TRANSMISSION SECURITY-RESPONSIBLE OPTIMAL SCHEDULING OF HYDRO-GENERATOR OPERATIONS IN A COMPETITIVE ENVIRONMENT

by

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B.Sc., The University of Huazhong Science and Technology, 1992

A THESIS SUBMITTED IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE OF

MASTER OF APPLIED SCIENCE

in

THE FACULTY OF GRADUATE STUDIES
(Department of Electrical and Computer Engineering)

We accept this thesis as conforming
to the required standard

THE UNIVERSITY OF BRITISH COLUMBIA

August, 2004

THE UNIVERSITY OF BRITISH COLUMBIA FACULTY OF GRADUATE STUDIES

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Title of Thesis: Transmission security-responsible optimal scheduling of hydro-generator operations in a competitive environment

Degree: Master of Applied Science Year: 2004

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ABSTRACT

Under the development of restructured electrical power industry, the competitive environment of transacting electricity among all the market participants creates more and more challenges to either suppliers or consumers. The goal of suppliers, who own the generating equipment, is to maximize their total profits by selling the electricity. The targets of distributors and consumers are to minimize their expense for purchasing the electricity. With the uncertainty of system demand and electricity market price, it is even more difficult to achieve the objectives of both suppliers and consumers.

This thesis presents an approach for short-term optimal hydro-generation scheduling considering transmission system security constraints based on uncertain load and electricity market price. The possible range of uncertain load is forecasted by fuzzy regression model, which was developed by an earlier work in our research group. The market price database is obtained from the analysis of Pennsylvania-New Jersey-Maryland (PJM) market price. The mixed integer non-linear unit commitment problem is solved by Lagrangian relaxation technique. Security-constrained economic dispatch is obtained by solving Lagrangian function with first gradient method for the equality constraints. After the feasible solution is reached with all the equality constraints satisfied, the heuristic search consisting of unit substitution and unit de-commitment is used to adjust the solution to satisfy all the inequality constraints. The proposed approach improves the final solution to be the best one achieving the global optimal solution. This approach is tested on a numerical example based on BC Hydro 500 kV network configuration. The results show this approach is applicable to optimize the system operation and gain the maximum profits for power suppliers, while maintaining the system security and reliability.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

Number *Page*

LIST OF ABBREVIATIONS

AI – Artificial Intelligence

ATC – Available Transmission Capacity

BPA – Bonneville Power Administration

CBM – Capacity Benefit Margin

CBUC – Cost-Based Unit Commitment

DisCos – Distribution Companies

DP- Dynamic Programming

EC – Evolutionary Computation

ED – Economic Dispatch

ETC – Existing Transmission Commitment

FERC – Federal Energy Regulatory Commission

FTR – Firm Transmission Right

GAs – Genetic Algorithms

GenCos – Generation Companies

ISO – Independent System Operator

LMP – Local Marginal Price

LR – Lagrangian Relaxation

MCP – Market Clearing Price

Nordpool – Norway pool market

PBUC – Price-Based Unit Commitment

PI – Performance Index

PJM – Pennylvania-New Jersey-Maryland

PoolCo – a Pool market

SCUC – Security-Constrained Unit Commitment

SA – Simulated Annealing

SMP – System Marginal Price

TransCos – Transmission Companies

TRM – Transmission Reliable Margin

TTC – Total Transfer Capacity

UC – Unit Commitment

WECC – Western Electrical Coordinating Council

ACKNOWLEDGEMENTS

I sincerely express my gratitude to all the professors and students in the power systems group in the University of British Columbia, who have helped and supported me during the period of my graduate study. I deeply appreciate all the precious advises on my thesis work and warm friendship in my daily life. All of the wonderful time we had together will be the invaluable treasure in my future life and make my memory colorful.

Particularly, I would like to give my thankfulness to:

Dr. Tak Niimura, for giving me the chance to further my study in UBC, for dedicating his knowledge and time on supervision of my thesis work, for the patience and encouragement on my weakness and for so many other things helpful during the period of my study here.

Dr. Luis Linares, for the concern of my study, for kindly helping and encouraging students and for the attractive explanation of challenging questions.

Dr. Jose Marti, for the valuable advises on my work, excellent course teaching and dedication to the study and research work in our group.

Dr. Hermann Dommel, for enriching my professional knowledge, for introducing me to the marvelous world of EMTP and for the magnificent devotion to our group and power system field all over the world.

I greatly thank the support from the resource planning department of British Columbia Hydro and Power Authority. They gave me valuable information from industrial point of view.

The financial assistance from Natural Sciences and Engineering Research Council of Canada and British Columbia Hydro and Power Authority is gratefully acknowledged.

At last, I also wish to give my thankfulness to my family and all of my friends here and in my hometown. Your love, support and encouragement inspire me to achieve my target.

Chapter 1

INTRODUCTION

1.1 Background

The electric power industry is undergoing vast changes in many parts of the world. Restructuring of the industry involves the separation of transmission and distribution operation from generation operation. The direct subsequent step is to introduce competition in the restructured power market. The main objective of opening up the electricity sector to competition is to improve the efficiency of electricity production and distribution and thereby to benefit the market participants, while maintaining the security and reliability of the power supply. Hence, the generation companies (GenCos) aim to ensure sufficient revenue recovery that would meet their targeted profit levels and maximize the profits.

The restructured electricity market consists of three major models. They are pool markets, bilateral contracts, and a hybrid model. The electricity energy is traded in such markets which are expected to be efficient, meaning that the markets not only operate at or very close to the optimal operating point, but should also provide a fair, transparent and open price-setting mechanism. Therefore, in the restructured market, all the participants want to have sufficient information about the electricity price, power supply, demand and transmission capability. Although the theory supporting the electricity market with ideal competition is relatively simple, its implementation has been found to be very complex. The practical problems stem from implicit coordination, such as game opportunities for over-bidding to push up the market clearing price, lack of transparency, lack of demand-side involvement and transmission capability, price manipulations by market power, and the weakness of long term contracts, etc.

These shortcomings are evident in some European and North American electricity markets and have led to a review and development.

One of the motivations of the review is to improve competition by facilitating all the market participants, thus to increase its efficiency and provide more choices to them, while maintaining the system operation security and reliability. Under this circumstances, the new arrangement is to abandon the current centralized scheme of scheduling and pricing, to minimize central administration, to increase participation from the demand side, and to give all the sellers and buyers more freedom to negotiate their sales and purchases based on the level of risks they are willing and able to accept. Trades can be arranged in advance via long-term contracts or through short-term or spot markets (power exchanges). While the settling of trades would be left to the market participants themselves, the system balance of supply and demand would be controlled by the independent system operator (ISO).

1.2 Motivation and objective

In order to be competitive in the electricity market, an electric utility company must achieve the sufficient revenue to meet the target profit margin first and further to maximize its own profits. Therefore, the profit maximization comes to be the objective of GenCos and also is the part of the motivation for this thesis work. The specific objective of the thesis is to develop a computer application system to solve the unit commitment[1] problem and achieve optimal generation dispatch[2] to maximize the GenCos' total profits over a given scheduling period in the restructured power market, while maintaining the system security and reliability. With the consideration of

[1] Unit commitment means that the status of unit is turned on, that is , to bring the unit up to speed, synchronize it to the system, and connect it so it can deliver power to the network [33].

[2] Generation dispatch is the output pattern of each on-line generator.

transmission security constraints, this program is also able to aid GenCos to decide on the firm or non-firm power exchange with external power market in each time interval.

1.3 Literature survey

Since a proper unit commitment (UC) is a crucial step in achieving the economic, secure and reliable operation in power systems, the unit commitment problem has been widely and deeply studied during the past 40 years. Many mathematical and intelligent approaches have been published to address this topic under both traditional integrated system and restructured power market conditions. These technologies are categorized into classical, non-classical, and hybrid model methodologies. Classical methods include, priority list [1], [2], dynamic programming [3], [4] and its modification [5], branch and bound [6], integer programming [7], Lagrangian relaxation [8], [9], [10]. From the end of the 90s', a series of non-classical methods was developed to solve the UC problems. In 1988, S. Mokhtari [11] provided an expert system-based consultant to assist system operators to schedule the operation of units. In 1991, M. S. Salam [12] used an expert system as the preprocessor and postprocessor to obtain the feasible solution of unit commitment. Fuzzy system aided models by considering the outage of units and uncertainty of demand were provided by S. K. Tong [13] in 1990. In 1997, S. Saneifard demonstrated the application of fuzzy logic to the UC problem. Artificial neural networks were first explored for solving the UC problem by applying Hopfield neural network by H. Sasaki in 1992 [14]. Later, it was found that UC cannot be handled accurately within this framework. In 1997, M. P. Walsh [15] presented an augmented network architecture to refine the scheme to solve the same problem. An extended mean field annealing neural network approach was successfully applied to solve the UC problem by R. H. Liang [16] in 2000. Genetic algorithm

(GA) was widely used in recent years. In 1994, G. B. Sheble applied this approach to the unit commitment problem [17]. In 1999, A. Rudolf [18] used the GA to solve UC of hydro-thermal power system and was tested on real system over a period of a day. Evolutionary programming is a quite new intelligent approach for UC problem, which started from 1996, by H. T. Yang [19]. In 2002, H. Chen proposed the extension of traditional evolutionary program which has considerable potential to solve more complex UC problem.

Some of these methods are simple, take short computation time, but sub-optimal; the others are complex but accurate [20], [21], [22], [23]. Thus, there exist a need for further improvement of the existing algorithms for UC solution. In 1991, C. C. Su [24] proposed a new fuzzy dynamic programming for UC problems. One year later, Z. Ouyang [25] studied a hybrid artificial neural network-dynamic programming. A new approach using GA-based neural networks and dynamic programming was proposed by S. J. Huang in 1997 [26].

As the electricity market is undergoing the restructuring, the unit commitment algorithm is required to be updated and improved to solve the UC problem in restructured electricity market. New formulations to the unit commitment problems suitable for an electric power producer in an deregulated market was studied by J. Valenzuela [27] and T. J. Larsen [28] in 2001. C. W. Richter proposed a price/profit based unit commitment formulation which considers the softer demand constraints and allocates fixed and transitional costs to the scheduled hours [29].

1.4 Contribution

The proposed approach in this thesis work performs effectively and efficiently to maximize the power suppliers' profits from the short-term day-ahead generation scheduling with the consideration of network security and reliability. It also generates the by-product of calculation of spinning reserve costs for GenCos whenever system spinning reserve is used to balance the high level load. The function of this procedure can be further extended to provide the instructions to the suppliers to decide the market-based real-time[3] dispatch at the highest economical level and lowest risk level because of the consideration of network security constraints. Furthermore, it would facilitate the power market to be transparent and consistant during the period of competitive electricity bidding.

1.5 Outline of thesis

Chapter 2 describes the profit maximization generation dispatch problem. First, it provides an overview of the restructured electricity market, with the emphasis given to the following: 1) traditional model, 2) pool market model, 3) bilateral contract model, and 4) hybrid model. Then, the unit commitment problem under deregulated market is discussed in detail by explaining the role of ISO and GenCo in pool market. Further discussion of unit commitment in pool market is given by comparison among traditional model, price-based UC, and security constrained UC. Finally, it leads to the profit maximization UC problem, which is classified into price-based unit commitment (PBUC) formulation and security constrained unit commitment (SCUC) formulation.

Chapter 3 presents three main categories of technologies that can be used to solve the profit maximization UC problems, which are named classical, non-classical, and hybrid methods. The basic features of some widely used methods in each category are reviewed and compared with each other to achieve the conclusion of method selection in this thesis.

Chapter 4 describes the proposed optimal generation dispatch solution procedure comprised of unit commitment solution, economic dispatch, power interchange, and spinning reserve. Lagrangian relaxation, first order gradient, and fuzzy logic model are used individually to solve

[3] Real-time market calculates the LMP in every five minutes.

the UC problem, economic dispatch (ED) and price forecast problems, along with examples to explain the solution of each part. This model takes into account of power interchange and spinning reserve to be constraints of reliability to satisfy the requirement of restructured electricity market.

Chapter 5 focuses on the consideration of security of the transmission network. First, the model provides the optimal operation in steady state without any transmission congestion. Further on, subject to N-1 contingency constraints, the final optimal dispatch is achieved by security management of recommitment and power interchange rescheduling. The series and parallel algorithm are used for the dispatch optimization.

Chapter 6 presents the case studies performed to validate the proposed approach. Numerical simulation is tested on a simplified BC Hydro 500kV system with14 buses and 6 generation stations including 5 hydro plants and 1 thermal plant. The first three study cases simulate the system with fixed medium load level, but with different market price level in each case: Higher market price in case #1, medium market price in case # 2 and lower market price in case # 3. In last two study cases, the model tests the system with fixed medium market price and different load level in each case: higher load level in case # 4 and lower load level in case # 5. The results are presented graphically and the comparison of each case is presented in the accompanying text.

Chapter 7 presents the contribution made by this work and concludes the thesis. The future work is also recommended.

All the references and appendix are listed following this chapter.

Chapter 2

THE UNIT COMMITMENT PROBLEM IN RESTRUCTURED POWER MARKET

2.1 Overview of restructured market

Restructuring of power industry involves a transition from natural monopolies with centralized planning to markets that are subject to competition. With the same goal of secure and economical operation, the restructured market has been classified into three major types based on different structures.

2.1.1 Pool market model

A pool market (PoolCo) is defined as central marketplace that clears the market for sellers and buyers [30]. The PoolCo is comprised of competitive power suppliers, vertically integrated transmission companies (TransCos), distribution companies (DisCos), and a separate entity which is called the independent system operator (ISO).

Pool market can be broadly classified into futures market, day-ahead or hour-ahead market and real-time regulation (balancing) market. The futures market serves for long-term supply contracts. The day-ahead or hour-ahead market is a forward market in which hourly locational marginal price (LMP)[1] are calculated for the next operating day or hour from scheduling operation based on generation offers, demand bids and settle transactions. The real-time regulation market is a spot market in which current LMPs are calculated at five-minute[2] intervals based on balancing supply and demand in actual grid operation. The final real-time market clearing prices are available based on LMP for all the market participants.

[1] Locational marginal price reflects the value of the energy at the specific location and time it is delivered. If the lowest-priced electricity can reach all locations, prices are the same across the entire grid. When there is transmission congestion, more-expensive electricity is ordered to meet the demand in those congested area. Thus, the LMP is higher.

[2] PJM real-time market calculates the LMP in every five minutes.

In a PoolCo, sellers compete for the right to inject power into grid, not for specific customers. Thus, if the suppliers bid too high, their bids can not be accepted by the pool, as a result, the providers can not sell the energy. On the other hand, if the buyers bid too low, they can not buy any power. The market is finally settled at market clearing price (MCP), which is applicable for all bidders—both buyers and sellers. In the day-ahead market, bids are accepted for both sellers and buyers in the form of linear segment denoting price and corresponding quantity. The bids are aggregated into several segments of price versus quantity curves for both of supply and demand sides, which are matched eventually to obtain the MCP. The market price settlement in day-ahead market in the Pennsylvania-New Jersey-Maryland (PJM) pool is illustrated in Figure 1.

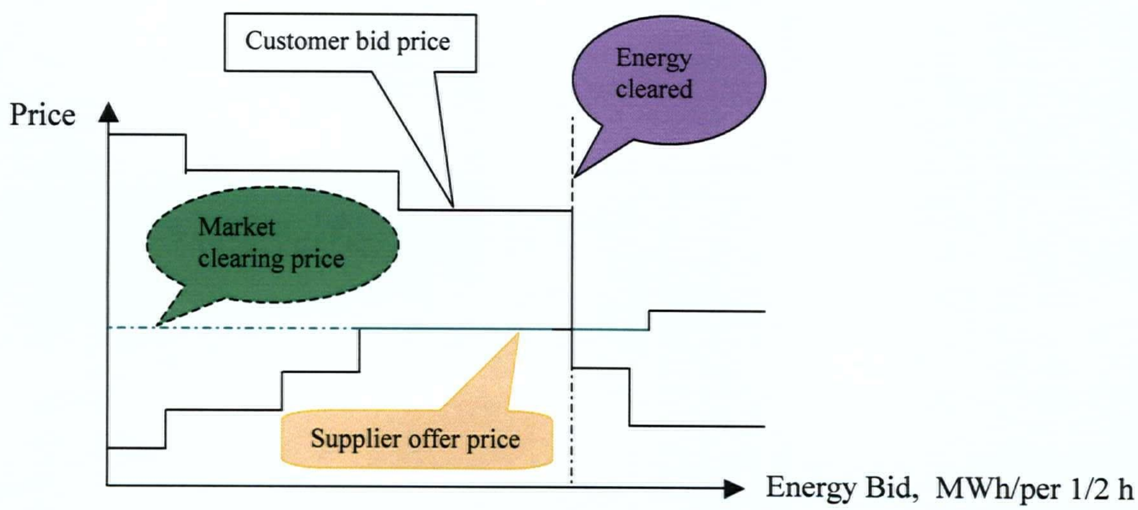

Figure 1 Day-ahead market settlement

In reality, market clearing price (MCP) in many pool market is decided when the highest bid match the forecast system demand. The amount of generation to be scheduled of each supplier is also decided from this and unit commitment decision is conveyed to each generation companies. In a typical pool market, the customer bid is not elastic, which is described in Figure 2. From this figure, it is easy to see that the generators whose bidding prices are lower than the pool price will achieve benefits.

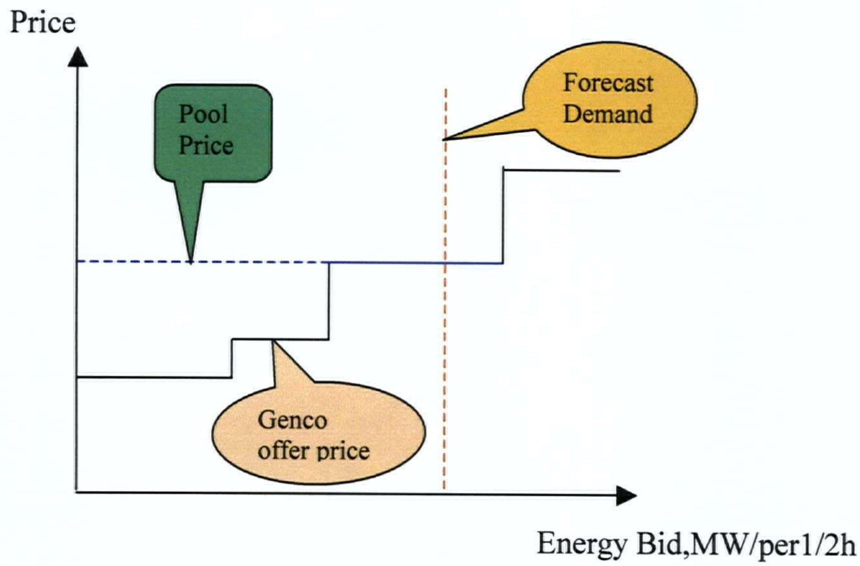

Figure 2: A typical pool market operation

2.1.2 Bilateral contract model

Bilateral contract model is also named direct access model, in which the buyers and seller negotiate contract directly without entering into pool arrangements. The contracts are settled independent of ISO. Hence, the ISO has less duty in bilateral market; it only ensures that sufficient supply is available to balance the system demand and to maintain the security and reliability of the system. After two parties agree on the contract terms such as price, quantity and locations, the GenCos would inform the ISO its unit commitment and generation dispatch schedules based on an hour or half an hour time period.

The bilateral model provides more freedom and flexibility for trading parties to specify their desired contract terms, while it protects all the participants from strategic bidding of powerful market players as well. However, it has a disadvantage of less economic efficiency of whole system operation than the efficiency of pool markets. The reduced efficiency comes from the lack of competitive trade in power exchange market. Currently, Nordpool (Norway) is based on this model.

2.1.3 Hybrid model

The hybrid model combines the various features of pool model and bilateral model. In the hybrid model, utilizing power exchange market is not mandatory, and customers are allowed to either settle their contracts with suppliers directly or bid for supply in pool market. The pool will serve all the participants who would not seek for the bilateral contract.

The advantage of this structure over pool model is that it provides participants more flexibility to purchase or sell power to the maximum satisfied by their own willingness. The other advantage is to simplify the balancing process of power supply. The loads not served bilaterally will be supplied by an economic generation dispatch through GenCos' bids in the pool. On the other hand, it is expensive to set up this model due to the separate entities required for operating the power exchange and transmission system. Early California market was based on this model.

2.2 Unit commitment in restructured pool market

In regulated power industry, unit commitment (UC) aims at minimizing the total generation cost with the satisfaction of system demand. In restructured market, in principle, the only objective of GenCos is to produce electricity and sell it to achieve the maximum profits. The UC models used for GenCos to achieve their goals are named price-based unit commitment (PBUC) [30] to emphasize the importance of price signal for GenCos. Since the main task of ISO in restructured market is to maintain the system security and reliability, security-constrained unit commitment (SCUC) [30] is indispensable for ISO to operate the whole system, and also necessary for GenCos to achieve the maximum profits by optimizing generation dispatch. In this section, these two typical unit commitment models are presented with all the necessary constraints included.

2.2.1 Introduction

2.2.1.1 The ISO in pool market

In a traditional vertically integrated market, the centrally dispatched power pool coordinate the operation and planning of generation and transmission among their members to improve the operating efficiency by minimizing the total generators' costs. Thus, the primary objective of ISO is not dispatching or re-dispatching generation, but matching the electricity supply with demand as necessary to ensure reliability [31]. With the increased generation due to the growth of demand, the access to transmission system became more limited. The integrated utilities favored their own generation facilities

whenever transmission congestion happened. This unfair industry practices impacted the growth of competitive generation and forced Federal Energy Regulatory Commission (FERC) to create an independent entity, so called the independent system operator (ISO), which provides all the competitive generation suppliers and electricity retailers an non-discriminatory open access to transmission grids. In the restructured pool market, the responsibility of ISO is extensively developed to comply with the FERC's non-discriminatory transmission tariff requirements. The main functions of ISO in a pool market are listed as follows [31].

- Stands as the control area operator.
- Maintains the security and reliability of power system.

- Performs security-constrained unit commitment.
- Manages transmission congestion.
- Calculates the LMP.
- Coordinates transmission planning, spot market and regulating market.
- Coordinates maintenance scheduling of transmission system and generating units.
- Coordinates regional transmission planning.
- Coordinates with neighboring control areas.
- Administers transmission tariffs, including determination of available transmission capacity (ATC), and manages firm transmission right (FTR) auction.
- Administers ancillary service market.
- Schedules transmission service.

To implement these services, ISO has to interact with other entities in the pool market, including GenCos, DisCos, TransCos, power marketers and the end-user customers.

Figure 3 below shows the interaction of ISO with all of these entities [31].

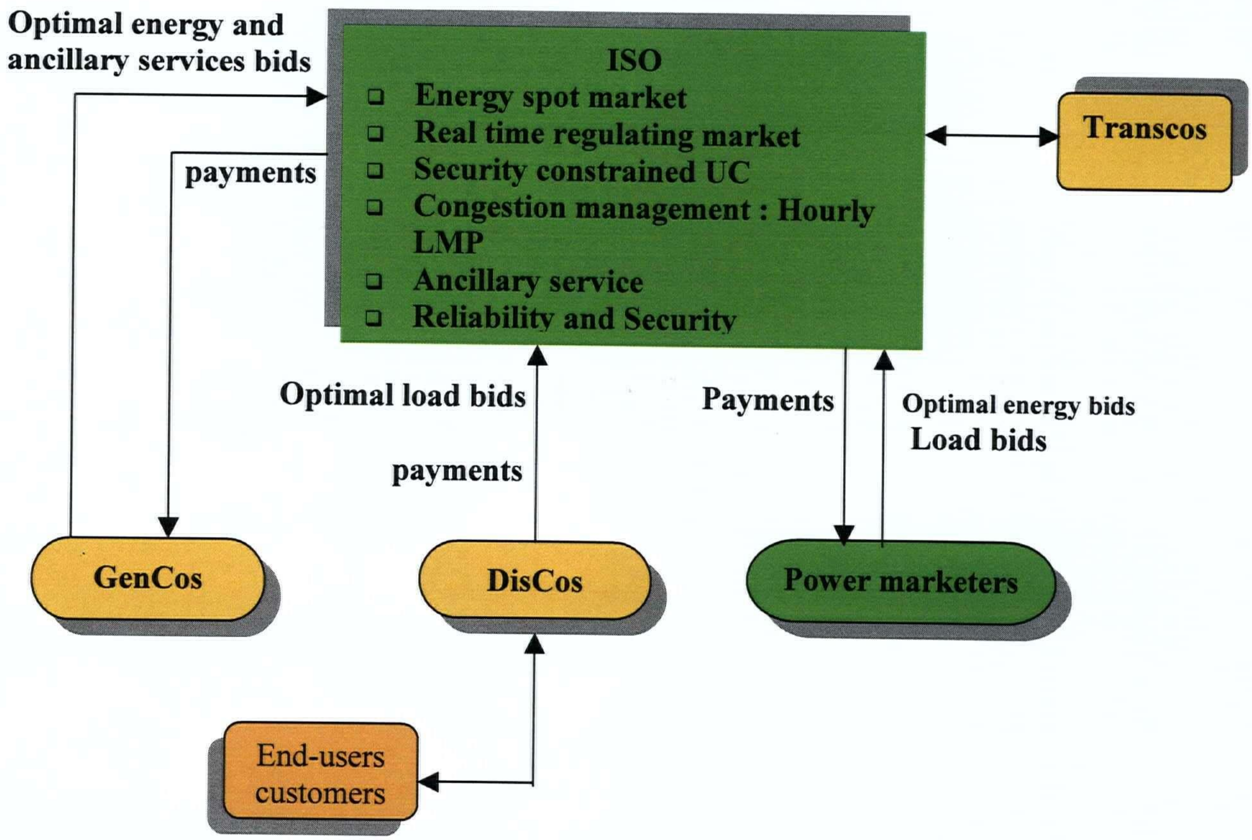

Figure 3: Interaction of ISO with other market entities

2.2.1.2 The GenCos in pool market

In a pool market, GenCos interact with the ISO on behalf of power plant owners. The GenCos are required to bid for energy supply and associated electricity price to ISO based on their estimation of market clearing price (MCP). In most cases, GenCos also need to provide ISO the units' characteristics such as start up cost, ramping rates, unit output limit and minimum up and down time, etc. to assist market operator to obtain the optimal dispatch and to settle the market price. The usual activities of Gencos in pool market can be outlined in time domain as follows [32]:

In day ahead spot market:

- Estimate the hourly market price for the next 24 hours.
- Based on units' characteristics (as stated above) and units' availability, determines bidding strategy for both of electricity quantity and corresponding price for next day hourly bidding.

In real time regulating market:

- Meet generation schedules required by ISO and sell the energy at market clearing price.

In a restructured pool market, the objective of GenCos is to maximize the profits from selling the energy. Hence, GenCos may choose to anticipate whatever market (forward market, spot market, ancillary services market, etc.) which can make profits for themselves with whatever bidding strategy (arbitraging, gaming). As more competition come into the restructured market, more risks exist. Thus, the consideration of risk management is also GenCos' responsibility.

2.2.2 Price-based unit commitment in pool market

2.2.2.1 Overview

In the regulated power industry, the objective of unit commitment was to minimize the total generation costs, which is generally called cost-based unit commitment (CBUC), while satisfying the system demand. In the deregulated environment, the competition of generation supply results in the goal of UC used by each individual GenCo being profit maximization. It is misleading to assume that maximizing the profit is essentially the same as minimizing the cost—CBUC has the same objective as PBUC does. Nevertheless, the profit is defined as the revenue minus cost. Whenever the revenue increment is larger than the cost increment, the

GenCos produce more generation to obtain more profit. In reverse, if the revenue decrement is larger than the cost decrement, GenCos lose interests to sell more energy.

The UC named price-based unit commitment (PBUC) is to emphasize the importance of electricity market price. In the pool market, there are usually two types of transaction for GenCos to bid for energy supply. One is the firm transaction, which has to be physically supplied, otherwise penalty must be paid. The bidding price for this kind of transaction is tightly based on the estimated market clearing price (MCP). The other is the non-firm transaction in which generation supply can be withdrawn partially or completely without penalty, but the offered price will be lower compared with the MCP. These features show that in PBUC all the useful information for profit maximization are reflected in the market price. Although the load balance constraint is not obligatory to GenCos, which means GenCos can bid at whatever quantity to gain maximum profits, load forecast (the information of load level is not available in real time for GenCos in the pool market) is still indispensable for GenCos to estimate market price. Another factor impacting the price is the transmission congestion. Congestion management by ISO affects the final market price, which in turn directly increase the discrepancies between the actual market price and GenCos' estimated market price and influence the profit maximization eventually.

In the competitive market, an efficient PBUC is critical to GenCos to maximize the value of generation assets to achieve their objectives. The formulation of PBUC model will be described in the next section.

2.2.2.2 Price-based unit commitment formulation

The price-based unit commitment problem can be stated as follows:

*In order to maximize the total profits, a Genco with N generating units and estimated electricity market price profile, determines each unit status of committing or decommitting and the power output levels of each committed unit at each time interval **t** over a specified scheduling period **T**, subject to the unit constraints and system constraints.*

Since the market-clearing price is determined by the ISO, GenCos can only estimate it in each scheduling time interval. The better estimation will help GenCos to dispatch the generation more economically and gain more profits. This is illustrated in Figure 4 for a fluctuating price profile and a generator's changeable cost due to the variable output.

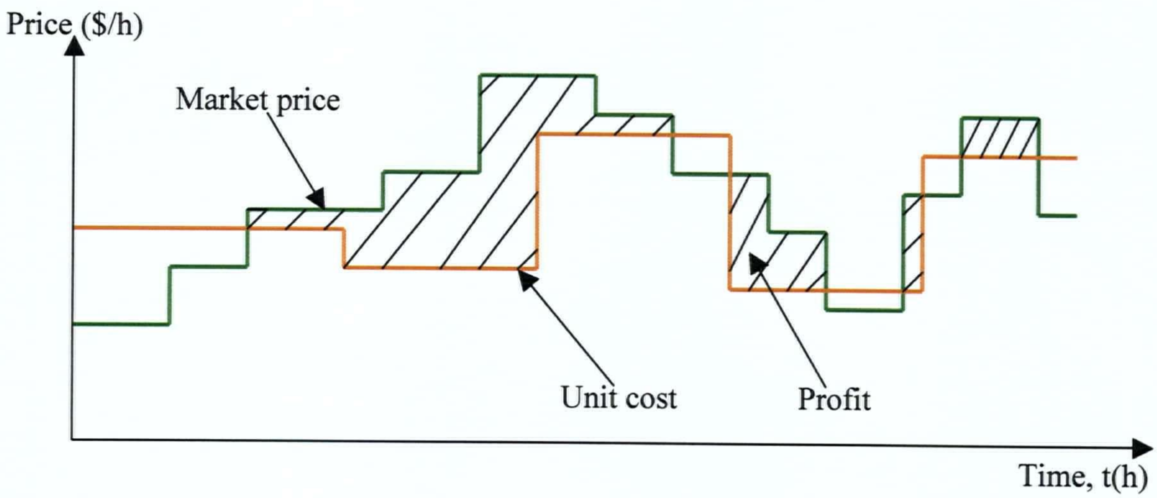

Figure 4 Profit determination with given price profile and unit cost

In Figure 4, the area above the cost curve gives the profit made during the period when market price is higher than unit's cost, while the area below the cost curve present the loss incurred during the time when the price is lower than the unit's cost. A GenCo would try to maximize the gains and minimize the losses to achieve the target of making as large profit as possible.

The fluctuation of cost during the whole time period results from the change of unit's output in each time segment. The unit's fuel cost, $F_i(P_i^t)$, of unit *i* in any given time interval *t*, is a function of the power output, P_i^t, of the unit *i* during the time interval *t*. There are usually two approaches to represent the unit cost function: the piece-wise linear cost function and second-order (quadratic) polynomial cost function.

- Piece-wise linear cost function is shown in Figure 5 as follows [33]:

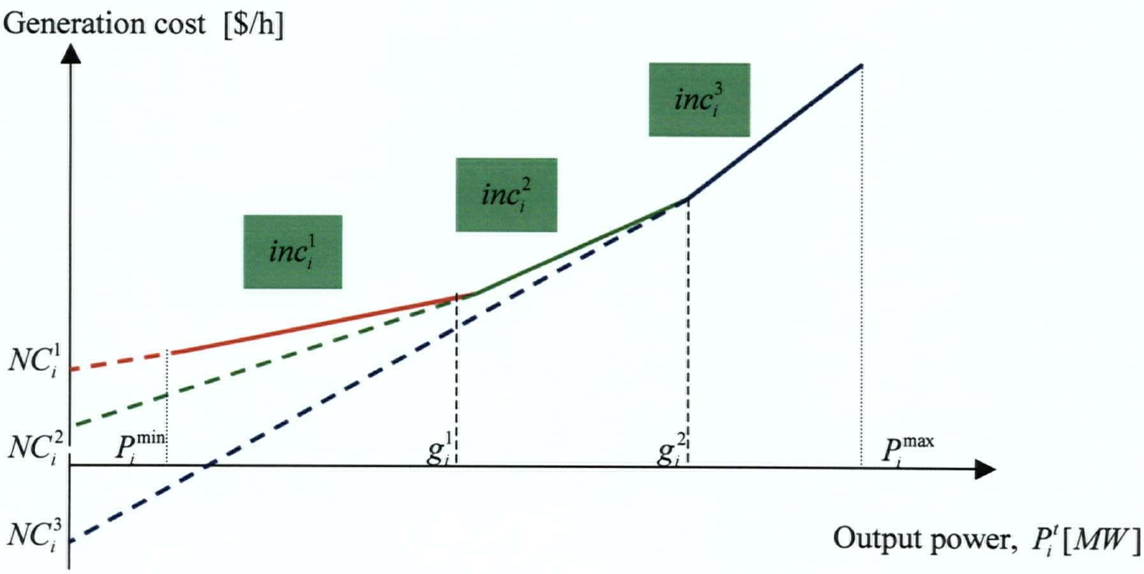

Figure 5: Piece-wise linear cost function

where:

inc_i^k : incremental cost of segment *k* of unit *i* [$/MWh], *k*=1,2, and 3;

NC_i^k : no-load cost of segment *k* of unit *i* [$/h], *k*=1,2, and 3;

P_i^{min}, P_i^{max} : the lower and upper limit of unit *i*, respectively, in [MW]; and

g_i^1, g_i^2 : the first and second elbow point of the piece-wise linear cost function of unit *i*, repectively in [MW].

In practical applications, this piece-wise linear model with two or three section might be used widely.

- Second-order polynomial cost function is given by equation (2.1) [33]:

$$C_i(P_i^t) = a_i(P_i^t)^2 + b_i P_i^t + c_i \tag{2.1}$$

where:

a_i, b_i *and* c_i are constant cost coefficients.

P_i^t is unit's power output.

$C_i(P_i^t)$ is production cost.

The following Figure 6 shows this type of cost function:

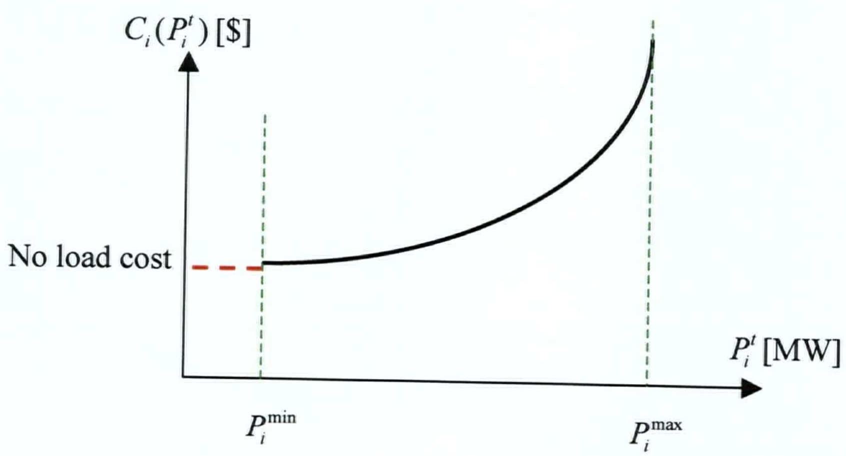

Figure 6: Second-order polynomial cost function

In this thesis work, we choose the second-order polynomial cost function to calculate the generator's cost since it is more precise.

The objective of PBUC is to maximize the profit, which is equal to revenue minus cost.

For a unit *i* at time interval *t*, the profit is presented as in the following equation:

$$f(i,t) = p^t \cdot d^t - U_i^t \cdot C_i^t(P_i^t) \tag{2.2}$$

In the scheduling horizon, the total profit of a GenCo with N units in PBUC model is given in the equation [2.3]:

$$F = \sum_{i=1}^{N} \sum_{t=1}^{T} f(i,t) \tag{2.3}$$

where:

T: extent of time horizon for scheduling

p^t: price of electrical energy per MW at time t

d^t: active power demand [MW] at time t

U_i^t: status of i-th generator at time t

$U_i^t = 1$: unit is on line during time interval t

$U_i^t = 0$: unit is off line during time interval t

P_i^t: active power output of i-th generator at time t

N: number of generators in the system

C_i: cost function of i-th generator in second-order polynomial model.

Thus, the PBUC problem is formulated as:

$$\text{Maximize} \sum_{i=1}^{N} \sum_{t=1}^{T} f(i,t) \tag{2.4}$$

subject to a set of practical constraints which are classified into system constraints and unit constraints, as discussed below [30] [33]:

- System constraints:

1) Power balance constraints:

$$g^{t} = d^{t} - \sum_{i=1}^{N} u_i^{t} \cdot P_i^{t} = 0 \tag{2.5}$$

2) Reserve limits constraints:

$$R^{\min}(t) \le \sum_{i=1}^{N} R(i,t) \cdot U_i^{t} \le R^{\max}(t) \tag{2.6}$$

where:

$R^{\min}(t)$, $R^{\max}(t)$: the lower and upper limits of total generation reserve from all the on line units at time interval t.

$R(i,t)$: the reserve of unit i at time interval t.

- Unit constraints:

1) Unit output limits constraints—unit can only generate between given lower and upper limtis:

$$P_i^{\min} \le P_i^{t} \le P_i^{\max} \qquad \text{for } i=1,2,\ldots,N \text{ and } t=1,2,\ldots,T \tag{2.7}$$

2) Unit minimum up time constraint [34]:

$$\sum_{t=t_u}^{t_d-1} u_i^{t} \ge T_i^{up} \qquad \text{for } i=1,2,\ldots,N \text{ and } t=1,2,\ldots,T \tag{2.8}$$

where:

t_u: time period when i-th generator comes online

t_d: time period when i-th generator drops offline.

T_i^{up} : minimum up time constraint [hours] of unit i.

3) Unit minimum down time constraint [34]:

$$\sum_{t=t_d}^{t_u-1} u_i^{t} \ge T_i^{down} \qquad \text{for } i=1,2,\ldots,N \text{ and } t=1,2,\ldots,T \tag{2.9}$$

where:

T_i^{down} : minimum down time constraint [hours] of unit i

Usually, for thermal generators, there are more constraints being considered, such as unit ramp-up constraint, ramp-down constraint, and start-up cost and shut-down cost constraints. Since the hydro generators are chosen in this thesis work, these constraints are not considered.

Another common constraint, which is widely used in practical industry, is unit status restriction—"must run" constraint, or unavailability due to planned maintenance or forced outage, which is named "must not run" constraints at certain time intervals. But this type of constraint is not considered here either, since reliability problem is simplified in this work, which will be discussed in detail in Chapter 5.

When PBUC model is used to achieve the maximum profits by GenCos, the load satisfaction is not an obligation. Furthermore, GenCos schedule and dispatch the generation without consideration of security of transmission network either, since the transmission operation is separated from GenCos. The Gencos may take some risks of bidding energy quantity and price in the competitive market, because the security constraints are unbandled from the profit maximization in PBUC model, which may lead the estimated market price quite far away from the real market price, especially whenever the market price increases dramatically due to transmission congestion. Since an accurate and flexible estimation of market price is critical to gain the target of maximizing the profit, a suitable model to simulate the fluctuated market price is necessary for GenCos. In our work, a fuzzy regression model is used to predict the real time market price range based on uncertain load in each time period.

2.2.3 Security constrained unit commitment in pool market

2.2.3.1 Overview

Security–constrained unit commitment (SCUC) is stated as:

For an electricity utility with N generating units, it is required to determine the schedule of all the units and dispatch output of all the committed units to minimize the total costs, subject to all the system constrains and unit constraints, while maintaining the system security and reliability.

In restructured pool markets, it is mandatory for GenCos to bid energy. The ISO plans the day-ahead schedule using the SCUC to finally determine which GenCo should be committed and how much it has to supply and reserve to keep the whole system load balance in regular hours and to meet the peak hour demand, while minimizing the violation of network flow. However, in some circumstances where most of the committed units are located in the regions which are close to each other, it becomes more difficult to satisfy network constraints throughout the whole system. Hence, the ISO has to reschedule all the units and re-dispatch their generation to relieve all the possible transmission congestion and violation in both of steady state and N-1 contingencies scenarios. This may lead to the whole system cost increased compared with it in the PBUC model. The increased cost is the trade-off of network limit violation minimization in SCUC model.

2.2.3.2 Security constrained unit commitment formulation

The objective function of SCUC is given as:

$$\text{Minimize} \sum_{i=1}^{N}\sum_{t=1}^{T} C_i(P_i^t)\cdot U_i^t \qquad \text{for } i=1,2,\ldots.\text{N and } t=1,2,\ldots..\text{T} \tag{2.10}$$

Similarly to PBUC, the constraints in SCUC have to be satisfied to achieve the objective. Since the unit constraints are the exactly the same as what they are in PBUC, only the system constraints are presented as follows:

- System real power balance:

$$\sum_{i=1}^{N} P_i^t \, U_i^t = P_D^t \qquad \text{for } i=1,2,\ldots..\text{N and } t=1,2,\ldots.\text{T} \qquad (2.11)$$

where:

P_D^t: the whole system demand at time interval t

- System spinning reserve requirement:

$$\sum_{i=1}^{N} R_s(i,t) \cdot U_i^t \geq R_s^t \quad \text{for } i=1,2,\ldots..\text{N and } t=1,2,\ldots\ldots\text{T} \qquad (2.12)$$

where:

$R_s(i,t)$: reserve of unit i at time interval t

R_s^t: total system reserve requirement at time interval t

- Real power flow limit from bus k to bus m:

$$-P_{km}^{\max} \leq P_{km}^t \leq P_{km}^{\max} \qquad \text{for } k=1,2,\ldots\text{Nb}, \ m=1,2,\ldots.\text{Nb and } t=1,2,\ldots..\text{T} \qquad (2.13)$$

where:

P_{km}^t: real power flow on transmission branch from bus k to bus m at time interval t

$(-P_{km}^t = P_{mk}^t)$

$P_{km}^{\max}$: the transmission limit from bus k to bus m

Nb: the total number of buses in the system network

The reactive power flow constraint on each network branch and voltage constraint on each bus are not considered in this work since they are considered in the ancillary services in the pool market.

As mentioned before, the GenCos can bid for energy by either firm and /or non-firm transaction in restructured pool market. For the ISO, security concern of transmission network is the same for firm and non-firm transactions, but transmission cost will be different, especially when a congestion happens. Therefore, the market price will be eventually affected. If GenCos can know how much cost difference will result between firm and non-firm transaction, they can efficiently bid for firm and non–firm power supply quantity and price, and achieve their objective eventually. From this point of view, it is necessary for GenCos to use this SCUC model to obtain the maximum profit.

Chapter 3

SOLUTION TECHNIQUES

3.1 Introduction

Unit commitment (UC) is a large, non-linear, mixed-integer combinatorial optimization problem with many constraints. The exact solution to this problem can only be achieved by complete enumeration, and at the expense of tremendous computation time for large- scale realistic power systems. Therefore, during the past decades, the researchers endeavored in finding an efficient, near-optimal unit commitment (UC) approach which can be applied to the large scale power systems meeting the reasonable storage and computation time requirements. The literature review in Chapter 1 reveals that there are various techniques being used to solve the UC problem. In general, these methods can be classified into three main categories:

1. Classical methods—numerical optimization techniques, which include priority list [1] [2], dynamic programming [3] [4], branch and bound [6], integer programming [7], and Lagrangian relaxation [8] [9] [10];
2. Non-classical methods—artificial intelligence methods, which include expert systems [11] [12], fuzzy logic [13], artificial neural networks [14], simulated annealing [15] [16], and genetic algorithms [17] [18].
3. Hybrid methods—a combination of two or more than two types of techniques from same or different categories.

This chapter briefly reviews some techniques listed above, which are widely used in recent years to solve UC problem. They are dynamic programming and Lagrangian relaxation methods in the category of classical methods, genetic algorithms and simulated annealing in the category of non-classical methods, and the hybrid method is also introduced briefly. The comparison of these approaches and conclusion are presented in the end.

3.2 Classical methods

3.2.1 Dynamic Programming

The dynamic programming (DP) method was developed in the 1950s through the work of Richard Bellman [35]. The main feature of DP is that a multi-variable optimization problems is decomposed into a series of stages with the sub-optimization being done at each stage by solving for only one variable. In other words, the optimal solution of original N-variable problem can be obtained from the optimal solutions of the N single-variable problems. The optimization technique used for optimization of each single-variable problem can be irrelevant. Thus, DP is suitable for the solution of complex problems with discrete variables, and non-convex, non-continuous, and non-differentiable functions in the wide range of decision making. The search for the optimal solution in DP is set up in either forward or backward recursive procedure.

DP was the earliest optimization-based technique to solve the UC problem and has been proved to be one of the successful approaches. Usually, the backward recursion is not suitable for UC solution due to the minimum up and down time and time-dependent start-up costs. Hence, the forward search first runs from the initial time interval to the final one with consideration of minimum up/down time constraints and accumulating the start-up costs, operating costs or profits, then traces backward from the last time interval to the first to search for the optimal schedule.

For N-unit power system, there will be 2^{N-1} possible unit combinations at each stage. Although this number will be significantly reduced due to the system and unit constraints, storing all of those feasible unit combinations at each time interval is still impossible, especially for a large-scale system. Therefore, many heuristic methods that search for a sub-set of all combinations are used to decrease the states at each stage so that to decrease the computation time and reduce the storage.

As widely known, the major drawback of DP is the curse of dimensionality. The complexities will increase tremendously with the number of constraint increase. Thus, using DP to solve the UC problem will expend much time and occupy a large memory space, and heuristic methods are also used to support the DP solution. The advantage of this method is its flexibility—DP can be easily modified to build up mathematical models for particular problems and the optimal results will be highly guaranteed.

3.2.2 Lagrangian relaxation

Lagrangian relaxation (LR) was developed in the early 1970s by Held and Karp [36] and became the indispensable technique to solve combinatorial optimization problems during the past decades.

LR is widely used to solve the mixed-integer problem involving a large number of variables and/or constraints. The constraints are added to the objective function by attaching the Lagrangian multipliers. The formal LR formulation is demonstrated on a simple numerical example as follows:

Minimize: $\mathbf{Cx}+\lambda(\mathbf{b}-\mathbf{Ax})$ (3.1)

Subject to: $\mathbf{Bx}\geq\mathbf{d}$

$$\mathbf{x}=\begin{cases}1\\0\end{cases} or$$

where:

$\mathbf{Ax}\geq\mathbf{b}$ and $\mathbf{Bx}\geq\mathbf{d}$ are constraint sets.

There are two key issues highlighted by the Lagrangian relaxation algorithm [37]:

- A strategic issue

A certain rule is applied to choose which constraints to be relaxed so that the relaxation can make the problem much easier.

- A tactical issue:

A good computation of multipliers yields results closer to the optimal solution.

Lagrangian relaxation is mainly based on the procedure of finding values for multipliers to produce the maximum lower bound, which is as close as possible to the value of the optimal solution of the primary problem (objective function). The problem with this procedure is called Lagrangian dual problem, which is expressed as [37]:

$$\max_{\lambda \geq 0} \left\{ \begin{array}{ll} \min & \mathbf{Cx} + \lambda(\mathbf{b} - \mathbf{Ax}) \\ \textit{subject to} & \mathbf{Bx} \geq \mathbf{d} \\ & \mathbf{x} = \begin{cases} 0 \\ 1 \end{cases} \textit{or} \end{array} \right\} \tag{3.2}$$

In the ideal situation, the value of the dual problem is equal to the value of the original mixed integer problem. In reality, there is a difference between these values; such problem is named the duality gap. A good approach to find the Lagrangian multipliers is helpful and necessary to reduce the duality gap.

A mainly used approach to decide the values for Lagrangian multipliers is subgradient optimization method.

Subgradient method is briefly described as follows:

1. Initialize the multiplier at λ^0 and upper bound Z_{UB} on the optimal solution to original problem.

2. Solve the Lagrangian dual problem with the current λ to get the solution of X of Z_{LB}.

3. Calculate duality gap, which is equal to $Z_{UB} - Z_{LB}$.

4. Update multipliers (vector $\boldsymbol{\lambda}^{k+1}$) using:

$$\boldsymbol{\lambda}^{k+1} = \max\left\{0, \boldsymbol{\lambda}^{k} - \alpha^{k}(\mathbf{b} - \mathbf{A}\mathbf{x}^{k})\right\} \tag{3.3}$$

where:

$\mathbf{x}^k$: an optimal solution of lower bound from dual program.

α^k: step size, which should not converge to zero too quickly, with the formula is given by:

$$\alpha_k = \frac{\delta_k (Z_{LB} - Z_{UB})}{\sum_{i=1}^{m}(b_i - \sum_{j=1}^{m} a_{ij}x_j^k)^2}, \tag{3.4}$$

where:

Z_{LB} : lower bound of optimal solution of the primary problem.

Z_{UB} : upper bound of optimal solution of the primary problem.

δ_k : a scalar chosen between 0 and 2, and will be reduced by 0.5 whenever Z_{LB} fails to decrease in a specified number of iterations.

5. Continue the procedure in above steps until the duality gap is less than the error limit or iteration times is more than pre-specified number of iterations.

Finally, Z_{UB} is the optimal solution of objective function. The process of obtaining the optimal results by subgradient optimization method is illustrated in Figure 7 [37]:

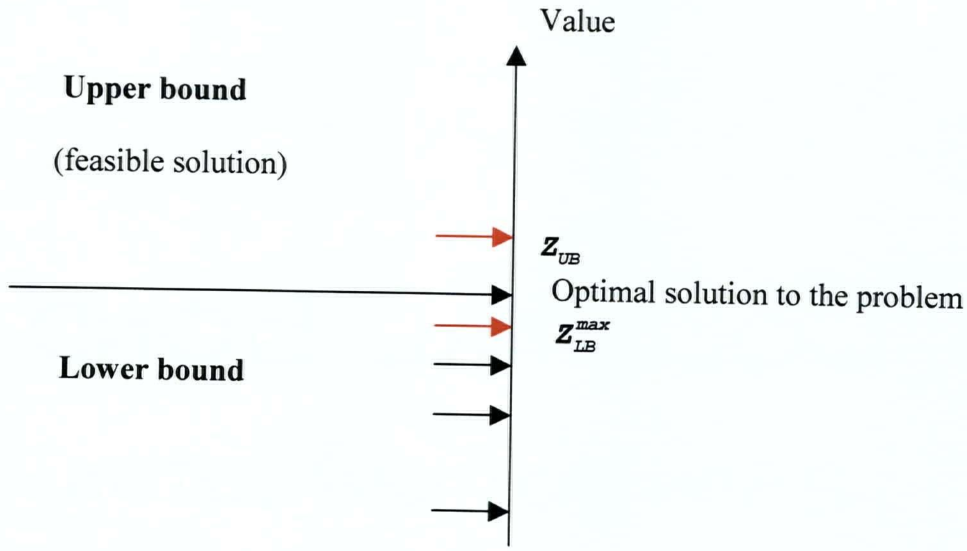

Figure 7 Subgradient optimization

Lagrangian relaxation approach has shown strong promise to solve the UC problem. In this approach, the Lagrangian dual problem of primary UC is formulated by attaching a set of chosen constraints to the original objective function via a set of Lagrangian multipliers. The procedure to solve the dual problem and primary problem is shown in the following Figure 8:

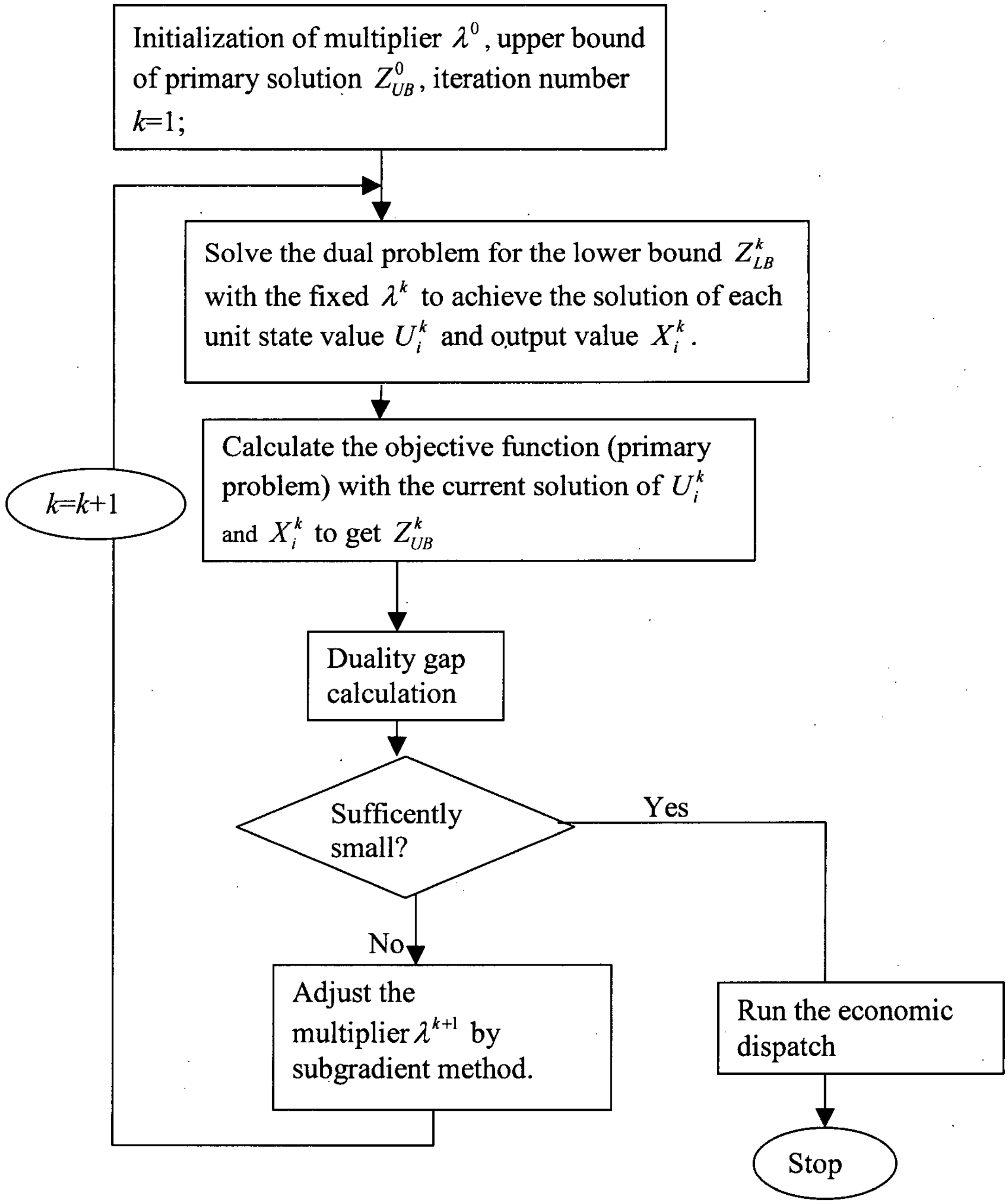

Figure 8 Flow chart of Lagrangian relaxation

Lagrangian relaxation is quite robust to solve the mixed-integer problem with a large number of variables and constaints by generating lower bound, which is sufficiently close to the optimal solution. For a large-scale mixed-integer problem, the linear programming branch and bound can not relax the large set of complicated constraints to produce lower bound for the primary problem. Using dynamic programming to solve it will consume a huge computation time, which maybe impossible in practice sometimes. LR has the advantage of reasonable computation time, effectiveness for solving large-scale combinatorial problem and robust flexibility. Hence, this method is widely used to solve the UC problem for many years. However, the optimal result is not guaranteed by LR in some particular cases, the sub-optimal solution is produced instead. This is the disadvantage of LR.

3.3 Non-classical methods

3.3.1 Overview

Since unit commitment (UC) problem has a typical feature of large-scale combinatorial optimization problems, the classical mathematical programming techniques may fail to solve the large-scale discrete variable problem mathematically. Therefore, non-classical methods like evolutionary computation (EC) or artificial intelligence (AI) methods are useful to set up an alternative approach, which usually can not provide mathematically optimal solutions, but near optimal ones [38]. The other advantage of using non-classical methods for solving this highly constrained combinatorial UC problem is that the objective function does not have to be differentiable. However, the EC and AI methods require expensive computation time with the large resources of computation. With the improvement of processor speed and sophistication, this limitation of computation time will diminish gradually.

3.3.2 Genetic algorithms

Genetic algorithms (GAs) are derived from the biological process of evolution based on Darwinian principle of natural selection [39]. GA was developed initially by Holland in 1960s, and first full theoretical treatment was contained in Holland' book *Adaptation in Natural and Artificial Systems* [40] published in 1975. In the last few years, the combinatorial aspect of UC problems started to be the natural target for the application of GAs due to the robustness, flexibility and efficiency of GAs.

GAs represent a complex structure by a set of vectors called *chromosomes*. Each chromosome simply consists of a string of 1s and 0s, which encodes a candidate solution of a particular problem. The variables are often called *genes*. In order to find the optimal solution to a large combinatorial problem, GA works by maintaining the a population of M *chromosomes*—potential parents, which are in equal size of strings. The fitness of each chromosome is a function similar or related to objective function of the original problem. The better the fitness value is, the higher chance of it being chosen to be parents is. The other parents are chosen randomly [37]. The parents must be in pair for the reproduction of next generation. The number of pairs of parents is specifically chosen based on individual problem. After the parents are selected for reproduction, they produce the children via the evolutionary processes by a set of genetic operators such as *crossover* and *mutation*. Thus, the new generation—"offspring" are produced on the existing chromosomes. They are the new problem solutions. The children generation created during the reproduction explores the different areas of solution space from what the parents generation did, and improves the fit feature of existing population. The typical procedure of GAs is in the following cycle:

1. Randomly initialize a population of chromosomes and set the generation counter to zero.
2. Calculate the fitness of each chromosome in the population.
3. Select those chromosomes with better fitness to be pairs of parents for reproduction.

4. Create the offspring based on chosen parents by operator of crossover and mutation.
5. Replace the chromosomes with worse fitness by the offspring to create new population.
6. Increment the generation counter and go to step2.

For solving the UC problem, the genes are units' status of on or off, which are represented by binary of 1s or 0s in each chromosome of a particular population. Each chromosome shows a particular unit's schedule over the specified time horizon. The population represents the schedule of all the units over the time horizon and yields the possible solution of UC problem with all the constraints satisfied. The fitness of each chromosome is evaluated by the value of objective function. The GA-based UC problem solution procedure is shown in Figure 9:

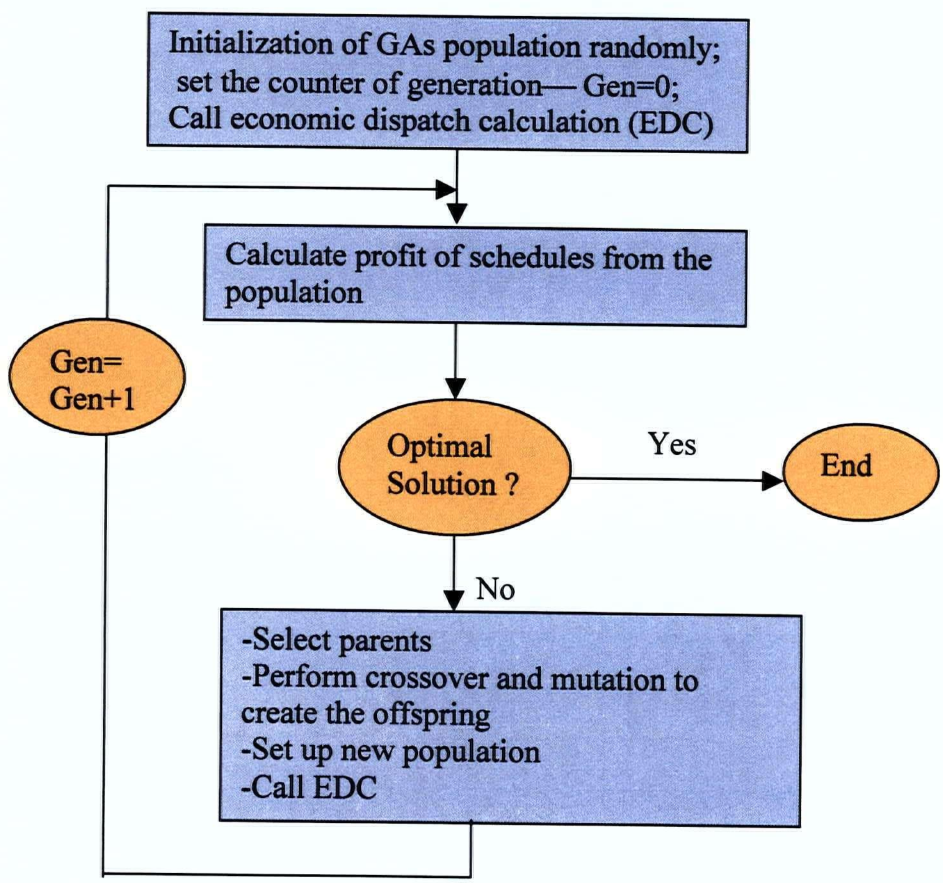

Figure 9 GAs based UC solution diagram

From the basic knowledge of GAs described above, it is easy to see that population size is determined by the number of units and the length of time horizon. The execution time varies approximately linearly with the size of population [40]. There are two main factors, which affect the convergence rate dramatically. One is the number of generations—indicates how many times GAs will go through the reproduction phases. The other one is the number of children per generation—how much of population will be replaced in each generation [40]. Although convergence rate determines the computation time, faster convergence rate is not highly recommended in case the GA process is trapped into a local sub-optimal solution. Since the initial population is randomly selected, it will also affect the iteration times to obtain the final optimal solution. Due to the stochastic nature of GAs, this algorithm will take long computation time to obtain the target for a large size system.

3.3.3 Simulated annealing

The ideas to form the basis of simulated annealing (SA) were first published by Metropolis in 1953 [41]. The use of SA as a technique to solve discrete optimization problem started from the early 1980s independently by Kirkparick, Gella and Vecchi [42]. As a comparatively new discrete optimization technique, SA has been proved to be very effective in solving large-scale combinatorial optimization problems, which is simulated as an annealing process. The basic scheme of SA is to randomly find an initial feasible solution, then search a neighbor of this solution by the pre-designed neighborhood search rule. The move to this neighbor is performed if either the neighbor has a better (lower) objective value or, in the case when the neighbor has a worse (higher) objective value but a condition is satisfied by the Boltzman distribution function[1]. Otherwise, the new neighbor will be rejected. The cooling temperature C_p, which is the control parameter of neighbor search, will be decreased based on particular schedule after some finite-time. Decreasing the C_p reduces the probability of accepting an increase in the objective value. The most important part of SA is to have a particular rule of each individual problem for searching the diversified neighborhood to enlarge the solution space as large as possible. The other indispensable part is to set up an appropriate rule to decrease the control parameter C_p to achieve the optimal solution.

The general SA algorithm is processed as follows [16]:

Step 1: Set the initial iteration count number to 0; initialize the C_p to a high value such that the probability of accepting any solution is close to 1.

Step 2: If the equilibrium condition is satisfied, go to step 5, otherwise go to next step.

Step 3: Generate the neighbor solution following the neighborhood search rule and calculate the objective value.

Step 4: Test the acceptance of the neighbor solution. Accept those neighbors which satisfies the Boltzman distribution function and move the current solution to the accepted neighbor solution. Then, go to step 2.

Step 5: Stop the process when the criteria is satisfied, else decrease C_p and go to step 2.

The SA algorithm to solve the optimum scheduling for UC is described below:

[1] Calculate the probability of acceptance by $\exp[(E_c - E_n)/C_p]$, and generate a random number between 0 and 1. If the probability of acceptance is larger than the random number, this neighbor is accepted, else reject it. $\Delta E = E_c - E_n$, is the increase of objective value of neighbor. E_c is the current objective value; E_n is neighbor objective value. C_p is the cooling temperature.

1. Randomly select the initial UC schedule, control parameter C_p, and the number of iteration time M; calculate the objective value E_c for the current UC.
2. Randomly disturb current UC or follow the particular generating trial rule to create new UC and calculate the new objective value E_{new}.
3. Compute the difference $\Delta E = E_c - E_{new}$.
4. Test the acceptance of the new pattern of UC according to Boltzman distribution function. If the UC is acceptable, update the UC and value of *E*.
5. Repeat from step 2 to step 4 up to M times.
6. Decrease C_p based on the pre-determined rule.
7. Go back to step 2 and repeat the process up to step 6, until C_p is sufficiently small and stop criteria is met.

Two methods are widely used for calculating C_p. They are the polynomial-time cooling schedule and Kirk's cooling schedule. About the neighborhood search, most of trial solutions are formulated involving minimum up and down time constraints.

The SA has very strong features. The advantages are:

- The initial solution is not tightly dependant on finding the optimal result. In other words, it can start from any given solution and improve the solution.
- Simple mathematical model for various complicated combinatorial problem.
- No large computational memory is needed.
- The possibility of convergence is high.

However, SA takes huge computation time, especially for the problem with large number of variables.

3.4 Hybrid methods

The existing UC algorithms are either simple to implement but sub-optimal, or complex but accurate. Thus, some techniques merging more than one algorithm together to form the hybrid models can be proposed in order to improve the performance of using these algorithms individually.

As already mentioned in Chapter 1, there are many approaches combining algorithms from classical category or non-classical category, such as simulated annealing-dynamic programming, neural network-dynamic programming, integrated simulated annealing, Tabu search and genetic algorithm, integrated expert systems, fuzzy systems, and neural networks, etc. In this thesis, the technique of Lagrangian relaxation based on heuristics is implemented to solve the UC problem, which will be discussed in detail in the following chapters.

3.5 Comparison and conclusion

Here, we compare the methods of dynamic programming (DP), lagrangian relaxation (LR), simulated annealing (SA) and genetic algorithms (GAs) with each other to draw the conclusion for the reason we choose our algorithm. The comparison is presented in the Table 1. From this table, we can see LR is a robust method with superior implementation performance. Thus, we choose LR to be the technique to solve the main UC problem. The heuristic methods are merged to the technique to improve the performance of the whole algorithm. From this table, we can see LR is a robust method with superior implementation performance. Thus, we choose LR to be the technique to solve the main problem. The heuristic methods are merged inside the technique to improve the performance of the whole algorithm.

Table 1 Comparison of DP, LR, SA, and GAs.

Method	Computation speed	Storage	Initial solution	Convergence performance	Flexibility &Adaptability
DP	low	large	dependent	guaranteed	high
LR	high	small	independent	adjacent	high
SA	low	medium	independent	guaranteed	good
GAs	high	large	dependent	adjacent	high

Chapter 4

PRICE-BASED OPTIMAL GENERATION DISPATCH SOLUTION PROCEDURE

4.1 Unit commitment solution

Unit commitment (UC) is one of the most important functions of generation companies (GenCos) and independent system operator (ISO). Most ISOs use UC functions to commit resources or schedule generation dispatch in order to balance load forecast and real load requirements of market participants, supply the ancillary services, and maintain the system security and reliability. GenCos also need UC functions to schedule the generation consistent with their bids in the competitive energy market based on the forecasted electricity price to maximize its own profits, while satisfying unit operation constraints and network security constraints. In this chapter, the objective of UC problem focuses on the profit maximization without the consideration of network security constraints. This UC problem, which is called the price-based unit commitment (PBUC), is widely used by GenCos to achieve their goals.

With the development of competitive markets, more and more energy suppliers compete to provide generations. Thus, the requirements of more accurate UC solutions are increased in most deregulated power markets. As mentioned in Chapter 3, Lagrangian relaxation (LR) is one of the most successful methods to solve UC problems. One of the most obvious advantages of LR is its quantitative measure of the solution quality based on the lower bound of dual problem and the upper bound of the primary problem. Although heuristics are usually involved in obtaining the feasible solution in LR procedure, LR is still a highly efficient and scalable approach for a large-scale UC problem with the cost of a small deviation from the optimal solution.

4.1.1 The unit commitment problem formulation

A. Objective function:

The objective function is:

Maximize profits

$$f(P_i^t, U_i^t, p^t, P_d^t) = \sum_{t=1}^{T} (p^t \cdot P_d^t - \sum_{i=1}^{N} U_i^t \cdot C_i(P_i^t)) \tag{4.1}$$

for i from 1 to N; t from 1 to T

where:

p^t : price [$/MWh]of electrical energy per MW at time t

P_d^t : active power demand [MW] at time t in local area

P_i^t : the ith unit's output at time t

U_i^t : the ith unit's state at time t

C_i : the ith unit's cost function

N: the number of total units in the system

T: the overall period

B. Generator cost function

The cost function of each generator is expressed in the equation as follows:

$$C_i(P_i^t) = a_i(P_i^t)^2 + b_i P_i^t + c_i \tag{4.2}$$

where:

P_i^t : the ith unit's output at time t for i *from 1 to N*, t from 1 to T

C_i : the total cost of each generator at the output of P_i^t for i *from 1 to N*

a_i, b_i *and* c_i are constant cost coefficients.

There is also one imaginary unit (the $(N+1)^{th}$ unit) to be used for calculation of interchange of power from external area. The strategy is:

- Import power from the neighboring power markets whenever their electricity price is lower than the local system marginal price.
- Export power to neighboring power market whenever their electricity price is higher than the local system marginal price.

C. Unit capacity constraints:

The generator output limits:

$$P_i^{\min} \le P_i^t \le P_i^{\max} \qquad \text{for } i=1,2,\ldots,N \text{ and } t=1,2,\ldots,T \tag{4.3}$$

where:

$P_i^{\min}$: unit minimum output (lower limit) when it is committed

$P_i^{\max}$: unit maximum output (upper limit) when it is committed

The output of each committed unit must be inside between its lower limit and upper limit. The import and export limits will be described in section 4.4.

D. System power balance:

$$P_d^t + P_{\mathrm{ex}}^t = \sum_{i=1}^{N} U_i^t \bullet P_i^t \tag{4.4}$$

where:

P_{ex}^t : amount of export power at time interval t for t from 1 to T

There are T-hour forecasted load patterns in the next day. The local system load in each hour t is represented by P_d^t. The transmission losses are not considered in equation (4.4).

E. Minimum up-time and down-time constraints:

Up-time constraint:

$$\sum_{t=t_u}^{t_d-1} U_i^t \geq T_i^{up} \qquad \text{for } i=1,2,\ldots,N \text{ and } t=1,2,\ldots,T \tag{4.5}$$

Down-time constraint:

$$\sum_{t=t_d}^{t_u-1} U_i^t \geq T_i^{down} \qquad \text{for } i=1,2,\ldots,N \text{ and } t=1,2,\ldots, T \tag{4.6}$$

F. System reserve requirements:

$$R^{\min}(t) \leq \sum_{i=1}^{N} R(i,t) \cdot U_i^t \leq R^{\max}(t) \tag{4.7}$$

where:

$R^{\min}(t)$, $R^{\max}(t)$: the lower and upper limits of total generation reserve on all the committed units at time t.

$R(i,t)$: the reserve of unit i at time t.

The detailed rule for calculation of system reserve requirements at each time interval t will be given in the section 4.3.

4.1.2 The procedure of unit commitment solution by Lagrangian relaxation

Step-1: Rearrange the original Lagrangian equation.

The original Lagrangian equation is:

$$\ell = \sum_{t=1}^{T} (p^t \cdot P_d^t - \sum_{i=1}^{N} U_i^t \cdot C_i(P_i^t)) - \sum_{t=1}^{T} \lambda^t (P_d^t - \sum_{i=1}^{N} U_i^t \bullet P_i^t) \tag{4.8}$$

Rearrange the equation above as:

$$\ell = -\sum_{t=1}^{T} \sum_{i=1}^{N} (U_i^t \cdot (C_i(P_i^t) - P_i^t \bullet \lambda^t)) - \sum_{t=1}^{T} \lambda^t \bullet P_d^t + \sum_{t=1}^{T} p^t \bullet P_d^t \tag{4.9}$$

The original objective is to maximize the function (4.1). Since p^t and d^t are constant at each time interval t, the maximum of profit can be obtained by minimizing the total generation cost. Thus, the primary problem can be changed to:

$$\text{Minimize} \quad f(P_i^t, U_i^t) = \sum_{t=1}^{T} \sum_{i=1}^{N} U_i^t \cdot C_i^t(P_i^t) \tag{4.10}$$

Further rearrangement of (4.9) as function of U_i^t, P_i^t and λ^t yields the Lagrangian function as follows:

$$\ell = \sum_{t=1}^{T} \sum_{i=1}^{N} (U_i^t \cdot (C_i\ (P_i^t) - P_i^t \bullet \lambda^t)) + \sum_{t=1}^{T} \lambda^t \bullet P_d^t \tag{4.11}$$

In equation (4.11), P_i^t must follow constraint (4.3), and U_i^t must be either 1 or 0.

Step-2: Set up the dual problem

Define $q(\lambda)$ as:

$$q(\lambda) = \min_{P_i^t, U_i^t} \ell \tag{4.12}$$

Here, P_i^t must obey the unit capacity constraint; U_i^t must be either 0 or 1.

The dual problem is set up as follows:

$$q^*(\lambda) = \max_{\lambda \geq 0} q(\lambda) \tag{4.13}$$

where:

$q^*(\lambda)$: the lower bound of primary problem.

Step-3: Initialize the Lagrangian multiplier λ^t; assume all the generators are on line.

Step-4: Solve the dual problem with the known value of λ^t

(1) Simplify the equation of (4.11)

Since P_d^t is fixed at each time interval t, equation of (4.11) can be simplified as:

$$\text{Minimize} \sum_{t=1}^{T}\sum_{i=1}^{N} U_i^t \cdot (C_i^t(P_i^t) - P_i^t \bullet \lambda^t) \tag{4.14}$$

(2) Decompose the equation (4.14) into T sub-equations corresponding T time intervals and rearrange it as:

$$\text{Minimize} \sum_{i=1}^{N} U_i^t \cdot (C_i^t(P_i^t) - P_i^t \bullet \lambda^t) \qquad \text{for } t=1,2\ldots,T \tag{4.15}$$

(3) Search for the optimal P_i^t by first-order gradient method

With U_i^t and λ^t fixed, the optimal value of P_i^t will be found by solving the equation as follows:

$$U_i^t \cdot \frac{d(C_i(P_i^t) - P_i^t \bullet \lambda^t)}{dP_i^t} = 0 \qquad \text{for } i=1,2,\ldots,N \tag{4.16}$$

(4) Decide the state of U_i^t

Calculate each term in equation (4.15) with the value of P_i^t obtained from (4.16).

If $C_i(P_i^t) - P_i^t \bullet \lambda^t \geq 0$, set the corresponding U_i^t =0 to minimize the Lagrangian function of (4.11); otherwise set the corresponding U_i^t =1.

(5) Calculate the lower bound of the primary problem which is the dual value q^* by (4.11).

Step-5: Calculate the upper bound of the primary problem J^*, following the equation of (4.10) with the known U_i^t and P_i^t.

Step-6: Calculate the duality gap.

(1) The duality gap is defined as:

$$\text{Duality gap}=\frac{J^* - q^*}{q^*}$$

(2) Check the criterion for the termination:

If $\frac{J^* - q^*}{q^*} \leq \varepsilon$, the final optimal value is found

where:

ε: positive small number, for example 10^{-3}

If $\frac{J^* - q^*}{q^*} \geq \varepsilon$, update the value of λ^t by sub-gradient method expressed in following equation (4.17) to maximize the lower bound $q(\lambda)$ in equation (4.13).

$$\lambda_{k+1}^t = \lambda_k^t + \delta_k * w \qquad k=1,2,\ldots \tag{4.17}$$

where:

$$\delta_k = \frac{\gamma * (1.05 \times J^* - q^*)}{w^2} \tag{4.18}$$

$$w = P_d^t - \sum_{i=1}^{N} U_i^t \bullet P_i^t \tag{4.19}$$

γ starts at value 2 based on experiences. If q^* has not increased after several iterations, then γ becomes $\gamma/3$ to calculate λ^{t+1} again by (4.17).

Step-7: Go back to step-4, iterate from step-4 to step-6 until the criterion is reached in step 6 to achieve the value of U_i^t for each unit in each hour.

Step-8: Adjust each unit status U_i^t in each time stage *t* to satisfy minimum up/down time constraints.

The procedure of this program will be described in detail after Step-9.

Step-9: Save the value of U_i^t of each unit *i* in each hour *t* for the economic dispatch program in section 4.2.

The procedure to solve minimum up/down time constraints is described by the example below:

1. Status description:

There is one unit *i* with commitment pattern in 12 hours, which is given as below:

$\boldsymbol{U}$ =[0 0 1 1 1 0 0 1 0 1 0 0], from hour 1 to hour 12

The minimum up and down time are:

$\boldsymbol{T}_i^{up}=5$; $\boldsymbol{T}_i^{down}=3$

Analyze the changes and duration of *U* states in the 12 hours:

- State changed from down state to up state at the hour [3,8,10]
- State changed from up state to down state at the hour [6,9,11]
- Duration for the unit being on line [3,1,1]
- Duration for the unit being off line [2,2,1,2]

2. Adjustment of *U* state based on the minimum up /down time constraints:

When the unit *i* is first committed, it has to keep being on line up to the duration of minimum up time to satisfy the minimum up time constraint. After the duration of being on line is equal to minimum up time, it is then possible for the unit off line or keeping on line state. On the other hand, if the unit starts to be off line, it has to keep the off line state up to the time when minimum down time constraint is satisfied. After passing the duration of minimum down time, it can then shift to the state of on line.

In this example, the unit is off at the first hour. Thus, it has to keep being off for another 2 hours to satisfy the minimum down time constraint of 3 hours. Hence, the $\boldsymbol{U}$ matrix is changed to $\boldsymbol{U}$ =[0 0 $\underline{\boldsymbol{0}}$ 1 1 0 0 1 0 1 0 0]. The unit starts to be on line at the hour 4 and has to keep the on line state for another 4 hours to satisfy the minimum up time duration of 5 hours. Thus, the $\boldsymbol{U}$ matrix will be shifted to $\boldsymbol{U}$ =[0 0 $\underline{\boldsymbol{0}}$ 1 1 $\underline{\boldsymbol{1}}$ $\underline{\boldsymbol{1}}$ 1 0 1 0 0]. At hour 9, the unit is turned off again. But it has to stay off line for another two hours, which means the state of the unit must be off at the hour 10. Consequently, the final $\boldsymbol{U}$ matrix is $\boldsymbol{U}=[0\ 0\ \underline{\boldsymbol{0}}\ 1\ 1\ \underline{\boldsymbol{1}}\ \underline{\boldsymbol{1}}\ 1\ 0\ \underline{\boldsymbol{0}}\ 0\ 0]$.

In this thesis, the overall time period is 24 hours. The unit state in each time stage is checked by this program of minimum up/down time constraints during the 24 hours after the value of U is found in Step-7.

The implemented software procedure is illustrated in the following Figure 10.

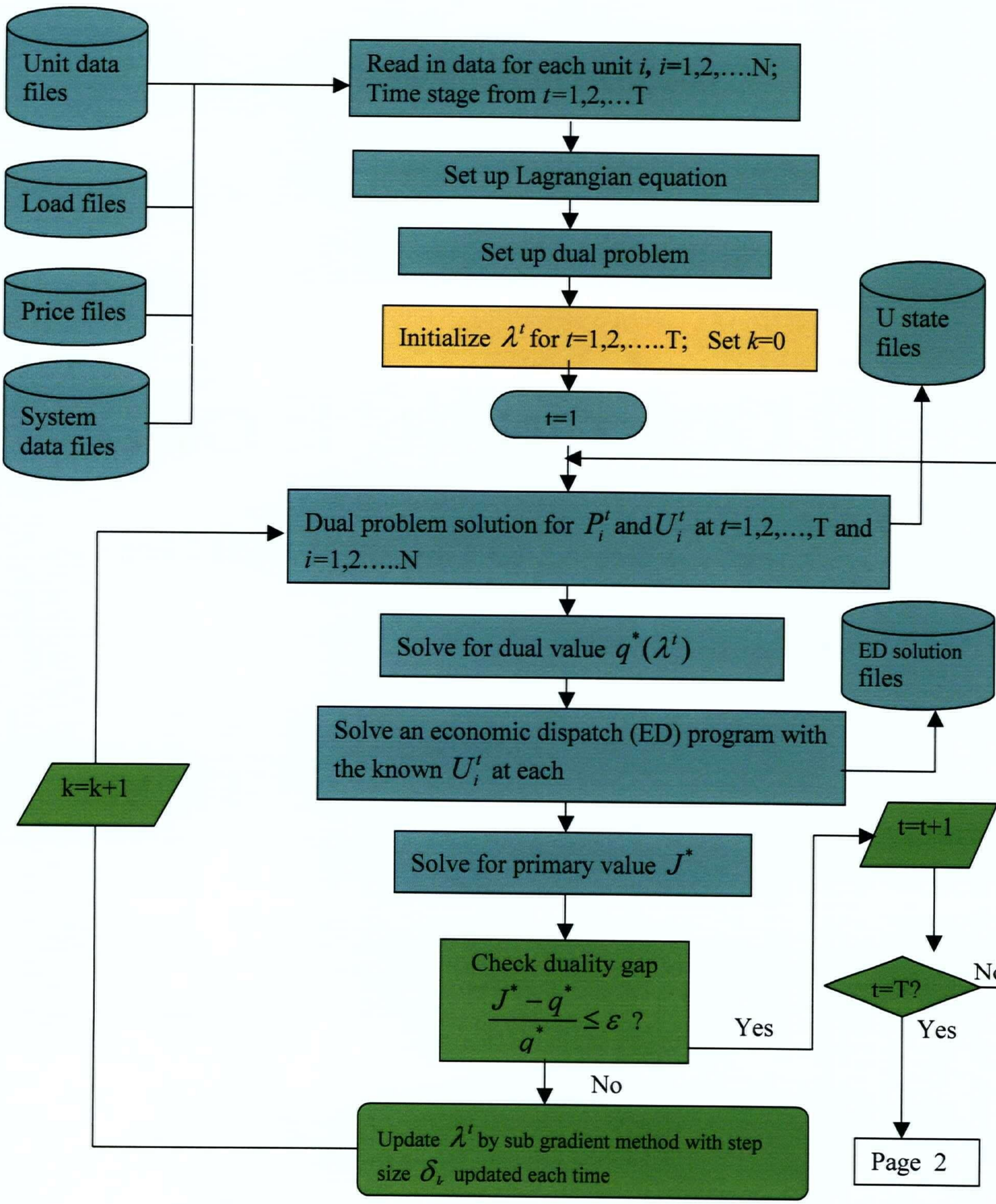

Figure 10 Unit commitment solution by Lagrangian relaxation (1/2)

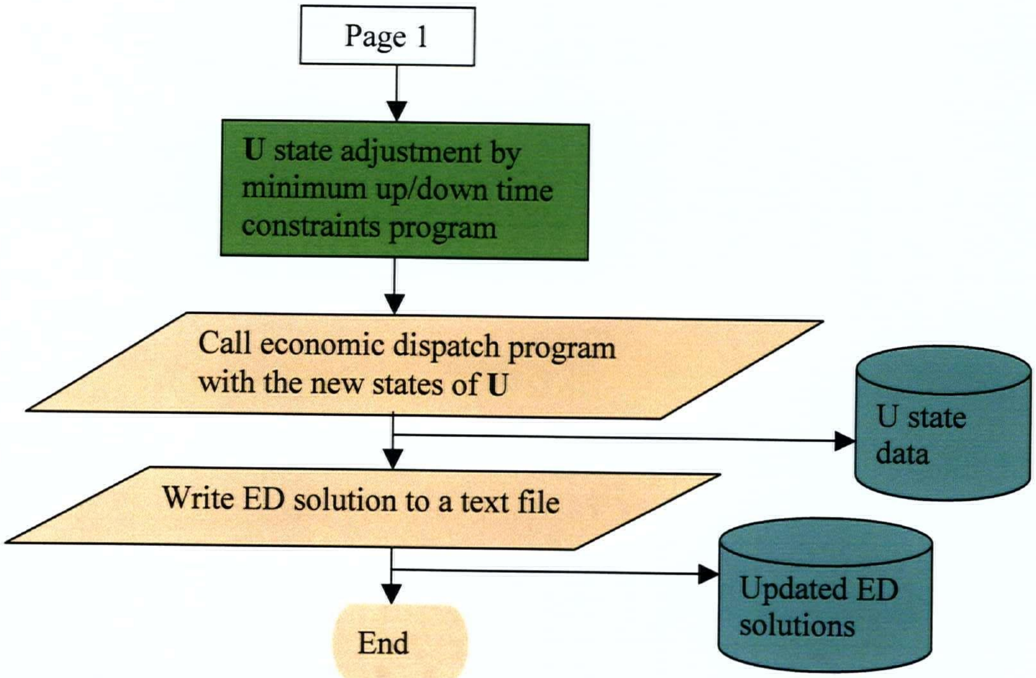

Figure 10 Unit commitment solution by Lagrangian relaxation (2/2)

The economic dispatch program in the above figure will be described in the next section 4.2

4.2 Economic dispatch

4.2.1 Overview of economic dispatch

Economic dispatch (ED) is an important operational problem for the competitive power market. Generation companies (GenCos) are interested in obtaining the maximum profits by using ED to optimize the generation scheduling. The independent system operator (ISO) maintains the whole power system security and reliability under optimal power flow operation condition. The available transmission capacity will also be involved in ED to solve the problem of power interchange, which will be discussed in section 4.4.

In regular power system operation environment, there is a coupling between active power flows and voltage phase angles, while the reactive power is coupled with voltage magnitudes. In classical quadratic generation cost function, the costs are critically dependent on the active power, only marginally dependent on the reactive power and voltage magnitude. Thus, the ED problem formulation is simplified by entirely depending on the active power and setting all the voltage magnitudes at a nominal value. Furthermore, the ED formulation is simplified by ignoring the transmission losses in the whole system network.

4.2.2 Economic dispatch problem formulation

Assume the power system operates with N units. At specific hour t, the total system load is P_d^t, and number of committed units N^t is derived from unit commitment solution.

In this section, the ED is to optimally dispatch total generation, which balances the system load at the minimum costs. The ED with the consideration of transmission network security, which is usually called security constrained economic dispatch, will be described in Chapter 5.

The Economic dispatch problem formulation:

A. At hour t, the optimization problem is:

$$\text{Min } F^t = \sum_{i=1}^{N^t} F_i(P_i^t) \qquad i = 1,2, \ldots, N^t \tag{4.20}$$

B. The cost function is set up in the quadratic function as follows:

$$F_i(P_i^t) = a_i \cdot (P_i^t)^2 + b_i \cdot P_i^t + c_i \qquad i = 1,2, \ldots, N^t \tag{4.21}$$

$a_i, b_i, and\ c_i$ are coefficients of cost function

C. Subject to:

- Load balance constraint:

$$\sum_{i=1}^{N^t} P_i^t = P_d^t \qquad i=1,2,\ldots,N^t \tag{4.22}$$

- Unit capacity limits:

$$P_i^{\min} \le P_i^t \le P_i^{\max} \qquad i=1,2,\ldots,N^t \tag{4.23}$$

- System spinning reserve requirement:

Due to the system spinning reserve requirement, each on-line unit's maximum output will deviate from original maximum capacity. The limit of minimum output will be constant. This will be illustrated in the next section 4.3.

4.2.3 Economic dispatch solution

From equation (4.20) to (4.23), this optimization problem can be solved by Lagrangian function, which is formed as:

$$\ell = F^t + \lambda \cdot g \qquad t=1,2,\ldots,T \tag{4.24}$$

where:

F^t: the objective function

g: the equality constraint

$$g = \sum_{i=1}^{N^t} P_i^t - P_d^t = 0 \qquad t=1,2,\ldots,T \tag{4.25}$$

λ: the Lagrangian multiplier for the equality constraint

Thus, the Lagrangian function is formed as:

$$\ell^t(P_i^t, \lambda^t) = \sum_{i=1}^{N^t} F_i(P_i^t) + \lambda^t \cdot (P_d^t - \sum_{i=1}^{N^t} P_i^t) \qquad i=1,2,\ldots,N^t,\ t=1,2,\ldots,T \tag{4.26}$$

The first order gradient of cost equation is defined as incremental cost function in the following equation:

$$IC_i = \frac{dF_i(P_i^t)}{dP_i^t} \qquad i=1,2,\ldots,N^t,\ t=1,2,\ldots,T$$

(4.27)

Since the cost function is simplified as quadratic function of (4.21), the incremental cost curves are formed by linear functions as:

$$IC_i = 2a_i \cdot P_i^t + b_i \qquad i=1,2,\ldots,N^t \tag{4.28}$$

Equation (4.28) is the slope of cost function (4.21), which is illustrated in following Figure 11.

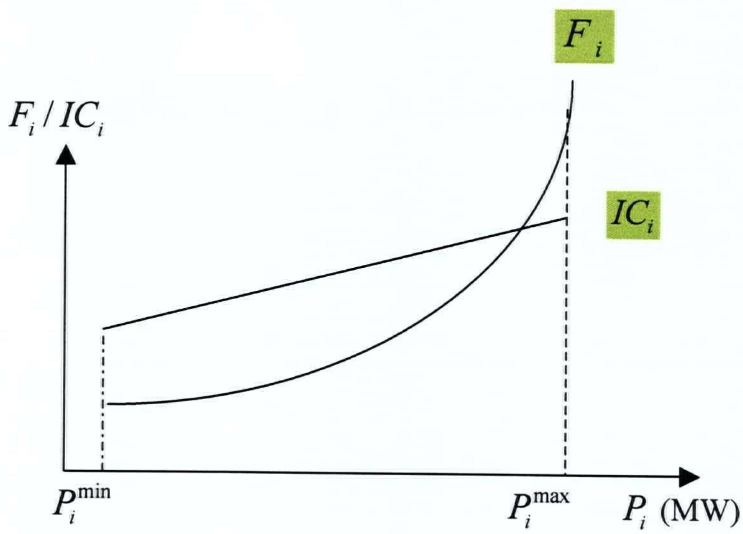

Figure 11 Generator cost function and incremental cost function

Since ED is an optimization problem, usually it is solved by traditional optimization methods such as the lambda–iteration method, gradient search method and Newton's method. The following Table 2 lists the main drawback of each method.

Table 2. The drawback of three optimization techniques

Method	Main drawback
Lambda-iteration	Converge slowly and convergence is not guaranteed
Gradient search	Convergence speed dependents on direction and step width
Newton's method	Expensive computation time to solve Hessian matrix of high order non-linear function

In this thesis, the first order gradient method of Lagrangian function mixed with heuristic rule to satisfy the inequality constraints is used to solve the ED problem. The detailed procedure is described as follows:

Step-1: Use the first order derivative of Lagrangian function (4.26) with respect to each independent variable and set the derivatives to be zero—necessary conditions for an optimal value of the objective function:

$$\frac{d\ell}{dP_i^t} = \frac{dF_i(P_i^t)}{dP_i^t} - \lambda^t = 0 \qquad i = 1,2, \ldots, N^t,\ t=1,2,\ldots,\mathrm{T} \tag{4.29}$$

$$\frac{d\ell}{d\lambda^t} = P_d^t - \sum_{i=1}^{N^t} P_i^t = 0 \qquad i = 1,2, \ldots, N^t,\ t=1,2,\ldots,\mathrm{T} \tag{4.30}$$

Applying equation (4.27) to equation (4.29), the equation is rewritten as:

$$IC_i - \lambda^t = 0 \qquad \text{for } i=1,2,\ldots, N^t,\quad t=1,2,\ldots,\mathrm{T} \tag{4.31}$$

Equation (4.31) shows optimal values are obtained when the incremental cost of each on line unit is equal to each other (without consideration of unit's output inequality constraints), which is λ^t. In equation (4.26), the λ^t represents the increase of the whole system operating cost versus the increase of total system demand in per unit, which is named the system marginal cost.

Step-2: Heuristic rule for consideration of unit output inequality constraints:

P_i^t and λ^t can be obtained by solving equation (4.29) and (4.30).

Since each unit has capacity limits, which is given in equation (4.23), P_i^t may violate the corresponding capacity limit. If the number of constraint of limit violated units is more than one, the unit *i* with the worst constraint violated is first fixed at the corresponding violated limit $P_i^{\max}$, and will be kept constant in remaining procedure. Then, recalculate the new system load by the equation:

$$P_{d(new)}^t = P_d^t - P_i^{\max} \tag{4.32}$$

Step-3: End the iteration if no other unit violates the limit, the final unbounded incremental cost λ^t gives the system marginal cost. Otherwise, if any unit violates the limit, go to step-1.

The following Figure 12 illustrates the solution of ED with inequality capacity constraints by an example of a simple system with three units.

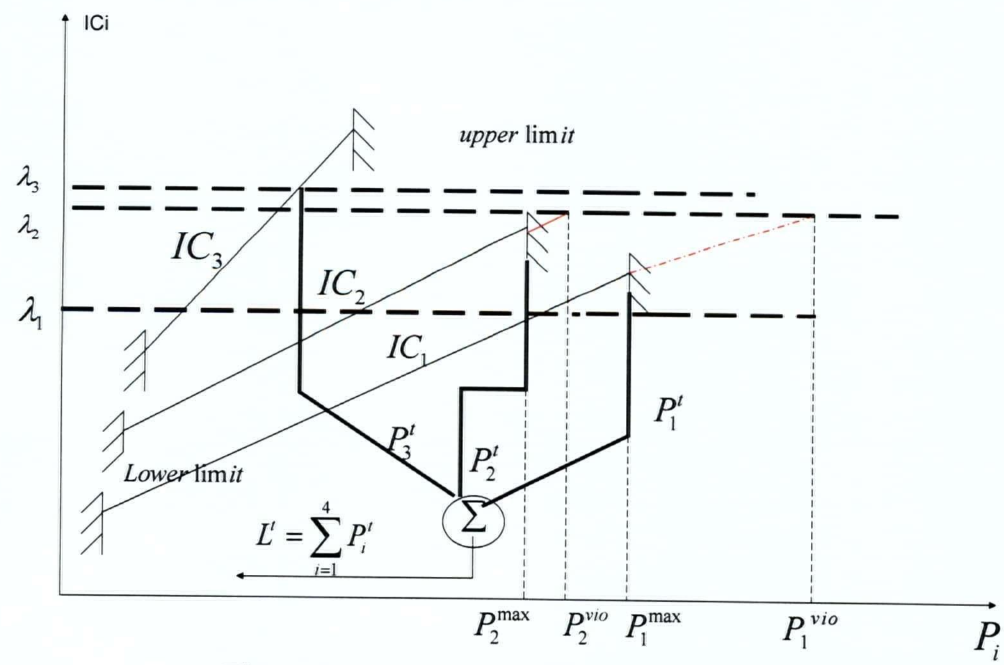

Figure 12 Economic dispatch with unit capacity constraints

In Figure 12 above,

When $\lambda^t = \lambda_1$, no unit violates limits. Thus, the system marginal cost is λ_1;

When $\lambda^t = \lambda_2$, both of unit #1 and unit # 2 violate their upper limits. Since $P_1^{vio} - P_1^{\max} \geq P_2^{vio} - P_2^{\max}$, unit # 1 is first bound up with its upper limit $P_1^{\max}$. Then, the load is reduced from L^t to $L^t - P_1^{\max}$. Repeat the ED process with this new load and unit #2 and unit #3 on line status, and find out unit #2 violates the upper limit. Thus, the output of unit #2 is fixed at its upper limit. The output of unit # 3, $P_3^t = L_t - P_1^{\max} - P_2^{\max}$, gives the incremental cost λ_3, which is also the system marginal cost.

In the day-ahead electricity market, the Gencos maximize their profits through their market price estimation model, load forecast model, and an appropriate model to run unit commitment (UC) and economic dispatch (ED) program. Using the UC and ED program, the Gencos offer a certain amount of power to the system that it makes its incremental costs as close as possible to the system marginal cost that will be determined when the market is cleared . The Gencos obtain the profits whenever the market clearing price (MCP) is larger than its average cost,

$$\overline{\lambda^t} = \frac{\sum_{i=1}^{N^t} F_i(P_i^t)}{\sum_{i=1}^{N^t} P_i^t}$$, and losses profits in the opposite case.

4.3 Operating spinning reserve

4.3.1 Requirement of operating reserve

Under restructured electrical power system, the system not only operates economically, but maintains the security and reliability over the whole system at the same time. To ensure reliable operation of the interconnected bulk power system, the minimum operating reserve criteria is established by WECC[1] in its " WECC Operating Reserve White Paper". The WECC minimum operating reliability criteria requirement states as follows [44]:

"The reliable operation of the interconnected power system requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies. This generating capacity, which is above firm system demand requirement, is necessary to:

- *Supply for load variations due to the load forecast error and provide regulation.*
- *Replace scheduled outages and compensate energy lost due to forced equipment outages.*
- *Meet on-demand load.*
- *Replace the energy lost due to the curtailment of interruptible imports."*

Operating reserve consists of spinning reserve and non-spinning reserve. Here, only spinning reserve is considered.

Spinning reserve is defined as [45]:

"Unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating Reserve and Contingency Reserve."

"Regulating reserve—An amount of spinning reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.

Contingency Reserve—An additional amount of operating reserve sufficient to reduce Area Control Error to zero in ten minutes following loss of generating capacity, which would result from the most severe single contingency. At least 50% of this operating reserve shall be Spinning Reserve, which will automatically respond to correct frequency deviation."

[1] WECC: Western Electrical Coordinating Council, formerly Western Systems Coordinating Council (WSCC)

4.3.2 Scheduling of spinning reserve

A. Amount of spinning reserve definition

According to the WECC reserve white paper, the minimum requirement of operating reserve is defined in the following equation:

Total operating reserve requirement= $R_m + R_r$

R_m= 10 minutes forecasted regulating reserve requirement, which is usually equal to 1%~2% of control area load.

R_r= capacity of outage element in most severe single contingency case.

The control area load is defined as:

The firm load inside the control area plus firm exports minus firm imports.

Since only spinning reserve is considered in this work, the total operating reserve is the total spinning reserve , which is given in the following equation:

$$SR^t = 2\% * P_d^t + \text{Max}(P_i^{max}, i=1,2,\ldots.N, \text{ at hour } t) + P_{ex}^t - P_{im}^t \tag{4.33}$$

B. Even distribution of the total spinning reserve in the whole system

To maintain the whole system network reliable, the total spinning reserve is dispatched to each online unit following its own rate, which is given in the following equation:

$$rt_i^t = \frac{U_i^t \cdot P_i^{max}}{\sum_{i=1}^{N^t} U_i^t \cdot P_i^{max}} \qquad i=1,2,\ldots N^t \qquad t=1,2,\ldots,T \tag{4.34}$$

C. Adjustment of on-line unit's upper limit

Due to the distribution of spinning reserve in each on line unit, the available maximum output is adjusted by the equation:

$$P_i^{max(new)} = P_i^{max} - rt_i^t * SR^t \qquad i=1,2,\ldots N^t,\ t=1,2,\ldots,T \tag{4.35}$$

D. Revised economic dispatch

(1). Use equation (4.35) to replace the $P_i^{\max}$ in equation (4.24) to run the economic dispatch program once more.

(2). Compare each unit's output P_i^t with its upper limit $P_i^{\max(new)}$, if $P_i^t \geq P_i^{\max(new)}$, fix P_i^t at $P_i^{\max(new)}$.

(3). Add up all the committed units output by equation:

$$P^t = \sum_{i=1}^{N^t} P_i^t \tag{4.36}$$

(4). If $P^t < P_d^t$,

i. Adjust the unit combinations by heuristics, which is described as follows:

- List all the shut down units at hour t in an ascending average incremental cost order and denotes this list by Uplist.
- Delete those units which can not be committed at hour t due to the minimum down time constraints.
- Commit units in the Uplist from top to bottom until the supply deficiency is solved
- Set up the new unit commitment combination.

ii. Use the new unit commitment combination to repeat the procedure from step (1).

4.4 Power interchange

4.4.1 The calculation of TTC and ATC of tie line

This work considers two areas interconnected with each other by a tie line, which is described in the following Figure 13.

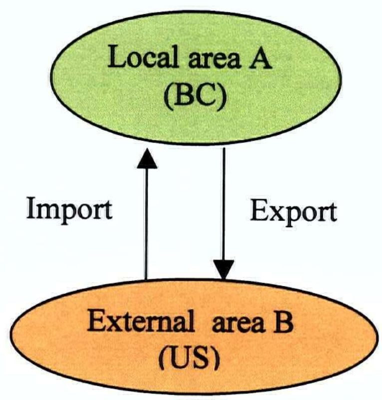

Figure 13 Configuration of interconnection

4.4.1.1. Definition of TTC and ATC

Total transfer capability (TTC) is defined as [45]:

" The amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post-contingency system conditions"

Available transfer capacity (ATC) is defined as [45]:

" A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses."

4.4.1.2 TTC and ATC calculation:

Usually, the capacity of a transmission network is limited by transient stability, voltage stability, and thermal limit constraints. TTC is the minimum of these three constraints.

Since the operation condition changes by time, the minimum limit of TTC may change from one system constraint to another system constraint. Thus, the TTC calculation becomes complicated on real time system. Here, the TTC is assumed to be the following in the two-area example:

- BC to US: 3150 MW
- US to BC: 2000MW

ATC is equal to TTC minus transmission reliability margin (TRM), capacity benefit margin (CBM) and existing transmission commitments (ETC), which is given in the following equation:

ATC=TTC-TRM-CBM-ETC

In the above example, the ETC is assumed to be zero. CBM is fixed at 400 MW and TRM is 100 MW along with the rule of BC hydro calculation for ATC [46]. Hence, the ATC on the tie line are:

- BC to US: 2650 MW
- US to BC: 1500 MW

The TTC and ATC mentioned in this work are all firm for simplifying the whole problem.

4.4.2 Power interchange

4.4.2.1 Power interchange strategy

In this work, the local area system is dominated by hydro generation power system, which is interconnected with an external electrical power network. The local hydro system will export electricity during the time when the electricity price in the external market is higher than the local system marginal price. Usually, this time period is the peak-load hours. In the valley-load hours, the electricity price in the external market decreases, thus, the hydro system imports power from the external market in order to store water. The stored water will be used later to achieve profits if the market price is higher than the system marginal cost. The system marginal cost is the extra cost of producing an extra unit of generation in the system. The system marginal price is the offer price of the most expensive on-line generating unit in per unit time horizon (usually half an hour).

The amount of power interchange is related to the difference between local system marginal price and electricity market price in the external market and the ATC of tie line. Without tie line transmission constraints, the maximum amount of import power will be achieved when the local system marginal price is equal to the system marginal price of external area. Same applies the power exports in the opposite case.

In reality, with the constraint of ATC of tie-line, the amount of interchange will not be equal to the amount of ideal case without tie-line constraints, which leads the local system marginal price not equal to the system marginal price of external area. The electricity price in the external market is represented by λ_{ex}, and local system marginal price is represented by λ_{sys}.

4.4.2.2 Import power calculation

When $\lambda_{ex} \leq \lambda_{sys}$, the local system imports power from interconnected external area. To make power import easily be calculated, the external power network with the system marginal price of λ_{ex} is imagined as a fictitious generator with incremental cost of λ_{ex}. The cost function of this fictitious unit is also quadratic function as in the following equation:

$$F_f(P_{im}) = 10e^{-9} \cdot (P_{im})^2 + \lambda_{ex} \cdot P_{im} \tag{4.37}$$

The capacity of this fictitious unit is:

$$0 \leq P_{im} \leq P_{im}^{\max} \tag{4.38}$$

λ_{ex}=electricity price in external power market

where:

P_{im} : import power amount

λ_{ex}: system marginal price of interconnected external area

$P_{im}^{\max}$: ATC of tie line from external area to local area

There are no minimum up/down time constraints and spinning reserve requests for this fictitious unit.

The procedure for import power calculation in each hour is summarized as follows:

Step-1: Compare system marginal price λ_{sys} with electricity price in the external area to decide either import power or export power.

Step-2: If the import power is needed, set up the fictitious unit's cost function based on the external market price.

Step-3: Add this fictitious unit to those units committed in economic dispatch program to set up new unit commitment combination.

Step-4: Run economic dispatch to calculate the output of the fictitious unit, which is the amount of import P_{im}.

Step-5: If $P_{im} > P_{im}^{\max}$, fix P_{im} at $P_{im}^{\max}$, and will be kept constant in the remaining procedure; reduce the load by equation $P_{d(new)}^{t} = P_{d(old)}^{t} - P_{im}^{\max}$, else go to Step-8.

Step-6: Adjust spinning reserve distribution to each on-line unit and unit's upper limit:

- Recalculate the equation of (4.33) to obtain

$$SR^{t} = 2\% * P_{d}^{t} + \text{Max}(P_{i}^{\max},\ U_{i}^{t} = 1,\ i=1,2,\ldots.N,\ \text{at hour t}) - P_{im} \tag{4.39}$$

- Recalculate the equation of (4.35) to obtain the new upper limit for each on line unit.

$$P_{i}^{\max(new)} = P_{i}^{max} - rt_{i}^{t} * SR^{t}$$

Step-7: Run economic dispatch once more to calculate the optimal generation dispatch and system marginal cost.

Step-8: When $P_{im} \le P_{im}^{max}$, amount of import power is P_{im}. End the program for calculation of import power.

4.4.2.3 Export power calculation

When $\lambda_{ex} \ge \lambda_{sys}$, the local system exports power to external external power market. Based on the economic dispatch theory, the optimal operation point is reached when the local system marginal price is equal to electricity price in external market. In practice, due to the tie-line ATC constraint, unit capacity constraints and reserve constraints, the practical export amount deviates from the optimal amount. The detailed calculation procedure is explained as follows:

Step-1: If $\lambda_{sys} \le \lambda_{ex}$, decide to export power to the external market.

Step-2: Set system marginal price equal to electricity market price to calculate each on-line unit's output by the equation as:

$$P_i^t = \frac{\lambda_{ex} - b_i}{2a_i} \tag{4.40}$$

where:

a_i, b_i *and* c_i are each on line unit's cost function coefficients.

Step-3: Calculate total spinning reserve by the equation as follows:

Total spinning reserve:

$$SR^t = 2\%*(P_d^t + P_{ex}^t) + \text{Max}(P_i^{max},\ U_i^t = 1,\ i=1,2,\ldots,N,\ \text{at hour } t) \tag{4.41}$$

where:

P_{ex}^t: the export power amount at hour t

In equation (4.41), the P_{ex}^t is replaced by P_{ex}^{max}—ATC on tie line for export power from local area to external external area— to make the whole calculation of export power easier since export amount will not affect SR^t much based on the 2% coefficient. SR^t is calculated as follows:

$$SR^t = 2\%*(P_d^t + P_{ex}^{max})+ \text{Max}(P_i^{max} ,\ U_i^t = 1 ,\ i=1,2,\ldots,N, \text{ at hour t}) \tag{4.42}$$

Step-4: Calculate each on line unit's upper limit:

$$P_i^{max(new)} = P_i^{max} - rt_i^t * SR^t$$

Step-5: Compare P_i^t with $P_i^{max(new)}$, if $P_i^t \geq P_i^{max(new)}$, fix P_i^t at $P_i^{max(new)}$.

Step-6: Add up all the committed units' output by equation:

$$P^t = \sum_{i=1}^{N^t} P_i^t \times U_i^t \tag{4.43}$$

Step-7: If $P^t > P_d^t$,

7.1 If $P_{ex}^t = P^t - P_d^t \leq P_{ex}^{max}$, export amount is equal to $P_{ex}^t = P^t - P_d^t$. Then, go to Step-8

7.2 If $P_{ex}^t = P^t - P_d^t > P_{ex}^{max}$,

A. Fix the export P_{ex}^t at P_{ex}^{max}; increase P_d^t by the equation below:

$$P_{d(new)}^t = P_d^t + P_{ex}^{max} \tag{4.44}$$

B. Run economic dispatch program once more with the same unit commitment combination to achieve the optimal generation dispatch.

Step-8: End the program for export amount calculation.

The flowchart for the power interchange at hour *t* is given in the following Figure 14:

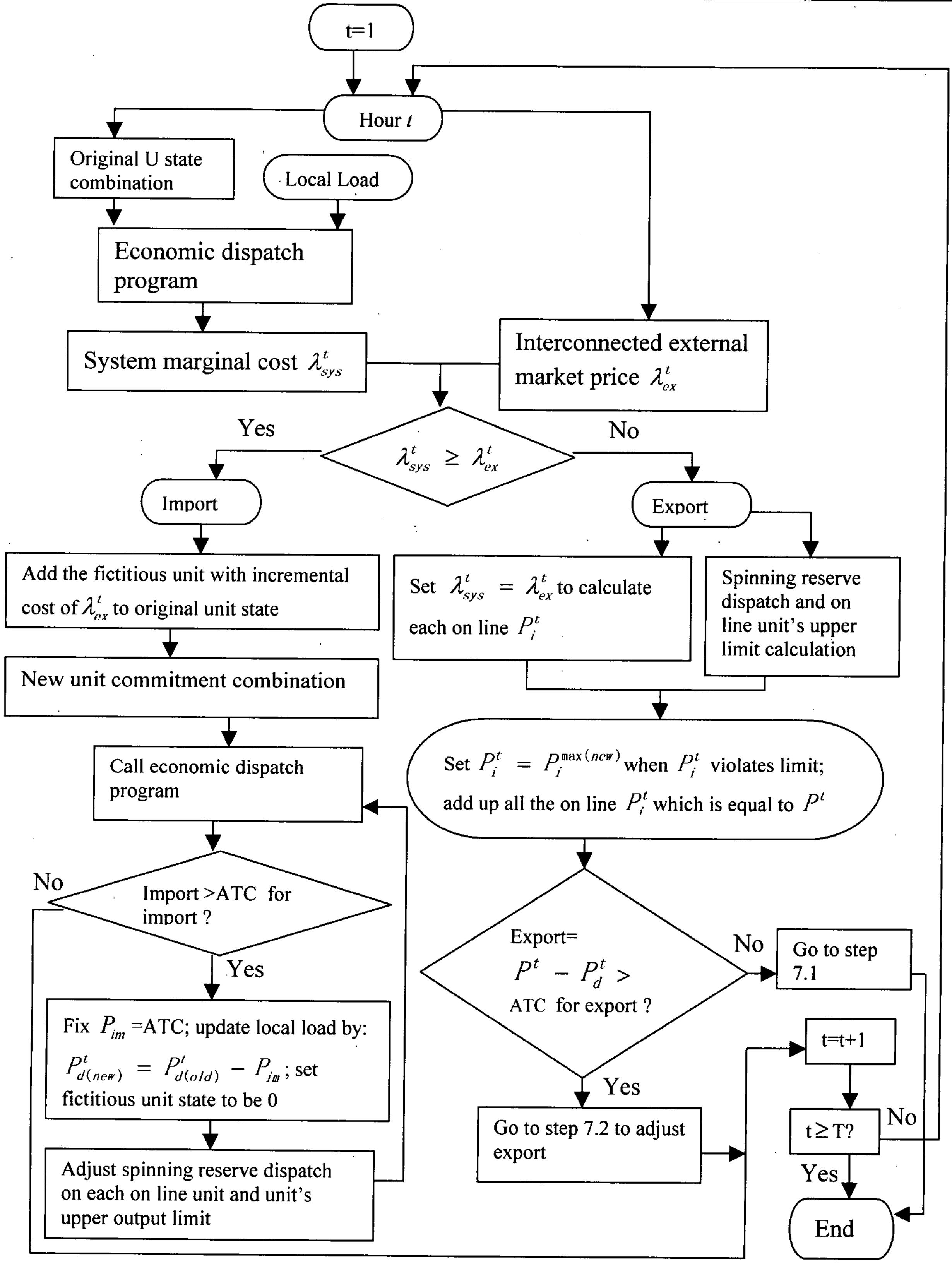

Figure 14 Flowchart for power interchange program algorithm

4.4.2.4 Calculation of profits including power interchange

In this thesis work, we assume the electricity-selling price is calculated by the following equation:

$$p^t = 1.2 * (\sum_{i=1}^{N} IC_i^t) / N \qquad i=1,2,\ldots,N, \quad t=1,2,\ldots,T \tag{4.45}$$

where:

$\lambda_i^t = 2a_i \cdot P_i^t + b_i$, is the incremental cost of unit i at hour t

N: the number of generators

P_i^t: output of unit i at hour t

a_i, b_i: coefficients of cost function of unit i

The multiplier of 1.2 is arbitrarily chosen to set up the electricity-selling price higher than the system marginal cost to compensate the loss and earn the profits.

The original objective in 4.1.2 is updated by the following equation:

$$f(P_i^t, U_i^t, p^t, P_d^t, p_{market}^t, P_{im}^t, P_{ex}^t) = \sum_{t=1}^{T} (p^t \cdot P_d^t - \sum_{i=1}^{N} U_i^t \cdot C_i(P_i^t) - P_{im}^t \cdot p_{market}^t + P_{ex}^t \cdot p^t) \tag{4.46}$$

where:

p_{market}^t: external market electricity price at hour t.

Chapter 5

SECURITY-CONSTRAINED OPTIMAL GENEATION DISPATCH

5.1 Overview of power system security

The two major roles of power system operation are reliable power delivery and economical system operation. The reliability of power system is further interpreted in two main functions: adequacy and security [33]. The former guarantees an adequate amount of generation will be available to balance the load demand in the peak hour. The latter supports the system to be able to withstand any changes or contingencies to maintain system secure status during daily base or hourly base system operation.

In practical electric power systems, the systems are built with sufficient redundant generation and transmission capacity to reduce the possibility of shedding load and transmission overload whenever the system is undergoing unanticipated failures and operation states. However, from the perspective of economy and practicality, the system can not be built with so much redundancy that no load will be shed or no transmission lines will be overloaded during the operation in whole time horizon, especially under the contingency situation. Therefore, the security of system operation is strongly influenced by the limitations of transmission network. In traditional regulated power systems, since the generation and transmission are integrated together, the system operators follow the operating rules and procedures corresponding to the system configuration to dispatch the generation so that the systems operate reliably. As the power industry evolved to deregulated environment, the participants in the open markets compete for gaining their maximum profits with minimum costs by bidding generation and load demand without considering the transmission security. Thus, it is highly required to develop non-discriminatory and economical schedules that also guarantee the security of system operation.

Usually, the independent system operator (ISO) takes charge of issuing the schedules to maintain the whole system's secure operation status under both of pre-contingency and post-contingency situations by means of ordering re-dispatched generation to generation companies (GenCos) , shedding load to distribution companies (DisCos), and using various control devices such as phase shifters, tap-changing transformers, and Flexible AC Transmission systems (FACTS) devices to relieve the transmission security violation. For GenCos, the objective is to achieve the maximum profits. In general, since GenCos bid for generation in energy market without consideration of transmission security, the provided generation usually is adjusted by the ISO re-dispatch to maintain the system security. Thus, if GenCos take the network security constraints into account, they will minimize the difference between their actual energy bids and ISO final orders, which lead them to achieve as much profits as possible, while maintaining the system security requirement. Consequently, the security analysis is necessary for Gencos to plan their generation schedule before they compete their bids in the open market.

Since DC power flow is wildly used by ISOs to get the fast and approximate solution, in this thesis work, the system is modeled in DC power flow to calculate the active power flow in each transmission link for both of pre-contingency and post-contingency cases. The selected N-1 contingency cases are used for detailed network contingency analysis. The following flow chart describes the outline of structure of Chapter 5:

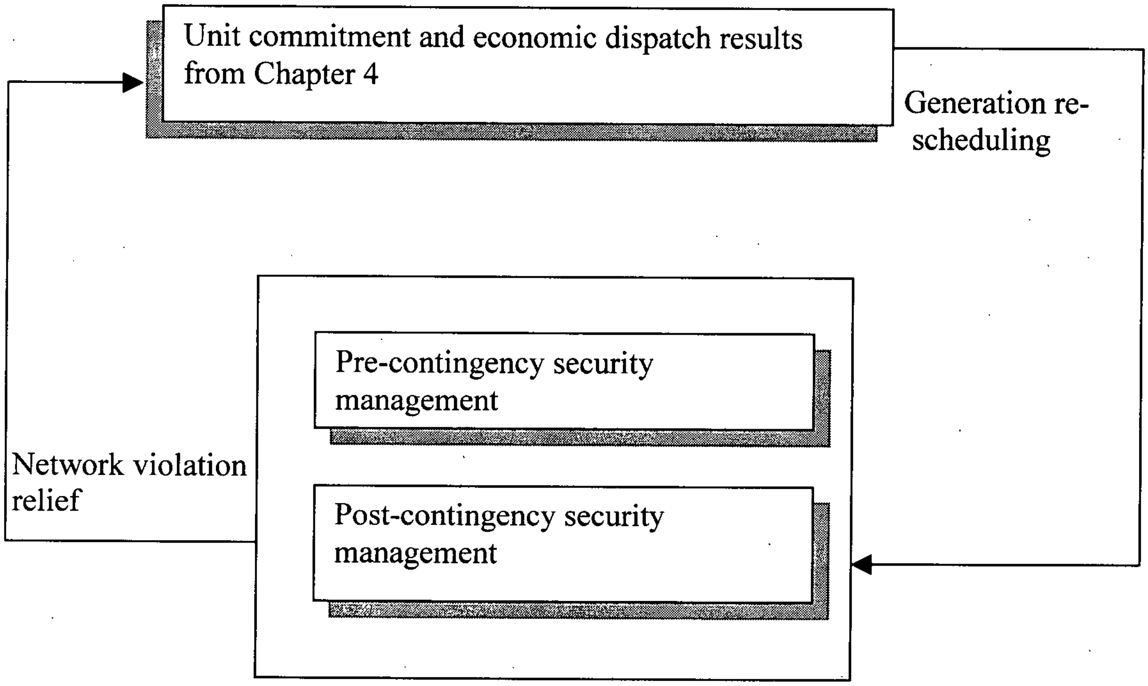

Figure 15 Generation scheduling with network security constraints

5.2 Security-constrained scheduling in pre-contingency network

5.2.1 Transmission security assessment

In the restructured power market, whenever the suppliers and customers desire to deliver the power and consume the power in amount that leads the system operation violating its transfer limits, the system is insecure. In general, power system security is referred to ensure each link operates within its available limit on the amount of power it can transfer at a given time. In this thesis, only available capacity limits, which are defined in section 4.4, are considered to be the transfer limits based on the DC power flow model without consideration of voltage security violation. The power system operation must be within its transfer limits in both of normal operation and contingency cases, so that this system operation is secure in the whole time horizon. In section 5.2, only base case security, which is also called the pre-contingency security, is discussed. The post-contingency security will be discussed in detail in the section 5.3. Maintaining system security is critical for preventing the system from cascaded failures which finally leads the whole network to blackout. The objective of maintaining the network security is to sustain the power flow in each link within its transfer limit which is the available capacity limit as mentioned above. There are two widely used methods to achieve this objective. First, power flow in each individual link is controlled to be within its transfer limit by apparatus like phase shifters and FACTS. Second, generation scheduling in the whole network is adjusted to re-dispatch the power flow in each link. Since the electronic equipment is expensive and its connection to network causes complicated dynamic problems, in this work, the second method is used based on the assumption of either the apparatus for power flow control are installed in the system already or they are not applied in the network.

5.2.2 Pre-contingency security management

5.2.2.1 Network constraints

In DC power flow, assuming bus #1 being the slack bus, the relation between net bus active power and bus voltage angles are shown in the following equation [33]:

$$\begin{bmatrix} P_2 \\ P_3 \\ \cdot \\ \cdot \\ \cdot \\ P_M \end{bmatrix} = \begin{bmatrix} B_{22}\ B_{23}\dots B_{2M} \\ B_{32}\ B_{33}\ \dots B_{3M} \\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot \\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot \\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot \\ B_{M2}\ B_{M3}\dots B_{MM} \end{bmatrix} * \begin{bmatrix} \delta_2 \\ \delta_3 \\ \cdot \\ \cdot \\ \cdot \\ \delta_M \end{bmatrix} \tag{5.1}$$

where:

M: the number of buses (bus 1 is slack bus with voltage phase angle $\delta_1 = 0$)

P_i : the bus i net injected active power $i=2,3,\ldots,$ M

δ_i : the bus i voltage phase angle $i=2,3,\ldots,$ M

B_{ii} : susceptance of bus i $i=2,3,\ldots,$ M

$$B_{ii} = \sum_{k=1}^{M} \frac{1}{x_{ik}}\text{, assuming branch from bus } i \text{ to bus } k$$

B_{ij} : susceptance from bus i to bus j

$$B_{ij} = -\frac{1}{x_{ij}}\text{, assuming branch from bus } i \text{ to bus } j$$

x_{ik} : reactance of transmission line from bus i to bus k.

$$P_i = P_{gi} - P_{di} \tag{5.2}$$

where:

P_{gi} : the injected generation at bus i

P_{di} : the load demand at bus i.

Therefore, voltage phase angles of the system are:

$$\begin{bmatrix} \delta_2 \\ \delta_3 \\ \cdot \\ \cdot \\ \cdot \\ \delta_M \end{bmatrix} = \begin{bmatrix} X_{22}\ X_{23} \ldots X_{2M} \\ X_{22}\ X_{33} \ldots X_{3M} \\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot \\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot \\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot \\ X_{M2}\ X_{M3} \ldots X_{MM} \end{bmatrix} * \begin{bmatrix} P_2 \\ P_3 \\ \cdot \\ \cdot \\ \cdot \\ P_M \end{bmatrix} \tag{5.3}$$

where:

$$\begin{bmatrix} X_{22}\ X_{23}\dots X_{2M} \\ X_{32}\ X_{33}\dots X_{3M} \\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot \\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot \\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot \\ X_{M2}\ X_{M3}\dots X_{MM} \end{bmatrix} = \begin{bmatrix} B_{22}\ B_{23}\dots B_{2M} \\ B_{32}\ B_{33}\dots B_{3M} \\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot \\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot \\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot\ \cdot \\ B_{M2}\ B_{M3}\dots B_{MM} \end{bmatrix}^{-1} \tag{5.4}$$

At bus *i*, the voltage phase angle is in the equation as below:

$$\delta_i = \sum_{i=2}^{M} X_{ki} \cdot P_i \qquad k=2,3,\dots,M;\ \ i=2,3,\dots,M \tag{5.5}$$

The power flow in each transmission line using DC power flow model is:

$$Pf_{km} = (\delta_k - \delta_m) / x_{km} \tag{5.6}$$

where:

Pf_{km} : active power flow on the transmission line from bus *k* to bus *m* ($k \neq m$)

Substituting equation (5.5) to equation (5.6), the equation (5.6) will be:

$$Pf_{km} = \frac{1}{x_{km}} (\sum_{i=2}^{M} X_{ki} \cdot P_i - \sum_{i=2}^{M} X_{mi} \cdot P_i) = \sum_{i=2}^{M} (\frac{X_{ki} - X_{mi}}{x_{km}}) \cdot P_i = \sum_{i=2}^{M} S_{km}^{i} \cdot P_i \tag{5.7}$$

$$S_{km}^{i} = \frac{X_{ki} - X_{mi}}{x_{km}} \tag{5.8}$$

where:

S_{km}^{i} : sensitivity factor of net active power at bus *i* verus power flow change on line from bus *k* to bus *m*

X_{ki} : the k^{th} element on i^{th} row in matrix [X] in equation (5.4)

X_{mi} : the m^{th} element on i^{th} row in matrix [X] in equation (5.4)

x_{km} : reactance of transmission line *k-m*

For secure operation, the transmission flow constraint in hour t is given by:

$$-Pf_{km}^{\max} \le Pf_{km}^{t} = \sum_{i=2}^{M} S_{km}^{i} \cdot P_i^t \le Pf_{km}^{\max} \qquad k=1,2,\ldots,\mathrm{M};\ m=1,2,\ldots,\mathrm{M};\ t=1,2,\ldots,\ \mathrm{T} \qquad (5.9)$$

where:

$Pf_{km}^{\max}$: upper limit for available transmission capacity of line *k-m*

P_i^t: net active power injection at bus i in hour t

Since voltage magnitude of each bus in DC model is assumed to be constant value 1.0, the voltage constraints are neglected.

5.2.2.2 Network security violation relief

5.2.2.2.1 Problem formulation

For the overloaded transmission lines, the target is to relieve the transmission security violation with the lowest cost of generation scheduling adjustment, while satisfying all the system constraints and unit constraints mentioned in Chapter 4 and transmission flow constraints.

I. Objective function

$$\text{Minimize} \quad g(t) = \sum_{i=1}^{N} IC_i \cdot \Delta^1 P_i^t \cdot U_i^t \qquad t=1,2,\ldots,\mathrm{T} \qquad (5.10)$$

where:

IC_i: incremental cost of unit i

$\Delta_1 P_i^t$: output adjustment of unit i from its output obtained in Chapter 4

U_i^t: unit i status (with $U_i^t = 1$, the unit is on line)

subject to:

(1) Load balance:

$$\sum_{i=1}^{N}\Delta_1 P_i^t \cdot U_i^t = 0 \tag{5.11}$$

(2) Transmission violation adjustment :

If the limit of transmission line *k-m* is violated, the amount of violation is:

$$W_{km}^t = Pf_{km}^t - Pf_{km}^{\max} \qquad k=1,2,\ldots,M;\ m=1,2,\ldots,M;\ t=1,2,\ldots,\ T \tag{5.12}$$

The generation adjustment must relieve this transmission security violation, which is given in the following:

$$\sum_{i=1}^{N}(S_{km}^i \cdot \Delta_1 P_i^t \cdot U_i^t) + W_{km}^t \le 0 \qquad k=1,2,\ldots,M;\ m=1,2,\ldots,M;\ t=1,2,\ldots,T \tag{5.13}$$

II. Lagrangian function:

Based on the objective function and constraints above, the Lagrangian function to relieve the transmission line *k-m* security violation with the lowest cost is formulated as:

$$l = \sum_{i=1}^{n}(IC_i \cdot \Delta_1 P_i^t \cdot U_i^t) + \lambda_1^t \cdot (\sum_{i=1}^{N}\Delta_1 P_i^t \cdot U_i^t) + \lambda_2^t \cdot (\sum_{i=1}^{N} S_{km}^i \cdot \Delta_1 P_i^t \cdot U_i^t + W_{km}^t) \qquad k=1,2,\ldots,M;$$

$$m=1,2,\ldots,M;\ k \neq m;\ \ t=1,2,\ldots,T \tag{5.14}$$

5.2.2.2.2 Security-constrained unit commitment and economic dispatch

The procedure of security constrained unit commitment and economic dispatch is described in the following process.

Step-1:

Calculate the DC power flow on all the transmission lines starting from hour 1.

Step-2:

Check the power flow of each line, calculate the amount of violation on the violated line and choose the worst violated line.

Step-3:

Relieve the worst violation by minimizing the Lagrangian function in equation (5.14) with first order gradient method to obtain the output adjustment $\Delta_1 P_i^t$ of all the online units.

Step-4:

1. Calculate all the online unit's output by the equation below:

$$P_{i(new)}^t \cdot U_i^t = (P_i^t + \Delta_1 P_i^t) \cdot U_i^t \qquad i=1,2,\ldots, N;\ t=1,2,\ldots T \tag{5.15}$$

2. Calculate the violation of output limit:

A. If $P_{i(new)}^t > P_i^{\max(new)}$,

$$\Delta P_i^t = (P_{i(new)}^t - P_i^{\max}) \cdot U_i^t \qquad i=1,2,\ldots,N; \quad t=1,2,\ldots,T \tag{5.16}$$

where:

$P_i^{\max(new)}$ is the upper limit of output of unit i with spinning reserve, which is given in equation (4.35)

B. If $P_{i(new)}^t \le P_i^{\min}$,

$$\Delta P_i^t = (P_{i(new)}^t - P_i^{\min}) \cdot U_i^t \qquad i=1,2,\ldots,N; \quad t=1,2,\ldots,T \tag{5.17}$$

Otherwise, ΔP_i^t=0 (no violation)

Step-5:

Rank the absolute value of ΔP_i^t in equation (5.16) and (5.17). Choose the maximum value and corresponding unit which is represented by unit j.

Step-6:

Case1: If $P_{j(new)}^t > P_j^{\max(new)}$, set $P_{j(new)}^t = P_j^{\max(new)}$

$$\Delta_2 P_j^t = P_j^t - P_j^{\max} \qquad t=1,2,\ldots,T \tag{5.18}$$

where:

P_j^t: the j^{th} unit's output from unit commitment and economic dispatch program in Chapter 4.

Case 2: If $P_{j(new)}^t < P_j^{\min}$, set $P_{j(new)}^t = P_j^{\min}$

$$\Delta_2 P_j^t = P_j^t - P_j^{\min}, \qquad t=1,2,\ldots,T \tag{5.19}$$

where:

P_j^t: the j^{th} unit's output from unit commitment and economic dispatch program in Chapter 4.

3. In either case 1 or case 2, the amount of transmission violation is reduced in the following equation:

$$W_{km(new)}^t = W_{km}^t - \Delta_2 P_j^t \cdot S_{km}^j \qquad t=1,2,\ldots,T \tag{5.20}$$

Step-7:

Distribute $\Delta_2 P_j^t$ in Step-6 to all the other online units except unit j with the consideration of both violation relief and economics. The Lagrangian function in equation (5.14) is further rewritten by the following equation:

$$l = \sum_{i=1, i\neq j}^{n} (IC_i^t \cdot \Delta_1 P_i^t \cdot U_i^t) + \lambda_1^t \cdot (\sum_{i=1, i\neq j}^{N} \Delta_1 P_i^t \cdot U_i^t + \Delta_2 P_j^t) + \lambda_2^t \cdot (\sum_{i=1, i\neq j}^{N} S_{km}^i \cdot \Delta_2 P_i^t \cdot U_i^t + W_{km(new)}^t)$$

$$k=1,2,\ldots,M; \; m=1,2,\ldots,M; \; k \neq m; \; t=1,2,\ldots,T \tag{5.21}$$

Solve equation (5.21) with first order gradient method.

Step-8:

Repeat the process from Step-3 to Step-7. If no unit violates its output limits and the transmission violation is totally relieved, end the process; we have the final solutions. If there is no unit within the output limits left which can be adjusted its output to compensate other units' output violation, the program goes to next step.

Step-9:

Check the sensitivity factors at the buses with the off-line units. Commit the off line units with negative sensitivity factors to the violated transmission line *k-m* ($S_{km}^{j} < 0$, unit *j* is off line) and with minimum up/down time constraints satisfied (function (4.5) and (4.6)), since they will reduce the transmission line violation. Go back to step-3 to repeat the process up to step-8 and save the solutions.

Step-10:

Go back to step-1 to re-calculate the power flow on each transmission line with the solution obtained for the worst violation relief before and check a new violation. Repeat the process from step-3 to step-9 for the worst transmission violation and save the solutions.

Step-11:

When there is no new security violated lines, the solution is the final secure optimal solution. Repeat the whole procedure starting from Step-1 for 24 hours.

In this thesis work, it is assumed that violation can be relieved by unit recommitment, generation re-dispatch and power interchange adjustment, without shedding the load. In real power system, the load may need to be shed in some critical cases to maintain the system security. Since load curtailment is a large reliability issue, which can be discussed in a larger context, this option is ignored in this research work.

The whole process above is illustrated in the following Figure 17:

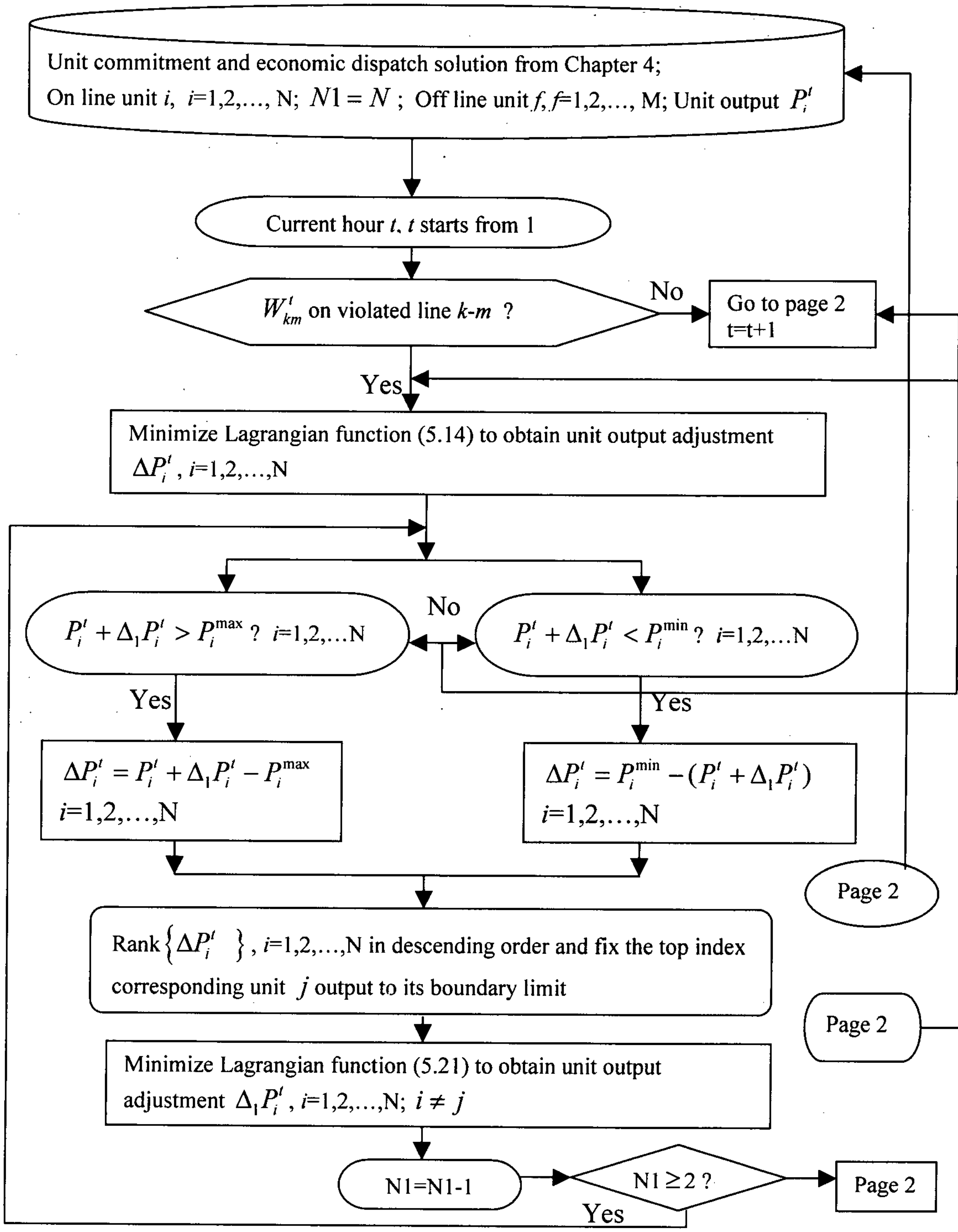

Figure 16 Security constrained unit commitment and economic dispatch (Page 1)

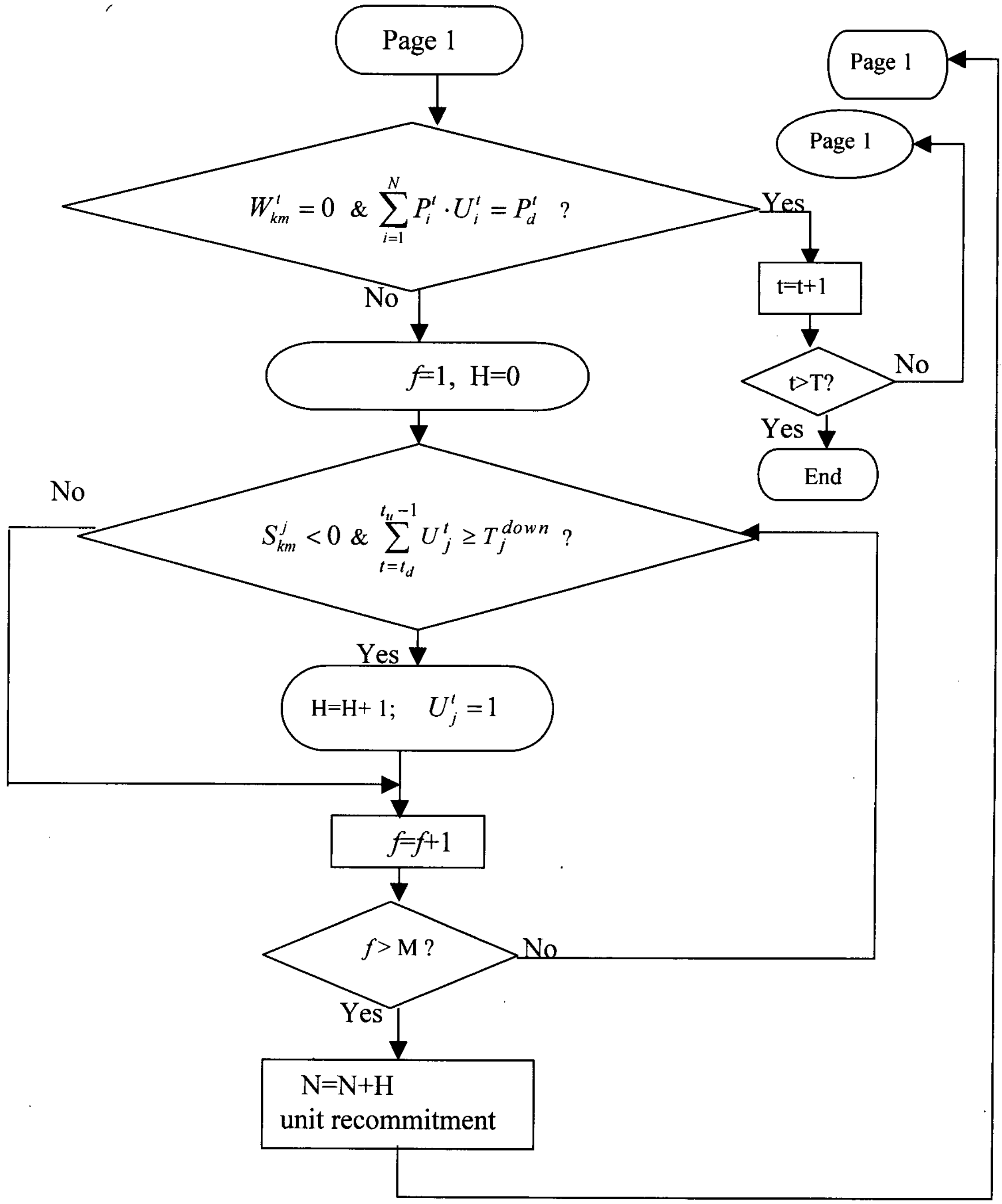

Figure 16 Security constrained unit commitment and economic dispatch (Page 2)

5.3 Post-contingency generation rescheduling

5.3.1 N-1 contingency analysis

Contingency analysis is the procedure of modeling the single failure events such as one transmission line or one unit outage or multiple failure events including multiple lines or units failure or outage of lines plus units. In this work, only single transmission line outage is considered, which is usually called N-1 contingency analysis.

The largest difficulty to cope with in N-1 contingency analysis is the speed of solution of the simulated model and logical selection of possible outages. In this work, the DC power flow model is used with sufficient accuracy and without voltage magnitude concern. Around 70% of transmission lines in the whole system model are selected to be the N-1 contingency cases. All the N-1 contingency cases are sorted by their performance index in a list so that the worst N-1 contingency case, which is on the top of the list, is executed first for the security analysis, and so on down the list until there is no alarm to show that the system is insecure. The performance index calculation to sort the selected N-1 contingency cases is given in the following.

In traditional methods, the performance index (PI) is defined as [33]:

$$\mathrm{PI}=\sum_{l=1}^{Nl}\left(\frac{Pf_l}{Pf_l^{\max}}\right)^{2n} \tag{5.22}$$

where:

Nl : the total number of transmission lines in the system

Pf_l : the power flow on transmission line l

$Pf_l^{\max}$: the maximum available capacity of transmission line l.

However, when n=1, the lines with power flow that just below their limits contribute to PI is almost equal to those lines with power flow just over their limits. Hence, the weakness of PI calculation by the equation (5.22) is that the PI ability to detect bad cases is limited when n=1. To overcome this shortcoming, the new PI is formulated by the following equation:

$$PI_i^t = \sum_{l=1}^{Nl} Max\{ \ (\frac{Pf_l^t - Pf_l^{\max}}{Pf_l^{\max}}),0\} \qquad i=1,2,\ldots,NC;\ t=1,2,\ldots,T \tag{5.23}$$

where:

PI_i^t : the i^{th} N-1 contingency case performance index at hour t

NC: the total number of selected N-1 contingency cases.

Sort all the PI_i^t in the descending list. The top one represents the worst N-1 contingency case, then the second and so on down the list.

5.3.2 Post-contingency violation management

5.3.2.1 Problem formulation

(1) Parameter update

For each N-1 contingency case, for example in the r^{th} N-1 contingency case, first, the original matrix [B] in equation (5.1) is updated since the single line outage changes the corresponding susceptances in the original matrix [B]. The new matrix is represented by [B_r]. The same is applied to matrix [X] in equation (5.4). Thus, the new matrix is represented by [X_r]. Second, the sensitivity factor in equation (5.8) is also updated due to the new matrix [X_r] and represented in matrix [S_r]. The variable r ranges from 1 to NC.

(2) Rank the severity of all the selected N-1 contingency cases

Calculate the DC power flow on all the transmission lines in each N-1 contingency case. Sort the value of PI in each N-1 contingency case in descending order. The one on the top of the list is the worst N-1 case.

(3) Objective:

- Modify the preferred schedule obtained from security violation management to relieve the violation of post N-1 contingency.
- Minimize the total cost of generation re-dispatch for the system security.

(4) Constraints:

- System balance constraint

$$P_d^t + P_{ex}^t = \sum_{i=1}^{N} U_i^t \cdot P_i^t$$

- System reserve requirement

$$R^{\min}(t) \le \sum_{i=1}^{N} R(i,t) \cdot U_i^t \le R^{\max}(t)$$

- Power interchange limits

See section 4.4.1.2

- Unit capacity constraints

$$P_i^{\min} \le P_i^t \le P_i^{\max} \qquad \text{for } i\text{=1,2,…,N and } t\text{=1,2,…,T}$$

- Minimum up/down time constraints

$$\sum_{t=t_u}^{t_d-1} U_i^t \ge T_i^{up} \qquad \text{for } i\text{=1,2,…,N and } t\text{=1,2,…,T}$$

$$\sum_{t=t_d}^{t_u-1} U_i^t \ge T_i^{down} \qquad \text{for } i\text{=1,2,…,N and } t\text{=1,2,…, T}$$

- Transmission flow constraint

$$-Pf_{km}^{\max} \le Pf_{km}^t = \sum_{i=2}^{M} S_{km}^i \cdot P_i^t \le Pf_{km}^{\max} \qquad k\text{=2,3,…,M; } m\text{=2,3,…,M; } t\text{=1,2,…, T}$$

The Lagrangian function to relieve the transmission line *k-m* violation with the lowest cost in the r^{th} N-1 post contingency case is formulated as:

$$l_r^t = \sum_{i=1}^{n}(IC_i \cdot \Delta P_i^t \cdot U_i^t) + \lambda_1^t \cdot (\sum_{i=1}^{N} \Delta P_i^t \cdot U_i^t) + \lambda_2^t \cdot (\sum_{i=1}^{N} S_{r,km}^{\ i} \cdot \Delta P_i^t \cdot U_i^t + W_{km}^t) \qquad k=1,2,\ldots,M;$$

$$m=1,2,\ldots,M;\ t=1,2,\ldots,T;\ k \neq m;\ r=1,2,\ldots,NC \qquad (5.24)$$

where:

NC: the total number of selected N-1 contingency cases

l_r^t: Lagrangian function for the economical violation relief in the r^{th} N-1 contingency case

$S_{r,km}^{\ i}$: the sensitivity factor of bus *i* net injected active power versus transmission power flow on line *k-m* in the r^{th} N-1 contingency case.

5.3.2.2 Post-contingency security violation relieving procedure

Step-1:

Start at hour 1. Run the DC power flow for each selected N-1 contingency case with the solution obtained from 5.2.2.2.2. Save the corresponding case numbers of all the insecure post contingency cases.

Step-2:

Calculate the PI by equation (5.23) for each selected insecure N-1 contingency case and sort their value of PI in decremental order to set up the PI list, and number them starting from case #1.

Step-3:

Choose an N-1 contingency case on the PI list from top to bottom one at a time. Thus, the worst N-1 case # *i* is chosen first. (initialize *i*=1).

Step-4:

Relieve the violation on each security-violated transmission line in the selected N-1 contingency case *i* above by the approach of security constrained unit commitment and economic dispatch in section 5.2.2.2.2. Save the corresponding solution and counter it by number starting from 1.

Step-5:

Update *i* by equation $i=i+1$ and repeat the process from Step-3 to Step-4.

Step-6:

If i >NC, go to step-7; otherwise, repeat the process from Step-3 to Step-5.

Step-7:

Try each of the saved solutions in particular N-1 contingency case one at a time for all the other selected N-1 contingency cases on the PI list. The solution, which guarantees all the N-1 post contingency cases secure, is the final optimal solution. If there are more than one feasible solutions, the one with the minimum adjustment of generation re-dispatch will be the final optimal solution.

It may not obtain the solution in Step-4 and Step-5 that can guarantee all the other N-1 post contingency cases to be secure and no any transmission line violated in the particular case, then reduce some export power to relieve the violation during the hours of export. If the system is in the import hours, some load must be shed. However, the topic related to load shedding will not be discussed in this work.

Step-8:

Repeat all the procedure from Step-1 to Step-7 for T hours.

The whole scheme of optimal generation scheduling with consideration of network security constraints is illustrated by the following Figure 18:

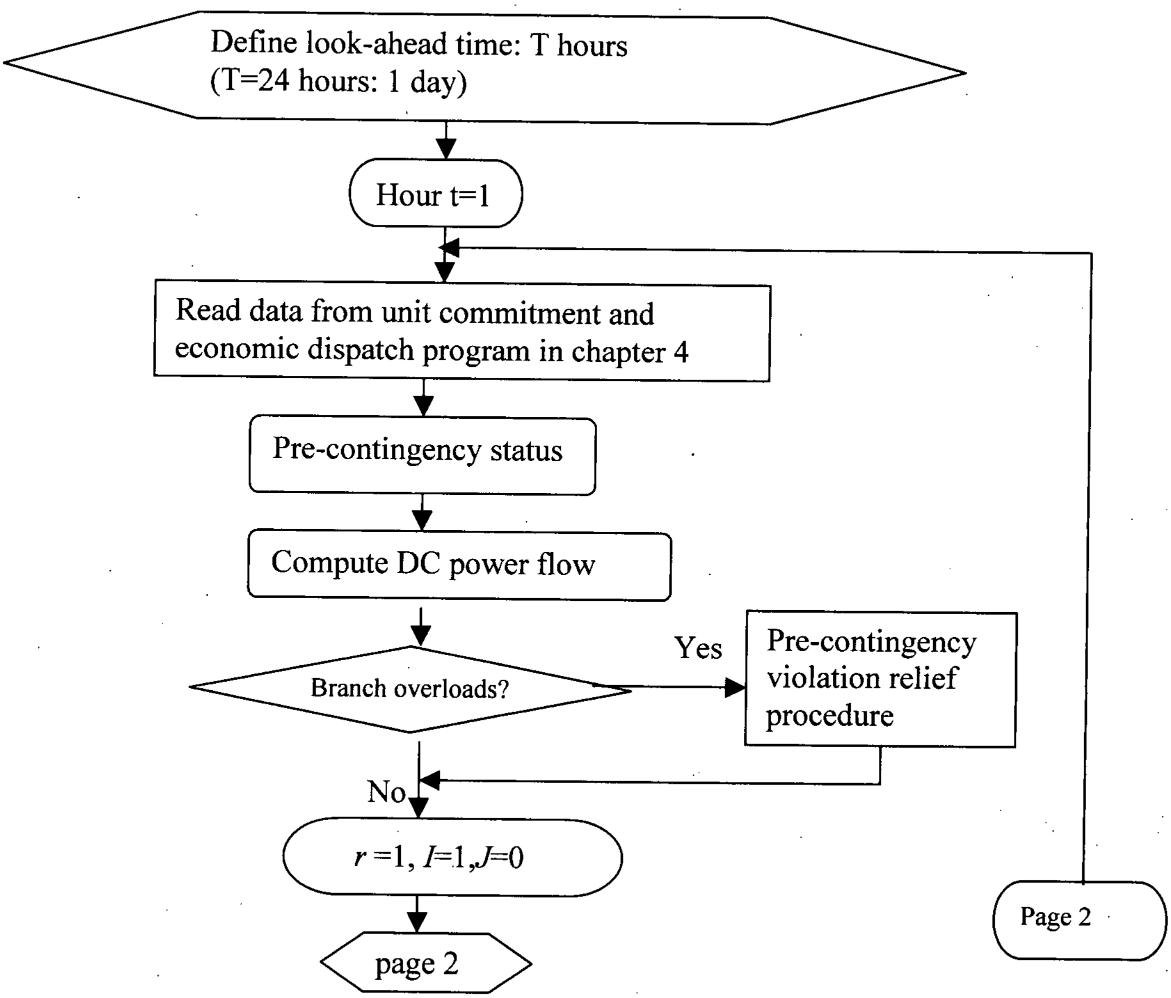

Figure 18 Generation scheduling with network security constraints (page 1)

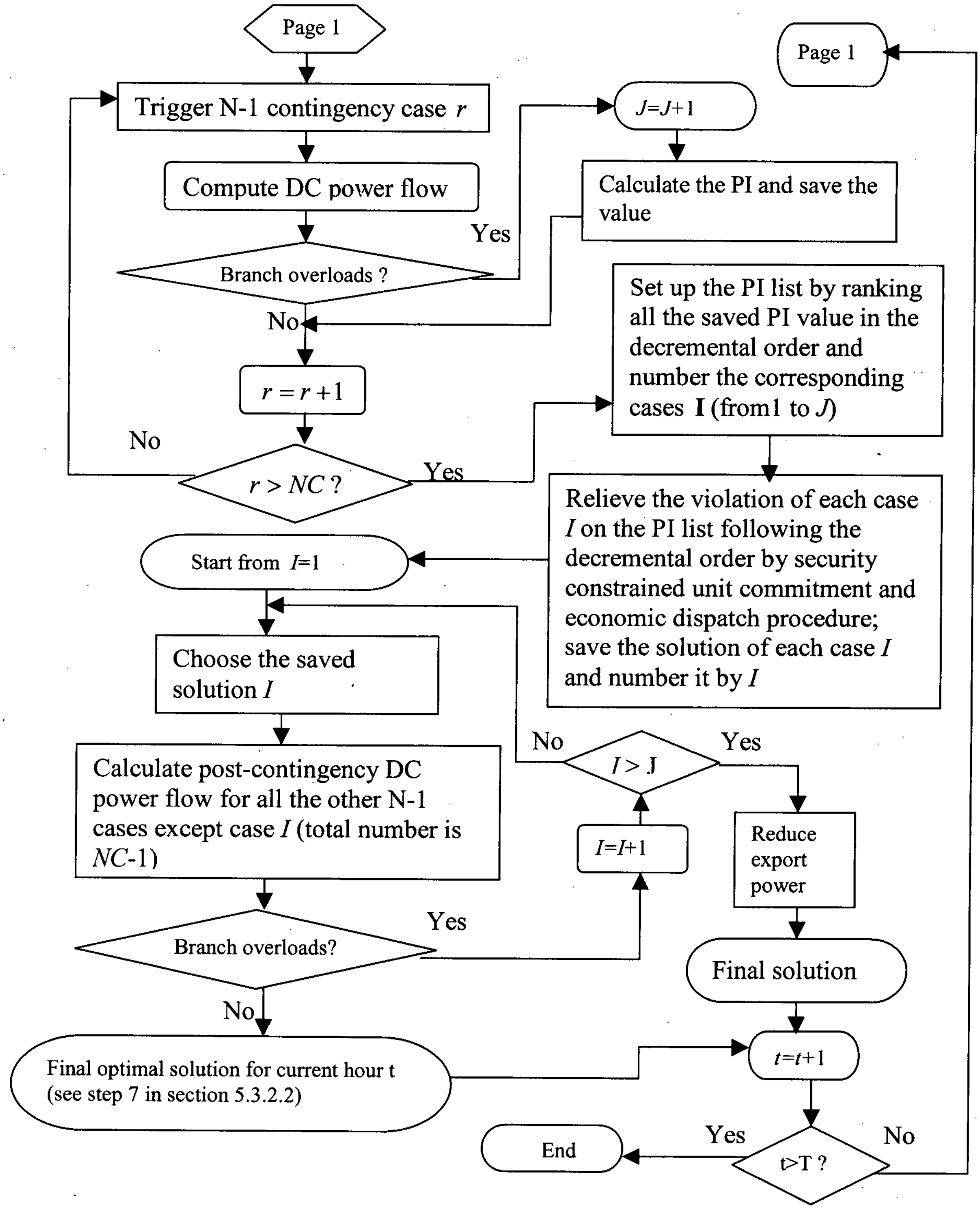

Figure 18 Generation scheduling with network security constraints (page 2)

Chapter 6

CASE STUDIES

In this chapter the models developed in Chapter 4 and Chapter 5 are tested in five cases with different load patterns and electricity price patterns. In the first case, the system has medium load level and higher electricity price. The second case is about the medium system load level and medium electricity price. The third case consists of medium level of system load and lower electricity price. The higher load level pattern and medium electricity price pattern are considered in the fourth case. In the fifth case, the system is in the pattern of lower load level and medium electricity price. The numerical simulation is tested on the simplified BC Hydro 500kV 14 bus network.

6.1 Illustration of test system

The proposed approach is tested by the network shown in Figure 19:

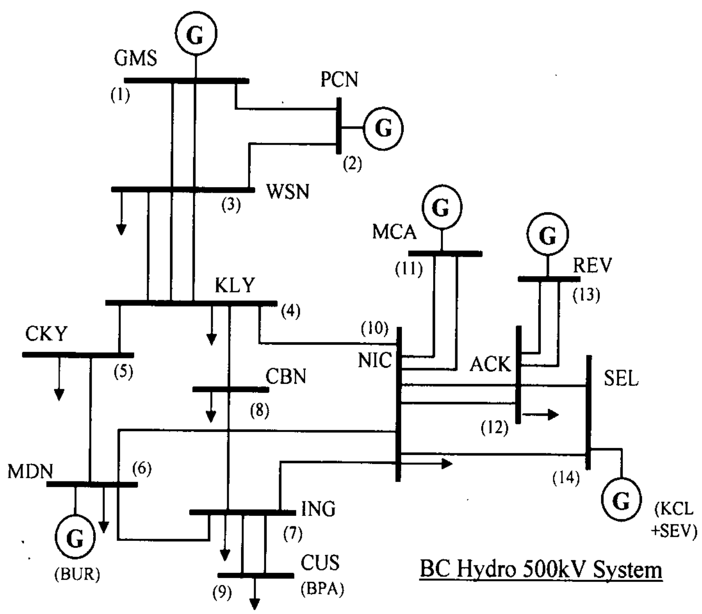

Figure 18 Test system of 14 bus transmission network

The test system above is a 14-bus system comprising of 24 transmission lines, 6 generating stations and 9 load centers (substations). The key parameters and database are summarized through Table 3 to Table 6. Table 1 lists the key generator parameters, including cost function parameters, output limits, and minimum up/down time. Table 4 lists all the transmission line capacity and per unit reactance. The selected N-1 contingency cases are listed in Table 5. To simplify the load distribution at each load bus in each hour, we assume the individual load bus keeps a constant contraction of the total system load in each hour and in each of three load level patterns. Table 6 lists the contribution of each load to the total load in the system. Table 7 lists the system load at each corresponding load bus by hour in each of three load level patterns. Three electricity market price patterns from the analysis of Pennsylvania-New Jersey-Maryland (PJM) power market in the year 2000, which are higher level price, medium level price and lower level price, are listed in Table 8.

Table 3. Generator parameters

Unit name	Bus Number	a_i	b_i	c_i	P_i^{min}	P_i^{max}	T_i^{up}	T_i^{down}
G(1)	1	0.00262	7.62	0	400	2750	4	3
G(2)	13	0.00308	8.18	0	320	2000	4	3
G(3)	6	0.00798	18.57	0	200	900	4	3
G(4)	2	0.00418	10.34	0	120	700	4	3
G(5)	11	0.00329	8.56	0	300	1800	4	3
G(6)	14	0.00314	9.28	0	200	1200	4	3

Table 4. Transmission line parameters

Line	Capacity (MW)	Reactance (p.u)
Bus 1-2	1500	0.00178
Bus 1-3 Circuit #1	2250	0.01854
Bus 1-3 Circuit #2	2250	0.01854
Bus 2-3	1300	0.01863
Bus 3-4 Circuit #1	1500	0.02151
Bus 3-4 Circuit #2	1500	0.02151
Bus 3-4 Circuit #3	1500	0.02151
Bus 4-5	2000	0.01198
Bus 4-8	2000	0.01548
Bus 4-10	2000	0.01895
Bus 5-6	2000	0.00880
Bus 6-7	2000	0.00259
Bus 6-10	2000	0.01650
Bus 7-8	2000	0.00659
Bus 7-9 Circuit #1	1500	0.00484
Bus 7-9 Circuit #2	1500	0.00484
Bus 7-10	2500	0.01837
Bus 10-11 Circuit #1	1800	0.03666
Bus 10-11 Circuit #2	1800	0.03666
Bus 10-12 Circuit #1	1500	0.01536
Bus 10-12 Circuit #2	1500	0.01536
Bus 10-14	2000	0.03896
Bus 12-13 Circuit #1	1800	0.01100
Bus 12-13 Circuit #2	1800	0.01100
Bus 12-14	2000	0.02893

Table 5. Selected N-1 Contingency cases

Case Number	Line opened
1	One circuit from Bus #1 to Bus #3
2	Bus #2 to Bus #3
3	One circuit from Bus #3 to Bus #4
4	Bus #4 to Bus #5
5	Bus #4 to Bus #8
6	Bus #6 to Bus #10
7	Bus #7 to Bus #8
8	Bus #7 to Bus #10
9	One circuit from Bus #10 to Bus #11
10	One circuit from Bus #10 to Bus #12
11	One circuit from Bus #12 to Bus #13

Table 6. Percentage of system load at each load bus

Bus Number	Percentage(%)
3	8.89
4	1.31
5	9.62
6	12.36
7	22.47
8	4.6
9	28.05
10	5.35
12	7.36

Table 7. System load by hour in three patterns

Hour	Lower level load (MW)	Medium level load (MW)	High level load (MW)	Hour	Lower level load (MW)	Medium level load (MW)	High level load (MW)
1	4830.99	5632.68	6241.71	13	6607.09	7757.20	8380.72
2	4610.63	5338.85	5994.31	14	6739.81	7958.27	8504.43
3	4411.55	5145.57	5775.57	15	6865.96	8071.06	8632.23
4	4345.01	5041.06	5721.50	16	6824.18	8167.46	8574.88
5	4277.20	5060.60	5691.19	17	6987.21	8192.30	8734.63
6	4525.43	5257.70	6030.35	18	7001.14	8149.24	8721.52
7	4883.43	5653.72	6462.91	19	6512.06	7893.34	8189.84
8	5249.63	6072.92	6889.72	20	6538.28	7619.23	8259.48
9	5479.01	6431.84	7200.21	21	6652.15	7559.93	8384.01
10	5776.39	6803.34	7569.69	22	6225.33	7307.18	7862.15
11	6172.08	7227.35	7981.76	23	5778.85	6737.92	7307.53
12	6348.21	7552.48	8134.14	24	5171.79	6139.67	6584.97

Table 8. Three patterns of electricity price in external market

Hour (t)	Lower price ($/MW)	Medium price ($/MW)	Higher price ($/MW)	Hour (t)	Lower price ($/MW)	Medium price ($/MW)	Higher price ($/MW)
1	1.00	6.741	138.93	13	7.63	41.35	214.48
2	1.00	6.095	133.99	14	6.83	39.49	211.36
3	1.00	6.091	133.93	15	5.49	36.36	205.97
4	1.00	6.211	135.25	16	5.39	36.12	205.56
5	1.00	7.072	140.66	17	8.56	43.47	218.03
6	1.00	12.89	159.25	18	21.72	71.19	261.49
7	3.29	30.94	196.41	19	31.58	90.54	289.89
8	12.06	51.17	230.57	20	28.12	83.84	280.19
9	14.05	55.42	237.30	21	22.44	72.63	263.66
10	11.96	50.96	230.23	22	17.62	62.87	248.87
11	10.81	48.47	226.21	23	7.84	41.83	215.29
12	9.53	45.64	221.61	24	1.05	24.89	185.14

6.2 Results of case studies

This section discusses the results of case studies for the BC Hydro's simplified bulk system with 14 buses and one external power market—Bonneville Power Administration (BPA). The simulation results are calculated based on the assumption that all generators bid according to their variable generation cost due to lacking of actual bidding data from real power market. All the data of generation cost are based on the approximation of five hydro generators' cost functions and one thermal unit's fuel cost function. The database of electricity market price of BPA is obtained by analyzing the data of the PJM market in the year 2000. The data of forecasting load patterns are from the earlier results based on a fuzzy logic model in our group research work.

6.2.1 Case #1----- with medium load and higher market price pattern

In this case, the electricity price in the external power market is of the highest price pattern as it is listed in Table 8, which is substantially higher than the system marginal price during the 24 hours in a day-ahead time schedule. The local load is at the medium level. There are two categories of exports discussed in each case study, which are firm export and non-firm export. Firm export potential appears most promising. The calculation of firm export is based on the security constrained unit commitment and economic dispatch. The non-firm export is the result without consideration of N-1 contingency cases. Thus, the amount of non-firm export is not guaranteed to be provided whenever the system undergoes contingency situation, but the price of non-firm export is lower than that of firm export. Similarly, we also have the firm/non-firm import, spinning reserve and profits corresponding to the pre-contingency and post-contingency cases. Since there are no sufficient market information, in our work, we assumed that the price of firm export is 85% of external market price and non-firm export price is 50% of external market price.

The results of generation scheduling, firm/non-firm export and electricity selling price, corresponding profits, firm spinning reserve achieved by GenCos in this case are listed in the following Table 9 and illustrated in the Figures 18, 19, 20, 21, and 22.

Table 9 (a). Post-contingency generation dispatch and spinning reserve in case #1

Hour	Unit status						Generator output (MW)						Reserve (firm) (MW)
	U1	U2	U3	U4	U5	U6	G(1)	G(2)	G(3)	G(4)	G(5)	G(6)	
1	1	1	1	1	1	1	2039.20	1582.44	335.70	631.31	1423.68	1117.42	2220.25
2	1	1	1	1	1	1	1979.50	1515.02	309.68	652.18	1360.56	1118.03	2415.03
3	1	1	1	1	1	1	1926.73	1470.66	292.56	652.42	1319.04	1118.43	2570.17
4	1	1	1	1	1	1	1898.20	1446.68	283.31	652.54	1296.59	1118.64	2654.05
5	1	1	1	1	1	1	1903.53	1451.17	285.04	652.52	1300.79	1118.60	2638.36
6	1	1	1	1	1	1	1957.34	1496.39	302.49	652.28	1343.13	1118.20	2480.17
7	1	1	1	1	1	1	2042.22	1587.26	337.57	628.56	1428.20	1117.38	2208.82
8	1	1	1	1	1	1	2102.33	1683.46	374.69	573.72	1518.25	1116.52	1981.05
9	1	1	1	1	1	1	2153.79	1765.82	406.48	526.76	1595.35	1115.78	1786.03
10	1	1	1	1	1	1	2208.44	1800.00	439.38	476.90	1672.52	1115.01	1637.76
11	1	1	1	1	1	1	2298.26	1800.00	476.94	394.94	1671.21	1114.14	1594.52
12	1	1	1	1	1	1	2297.66	1800.00	835.10	395.49	1670.20	1113.47	1238.08
13	1	1	1	1	1	1	2297.29	1800.00	834.78	395.83	1669.57	1113.05	1239.48
14	1	1	1	1	1	1	2296.92	1800.00	834.47	396.17	1668.95	1112.63	1240.86
15	1	1	1	1	1	1	2296.71	1800.00	834.30	396.36	1668.60	1112.40	1241.64
16	1	1	1	1	1	1	2296.53	1800.00	834.15	396.52	1668.30	1112.20	1242.30
17	1	1	1	1	1	1	2296.49	1800.00	834.11	396.56	1668.22	1112.15	1242.47
18	1	1	1	1	1	1	2296.56	1800.00	834.18	396.49	1668.36	1112.24	1242.17
19	1	1	1	1	1	1	2297.04	1800.00	834.57	396.06	1669.15	1112.77	1240.42
20	1	1	1	1	1	1	2297.54	1800.00	835.00	395.60	1670.00	1113.33	1238.54
21	1	1	1	1	1	1	2297.65	1800.00	835.09	395.50	1670.18	1113.45	1238.13
22	1	1	1	1	1	1	2298.11	1800.00	484.01	395.08	1670.96	1113.97	1587.87
23	1	1	1	1	1	1	2197.68	1800.00	433.59	486.72	1661.10	1115.15	1655.77
24	1	1	1	1	1	1	2111.90	1698.77	380.60	564.98	1532.59	1116.38	1944.78

Table 9 (b). Pre- and post-contingency export, selling price, and profits in case #1

Hour (t)	Export (firm) (MW)	Export (non-firm) (MW)	Selling price (firm) ($/MW)	Selling price (non-firm) ($/MW)	Profit (firm) ($)	Profit (non-firm) ($)
1	2608.96	2650.00	20.84	19.16	375465.53	262000.00
2	2650.00	2650.00	20.56	18.85	364170.83	250000.00
3	2650.00	2650.00	20.34	18.65	360891.44	247000.00
4	2650.00	2650.00	20.23	18.54	362216.10	248000.00
5	2650.00	2650.00	20.25	18.56	374705.81	256000.00
6	2650.00	2650.00	20.47	18.76	419746.39	286000.00
7	2603.51	2650.00	20.85	19.17	502365.01	346000.00
8	2494.83	2650.00	21.18	19.61	564161.84	402000.00
9	2401.78	2650.00	21.46	19.98	566235.18	418000.00
10	2251.88	2650.00	21.68	20.37	529015.73	413000.00
11	1954.81	2521.65	21.75	20.64	470204.86	396000.00
12	2050.30	2614.15	22.90	21.69	493217.96	413000.00
13	1884.59	2446.56	22.90	21.68	454333.28	387000.00
14	1721.83	2281.95	22.90	21.68	423790.44	367000.00
15	1630.53	2189.61	22.89	21.68	401997.64	352000.00
16	1552.50	2110.70	22.89	21.67	389550.18	344000.00
17	1532.39	2090.36	22.89	21.67	402733.80	344000.00
18	1567.25	2125.61	22.89	21.67	466300.89	411000.00
19	1774.39	2335.10	22.90	21.68	550479.38	473000.00
20	1996.27	2559.51	22.90	21.69	583663.87	490000.00
21	2044.27	2608.05	22.90	21.69	565284.63	473000.00
22	1897.38	2463.49	21.78	20.66	497296.09	421000.00
23	2286.38	2650.00	21.66	20.30	505667.26	390000.00
24	2477.52	2650.00	21.23	19.68	466321.70	337000.00

Table 9 (c). Pre-contingency generation dispatch and spinning reserve in case #1

Hour	Generator output (MW)						Reserve (non) (MW)
	G(1)	G(2)	G(3)	G(4)	G(5)	G(6)	
1	2059.72	1582.44	335.70	651.83	1423.68	1117.42	2179.21
2	1979.50	1515.02	309.68	652.18	1360.56	1118.03	2415.03
3	1926.73	1470.66	292.56	652.42	1319.04	1118.43	2570.17
4	1898.20	1446.68	283.31	652.54	1296.59	1118.64	2654.05
5	1903.53	1451.17	285.04	652.52	1300.79	1118.60	2638.36
6	1957.34	1496.39	302.49	652.28	1343.13	1118.20	2480.17
7	2065.46	1587.26	337.57	651.81	1428.20	1117.38	2162.33
8	2179.91	1683.46	374.69	651.30	1518.25	1116.52	1825.87
9	2277.90	1765.82	406.48	650.87	1595.35	1115.78	1537.81
10	2381.97	1851.06	439.38	650.42	1672.52	1115.01	1239.64
11	2553.23	1856.90	476.94	649.91	1671.21	1114.14	1027.68
12	2551.70	1855.78	835.10	649.52	1670.20	1113.47	674.23
13	2550.73	1855.08	834.78	649.28	1669.57	1113.05	677.52
14	2549.78	1854.39	834.47	649.04	1668.95	1112.63	680.75
15	2549.25	1854.00	834.30	648.90	1668.60	1112.40	682.56
16	2548.79	1853.67	834.15	648.78	1668.30	1112.20	684.10
17	2548.68	1853.58	834.11	648.75	1668.22	1112.15	684.50
18	2548.88	1853.73	834.18	648.81	1668.36	1112.24	683.81
19	2550.09	1854.61	834.57	649.11	1669.15	1112.77	679.70
20	2551.38	1855.55	835.00	649.44	1670.00	1113.33	675.31
21	2551.66	1855.75	835.09	649.51	1670.18	1113.45	674.35
22	2552.85	1856.62	484.01	649.82	1670.96	1113.97	1021.77
23	2361.47	1836.05	433.59	650.50	1661.10	1115.15	1292.15
24	2198.13	1698.77	380.60	651.22	1532.59	1116.38	1772.30

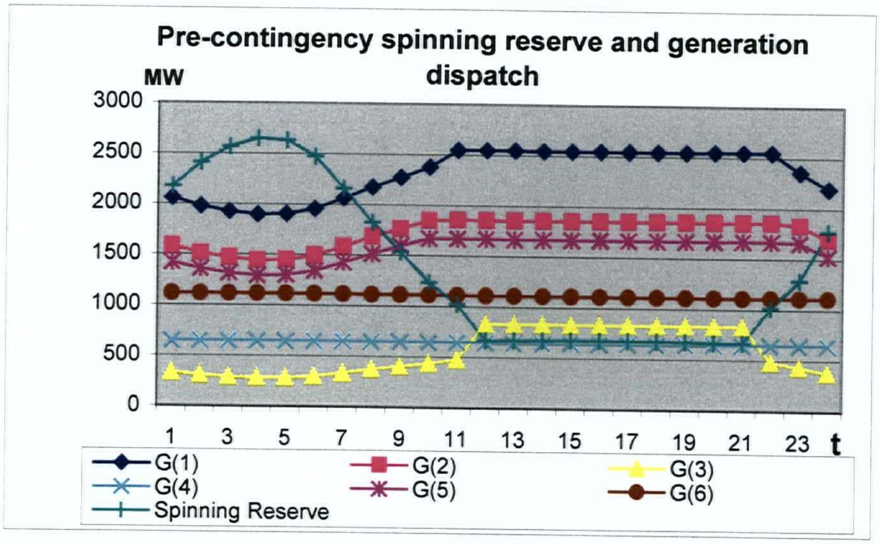

Figure 19 Pre-contingency spinning reserve and generation scheduling of case #1

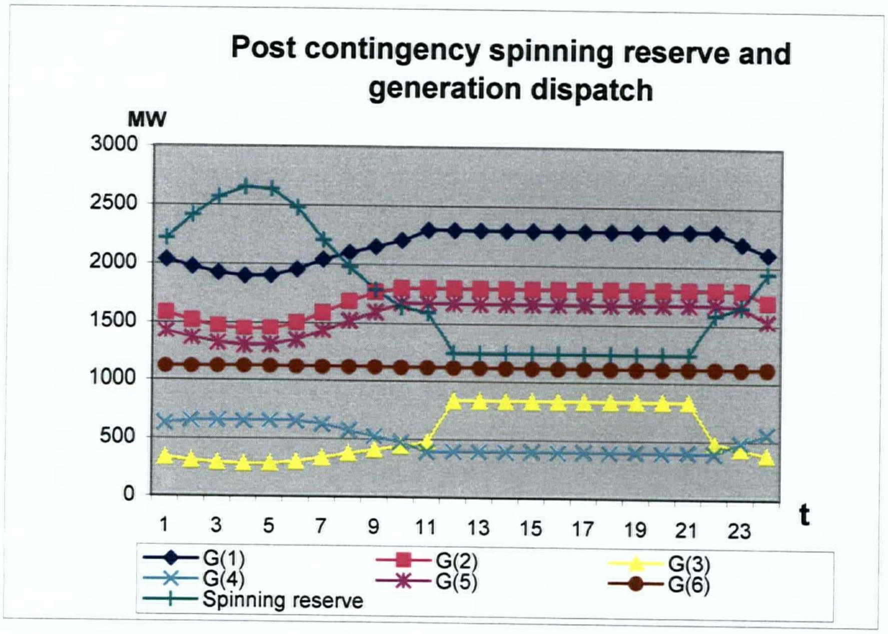

Figure 20 Post-contingency spinning reserve and generation scheduling of case #1

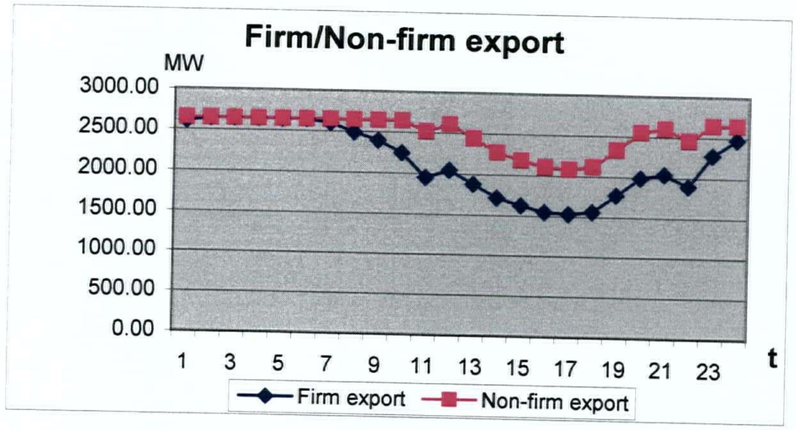

Figure 21 Export of pre-contingency and post-contingency cases

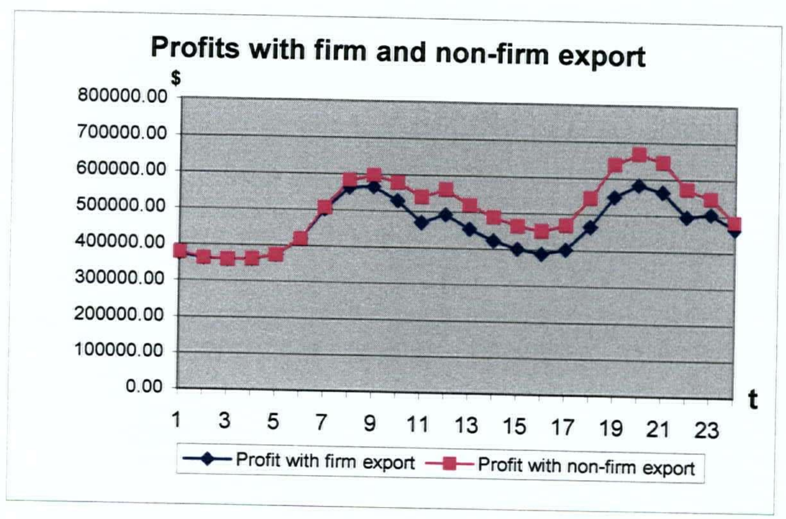

Figure 22 Profits with firm and non-firm export

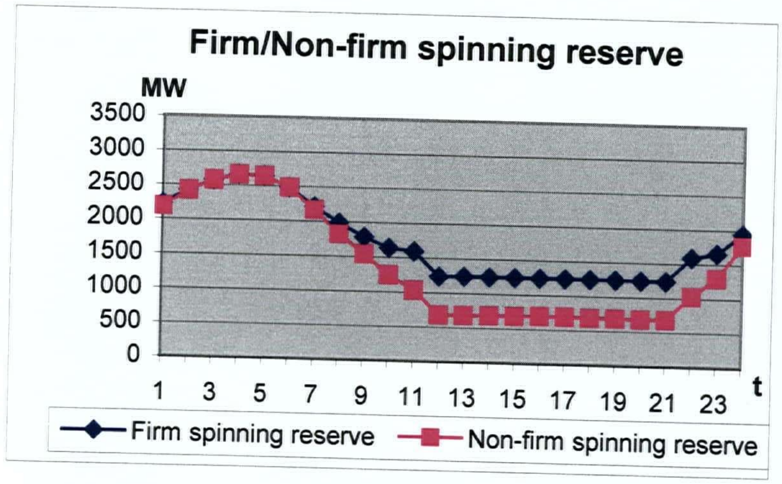

Figure 23 Firm and non-firm spinning reserve

From Figure 19 and 20, we can see that the generation dispatch changes with the consideration of transmission security constraints. In Figure 20, the generation dispatch of unit "G(1)","G(2)" and "G(4)" decrease compared with the dispatch pattern in Figure 22 from hour 7 to hour 24. This results in the spinning reserve increasing from pre-contingency to post-contingency, which is shown in Figure 23. Thus, the system achieves more security and reliability. With the decreased output of corresponding units from hour 7 to hour 24, the export in post contingency is less than that in pre-contingency, which can be found in Figure 21. The generation dispatch is not adjusted from hour 1 to hour 6 since the load pattern is not as high as it is in the later hours which cause the transmission constraints violated.

The results in Figure 21 show that the system exports power in each hour during the whole time horizon, either in the pre-contingency or post contingency situation. The electricity price in the external power market, which is higher than the local system marginal price, drives the

The results in Figure 21 show that the system exports power in each hour during the whole time horizon, either in the pre-contingency or post contingency situation. The electricity price in the external power market, which is higher than the local system marginal price, drives the system to generate extra power to export. From above Figures 21 and 22, we can see that the local GenCo earn more profits with the non-firm amount of export power compared with it with firm export, although the price of firm export is higher than that of non-firm export. However, it involves risks for customers to buy the non-firm export with lower price since the reliability of non-firm export is lower than that of firm export.

6.2.2 Case #2----- with medium load and medium market price pattern

In this case, both of system load and market price are of medium level. The assumption of firm and non-firm export price and system marginal price are as same as those assumed in case #1. The calculation results are in the following Table 8 and presented in Figures 24, 25, and 26.

Table 10 (a). The results of post-contingency generation dispatch in case #2

Hour	Generator output (MW)					
	G(1)	G(2)	G(3)	G(4)	G(5)	G(6)
1	906.93	713.12	0.00	268.89	609.72	524.24
2	849.51	664.20	0.00	231.00	563.95	476.32
3	811.73	631.97	0.00	207.26	533.94	444.81
4	791.32	614.68	0.00	194.52	517.73	427.75
5	795.96	617.92	0.00	196.93	520.74	430.87
6	833.61	650.67	0.00	221.10	551.43	463.08
7	2042.22	1587.26	337.57	628.56	1428.20	1117.38
8	2102.33	1683.46	374.69	573.72	1518.25	1116.52
9	2153.79	1765.82	406.48	526.76	1595.35	1115.78
10	2208.44	1800.00	439.38	476.90	1672.52	1115.01
11	2298.26	1800.00	476.94	394.94	1671.21	1114.14
12	2297.66	1800.00	835.10	395.49	1670.20	1113.47
13	2297.29	1800.00	834.78	395.83	1669.57	1113.05
14	2296.92	1800.00	834.47	396.17	1668.95	1112.63
15	2296.71	1800.00	834.30	396.36	1668.60	1112.40
16	2296.53	1800.00	834.15	396.52	1668.30	1112.20
17	2296.49	1800.00	834.11	396.56	1668.22	1112.15
18	2296.56	1800.00	834.18	396.49	1668.36	1112.24
19	2297.04	1800.00	834.57	396.06	1669.15	1112.77
20	2297.54	1800.00	835.00	395.60	1670.00	1113.33
21	2297.65	1800.00	835.09	395.50	1670.18	1113.45
22	2298.11	1800.00	484.01	395.08	1670.96	1113.97
23	2197.68	1800.00	433.59	486.72	1661.10	1115.15
24	2111.90	1698.77	380.60	564.98	1532.59	1116.38

Table 10 (b). Pre- and post-contingency power interchange and profits in case #2

Hour	Interchange (firm)	Interchange (non-firm)	Spinning reserve (firm)	Spinning reserve (non-firm)	Profit (firm)	Profit (non-firm)
1	-1500.00	-1500.00	5427.10	5427.10	26206.67	26206.67
2	-1500.00	-1500.00	5665.02	5665.02	25275.34	25275.34
3	-1500.00	-1500.00	5820.29	5820.29	24053.68	24053.69
4	-1500.00	-1500.00	5904.00	5904.00	23224.37	23224.37
5	-1500.00	-1500.00	5887.58	5887.58	22049.18	22049.18
6	-948.00	-948.00	5730.11	5730.11	21670.08	33770.91
7	2603.50	2650.00	2208.82	2162.33	68942.44	69151.97
8	2494.80	2650.00	1981.05	1825.87	113244.85	115567.50
9	2401.80	2650.00	1786.03	1537.81	121559.18	125873.60
10	2251.90	2650.00	1637.76	1239.64	110474.70	116491.20
11	1954.80	2521.65	1594.52	1027.68	99937.07	108010.30
12	2050.30	2614.15	1238.08	674.23	103335.30	110772.50
13	1884.60	2446.56	1239.48	677.52	93813.94	100147.30
14	1721.80	2281.95	1240.86	680.75	89095.40	95014.68
15	1630.50	2189.61	1241.64	682.56	83759.62	88859.58
16	1552.50	2110.70	1242.30	684.10	82797.68	87878.54
17	1532.40	2090.36	1242.47	684.50	92225.84	99372.98
18	1567.30	2125.61	1242.17	683.81	129649.56	144512.60
19	1774.40	2335.10	1240.42	679.70	166658.89	186855.40
20	1996.30	2559.51	1238.54	675.31	167292.54	185519.50
21	2044.30	2608.05	1238.13	674.35	150139.46	165187.40
22	1897.40	2463.49	1587.87	1021.77	122202.26	134392.70
23	2286.40	2650.00	1655.77	1292.15	93335.57	97181.67
24	2477.50	2650.00	1944.78	1772.30	57853.57	58178.76

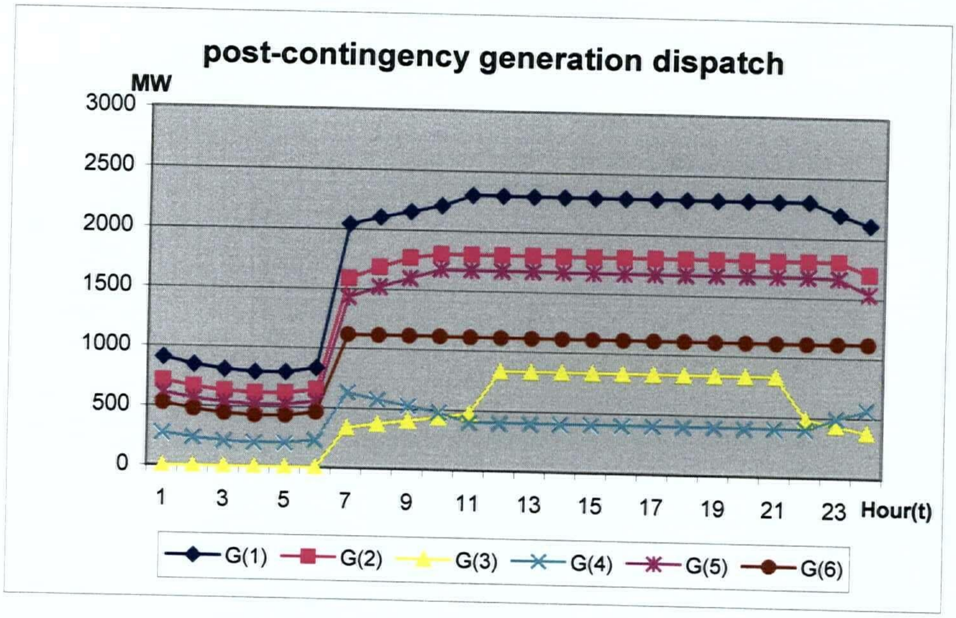

Figure 24 Post-contingency generation dispatch in case # 2

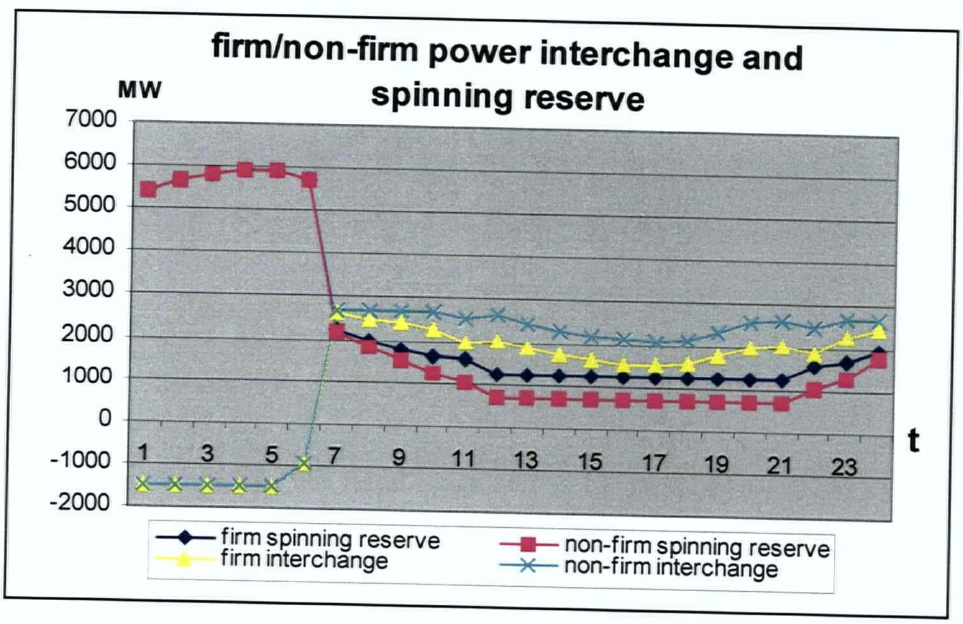

Figure 25 Comparison of power interchange and spinning reserve with firm /non-firm export

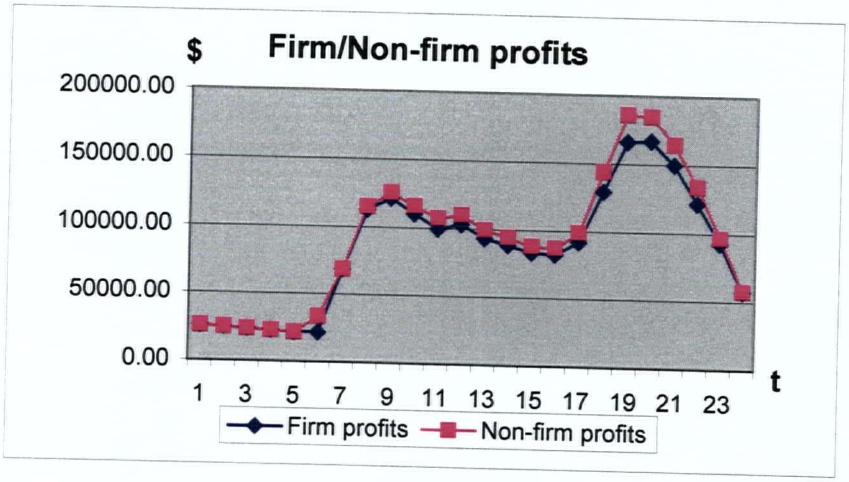

Figure 26 Profits with /without security constraints

In Figure 24, we present transmission security-constrained generation dispatch and spinning reserve. The pre-contingency generation dispatch and reserve will be omitted in this case and in all the other following cases as well, since they are not the main data need to be discussed. Since the external market price from hour 1 to hour 6 in this case is lower than system marginal price, the system imports power from external power market, which is shown in Figure 25. The market price from hour 7 to hour 24 is much higher than the corresponding system marginal price, therefore, the GenCo exports power to external market to gain much more profits than those in the import hours, which is illustrated in Figure 26. With the consideration of transmission security constraints, the export power in post-contingency situation is lower than that in the situation without consideration of security constraints. Therefore, the non-firm export is more than firm export, which is shown in Figure 25. The system imports the generation at the maximum limit level during the first 6 hours in both of pre-contingency and post-contingency cases, since the market price is much lower than system marginal price in both cases. This can be seen in Figure 25.

6.2.3 Case #3----- with medium load and lower market price pattern

In this case, system load is of medium level pattern, and market price is of lower level pattern.

The price is quite low during hour 1 to hour 7 and rise extensively a lot during hour 18 to hour 21. This drives the system power interchange from import to export, which is shown in Figure 28. The corresponding spinning reserve fluctuates dramatically when system changes its power interchange pattern from import to export, which is presented in the same Figure 28. The comparison of GenCos' profits between pre-contingency and post-contingency with the non-firm power interchange and firm power interchange is illustrated in Figure 29. All the related data to these three figures (Figures 27-29) are listed in Table 11.

Table 11 (a). The post-contingency generation dispatch in case # 3

Hour	Unit status						Generator output (MW)					
	U1	U2	U3	U4	U5	U6	G(1)	G(2)	G(3)	G(4)	G(5)	G(6)
1	1	1	0	1	1	1	906.93	713.12	0.00	268.89	609.72	524.24
2	1	1	0	1	1	1	849.51	664.20	0.00	231.00	563.95	476.32
3	1	1	0	1	1	1	811.73	631.97	0.00	207.26	533.94	444.81
4	1	1	0	1	1	1	791.32	614.68	0.00	194.52	517.73	427.75
5	1	1	0	1	1	1	795.96	617.92	0.00	196.93	520.74	430.87
6	1	1	0	1	1	1	833.61	650.67	0.00	221.10	551.43	463.08
7	1	1	0	1	1	1	911.12	716.38	0.00	269.62	612.98	527.61
8	1	1	0	1	1	1	992.88	786.15	0.00	320.90	678.22	595.97
9	1	1	0	1	1	1	1188.73	952.75	0.00	443.66	834.19	759.39
10	1	1	0	1	1	1	1135.58	907.54	0.00	410.34	791.86	715.04
11	1	1	0	1	1	1	1218.42	978.00	0.00	462.34	857.76	784.18
12	1	1	1	1	1	1	1209.10	970.10	200.00	355.71	850.38	776.39
13	1	1	1	1	1	1	1201.01	963.16	200.00	348.95	844.03	769.57
14	1	1	1	1	1	1	1192.30	955.83	200.00	339.67	836.98	762.42
15	1	1	1	1	1	1	1167.63	934.77	200.00	316.22	817.38	741.80
16	1	1	1	1	1	1	1185.10	949.60	200.00	332.80	831.30	756.30
17	1	1	1	1	1	1	1189.63	953.47	200.00	337.13	834.90	760.07
18	1	1	1	1	1	1	2296.56	1800.00	573.18	396.49	1668.36	1112.24
19	1	1	1	1	1	1	2297.04	1800.00	834.57	396.06	1669.15	1112.77
20	1	1	1	1	1	1	2297.54	1800.00	835.00	395.60	1670.00	1113.33
21	1	1	1	1	1	1	2297.65	1800.00	618.42	395.50	1670.18	1113.45
22	1	1	1	1	1	1	1870.23	1532.47	316.42	649.82	1376.90	1113.97
23	1	1	0	1	1	1	1122.78	896.72	0.00	402.34	781.70	704.36
24	1	1	0	1	1	1	1005.88	797.23	0.00	329.14	688.55	606.90

Table 11 (b). The power interchange, spinning reserve, and profits in both of pre- and post-contingency situation in case # 3.

Hour	Import (firm)	Export (firm)	Import (non-firm)	Export (non-firm)	Reserve (firm)	Reserve (non-firm)	Profit (firm)	Profit (non-firm)
1	1500.00	0.00	1500.00	0.00	5427.10	5427.00	40226.62	40226.00
2	1500.00	0.00	1500.00	0.00	5665.02	5665.00	38037.30	38037.00
3	1500.00	0.00	1500.00	0.00	5820.29	5820.00	36629.48	36629.00
4	1500.00	0.00	1500.00	0.00	5904.00	5904.00	35879.51	35879.00
5	1500.00	0.00	1500.00	0.00	5887.58	5887.00	36013.15	36013.00
6	1500.00	0.00	1500.00	0.00	5730.11	5730.00	37441.90	37441.00
7	1500.00	0.00	1500.00	0.00	5412.29	5412.00	36977.63	36977.00
8	1500.00	0.00	1500.00	0.00	5075.87	5075.00	27092.01	27092.00
9	983.00	0.00	983.00	0.00	4271.28	4271.00	30608.85	30608.00
10	1500.00	0.00	1500.00	0.00	4489.64	4489.00	33283.07	33283.00
11	1500.00	0.00	1500.00	0.00	4149.30	4149.00	38715.94	38715.00
12	1500.00	0.00	1500.00	0.00	4988.32	4988.00	45757.67	45757.00
13	1500.00	0.00	1500.00	0.00	5023.28	5023.00	51827.65	51827.00
14	1500.00	0.00	1500.00	0.00	5062.80	5062.00	56212.06	56212.00
15	1500.00	0.00	1500.00	0.00	5172.20	5172.00	60444.45	60444.00
16	1500.00	0.00	1500.00	0.00	5094.90	5094.00	61590.22	61590.00
17	1500.00	0.00	1500.00	0.00	5074.80	5074.00	57092.26	57092.00
18	0.00	1306.26	0.00	1860.00	1503.17	944.00	64098.53	65180.00
19	0.00	1774.39	0.00	2340.00	1240.42	679.00	80312.45	83928.00
20	0.00	1996.27	0.00	2560.00	1238.54	675.00	75071.36	77644.00
21	0.00	1827.60	0.00	2390.00	1454.80	891.00	63404.09	64323.00
22	0.00	995.06	0.00	995.00	2490.20	2490.00	51226.11	51225.00
23	1500.00	0.00	1500.00	0.00	4542.10	4542.00	38903.83	38903.00
24	1500.00	0.00	1500.00	0.00	5022.30	5022.00	44141.03	44141.00

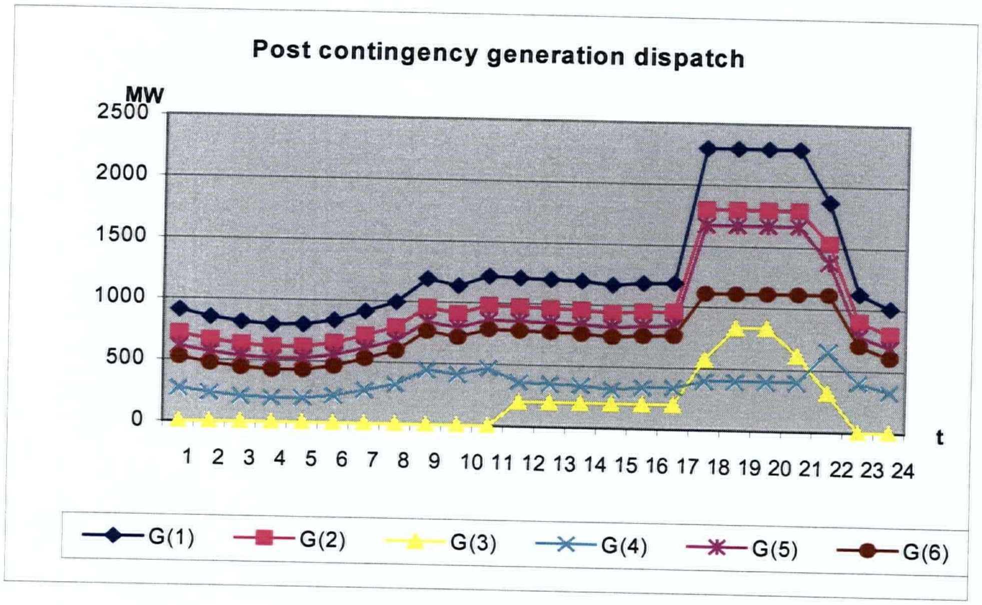

Figure 27 Post-contingency generation dispatch in case # 3

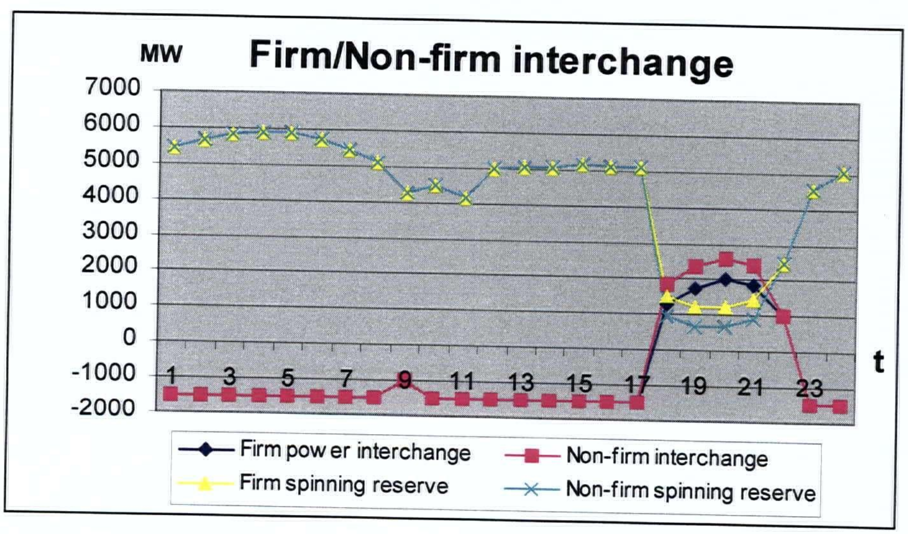

Figure 28 Firm/non-firm power interchange and spinning reserve

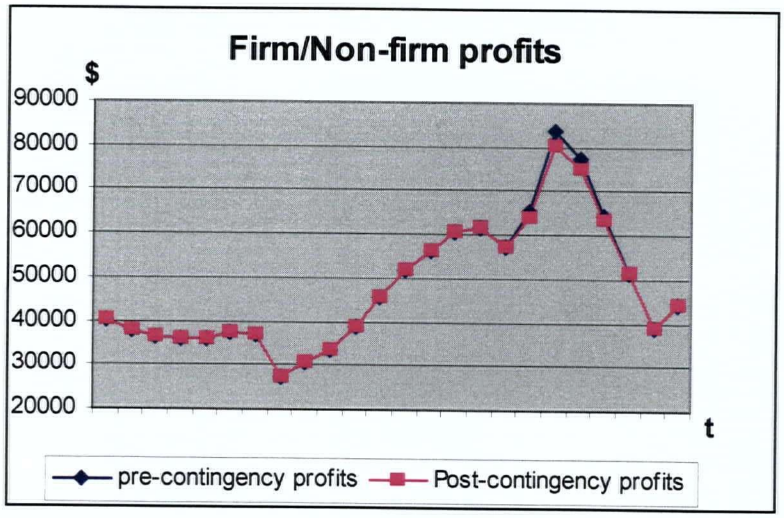

Figure 29 Profits in pre-contingency and post contingency cases

From above figures, we can see that the system imports power in most of hours, and only exports power from hour 18 to hour 22 when the market prices are higher than the system marginal price. The system has more spinning reserve during the hours of import than that during the hours of export. The total spinning reserve is much more than that in previous two cases. In post-contingency situation, the transmission limits are violated in the hours of export (from hour 18 to hour 22). Thus, the relief of transmission violation results in some decrease of export compared with the export in pre-contingency case, so does the profits. The slight changes of profits and spinning reserve, which can be seen in Figure 29 and 28, tell us that the system with medium load pattern and lower market price pattern is more secure and profitable compared with two previous cases.

6.2.4 Case #4----- with higher load and medium market price pattern

In case # 4, the system load is in higher level and market price is in medium level. The system interchanges power with external market following the same pattern as it happened in case # 2 (the market price is in medium level), importing power from hour 1 to hour 6, and exporting power during the left hours in 24 hours day-ahead time schedule. But the amount of interchange power varies from hour to hour, since the load patterns are different between these two cases. The results of generation dispatch with the security constraint consideration are listed in Table 12(a) and the results of power interchange, spinning reserve and profits are presented in Table 12(b).

Table 12(a). Generation dispatch in post-contingency situation in case # 4

Hour	Unit status						Generator output (MW)					
	u1	u2	u3	u4	u5	u6	G(1)	G(2)	G(3)	G(4)	G(5)	G(6)
1	1	1	0	1	1	1	1025.70	814.10	0.00	341.50	704.40	623.40
2	1	1	0	1	1	1	977.50	773.10	0.00	311.30	666.00	583.20
3	1	1	0	1	1	1	934.80	736.70	0.00	284.50	632.00	547.50
4	1	1	0	1	1	1	924.20	727.80	0.00	277.90	623.50	538.70
5	1	1	0	1	1	1	918.30	722.70	0.00	274.20	618.80	533.70
6	1	1	0	1	1	1	984.57	779.08	0.00	315.69	671.60	589.03
7	1	1	1	1	1	1	2158.24	1772.94	409.23	522.69	1602.03	1115.71
8	1	1	1	1	1	1	2237.38	1800.00	447.03	450.49	1672.25	1114.83
9	1	1	1	1	1	1	2298.31	1800.00	474.53	394.90	1671.29	1114.19
10	1	1	1	1	1	1	2297.63	1800.00	835.07	395.52	1670.15	1113.43
11	1	1	1	1	1	1	2296.87	1800.00	834.44	396.21	1668.88	1112.58
12	1	1	1	1	1	1	2296.59	1800.00	834.20	396.47	1668.40	1112.27
13	1	1	1	1	1	1	2296.14	1800.00	833.82	396.88	1667.64	1111.76
14	1	1	1	1	1	1	2295.91	1800.00	833.63	397.09	1667.26	1111.51
15	1	1	1	1	1	1	2295.68	1800.00	833.43	397.30	1666.87	1111.24
16	1	1	1	1	1	1	2295.78	1800.00	833.52	397.21	1667.04	1111.36
17	1	1	1	1	1	1	2295.49	1800.00	833.27	397.47	1666.55	1111.03
18	1	1	1	1	1	1	2295.51	1800.00	833.29	397.45	1666.59	1111.06
19	1	1	1	1	1	1	2296.49	1800.00	834.12	396.56	1668.23	1112.15
20	1	1	1	1	1	1	2296.36	1800.00	834.01	396.68	1668.02	1112.01
21	1	1	1	1	1	1	2296.13	1800.00	833.82	396.89	1667.63	1111.75
22	1	1	1	1	1	1	2297.09	1800.00	834.62	396.01	1669.24	1112.83
23	1	1	1	1	1	1	2298.11	1800.00	484.04	395.08	1670.96	1113.97
24	1	1	1	1	1	1	2175.75	1800.95	420.04	506.73	1628.25	1115.46

Table 12(b). Power interchange, spinning reserve and profits in both of pre and post-contingency situation in case #4

Hour	Interchange (firm)	interchange (non-firm)	Reserve (firm)	Reserve (non-firm)	Profit (firm)	Profit (non-firm)
1	-1500.00	-1500.00	4940.90	4940.90	30421.02	30400.00
2	-1500.00	-1500.00	5138.90	5138.90	29649.3	29600.00
3	-1500.00	-1500.00	5314.50	5314.50	28150.57	28200.00
4	-1500.00	-1500.00	5357.90	5357.90	27606.16	27600.00
5	-1500.00	-1500.00	5382.30	5382.30	26113.39	26100.00
6	-1500.00	-1500.00	5110.04	5110.04	19700.5	19700.00
7	2393.73	2650.00	1769.15	1512.87	71690.44	70600.00
8	2192.29	2650.00	1628.02	1170.31	109512.69	114000.00
9	1974.33	2541.42	1596.78	1029.69	111949.99	119000.00
10	2036.37	2600.06	1238.19	674.51	112321.21	116000.00
11	1702.82	2262.72	1241.02	681.12	101860.29	105000.00
12	1579.48	2137.97	1242.07	683.57	95805.4	98500.00
13	1379.87	1936.10	1243.76	687.53	87579.68	89200.00
14	1279.74	1834.83	1244.61	689.51	84329.7	85500.00
15	1176.29	1730.21	1245.48	691.56	80073.97	80500.00
16	1222.71	1777.16	1245.09	690.64	80191.17	80500.00
17	1093.40	1646.38	1246.19	693.21	86008.62	88400.00
18	1104.01	1657.11	1246.09	693.00	112171.65	122000.00
19	1534.38	2092.37	1242.45	684.46	153656.68	169000.00
20	1478.02	2035.36	1242.93	685.58	142173.22	156000.00
21	1377.22	1933.42	1243.78	687.58	124164.44	135000.00
22	1799.64	2360.64	1240.20	679.20	125683.77	133000.00
23	1897.13	2463.23	1587.84	1021.74	88265.71	91600.00
24	2362.08	2650.00	1702.82	1414.90	59991.85	58100.00

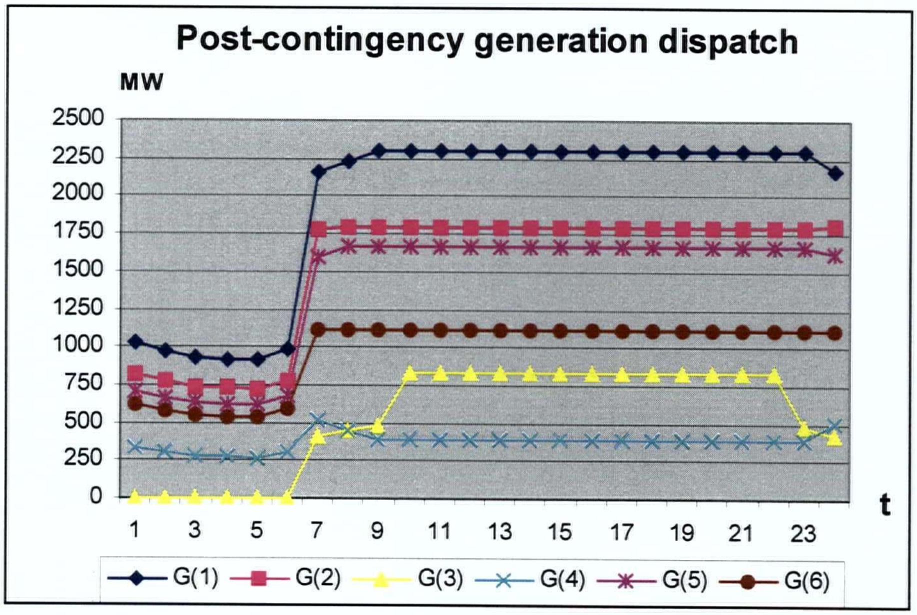

Figure 30 Post-contingency generation dispatch in case # 4

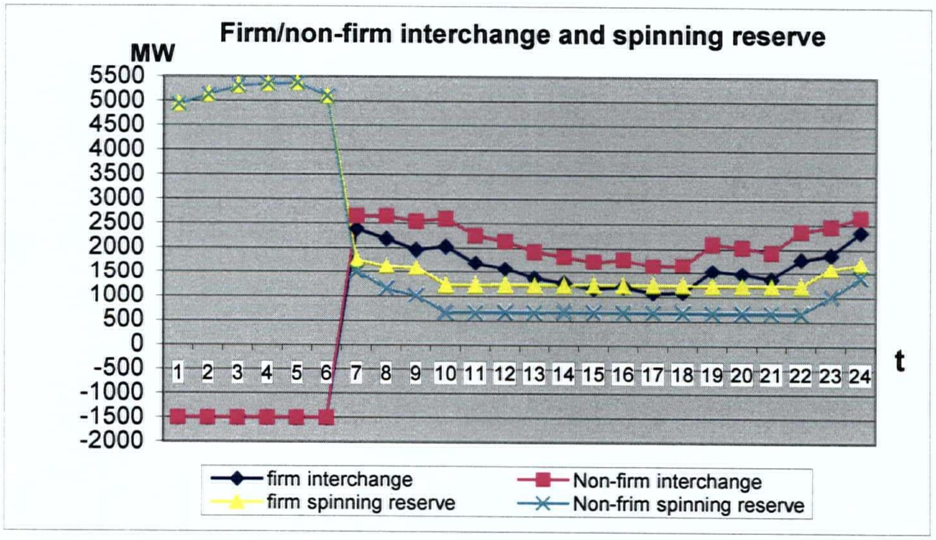

Figure 31 Firm/Non-firm power interchange and spinning reserve

Figure 32 External market price

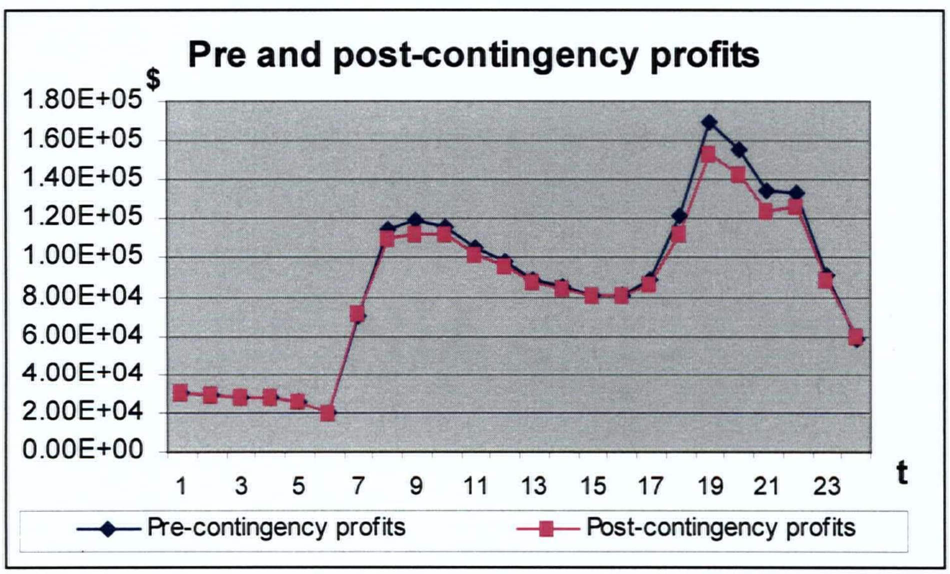

Figure 33 Pre- and post-contingency profits

From above figures, we can see that the system imports power from hour 1 to hour 6 and exports power from hour 7 to hour 24 in either pre-contingency or post contingency. With the security constraints, the export power decreases compared with the value in pre-contingency in each hour during the export period. The spinning reserve in post-contingency is larger than that in pre-contingency in each hour from hour 7 to hour 24. Thus, the system achieves more security and reliability by saving more spinning reserve, but it loses certain profits due to the decreased export, which is shown in Figure 33. Although this case has the same market price pattern as case #2 has, the GenCo gains less profit in both of pre- and post-contingency cases than they do in case # 2.This is resulted from the decreased export in this case due to the higher load. The curves of profit shown in Figure 33 almost follow the same pattern as the pattern of market price presented in Figure 32.

6.2.5 Case #5----- with lower load and medium market price pattern

In case # 5, the system has lower load pattern, and the external market has the medium market price pattern. The interests of modeling this case is to see the difference of profits between this case and case # 2, and the affects of security constraints to profits and power interchange. The following Table 13 (a) listed the generation dispatch in post-contingency, and the results of power interchange, spinning reserve and profits are presented in Table 13 (b).

Table 13 (a). Post-contingency generation dispatch in case # 5

Hour	Unit status						Generator output (MW)					
	u1	u2	u3	u4	u5	u6	G(1)	G(2)	G(3)	G(4)	G(5)	G(6)
1	1	1	0	1	1	1	750.30	579.80	0.00	168.80	485.00	393.50
2	1	1	0	1	1	1	707.20	543.10	0.00	141.80	450.70	357.60
3	1	1	0	1	1	1	667.58	509.43	0.00	120.00	419.16	324.54
4	1	1	0	1	1	1	652.28	496.42	0.00	120.00	406.98	311.77
5	1	1	0	1	1	1	636.60	483.08	0.00	120.00	394.50	298.69
6	1	1	0	1	1	1	967.70	764.73	0.00	305.11	658.17	574.96
7	1	1	1	1	1	1	1855.16	1410.51	269.35	652.73	1262.73	1118.97
8	1	1	1	1	1	1	1955.14	1494.54	301.78	652.29	1341.39	1118.21
9	1	1	1	1	1	1	2017.77	1547.18	322.09	652.02	1390.67	1117.74
10	1	1	1	1	1	1	2059.81	1615.41	348.43	612.51	1454.55	1117.13
11	1	1	1	1	1	1	2116.54	1706.21	383.47	560.74	1539.55	1116.31
12	1	1	1	1	1	1	2141.80	1746.63	399.07	537.70	1577.39	1115.95
13	1	1	1	1	1	1	2178.92	1800.00	422.00	503.83	1633.00	1115.42
14	1	1	1	1	1	1	2197.95	1800.00	433.76	486.47	1661.51	1115.14
15	1	1	1	1	1	1	2021.70	1554.43	324.89	647.28	1397.46	1117.67
16	1	1	1	1	1	1	2213.80	1800.00	441.23	472.00	1672.45	1114.97
17	1	1	1	1	1	1	2274.34	1800.00	455.67	416.77	1671.95	1114.63
18	1	1	1	1	1	1	2279.62	1800.00	456.90	411.95	1671.91	1114.60
19	1	1	1	1	1	1	2165.29	1784.22	413.59	516.26	1612.59	1115.61
20	1	1	1	1	1	1	2169.05	1790.24	415.91	512.83	1618.22	1115.56
21	1	1	1	1	1	1	2185.38	1800.00	425.99	497.94	1642.68	1115.32
22	1	1	1	1	1	1	2124.18	1718.43	388.19	553.78	1550.99	1116.20
23	1	1	1	1	1	1	2060.16	1615.98	348.65	612.19	1455.08	1117.12
24	1	1	1	1	1	1	1933.89	1476.68	294.88	652.38	1324.67	1118.37

Table 13 (b). Pre- and post-contingency cases power interchange, spinning reserve and profits

Hour	Interchange (firm)	Interchange (non-firm)	Reserve (firm)	Reserve (non-firm)	Profit (firm)	Profit (non-firm)
1	-1500.00	-1500.00	6072.60	6070.00	21153.62	21200.00
2	-1500.00	-1500.00	6249.60	6249.51	20830.10	20800.00
3	-1500.00	-1500.00	6409.29	6409.29	19694.19	19700.00
4	-1500.00	-1500.00	6462.55	6462.55	19154.24	19200.00
5	-1500.00	-1500.00	6517.12	6517.12	17498.07	17500.00
6	-361.45	-361.45	5179.35	5179.35	16238.38	16200.00
7	2650.00	2650.00	2780.56	2780.00	64222.83	62200.00
8	2650.00	2650.00	2486.65	2490.00	112324.10	110000.00
9	2650.00	2650.00	2302.55	2300.00	123529.72	121000.00
10	2571.71	2650.00	2142.16	2060.00	113111.67	111000.00
11	2469.12	2650.00	1927.17	1750.00	107454.68	106000.00
12	2423.46	2650.00	1831.47	1600.00	101572.40	100000.00
13	2350.32	2650.00	1696.83	1400.00	92911.85	91700.00
14	2285.46	2650.00	1655.18	1290.00	88800.71	87600.00
15	2640.61	2650.00	2286.57	2280.00	80638.60	77900.00
16	2237.36	2650.00	1635.55	1220.00	81915.82	80300.00
17	2125.42	2650.00	1616.65	1090.00	94025.92	95100.00
18	2115.87	2650.00	1615.02	1080.00	143716.01	152000.00
19	2380.98	2650.00	1742.44	1470.00	192503.19	198000.00
20	2374.19	2650.00	1728.20	1450.00	178709.69	183000.00
21	2328.30	2650.00	1682.69	1360.00	154640.73	159000.00
22	2455.32	2650.00	1898.23	1700.00	137505.69	138000.00
23	2571.07	2650.00	2140.83	2060.00	93156.25	90800.00
24	2650.00	2650.00	2549.11	2550.00	52605.01	50200.00

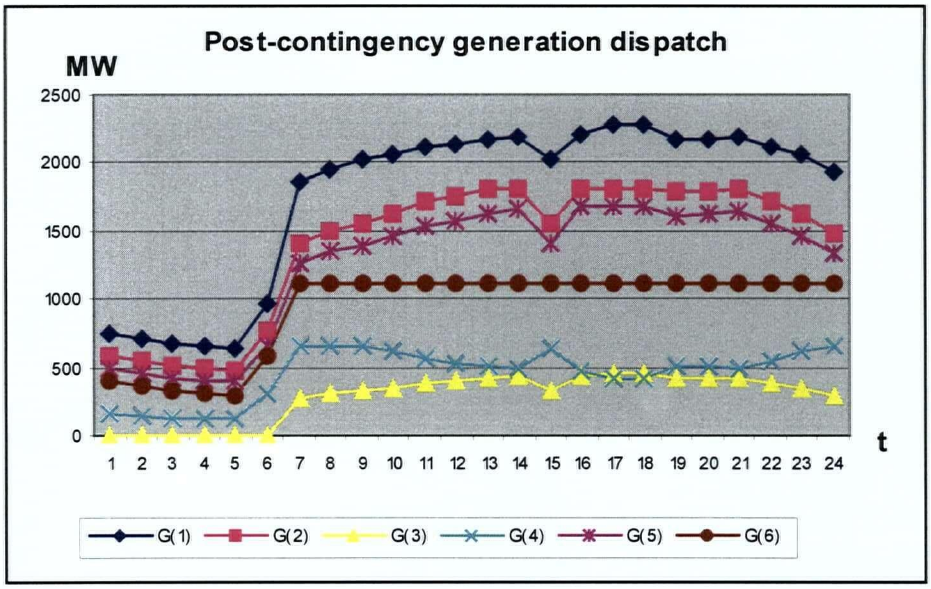

Figure 34 Post-contingency generation dispatch in case # 5

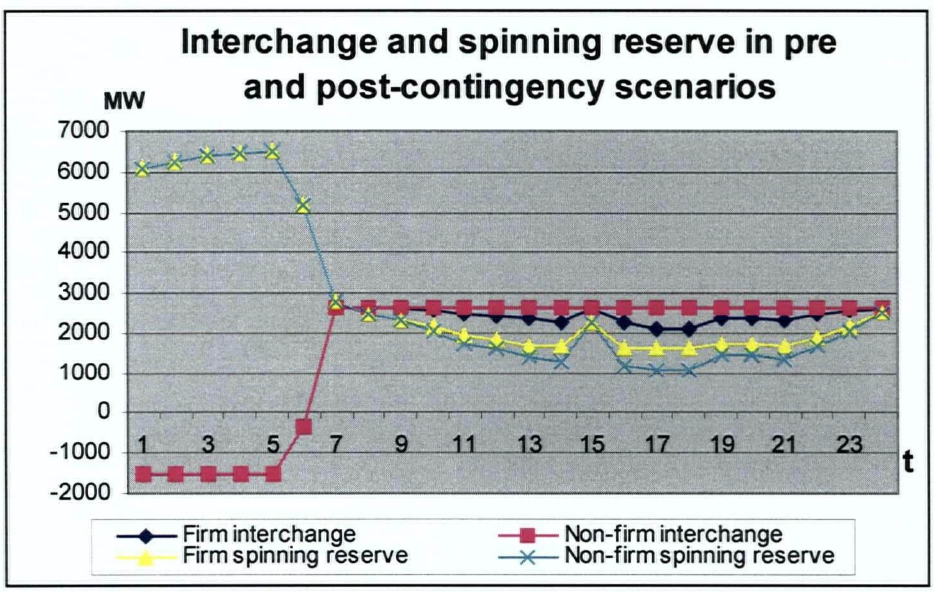

Figure 35 Firm/Non-firm power interchange and spinning reserve

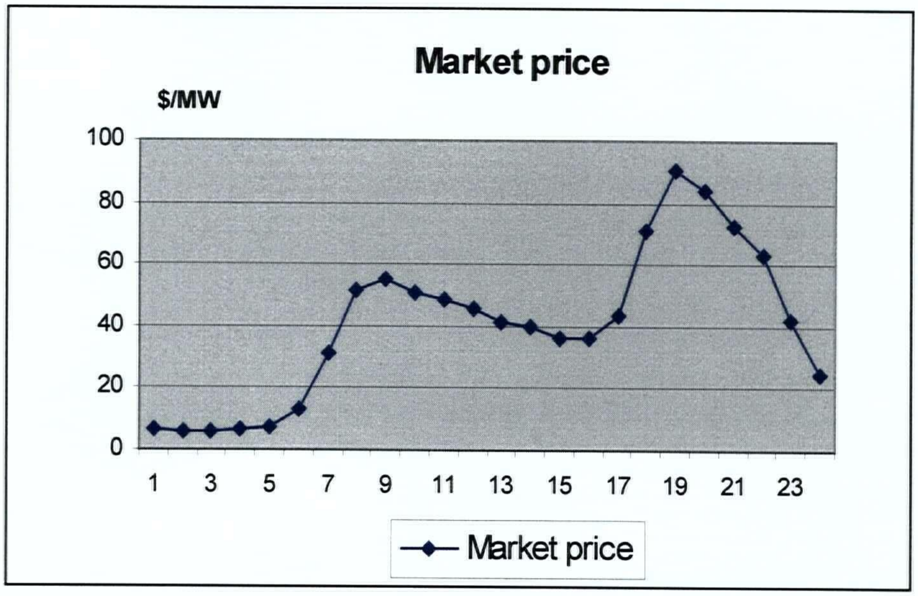

Figure 36 The external market price

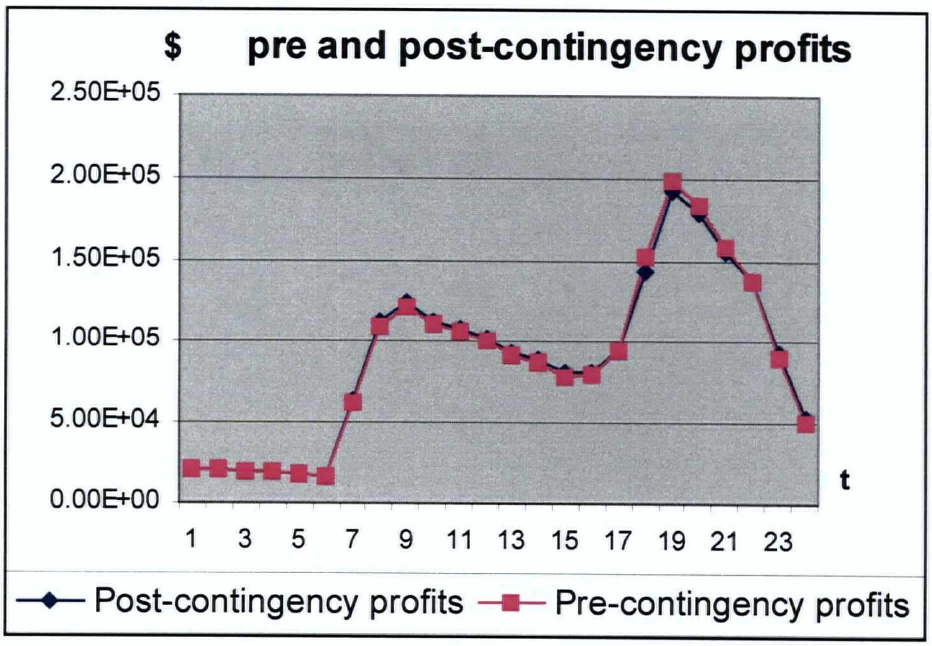

Figure 37 Pre-contingency and post-contingency cases profits

There are only several hours with the transmission violation relief during the 24 hour time schedule, therefore, the differences of export, spinning reserve and profits between pre-contingency and post-contingency are quite small, which are shown in Figures 35 and 37. Since the load pattern in this case is the lowest, the profits in post-contingency case is the highest compared with the profits in case # 2 and case # 4 due to the large export amount. Therefore, when the system is at lower load level and medium external price level, the post-contingency dispatch is the optimal solution since it makes the system more secure and gains the most profits.

Chapter 7

CONCLUSIONS AND RECOMMENDATION FOR FUTURE WORK

This thesis have presented a new approach to operational planning optimization of hydro-generation with consideration of transmission security constraints in a competitive environment. The mixed integer non-linear unit commitment problem is solved by Lagrangian relaxation technique. The security-constrained economic dispatch is optimized by Lagrangian function with the first gradient solution. The best feasible solution of objective function, which satisfies the network constraints and unit constraints, are effectively obtained by heuristic search consisting of unit substitution, unit decommitment and generation dispatch adjustment. This approach is tested on the simplified BC Hydro 500 kV system. The results show that the procedure performs in high efficiency with total computation time less than 2 minutes for 24 hours.

In deregulated power industry, the demand and market-based price fluctuate by time. This makes the operation scheduling more difficult compared with traditional short-time dispatch scheduling. In this work, we have omitted the effects of different bidding strategies and taken the Pennsylvania-New Jersey-Maryland (PJM) market price as our external market price. The forecasted load pattern is achieved from fuzzy logic model of our group research work done earlier. The selling price of generation to local customers is set up based on average unit marginal cost. Using these calculated data may drive the results slightly away from the reality, but it is easy to substitute all of these assumed data by the real data whenever they are available.

In this thesis work, the proposed approach performs effectively and efficiently to maximize the power suppliers' profits from the day-ahead transmission security-constrained generation scheduling in a competitive restructured power market. It also generates the by-product of calculation of spinning reserve costs for GenCos whenever system spinning reserve has to be used to balance the high level load. It will further provide the instructions to the suppliers to do the market-based real-time dispatch at the most economical level and lowest risk level with the consideration of network security. Further more, it would support the power market to operate transparently and consistantly during the competitive generation bidding period.

With the fast-paced development of restructured power industry, many new technologies are being researched to solve power system problems, especially in operational generation scheduling. Some new heuristic approaches such as partical swarm optimization [46] and ant colony model [47] are being studied to solve the large-scale mixed integer non-linear problems, in order to replace the classical Lagrangian relaxation method to avoid its locally optimal results and non-guaranteed convergence. For more complex and expanding power system, N-2 or N-3 contingency criteria is suggested to be used instead of using N-1 contingency to enhance the system security and reliability level. Thus, in our future work, the security constraints should be extended from N-1 contingency scenario to either N-2 or N-3 contingency to match the new reliability requests. Developing a new approach, which is more robust and efficient in computation time, is also a target to further improve the work.

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APPENDIX

Software framework:

The core software developed consists of several different functions. Each function is developed for individual targets to fulfill the whole approach for this thesis. They are listed as follows:

- Main
- LRUCED
- EXSPRE
- SeContin
- MinUp-Down

The following section will present the detailed description of each function above.

1.1 Main

An input and output diagram of the function "main" is given below:

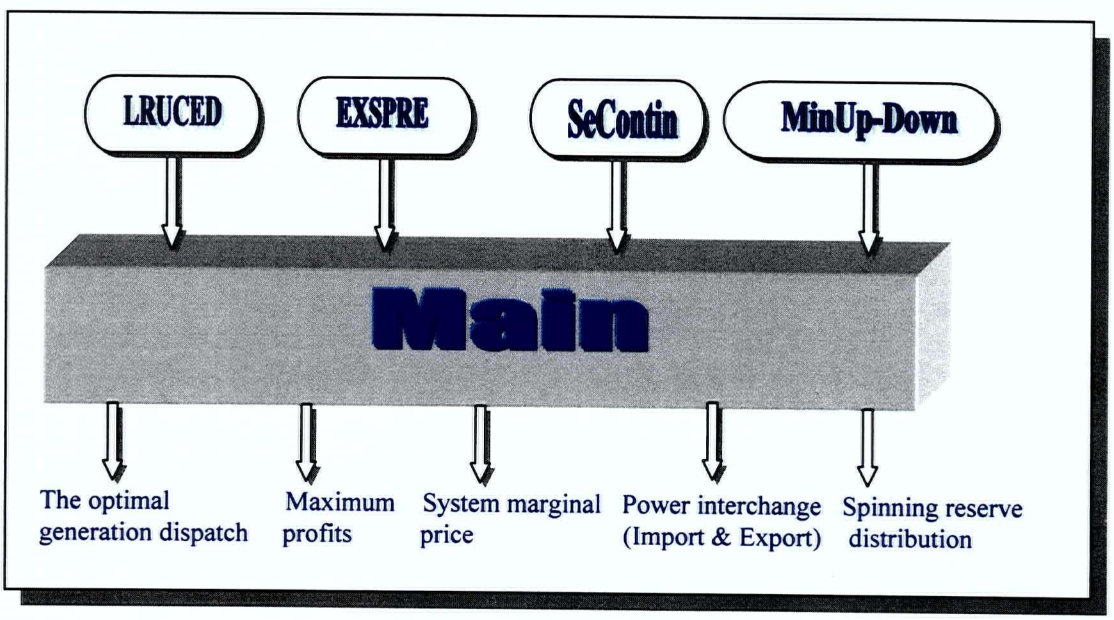

Figure 38 Input/output diagram for Main function

This function runs the program to calculate security constrained optimal generation scheduling for the generation suppliers in restructured bulk power market to obtain the maximum profits during the specified look-ahead time period in accordance with the forecasted local area load demand and electricity market price. The four functions, which are LRUCED, EXSPRE, SeContin and MinUp-Down, consist of the algorithms and relevant database to be used to calculate the output including optimal generation dispatch, the maximum profits, system marginal price, spinning reserve distribution and power interchange with the external power market.

1.2 LRUCED

An input and output diagram of the function " LRUCED" is illustrated below.

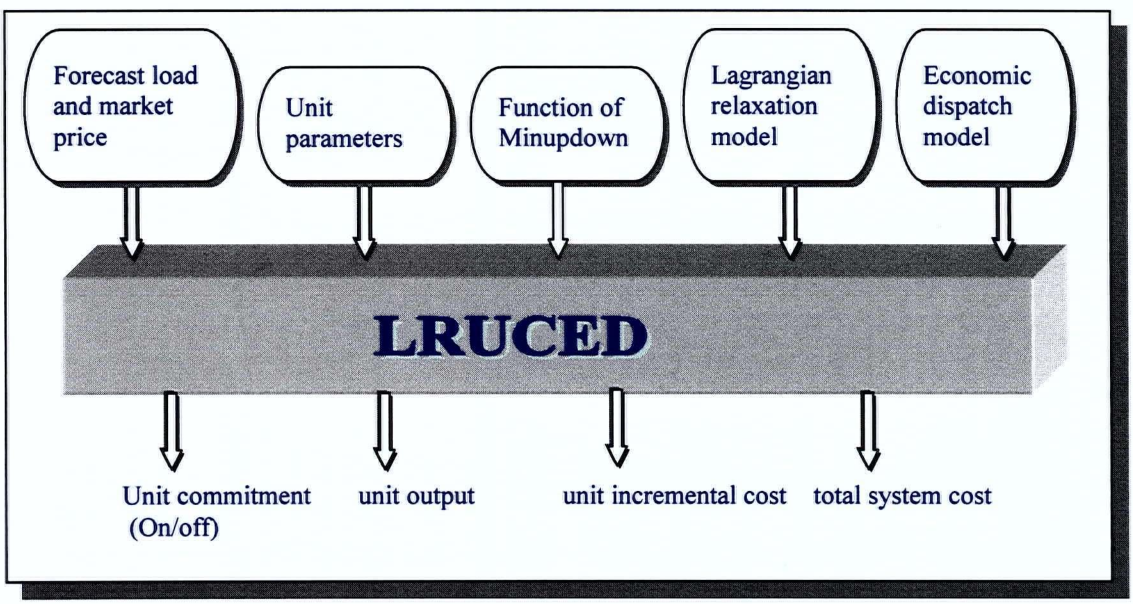

Figure 39 Input/output diagram for LRUCED function

This function, given the forecast load demand, external market price and each unit's parameters including minimum output, maximum output and cost function, will run the designed function of minimum up/down time constraint, Lagrangian relaxation model and economic dispatch model. The status of unit commitment, each on line unit output, unit incremental cost and total generation cost in system are directly achieved from this LRUCED function. Since only the system equality constraint and unit inequality constraints are considered in this function, each unit commitment and its output are the temporary results, which will be updated in the further calculation to satisfy the other system constraints.

1.3 EXSPRE

The input/output diagram of function " EXSPRE" is describe as follows:

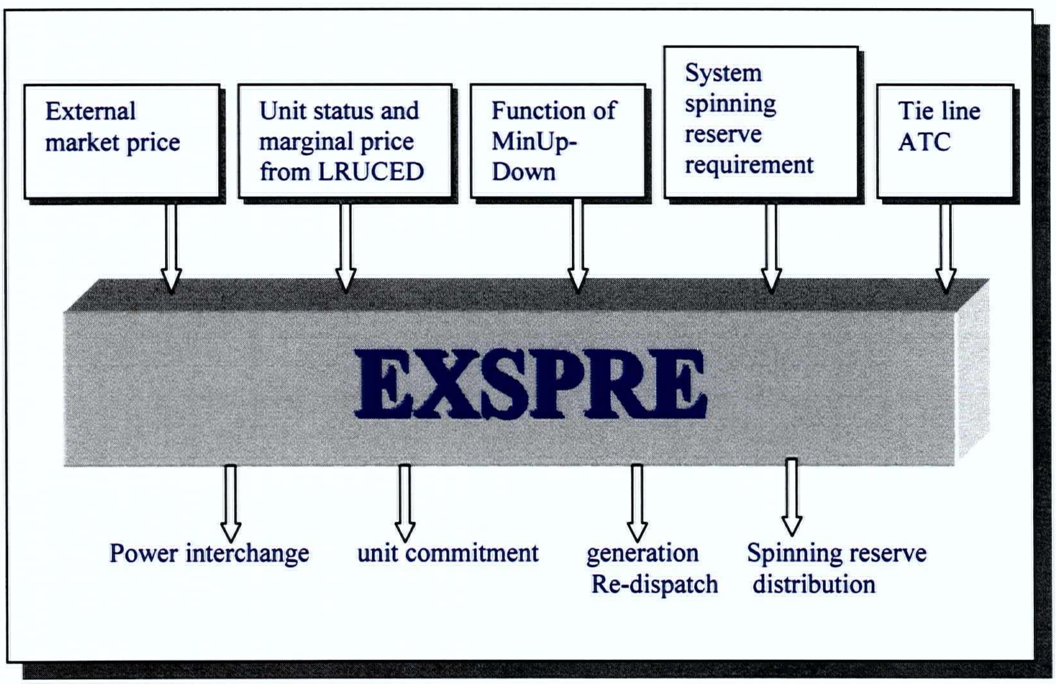

Figure 40 Input/output diagram for EXSPRE function

This function, with the required input data of external market price, unit commitment, system marginal price from LRUCED calculation, minimum up/down time constraints, system spinning reserve requirement, and given information of tie line ATC, will calculate the power interchange (import and export) with neighboring area and obtain the updated unit commitment, generation re-dispatch and system spinning reserve distribution. The results of unit status and generation dispatch are still not the final solution at this step since the system security constraints are not considered yet. The same happens to the power interchange amount, which may be needed to be adjusted for the system security requirements in function " SeContin".

1.4 SeContin

The input/output diagram of the function " SeContin" is shown below.

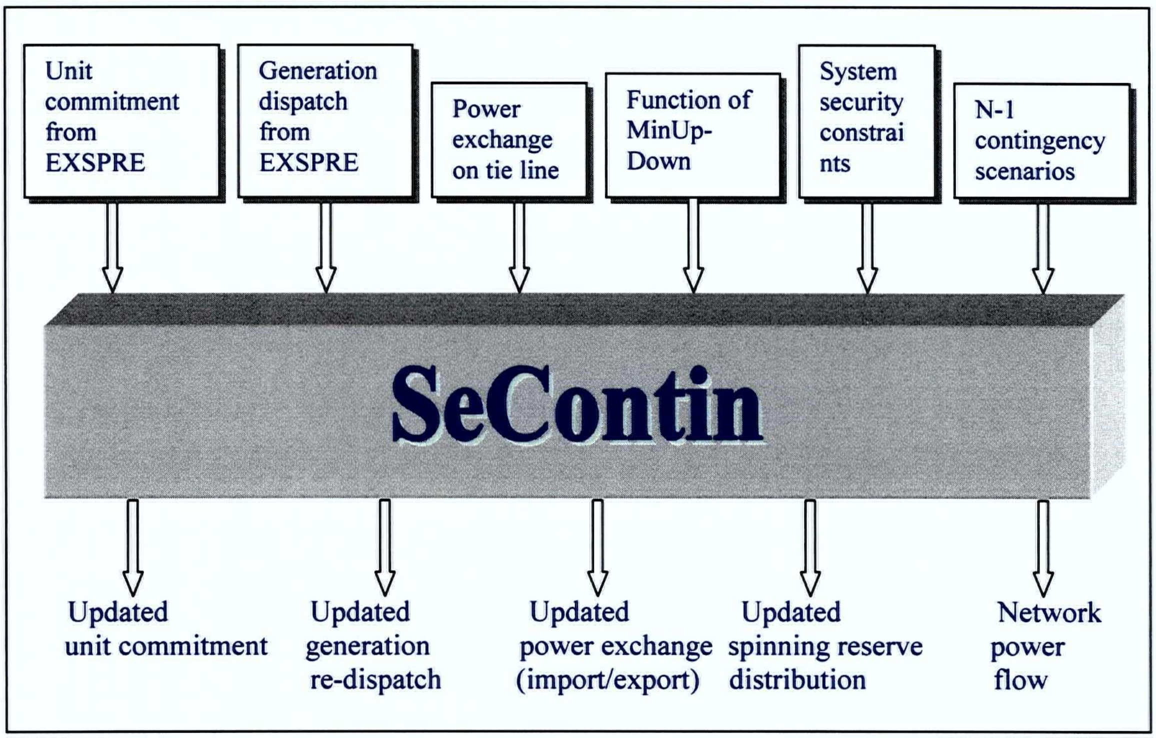

Figure 41 Input/output diagram for SeContin function

In this function, the solution of commitment, generation dispatch and power interchange from the function "EXSPRE" will be tested again with the consideration of system security constraints for the chosen post-N-1 contingency scenarios. Minimum up/down time constraints are also under consideration for the eventual unit commitment. With all of these input, running this function will obtain the outputs, which are updated unit commitments, generation re-dispatch, final power exchange and spinning reserve distribution and power flow on each transmission branch in the whole network.

1.5 MinUp-Down

The input/output diagram of the function " MinUp-Down" is presented in the following Figure 23.

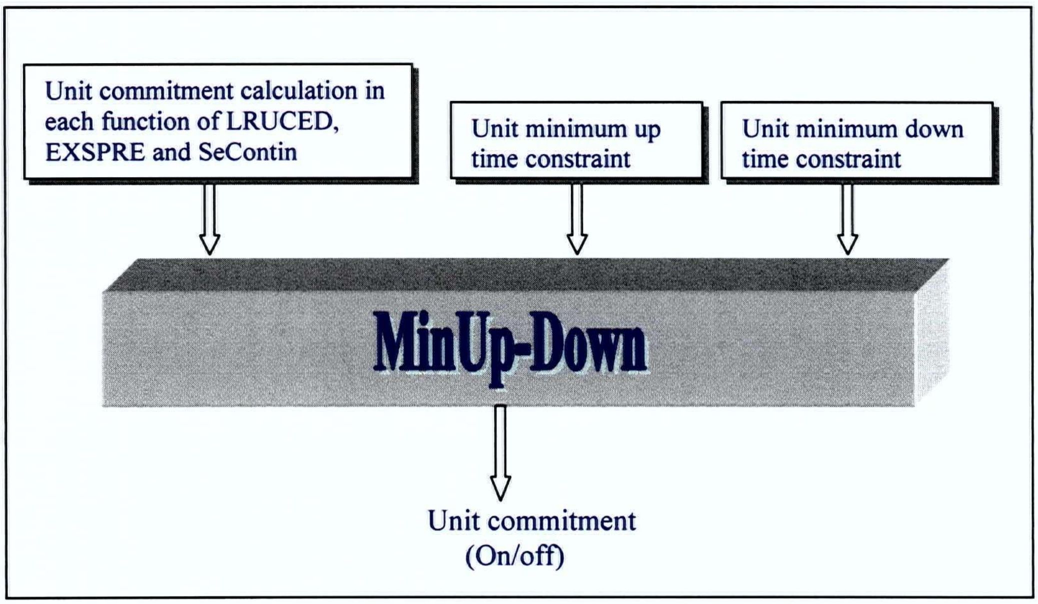

Figure 42 Input/output diagram for MinUp-Down function

MinUp-Down is a small function that is used to adjust the unit commitment obtained from relevant calculation in each function of LRUCED, EXSPRE and SeContin, in order to satisfy the unit minimum up and down time constraints. The output is the updated unit on/off status from the original results.