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RELIABILITY EVALUATION OF DEREGULATED POWER SYSTEM CONSIDERING COMPETITIVE ELECTRICITY MARKET*

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Abstract– In a deregulated electric power system in which a competitive electricity market can influence system reliability, system analysts are rapidly recognizing that they cannot ignore market risks. This paper first proposes an analytical probabilistic model for the reliable evaluation of competitive electricity markets and then develops a methodology for incorporating the market reliability problem into composite power system reliability studies. The market reliability is evaluated using the Markov state space diagram. Since the market is a continuously operated system, the concept of absorbing states is applied to it in order to evaluate reliability. The market states are identified using market performance indices and the transition rates are calculated using historical data. The key point in the proposed method is the concept that the reliability level of a restructured electric power system can be calculated using the availability of the composite power system and the reliability of the electricity market. To illustrate an interesting feature of the proposed methodology, two case studies are carried out over a test system.

Keywords– Deregulation, electricity market, Markov modeling, reliability, risk, performance indices

1. INTRODUCTION

For about a hundred years, the electricity supply industry was in the 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. [1]

It can be clearly seen that the thrust towards privatization and deregulation of the electric utility industry has introduced a wide range of reliability issues that will require new criteria and analytical tools that recognize the residual uncertainties in the new environment. The traditional uncertainties associated with equipment availabilities will be augmented by a new set of concerns such as uncertainties associated with a competitive market mechanism. [2-5]

There are many variations on the definition of reliability, but a widely accepted form [6] is as follows: *Reliability is the probability of a device/component/system performing its purpose adequately for the period of time intended under the operating conditions encountered.* The criterion of 'adequate performance' is an engineering and managerial problem. It is evident that the criteria of adequate performance for a restructured power system are not the same as the criteria for a traditional one. (Fig. 1)

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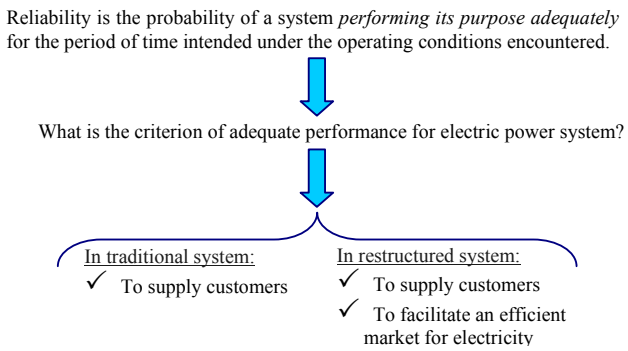

Fig.1. Reliability definition and its interpretation in electric power system

There is a wide range of probabilistic tools and indices which can be used to effectively analyze the bulk system reliability. Traditionally, the basic techniques for reliability evaluation have been categorized in terms of their application to the main functional zones of an electric power system. These are: generation systems, composite generation and transmission (or bulk power) systems, and distribution systems. 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. 2, 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 the complete system including distribution. [7] The target of this study is the reliability evaluation of HLII in a competitive market environment.

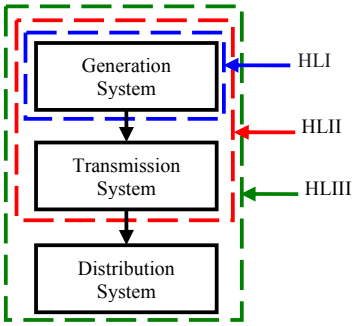

Fig. 2. Electric power system hierarchical level diagram [7].

This paper presents a new method for evaluating reliability indices of a competitive electric power system. The key point in the proposed method is the concept that the reliability level of a restructured electric power system can be calculated using the availability of the composite power system (HLII) and the reliability of the electricity market (Fig. 3). Two numerical examples showing the application of the proposed method in a deregulated power system are described.

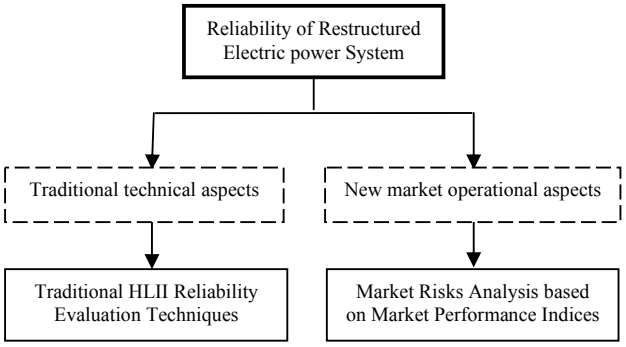

Fig. 3. Reliability aspects of a restructured electric power system and their assessment tasks

The paper has the following structure. A brief introduction to competitive electricity market structure and its performance indices is provided in Section 2; Section 3 describes concepts and techniques of Markov modeling and reliability evaluation; the proposed methodology is studied in Section 4; case studies are presented in Section 5; and finally, conclusions are presented in Section 6.

2. ELECTRICITY MARKET

Markets are a very old invention that can be found in most civilizations. A market is an environment designed to help buyers and sellers interact and agree on transactions. The development of electricity markets is based on the premise that electrical energy can be treated as a commodity [1]. In this paper, a wholesale competition structure is considered which includes a power-pool. The structure is shown in Fig. 4.

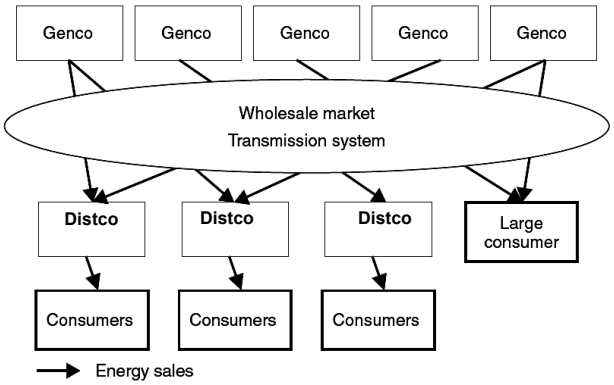

Fig. 4. Wholesale competition model for electricity market [1]

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 (DistCos)* own and operate distribution networks. In a wholesale competition model, they have a monopoly on the sale of electrical energy to all consumers connected to their network.

✓ *The independent system operator (ISO).* 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 electricity markets are typically operated subject to reliability constraints. The ISO is an entity which "sees" the overall generation, transmission and load "picture" and handles what is called "reliability management".

Market monitoring has been identified as a basic function in the deregulated electricity environment. The existing ISOs have market monitoring units and have developed, or are developing, systems and procedures to accomplish this function in their respective areas of responsibility [8]. Essential to system monitoring is effective system analysis. In a narrow sense, system monitoring focuses on the observation of the system performance indices and detection of inefficient outcomes. A few of the widely used market performance indices are defined in the following [8-15]:

- *System available/committed capacity reserve margin (CRM)*

CRM is the system capacity reserve margin calculated by the system's currently available capacity (or day-ahead capacity) and the system current load. This index will take the uncertain factors into account and test how reliable and prepared the system has been.

$$CRM = \frac{Available\,Capacity - Load}{Available\,Capacity} \times 100\% \quad (1)$$

- *Transmission congestion index (TCI) and TCI in percentage (TCIP)*

TCI in $/MWh is defined as the total transmission congestion cost divided by the total system energy. TCI in percentage (TCIP) is defined as TCI divided by the system energy-weighted average market clearing price.

$$TCI = \frac{Total\ Congestion\ Cost\ (\$)}{Total\ System\ Energy\ (MWh)} \quad (2)$$

$$TCIP = \frac{TCI}{System\ Average\ Market\ Clearing\ \Pr ice} \times 100\% \quad (3)$$

- *Market clearing price monitoring index (CPMI)*

CPMI is the difference in percentage between the highest market clearing price and the highest generation cost. It is designed to test whether the market price is within a reasonable profit range for the players and consumers. In order to simplify the equation, highest market clearing price is abbreviated as MaxMCP, reasonable profit margin is abbreviated as RPM, and ISO-estimated equivalent generation cost in $/MWh for the highest accepted bidder is abbreviated as MaxCost.

$$CPMI = \frac{MaxMCP - MaxCost \times RPM}{MaxCost \times RPM} \times 100\% \quad (4)$$

- *Market clearing price deviation (CPD) and market clearing price distribution index (CPDI)*

Market clearing price deviation (CPD) is the standard deviation of system market clearing prices. CPDI is defined as the CPD divided by the system energy-weighted average market clearing price.

$$CPD = \sqrt{\frac{\sum_{i}^{L} (MCP_i - AvgMCP)^2}{L}} \quad (5)$$

$$CPDI = \frac{CPD}{|AvgMCP|} \times 100\% \quad (6)$$

- *Herfindahl-Hirschman Index (HHI)*

Group HHI is defined as the sum of the squares of the generation (energy) shares in percentage for all load areas at a certain hour. If a group is made up of m generation owners, the group HHI, at a certain hour, can be expressed as follows:

$$HHI_G = \sum_{i=1}^{m} \left(\frac{MWh_i}{Total_G} \times 100 \right)^2 \quad (7)$$

System HHI is defined as the square root of weighted average HHI^2 based upon the generation (energy) shares in percentage for all groups at a certain hour. If a power system is made up of n groups, the system HHI at a certain hour can be expressed as follows:

$$HHI_S = \sqrt{\sum_{j=1}^{n} \left(\frac{MWh_j}{Total_S} \times HHI_{Gj}^2 \right)} \quad (8)$$

- *Market power monitoring index (MPMI)*

System MPMI is equal to system HHI every hour. The yearly index is the square root of energy-weighted average $MPMI^2$ as follows:

$$MPMI_{hr} = HHI_S \tag{9}$$

$$MPMI_{yr} = \sqrt{\sum_{k=1}^{8760}\left(\frac{MWh_k}{Total_{yr}} \times MPMI_k^2\right)} \tag{10}$$

3. MARKOV MODELING AND RELIABILITY EVALUATION

Reliability evaluation techniques are being used in a wide range of engineering systems. The two main categories into which systems can be divided are mission oriented systems and continuously operated systems. Mission oriented systems are those that must continue to function without failure for the duration of the mission. Continuously operated systems, however, are those in which a number of system down states are tolerable provided they do not happen too frequently or last too long.

One very important technique for evaluating the reliability of systems is known as the Markov modeling. The Markov approach can be applied to the random behavior of systems that vary discretely or continuously with respect to time and space. Reliability problems are normally concerned with systems that are discrete in space, i.e., they can exist in one of a number of discrete and identifiable states, and be continuous in time; i.e., they exist continuously in one of the system states until a transition occurs which takes them discretely to another state in which they then exist continuously until another transition occurs.

The basic concepts of Markov modeling of continuous processes can be illustrated by considering the simple system shown in Figure 5(a), in which two system states are identifiable, being designated 0 and 1.

The parameters λ and μ are referred to as state transition rates since they represent the rate at which the system transits from one state of the system to another. This concept of a transition rate leads to the definition

Transition rate=number of times a transition occurs from a given state/time spent in that state (11)

The probabilities of remaining in or leaving a particular state can be derived using the state transition rates. Some states of a system may be absorbing states, i.e., states which, once entered, cannot be left until the system starts a new mission. These can readily be identified in terms of mission oriented systems. The principle behind such systems can also be applied to continuously operated (repairable) systems in order to evaluate the average time the system will operate satisfactorily before entering an undesirable state.

It is evident from the definition of reliability in section 1 that this definition relates to the ability of a system to continue functioning without failure, i.e., to complete a mission satisfactorily. Therefore, reliability can be interpreted as *the probability of a component/device/system staying in the operating state without failure.* Therefore, this measure is suitable for quantifying the adequacy of mission oriented systems and is unsuitable as a measure for continuously operated systems that can tolerate failures. The measure used for these systems is 'availability', which is interpreted as *the probability of finding the component/device/system in the operating state at some time into the future.* Consider the case of a single repairable system for which the failure rate and repair rate are constant, i.e. they are characterized by the exponential distribution. The state transition diagram for this system is shown in Fig. 5. [6]
The time dependent availability A(t) of the system is given by Eq. (12), i.e.,

$$A(t) = \frac{\mu}{\lambda+\mu} + \frac{\lambda}{\lambda+\mu}e^{-(\lambda+\mu)t} \tag{12}$$

As noted earlier, this is the probability of being found in the operating state at some time t in the future given that the system started in the operating state at time t=0. This is quite different from the reliability R(t) as given by

$$R(t) = e^{-\lambda t} \tag{13}$$

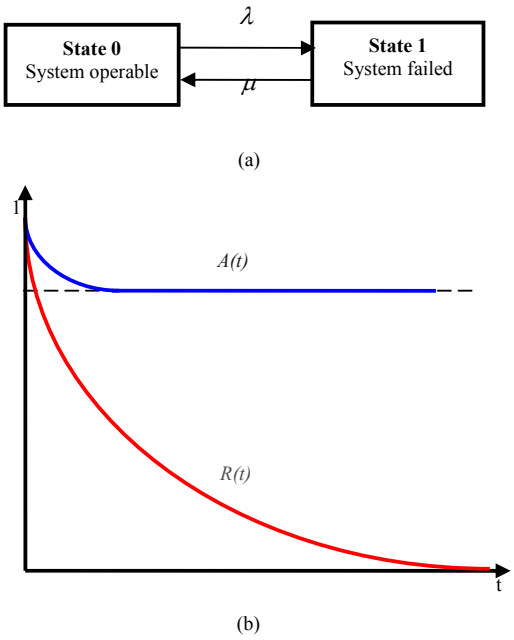

Fig. 5. Repairable system: a) State space diagram. b) Variation of reliability and availability [3]

4. METHODOLOGY

The electricity market "risks" can be analyzed using Markov modeling. Risk is the exposure to uncertainty. A common classification of risks is based on the source of underlying uncertainty. Competition in restructured electricity markets has created new risks which could include price risk, among others.

The market is a continuously operated system, however, as noted previously, the concept of absorbing states can be applied to it in order to evaluate the reliability. The market states can be identified using market performance indices and the transition rates can be calculated using historical data.

The main issues of market performance and their related indices are shown in Table 1. The ranges of the proposed indices and their interpretations are derived from a number of selected references [8-15].

Table 1. The main issues of electricity market performance and their related indices

Market issue	Index	Range	Interpretation
Available (committed) generation capacity	CRM	CRM>5%	Adequate capacity
		CRM<5%	Inadequate capacity
Transmission congestion	TCIP	TCIP>10%	Congested network
		TCIP<10%	Open network
Profit for the players and consumers	CPMI	CPMI<5%	Reasonable profit
		CPMI>5%	Unreasonable profit
Market power	HHI	HHI<1000	Competitive market
		1000<HHI<1800	Moderately competitive market
		HHI>1800	Anti-competitive market

It can be seen from Table 1 that $2 \times 2 \times 2 \times 3 = 24$ states can be identified for the electricity market. In order to consider the joint effects of all market issues, an electricity market can be represented by the twenty four-state model shown in Table 2 and Fig. 6. Obviously, the number of states in the state space diagram increases as the number of market performance indices increases and the model can therefore become unmanageable.

Two solutions are possible in these circumstances. The first involves state truncation. This approach utilizes engineering and managerial judgment based on experience to reduce the number of possible market states by neglecting those that have a very low probability of occurrence. The second solution involves approximate modeling based on only a few selected indices. A simple three state Markov model for the electricity market is shown in Fig. 7.

Table 2. Twenty four states of the electricity market

State	Market issues			
	Available (committed) generation capacity	Transmission congestion	Profit for players and consumers	Market power
1	Adequate	Open	Reasonable	Competitive
2	Adequate	Open	Reasonable	Moderately competitive
3	Adequate	Open	Reasonable	Anti-competitive
4	Adequate	Open	Unreasonable	Competitive
5	Adequate	Open	Unreasonable	Moderately competitive
6	Adequate	Open	Unreasonable	Anti-competitive
7	Adequate	Congested	Reasonable	Competitive
8	Adequate	Congested	Reasonable	Moderately competitive
9	Adequate	Congested	Reasonable	Anti-competitive
10	Adequate	Congested	Unreasonable	Competitive
11	Adequate	Congested	Unreasonable	Moderately competitive
12	Adequate	Congested	Unreasonable	Anti-competitive
13	Inadequate	Open	Reasonable	Competitive
14	Inadequate	Open	Reasonable	Moderately competitive
15	Inadequate	Open	Reasonable	Anti-competitive
16	Inadequate	Open	Unreasonable	Competitive
17	Inadequate	Open	Unreasonable	Moderately competitive
18	Inadequate	Open	Unreasonable	Anti-competitive
19	Inadequate	Congested	Reasonable	Competitive
20	Inadequate	Congested	Reasonable	Moderately competitive
21	Inadequate	Congested	Reasonable	Anti-competitive
22	Inadequate	Congested	Unreasonable	Competitive
23	Inadequate	Congested	Unreasonable	Moderately competitive
24	Inadequate	Congested	Unreasonable	Anti-competitive

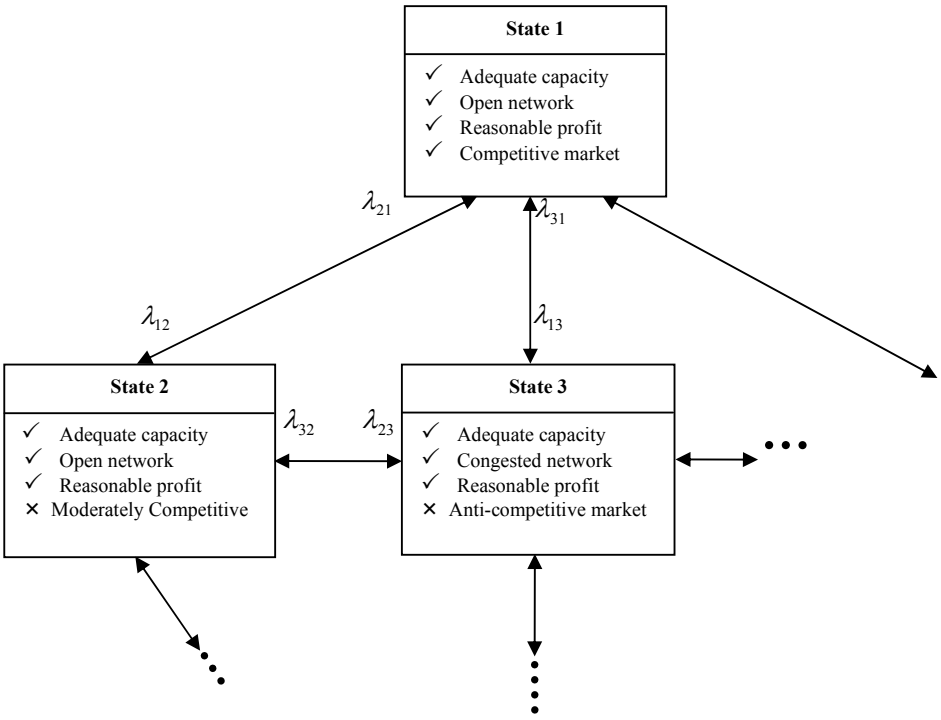

Fig. 6. Part of Markov state space diagram of the electricity market. The number of states in the diagram increases as the number of market performance indices increases and the number of states in which each index can reside increases. If $n+m$ indices are considered, the number of states in the diagram are $2^n \times 3^m$ where n is the number of 2-state indices and m is the number of 3-state ones

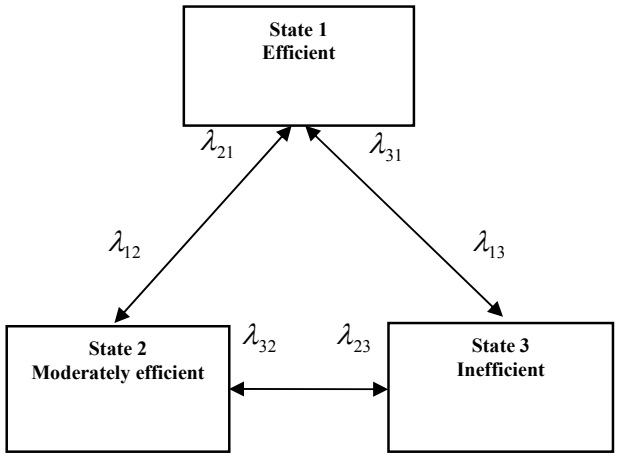

Fig.7. A typical three state Markov model for the electricity market. The transition rates are in occ./yr

5. CASE STUDIES

a) Markov modeling based on market power index (HHI_S)

Consider an electricity market with historical data shown in Table 3. It is assumed here that the Markov modeling is based on the market power index (HHI_S). This assumption can easily be removed allowing more indices to be considered in market modeling.

Table 3. Market states data for the last year of market operation

State	Hours per year	Transition	
1. Competitive (HHI_S<1000)	5221	To state 1:	3995
		To state 2:	1181
		To state 3:	45
2. Moderately competitive (1000<HHI_S<1800)	3167	To state 1:	1117
		To state 2:	1807
		To state 3:	241
3. Anti-competitive (HHI_S>1800)	374	To state 1:	109
		To state 2:	177
		To state 3:	88

From the above data, the model shown in Fig. 7 and the concept of Eq. (11), the transition rates can be calculated as $\lambda_{12}=0.226$, $\lambda_{21}=0.353$, $\lambda_{23}=0.076$, $\lambda_{32}=0.473$, $\lambda_{13}=0.009$ and $\lambda_{31}=0.291$.

Using the above transition rates, the time dependent state probabilities can be derived from the following differential equations

$$P_1(t+dt)=P_1(t)\times(1-(\lambda_{12}+\lambda_{13})\times dt)+P_2(t)\times\lambda_{21}\times dt+P_3(t)\times\lambda_{31}\times dt \tag{14}$$

$$P_2(t+dt)=P_1(t)\times\lambda_{12}\times dt+P_2(t)\times(1-(\lambda_{21}+\lambda_{23})\times dt)+P_3(t)\times\lambda_{32}\times dt \tag{15}$$

$$P_3(t+dt)=P_1(t)\times\lambda_{13}\times dt+P_2(t)\times\lambda_{23}\times dt+P_3(t)\times(1-(\lambda_{31}+\lambda_{32})\times dt) \tag{16}$$

Therefore,

$$\begin{pmatrix}P_1'(t) & P_2'(t) & P_3'(t)\end{pmatrix}=\begin{pmatrix}P_1(t) & P_2(t) & P_3(t)\end{pmatrix}\times\begin{pmatrix}-(\lambda_{12}+\lambda_{13}) & \lambda_{12} & \lambda_{13}\\ \lambda_{21} & -(\lambda_{21}+\lambda_{23}) & \lambda_{23}\\ \lambda_{31} & \lambda_{32} & -(\lambda_{31}+\lambda_{32})\end{pmatrix} \tag{17}$$

The above state probability expressions give the probability of being found in each of the three states at a given time t in the future. In order to calculate the market reliability, the process must come to a halt when state 3 is encountered. This can be achieved by modifying the state space diagram to make state 3 an absorbing state. When state 3 is encountered, the market effectively comes to a halt until the whole process is started again at state 1.

Equation (17) is modified as follows:

$$\begin{pmatrix}P_1'(t) & P_2'(t) & P_3'(t)\end{pmatrix}=\begin{pmatrix}P_1(t) & P_2(t) & P_3(t)\end{pmatrix}\times\begin{pmatrix}-(\lambda_{12}+\lambda_{13}) & \lambda_{12} & \lambda_{13}\\ \lambda_{21} & -(\lambda_{21}+\lambda_{23}) & \lambda_{23}\\ 0 & 0 & 0\end{pmatrix} \tag{18}$$

Solving this set of differential equations, the market risk and reliability can be calculated:

$$Market\ reliability=P_1(t)+P_2(t)=1.040e^{-0.034t}-0.040e^{-0.630t} \tag{19}$$

and

$$Market\,risk = P_3(t) = 1 - 1.040e^{-0.034t} + 0.040e^{-0.630t} \tag{20}$$

The time dependent variation of market reliability is shown in Fig. 8.

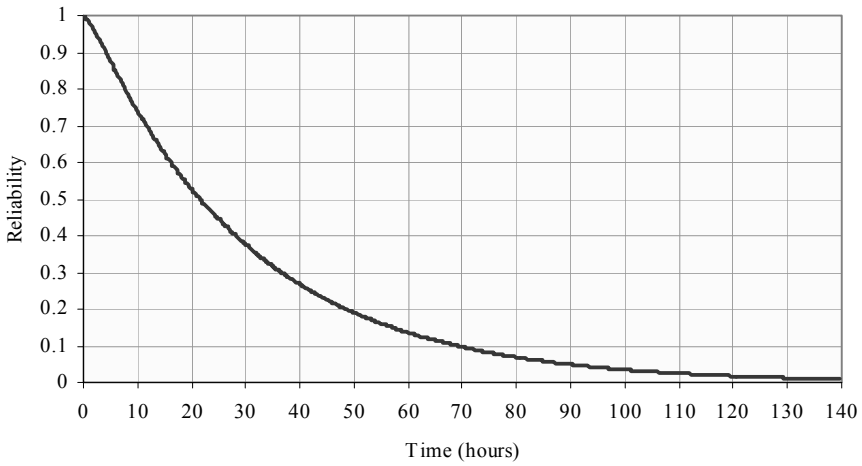

Fig. 8. Time dependent variation of market reliability

b) Nodal evaluation of system success in a competitive environment

Figure 9 shows the competitive power system of which market reliability was studied in part B. The system includes two generation companies (GenCo) and two distribution companies (DistCo). The open access transmission network is managed by the ISO. The relevant data are listed in Table 4.

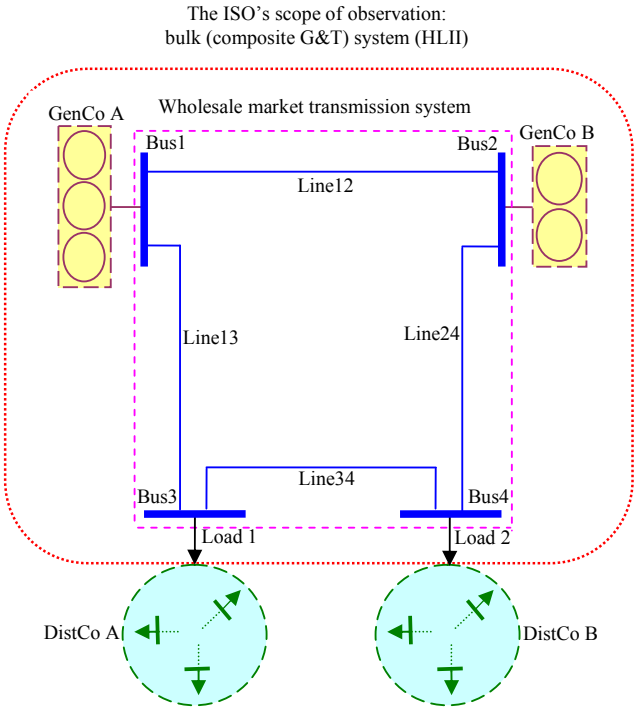

Fig. 9. Test system

Table 4. System data

Generation data

GenCo	No. of units	Unit capacity (MW)	Failure rate λ (failures/year)	Repair rate μ (repairs/year)
A	3	25	2	98
B	2	30	4	46

Transmission line data

Line	Failure rate λ (failures/year)	Repair time (hours)	Load carrying capability (MW)
12	2	12	50
13	5	15	100
24	3	15	90
34	4	12	50

Distribution data

Disco	Load (MW)
A	60
B	40

The probability of failure $LOLP_K$ at load point K in the network can be expressed as [7]

$$LOLP_K = \sum_j \left[P(B_j) \times \left(P_{gj} + P_{lj} - P_{gj} \times P_{lj}\right)\right] \tag{21}$$

where

B_j = an outage condition in the transmission network (including zero outages)

P_{gj} = probability of the generating capacity outage exceeding the reserve capacity

P_{lj} = probability of load at bus K exceeding the maximum load that can be supplied at the bus without failure.

The probabilistic models of GenCo A, GenCo B and the total generation system are shown in Table 5. The transmission line availabilities (A) and unavailabilities (U) for the system in Fig. 9 are given in Table 6 using the data from Table 4. Table 7 shows all 16 possible outage conditions in the transmission network and their probabilities.

Table 5. Probabilistic models of generation system

GenCo A: $3 \times 25MW, FOR = 2\%$

State	Capacity in	Capacity out	Individual probability	Cumulative probability
1	75	0	$A^3 = 0.941192$	1.000000
2	50	25	$3A^2U = 0.057624$	0.058808
3	25	50	$3AU^2 = 0.001176$	0.001184
4	0	75	$U^3 = 0.000008$	0.000008

GenCo B: $2 \times 30MW, FOR = 8\%$

State	Capacity In	Capacity out	Individual probability	Cumulative probability
1	60	0	$A^2 = 0.8464$	1.0000
2	30	30	$2AU = 0.1472$	0.1536
3	0	60	$U^2 = 0.0064$	0.0064

Probabilistic model of total generation system

State	Capacity in	Capacity out	Individual probability	Cumulative probability
1	135	0	0.79662491	1.00000000
2	110	25	0.04877295	0.20337510
3	105	30	0.13854346	0.15460215
4	85	50	0.00099537	0.01605869
5	80	55	0.00848225	0.01506332
6	75	60	0.00602363	0.00658107
7	60	75	0.00000677	0.00055744
8	55	80	0.00017311	0.00055067
9	50	85	0.00036880	0.00037756
10	30	105	0.00000118	0.00000876
11	25	110	0.00000753	0.00000758
12	0	135	0.00000005	0.00000005

Table 6. Transmission lines statistics

Line	Availability	Unavailability
12	0.99726776	0.00273224
13	0.99151104	0.00848896
24	0.99488927	0.00511073
34	0.99455041	0.00544959

Table 7. Outage conditions in the transmission network and their probabilities

State j	Transmission lines				$P(B_j)$
	12	13	24	34	
1	In	In	In	In	0.97838747
2	In	In	In	Out	0.00536103
3	In	In	Out	In	0.00502596
4	In	In	Out	Out	0.00002754
5	In	Out	In	In	0.00837660
6	In	Out	In	Out	0.00004590
7	In	Out	Out	In	0.00004303
8	In	Out	Out	Out	0.00000024
9	Out	In	In	In	0.00268051
10	Out	In	In	Out	0.00001469
11	Out	In	Out	In	0.00001377
12	Out	In	Out	Out	0.00000075
13	Out	Out	In	In	0.00002295
14	Out	Out	In	Out	0.00000013
15	Out	Out	Out	In	0.00000012
16	Out	Out	Out	Out	0.00000000

The load point index of service availability ($LOLP_K$) can be found using Eq. (21). The results are shown in Table 8.

Table 8. HLII study results for the test system

Bus	Load point	LOLP
3	1	0.024426
4	2	0.016032

Consider A as the event that the service is available at load point K and B as the event that the electricity market is efficient. The probability of system success is equal to the probability that both A and B occur:

$$\begin{aligned} P(\textit{system success at node } K) &= P(A \cap B) \\ &= P(B|A) \times P(A) \\ &= P(A|B) \times P(B) \end{aligned} \tag{22}$$

What is the probability of market success for a specified period of time given that the service has been available at load-point K? What is the probability of service being available at load-point K given that the market has been efficient for a specified period of time? These are difficult questions to answer. It is evident that market performance indices (esp. CRM and TCIP) depend on the adequacy and security of a composite G&T system, but the mechanism of this dependency is not clear and it is a very difficult task to analyze it quantitatively. If it can be assumed that A and B are independent events, then

$$P(\textit{system success at node } K) = P(A) \times P(B) = (1 - LOLP_K) \times \textit{Market reliability}\Big|_{t=\textit{Mission time}} \tag{23}$$

Since the electricity market is usually scheduled and operated for 24-hour time periods, it is an appropriate assumption that $t = 24\,hours$. Hence, the load point index of system success can be found using Eq. (23), Table 8 and Fig. 8. The results are shown in Table 9.

Table 9. Numerical results of nodal evaluation of system success

Bus	Load point	Prob. of system success
3	1	0.448652
4	2	0.452512

The results in Table 9 show that reliability is decreased when market risks are included in HLII studies.

It is useful here to state that in some cases, nodal indices of market performance can be defined. For example, a nodal index of transmission congestion can be defined as

$$TCI_K = \frac{\textit{Nodal Congestion Cost (\$)}}{\textit{Nodal Energy}\,(MWh)} \tag{24}$$

$$TCIP_K = \frac{TCI_K}{\textit{Locational Marginal Price at Node } K\,(LMP_K)} \times 100\% \tag{25}$$

The nodal indices of market performance can be employed to evaluate load-point indices of market reliability using the Markov approach as presented in section 4.

The time span for a power system is divided into two sectors: the planning phase (long-term) and the operating phase (short-term). Market efficiency in the short-term refers to a market outcome that maximizes the sum of the producer surplus and consumer surplus. In other words, short-term market efficiency will result when the most cost-effective generation resources are used to serve the load. Long-term market efficiency results from choosing the optimal level of investment in generation and transmission. [8] It should be realized that conventional generation planning has disappeared in the new environment and that composite generation and transmission planning have become the primary focus [3]. Composite generation and transmission system reliability evaluation will therefore be required to assess the effects of adding new capacities into the overall system. It is evident that the proposed nodal index of HLII reliability (the probability of system success at a given load-point) can be used in the long-term planning of a composite generation and transmission power system in a competitive environment.

6. CONCLUSION

This paper contends that the traditional definition of power system reliability may not be appropriate for deregulated electricity markets. Therefore, a methodology for reliability evaluation in a competitive market structure is proposed. In this method, a proper Markov state space model is employed to evaluate market reliability. Since the market is a continuously operated system, the concept of absorbing states is applied to it in order to evaluate the reliability. The market states are identified using market performance indices and the transition rates are calculated using historical data. The key point in the proposed method is the concept that the reliability level of a restructured electric power system can be calculated using the availability of the composite power system (HLII) and the reliability of the electricity market. The proposed methodology has been applied to a test system, and numerical results for two case studies are presented to show its applicability.

Further study includes the application of the proposed method to the planning and reliability evaluation of more complicated systems. The 24-state Markov model and nodal indices of market reliability may be necessary when a more detailed analysis of market risks is required.

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