World Applied Sciences Journal 10 (9): 1084-1105, 2010
ISSN 1818-4952

A Comparison of Risk-constrained Mechanisms for Reserve Provision in Competitive Electricity Markets

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Abstract: Operating reserve assessment has become increasingly important in the new utility environment in which ancillary services have been assigned a value and purchased in a competitive market. This paper first presents a procedure for compulsory provision of spinning reserve using a risk-constrained cost-based mechanism and then proposes a competitive market structure for spinning reserve procurement. In both mechanisms, the electrical energy and spinning reserve are dealt with simultaneously because the procurement of reserve cannot be decoupled from the procurement of energy. Generators are paid the opportunity cost associated with their reduced energy because compulsion is financially unattractive among them. The transmission system reliability is considered in a simplified manner when computing composite system risk. The acceptable risk level is determined through cost-benefit analyses. In the proposed competitive market structure, the Independent System Operator (ISO) is responsible for reliability management and is thus responsible for purchasing sufficient reserve on behalf of the users of the system. The results are compared and discussed by application to the IEEE-RTS and the RBTS. The General Algebraic Modeling System (GAMS Rev. 140) is used to solve the mixed integer nonlinear co-optimization problems.

Key words: Co-optimization . electricity market . reliability . reserve . risk . transmission . unit commitment

INTRODUCTION

For about a hundred years, the electricity supply industry was in hands of vertically integrated monopoly utilities. Electricity market restructuring has been underway for more than a decade since the United Kingdom opened a Power Pool in April 1990. Restructuring has resulted in greater competition, emphasis on efficiency and reliability and the development of a market structure for trading and supplying electrical energy and ancillary services [1, 2].

Electric power systems are typically operated at least cost subject to technical and reliability constraints. Reserve assessment is a very important issue in operational planning of electric power systems because providing reliable service for electricity consumers is equivalent to having sufficient generation reserve. Unit commitment (UC) and optimal power flow (OPF) are two major elements in system operational planning [3].

The process of determining the startup or shutdown schedule of generating units is referred to as Unit Commitment (UC) [3, 4]. In the traditional UC model, the objective is to minimize system operating costs for supplying the system load while satisfying various system and unit constraints. In a deregulated power industry, the pool implements a power auction based on a UC model. It is a standard practice for suppliers to bid their price-based supply curves. These supply curves are not necessarily identical to the respective marginal costs. Supply bids include real power (MW) and ancillary services. Suppliers submit their bids to supply the forecasted daily demand. Each bid consists of a price function and a set of parameters that define the operative limits of the generating unit. After the ISO solves the UC problem, the Market Clearing Price (MCP) is determined for each time period [4].

Traditionally, reliability constraints in the UC problem are based on the (N-1) criterion, which means that there must be sufficient reserve on the system such that no load will lose power if any one line or any one generator fails. A more consistent and realistic criterion would be based on probabilistic methods. A risk index based on such methods would enable a consistent comparison to be made between various operating strategies and the economics of such strategies. The acceptable risk level is a management decision made by the Independent System Operator (ISO) based on economic and social requirements. A major element in the determination of an appropriate risk level is reliability cost (the cost needed to achieve a certain

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level of reliability) and reliability worth (the benefit derived by the utility, consumer and society) assessment of a power system [1, 5].

Several excellent references are available which provide a detailed description of reliability constrained operational planning and reserve assessment [5-21]. Billinton and Allan [5] recommended that systems be operated based on both the level of risk and the economic benefits associated with them. Prada and Ilic [6] proposed the allocation of operating reserve in power systems through competitive capacity markets using a probabilistic approach. Flynn *et al*. [7] suggested a method of generation scheduling in a competitive market that considers the Value of Lost Unit (VOLU) as a reliability index of generating units. Li and Shahidehpour [8] introduced a security-constrained unit commitment model with emphases on the simultaneous optimization of energy and ancillary services markets. Allen and Ilic [9] described the general form that a market for reserve can take. Billinton and Fotuhi-Firuzabad [10] developed a reliability framework for generating unit commitment using well-being analysis. This paper will attempt to improve the work carried out by these references considering several important points. The proposed method solves the unit commitment (UC) and the optimal power flow (OPF) problems simultaneously and considers the transmission network in three respects: the limited transmission line capacities, the network losses and the transmission system reliability. Two mechanisms of reserve provision are compared in the paper in terms of economic efficiency.

The structure of this paper is as follows: Section 2 describes concepts of reliability and reserve in operating phase and reviews the main issues of unit commitment risk and transmission system reliability. A brief introduction to competitive electricity market structure is provided in Section 3 In Section 4, the proposed methodology is studied and the problem formulation is done. Numerical examples comprising the application of the proposed methodology are presented and discussed in Sections 5 and 6, and finally, the paper is concluded in Section 7.

RELIABILITY AND RISK IN OPERATING PHASE

There are many variations on the definition of reliability, but a widely accepted form [22] is as follows: Reliability is the probability of a system performing its purpose adequately for the period of time intended under the operating conditions encountered. Traditionally, the basic techniques for reliability evaluation have been categorized in terms of their

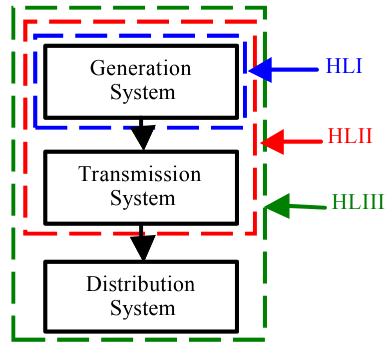

Fig. 1: Electric power system hierarchical level diagram [5]

application to the main functional zones of an electric power system. These are: generation system, composite generation and transmission (or bulk power) system and distribution system. The concept of Hierarchical Levels (HL) has been developed in order to establish a consistent means of identifying and grouping these functional zones. These are illustrated in Fig. 1, in which the first level (HLI) refers to generation facilities, the second level (HLII) refers to the composite generation and transmission (bulk power) system and the third level (HLIII) refers to complete system including distribution [5]. In this paper, the HLII reliability is studied in a competitive market environment.

The time span for an electric power system is divided into two sectors: the planning phase and the operating phase. In power system operation, sufficient generation must be scheduled according to the forecasted load. Reserve generation must also be scheduled in order to account for possible outages of generation units and transmission components [5].

Operating reserve can be generally divided into the two classes of spinning reserve and supplemental reserve. The Federal Energy Regulatory Commission of the United States (FERC) has defined the spinning reserve as the provision of generating capacity (usually with governors and AGC) that is synchronized to the grid, is unloaded, can respond immediately to correct for generation/load imbalances caused by generation and transmission outages and that is fully available within 10 minutes [23]. Traditionally, operating reserve requirements have been based on either deterministic or probabilistic approach. In deterministic approach, reliability constraints are based on technical standards/operator experience. A widely used deterministic criterion is the N-1 criterion, which means that there must be sufficient spinning reserve on the system such that no load will lose power if any one line or any one generator fails. Probabilistic approach is a

Table 1: A typical capacity outage probability table for a generation system with three units. The risk of each state is equal to the cumulative probability of that state and is calculated in the last column of this table. It is assumed here that $P_{1max}>P_{2max}>P_{3max}$

State	Generation units 1	2	3	Available capacity	Unavailable capacity	Individual probability	Cumulative probability
1	ON	ON	ON	$P_{1max}+P_{2max}+P_{3max}$	0	$Pr_1=\prod_{i=1}^{3}(1-ORR_i)$	1
2	ON	ON	OFF	$P_{1max}+P_{2max}$	P_{3max}	$Pr_2=ORR_3\times\prod_{i=1}^{2}(1-ORR_i)$	$\sum_{i=2}^{8}Pr_i$
3	ON	OFF	ON	$P_{1max}+P_{3max}$	P_{2max}	$Pr_3=(1-ORR_1)\times ORR_2\times(1-ORR_3)$	$\sum_{i=3}^{8}Pr_i$
4	OFF	ON	ON	$P_{2max}+P_{3max}$	P_{1max}	$Pr_4=ORR_1\times\prod_{i=2}^{3}(1-ORR_i)$	$\sum_{i=4}^{8}Pr_i$
5	ON	OFF	OFF	P_{1max}	$P_{2max}+P_{3max}$	$Pr_5=(1-ORR_1)\times\prod_{i=2}^{3}ORR_i$	$\sum_{i=5}^{8}Pr_i$
6	OFF	ON	OFF	P_{2max}	$P_{1max}+P_{3max}$	$Pr_6=ORR_1\times(1-ORR_2)\times ORR_3$	$\sum_{i=6}^{8}Pr_i$
7	OFF	OFF	ON	P_{3max}	$P_{1max}+P_{2max}$	$Pr_7=(1-ORR_3)\times\prod_{i=1}^{2}ORR_i$	$\sum_{i=7}^{8}Pr_i$
8	OFF	OFF	OFF	0	$P_{1max}+P_{2max}+P_{3max}$	$Pr_8=\prod_{i=1}^{3}ORR_i$	Pr_8

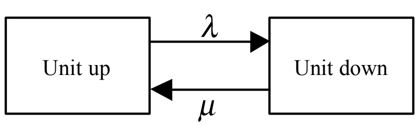

Fig. 2: Two state model

more realistic one in which a risk index enables a comparison to be made between various operating scenarios. The acceptable risk level is a management decision based on economic requirements. Once a risk level has been defined, sufficient generation can be scheduled to satisfy this risk level. This process can be done using the concept of unit commitment risk [5].

Unit commitment risk: In reliability studies of generation systems, each unit is represented by a two state model as shown in Fig. 2. In this model, λ and μ are the failure and repair rates respectively.

The time dependent availability and unavailability of a unit are given by Equations 1 and 2 respectively [5].

$$Pr_{Up}(t)=\frac{\mu}{\lambda+\mu}+\frac{\lambda}{\lambda+\mu}e^{-(\lambda+\mu)t} \quad (1)$$

$$Pr_{Down}(t)=\frac{\lambda}{\lambda+\mu}-\frac{\lambda}{\lambda+\mu}e^{-(\lambda+\mu)t} \quad (2)$$

It is assumed here that the system lead time is relatively short and therefore the probability of repair occurring during the small lead time is negligible. Under this condition the time dependent probabilities of the unit states at a given delay time of T can be approximated as

$$Pr_{Down}(T)=1-e^{-\lambda T} \quad (3)$$

If $\lambda T<<1$, which is generally true for short lead times,

$$Pr_{Down}(T)=\lambda T \quad (4)$$

Equation 4 is known as the Outage Replacement Rate (ORR) and represents the probability that a unit fails and not replaced during the lead time T. The ORR is directly analogous to the forced outage rate (FOR) used in planning studies [5].

The generation model required for evaluating unit commitment risk is a capacity outage probability table which is constructed using the priority list and the outage replacement rates of units (Table 1). The value of unit commitment risk can be deduced directly from the generation model. The acceptable risk level is a management decision based on economic and social requirements. The ability to incorporate risk evaluation in the continuous operating framework of an electric power system is an integral aspect in the ISO responsibility.

Once a risk level has been defined, sufficient generation can be scheduled to satisfy this risk level. An integral element in the overall problem of allocating

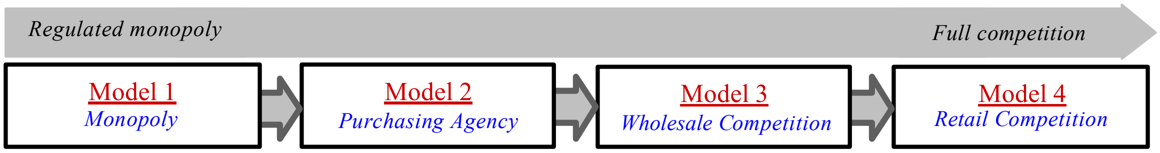

Fig. 3: Models of competition

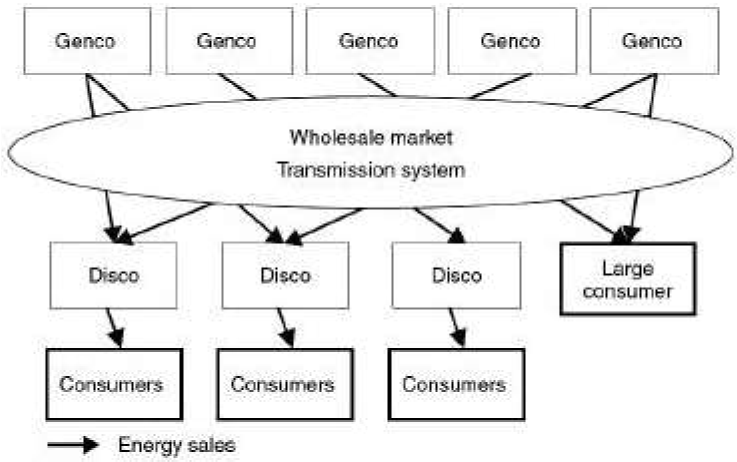

Fig. 4: Wholesale competition model for electricity market [1] (Genco: Generating company, Disco: Distribution company)

operating resources is the assessment of reliability cost and reliability worth [5]. The economic impact of supply reliability is estimated through an index known as the Value of Lost Load (VOLL). Since the economic impact of supply reliability is different for each customer, the average VOLL of all customers is considered by the ISO. The less the average VOLL is estimated, the higher level of risk is accepted.

Transmission system reliability: In many papers, the transmission system has been assumed to be fully reliable. Transmission outages are therefore completely neglected. Even though transmission lines typically have failure probabilities smaller than generating units, in most systems, transmission outages significantly contribute to the system risk. Therefore, the outages of the transmission lines should be considered, at least in some simplified manner, when computing the necessary power reserves to fulfill a pre-specified reliability level.

Since the repair time of transmission lines is much smaller than of generation units, their repair process cannot be neglected during operation lead time T, i.e.,

$$\mathrm{Pr}_{\mathrm{Down}}(\mathrm{T}) = \frac{\lambda}{\lambda+\mu}(1-e^{-(\lambda+\mu)\mathrm{T}}) \tag{5}$$

Assuming that the system success depends on the availability of at least N_{Line}-1 transmission lines, the probability of transmission system success can be determined as

$$\begin{aligned} \mathrm{Pr}(\mathrm{Transmission system success}) &= \prod_{i=1}^{N_{Line}}(1-\mathrm{Pr}_{\mathrm{Down},i}(\mathrm{T})) \\ &+ \sum_{i=1}^{N_{Line}}\left(\mathrm{Pr}_{\mathrm{Down},i}(\mathrm{T}) \times \prod_{\substack{j=1 \\ j\neq i}}^{N_{Line}}(1-\mathrm{Pr}_{\mathrm{Down},j}(\mathrm{T}))\right) \end{aligned} \tag{6}$$

where N_{Line} is the number of transmission lines. Composite (generation and transmission) system risk can be therefore determined as

$$\begin{aligned} \mathrm{Risk}_{\mathrm{HLII}} &= \mathrm{Risk}_{\mathrm{Trans.}} + (1-\mathrm{Risk}_{\mathrm{Trans.}}) \times \mathrm{Risk}_{\mathrm{HLI}} \\ &= 1-(1-\mathrm{Risk}_{\mathrm{HLI}}) \\ &\quad \times \mathrm{Pr}(\mathrm{Transmission system success}) \end{aligned} \tag{7}$$

MARKET STRUCTURE

The development of electricity markets is based on the premise that electrical energy can be treated as a commodity. There are four proposed models to chart the evolution of the electricity supply industry from a regulated monopoly to full competition (Fig. 3).

Although the model 4 is the most satisfactory from an economic perspective, implementing this model requires considerable amounts of metering,

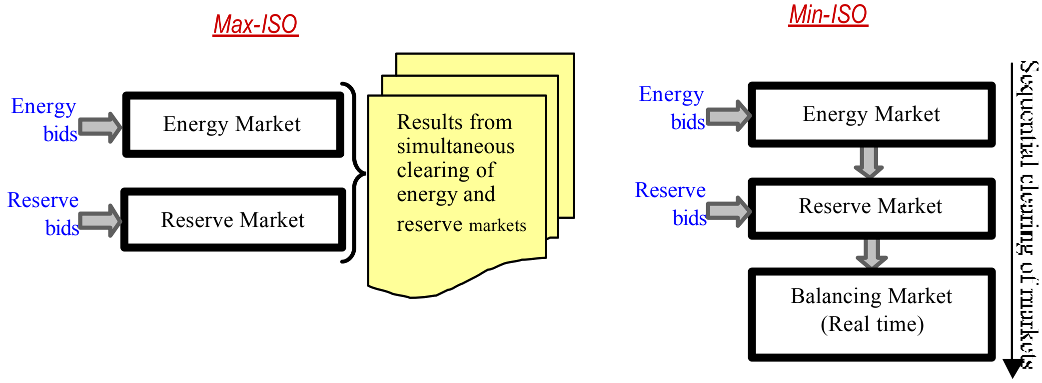

Fig. 5: Min-ISO and Max-ISO models for clearing energy and reserve markets

communication and data processing in distribution systems which make it impractical in many markets. In this paper, a wholesale competition structure (model 3) is considered which includes a power-pool. The model includes both energy and reserve markets with centrally optimized scheduling (MaxISO) where each unit is dealt with as a separate entity. The structure is shown in Fig. 4.

It is useful here to introduce the types of companies and organizations that play a role in the above market.

- Generating companies (Gencos) produce and sell electrical energy and ancillary services. A generating company can own a single plant or a portfolio of plants of different technologies.
- Distribution companies (Dis cos) own and operate distribution networks. In a wholesale competition model, they have a monopoly for the sale of electrical energy to all consumers connected to their network.
- The Independent System Operator (ISO). It is widely understood that an unmanaged open market is unable to maintain the reliability of the power system. The ISO's mission is to ensure the power grid (transmission system) is safe and reliable and that there is a competitive market for electricity. The ISO is independent of the owners of generation and transmission.

In this paper, the electrical energy and spinning reserve are dealt with simultaneously (Max-ISO model) because the procurement of reserve cannot be decoupled from the procurement of energy (Fig. 5). In the early years of competitive electricity markets, this issue was not fully understood. Energy and reserve were traded in separate markets (Min-ISO model). These markets were cleared successively in a sequence. The energy market was cleared first and the results were considered as the starting point of the reserve market. Experience showed that this approach led to problems [24]. System is run with security criteria and units are dispatched based on their bids and their operational constraints.

METHODOLOGY AND FORMULATION

There are two mechanisms that can be used to ensure that the ISO obtains the amount of spinning reserve that is required. The first approach consists in making the provision of some spinning reserve compulsory. The second entails the creation of a market for the service [1]. Both approaches have advantages and disadvantages. The choice of one mechanism over the other is influenced by the nature of the power system and historical circumstances.

Compulsory provision of spinning reserve: In this approach, as a condition for being allowed to participate in energy market, the generation bodies are obligated to provide the required spinning reserve. This approach represents the minimum deviation from the practice of vertically integrated utilities. It also guarantees that enough reserve will be available to maintain the reliability of the system. While compulsion is apparently simple, it is not necessarily a good economic policy and presents certain implementation difficulties [1].

In this case, the ISO is responsible for maintaining adequate supply reliability levels. This is done by obligating the generators to provide the required spinning reserve. Compulsion tends to be financially unattractive among the generators because they forgo an opportunity to sell energy. One way to overcome this limitation is to pay them the opportunity cost associated with the reduced energy. Therefore, generators receive an additional remuneration associated to the contribution of their generation capacity to system reliability and the resulting costs are transferred to customers depending on their energy demand and requested reliability.

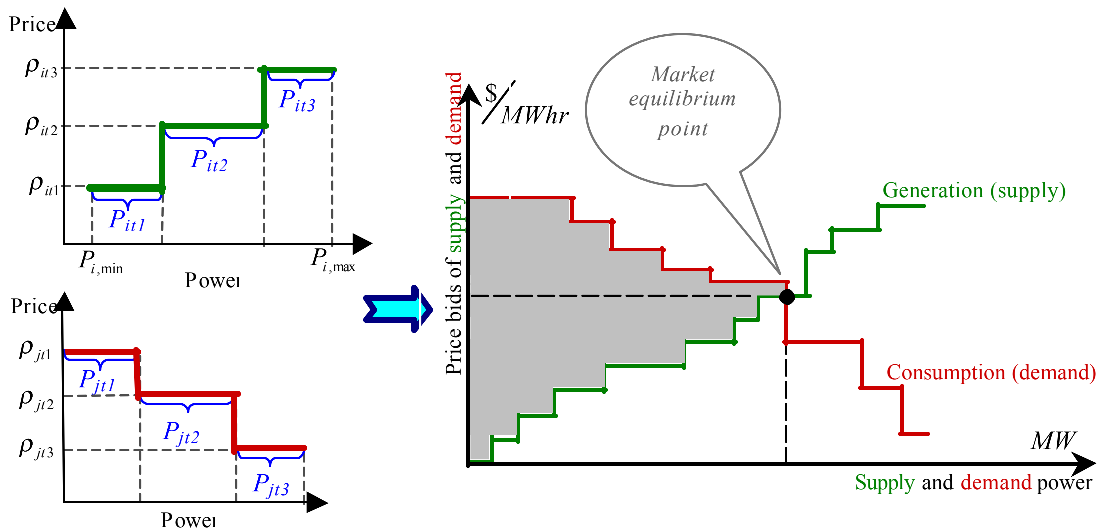

Fig. 6: Piecewise constant price curves of a generating unit (left-up) and a distribution company (left-down) and stacks of bids of supply and demand sides (right). The equilibrium point is such that the power that the suppliers are willing to provide is equal to the power that the consumers wish to obtain. The grey area between supply and demand curves is the sum of the net consumers' surplus and the producers' profit and is called the social welfare. It can be shown that the social welfare has its maximum value at the equilibrium point

Ideally, the level of reliability provided through the purchases of spinning reserve should be determined through a cost-benefit analysis. This analysis would set this level at the optimal point where the marginal cost of providing more reliability is equal to the marginal value of this reliability. The economic impact of supply reliability is estimated through an index known as the Value of Lost Load (VOLL). The acceptable level of risk is proportional to customers' VOLL. Since the economic impact of supply reliability is different for each customer, the average VOLL of all customers is considered by distribution companies. The more the average VOLL is estimated, the lower level of risk is accepted. An exhaustive discussion of the techniques used for calculating reserve requirements is presented in [5].

Based on this approach, the model can be formulated as the following constrained optimization problem:

Objective function: The objective of energy and reserve market operation is the social welfare maximization that is given as:

$$\text{Maximize}\left\{\begin{array}{l}\sum_{t=1}^{24}\sum_{j=1}^{N_D}\left(\rho_{jt1}P_{jt1}+\rho_{jt2}P_{jt2}+\rho_{jt3}P_{jt3}\right)\\ -\sum_{t=1}^{24}\sum_{i=1}^{N_G}u_{it}\left(\rho_{it1}P_{it1}+\rho_{it2}P_{it2}+\rho_{it3}P_{it3}\right)\end{array}\right\} \quad (8)$$

It is assumed here that the generating units and the distribution companies will bid in three-step piecewise energy prices as shown in Fig. 6. This assumption can easily be removed allowing more general forms of bid curves (such as quadratic ones) to be considered.

Equality constraints

- Supply-side energy bids:

$$P_{it} = P_{it1} + P_{it2} + P_{it3} \quad t=1,2,\ldots,24 \quad i=1,2,\ldots,N_G \quad (9)$$

- Demand-side energy bids:

$$P_{jt} = P_{jt1} + P_{jt2} + P_{jt3} \quad t=1,2,\ldots,24 \quad i=1,2,\ldots,N_D \quad (10)$$

- Power balance:

$$\sum_{i=1}^{N_G} P_{it} = \sum_{j=1}^{N_D} P_{jt} + P_{Loss,t} \quad t=1,2,\ldots,24 \quad (11)$$

where the B matrix loss formula is used as a practical method for loss calculations [3]:

$$P_{Loss,t} = [P]^T[B][P] + [B_0]^T[P] + B_{00} \quad t=1,2,\ldots,24 \quad (12)$$

$[P]$ = vector of all generator bus net MW at time *t*
$[B]$ = square matrix of the same dimension as P
$[B_0]$ = vector of the same length as P
B_{00} = constant

* DC power flow equations:

$$[\Delta P_t] = [B'] \times [\Delta \Theta_t] \quad t = 1,2,\ldots,24 \tag{13}$$

Where:

$$B'_{mn} = -\frac{1}{x_{mn}} \tag{14}$$

$$B'_{mm} = \sum_n \frac{1}{x_{mn}} \tag{15}$$

$$P_{lt} = \frac{1}{x_{mn}} \times (\theta_m - \theta_n) \quad t = 1,2,\ldots,24 \tag{16}$$

In Equation 16, index l refers to transmission lines from bus m to bus n.

* Must-run hydro units:

$$\underbrace{u_{it} = 1 \quad t = 1,2,\ldots,24}_{\text{Generator i is a must-run hydro unit}} \tag{17}$$

Must-run hydro units are units where their output water stream must be available for 1) irrigation, 2) other hydroelectric plants and 3) reproduction of endangered species of fish [1, 25].

Inequality constraints

* Supply-side energy bids

$$0 \le P_{it1} \le P_{it1(max)} \quad t = 1,2,\ldots,24 \quad i = 1,2,\ldots,N_G \tag{18}$$

$$0 \le P_{it2} \le P_{it2(max)} \quad t = 1,2,\ldots,24 \quad i = 1,2,\ldots,N_G \tag{19}$$

$$0 \le P_{it3} \le P_{it3(max)} \quad t = 1,2,\ldots,24 \quad i = 1,2,\ldots,N_G \tag{20}$$

* Demand-side energy bids:

$$0 \le P_{jt1} \le P_{jt1(max)} \quad t = 1,2,\ldots,24 \quad j = 1,2,\ldots,N_D \tag{21}$$

$$0 \le P_{jt2} \le P_{jt2(max)} \quad t = 1,2,\ldots,24 \quad j = 1,2,\ldots,N_D \tag{22}$$

$$0 \le P_{jt3} \le P_{jt3(max)} \quad t = 1,2,\ldots,24 \quad j = 1,2,\ldots,N_D \tag{23}$$

* Maximum and minimum output limits on generators:

$$P_{i,min} \le P_{it} + R_{it} \le P_{i,max} \quad t = 1,2,\ldots,24 \quad i = 1,2,\ldots,N_G \tag{24}$$

* Ramp rate constraints (Eq. 25 is about 10-minute spinning reserve) [3, 23]:

$$0 \le R_{it} \le 10RR_i \quad t = 1,2,\ldots,24 \quad i = 1,2,\ldots,N_G \tag{25}$$

$$\begin{aligned} P_{it} - P_{i(t-1)} &\le [1 - u_{it}(1 - u_{i(t-1)})] \times 60RR_i \\ &+ u_{it}(1 - u_{i(t-1)})P_{i,min} \\ &t = 1,2,\ldots,24 \\ &i = 1,2,\ldots,N_G \end{aligned} \tag{26}$$

$$\begin{aligned} P_{i(t-1)} - P_{it} &\le [1 - u_{i(t-1)}(1 - u_{it})] \times 60RR_i \\ &+ u_{i(t-1)}(1 - u_{it})P_{i,min} \\ &t = 1,2,\ldots,24 \\ &i = 1,2,\ldots,N_G \end{aligned} \tag{27}$$

* Minimum up-time constraints:

$$\begin{aligned} &(X_{i(t-1),up} - T_{i,up}) \times (u_{i(t-1)} - u_{it}) \ge 0 \\ &t = 1,2,\ldots,24 \\ &i = 1,2,\ldots,N_G \end{aligned} \tag{28}$$

* Minimum down-time constraints:

$$\begin{aligned} &(X_{i(t-1),down} - T_{i,down}) \times (u_{it} - u_{i(t-1)}) \ge 0 \\ &t = 1,2,\ldots,24 \\ &i = 1,2,\ldots,N_G \end{aligned} \tag{29}$$

* Daily available energy constraints for Hydro units:

$$\sum_{t=1}^{24} P_{it} \le Energy_{i,max} \tag{30}$$

* Network constraints:

$$P_{lt} \le P_{Limit,l} \quad l = 1,2,\ldots,N_l \quad t = 1,2,\ldots,24 \tag{31}$$

* System risk constraint:

$$Risk_{system,t} \le AcceptableRiskLevel \quad t = 1,2,\ldots,24 \tag{32}$$

Since performing a cost-benefit analysis is not practical in some systems, alternative methods can be used that approximate the required amount of reserve. These methods are usually based on technical standards/engineering judgment/operator experience. Traditionally, reserve constraints are based on the (N-1) criterion, which means that there must be sufficient reserve on the system such that no load will lose power if any one line or any one generator fails:

* Approximate amount of reserve required for system security based on operator experience:

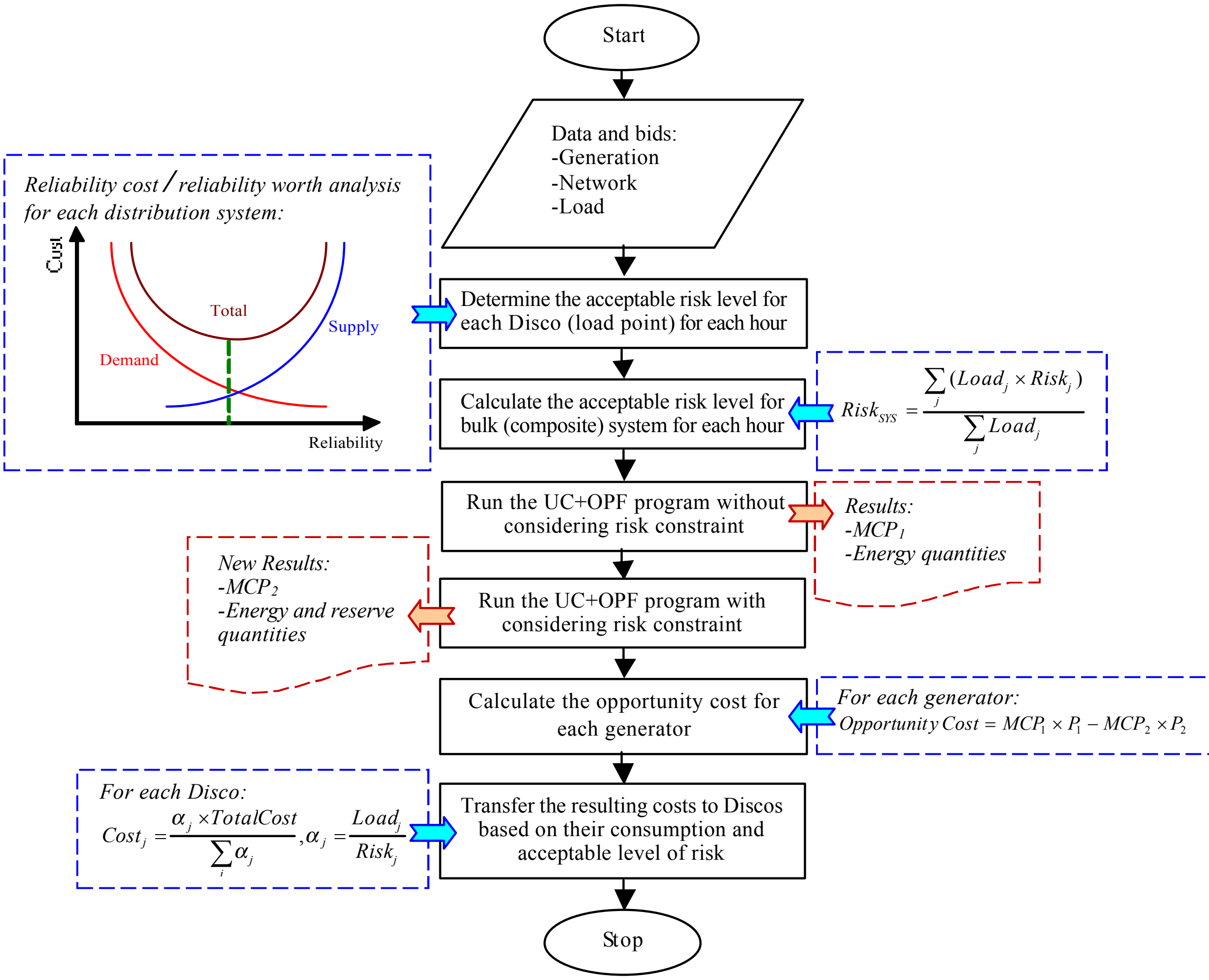

Fig. 7: Flowchart of the proposed method for market scheduling with compulsory provision of spinning reserve

$$\sum_{i=1}^{N_G} R_{it} \geq \text{Max}\left\{\beta_1 \underset{i}{\text{Max}} P_{i,\max}, \beta_2 \underset{l}{\text{Max}} P_{\text{Limit},l}, \beta_3 \sum_{j=1}^{N_D} P_{jt}\right\} \quad (33)$$

$$t = 1,2,\ldots,24$$

Where β_1, β_2 and β_3 are experimental factors.

Assumptions:

- The electricity transactions are provided only through the pool auction market.
- The required spinning reserve is procured through a short-term market mechanism.
- A thermal unit can not provide spinning reserve unless it is also providing energy.
- The ISO contracts with suppliers to provide for the losses. Energy losses are paid for on a *$/MWhr* basis and vary with time based on the variable MCP. The allocation of electric losses to generators and loads participating in energy market is beyond the scope of this paper.
- All Discos have the same normalized hourly peak load curve. This assumption can easily be removed allowing different load curves to be considered.
- The ISO is not responsible for considering specified terms for units' capital cost and startup cost in market scheduling program. These costs are recoverable in two ways: 1) they can be included in the generator's price bids; and 2) they can be recovered through MCP mechanism in which the producers' profit or net surplus is due to their ability to sell their commodity at a price higher than their incremental cost (Fig. 5).
- Generation companies make decisions independently and simultaneously and do not cooperate with each other. These firms are competitors and exchanging information is illegal.

The cost-based approach is summarized in the flowchart shown in Fig. 7.

Table 2: The comparison of two proposed mechanisms for providing spinning reserve

Mechanism A	Mechanism B
Compulsory provision of reserve	Competitive market for trading reserve
Cost-based approach	Price-based approach
ISO is responsible for reliability management	ISO is responsible for reliability management
Discos submit their energy bids and acceptable levels of risk to the ISO	Discos submit their energy bids and acceptable levels of risk to the ISO
Gencos submit their energy bids to the ISO	Gencos submit their energy and reserve bids to the ISO

Competitive market for spinning reserve: Despite difficulties on its application, the compulsory provision of reserve is a valid economic approach, but it requires centralized decision-making. This approach does not incorporate individual choice in supply for reserve, being hardly compatible with a competitive electricity market, where suppliers prefer to decide individually the amount of capacity to commit. On the other hand, economics states that under certain conditions competitive markets lead to efficient outcomes. A managed competitive market allocates resources efficiently, without need of centralized direction. It allows individuals to decide what is best for them. Market allocation is then economically efficient; it allows decentralized decision making and foster individual choice. Therefore, given the economic disadvantages and the practical difficulties of compelling generators to provide spinning reserve, it is usually considered desirable to set up a market mechanism for trading the service. Markets provide a more flexible and more economically efficient mechanism for the procurement of spinning reserve than compulsion [1].

In this mechanism, the ISO is responsible for purchasing sufficient reserve. The purpose of reserve is not only to satisfy economic requirements of customers but also to maintain the security of the system in the face of unpredictable events (these two entities cannot be separated from each other). It is a very difficult task for a customer to predict his required amount of reserve service; because, when he negotiates a supply contract with a distribution company, it cannot take into account the bulk system security. The reason is that it depends on the overall system operation, i.e. on the availability of all generators and transmission facilities and not on the characteristics of an individual distribution network. In other words, security is a "system" concept that must be centrally managed. The ISO is an entity which "sees" the overall generation, transmission and load "picture" and handles what is called "reliability management". It is thus responsible for purchasing sufficient reserve on behalf of the users of the system. Since it is assumed that a market mechanism has been adopted for the procurement of spinning reserve, the ISO will have to pay the providers of this service. It will then have to recover this cost from the users.

Based on this approach, the objective function of Equation 8 can be rewritten as follows:

$$\text{Maximize}\left\{\sum_{t=1}^{24}\left[\begin{array}{l}\sum_{j=1}^{N_D}\left(\rho_{jt1}P_{jt1}+\rho_{jt2}P_{jt2}+\rho_{jt3}P_{jt3}\right)\\ -\sum_{i=1}^{N_G}u_{it}\left(\rho_{it1}P_{it1}+\rho_{it2}P_{it2}+\rho_{it3}P_{it3}+u_{itr}\rho_{itr}R_{it}\right)\end{array}\right]\right\} \quad (34)$$

The optimization model is subject to the same constraints as shown in Equations 9 to 33. The following constraints should be added to the previous equations:

- Supply-side reserve bids:

$$0 \le R_{it} \le R_{it(max)} \quad t=1,2,\ldots,24 \quad i=1,2,\ldots,N_G \quad (35)$$

The two mechanisms of reserve provision are compared in Table 2.

NUMERICAL EXAMPLES

Example 1: The proposed method of considering transmission system reliability in risk state probability table is first applied to the IEEE-RTS shown in Fig. 8 [26]. The test system was first published in 1979 and then modified in 1996 to reflect an enhanced test system for use in bulk power system reliability evaluation studies. It is a relatively large system in which sufficient complexity and detail have been included to make the test system representative for an actual utility system.

The availabilities and un-availabilities of generation units and transmission lines are calculated in Appendix A using the data from [26]. The probabilities are evaluated for a lead time of 1 hour (= the normal time step in most unit commitment programs). In the studies presented in this paper, the same lead time is considered for unit commitment at HLII.

It can be seen that for the total number of 32 units, the maximum number of possible generation system states is $2^{32} = 4.29\times10^9$, which is a horror number to think about. This number is the upper bound for the number of required enumerations. Fortunately, the state probabilities are such that we do not approach this large

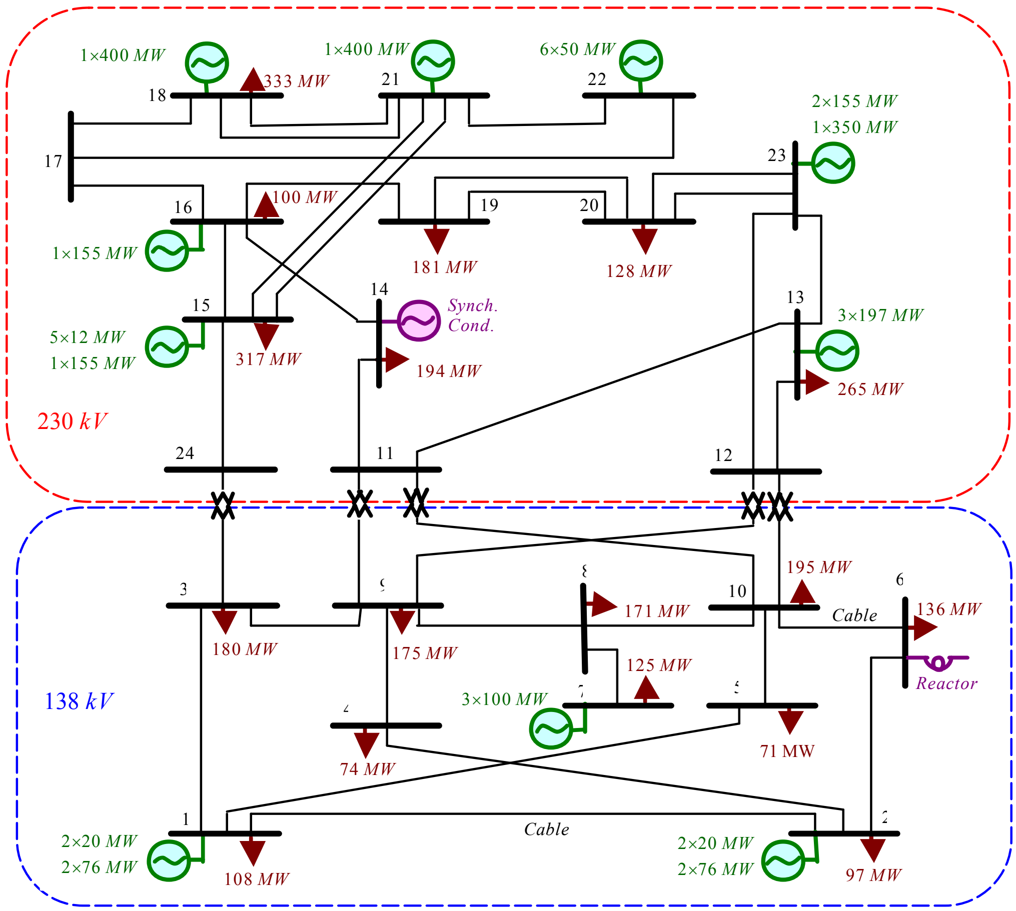

Fig. 8: The IEEE-RTS [26]

Table 3: Capacity outage probability table of the IEEE-RTS. Only full capacity state and single contingencies (N-1 states) are included in this table. More severe contingencies are not considered here because their probabilities of occurrence are negligible

State	Capacity in (MW)	Capacity out (MW)	Individual probability	Generation system risk	Composite system risk	
1	3405	0	0.972204	1.000000	1.000000	
2	3393	12	0.001653	0.027796	0.029574	
3	3385	20	0.008652	0.026143	0.027924	
4	3355	50	0.002947	0.017491	0.019288	
5	3329	76	0.001984	0.014544	0.016346	
6	3305	100	0.002432	0.012560	0.014366	
7	3250	155	0.004056	0.010128	0.011938	
8	3208	197	0.003074	0.006072	0.007890	
9	3055	350	0.000847	0.002998	0.004822	<0.005
10	3005	400	0.001769	0.002151	0.003976	
11	2993	412	…	0.000382	0.002210	
⋮	⋮	⋮	⋮	⋮	⋮	

number. It can be shown from a probabilistic analysis of the capacity outage states that the probability that two or more units are out is only 0.000396, which is very small and can be neglected. The capacity outage probability table can therefore be summarized as shown in Table 3 without loss of accuracy.

The probability of composite system success depends on not only generation risk but also transmission risk because there are cases in which even though the system has enough generation capacity reserve to support the contingencies, the transmission system is not able to transfer the reliability-related

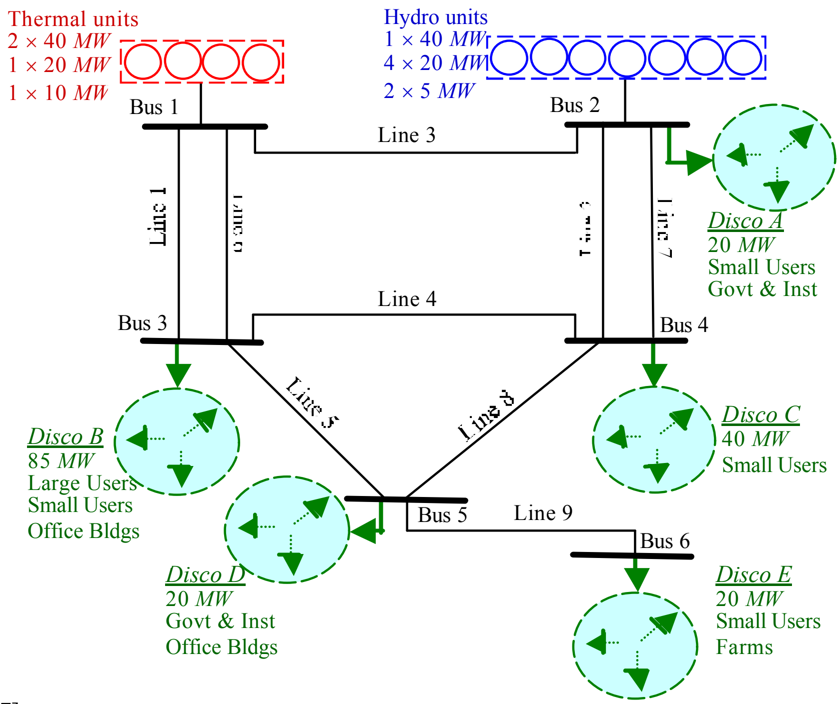

Fig. 9: The RBTS [27]

re-dispatched power. The risk of transmission system can be determined based on the line availabilities (Table A2) as

$$\begin{aligned}\text{Transmission system risk} &= 1 - \Pr(\text{all lines operational}) \\ &\quad - \Pr(\text{any } N-1 \text{ state}) \\ &= 1 - 0.941028 - 0.057143 \\ &= 0.001829\end{aligned} \tag{36}$$

where it is assumed that: 1) the transmission system is N-1 secure; and 2) all double contingencies and more severe outages will result in loss of load.

Composite system risk can be determined using Equation 7. The results of risk calculations for HLI (generation system) and HLII (composite generation and transmission system) are shown in columns 4 and 5 of Table 3.

In order to illustrate the deduction of unit commitment risk, an expected demand of 2850 MW is considered. From Table 3, the risk is 0.000382 and 0.002210 for generation and composite systems respectively. If the peak load grows to 3135 MW (10% higher), the risk in generation and composite systems are 0.006072 and 0.007890 respectively.

It is necessary to first define an acceptable risk level in order to determine the maximum demand that the committed system can meet. For example, if it is considered that a maximum risk of 0.005 is acceptable, the minimum required spinning reserve is 350 MW and a maximum demand of 3055 MW can be supplied.

Table 4: Contingency enumeration for the RBTS transmission network neglecting N-3 states and higher order contingencies. Only events which result in loss of load are considered here

State	Failure event	Line(s) out	Probability
1	Single contingency	9	0.003599
2	Common mode failure	1, 6	0.000257
3	Double contingencies	9, any line	0.000242
4	Double contingency	1, 2	0.000090
5	Double contingency	1, 7	0.000090
6	Double contingency	2, 6	0.000090
7	Double contingency	6, 7	0.000090
8	Double contingency	1, 6	0.000027
9	Double contingency	5, 8	0.000012
	Total:		0.004497

Example 2: The IEEE-RTS is an excellent system for study purposes using developed programs. In this paper, however, there is a need for a system which includes: 1) generating unit cost data to determine generation price bids and 2) detailed customer data to determine acceptable risk levels at HLII load points. Figure 9 shows a 6-bus system designated as the Roy Billinton Test System (RBTS). The RBTS is an excellent educational test system evolved from the

Table 5: Capacity outage probability table for the RBTS

State	Capacity in (MW)	Capacity out (MW)	Individual probability	Generation system risk	Composite system risk
1	240	0	0.995716	1.000000	1.000000
2	235	5	0.000454	0.004284	0.008762
3	230	10	0.000455	0.003830	0.008310
4	225	15	0.000000	0.003375	0.007857
5	220	20	0.001661	0.003375	0.007857
6	215	25	0.000001	0.001714	0.006203
7	210	30	0.000000	0.001713	0.006202
8	205	35	0.000000	0.001713	0.006202
9	200	40	0.001706	0.001713	0.006202
10	195	45	…	0.000007	0.004504
⋮	⋮	⋮	⋮	⋮	⋮

Table 6: Capacity outage probability table for the RBTS without considering the 10 MW unit

State	Capacity in (MW)	Capacity out (MW)	Individual probability	Generation system risk	Composite system risk
1	230	0	0.996171	1.000000	1.000000
2	225	5	0.000454	0.003829	0.008309
3	220	10	0.000000	0.003375	0.007857
4	210	20	0.001661	0.003375	0.007857
5	205	25	0.000000	0.001714	0.006203
6	200	30	0.000000	0.001714	0.006203
7	190	40	0.001707	0.001714	0.006203
8	185	45	…	0.000007	0.004504
⋮	⋮	⋮	⋮	⋮	⋮

Table 7: Capacity outage probability table for the RBTS without considering the 10 MW and 20 MW units

State	Capacity in (MW)	Capacity out (MW)	Individual probability	Generation system risk	Composite system risk
1	210	0	0.996740	1.000000	1.000000
2	205	5	0.000455	0.003260	0.007742
3	200	10	0.000000	0.002805	0.007289
4	190	20	0.001093	0.002805	0.007289
5	185	25	0.000000	0.001712	0.006201
6	180	30	0.000000	0.001712	0.006201
7	170	40	0.001707	0.001712	0.006201
8	165	45	…	0.000005	0.004502
⋮	⋮	⋮	⋮	⋮	⋮

Table 8: Capacity outage probability table for the RBTS without considering the 10 MW, 20 MW and one of the 40 MW units.

State	Capacity in (MW)	Capacity out (MW)	Individual probability	Generation system risk	Composite system risk
1	170	0	0.997423	1.000000	1.000000
2	165	5	0.000455	0.002577	0.007062
3	160	10	0.000000	0.002122	0.006609
4	150	20	0.001093	0.002122	0.006609
5	145	25	0.000000	0.001029	0.005521
6	140	30	0.000000	0.001029	0.005521
7	130	40	0.001025	0.001029	0.005521
8	125	45	…	0.000004	0.004501
⋮	⋮	⋮	⋮	⋮	⋮

Table 9: Summary of results from the previous capacity outage probability tables

State	Generation units 1	2	3	4	5	6	7	8	9	10	11	Capacity in (MW)	Capacity out (MW)	Maximum demand can be supplied (MW) (risk<0.005)	Spinning reserve required (MW)
1	ON	ON	ON	ON	ON	ON	ON	ON	ON	ON	ON	240	0	195	45
2	ON	ON	ON	ON	ON	ON	ON	ON	ON	ON	OFF	230	10	185	45
3	ON	ON	ON	ON	ON	ON	ON	ON	ON	OFF	OFF	210	30	165	45
4	ON	ON	ON	ON	ON	ON	ON	ON	OFF	OFF	OFF	170	70	125	45
5	ON	ON	ON	ON	ON	ON	ON	OFF	ON	OFF	OFF	170	70	125	45
6	ON	ON	ON	ON	ON	ON	ON	OFF	OFF	OFF	OFF	130	110	85	45

1: 40MW-Hydro; 2: 20MW-Hydro; 3: 20MW-Hydro; 4: 20MW-Hydro; 5: 20MW-Hydro; 6: 5MW-Hydro; 7: 5MW-Hydro; 8: 40MW-Thermal; 9: 40MW-Thermal; 10: 20MW-Thermal; 11: 10MW-Thermal

reliability research activities conducted by the power systems research group at the University of Saskatchewan [27]. The system consists of nine transmission lines, eleven generation units and five load points. The system data are given in Appendix B.

The risk of transmission system can be determined using the line availabilities, common mode failure probabilities (Table B3 and B4) and contingency enumeration technique as shown in Table 4.

Using the generators data (Table B1) and the transmission system risk (Table 4), the capacity outage probability tables (Table 5-8) can be derived. The maximum acceptable risk level of the system is 0.005 (Table B7).

The results of Table 5-8 can be summarized as shown in Table 9.

From Table 9, it can be observed that the minimum required spinning reserve is 45 *MW* for all states considered here and the maximum load that can be supplied with a risk of 0.005 is 195 *MW*. To supply this load, all units should be committed. If for example, the system load is less than 165 *MW* and more than 125 *MW*, all units but the 10 MW and 20 MW thermal units should be committed.

Before delving into the application of the proposed mechanisms of reserve provision to a competitive RBTS, it is necessary to discuss supply-side and demand-side perspectives. Here, it can be seen that low price elasticity of demand and high degree of market concentration facilitate the exercise of “market power”.

- Supply-side perspective

Microeconomic theory suggests that if the potential output of each generation company is very small compared to the size of the market, the competition will be perfect. In such a market, since the company’s actions do not affect the prices, it can optimize its activities independently of what other producers or customers might do. The RBTS is, however, a case in which the generation capacity owned by a single company is large enough to influence the price of energy. When competition is less than perfect, some firms (the strategic players) are able to influence the market price through their actions [1, 28]. In this example, the case of a market is considered with eleven firms compete for the supply of electrical energy. It is assumed here that the hydroelectric units have a substantial reservoir. They can adjust their production at will and the amount of energy they have available is not limited.

Considering an imperfect competition in this market, hydroelectric units would set their price at slightly less than the minimum incremental cost of production of thermal units and would capture the whole market during periods of light load. At first sight, this may seem very difficult because these firms are competitors and exchanging information would be illegal. However, all firms are trying to maximize their profits through a non-cooperative game. The profit of the i^{th} unit at time t can be written as follows:

$$\mathrm{Profit}_{it} = \mathrm{MCP}_t \times \mathrm{P}_{it} - \mathrm{C}_i(\mathrm{P}_{it}) \qquad (37)$$

Where: $C_i(P_i)$ is the cost function of the i^{th} unit.

The solution of such a game is called "Nash equilibrium" and represents market equilibrium under imperfect competition [1]. It should be noted that a Bertrand interaction between firms (a game in prices) is considered here.

To apply the proposed mechanism B to the competitive RBTS, it is assumed here that (1) each generator will bid in constant reserve price for every hour; and (2) the generators apply the same "strategy factor" to their price bids for both energy and spinning reserve. The strategy factor is an optional coefficient which depends on the generator’s bidding strategy (Fig. B1 and Table B2).

Table 10: Schedule using cost-based approach (mechanism A) without considering risk constraint

	Power generation (MW)											MCP
Hour	1	2	3	4	5	6	7	8	9	10	11	($/MWhr)
1	39.30	19.65	19.65	19.65	19.65	4.91	4.91	OFF	OFF	OFF	OFF	12.25
2	36.88	18.44	18.44	18.44	18.44	4.61	4.61	OFF	OFF	OFF	OFF	12.25
3	35.07	17.54	17.54	17.54	17.54	4.38	4.38	OFF	OFF	OFF	OFF	12.25
4	34.47	17.24	17.24	17.24	17.24	4.31	4.31	OFF	OFF	OFF	OFF	12.25
5	34.47	17.24	17.24	17.24	17.24	4.31	4.31	OFF	OFF	OFF	OFF	12.25
6	35.07	17.54	17.54	17.54	17.54	4.38	4.38	OFF	OFF	OFF	OFF	12.25
7	40.00	20.00	20.00	20.00	20.00	5.00	5.00	10.77	OFF	OFF	OFF	12.30
8	40.00	20.00	20.00	20.00	20.00	5.00	5.00	16.51	16.51	OFF	OFF	12.30
9	40.00	20.00	20.00	20.00	20.00	5.00	5.00	24.90	24.90	OFF	OFF	12.50
10	40.00	20.00	20.00	20.00	20.00	5.00	5.00	25.83	25.83	OFF	OFF	12.50
11	40.00	20.00	20.00	20.00	20.00	5.00	5.00	25.83	25.83	OFF	OFF	12.50
12	40.00	20.00	20.00	20.00	20.00	5.00	5.00	24.90	24.90	OFF	OFF	12.50
13	40.00	20.00	20.00	20.00	20.00	5.00	5.00	24.90	24.90	OFF	OFF	12.50
14	40.00	20.00	20.00	20.00	20.00	5.00	5.00	24.90	24.90	OFF	OFF	12.50
15	40.00	20.00	20.00	20.00	20.00	5.00	5.00	23.03	23.03	OFF	OFF	12.50
16	40.00	20.00	20.00	20.00	20.00	5.00	5.00	23.96	23.96	OFF	OFF	12.50
17	40.00	20.00	20.00	20.00	20.00	5.00	5.00	28.64	28.64	OFF	OFF	12.50
18	40.00	20.00	20.00	20.00	20.00	5.00	5.00	29.58	29.58	OFF	OFF	12.50
19	40.00	20.00	20.00	20.00	20.00	5.00	5.00	29.58	29.58	OFF	OFF	12.50
20	40.00	20.00	20.00	20.00	20.00	5.00	5.00	25.83	25.83	OFF	OFF	12.50
21	40.00	20.00	20.00	20.00	20.00	5.00	5.00	21.16	21.16	OFF	OFF	12.50
22	40.00	20.00	20.00	20.00	20.00	5.00	5.00	13.72	13.72	OFF	OFF	12.30
23	38.48	19.24	19.24	19.24	19.24	4.81	4.81	10.00	OFF	OFF	OFF	12.30
24	36.88	18.44	18.44	18.44	18.44	4.61	4.61	OFF	OFF	OFF	OFF	12.25

1: 40MW-Hydro; 2: 20MW-Hydro; 3: 20MW-Hydro; 4: 20MW-Hydro; 5: 20MW-Hydro; 6: 5MW-Hydro; 7: 5MW-Hydro; 8: 40MW-Thermal; 9: 40MW-Thermal; 10: 20MW-Thermal; 11: 10MW-Thermal

These assumptions are without loss of generality and can easily be removed allowing other assumptions to be considered. The reserve price associated with generator i at time t is then:

$$\rho_{itr} = \text{StrategyFactor}_{it} \times [(1 - \text{Risk}_{\text{system},t}) \times \text{Operat.Cost}_i + \text{Risk}_{\text{system},t} \times (\text{Operat.Cost}_i + \text{FuelCost})] \quad (38)$$

- Demand-side perspective

In the wholesale competition model considered in this paper, distribution companies (Discos A, B, C, D and E) are employed by their customers to forecast their demand and trade in the electricity market. They are in business to bridge the gap between the wholesale market and their customers. Here, the "wires" activities of the distribution companies are not separated from their retail activities because they have a local monopoly for the supply of electrical energy in the area covered by their network.

Electricity consumers increase their demand up to the point at which the marginal benefit they derive from the electricity is equal to the price they have to pay. It is evident from data presented in Appendix B that the price of electrical energy is only a small portion of the interruption cost (VOLL) of customers. As a result, the price elasticity of the demand for electricity is small. In other words, on a price versus quantity diagram, the slope of the demand curve is very steep and a nearly constant demand can be considered for each hour. In fact, consumers have a much more passive role than producers do in the market.

The previous discussion about supply-side and demand-side perspectives is used to apply the proposed mechanisms of reserve provision (cost-based and price-based methods) to a competitive RBTS. The cost-based approach (mechanism A) is applied to the test system by solving the optimization problem of Equations 8 to 32 and subsequently, two schedules are derived. These schedules are shown in Table 10 and 11 where the first one is without considering risk constraint and the

Table 11: Schedule using cost-based approach (mechanism A) with considering risk constraint

Hour	Power generation (MW) 1	2	3	4	5	6	7	8	9	10	11	Available 10-minute spinning reserve (MW)	MCP ($/MWhr)
1	32.78	16.39	16.39	16.39	16.39	4.10	4.01	10.00	10.00	OFF	OFF	63.47	12.30
2	32.31	16.15	16.15	16.15	16.15	4.04	4.04	14.05	OFF	OFF	OFF	45.00	12.30
3	31.82	15.91	15.91	15.91	15.91	3.98	3.98	10.00	OFF	OFF	OFF	46.58	12.30
4	31.19	15.59	15.59	15.59	15.59	3.90	3.90	10.00	OFF	OFF	OFF	48.64	12.30
5	31.19	15.59	15.59	15.59	15.59	3.90	3.90	10.00	OFF	OFF	OFF	48.64	12.30
6	31.82	15.91	15.91	15.91	15.91	3.98	3.98	10.00	OFF	OFF	OFF	46.58	12.30
7	36.98	18.49	18.49	18.49	18.49	4.62	4.62	10.00	10.00	OFF	OFF	49.80	12.30
8	38.46	19.23	19.23	19.23	19.23	4.81	4.81	18.87	18.87	OFF	OFF	45.00	12.30
9	40.00	20.00	20.00	20.00	20.00	5.00	5.00	22.40	22.40	5.00	OFF	45.20	12.75
10	40.00	20.00	20.00	20.00	20.00	5.00	5.00	22.50	22.50	6.67	OFF	45.00	12.75
11	40.00	20.00	20.00	20.00	20.00	5.00	5.00	22.50	22.50	6.67	OFF	45.00	12.75
12	40.00	20.00	20.00	20.00	20.00	5.00	5.00	22.40	22.40	5.00	OFF	45.20	12.75
13	40.00	20.00	20.00	20.00	20.00	5.00	5.00	22.40	22.40	5.00	OFF	45.20	12.75
14	40.00	20.00	20.00	20.00	20.00	5.00	5.00	22.40	22.40	5.00	OFF	45.20	12.75
15	40.00	20.00	20.00	20.00	20.00	5.00	5.00	20.53	20.53	5.00	OFF	48.94	12.75
16	40.00	20.00	20.00	20.00	20.00	5.00	5.00	21.46	21.46	5.00	OFF	47.07	12.75
17	40.00	20.00	20.00	20.00	20.00	5.00	5.00	24.64	24.64	5.00	3.00	47.71	12.76
18	40.00	20.00	20.00	20.00	20.00	5.00	5.00	25.58	25.58	5.00	3.00	45.84	12.76
19	40.00	20.00	20.00	20.00	20.00	5.00	5.00	25.58	25.58	5.00	3.00	45.84	12.76
20	40.00	20.00	20.00	20.00	20.00	5.00	5.00	22.50	22.50	6.67	OFF	45.00	12.75
21	40.00	20.00	20.00	20.00	20.00	5.00	5.00	18.66	18.66	5.00	OFF	50.00	12.75
22	38.46	19.23	19.23	19.23	19.23	4.81	4.81	16.08	16.08	OFF	OFF	45.00	12.30
23	36.38	18.19	18.19	18.19	18.19	4.55	4.55	10.00	10.00	OFF	OFF	51.76	12.30
24	32.31	16.15	16.15	16.15	16.15	4.04	4.04	14.05	OFF	OFF	OFF	45.00	12.30

1: 40MW-Hydro; 2: 20MW-Hydro; 3: 20MW-Hydro; 4: 20MW-Hydro; 5: 20MW-Hydro; 6: 5MW-Hydro; 7: 5MW-Hydro; 8: 40MW-Thermal; 9: 40MW-Thermal; 10: 20MW-Thermal; 11: 10MW-Thermal

Table 12: Opportunity cost of generating units

Hour	Opportunity cost ($) 1	2	3	4	5	6	7	8	9	10	11	Total hourly opportunity cost ($)
1	78.23	39.12	39.12	39.12	39.12	10.82	10.82	0.00	0.00	0.00	0.00	256.35
2	54.37	27.25	27.25	27.25	27.25	6.78	6.78	0.00	0.00	0.00	0.00	176.93
3	38.22	19.17	19.17	19.17	19.17	4.70	4.70	0.00	0.00	0.00	0.00	124.30
4	38.62	19.43	19.43	19.43	19.43	4.83	4.83	0.00	0.00	0.00	0.00	126.00
5	38.62	19.43	19.43	19.43	19.43	4.83	4.83	0.00	0.00	0.00	0.00	126.00
6	38.22	19.17	19.17	19.17	19.17	4.70	4.70	0.00	0.00	0.00	0.00	124.30
7	37.15	18.57	18.57	18.57	18.57	4.67	4.67	9.47	0.00	0.00	0.00	130.24
8	18.94	9.47	9.47	9.47	9.47	2.34	2.34	0.00	0.00	0.00	0.00	61.50
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.65	25.65	0.00	0.00	51.30
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.00	36.00	0.00	0.00	72.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.00	36.00	0.00	0.00	72.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.65	25.65	0.00	0.00	51.30
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.65	25.65	0.00	0.00	51.30
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.65	25.65	0.00	0.00	51.30
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26.12	26.12	0.00	0.00	52.24
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.89	25.89	0.00	0.00	51.78
17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.59	43.59	0.00	0.00	87.18
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.35	43.35	0.00	0.00	86.70
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.35	43.35	0.00	0.00	86.70
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.00	36.00	0.00	0.00	72.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26.59	26.59	0.00	0.00	53.18
22	18.94	9.47	9.47	9.47	9.47	2.34	2.34	0.00	0.00	0.00	0.00	61.50
23	25.83	12.92	12.92	12.92	12.92	3.20	3.20	0.00	0.00	0.00	0.00	83.91
24	54.37	27.25	27.25	27.25	27.25	6.78	6.78	0.00	0.00	0.00	0.00	176.93
Total daily opportunity cost:												2286.94

1: 40MW-Hydro; 2: 20MW-Hydro; 3: 20MW-Hydro; 4: 20MW-Hydro; 5: 20MW-Hydro; 6: 5MW-Hydro; 7: 5MW-Hydro; 8: 40MW-Thermal; 9: 40MW-Thermal; 10: 20MW-Thermal; 11: 10MW-Thermal

Table 13: Schedule using price-based approach (mechanism B)

	Power generation (MW)											Total hourly generated power (MW)	MCP ($/MWhr)
Hour	1	2	3	4	5	6	7	8	9	10	11		
1	26.15	13.08	13.08	13.08	13.08	3.27	3.27	20.36	20.36	OFF	OFF	125.73	12.50
2	26.15	13.08	13.08	13.08	13.08	3.27	3.27	16.63	16.63	OFF	OFF	118.26	12.30
3	26.15	13.08	13.08	13.08	13.08	3.27	3.27	13.84	13.84	OFF	OFF	112.67	12.30
4	26.15	13.08	13.08	13.08	13.08	3.27	3.27	12.91	12.91	OFF	OFF	110.81	12.30
5	26.15	13.08	13.08	13.08	13.08	3.27	3.27	12.91	12.91	OFF	OFF	110.81	12.30
6	26.15	13.08	13.08	13.08	13.08	3.27	3.27	13.84	13.84	OFF	OFF	112.67	12.30
7	26.15	13.08	13.08	13.08	13.08	3.27	3.27	26.92	26.92	OFF	OFF	138.83	12.50
8	26.15	13.08	13.08	13.08	13.08	3.27	3.27	38.21	38.21	OFF	OFF	161.43	12.70
9	26.15	13.08	13.08	13.08	13.08	3.27	3.27	40.00	40.00	13.48	OFF	178.48	12.75
10	26.15	13.08	13.08	13.08	13.08	3.27	3.27	40.00	40.00	15.38	OFF	180.38	12.75
11	26.15	13.08	13.08	13.08	13.08	3.27	3.27	40.00	40.00	15.38	OFF	180.38	12.75
12	26.15	13.08	13.08	13.08	13.08	3.27	3.27	40.00	40.00	13.48	OFF	178.48	12.75
13	26.15	13.08	13.08	13.08	13.08	3.27	3.27	40.00	40.00	13.48	OFF	178.48	12.75
14	26.15	13.08	13.08	13.08	13.08	3.27	3.27	40.00	40.00	13.48	OFF	178.48	12.75
15	26.15	13.08	13.08	13.08	13.08	3.27	3.27	40.00	40.00	9.68	OFF	174.68	12.75
16	26.15	13.08	13.08	13.08	13.08	3.27	3.27	40.00	40.00	11.58	OFF	176.58	12.75
17	26.15	13.08	13.08	13.08	13.08	3.27	3.27	40.00	40.00	17.99	3.00	185.99	12.76
18	26.15	13.08	13.08	13.08	13.08	3.27	3.27	40.00	40.00	19.89	3.00	187.89	12.76
19	26.15	13.08	13.08	13.08	13.08	3.27	3.27	40.00	40.00	19.89	3.00	187.89	12.76
20	26.15	13.08	13.08	13.08	13.08	3.27	3.27	40.00	40.00	15.38	OFF	180.38	12.75
21	26.15	13.08	13.08	13.08	13.08	3.27	3.27	40.00	40.00	5.89	OFF	170.89	12.75
22	26.15	13.08	13.08	13.08	13.08	3.27	3.27	35.38	35.38	OFF	OFF	155.76	12.70
23	26.15	13.08	13.08	13.08	13.08	3.27	3.27	25.98	25.98	OFF	OFF	136.96	12.50
24	26.15	13.08	13.08	13.08	13.08	3.27	3.27	16.63	16.63	OFF	OFF	118.26	12.30

1: 40MW-Hydro; 2: 20MW-Hydro; 3: 20MW-Hydro; 4: 20MW-Hydro; 5: 20MW-Hydro; 6: 5MW-Hydro; 7: 5MW-Hydro; 8: 40MW-Thermal; 9: 40MW-Thermal; 10: 20MW-Thermal; 11: 10MW-Thermal

second one is with considering it. The opportunity costs of generating units are calculated in Table 12 using the results from Table 10 and 11 (Fig. 7). The value of opportunity cost for the i^{th} unit at time t is calculated as follows:

$$\text{OpportunityCost}_{it} = \begin{cases} (MCP_{1t} \times P_{it1}) - (MCP_{2t} \times P_{it2}) & ; \quad (MCP_{1t} \times P_{it1}) > (MCP_{2t} \times P_{it2}) \\ 0 & ; \quad (MCP_{1t} \times P_{it1}) \leq (MCP_{2t} \times P_{it2}) \end{cases} \tag{39}$$

where: indices 1 and 2 refer to results from Table 10 and 11, respectively.

The results of applying mechanism B (considering a competitive market for trading energy and spinning reserve simultaneously) to the RBTS are presented in Table 13.

RESULTS AND DISCUSSION

The proposed mechanisms have shown themselves to be capable of considering generation and transmission reliabilities and also the maximum acceptable risk level of customers. The algorithms are flexible in handling equality and inequality constraints. Some useful outputs from the algorithms are the opportunity costs (mechanism A) and the prices of energy and reserve (mechanism B).

The variations in system energy and total costs ($) are shown in Fig. 10. As expected, the shape of these variations is similar to the load shape (Fig. B2). It should be noted here that though there is a very small deviation between energy costs in the proposed mechanisms (0.27% average), total cost in mechanism A is slightly higher than that in mechanism B (2.12% average). This is because of considerable difference between reserve provision costs: The opportunity cost in mechanism A is 65.4% (average) higher than the reserve procurement cost in mechanism B.

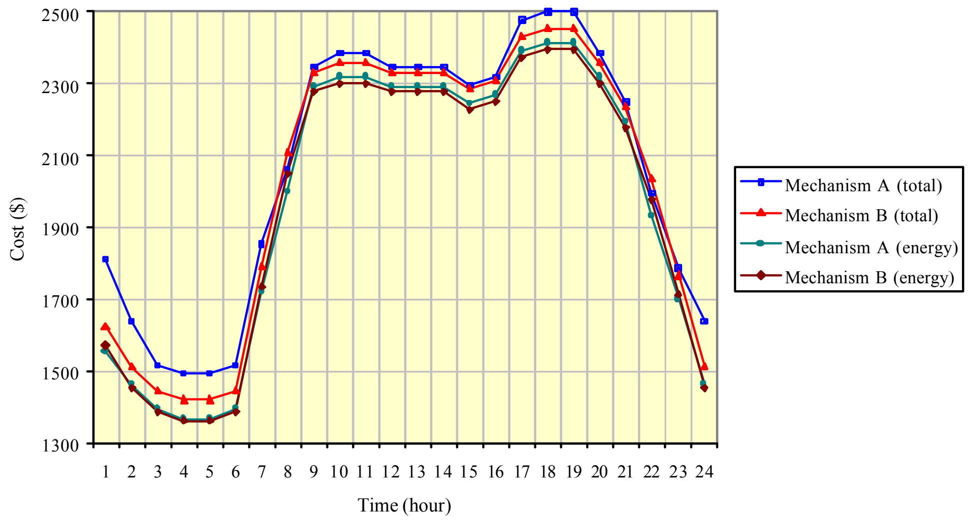

Fig. 10: Variations in energy and total cost

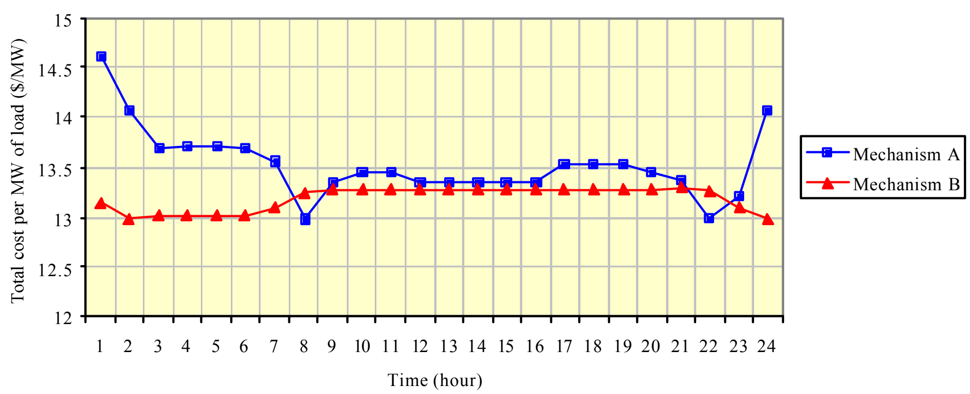

Fig. 11: Total cost per MW of load

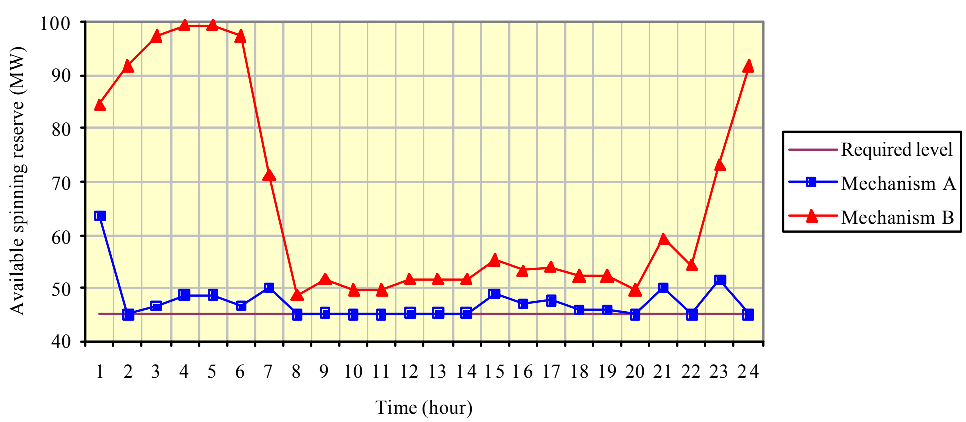

Fig. 12: Available spinning reserve

A more detailed comparison between the proposed mechanisms is possible using Fig. 11 and 12. It can be observed from Fig. 11 that for 91.67% of the time period, system operation cost ($/*MW*) of the price-based method is lower than that of the cost-based approach. It seems reasonable because in a price-based competitive environment, the ISO simply buys the required 45 *MW* spinning reserve from low price hydro units; it is not obliged to pay for the spinning reserve provided by thermal units.

Table 14: Comparison of IEEE-RTS and RBTS

System	No. of units	No. of lines	No. of load points	Available capacity (MW)	Peak Load (MW)	No. of unit types	Capacity ratio[a]	Transmission network reliability	Detailed cost data of units?	VOLL data of customers?
IEEE-RTS	32	38	17	3405	2850	4	0.117	0.998171	No	No
RBTS	11	9	5	240	185	2	0.167	0.995503	Yes	Yes

[a]Capacity ratio = Capacity of Largest Unit/Available Capacity

According to Fig. 12, the available spinning reserve in mechanism A is closer to the required level (45 *MW*) than that in mechanism B. In other words, in price-based method, despite the generation system is scheduled to deliver more reserve, it is paid less for the service.

It is useful here to compare the two test systems studied in this paper. This comparison is shown in Table 14. It can be seen from columns 2 to 7 that the RBTS is simpler than the IEEE-RTS, but, it is not a reasonable conclusion that the IEEE-RTS is more appropriate to simulate a competitive electricity market. The subject is confirmed using the results presented in columns 8 to 11:

- The RBTS is more compatible with an ill-conditioned test system and this is an advantage in many case studies. A comparison between values of capacity ratio (column 8) shows that the RBTS has better condition to facilitate the exercise of market power by the producers. Furthermore, the transmission network of the RBTS is less reliable (column 9).
- The RBTS includes some data required for a detailed simulation study which the IEEE-RTS does not include (columns 10 and 11).

CONCLUSION

Two mechanisms for providing spinning reserve in a deregulated power system have been presented. The mechanisms are formulated as mixed integer nonlinear co-optimization problems subject to a number of equality and inequality constraints. A wholesale competition model has been considered where an ISO dispatches power and services in such a manner as to maximize the social welfare given the demand bids and supply offers. The simultaneous clearing of energy and spinning reserve markets has been emphasized in the paper. A method for considering transmission network reliability in the scheduling process which simplifies the HLII assessment problem has been developed. The suggested mechanisms have been applied to the IEEE-RTS and the RBTS to show their applicability and the results have been compared and discussed.

Table A1: Generators probabilistic data

Unit (MW)	Type	MTTF (hr)	MTTR (hr)	λ (f/yr)	ORR
12	Oil/steam	2940	60	2.98	0.000340
20	Oil/CT	450	50	19.47	0.002222
50	Hydro	1980	20	4.42	0.000505
76	Coal/steam	1960	40	4.47	0.000510
100	Oil/steam	1200	50	7.30	0.000833
155	Coal/steam	960	40	9.125	0.001042
197	Oil/steam	950	50	9.22	0.001053
350	Coal/steam	1150	100	7.62	0.000870
400	Nuclear	1100	150	7.96	0.000909

Table A2: Transmission lines probabilistic data

Line	From bus	To bus	$\lambda = \lambda_p + \lambda_t$ (f/yr)	Dur. (hr)	μ (r/yr)	Pr (Down)
A1	1	2	0.24	16	547.5	0.000412
A2	1	3	3.41	10	876.0	0.003507
A3	1	5	1.53	10	876.0	0.001577
A4	2	4	2.09	10	876.0	0.002153
A5	2	6	3.08	10	876.0	0.003169
A6	3	9	1.98	10	876.0	0.002040
A7	3	24	0.02	768	11.41	0.001747
A8	4	9	1.76	10	876.00	0.001814
A9	5	10	1.54	10	876.00	0.001588
A10	6	10	0.33	35	250.29	0.001280
A11	7	8	1.10	10	876.00	0.001135
A12-1	8	9	2.74	10	876.00	0.002820
A13-2	8	10	2.74	10	876.00	0.002820
A14	9	11	0.02	768	11.41	0.001747
A15	9	12	0.02	768	11.41	0.001747
A16	10	11	0.02	768	11.41	0.001747
A17	10	12	0.02	768	11.41	0.001747
A18	11	13	1.20	11	796.36	0.001374
A19	11	14	1.09	11	796.36	0.001248
A20	12	13	1.20	11	796.36	0.001374
A21	12	23	2.12	11	796.36	0.002424
A22	13	23	1.99	11	796.36	0.002276
A23	14	16	1.08	11	796.36	0.001236
A24	15	16	0.63	11	796.36	0.000722
A25-1	15	21	1.21	11	796.36	0.001385
A25-2	15	21	1.21	11	796.36	0.001385
A26	15	24	1.31	11	796.36	0.001499
A27	16	17	0.75	11	796.36	0.000859
A28	16	19	0.74	11	796.36	0.000848
A29	17	18	0.52	11	796.36	0.000596
A30	17	22	2.34	11	796.36	0.002674
A31-1	18	21	0.75	11	796.36	0.000859
A31-2	18	21	0.75	11	796.36	0.000859
A32-1	19	20	1.08	11	796.36	0.001236
A32-2	19	20	1.08	11	796.36	0.001236
A33-1	20	23	0.74	11	796.36	0.000848
A33-2	20	23	0.74	11	796.36	0.000848
A34	21	22	1.65	11	796.36	0.001888

Table B1: Generators data

Unit (MW)	Type	MTTF (hr)	MTTR (hr)	λ (f/yr)	ORR (T=1hr)	Cost function ($/hr)	Fuel cost ($/MWhr)	Operat.cost ($/MWhr)	Min. output (MW)	Ramp rate (MW/min)
5	Hydro	4380	45	2.0	0.000228	0.5P	0.45	0.05	0	1
10	Thermal	2190	45	4.0	0.000457	$14+12.5P+0.02P^2$	10.0	2.50	3	1
20	Hydro	3650	55	2.4	0.000274	0.5P	0.45	0.05	0	4
20	Thermal	1752	45	5.0	0.000571	$16+12.25P+0.02P^2$	9.75	2.50	5	1
40	Hydro	2920	60	3.0	0.000342	0.5P	0.45	0.05	0	8
40	Thermal	1460	45	6.0	0.000685	$26+12P+0.01P^2$	9.50	2.50	10	2

Table B2: Incremental cost and price bid data for the RBTS generators

Unit (MW)	Type	Incremental cost ($/MWhr)	Strategy factor	Energy price bid ($/MWhr)	Reserve price bid ($/MWhr)
5	Hydro	0.50; $0 \le P \le 5$	24.5	12.25; $0 \le P \le 5$	1.28; $0 \le R \le 5$
20	Hydro	0.50; $0 \le P \le 20$	24.5	12.25; $0 \le P \le 20$	1.28; $0 \le R \le 20$
40	Hydro	0.50; $0 \le P \le 40$	24.5	12.25; $0 \le P \le 40$	1.28; $0 \le R \le 40$
10	Thermal	12.76; $3 \le P \le 10$	1	12.76; $3 \le P \le 10$	2.55; $0 \le R \le 7$
20	Thermal	12.75; $5 \le P \le 20$	1	12.75; $5 \le P \le 20$	2.55; $0 \le R \le 15$
40	Thermal	12.30; $10 \le P \le 20$	1	12.30; $10 \le P \le 20$	2.55; $0 \le R \le 30$
		12.50; $20 \le P \le 30$		12.50; $20 \le P \le 30$	
		12.70; $30 \le P \le 40$		12.70; $30 \le P \le 40$	

Table B3: Transmission lines data

Line	From bus	To bus	$\lambda = \lambda_p + \lambda_t$ (f/yr)	Dur. (hr)	μ (r/yr)	Pr (Down)	R (p.u.)	X (p.u.)	B/2 (p.u.)	Current rating (p.u.)
1	1	3	5.25	10	876	0.005387	0.0342	0.180	0.0106	0.85
2	2	4	17.50	10	876	0.017687	0.1140	0.600	0.0352	0.71
3	1	2	14.00	10	876	0.014211	0.0912	0.480	0.0282	0.71
4	3	4	3.50	10	876	0.003599	0.0228	0.120	0.0071	0.71
5	3	5	3.50	10	876	0.003599	0.0228	0.120	0.0071	0.71
6	1	3	5.25	10	876	0.005387	0.0342	0.180	0.0106	0.85
7	2	4	17.50	10	876	0.017687	0.1140	0.600	0.3520	0.71
8	4	5	3.50	10	876	0.003599	0.0228	0.120	0.0071	0.71
9	5	6	3.50	10	876	0.003599	0.0228	0.120	0.0071	0.71

100 MVA base; 230 kV base

Table B4: Common mode failures in transmission system

Line	From bus	To bus	λ (f/yr)	Dur. (hr)	μ (r/yr)	Probability
1 6	1	3	0.150	16	547.5	0.000257
2 7	2	4	0.500	16	547.5	0.000857

Appendix A: This appendix gives the required probabilistic data for the IEEE-RTS. The generation and transmission data are shown in Table A1 and A2 respectively.

Appendix B: This appendix gives the RBTS data. Generators data are shown in Table B1 and B2. Price

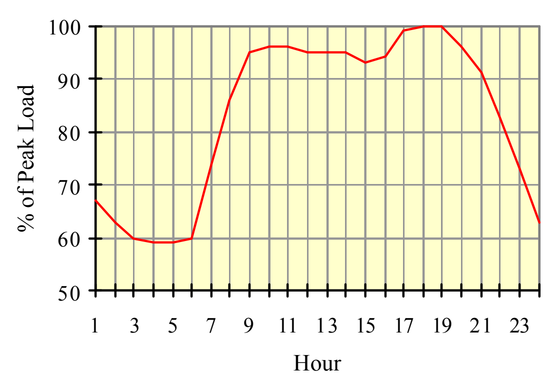

Fig. B2: Hourly peak load in percent of annual peak (= 185 *MW*)

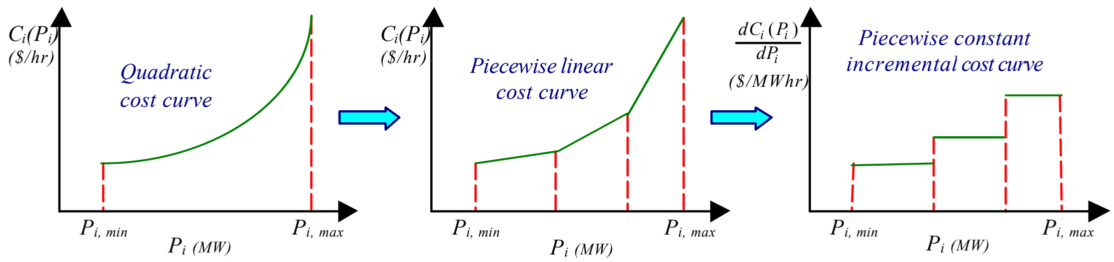

Fig. B1: Quadratic cost curve and its associated piecewise linear cost curve and piecewise constant incremental cost curve [1]. It is considered here that suppliers bid their price-based supply curves as their incremental cost multiplied by a strategy factor

Table B5: Hourly peak load for a winter weekday [26]

Hour		1	2	3	4	5	6	7	8	9	10	11	12
Load	%	67	63	60	59	59	60	74	86	95	96	96	95
	MW	123.95	116.55	111.00	109.15	109.15	111.00	136.90	159.10	175.75	177.60	177.60	175.75
Hour		13	14	15	16	17	18	19	20	21	22	23	24
Load	%	95	95	93	94	99	100	100	96	91	83	73	63
	MW	175.75	175.75	172.05	173.90	183.15	185.00	185.00	177.60	168.35	153.55	135.05	116.55

Table B6: The VOLL of customers ($/MWhr) for an interruption duration of 1 hr

Large users	Industrial	Commercial	Agriculture	Residential
163	2990	2951	295	243

Table B7: Discos data

Disco	Bus	Customers	Demand (MW)	Maximum acceptable risk level
A	2	Small users, governmental and industrial	20	0.005
B	3	Large users, small users, office buildings	85	0.003
C	4	Small users	40	0.008
D	5	Governmental and industrial, office buildings	20	0.002
E	6	Small users, farms	20	0.010
Total:	185	0.005		

Table B8: Relative contribution of discos to total system opportunity cost

Disco A	Disco B	Disco C	Disco D	Disco E
8.11%	57.43%	10.14%	20.27%	4.05%

bids (Table B2) are determined using generation cost data presented in Table B1 and the methodology shown in Fig. B1. Transmission network data are presented in Table B3 and B4 and the required data for distribution companies and load sector are shown in Table B5-B8 and Fig. B2.

The B matrix loss formula (Equation 12) for the RBTS network is given here. All power values must be per unit on 100MVA base. The formula has been obtained using the MATLAB power system toolbox [29].

$$P_{Loss,t} = [P]^T \times \begin{bmatrix} 0.0155 & 0.0009 \\ 0.0009 & 0.0301 \end{bmatrix} \times [P] + [0.0004 \quad -0.0018] \times [P] + 3.5608 \times 10^{-4} \quad \text{(B1)}$$

$$t = 1,2,\ldots,24$$

Nomeclature

i:	Index for generating unit.
t:	Index for time.
UC:	Unit commitment.
RTS:	Reliability test system.
ISO:	Independent system operator.
Genco:	Generation company.
VOLL:	Value of lost load.
λ:	Failure rate (failures per year).
λ_p:	Permanent failure rate (failures per year).
MTTF:	Mean time to failure.

$Pr_{Up}(t)$: Probability of Up state as a function of time.
$Load_j$: Load of the j^{th} consumer (Disco).
$Risk_{System,t}$: System risk at time t.
$Risk_{HLI}$: Generation system risk.
ORR: Outage replacement rate.
$P_{i,min}$: Minimum output power of the i^{th} generating unit.
ρ_{it}: Energy price bid of the i^{th} generator at time t.
P_{it}: Power of the i^{th} generator at time t.
N_G: Total number of generators.
$P_{Loss,t}$: Power losses of transmission system at time t.
$[B']$: Constant square matrix in DC power flow formula.
P_{lt}: Power flow of the l^{th} transmission line at time t.
R_{it}: Spinning reserve of the i^{th} generator at time t.
T: Lead time.
Dur: Repair time.
ρ_{itr}: Reserve price bid of the i^{th} generator at time t.
u_{it}: Discrete variable which represents the status of the i^{th} generator at time t and equals 1 if the unit is on and 0 if the unit is off.
$T_{i,\,up}$: Minimum up time of the i^{th} generator.
$X_{it,\,up}$: On time of the i^{th} generator at time t.
R: Resistance of transmission line.
B: Charging susceptance of transmission line.
$Energy_{i,\,max}$: Maximum available energy of the i^{th} hydro unit in a 24 hr. period.
α_j: A factor which represents the participation of the j^{th} consumer (Disco) in total system reserve cost.
N_{Line}: Total number of transmission lines.
j: Index for consumer (load).
l: Index for transmission line.
OPF: Optimal power flow.
RBTS: Roy Billinton test system.
GAMS: General algebraic modeling system.
Disco: Distribution company.
VOLU: Value of lost unit.
μ: Repair rate (repairs per year).
λ_t: Temporary failure rate (failures per year).
MTTR: Mean time to repair.
$Pr_{Down}(t)$: Probability of Down state as a function of time.
$Risk_j$: Acceptable risk of the j^{th} consumer (Disco).
$Risk_{Trans}$: Transmission system risk.
$Risk_{HLII}$: Composite system risk.
FOR: Forced outage rate.
$P_{i,max}$: Maximum output power (capacity) of the i^{th} generating unit.
ρ_{jt}: Energy price bid of the j^{th} consumer (Disco) at time t.
P_{jt}: Demand power of the j^{th} consumer (Disco) at time t.
N_D: Total number of consumers (Discos).
$[B], B_0, B_{00}$: Constants in the B matrix loss formula.
$[\Delta\Theta_t]$: Vector of system bus angles at time t.
$P_{Limit,l}$: Maximum transmission capacity of the l^{th} line
RR_i: Ramp rate of the i^{th} generator in MW per minute.
$C_i(P_i)$: Cost function of the i^{th} generator.
MCP_t: Market clearing price at time t.
$R_{it(max)}$: Maximum reserve of the i^{th} generator at time t.
u_{itr}: Discrete variable which is 1 if the i^{th} generator is committed for reserve at time t and 0 if it is not.
$T_{i,\,down}$: Minimum down time of the i^{th} generator.
$X_{it,\,down}$: Off time of the i^{th} generator at time t.
X: Reactance of transmission line.
$Profit_{it}$: Profit of the i^{th} generator at time t.
Operat. $Cost_i$: Operating cost of the i^{th} generator.
$\beta_1, \beta_2, \beta_3$: Experimental factors for approximating the amount of reserve required for system security.

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