extended equal area criterion method.

3. Hybrid Method

Hybrid methods combine the time domain method and the transient energy function (TEF) evaluation to produce stability indices using the concept of transient energy margin and simulated system responses [99]. Regarded as one of the best methods which are widely used, time-domain methods have outstanding performance on accuracy, reliability and modeling capability. However, time-domain methods are inherently slow and cannot provide any information about the degree of stability of the system. The TEF method, as another alternative tool for transient stability evaluation, is known as the fast computational speed and its ability to provide a performance index. But it also has some drawbacks such as convergence problems and limited modeling capacity. In order to overcome the drawbacks of these two methods, the hybrid methods have been developed to incorporate time domain simulation and TEF method. The restriction on the application of the classical models has been removed and the problem of erratic nonlinearity of the transient energy margin that results in an unreliable prediction of the stability limits has been also overcome.

ISO should take appropriate actions to cope with stability-related symptoms, especially when the transient stability concerns are considered. Some researchers recommend improving transient stability of power systems using the FACTS devices in [94]. In [95], the authors present a formulation of the multicontingency transient stability constrained optimal power flow (MC-TSCOPF) problem and introduce a modified formulation for integrating transient stability model into conventional OPF, which reduces the calculation load considerably. A new approach to on-line optimal dispatching, considering a global transient stability constraint, which is formulated in a probabilistic frame using the Lyapunov direct method, is proposed in [96]. In [97], the authors present a new generation rescheduling approach for preventive control of power systems to optimally reallocate power generations for multiple unstable contingencies. A heuristic stability performance index is used to describe the transient stability constraints.

In this chapter, a new optimal dispatch method is proposed to improve the transient stability in power markets, which both generation rescheduling and ILM are considered. Transient stability assessment and computation of transient stability index are first introduced and integrated into the optimal dispatch method developed in Chapter 5.

7.2 Transient stability assessment

Transient stability assessment is to evaluate the stability of a power system to withstand specified contingencies by surviving the subsequent transient events to arrive at an acceptable steady state operating condition [98].

Transient stability assessment can be implemented by computing a stability index for the contingencies. Many advanced methods have been developed for transient stability assessment [99-101]. The hybrid method in [102] will be used in this study and described in this chapter.

7.2.1 System models

The system equations for an W-generator system in the classical formulation with respect to the centre of inertia (COI) are generally denoted by:

$$M_j\dot{\tilde{\omega}}_j = P_{mj} - P_{ej} - \frac{M_j}{M_T}P_{COI} \equiv f_j(\cdot) \tag{7.1}$$

$$\dot{\sigma}_j = \tilde{\omega}_j \tag{7.2}$$

$$P_{COI} = \sum_{j=1}^{n}(P_{mj} - P_{ej}) \qquad j = 1, 2, \cdots, W \tag{7.3}$$

where:

σ_j = rotor angle of machine j in COI frame,

$\tilde{\omega}_j$ = rotor speed of machine j in COI frame,

M_j = inertia constant of machine j,

$M_T = M_1 + M_2 + \ldots + M_W$,

P_{mj} = mechanical power input of machine j,

P_{ej} = electrical power output of machine j,

$f_j(\cdot)$ = acceleration power of machine j.

The equations for evaluation of P_{ej} are different for different system models.

The TEF of an n-machine system modeled above is defined as:

$$TEF \equiv KE + PE \tag{7.4}$$

$$KE = \frac{1}{2}\sum_{j=1}^{W} M_j\dot{\tilde{\omega}}_j^2 \tag{7.5}$$

$$PE = -\sum_{j=1}^{W}\int_{\sigma_j^{SEP}}^{\sigma_j} f_j^P(\cdot)d\sigma_j \tag{7.6}$$

where,

KE= system kinetic energy,

PE= system potential energy,

σ_j^{SEP} = rotor angle of the post-fault system's stable equilibrium point,

$f_j^{P}(\cdot)$ =accelerating power of the post-fault systems.

The TEF remains constant in the post-fault period. This is called the TEF conservation property and it holds only if there is no damping involved during this period.

7.2.2 Transient stability index assessment methods

Most hybrid methods, despite the improvements mentioned before, however, suffer from the drawback that the correct critical machine group (CMG) has to be identified before an estimation of the stability index can be performed [99-101]. It is usually difficult to identify the CMG of a stable trajectory that involves complex oscillation modes for a multi-machine system. Furthermore, the CMG may vary with power relocation between critical generators. The above phenomena will decrease the efficiency and reliability of a CMG dependent transient stability assessment method.

In this work, the methodology described in [102], which does not rely on the CMG concept to get the transient stability index, is used. The transient stability index used in this work is critical clearing time (CCT). If the contingency is cleared before CCT, the system will remain stable; otherwise, it will become unstable. The characteristics of the minimum kinetic energy (KE) curve for the contingencies versus fault clearing time were fully investigated in [102]. The identical minimum KE curve is shown in Fig. 7.1.

The generalized characteristics of the minimum KE curves versus fault clearing time are summarized as follows:

1.The minimum KE curves consist of two almost linear segments corresponding to stable and unstable trajectories, respectively.

2.The slope of the segment corresponding to unstable trajectories is much larger than that of the stable segment.

3.The inflexions of the minimum KE curves correspond to the CCT of the contingencies.

4.The slope of the segment of the minimum KE corresponding to unstable cases can be approximated by the slope of the fault-on TEF curve at the same fault clearing time.

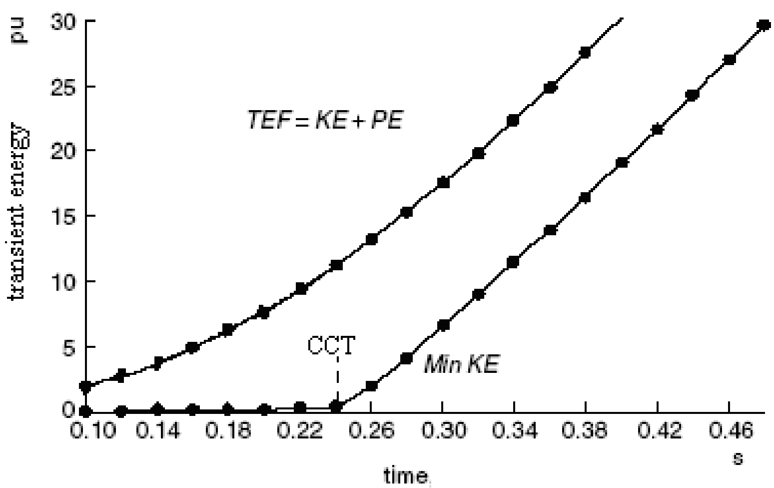


Fig. 7.1 Curves of fault-on TEF, minimum KE versus the fault clearing time

Based on the above characteristics of the minimum KE curves, the procedure for CCT estimation is summarized as follows:

Procedure 1: Perform a fault-on trajectory simulation till potential energy boundary surface crossing, and record the time as T_{pebs} ; compute and store the TEF values of the trajectory.

Procedure 2: Predict the CCT using (7.7) and name the result as CCT' , where the $KE_{\min}(T_{pebs})$ and $Slope(T_{pebs})$ are the KE and TEF curve slope of the fault–on trajectory at time T_{pebs}.

Procedure 3: Perform a post-fault simulation with fault clearing time CCT'. If the trajectory is unstable, correct the CCT using (7.7) again with $T_{pebs} = CCT'$ and go to Procedure 1. If the trajectory is stable, correct the CCT using (7.8) where $KE_{min}(CCT')$ is the minimum KE of the trajectory cleared at time CCT'; and stop.

$$CCT' = T_{pebs} - \frac{KE_{\min}(T_{pebs})}{Slope(T_{pebs})} \tag{7.7}$$

$$CCT'' = T_{pebs} - \frac{KE_{\min}(T_{pebs}) - KE_{\min}(CCT')}{Slope(T_{pebs})} \tag{7.8}$$

7.3 Mathematical model of optimal methodology

7.3.1 Objective function

Since the transient stability problem always occurs with a very short period after the disturbances, only the preventive control is considered. So the objective function is modified according to Chapter 5 and reformulated as follows:

$$Min[\sum_{j\in BG} \rho_{G_j} \left|\Delta P_{G_j}\right| + \sum_{i\in K} y_i\,(x_i\,)] \tag{7.9}$$

where $y_i\,(x_i\,)$ is the compensation cost paid to customer *i* for x_i amount of load curtailment and ΔP_{G_j} is the change of generation active power output. ρ_{G_j} is the rescheduling price of generation. The first term in the objective function

($\sum_{j\in BG} \rho_{G_j} \left|\Delta P_{G_j}\right|$) represents the total generation rescheduling cost when the system still has certain generation rescheduling capacity along with interruptible loads and additional power injections purchasing outside of the scheduled plan which may be much more expensive to cope with the problems. And this term is equal to zero when no generation rescheduling action is taken. The second term ($\sum_{i\in K} y_i\,(x_i)$) represents the ILM cost.

Since preventive aspect is considered only, the following constraints on control actions and power balance are modified according to Sections 5.2.3 and 5.2.4.

$$P_{G_{j,\min}} - P_{G_j} \le \Delta P_{G_j} \le P_{G_{j,\max}} - P_{G_j} \qquad j \in BG \tag{7.10}$$

$$x_i \le x_{i,\max} \quad i \in K \tag{7.11}$$

$$\Delta P_m - \sum_{i\in K} \gamma_i\, x_i - \sum_{j\ne m,\, j\in BG} \gamma_{G_j} \Delta P_{G_j} = 0 \tag{7.12}$$

The constraints of the transient stability requirement should be formulated according to Section 7.3.2 and integrated into the optimal problem.

7.3.2 Constraints of transient stability requirement

The sensitivities of CCT to changes of generation active output and load amounts correspond to the system operating point, S_{G_j} and S_{T_i} are computed, and then integrated into the linear program. The rescheduling results should fulfill the CCT requirement, which can be expressed by the following inequality constraints:

$$\sum_{j\neq m, j\in BG} S^n_{GT_j} \Delta P_{G_j} + \sum_{i\in K} S^n_{T_i} x_i \geq CCT^n_r - CCT^n \qquad n \in N \tag{7.13}$$

where $S^n_{GT_j}$ and $S^n_{T_i}$ are the sensitivities of CCT corresponding to active power changes of generation j's output and the curtailment of the load customer i. CCT^n is the actual transient stability index under the normal state and contingency n; CCT^n_r is CCT requirement under contingency n.

The relationship between CCTs and active powers of generation output or load are made as follows: Based on the on-line transient stability assessment introduced in Section 7.2, CCTs are calculated for the present system condition and for the new condition after certain control parameter, such as generation active power output or load amounts, changes from the present condition. Since the relationship is virtually linear, the sensitivities of CCT with respect to the control parameters can be obtained.

7.3.3 Computation flow of optimization methodology

The procedure for solving the optimal problem in (7.9) can be shown as follows:

Step 1: Based on the current system operating condition, CCTs are calculated. For contingencies, three phase to ground faults at buses, which are the severest cases for transient stability, are considered;

Step 2: If the CCTs are larger than target values (always larger than the actual operating times of circuit breakers in the power systems), preventive control is not necessary and the program ends. If one or more contingencies have smaller CCTs, preventive control should be taken and the optimal problem should be formulated;

Step 3: The objective function and all the constraints are formulated based on the current system condition;

Step 4: Preventive control actions are determined by solving the proposed optimal problem in (7.9);

Step 5: With the new system operation condition, transient stability assessment is executed. If CCTs fulfill the requirement, then the program ends; and if not, it goes to step 3 until the final optimal preventive control actions are obtained.

7.4 Case study

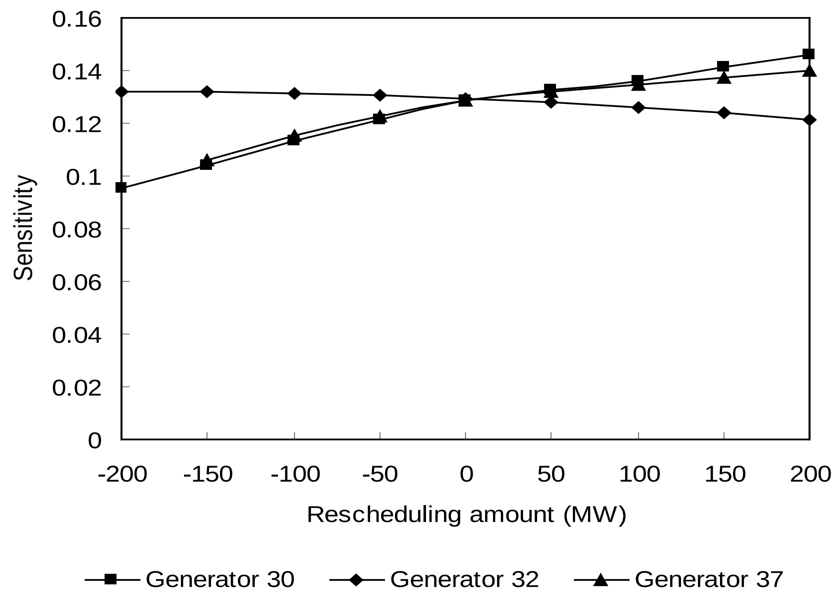
The 39-bus New England system is used to test the proposed method. All the generators are represented by the classical model and fixed impedance load models are adopted here. It is assumed that based on the investigation of ISO, there are 14 typical load types in the system including θ = 0.1, 0.2, 0.3, 0.4, 0.5, 0.55, 0.6, 0.65, 0.7, 0.75, 0.8, 0.85, 0.9 and 0.95 as shown in Table 7.1. Only generations at buses 30, 32 and 37 will participate in generation rescheduling.

Power factor of the loads is assumed to be kept constant when the load at each bus is being curtailed. The parameters K_1 and K_2 of the compensation function are set to 0.05 $/MW^{2}h and 460 $/MWh. Assuming that the marginal load type parameter in this study is 0.4, ISO only considers those contracts signed by the customers with load type greater than 0.4. A three-phase fault occurring near bus 16 at the end of the line 16-17 is used as the disturbance. This disturbance is the severest contingency because its CCT is 0.129 s, which is the smallest one under all the contingencies. It is noted that the choice of contingencies will not affect the effectiveness of the proposed method.

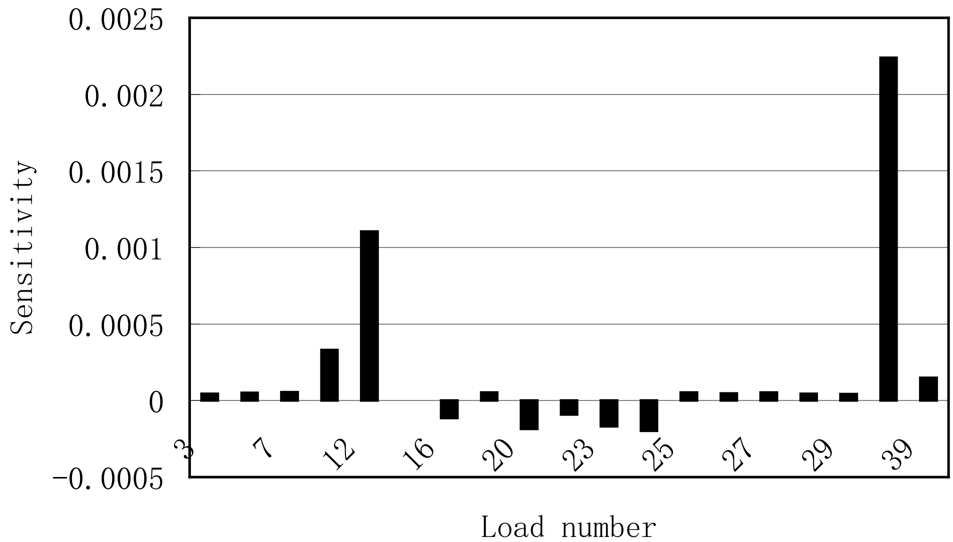
Table 7.1 Load type data

Bus	θ	Bus	θ
3	0.1	23	0.70
4	0.2	24	0.75
7	0.3	25	0.75
8	0.4	26	0.8
12	0.5	27	0.8
15	0.55	28	0.85
16	0.6	29	0.9
18	0.6	31	0.9
20	0.65	39	0.95
21	0.70		

ISO first computes the sensitivities of CCTs for those contingencies with respect to different load curtailments and generation rescheduling. The sensitivities of different loads and different generation rescheduling under contingency are illustrated in Fig. 7.3. Then the optimization problem in Section 7.3 is solved by quadratic programming method and the suitable preventive control actions are chosen.



a) Sensitivity of active power output of Generators



b) Sensitivity of active power load at different bus

Fig. 7.3 Sensitivities of different generation reschedulings and loads under contingency

Table 7.2 shows different control actions for the cases of generation rescheduling only or both generation rescheduling and ILM. When the generation rescheduling price turns out to be high (12$/MWh in the case), interruptible load will offer ISO a more commercial alternation as both ways can handle the problem. When the generation rescheduling price is equal to 6 $/MWh, generation rescheduling becomes more economical and preferred. Fig. 7.4 shows the management costs under different generation rescheduling prices.

Table 7.2 Final preventive actions under different conditions

ρ_{G_i} ($/MWh)	Preventive Actions			CCT (s)	Cost ($/h)
6	Generation rescheduling (MW)	Generator 30	+138	0.140	1656.000
		Generator 32	-138		
12	Load curtailment (MW)	Load 12	1.50	0.140	2782.542
		Load 31	1.84		
		Load 39	154		

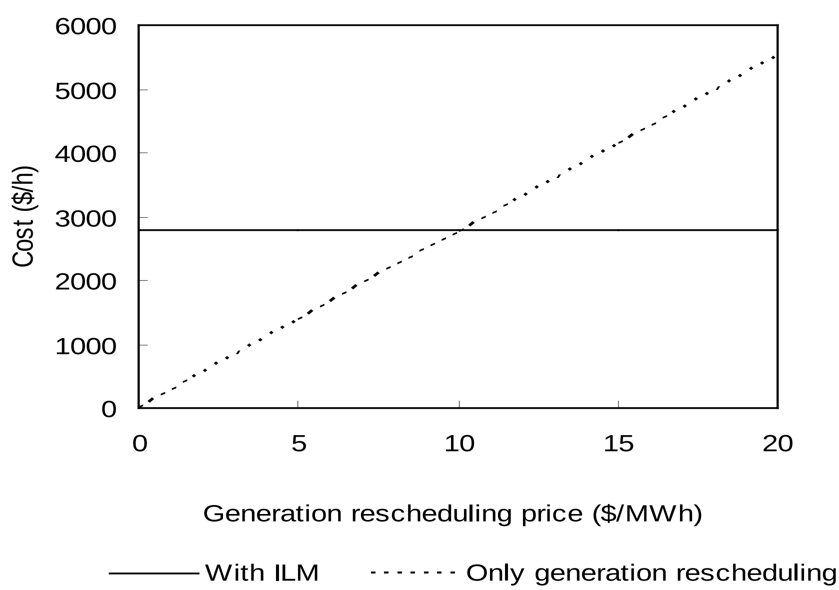


Fig. 7.4 Cost under different generation rescheduling prices

7.5 Summary

This chapter studies the effectiveness of the proposed ILM in transient stability enhancement. The transient stability index has been successfully integrated into the optimization methodology proposed in Chapter 6. Only the preventive aspect is considered according to the characteristic of transient stability problem. Based on the 39-bus New England test system, ILM has been demonstrated to be as an efficient way to enhance the transient stability performance of power systems.

CHAPTER 8 CONCLUSION AND FUTURE WORK

8.1 Conclusion

The main work and conclusions can be summarized as follows:

A. *Interruptible load customer as a competitor in the reserve market*

Based on the operation of traditional reserve market, the implementation of interruptible load customers as the reserve market competitors is investigated. A bidding mechanism is developed when interruptible load customers are considered as reserve service suppliers. The option contract is introduced and interruptible load customers can participate the bidding through signing the option contract with ISO. Also, the optimal bidding capacity is computed out to maximize the benefit of the interruptible load customer on both the energy and reserve markets while the market risk is integrated into the benefit function. Also, the impacts of risk aversion coefficient and correlation of the two markets (energy market and reserve market) on the bidding strategy are analyzed. Case studies show that interruptible load customers which are allowed to compete in the reserve market will help ISO to reduce the cost to procure the reserves.

B. *Interruptible load contract design*

How to sufficiently stimulate the load customers to take part in the management plan while preventing the abuse of market power because of the lack of available customer cost information is a difficult but important issue faced to

ISO. On one hand, ISO should focus on offering sufficient incentives to load customers for effective implementation of management. But on the other hand, the customer cost is difficult to obtain and ISO has to prevent the abuse of market power due to the private interruption cost information of load customers. So it is important to design cost-effective demand management programs that do not need the private information of customer outage costs while encouraging the load customers report their true interruption cost information. Mechanism design with revelation principle is an efficient way to sufficiently compensate and stimulate load customers to participate in the ILM voluntarily while ensuring the profits of utilities.

To be incentive compatible and also individual rational, the interruptible load contract is designed under the direction of mechanism design with revelation principle. ISO can offer a set of contracts with different load type for load customers to sign and the load customers can obtain the sufficient compensation while the benefit can be maximized by signing the contract designed for its own load type.

C. *Interruptible load as an control action to enhance safety and reliability of power systems*

ILM can be introduced to ISO as alternative solution to congestion management when shortage of system power output occurs or other controls are not economically effective. It is found that this scheme can greatly contribute to the ability of system to alleviate the congestion. The interruptible cost of different loads is considered and the load customers are sufficiently compensated in order to encourage them to participate in ILM actively. An optimal management procedure is developed and the requirements of congestion management under the normal and contingency conditions are also considered. The modified IEEE 30-bus system has been used to demonstrate the effectiveness of the proposed method. Besides, the proposed scheme has been extended to consider the voltage and transient stability indexes; and can greatly contribute to the ability of system to withstand the risks of voltage and transient instabilities.

8.2 Future work

In this thesis, the static load model is adopted and the constant power factor is assumed. The dynamical characteristic of loads is not included. To pave the way to smoothly implementation of ILM, the characteristics of load customers should be studied deeply. Dynamic load models can be integrated into the proposed method to help ISO design the more rational management scheme for power markets.

The closest saddle-node bifurcation point is used to study the voltage stability in power systems. Voltage stability can be caused by other local bifurcations such as HB and SIB. The relationship between the ILM and the characteristic of voltage stability in power systems should be studied comprehensively.

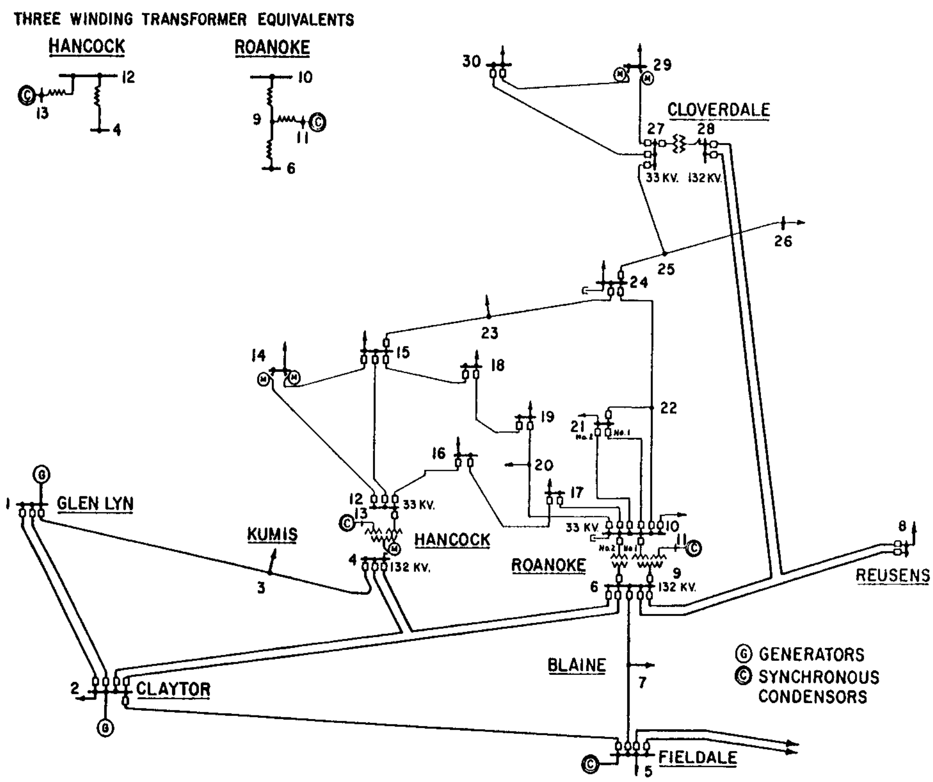
In this thesis, interruptible load is viewed as the reserve supplier and emergency control action, and it can play a more active role under the deregulated power systems. The scale of the power networks keeps increasing dramatically and more and more interconnected large-scale power systems emerge. Among the interconnected power systems, the power utility can make profits by curtailing the interruptible load customers in its own zone and transferring the additional power to the neighboring power systems whose power price is relatively high. Under this circumstance, the new role of interruptible load can be discussed. Also, the impacts on the power price on the real time market because of load curtailment should be considered in the profit analysis of system operation cost.

With the rapid development of distributed generation system, especially the worldwide application of renewable energy, the status of traditional load customers will be changed and ISO will face new challenge to manage the load customers and design effective interruptible load scheme.

APPENDICES

Appendix I Modified IEEE 30-bus system

- *Network figure*



- *Generation data*

Bus	Active power (MW)	Voltage (p.u.)	Cost coefficient	
			c ($/MW^2)	*b* ($/MW)
1	-	1.065	0.00210	1.5
2	81.60	1.075	0.00280	1.6
11	25.00	1.080	0.00300	1.8
13	26.46	1.065	0.00165	1.7

- *Branch data*

Bus		Resistance (p.u.)	Reactance (p.u.)	Charging (p.u.)	$I_{l,\max}$ (p.u.)
From	To				
1	2	0.0192	0.0575	0.0264	1.30
1	3	0.0452	0.1852	0.0204	1.30
2	4	0.0570	0.1737	0.0184	0.65
3	4	0.0132	0.0379	0.0042	1.30
2	5	0.0472	0.1983	0.0209	1.30
2	6	0.0581	0.1763	0.0187	0.65
4	6	0.0119	0.0414	0.0045	0.90
5	7	0.0460	0.1160	0.0102	0.70
6	7	0.0267	0.0820	0.0085	1.30
6	8	0.0120	0.0420	0.0045	0.32
6	9	0.00	0.2080	1.0000	0.65
6	10	0.00	0.5560	1.0000	0.32
9	11	0.00	0.2080	0.00	0.65
9	10	0.00	0.1100	0.00	0.65
4	12	0.00	0.2560	1.0000	0.65
12	13	0.00	0.1400	0.00	0.65
12	14	0.1231	0.2559	0.00	0.32
12	15	0.0662	0.1304	0.00	0.32
12	16	0.0945	0.1987	0.00	0.32
14	15	0.2210	0.1997	0.00	0.16
16	17	0.0824	0.1923	0.00	0.16
15	18	0.1070	0.2185	0.00	0.16
18	19	0.0639	0.1292	0.00	0.16
19	20	0.0340	0.0680	0.00	0.32

10	20	0.0936	0.2090	0.00	0.32
10	17	0.0324	0.0845	0.00	0.32
10	21	0.0348	0.0749	0.00	0.32
10	22	0.0727	0.1499	0.00	0.32
21	22	0.0116	0.0236	0.00	0.32
15	23	0.1000	0.2020	0.00	0.16
22	24	0.1150	0.1790	0.00	0.16
23	24	0.1320	0.2700	0.00	0.16
24	25	0.1885	0.3292	0.00	0.16
25	26	0.2544	0.3800	0.00	0.16
25	27	0.1093	0.2087	0.00	0.16
28	27	0.00	0.3960	1.0000	0.65
27	29	0.2198	0.4153	0.00	0.16
27	30	0.3202	0.6027	0.00	0.16
29	30	0.2399	0.4533	0.00	0.16
8	28	0.0636	0.2000	0.0214	0.32
6	28	0.0169	0.0599	0.0065	0.32

- *Load data*

Bus	Active Power (MW)	Reactive Power (MVAr)	Load type
3	2.4	1.2	0.9
4	7.6	1.6	0.8
5	102.2	9.0	0.75
7	22.8	10.9	0.7
8	12.5	6.0	0.65
10	5.8	2.0	0.6

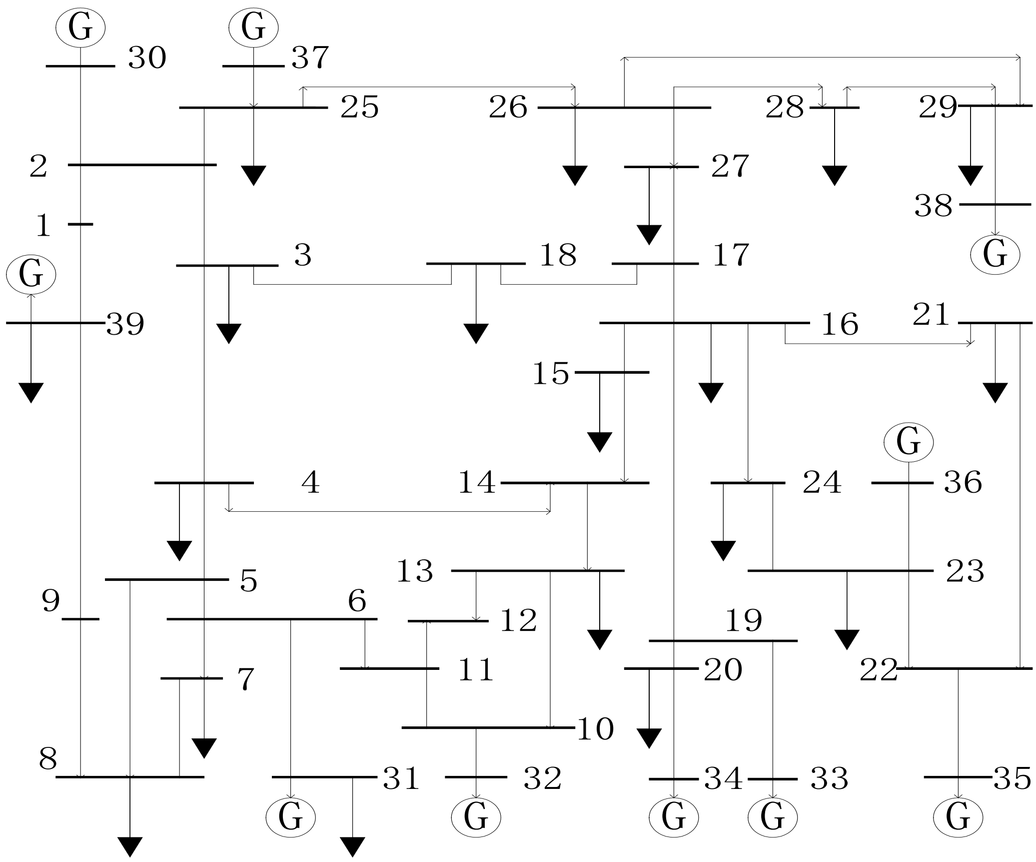
12	11.2	7.5	0.55
14	6.2	1.6	0.5
15	8.2	2.5	0.45
16	3.5	1.8	0.4
17	9.0	5.8	0.35
18	3.2	0.9	0.35
19	9.0	3.4	0.3
20	2.2	0.7	0.3
21	17.5	11.2	0.25
23	3.2	1.6	0.25
24	8.7	6.7	0.2
26	3.5	2.3	0.2
29	2.4	0.9	0.15
30	10.6	1.9	0.1

- *Static capacitor data*

Bus	Susceptance (p.u.)
5	0.3
10	0.19
24	0.043

Appendix II Modified 39-bus New-England system

- *Network figure*



- *Generation data*

Bus	Active power (MW)	Reactive power (MVAr)		Voltage (p.u.)
		Min	Max	
29	-	-200.00	300.00	1.05048
30	250.00	-200.00	300.00	1.04750
31	572.86	-200.00	250.00	0.98200
32	650.00	-200.00	300.00	0.98310

33	632.00	-200.00	300.00	0.99720
34	508.00	-200.00	300.00	1.01230
35	650.00	-200.00	300.00	1.04930
36	560.00	-200.00	300.00	1.06350
37	540.00	-200.00	300.00	1.02780
38	830.00	-200.00	300.00	1.02650
39	1000.00	-200.00	300.00	1.03000

- *Branch data*

Bus		$I_{l,\max}$ (p.u.)	Bus		$I_{l,\max}$ (p.u.)
From	To		From	To	
1	2	3.80	16	24	3.80
1	39	3.80	17	18	6.00
2	3	6.00	17	27	3.80
2	25	6.00	21	22	9.00
3	4	6.00	22	23	3.80
3	18	6.00	23	24	6.00
4	5	3.80	25	26	6.00
4	14	9.00	26	27	9.00
5	6	9.00	26	28	3.80
5	8	9.00	26	29	3.80
6	7	9.00	28	29	6.00

6	11	6.00	12	11	3.80
7	8	9.00	12	13	3.80
8	9	3.80	6	31	9.00
9	39	3.80	10	32	9.00
10	11	9.00	19	33	9.00
10	13	9.00	20	34	9.00
13	14	6.00	22	35	9.00
14	15	6.00	23	36	9.00
15	16	9.00	25	37	9.00
16	17	9.00	2	30	6.00
16	19	9.00	29	38	12.00
16	21	6.00	19	20	3.80

- *Load data*

Bus	Active Power (MW)	Reactive Power (MVAr)	Load type
3	322.00	2.40	0.95
4	500.00	184.00	0.9
7	233.80	84.00	0.85
8	522.00	176.00	0.8
12	88.50	28.00	0.75
15	320.00	153.00	0.7
16	329.40	32.30	0.65
18	158.00	30.00	0.6

20	680.00	103.00	0.55
21	274.00	115.00	0.5
23	247.50	84.60	0.45
24	308.60	-92.20	0.4
25	224.00	47.20	0.35
26	139.00	17.00	0.3
27	281.00	75.50	0.25
28	206.00	27.60	0.2
29	283.50	126.90	0.15
31	9.20	4.60	0.1
39	1104.00	250.00	0.05

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