COMPOSITE SYSTEM OPERATING STATE RISK EVALUATION

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COMPOSITE SYSTEM OPERATING STATE RISK EVALUATION

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ABSTRACT

There is considerable interest in the application of probability methods in composite system reliability evaluation. The problem is extremely complex because of the need to include detailed modeling of both generation and transmission facilities and their auxiliary elements. Quantitative adequacy assessment of a composite power system is generally performed for individual load points and the overall system. Many utilities have difficulty in interpreting some of the calculated indices as the existing models are often not perceived to include actual system operating conditions. A security constrained adequacy evaluation technique can be used to alleviate the utility concerns. The performance of a composite system can be examined using a set of predefined operating states in terms of the degree to which both adequacy and security constraints are satisfied. This technique is extended in this thesis to examine the impact on system reliability of common mode and station originated outages. A new approach to combine the dependent and independent outages is developed.

Composite system operating state risk (CSOSR) depends on many factors such as the actual physical power system, the system operating conditions and the applied constraints. This risk index can be compared with the loss of load probability (LOLP) which is commonly used in HL I studies. The effect on the CSOSR of a wide range of factors is extensively examined in this thesis. Most utilities are concerned with not only the system risk but also the system wellbeing in terms of the degree of margin or comfort. A new technique associated with composite system performance is developed to combine deterministic considerations and probabilistic indices to describe the wellbeing of an electric power system. Generating unit commitment analysis is usually performed at HL I based on a presumed acceptable risk level and the predicted system load. Two new procedures are presented to conduct composite system unit commitment for operational planning and daily operation. A matrix multiplication method is utilized to calculate the required time dependent state component probabilities which satisfies the precision, speed and simplicity requirements.

The concepts, techniques and procedures developed in this thesis are illustrated numerically using two reliability test systems. It is believed that the concepts and procedures presented will provide useful tools for power system managers, planners, designers and operators and permit them to perform composite system risk assessments, wellbeing analyses and unit commitment studies.

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LIST OF SYMBOLS AND ABBREVIATIONS

λ	Failure rate (f/yr).
λ_a	Active failure rate (f/yr).
λ_p	Passive failure rate (f/yr).
λ_t	Total failure rate (f/yr).
λ_m	Maintenance outage rate (f/yr).
μ	Repair rate (occ/yr).
μ_m	Maintenance repair rate (occ/yr).
μ_{sw}	Switching rate (occ/yr).
$[\delta]$	Phase angle vector.
$[B]$	Susceptance matrix.
$[P]$	Active power vector.
$[Q]$	Reactive power vector.
$[V]$	Voltage vector.
$[X]$	Reactance matrix.
$[\Delta P]$	Active power increment vector.
$[\Delta Q]$	Reactive power increment vector.
f	Frequency.
$f(t)$	Failure density function.
$F(t)$	Cumulative unreliability function.
$g(t)$	Repair density function.
$G(t)$	Cumulative repair function.
P	Probability.
P_i	Probability of State i.
$q(t)$	Switching density function.
$Q(t)$	Cumulative switching function.
r	Repair time (hours).
T_{SW}	Average switching time (hours).
T_{dn}	Duration in outage state.
T_{up}	Duration in up state.

AOP	Analytical Outage Probability.
COMREL	COMposite system RELiability evaluation program.
CP	Cumulative Probability.
CSOSR	Composite System Operating State Risk.
DPLVC	Daily Peak Load Variation Curve.
EPRI	Electric Power Research Institute.
HL	Hierarchical Level.
HL I	Hierarchical Level One.
HL II	Hierarchical Level Two.
HL III	Hierarchical Level Three.
LDC	Load Duration Curve.
LOLE	Loss Of Load Expectation.
LOLP	Loss Of Load Probability.
MRBTS	Modified Roy Billinton Test System.
NBR	Total number of breakers.
NBUS	Total number of buses.
NTRS	Total number of transformers.
OD	Outage Duration.
OP	Outage Probability.
OR	Outage Rate.
ORR	Outage Replacement Rate.
RBTS	Roy Billinton Test System.
RTS	Reliability Test System.
SECDEP	SECurity constrained reliability evaluation program with inclusion of DEPendent outages.
Set I	Voltage violation problems.
Set II	Overload problems.
Set III	Operating reserve constraints.
SOD	Simulated Outage Duration.
SOP	Simulated Outage Probability.
SOR	Simulated Outage Rate.
TTF	Time To Failure.
TTR	Time To Repair.
TTS	Time To Switching.

1. INTRODUCTION

1.1. Introduction

The basic function of an electric power system is to supply electrical energy to its customers as economically as possible and with a reasonable assurance of continuity, safety and quality. Modern society, because of its pattern and working habits, has come to expect the supply to be continuously available on demand. This creates the difficult problem of balancing the need for continuity of power supply and the cost involved. However, no matter how much money, time and effort are invested, and no matter how advanced techniques are utilized, it is impossible to eliminate the possibility of equipment outages and the need to remove equipment from service to perform preventive maintenance. It is therefore impossible economically and technically to design a power system with one hundred percent reliability. The probability of customers being disconnected can be reduced by increased investment during either the planning phase, the operating phase or both. Power system engineers have always attempted to provide as good a quality of supply as possible to their customers and to make this supply available at a minimum cost.

1.1.1. Power System Reliability

The ability of a power system to provide customers with adequate electrical energy is usually designated by the term "reliability". The concept of power system reliability is extremely broad and covers all aspects of the ability of the power system to satisfy the customers' requirements. The term reliability has a very wide range of meaning and can not be associated with a single specific definition. Power system reliability evaluation can be subdivided into the two domains of adequacy and security assessment [1, 2].

Adequacy relates to the existence of sufficient facilities within the power system to satisfy the customer load demand. This includes the necessary facilities to generate sufficient electrical energy and the associated transmission and distribution required to transfer the energy to the actual customer load points. Adequacy is associated with system static conditions. Security relates to the ability of the system to respond to disturbances. Security is therefore associated with the response of the system to whatever perturbations it is subjected to. These include the conditions associated with both local and widespread disturbances and the loss of major generation and transmission facilities. Therefore adequacy involves the steady state post outage analysis of power systems while security involves the analysis of both static and dynamic conditions.

1.1.2. Functional Zones and Hierarchical Levels

A modern electric power system is highly integrated, usually very large and very complex. The electrical energy is generated at its generating stations and supplied to the individual customers through a suitable transmission and distribution network. It is difficult or impossible to analyze the whole power system as a single entity using a completely realistic and exhaustive procedure. A power system is therefore usually divided into segments which can be analyzed separately. These segments include generating facilities, transmission elements and distribution networks [1, 2]. The functional zones and hierarchical levels are shown in Figure 1.1. Reliability assessment is usually focused on one or more of these functional zones. The assessment can be performed on combinations of these functional zones in the form of hierarchical levels. The evaluation of only the generating facilities is designated as hierarchical level I (HL I) assessment. The evaluation of the composite generating station and transmission system is designated as an hierarchical level II (HL II) study. The evaluation of the entire power system including the distribution functional zone is designated as hierarchical level III (HL III) evaluation. The research work described in this thesis is focused on reliability evaluation at HL II.

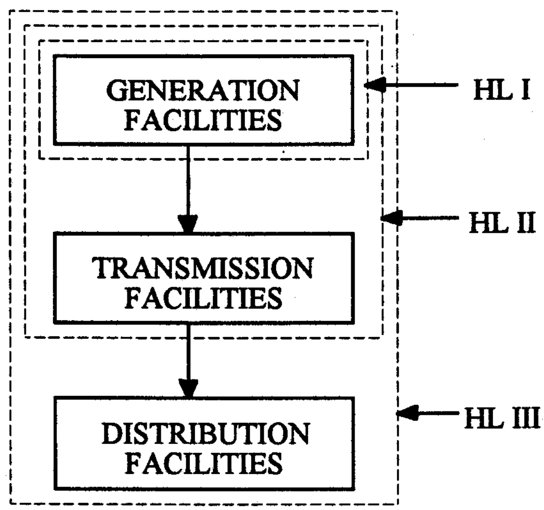


Figure 1.1: Hierarchical levels for reliability analysis.

1.1.3. Methods Used in Reliability Assessment

The techniques and the criteria used in power system reliability evaluation can be divided into the two broad categories of deterministic and probabilistic approaches. Typical deterministic techniques include (1) installed capacity equal to the expected maximum demand plus a fixed percentage of the expected maximum demand, (2) spinning capacity equals expected load demand plus a reserve equal to one or more of the largest units, (3) A n-1 criterion in which the system should meet the demand with the loss of any one element.

Although these and other similar approaches have been developed in order to account for randomly occurring failures, they are inherently deterministic. The essential weakness of these approaches is that they do not and can not account for the probabilistic or stochastic nature of system behavior, of customer demands or of component failures. A probabilistic approach can be used to recognize the stochastic nature of system components and to incorporate them in a consistent evaluation of the composite system reliability. This approach is illustrated in detail in this thesis. A combination of the deterministic and probabilistic approaches is also presented in order to provide power system managers, designers, planners and operators with a set of simple and understandable system planning and operating criteria.

1.2. Historical Development of Probabilistic Reliability Evaluation in Composite Systems

A power system generates electrical energy at its generating stations and supplies it to the individual customers through a suitable transmission and distribution network. The basic techniques for reliability assessment can, therefore, be divided in terms of their application to the functional zones and hierarchical levels as shown in Figure 1.1. Reliability assessment at the different functional zones and hierarchical levels has undergone continuous development and application since the 1930's. These developments can be seen from the bibliographies [3 - 7] published in the IEEE Transactions which contain more than 700 papers on reliability evaluation of power systems. Hierarchical level II includes both generation and transmission facilities and is also known as a composite or bulk power system. Composite system reliability evaluation techniques are therefore concerned with the total problem of assessing the generation and transmission facilities in regard to their ability to supply adequate electrical energy to the major customer load points.

The development of composite generation and transmission system reliability evaluation dates from the 1960's in North American and Europe. Reliability assessment was mainly focused on the generation area prior to this time. Reference 8 is an early example of considering both generation and transmission problems in reliability evaluation. Billinton proposed the term "composite system reliability evaluation" in a 1969 reference [9]. The approach described in Reference 9 includes a more completed composite system representation of the form used in load flow analysis. This technique utilizes a quality of service rather than a simple continuity of service criterion. A system failure is charged if the supply at a major transmission bus does not meet predetermined voltage standards and/or allowable equipment loadings. In this approach, adequacy evaluation of a composite generation and transmission system involves the simulation and computation of the system conditions for each possible outage condition in the system in order to determine the voltage violations, line and generator overloads, violation of generator MVAr limits, etc. The concepts outlined in

Reference 9 can be considered as the starting point in the development of techniques for composite system adequacy assessment. Two different methods have been applied to the reliability evaluation of composite power systems. The two methods are generally known as contingency enumeration and Monte Carlo simulation respectively [10 - 14]. These two approaches to reliability assessment are fundamentally different. The utilization of the simulation method at HL II appears to have been initiated by a need to suitably represent energy limited generating elements in HL I studies. Considerable research in both the areas of simulation [15 - 27] and contingency enumeration [28 - 39] have been published in the literature. A comparison between contingency enumeration and simulation techniques was published in 1985 [40] using the IEEE Reliability Test System [41]. The comparison indicates the conceptual differences in modeling and problem perception and allows a better understanding of the merits and demerits of the two approaches. A series of important selected papers on reliability assessment of electric power systems are presented in Reference 42.

Reliability evaluation at HL II is a complex task and there is no single accepted procedure available to include the various concerns of all the utilities. The computation time required to analyze a practical power system can be quite significant as a determination of the effects of unscheduled or unexpected disturbances or contingencies including load flows must be performed for each of the contingencies of interest. The purpose of this simulation is to determine the contingencies which cause limit violation(s) and the associated violation(s). There is a wide variation both in terms of techniques utilized to analyze the system and the quantitative indices created to reflect the reliability of the system.

A contingency is a sudden change in a power system due to unscheduled outages of equipment such as generating units and transmission lines, sudden and large changes in the load, and the occurrence of equipment faults. It is important to determine if the operating system is able to withstand disturbance without violating the system constraints. These analyses are an integral part of security assessment. There are two basic types of security analysis: steady state and transient [43, 44]. In the latter case, assessment consists of determining if the system oscillations following an outage or a fault will cause loss of synchronism among generating units. The objective of steady state security analysis is to determine whether, following the occurrence of a contingency, there exists a new steady state secure operating point where the perturbed power system will settle after the dynamic oscillations have damped out. The research work discussed in this thesis considers steady state assessment of the security problem in composite system reliability evaluation.

A contingency may or may not result in the violation of some of the equipment and system constraints. If the operating system passes all of the contingency tests, it is said to be operating in a secure state and no further action is taken. If the operating system fails to pass any one of the contingency tests, it is said to be operating in an insecure state and the particular contingency and associated limit violations are noted. When the system is operating in the insecure state, it may be possible to execute a preventive control action aimed at bringing the system into the acceptable operating state. Preventive control can be implemented using the following approaches: (1) modifying real power flows by rescheduling real power generation, resetting phase shifting transformers, etc., (2) modifying reactive power flows by rescheduling reactive power generation, and by using shunt capacitors and tap changing transformers, (3) changing the network topology via switching action, etc..

Exhaustive power flow simulation should be performed in order to determine the effect of contingencies on the network. However, this is not computationally feasible for a large system due to the large computing time required. It is not necessary to solve all possible contingencies by an actual ac load flow analysis if all possible contingencies [45, 46] do not create system problems. An approximate method can be used to determine the list of contingencies which create system problems and a detailed investigation of these contingencies can be conducted in further studies. The approximate method must have two main properties to be useful. The computation burden for the approximate method with the subsequent ac analysis of the selected contingencies must be less than that for ac analysis of all contingencies. This can be measured by the ratio of the execution times for the contingency selection and the time required for a full ac load flow analysis. The second desirable property is that the selection should be accurate in the sense that no constraints which contribute to the system risk are overlooked. Unfortunately, none of the available methods can attain this second desirable property. At best, they can provide a set of contingencies containing most of the cases causing system failure. Some severe contingencies may be omitted and some that are not severe may be included. An increase in accuracy can be obtained only at the cost of an increase in execution time.

There are two classes of approximate methods which have evolved over the last twenty years: screening and sensitivity-based ranking methods. The sensitivity-based ranking methods [47 - 56] do not identify or solve for specific system conditions. Rather, they quantify the severity of each outages by explicitly calculating a scalar value called a "performance index" by which all contingencies can be ranked. The methods, however, are not completely reliable since they are prone to "masking errors". Specifically, a contingency having a few severe violations can be ranked equally with one having many minor violations or even worse, with one without violations. The screening methods [57 - 66], though more demanding in computer resources, permit the identification of actual violations/major shifts and, therefore avoid masking error.

1.3. Objectives and Scope of the Thesis

There is considerable interest in the application of probability methods in composite system reliability evaluation. The problem is extremely complex because of the need to include detailed modeling of both generation and transmission facilities and to consider multiple levels of component failures. Composite system reliability assessment involves both generation and transmission facility outages and failure is defined when the system can not satisfy a defined set of constraints. The probabilities associated with different unacceptable conditions can be computed using the probabilities of the contingencies that cause these conditions. A direct approach to this problem requires a full ac load flow analysis for each contingency, followed by a check of the limit violations that constitute system problems in the studies. A completely exhaustive method is not computationally feasible, especially for large power systems. Since all the possible contingencies do not create system problems, a contingency set can be constructed which contains those contingencies that yield constraint violations. A computationally efficient computer algorithm is therefore needed that can identify those contingencies that result in constraint violations without performing exhaustive power flow calculations.

The presently available techniques and related topics in composite system reliability evaluation were addressed at an IEEE Power Engineering Society tutorial [67] and are summarized in Reference 68. Most of the presently available techniques for quantitative reliability evaluation of composite power systems are in the adequacy domain [67]. There are a number of different computer programs available for composite system adequacy evaluation. These programs are briefly discussed in Reference 69, including a list of the calculated indices and the factors involved in the assessment. Composite system adequacy evaluation is normally conducted to determine both individual load point and overall system indices [70]. The evaluation procedure and the resulting indices provide an important knowledge base for system designers, planners and operators. Many utilities have difficulty in interpreting some of the calculated indices as the existing models are often not perceived to include actual system operating conditions. A security constrained adequacy evaluation technique can be used to alleviate this difficulty [71]. The performance of a composite system can be examined for a set of predefined operating states classified in terms of the degree to which both adequacy and security constraints are satisfied. The events leading to each operating state can be identified and the probabilities and frequencies associated with these operating states evaluated.

A procedure for composite system security constrained adequacy evaluation is illustrated in detail in Reference 72. In this procedure, only independent outages of major components are considered. The generating stations are connected to the transmission facilities through switching stations and electrical energy is supplied from the bulk power system to the distribution network through substations. The switching stations and substations are therefore basic and important points of energy transfer between generating stations, transmission systems and distribution circuits.

They are essential and critical segments of an electric power system and play an important role in the reliability assessment [6, 7, 35 - 37, 42, 73 - 76]. These facilities are important factors in improving the reliability of a power system but it should be realized that failures originating in the stations themselves can create a significant number of system disturbances. Failure of even a limited number of components in a station can result in the interruption of several transmission circuits or generatings or both. It is therefore essential to design terminal stations very carefully in order that faults originating in a station have minimum effect on the system. Failures of the system major components and isolations of the individual load points due to station element failures are designated as station originated outages in composite power system reliability analysis.

Two or more transmission lines can be in the outage state simultaneously due to the overlapping of individual failures or due to a common cause when these transmission facilities are on a common tower or have some commonly used facilities [1, 70]. A common mode failure is an event having a single external cause with multiple failure effects which are not consequences of each other. Considerable attention has been given to the effects of common mode and station originated outages in recent years [34, 35, 77 - 86]. Some publications are particularly concerned with safety or mission-oriented systems [79, 80] while others focus on repairable systems [34, 35, 77, 78, 81 - 86]. Station originated and common mode failures are designated as dependent outages in this thesis and can have a significant impact on the reliability of composite systems. Recognition and inclusion of dependent outages in composite system reliability evaluation is essential and it is important to appreciate their impact on accurate system indices. One of the basic objectives of this research was to examine the effect of dependent outages on the composite system operating state risk calculated by the security constrained adequacy evaluation procedure. The effect on the system risk of system modifications such as additional lines or generators and alternate station configurations are analyzed in this thesis. The security constrained adequacy evaluation procedure is extended in this thesis to perform composite system generating capacity reserve assessment in the system operating phase. These evaluations include both dependent and independent outages of major components.

1.4. Outline of the Thesis

Two distinct approaches to station reliability evaluation, namely analytical and simulation analyses, are examined, compared, utilized and quantified in Chapter 2. Two groups of reliability indices are identified as being important in the station reliability analysis. One group is used in basic load point analysis while the other provides important input to composite system reliability assessment. The second group of reliability indices is used to conduct composite system security constrained adequacy evaluation which includes dependent outages. The frequency and duration method can be used to evaluate station reliability without difficulty when all of the station elements can be modeled as a Markov process. The computation time for this technique is relatively short and only a small amount of computer memory is required. The analytical technique can not be used in the case of the station elements with non-Markovian models without making some significant assumptions. An analytical method becomes complicated and tedious in this case. A Monte Carlo simulation method can be used without the assumptions required in an analytical approach. The simulation method can be easily utilized to evaluate station reliability where the elements have either Markov or non-Markovian models. The disadvantages of the simulation technique are long execution times and large memory requirements. A time sequential Monte Carlo method was developed [87] and the resulting reliability indices compared with those obtained by the frequency and duration method [88]. The simulation approach can also provide additional information which is not normally available when using analytical methods. This information, such as probability distributions of outage events and outage durations, etc. can prove useful either as data or additional reliability indices.

Some important mathematical models [72] are examined in Chapter 3 in order to understand their implications in assessing system operating conditions in reliability evaluation. The selection of an appropriate network solution technique can improve the computation speed and result precision. Sherman-Morrison corrections and other methods are used to reduce the computation time. Corrective actions are used to adjust component operating conditions so that the system operating risk is reduced. The security constrained adequacy evaluation technique is considerably different from a traditional composite system adequacy assessment approach as this procedure can include a more realistic consideration of the system operating constraints. The resulting indices include both probabilities and frequencies of the system operating states [72, 89]. Composite system performance is examined in this chapter using the operating state indices and a risk index designated as the "Composite System Operating State Risk". The reliability indices obtained at HL II are compared with those calculated at HL I. It is believed that the risk criterion defined at HL II can prove as useful as the conventional loss of load expectation index LOLE has been at HL I. The developed reliability evaluation procedure is applied to two test systems (the IEEE-RTS and the RBTS) [41, 90] throughout this thesis.

Dependent outages encountered in a composite system include both common mode outages of transmission lines and station element outages. Common mode outages are associated with those lines which have common support towers or other commonly used facilities. A common mode outage can place several system components in the outage state simultaneously. A station element outage may result in combined outages of both generating units and transmission lines. It can also cause the complete isolation of a load point from the system. The effect of dependent outages on the reliability indices are examined in Chapter 4. This work was conducted by separately considering the independent outages of major components, independent and common mode outages, independent and station originated outages, and independent and dependent outages respectively. It can be concluded from the studies that dependent outages can have very significant effect on system reliability for some systems. This may be not true for all systems. The evaluation was conducted at different system load levels and it was found that the system unreliability contributed by the dependent outages is not a direct function of system load. This can be easily understood by examining the impact on the system of specific dependent outages. It can be concluded from studies conducted in this chapter that the relative system risk caused by dependent outages increases as the system load decreases and the impact of dependent outages becomes prominent at light system loads.

The reliability indices of a composite system depend on many factors, such as the amount of installed capacity, the generating unit sizes, the reliability parameters of the major system components, the configuration of the system, the system load, the system operating conditions, the station configurations, the reliability parameters of the station elements, etc. Sensitivity studies were performed by varying the reliability parameters of the major components and station elements and the results are shown in Chapter 5. These studies include variation in transmission line failure rates, common mode outage rates of transmission lines, generating unit failure rates and station element failure rates. These studies were also conducted for different system load levels. The Composite System Operating State Risk (CSOSR) [91, 92] is used as the system failure criterion in these studies.

As noted earlier, the Composite System Operating State Risk (CSOSR) index depend on many factors. The studies described in the previous chapters are based on the two basic test system configurations and their element reliability data. A basic system may or may not meet its future load requirements at an acceptable risk level unless additional facilities are added to the system. The addition of generating or transmission capacity will generally have a positive effect on the system operating risk [91, 92]. A major system planning task is to determine the most effective and economic facility addition to maintain an acceptable risk level as the system load increases. The effect on the CSOSR of system modifications is examined in Chapter 6 by application to the Modified RBTS (MRBTS). This type of analyses is conducted in the following areas: (a) generating unit additions, (b) generating unit replacements, (c) transmission facility additions, and (d) transmission line removals for maintenance. The effect on the CSOSR of selected dependent outages is examined in each case. The studies are extended to analyze the effect on the CSOSR of selecting different station arrangements at all the system buses.

The studies described in the previous chapters are focused on the CSOSR index. Most electric power utilities use deterministic techniques to incorporate reliability considerations in transmission system planning [93]. Procedures such as ensuring that the system can withstand the loss of one or more transmission facility without violating operating constraints or cutting load are usually used. There is also considerable interest in combining deterministic considerations with probabilistic indices to monitor the wellbeing of an electric power system. This combination can be achieved by recognizing that the system operating states created by recognizing the system deterministic criteria can be categorized as being healthy, marginal or at risk and can be quantified using probability theory. The concept of system health and the margin from undesirable operating conditions involving load curtailment are illustrated in Chapter 7 by application to the MRBTS. The system operating conditions considered in this part of the research project include variations in system load, the addition of generating units, the addition of transmission facilities and line removals for maintenance.

Reliability evaluation of a power system can be conducted in the two distinct domains of system adequacy and security. Adequacy assessment is usually associated with long range planning while security assessment is performed in both planning and operating areas. The operating phase can be divided into the two domains of operational planning and daily operation. Security assessment involves both steady state and dynamic analyses. The assessment of the operating reserve required at any time of the day is a security problem. The load in a power system varies continuously and it is not economical or practical to continuously operate all the generating units required to satisfy the peak load. Usually, units are placed in service at one point in time and removed from service or additional units are committed to the system at another point in time depending on the system load level. Generating units should be put into service for different segments of the scheduling period in such a way that the system operating cost is minimized and a satisfactory level of reliability is attained at all hours.

There are a number of methods used in operating reserve assessment at HL I [5 - 7, 70, 94]. The available techniques can be generally grouped into the two broad categories of deterministic and probabilistic approaches. Deterministic criteria include considerations such as a percentage of system load or operating capacity, fixed capacity margins, and the largest unit loading. The assessment of the operating reserve risk can be performed using a single technique or a combination of these techniques. Deterministic approaches do not specifically recognize the probability of component failure, i.e. generating units, transmission lines, etc., in an assessment of the required operating reserve risk. A probabilistic approach can be used to recognize the stochastic nature of system components and to incorporate these phenomena in a consistent evaluation of the required operating reserve requirement.

The generating unit commitment risk assessment techniques presently used are focused on the generation functional zone (HL I). These approaches are relatively simple but they neglect the effect of other system components such as transmission facilities. This may be quite acceptable in some systems. This omission, however, can cause a large deviation in the calculated risk from the actual system risk. Chapter 8 presents a probabilistic technique which can be used to perform unit commitment risk assessment in a composite generation and transmission system (HL II) in the operational planning phase. In this method, outages of transmission lines and station elements are considered in addition to those of generating units. The unit commitment is performed at both HL I and HL II in this part of the research project. The Outage Replacement Rates (ORR) are used for the individual generating units in the studies at HL II conducted in the operational planning phase while the steady state unavailabilities are utilized for the transmission facilities and station elements. The study results obtained for the various cases are compared in order to understand and appreciate the effect of the transmission and station facilities on the unit commitment.

The effect on unit commitment of selected dependent outages such as common mode and station initiated failures is examined in the studies described in Chapter 8. It is concluded that the composite system operating reserve risk increases considerably with the inclusion of dependent outages, particularly station originated failures. This type of analyses neglects the time dependence of the state probabilities associated with the transmission and station facilities and can be used in operation planning. This procedure overcomes some of the disadvantages existing in the present techniques for generating capacity operating reserve assessment. Recognition of all the system component state probabilities as a function of lead time is important in composite system operation planning. This consideration has been studied in Chapter 9. The components considered in the composite system operating reserve risk assessment procedure include not only the generating units, but also the transmission lines and the station elements such as circuit breakers, bus sections and transformers. Outages of generating units, transmission lines, or station elements can all result in unsatisfactory system operating performance and load curtailment during the system lead time. The availabilities and unavailabilities of these major system elements are therefore all functions of the studied time period, i.e. the lead time. The calculated system operating risk is a function of the lead time. The risk also depends on many other factors such as the amount of installed generating capacity, the size of the various generating units, the reliability parameters of all the components considered, the system load, the generating unit outputs in terms of active power and voltage, and the system topology, etc. The risk evaluation procedure is illustrated by application to the MRBTS. The conclusions of the thesis are presented in Chapter 10.

2. STATION RELIABILITY EVALUATION

2.1. Introduction

Switching stations and substations are important configurations in a modern electric power system. These facilities are the energy transfer points between generating stations, transmission systems, subtransmission systems and distribution systems. Substations, in a general sense, provide the connection between the bulk power system and the consumer's facilities. In this research work, the term station is used to generally describe both switching and substation facilities. At these locations, lines interconnect, voltage transformation occurs and system control and protection functions are implemented. Stations are usually functionally designed with considerable flexibility in the arrangement of basic components such as circuit breakers, bus sections and transformers. Factors considered in the selection of a specific station configuration include service reliability and security, operating flexibility, simplicity, short circuit current limitations, protective relaying, equipment maintenance, future extensions and modifications, standardization, cost, etc. [95]. Stations are used to divide the total load at that point in a bulk power network into a number of dispersed load points to satisfy system needs and customer requirements. Station reliability is therefore an important requisite in a modern system. The reliability of a station depends primarily on the reliability of the basic station components and the arrangement of these components in the station.

The actual configuration and the resulting reliability of the stations connecting the transmission system and the distribution facilities are important elements in providing acceptable service to customers. Considerable work has been done and documented on station reliability evaluation [3 - 7, 96 - 99] as stations play an important role in the reliability evaluation of both composite systems and load points. The direct effect of stations on composite system reliability has been examined and research work associated with this area has been published [34 - 37, 74, 75]. The bulk of the techniques applied to station reliability evaluation are in the analytical area. Station reliability can, however, also be evaluated using Monte Carlo simulation [87]. A time sequential Monte Carlo simulation method used for station reliability evaluation is illustrated in this chapter. The reliability indices obtained using this simulation procedure are compared with those obtained using an analytical method.

2.2. Modeling Technique for Station Components

The element outage categories considered in this research work include permanent and scheduled maintenance outages. A permanent or sustained outage is an event whose cause is not self-clearing, and must be corrected by eliminating the hazard or by repair or replacement. A scheduled outage is an outage that results when a component is deliberately taken out of service at a selected time, usually for the purpose of construction or preventive maintenance. During the period a component is removed from service for preventive action, it can not perform its intended function. In the case of a permanent outage, the component is out of service until the repair is complete. Additional major component may be removed from service due to the failure of an associated component. The outage time of the additional components in these cases will generally be the time required to isolate the failed component.

Dependent outages usually result as a consequence of a circuit breaker or protective system component responding to a command to perform its intended function. Component permanent failures can be categorized as being active or passive failures [70]. An active failure is a component failure that causes the primary protection zone around the failed component to operate and can therefore cause the removal of other healthy components and branches from service. A passive failure is a component failure that does not cause the operation of protective elements and therefore does not have any impact on the remaining healthy components.

The following assumptions have been utilized in the analysis of the circuit breaker, bus section, and transformer elements.

(i) The probability of a stuck breaker condition is assumed to be zero.

(ii) Transformers and bus sections have only active failures.

(iii) The effect of adverse weather has been neglected.

(iv) Outages of major components (generators and transmission lines) are not considered in the station reliability evaluation procedure.

(v) Active and passive failures occur randomly.

(vi) Scheduled maintenance is performed during specific periods.

(vii) After scheduled maintenance or repair, the component is considered to reside in the useful life time domain and the failure rate is restored to its initial value (i.e. as good as new assumption).

(viii) Relays connected with all breakers in the station are assumed to be non-directional.

2.3. Station Reliability Indices

The reliability indices of a station can be classified into a number of groups. There are, however, two groupings which prove very useful in reliability assessment of individual stations and of composite systems. One group includes the outage probabilities and outage frequencies of the sets of external connections. These outage sets are mutually exclusive, i.e. the remaining connections must be in service when one set of the connections is in the outage state. This group of station reliability indices can be used in composite generation and transmission system reliability evaluation. These indices become part of the input data file of the COMREL and SECDEP programs utilized at the University of Saskatchewan to evaluate composite system reliability. The second group contains the outage probabilities, rates and durations for all the connections. These outage events are not mutually exclusive, i.e. the remaining connections can be in service or in an outage state when one connection is in the outage state. This group of indices includes the necessary reliability data to evaluate a particular connection such as a specific load point.

2.4. Station Reliability Evaluation Techniques

A number of techniques has been used to evaluate station reliability indices [3 - 7, 42, 88]. These techniques can be classified into the two categories of analytical and simulation methods. Assessment methods for station reliability evaluation are mainly concentrated in the analytical area. These techniques include the frequency and duration (F & D) method [73, 98 - 100], the state space diagram method [70] and the approximate approach [70]. This section provides a brief description of the frequency and duration method and a time sequential Monte Carlo simulation procedure.

2.4.1. Frequency and Duration Method

The frequency and duration method [73, 101] is based on a system Markov model, i.e. all transition rates between the system states are assumed to be constant. The Markov models for the basic terminal station components and the expressions for their reliability indices are given in this subsection.

2.4.1.1. Circuit Breaker Model

A circuit breaker and its associated relaying is a device which is capable of opening and closing a circuit, either manually or automatically. This component serves a similar function as a line fuse with the exception that it is reusable after it opens the circuit. Circuit breakers are located wherever branch circuit protection is required in the power system. The primary consideration in selecting a circuit breaker is that it can be set to trip at the proper value of fault current, and that it possesses a high enough interrupting rating to perform its function without being damaged.

A basic circuit breaker model involves three types of outage events, i.e. active failures, passive failures and maintenance outages. The state space diagram of a circuit breaker is shown in Figure 2.1.

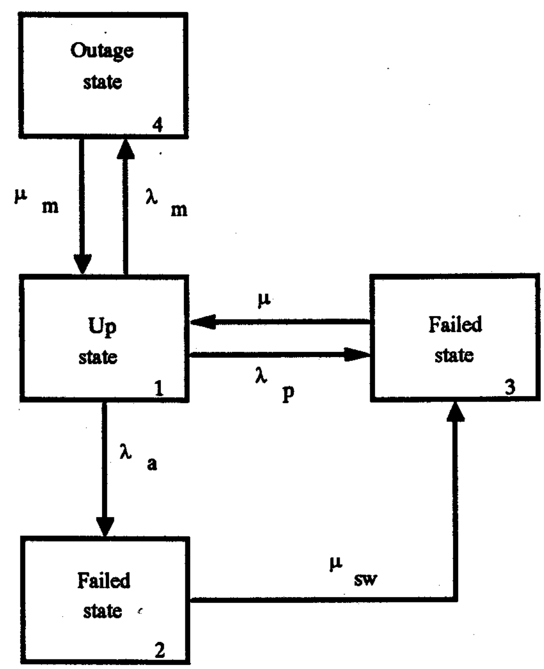


Figure 2.1: Markov model of a circuit breaker.

State 1 is the up state i.e. the breaker is in the operating state. The breaker can be found in State 2 following an active failure. The breaker remains in this state until it is switched out of the system. The active failure rate and switching rate are designated by λ_a and μ_{sw} respectively.

The breaker goes into State 3 after it is switched out of the system. It can also directly transit into State 3 by a passive failure. The passive failure rate and repair rate are designated by λ_p and μ respectively.

The breaker resides in State 4 by removing it from the system for preventive maintenance. The maintenance outage rate is λ_m. It can then be restored to the up state with a transition rate μ_m .

The state probabilities are given by Equations 2.1, 2.2, 2.3 and 2.4 respectively,

$$P_1 = \frac{\mu\mu_{sw}\mu_m}{\Delta}, \tag{2.1}$$

$$P_2 = \frac{\lambda_a\mu\mu_m}{\Delta}, \tag{2.2}$$

$$P_3 = \frac{(\lambda_a + \lambda_p)\mu_m\mu_{sw}}{\Delta}, \tag{2.3}$$

$$P_4 = \frac{\lambda_m\mu\mu_{sw}}{\Delta}, \tag{2.4}$$

where $\Delta = \mu_{sw}(\mu\mu_m + \lambda_p\mu_m + \lambda_m\mu + \lambda_a\mu_m) + \lambda_a\mu\mu_m$.

2.4.1.2. Bus Section Model

A bus section can be defined as a set of conductors to which two or more components are electrically connected. Bus bar failures are infrequent but when they occur, multiple transmission components can remain inoperative until the bus bar is repaired and returned to normal service. Customer load point indices can be seriously effected by bus bar failures.

Bus section outage rates include two types, i.e. total failure rate λ_t and maintenance outage rate λ_m. Virtually all the total failures of a bus bar can be considered to be active failures. The Markov model of a bus section is shown in Figure 2.2.

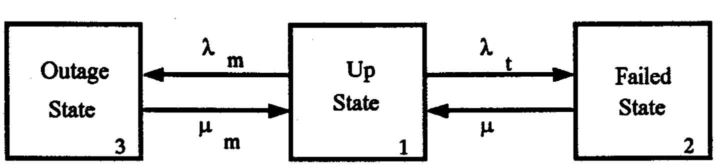


Figure 2.2: Markov model of a bus section.

State 1 represents the operating state in the state space diagram shown in Figure 2.2. State 2 represents the forced outage state of a bus section in which the bus section is repaired with a repair rate μ. The maintenance outage state is represented by State 3 and the maintenance repair rate is μ_m.

The probability of residing in each state associated with a bus section is obtained using Equations 2.5, 2.6 and 2.7 respectively,

$$P_1 = \frac{\mu\mu_m}{\Delta}, \tag{2.5}$$

$$P_2 = \frac{\lambda_t\mu_m}{\Delta}, \tag{2.6}$$

$$P_3 = \frac{\lambda_m\mu}{\Delta}, \tag{2.7}$$

where $\Delta = \mu\mu_m + \lambda_t\mu_m + \lambda_m\mu.$

2.4.1.3. Transformer Model

Transformers are used to step up or step down the voltage at appropriate points in the generation, transmission and distribution functional zones. Transformer outages are composed of two types and are represented by the total failure rate and the maintenance outage rate. It is assumed that all the total failures are active failures. The difference between the circuit breaker model and the transformer model is that there are no passive failures in the transformer model. The difference between the bus section model and the transformer model is that there is associated switching action after a transformer failure. The Markov model for the transformer is shown in Figure 2.3.

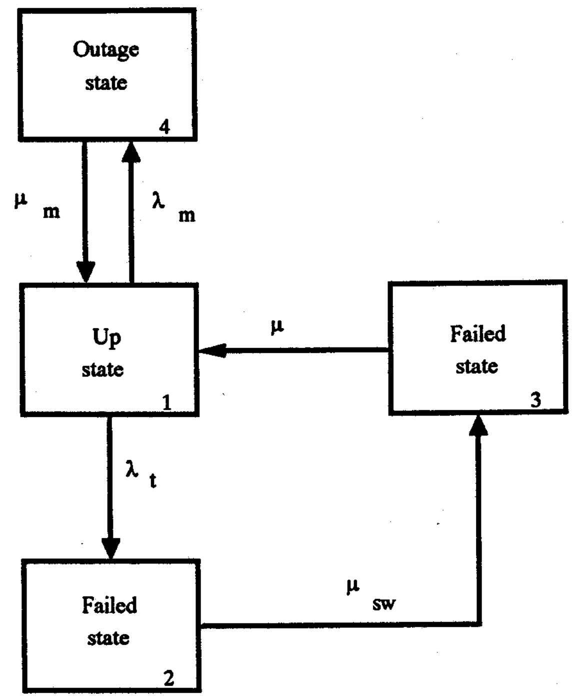


Figure 2.3: Markov model of a transformer.

The up state is represented by State 1. The forced outage of the transformer is represented by State 2 and it remains in this state until it is switched out for repair or replacement. In this state, certain other healthy components may be removed from service in order to clear the fault. State 3 is reached after the failed transformer is switched out of the system. It is then repaired with a repair rate μ. State 4 can be reached following the removal of the transformer from the system for scheduled maintenance.

The probability of residing in each state is obtained using Equations 2.8, 2.9, 2.10 and 2.11 respectively,

$$P_1 = \frac{\mu\mu_{sw}\mu_m}{\Delta}, \tag{2.8}$$

$$P_2 = \frac{\lambda_t\mu\mu_m}{\Delta}, \tag{2.9}$$

$$P_3 = \frac{\lambda_t\mu_m\mu_{sw}}{\Delta}, \tag{2.10}$$

$$P_4 = \frac{\lambda_m\mu\mu_{sw}}{\Delta}, \tag{2.11}$$

where $\Delta = \mu_{sw}(\mu\mu_m + \lambda_m\mu + \lambda_t\mu_m) + \lambda_t\mu\mu_m$.

As described in Reference 101, the frequency of departure from State i can be obtained using Equation 2.12,

$$f_i = P_i \times \lambda_i \ , \tag{2.12}$$

where P_i is the probability of being in State i and λ_i is the departure rate from this state.

When State i has more than one departure action, e.g. n departure activities, the total departure rate λ_i in Equation 2.12 is equal to the sum of all the departure rates from this state. The expression is given in Equation 2.13,

$$\lambda_i = \sum_{j=1}^{n} \lambda_{ij} \ , \tag{2.13}$$

where λ_{ij} indicates a transition rate from State i to State j.

2.4.1.4. Station Reliability Evaluation Technique

The probability of all the station components being in the up state is obtained using Equation 2.14,

$$A = \prod_{k=1}^{NBR} P_{bk,k} \prod_{k=1}^{NBUS} P_{bus,k} \prod_{k=1}^{NTRS} P_{trans,k} \ , \tag{2.14}$$

where $P_{bk,k}$ -- probability of the kth breaker being in up state,
$P_{bus,k}$ -- probability of the kth bus being in up state,
$P_{trans,k}$ -- probability of the kth transformer being in up state,
NBR -- total number of breakers in the station,
$NBUS$ -- total number of buses in the station,
$NTRS$ -- total number of transformers in the station.

The equations for station component outage overlapping are given in Reference 73. A station reliability evaluation program was developed by the author of Reference 73 using the frequency and duration method. The reliability indices calculated by this program are used as the input data for composite system analysis and are utilized to examine the effect of station originated outages on security constrained reliability evaluation of composite generation and transmission systems in this research work.

2.4.2. A Time Sequential Monte Carlo Simulation Method for Station Evaluation

The basic station component models are presented in the previous subsection. These models assume that the transition rates are constant. Monte Carlo simulation can also be used to evaluate these systems and does not have to be restricted to those situations in which the transition rates are constant. [88, 102]. The simulation approach can be used to calculate the reliability indices in non-Markovian situations. The application of simulation to the Markov case is illustrated in this section.

2.4.2.1. Component Simulation Procedure

As described in the previous section, the model of a circuit breaker is more complex than those of a bus section or a transformer. The simulation procedure for a breaker is illustrated in this section. As noted earlier, scheduled maintenance is not a random event as are the other outages. The simulation procedure for a breaker includes two parts. The artificial operating history of the element is first generated and then maintenance events are imposed on this artificial history. The breaker model is shown in Figure 2.1.

The probability density functions associated with the failure, switching and repair actions are given in Equations 2.15, 2.16 and 2.17 respectively,

$$f(t) = \lambda e^{-\lambda t} , \tag{2.15}$$

$$q(t) = \mu_{sw} e^{-\mu_{sw} t} , \tag{2.16}$$

$$g(t) = \mu e^{-\mu t} . \tag{2.17}$$

The cumulative probability functions, associated with failure, switching and repair actions, are given by Equations 2.18, 2.19 and 2.20 respectively,

$$F(t) = 1 - e^{-\lambda t} , \tag{2.18}$$

$$Q(t) = 1 - e^{-\mu_{sw} t} , \tag{2.19}$$

$$G(t) = 1 - e^{-\mu t} . \tag{2.20}$$

Equations 2.18, 2.19 and 2.20 can be utilized to calculate the component random operating durations (time to failure, *TTF*), switching durations (time to switching, *TTS*) and repair durations (time to repair, *TTR*) [103] respectively using uniformly distributed random numbers [104 - 106] substituted for $F(t)$, $Q(t)$ and $G(t)$. These randomly generated durations can be obtained using Equations 2.21, 2.22 and 2.23 respectively,

$$TTF = -\frac{1}{\lambda} \ln(1 - F(t)), \tag{2.21}$$

$$TTS = -\frac{1}{\mu_{sw}} \ln(1 - Q(t)), \tag{2.22}$$

$$TTR = -\frac{1}{\mu} \ln(1 - G(t)). \tag{2.23}$$

The generated history of a circuit breaker can be considered to consist of two segments. The first situation is one in which an active failure occurs and the component is forced to State 2 from State 1, switched to State 3 from State 2 and repaired to State 1 from State 3. The operating and outage durations of the circuit breaker can be calculated by Equations 2.24 and 2.25. The second situation is one in which a passive failure occurs and the circuit breaker is forced to State 3 from State 1 and repaired to State 1 from State 3. The operating and outage durations can be computed by Equations 2.26 and 2.27,

$$T_{up} = TTF = \frac{1}{\lambda_a}\ln(1-F(t)), \tag{2.24}$$

$$T_{dn} = TTS + TTR = -\frac{1}{\mu_{sw}}\ln(1-Q(t)) - \frac{1}{\mu}\ln(1-G(t)) \ , \tag{2.25}$$

$$T_{up} = TTF = \frac{1}{\lambda_p}\ln(1-F(t)) \ , \tag{2.26}$$

$$T_{dn} = TTR = -\frac{1}{\mu}\ln(1-G(t)). \tag{2.27}$$

The up and outage durations of a bus section or transformer can be calculated using Equations 2.26 and 2.27, or Equations 2.24 and 2.25 respectively.

2.4.2.2. Station Reliability Simulation Procedure

Figure 2.4 shows a station configuration proposed in a Canadian Electrical Association (CEA) report [95]. This station is composed of eleven components numbered from 1 to 11 which include five breakers, three bus sections and three transformers. The configuration has six external connections in total. A connection can be associated with either generating units, transmission lines or load feeders depending on the application of the station. The six connections are numbered (1), (2), (3), (4), (5) and (6) as shown in Figure 2.4. The protection associated with all of the breakers in this configuration are assumed to be non-directional. A breaker can therefore be tripped due to components which are directly or indirectly connected to it. For example, Breaker 1 can be tripped not only by Component 6 or 7, but also by Component 2, 4, 5, 9 or 10. Breaker 4 will be tripped not only by Bus 7, but also by Breaker 1, 2 or Transformer 10.

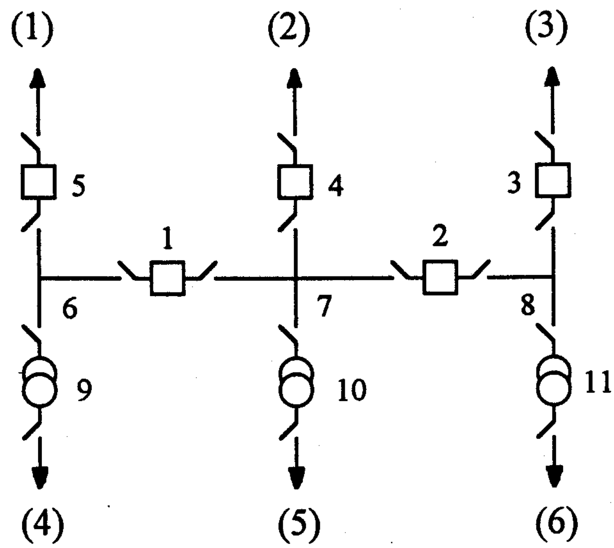


Figure 2.4: Configuration of a six connection station.

In the reliability simulation of a station configuration, the artificial performance history of each individual component is first generated from its operating and outage durations. The impact of related component failures on each circuit breaker are then considered. In the station configuration shown in Figure 2.4, for example, Breaker 1 has its own artificial history, but when Component 2, 4, 5, 6, 7, 9 or 10 fails actively, the breaker will operate and open. The generated history of Breaker 1 therefore will also include the influence of these relatively connected components, i.e. a breaker will be tripped when connected components including other breakers actively fail. When the failed component is switched out, the affected breaker can be reclosed and restored to service. Switching is not considered in the case of a busbar failure, i.e. Breaker 1 will remain open during the repair period of Bus 6 or 7. The artificial history of a breaker including the effects from connected component(s) is called its modified artificial history. After the modified history is obtained for every breaker in the station, the connection outage events can be studied, i.e. the removal of which component(s) will cause the connection to be out of service. In this study, connection outage events are only considered up to the third order level.

The station connection availability (A), unavailability (U), average failure rate (λ), repair duration (r) and the outage frequency (f) are calculated using Equations 2.28, 2.29, 2.30, 2.31 and 2.32 respectively,

$$A = \frac{\sum_{i=1}^{N} T_{up\,i}}{\sum_{i=1}^{N} (T_{up\,i} + T_{dn\,i})}, \tag{2.28}$$

$$U = \frac{\sum_{i=1}^{N} T_{dn\,i}}{\sum_{i=1}^{N} (T_{up\,i} + T_{dn\,i})}, \tag{2.29}$$

$$\lambda = \frac{N}{\sum_{i=1}^{N} T_{up\,i}}, \tag{2.30}$$

$$r = \frac{\sum_{i=1}^{N} T_{dn\,i}}{N}, \tag{2.31}$$

$$f = \frac{N}{\sum_{i=1}^{N} (T_{up\,i} + T_{dn\,i})}, \tag{2.32}$$

where N -- the total number of outages,
$T_{up\,i}$-- the *ith* operating duration,
$T_{dn\,i}$-- the *ith* outage duration.

2.5. Calculated Station Reliability Indices

The station element reliability data used in this chapter were provided by B.C. Hydro and are given in Table 2.1 [73]. Maintenance outages were not considered in the studies shown in this chapter. They have, however, been included in the composite system reliability evaluations described in later chapters.

Table 2.1: Station element reliability data.

Component	λ_a (f/yr)	λ_p (f/yr)	r (hrs)	T_{sw} (hrs)
Breaker	0.002	0.0001	126.0	1.0
Bus	0.025		13.0	
Transformer	0.026		43.1	1.0

2.5.1. Comparison of Station Connection Outage Probabilities

Both the time sequential Monte Carlo simulation approach and an analytical method were used to evaluate the connection reliabilities of the station configuration shown in Figure 2.4. The outage probabilities obtained by these two methods are shown in Table 2.2. Table 2.2 is not completely exhaustive as the probability of high order connection set outages is very small compared with the probability of low order sets. The precision of the simulation result is limited and some very small values may be distorted by simulation errors. The simulation duration must be very long if high order connection outages are to be considered. Very long simulation times are not practical and require extensive computer storage in addition to computer time. It can be seen from this table that the difference between the two types of results obtained by the two methods is very small. It can be, therefore, concluded that the simulation approach can be used to provide acceptable results. The question of how long to conduct a simulation is part of any Monte Carlo reliability assessment. A simulation can be terminated using an appropriate stopping rule or criterion. This is discussed in detail, in connection with station reliability evaluation in Reference 87.

Table 2.2: Outage probability comparison of the system in Figure 2.4.

Connection set	Outage probability	
	Simulated	Analytical
(1)	0.303784E-04	0.301867E-04
(2)	0.311544E-04	0.301876E-04
(3)	0.323512E-04	0.301867E-04
(4)	0.129359E-03	0.127842E-03
(5)	0.129863E-03	0.127846E-03
(6)	0.130515E-03	0.127842E-03
(1)(4)	0.392641E-04	0.402876E-04
(2)(5)	0.409251E-04	0.402828E-04
(3)(6)	0.418704E-04	0.402876E-04
(1)(2)(4)(5)	0.186389E-06	0.207811E-06
(2)(3)(5)(6)	0.237587E-06	0.207811E-06

2.5.2. Connection Set Sensitivity Studies

Sensitivity analysis is an important aspect of quantitative reliability assessment. The utilization of the developed Monte Carlo technique is illustrated by application to the configuration given in Figure 2.4. Outage probability and frequency of each set of connections are examined and the effect on these indices is illustrated by varying selected component parameters, such as failure rate and repair time. These studies clearly show that the connection set reliability indices are very dependent on the station component failure and repair parameters. This becomes particularly important in regard to the high order connection sets as these outage events can have significant impacts in a composite system reliability study. Recognition of station related outages in the analysis is an important step in incorporating system dependencies.

The effect on connection set outage probabilities and frequencies of variations in the breaker failure rates is shown in Tables 2.3 and 2.4. In this study, Case I is the base case and the breaker failure rates are doubled and tripled in Case II and Case III respectively.

Table 2.3: Outage probability as a function of breaker failure rates.

Connection set	Outage Probability		
	Case I	Case II	Case III
(1)	0.303784E-04	0.610557E-04	0.897773E-04
(2)	0.311544E-04	0.589801E-04	0.842579E-04
(3)	0.323512E-04	0.559409E-04	0.913654E-04
(4)	0.129359E-03	0.133463E-03	0.129398E-03
(5)	0.129863E-03	0.126985E-03	0.127261E-03
(6)	0.130515E-03	0.124308E-03	0.123855E-03
(1)(4)	0.392641E-04	0.393171E-04	0.411952E-04
(2)(5)	0.409251E-04	0.401165E-04	0.402621E-04
(3)(6)	0.418704E-04	0.417183E-04	0.412661E-04
(1)(2)(4)(5)	0.186389E-06	0.466841E-06	0.743696E-06
(2)(3)(5)(6)	0.237587E-06	0.464643E-06	0.685578E-06

Table 2.4: Outage frequency as a function of breaker failure rates.

Connection set	Outage frequency (occ/yr)		
	Case I	Case II	Case III
(1)	0.203704E-02	0.397531E-02	0.629630E-02
(2)	0.217284E-02	0.437037E-02	0.585185E-02
(3)	0.197531E-02	0.404938E-02	0.661728E-02
(4)	0.265802E-01	0.263827E-01	0.260864E-01
(5)	0.267160E-01	0.254321E-01	0.256173E-01
(6)	0.261358E-01	0.258765E-01	0.254691E-01
(1)(4)	0.537284E-01	0.548889E-01	0.566914E-01
(2)(5)	0.536667E-01	0.541605E-01	0.566667E-01
(3)(6)	0.533086E-01	0.555062E-01	0.571728E-01
(1)(2)(4)(5)	0.165432E-02	0.395062E-02	0.596296E-02
(2)(3)(5)(6)	0.202469E-02	0.407407E-02	0.606173E-02

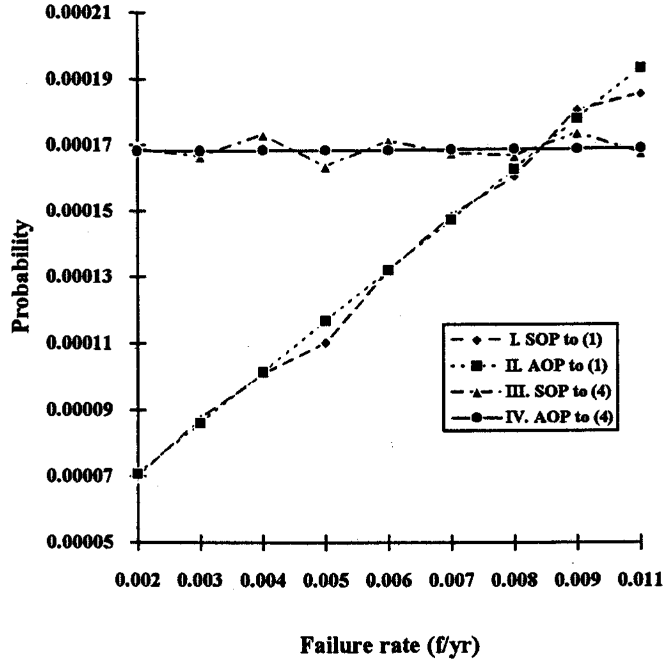
Table 2.3 shows the effect on connection set outage probabilities due to varying breaker failure rates (active and passive failure rates are changed at the same percentage). It can be seen that the outage probabilities of some connection sets are greatly effected by the breaker failure rates while those of other sets are almost constant. Table 2.4 shows that the effect on connection outage frequencies has the same general conclusion.

A physical appreciation of the phenomena can be obtained by considering Figure 2.4. In this configuration, the outage of Connection (1) is caused by passive failure of Breaker 5 only. The outage of Connection set (1) and (4) is caused by the outage of Bus 6, active failure of Transformer 9 and active failure of Breaker 5. The outage probability of Connection set (1) and (4) is therefore effected by all of these outage events. The repair duration of Transformer 9 affects only the outage probability of Connection (4) as Breakers 1 and 5 will be reclosed after the failed Transformer 9 is switched out.

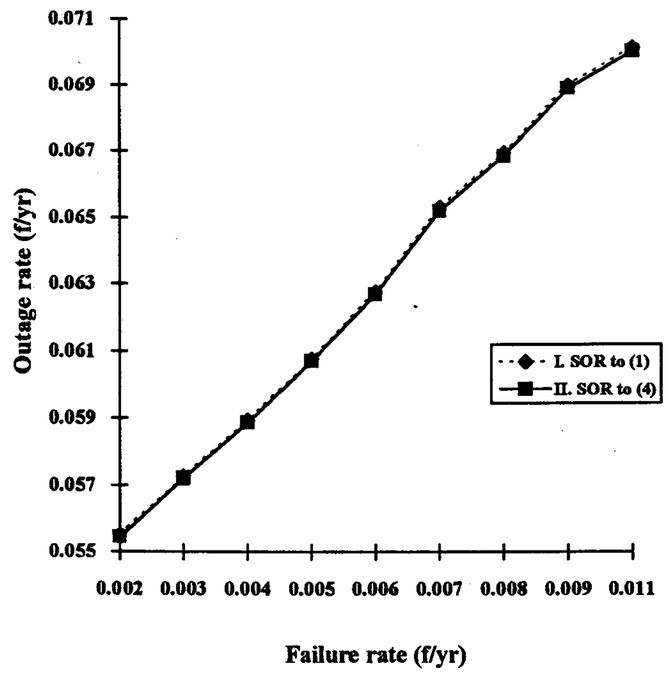
Similar sensitivity studies can be performed in which other parameters such as breaker repair rates, bus failure and repair rates and transformer failure and repair rate are varied.

2.5.3. Load Point Reliability Sensitivity Studies

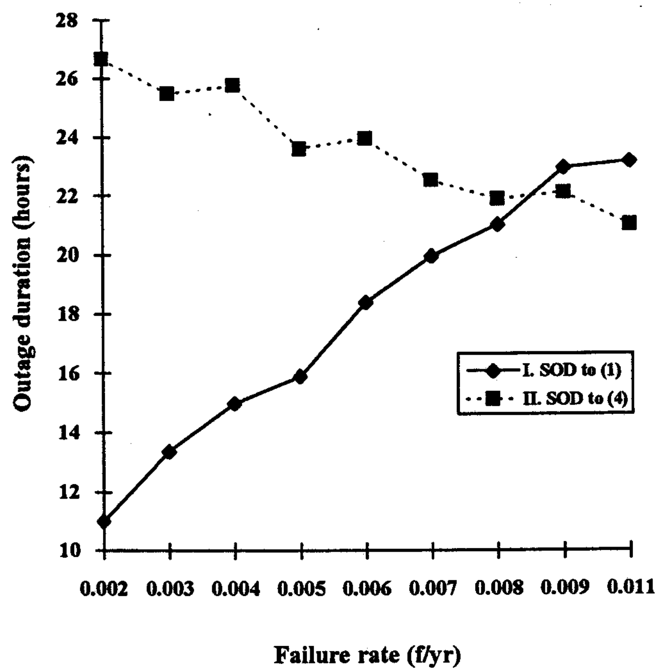
The emphasis in the previous section is on the determination of reliability indices for connection sets. These data are necessary when considering the effect of station configurations in composite system reliability assessment. This is not the same data required in an assessment of a substation containing a number of load points. There are a number of possible load points in Figure 2.4. Load points (1) and (4) have been selected to illustrate the concept of sensitivity analysis. The simulated load point outage probabilities are compared with those obtained using an analytical method. The basic difference between this section and the previous one is that all load points are not mutually exclusive, i.e. other load points may be in the operating state or outage state when one load point is in the outage state. The sensitivity study results are shown in Figure 2.5.


0.00021
0.00019
0.00017
0.00015
0.00013
0.00011
0.00009
0.00007
0.00005
Probability
I. SOP to (1)
II. AOP to (1)
III. SOP to (4)
IV. AOP to (4)
0.002 0.003 0.004 0.005 0.006 0.007 0.008 0.009 0.011
Failure rate (f/yr)

(a)


0.071
0.069
0.067
0.065
0.063
0.061
0.059
0.057
0.055
Outage rate (f/yr)
I. SOR to (1)
II. SOR to (4)
0.002 0.003 0.004 0.005 0.006 0.007 0.008 0.009 0.011
Failure rate (f/yr)

(b)



(c)

Figure 2.5: Load point reliability indices as a function of the breaker failure rates.

Figure 2.5(a) shows the effect on the load point outage probability (OP) of varying the breaker failure rates (active and passive failure rates are changed at the same percentage). This figure includes four curves. Curve I is the simulated outage probability (SOP) at Point (1) and Curve II is the analytical outage probability (AOP) at this point. Curves III and IV are the simulated and analytical outage probabilities of Point (4) respectively. It can be seen that the outage probability of Point (1) is greatly effected by the breaker failure rates and that the outage probability of Point (4) is almost constant. The difference between the results obtained by the two calculation techniques is very small.

Figure 2.5(b) shows the effect on load point outage rates (OR). Curve I is the simulated outage rate (SOR) of Point (1) and Curve II is the simulated outage rate (SOR) of Point (4). The outage rates of both Points (1) and (4) increase when the breaker failure rates increase. This general conclusion can be appreciated by considering the configuration diagram shown in Figure 2.4.

Figure 2.5(c) shows the effect on average load point outage durations (OD). Both curves are simulated results. Curve I shows the value of Point (1) and Curve II the value of Point (4). Curve I increases as the breaker failure rates increase which means that the load point average outage duration will be longer when the breaker failure rates are larger. Conversely, the average outage duration of Point (4) will decrease as the breaker failure rates increase.

The phenomena in Figure 2.5 can be explained as follows. The outage of Point (1) is caused by failures of Breaker 5 and Bus 6, the active failures of Breaker 1 and Transformer 9, overlapping of repair processes of Breaker 1 and Transformer 9. Breakers 1 and 5 will be reclosed after the failed Transformer 9 is isolated. The outage duration of Point 1 caused by this faulted transformer is therefore only the transformer switching time. Point 1 will be out of service during the repair of Bus 6 and Breaker 5. The breaker repair time is much longer than that of the bus section. the average outage duration and outage probability of this point therefore increase when the failure rates of the breakers increase. The outage rate of this point also increases with increase in the breaker failure rates.

The outage of Point (4) is caused by failures of Bus 6, Transformer 9 and active failures of Breakers 1 and 5. The point will be in the outage state when the two breakers are in the switching state. Point (4) will be back in service when the faulted breaker is switched out and being repaired. The outage probability of the point will be effected only slightly. The outage frequency of the point will be effected by the breaker failure rates.

2.6. Distributions of Load Point Reliability Indices

A time sequential Monte Carlo simulation approach can provide additional information which is not normally available when using analytical methods. This information can prove very useful either as data or as additional reliability indices. In order to illustrate this point, this section presents the probability distributions associated with the annual outage events and the individual outage duration for the six possible load points in Figure 2.4.

2.6.1. Probability Distribution of Outage Events

As previously noted, a modified artificial history can be generated using the time sequential Monte Carlo procedure for each load point in the station. This generated history can be used to calculate outage occurrences within given time units during the simulation period. The probability that specified outages will occur within one time unit will be equal to the corresponding subtotal time units divided by the total simulation time units. This calculation is described in Equation 2.33,

$$P_i = \frac{N_i}{\sum_{j=0}^{n} N_j} \qquad (i=0,1,2,\ldots,n)\,, \tag{2.33}$$

where N_i -- time units in which only i outage events occur within one time unit,

n -- maximum outage events within one time unit,

P_i--probability of i outage events occurring within one time unit.

The probability distribution of outage events at each load point is illustrated in Table 2.5. Column 1 shows the load point considered. Columns 2, 3, 4, 5 and 6 show the probabilities that there is 0, 1, 2, 3, 4 outages within one time unit respectively. The probability distribution of outage events at Load point (1) is shown in Figure 2.6 for illustrative purposes.

Table 2.5: Probability distribution of outage events.

Point	Probability of outage events				
	0	1	2	3	4
(1)	0.946160	0.052185	0.001617	0.000037	0.0
(2)	0.944074	0.054395	0.001519	0.000012	0.0
(3)	0.946210	0.052259	0.001506	0.000025	0.0
(4)	0.946235	0.052123	0.001605	0.000037	0.0
(5)	0.944185	0.054296	0.001519	0.000000	0.0
(6)	0.946259	0.052210	0.001506	0.000025	0.0

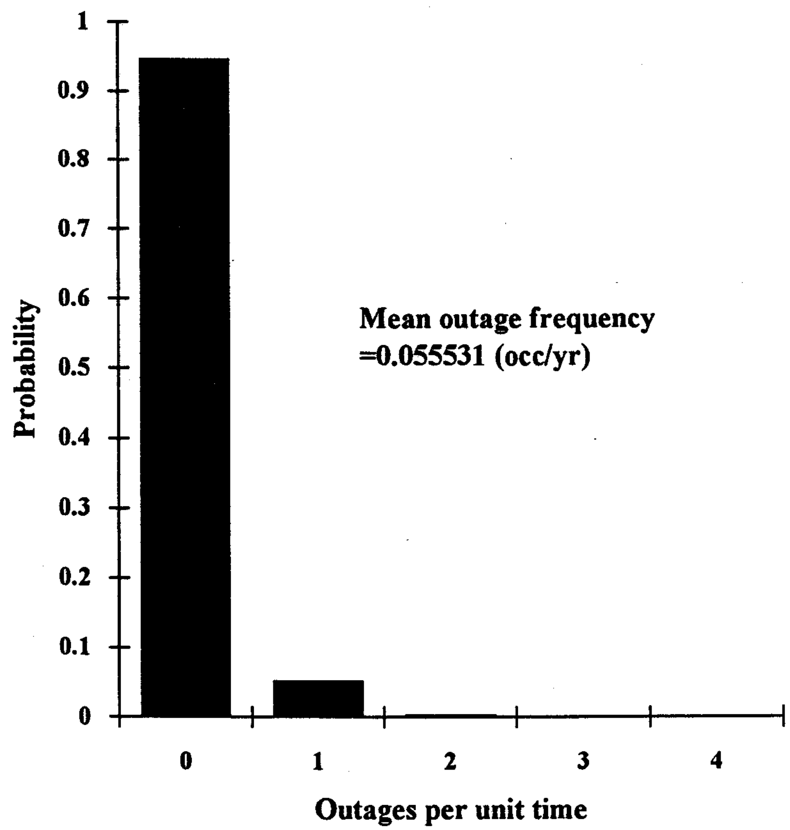


Figure 2.6: Load point probability distribution of outage events.

2.6.2. Cumulative Probability Distribution of Outage Events

The cumulative probability distribution of outage events can be calculated using Equation 2.34. The distribution at Load point (1) of the configuration shown in Figure 2.4 is illustrated in Figure 2.7.

$$CP_i = \sum_{j=0}^{i} P_j \qquad (i=0,1,2,...,n), \tag{2.34}$$

where CP_i -- probability of outage events occurring within one time unit is less than and equal to i,

P_j -- probability of j outages occurring within one time unit, same as that in Equation 2.33,

n -- same as that in Equation 2.33.

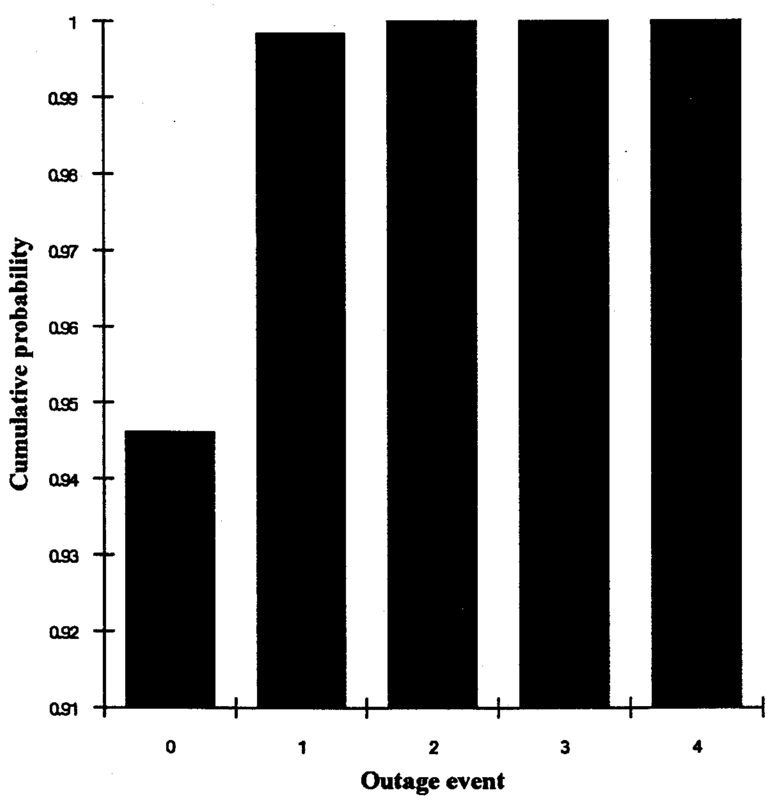


Figure 2.7: Load point cumulative probability distribution of outage events.

2.6.3. Probability Distribution of Outage Durations

Table 2.6 shows the probability distribution of load point outage durations. This distribution can be obtained using Equation 2.35. Column 1 shows the outage load point. Columns 2, 3, 4, 5 and 6 show the probability of outage duration between 0 to 10 hours, 10 to 20 hours, 20 to 30 hours, 30 to 40 hours and 40-50 hours respectively if a load point outage occurs. The probability of an outage duration longer than 50 hours is not shown in this table. The probability distribution of outage durations at Load point (1) is shown in Figure 2.8.

$$P_i = \frac{N_i}{\sum_{j=1}^{m} N_j} \qquad (i=1,2,\ldots,m), \tag{2.35}$$

where m --the segments which outage duration is divided into,
N_i --occurrences of outage duration between T_{i-1} and T_i ,
P_i --probability of outage duration between T_{i-1} and T_i .

Table 2.6: Probability distribution of outage durations.

Point	Probability of outage durations				
	(0-10 hrs)	(10-20 hrs)	(20-30 hrs)	(30-40 hrs)	(40-50 hrs)
(1)	0.761672	0.116719	0.056247	0.021787	0.007337
(2)	0.763695	0.107197	0.052417	0.025779	0.015252
(3)	0.750613	0.111756	0.055989	0.030560	0.015838
(4)	0.410154	0.183923	0.120908	0.076375	0.046538
(5)	0.419681	0.190568	0.110680	0.074289	0.049957
(6)	0.403885	0.184193	0.119893	0.082831	0.048895

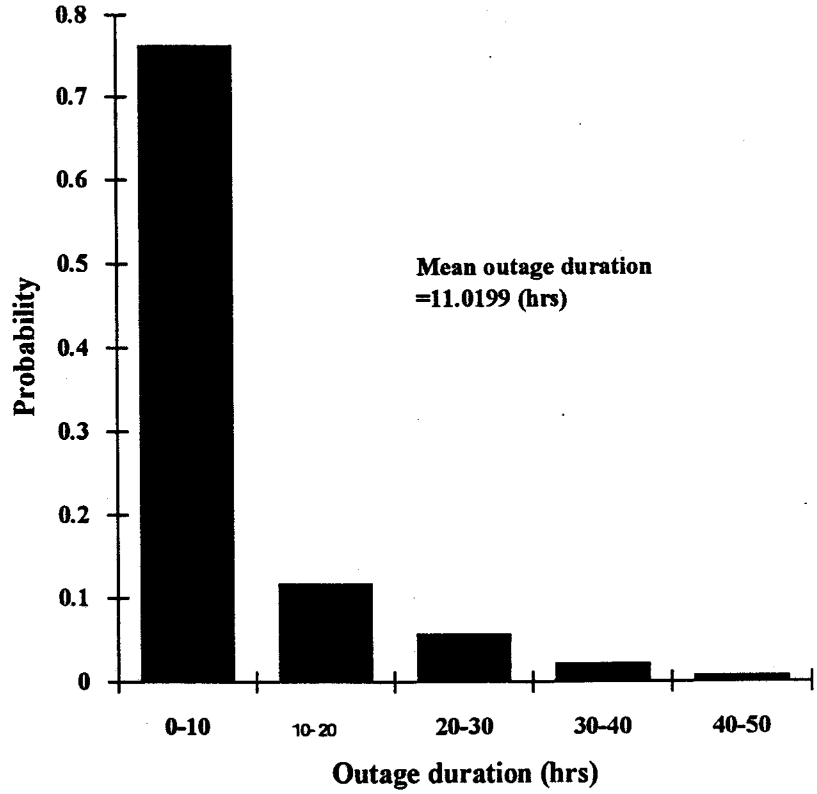


Figure 2.8: Load point probability distribution of outage durations.

2.6.4. Cumulative Probability Distribution of Outage Durations

The cumulative probability distribution of outage durations can be calculated using Equation 2.36. The distribution at Load point (1) of the configuration shown in Figure 2.4 is illustrated in Figure 2.9.

$$CP_i = \sum_{j=0}^{i} P_j \qquad (i=0,1,2,\ldots,m), \qquad (2.36)$$

where CP_i -- probability of the outage duration is less than and equal to T_i,

m -- same as that in Equation 2.35,

P_j -- same as that in Equation 2.35.

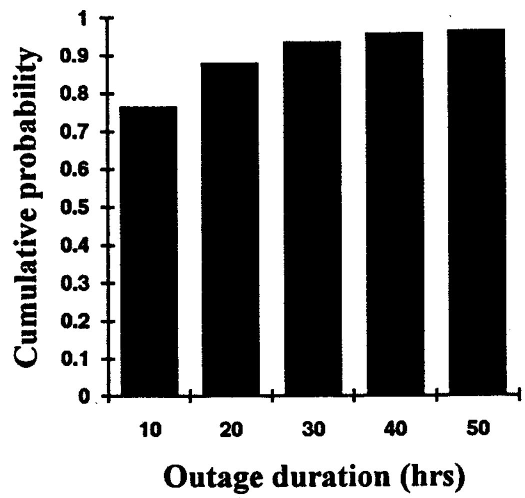


Figure 2.9: Load point cumulative probability distribution of outage durations.

Probability distribution data such as those shown in Tables 2.5 and 2.6 and Figures 2.6, 2.7, 2.8 and 2.9 provide an added dimension to reliability evaluation. The average frequency of failure and the average duration of outage do not provide any indication of the dispersion of the index. This information can be obtained analytically in certain specific situation [107] but can be obtained quite routinely when using a sequential Monte Carlo process [108].

2.7. Summary

Two distinct techniques used in station reliability assessment are discussed in this chapter. These two approaches can be used to obtain both station indices suitable for composite generation and transmission system reliability assessment and individual load point reliability evaluation. The effect of varying the basic component parameters on the reliability of specific connection sets has been illustrated by application to a basic station configuration. The study results show that the reliability indices of some connection sets are affected greatly by variations in the component parameters, while other sets are affected only slightly. This type of station analysis provides a quantitative basis for judicious selection of reliable and economical components. This chapter illustrates how the conventional analysis can be extended to produce probability distributions of the reliability indices rather than restrict the assessment to average or expected values. The probability distributions associated with the outage frequency and duration are presented. The time sequential Monte Carlo approach described in this chapter can provide data and indices which give a more physical appreciation of the station reliability than is normally available in an analytical assessment. The reliability indices associated with the individual load points discussed in this chapter can be combined with composite customer damage functions to conduct station reliability worth evaluation [109]. The simulation procedure can also be easily applied to station reliability assessment when the system components can not be represented by Markov models [110].

3. SECURITY CONSTRAINED ADEQUACY EVALUATION OF COMPOSITE SYSTEMS

3.1. Introduction

Reliability evaluation of composite power systems can be conducted in the two distinct domains of adequacy and security analyses. System adequacy is associated with the ability of the system to supply its load demands taking into consideration system constraints and scheduled and unscheduled outages of generation and transmission facilities. System security is associated with the ability of the power system to withstand disturbances arising from faults or from the unscheduled removal of bulk power supply equipment. Adequacy assessment, therefore, is a steady state post outage analysis while security assessment involves dynamic condition analysis. Adequacy evaluation of HL II is a major system planning task as it provides system managers, designers, planners and operators with an overall understanding of the system under study. The techniques used in adequacy evaluation of HL II have been extensively developed [3, 5, 6, 7]. The key problems existing in HL II evaluation are the required computation time and computer storage associated with network flow solutions. Adequacy evaluation of a practical HL II configuration can require considerable calculation time to analyze the different networks which are created in the enumeration process by considering selected or sampled outages. A number of techniques for reducing the computation time and computer storage have been developed in order to perform adequacy evaluation of large power systems [32, 46, 48 - 50, 52, 58, 64, 65, 111 - 115]. The reliability indices obtained are described in References 70 and 116. The basic techniques utilized in adequacy analysis are briefly described in this chapter.

The existing HL II adequacy assessment procedures can be used to provide indices at individual load points and for the overall system. Several concerns regarding these techniques are enumerated in an EPRI report [71]. This report also indicates that the inclusion of security constraints in adequacy evaluation can overcome some of the deficiencies which exist in the more traditional methods. Extended adequacy assessment is designated as security constrained adequacy evaluation in this thesis. The extended procedure is illustrated by application to two reliability test systems (the IEEE-RTS and the RBTS) [41, 90].

3.2. Basic Techniques Used in Adequacy Evaluation of Composite Systems

Quantitative adequacy assessment of a composite system can be performed using contingency enumeration [70, 117, 118] or Monte Carlo simulation [15, 16, 20]. The contingency enumeration approach was used in the research work described in this thesis. The basic concepts associated with their application to security constrained adequacy assessment are described in this chapter. The basic procedure involves the selection and evaluation of contingencies, the classification of each contingency according to selected failure criteria and the accumulation of adequacy indices. A range of contingency enumeration approaches, depending on the failure criteria and the intent behind the studies, are available in order to analyze the adequacy of a composite power system [119]. Conducting an adequacy evaluation of a bulk power system also includes the selection of an appropriate network solution technique, an appropriate set of corrective actions, an appropriate contingency level for both generating unit and transmission line outages and the calculation of an appropriate set of adequacy indices.

3.2.1. Network Solution Techniques

The adequacy evaluation of a composite power system generally involves the solution of network configurations under selected outage conditions. The three basic analytical approaches utilized in power system analysis are the network flow, dc load flow and ac load flow techniques. The selection of an appropriate technique is of prime importance and is an engineering decision. The key point is that the selected technique should be capable of satisfying the intent behind the studies from a management, planning and design point of view. The output from these studies may have to be related to consumer expectations, the standard of living and the economic and social consequences associated with an unreliable power supply.

It is not realistic to attempt to consider all possible contingencies in an adequacy evaluation study. The main constraint in considering a large number of outage events is the computation time required to solve these contingencies using an acceptable solution technique. In order to limit the number of contingencies, fixed criteria such as the selection of single or double level contingencies, variable criteria such as a frequency/probability cut-off limit, ranking cut-off limit, etc. are presently utilized. The techniques used to evaluate the system have a significant impact on both the results obtained and the computation time required to achieve a solution.

It can be easily appreciated that the contingency enumeration approach will require a large number of network solutions if all generator and line outage conditions are considered. This requires fast solution techniques using simplified or approximate methods. Various techniques, depending on the adequacy criteria utilized and the intent behind the studies are available. One of the simplest approaches is to treat the system as a transportation model [120] and to examine it in terms of its ability to ensure the continuity of power supply at various load centers. Approximate load flow techniques such as dc load flow [121, 122], are quite simple and fast but only provide an estimate of the line power flows, without including any estimate of the bus voltages and the reactive power limits of the generating units, etc. If the quality of the power supply such as voltage levels, and the MVAr limits of the generating units are important, more accurate ac load flow methods [111, 121, 123] such as Gauss-Seidel and Newton-Raphson load flow techniques, must be employed in order to calculate the adequacy indices. These techniques are not often used because they are computationally expensive and have large storage requirements. Several computationally fast ac load flow techniques, which are modifications of the Newton-Raphson load flow approach, are available. The fast decoupled load flow technique is one of them.

3.2.1.1. DC Load Flow Method

The DC load flow method is one of the simplest network solution techniques. This approach can be described in a matrix form as shown in Equation 3.1,

$$[P]=[B][\delta], \tag{3.1}$$

where [P] -- vector of bus power injection,
[B] -- system susceptance matrix and
[δ] -- vector of phase angle (radian).

The dimensions of [P] and [B] are $(N-1)\times 1$ and $(N-1)\times(N-1)$ respectively, where N is the total number of buses in the system, as one bus is specified as the "slack" or "swing" bus.

The vector of bus phase angles [δ] can be calculated by solving Equation 3.1 using [B] and [P]. Optimal ordering and triangular factorization of the system susceptance matrix are used to achieve a short solution time. The bus phase angle, computed using forward and backward substitution, and then used to determine the individual branch flows is given by Equation 3.2,

$$P_{ij}=\frac{\delta_i-\delta_j}{X_{ij}}, \tag{3.2}$$

where P_{ij} -- real power flow from bus i to bus j,
δ_i -- phase angle at bus i,
δ_j -- phase angle at bus j and
X_{ij} -- reactance of the line between bus i and bus j.

It can be seen from Equation 3.2 that for a fixed set of power injection [P], both [B] and [δ] will change their base case values when a line or several lines are removed. The changes in angle vector can be computed using the Sherman-Morrison correction formula [112] instead of rebuilding and factorizing the system susceptance matrix [B]. The new line flows can be calculated using Equation 3.2 and the new values of $[\delta]_{new}$.

Voltage, VAR effects and transmission line losses can not be evaluated in this simple method. However, the solution is fast and free of convergence problems.

3.2.1.2. Fast Decoupled Load Flow Method

The fast decoupled load flow technique is a good compromise between the basic ac and dc load flow approaches in regard to storage requirements and solution speed. It can also be used to check the continuity as well as the quality of a power system thus meeting the two important adequacy requirements. The fast decoupled load flow approach developed in Reference 64 is used to conduct the adequacy evaluation of composite generation and transmission systems. A brief description of the fast decoupled load flow technique is given below.

The general equations for the power mismatch at all system buses except the swing bus can be obtained using the Newton-Raphson method [121]. The fast decoupled load flow approach neglects the weak coupling between the changes in real power and voltage magnitude, and the changes in reactive power and phase angle. Therefore, the mismatches of active power and reactive power can be expressed by Equations 3.3 and 3.4 respectively,

$$[\Delta P]=[J_\delta][\Delta\delta]\,, \tag{3.3}$$

$$[\Delta Q]=[J_V][\Delta V/V]\,, \tag{3.4}$$

where ΔP_i -- active power mismatch at bus i,
ΔQ_i -- reactive power mismatch at bus i,

$\Delta\delta_i$ -- increment in phase angle of the voltage at bus i,
ΔV_i -- increment in magnitude of the voltage at bus i,
J_δ , J_V -- submatrices of the Jacabian matrix [72],
δ_i -- phase angle of the voltage at bus i and
V_i -- magnitude of the voltage at bus i.

Equations 3.3 and 3.4 can be further simplified by making the following assumptions, which are usually valid in a practical power system:

$\cos(\delta_i - \delta_j) \approx 1.0$,

$g_{ij} \cdot \sin(\delta_i - \delta_j) << b_{ij}$ and

$Q_i << b_{ij} \cdot V_i^2$,

where $g_{ij} - jb_{ij}$ -- series admittance of the line connecting buses i and j and
Q_i -- reactive power at bus i.

Equations 3.5 and 3.6 can be obtained by substituting the above assumptions in Equations 3.3 and 3.4,

$$[\Delta P] = [V.B'.V][\Delta\delta] , \tag{3.5}$$

$$[\Delta Q] = [V.B''.V][\Delta V / V] . \tag{3.6}$$

The final equations used in the fast decoupled load flow technique are given in Expressions 3.7 and 3.8 after making further physically-justifiable simplifications [64],

$$[\Delta P / V] = [B'][\Delta\delta] , \tag{3.7}$$

$$[\Delta Q] = [B''][\Delta V] . \tag{3.8}$$

Both matrices $[B']$ and $[B'']$ are real, sparse and contain only network admittances. Since $[B']$ and $[B'']$ are constant, they need to be inverted or factorized only once at the beginning of the iterative process. The magnitude of the voltage at each load bus and the phase angle at each bus except the slack bus are modified as given in Equations 3.9 and 3.10,

$$[\delta]_{new} = [\delta]_{old} + [\Delta\delta] \,, \tag{3.9}$$

$$[V]_{new} = [V]_{old} + [\Delta V] \,. \tag{3.10}$$

Power mismatch [ΔP] and [ΔQ] are calculated for these new values of bus angle and bus voltage. Equations 3.7 and 3.8 are iterated in some defined manner towards an exact solution, i.e. when power mismatches are less than the tolerance. In the case of line or transformer outages, the Sherman-Morrison correction formula can be used to reflect the outages instead of rebuilding and refactorizing the system matrices $[B']$ and $[B'']$.

3.2.2. Sherman-Morrison Correction

The Sherman-Morrison correction formula can be used to obtain load flow solutions under circuit outage conditions. Instead of rebuilding and factorizing the system admittance matrices for each line contingency, a single correction formula is used to adjust the base solution in order to effectively represent the line outage. The algorithm is applicable to both dc and the decoupled load flow techniques.

Essentially, the correction factors can be calculated by forward and backward substitution using the original factorized system admittance matrix and the base solution vector. Multiple line outages can be considered by applying the formula recursively, and updating the solution vector at each step.

The three equations, 3.1, 3.7 and 3.8, used in the dc and the fast decoupled load flow approaches can be represented by a simple expression. This expression is described by Equation 3.11,

$$[R] = [B][E] \,. \tag{3.11}$$

In the case of the outage of line l connecting bus i and j, the coefficient matrix *[B]* can be modified by Equation 3.12,

$$[B]_{new} = [B] + bmm^t \, , \tag{3.12}$$

where $b = -(1.0 / X_{ij})$ and m is a column vector with all elements zero except element i which is +1 and element j which is -1. The Sherman-Morrison correction formula, Equation 3.13 can be used to solve Equation 3.11,

$$\begin{aligned}[B]^{-1}_{new} &= [B]^{-1} - c[B]^{-1}mm^t[B]^{-1} \\ &= [B]^{-1} - c[Z]m^t[B]^{-1} \, ,\end{aligned} \tag{3.13}$$

where $[Z] = [B]^{-1}m$ and

$c = \{1/b + m^t[B]^{-1}m\}^{-1} = \{1/b + Z_i - Z_j\}^{-1}$.

Therefore, the solution to the outage problem can be solved by using Equation 3.14,

$$\begin{aligned}[E]_{new} &= \{[B]^{-1} - c[Z]m^t[B]^{-1}\}[R] \\ &= [E] - c[Z]m^t[B]^{-1}[R] \\ &= [E] - c(E_i - E_j)[Z] \\ &= [E] + [\Delta E] \, .\end{aligned} \tag{3.14}$$

The objective using the Sherman-Morrison approach is to reduce the computation time required in the network solution methods. In the case of multiple line outages, the Sherman-Morrison approach is applied recursively and the computation time is increased significantly. It has been reported in Reference 51 that for the third level of line outages, rebuilding and refactorization of the system matrices takes less computation time than the recursive use of the Sherman-Morrison correction formula. The computation time for the second order level of line outages is also comparable. A faster matrix correction method is introduced in detail in

Reference 72 and used in this research project in the case of multiple line outages. This technique avoids the recursive use of the Sherman-Morrison correction formula.

3.2.3. Corrective Actions

The simple occurrence of a system problem may be recorded as a failure event. In many cases, however, it may be possible to eliminate a system problem by taking appropriate corrective action. It is, therefore, of interest to determine whether it is possible to eliminate a system problem by employing proper corrective action. There is no consensus among power utilities and related organizations regarding uniform failure criteria and therefore all organizations do not use the same fundamental solution technique to calculate the adequacy of their systems [124]. There are seven types of failure criteria recommended in the dc and decoupled load flow approaches. They are (1) load curtailment at bus(es) due to capacity deficiency in the system, (2) load curtailment, if necessary, at isolated bus(es), (3) load curtailment, if necessary, at bus(es) in the network islands formed due to line outages, (4) load curtailment at bus(es) due to line or transformer overloads, (5) voltage collapse at system bus(es), (6) generating unit MVAr limit violations, (7) ill-conditioned network situations. The dc load flow method can be utilized in the first four criteria. The fast decoupled techniques can be employed in the all of them.

There are broad categories of corrective actions which can be utilized based on the recommended failure criteria. They are (1) generation rescheduling in the case of capacity deficiency in the system, (2) corrections of a generating unit MVAr limit violations, (3) bus isolation and system splitting under transmission line or transformer outages, (4) alleviation of line overloads [125, 126], (5) correction of a voltage problem at a bus and the solution of ill-conditioned network solutions using the ac load flow method, (6) load curtailment in the event of a system problem. The selection of a particular corrective action is dependent upon the situation that causes a failure in the network. A description of the corrective actions and load curtailment procedures can be found in References 1 and 127.

3.2.4. Modeling of Major Components

Generating units and the transmission lines are the major components in a composite generation and transmission system. The overall reliability evaluation of a composite system, if every possible system state is analyzed and all types of system component outages are included, involves exhaustive and formidable analyses and computation. In order to simplify the initial applications, several assumptions have been utilized to make these analyses less demanding. One of the main simplifications is that switching facilities and substations are modeled only as single bus sections without considering the internal configuration of the station and these bus sections are assumed to be fully reliable. The internal failures of the stations which could have a serious impact on the system performance are therefore neglected. Another major simplification is that only the independent outages of the major components are considered. The effects of these major simplifications are examined later in this thesis.

3.2.4.1. Single Component Model

A major component can be represented by the two state model shown in Figure 3.1. State 1 is the component operating state and State 2 is the outage state. The probabilities and the frequencies of these two states can be calculated using the frequency and duration method [101] and these expressions are given in Equations 3.15, 3.16 and 3.17 respectively,

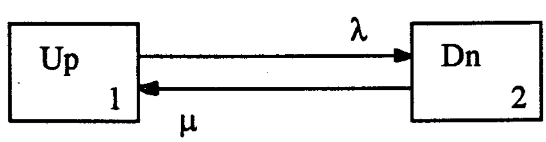


Figure 3.1: Single component outage model.

$$P_1 = \frac{\mu}{\mu+\lambda}, \tag{3.15}$$

$$P_2 = \frac{\lambda}{\mu+\lambda}, \tag{3.16}$$

$$f_1 = f_2 = \lambda \cdot P_1 = \mu \cdot P_2 \,, \tag{3.17}$$

where λ -- component failure rate,
μ -- component repair rate,
P -- probability,
f -- frequency.

3.2.4.2. Two Component Model

The state space diagram for two major components contains four states. The two components in this model are considered to be independent. The model is shown in Figure 3.2. State 1 has both components in the operating state. States 2 and 3 represent one component in the up state and one in the down state while both components are in the outage state in State 4. The probabilities and frequencies can be calculated using Equations 3.18, 3.19, 3.20, 3.21 and 3.22 respectively,

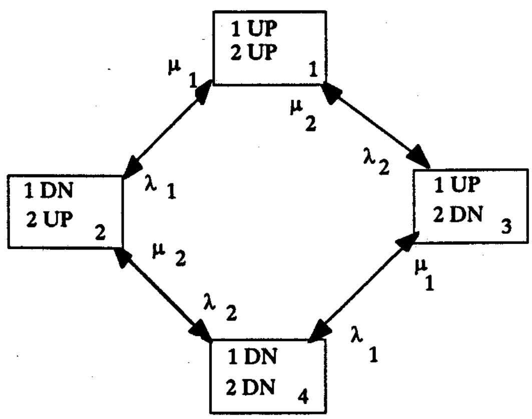


Figure 3.2: Two component outage model.

$$P_1 = \frac{\mu_1 \mu_2}{\Delta} \,, \tag{3.18}$$

$$P_2 = \frac{\lambda_1 \mu_2}{\Delta} \,, \tag{3.19}$$

$$P_3 = \frac{\mu_1 \lambda_2}{\Delta} \,, \tag{3.20}$$

$$P_4 = \frac{\lambda_1 \cdot \lambda_2}{\Delta}, \tag{3.21}$$

$$f_1 = P_1 \cdot \lambda_+, \tag{3.22}$$

where $\Delta = (\mu_1 + \lambda_1)\cdot(\mu_1 + \lambda_1)$ and
λ_+ -- summation of the transition rates which depart from the state.

3.2.4.3. Multiple Component Model

The equations used to calculate the probabilities and frequencies of the states shown in Figure 3.2 can be extended to calculate the probability and frequency of a contingency for a system including N major independent components. When components i, j, and k are in the outage state and the remaining components are in the operating state, the probability and frequency can be calculated by Equations 3.23 and 3.24 respectively,

$$P(i,j,k) = \prod_{m=i,j,k} \frac{\lambda_m}{(\mu_m + \lambda_m)} \prod_{\substack{n=1 \\ n \neq i,j,k}}^{N} \frac{\mu_n}{(\mu_n + \lambda_n)}, \tag{3.23}$$

$$f(i,j,k) = \Big(\sum_{m=i,j,k} \mu_m + \sum_{\substack{n=1 \\ n \neq i,j,k}}^{N} \lambda_n \Big) \cdot P(i,j,k) \,. \tag{3.24}$$

3.2.5. Adequacy Indices

Adequacy evaluation of bulk power systems has been a major system planning task for many years. There are four fundamental parameters in the calculation of the system adequacy. They are probability, frequency, duration and severity of events. Adequacy indices can be divided into the two basic categories of load point indices and system indices [70, 116]. The presently available techniques together with important concerns were addressed in an IEEE Power Engineering Society tutorial [67] and are summarized in Reference 68. There are a number of programs available for composite system adequacy evaluation. These programs are briefly described in Reference 69, including a list of the calculated indices and the factors involved in the assessment.

3.3. Security Considerations

Many utilities have difficulty in interpreting the expected load curtailment indices obtained in the traditional adequacy evaluation approaches as the existing models do not always consider actual system operating conditions. These concerns were expressed in response to a survey conducted as part of an EPRI project and are summarized in the project report [71]. This survey also indicated that security considerations are an important issue in composite system reliability evaluation. A framework for incorporating security considerations was proposed in the project report in response to the stated utility concerns.

Security assessment of a composite system includes two aspects, dynamic condition analysis and steady state post outage analysis. Dynamic security represents the capability of the operating system to remain stable when a failure occurs. Dynamic breaches of security analysis include the following considerations: (1) instability following some shock to the system, (2) shedding of load due to excessive frequency drop following loss of generation or a transmission line, (3) transmission line tripping due to excessive transient flow following an outage [28].

Steady state security assessment relates to whether the amount and response of the generation and transmission reserves, are sufficient to avoid excessive load cuts and other undesirable impacts in the aftermath of failure events. Steady state breaches of security study include the following considerations: (1) voltage at load buses constraints, (2) transmission line flow constraints, (3) real power generation constraints, (4) static generation capacity constraints, (5) operating reserve constraints. A steady state security constraint set may be constructed using any one or using a combination of these considerations. The constraint sets generally considered include the voltage violation problem (Set I), the overload problem (Set II) and the operating reserve requirements (Set III). These constraint sets are included and examined in the research work covered in this thesis.

3.4. Security Constrained Adequacy Evaluation

In order to achieve acceptable operational security, the system must be operated with sufficient "margin" such that it can withstand certain specified contingencies. For example, it is generally required that the system should be able to withstand the loss of any single transmission facility without resulting in the overload of any other facility. Dynamic models may be required to determine the operating limits. These limits are often called "security constraints", although some operating limits may be set by other factors, such as thermal transmission line ratings. Once the operating margins are determined, the system is then operated in accordance with these constraints. It is not necessary to continuously use dynamic models to determine if a security constraint is violated as the constraints themselves become steady state operating limits. The calculation of reliability indices under "security constrained" operation can be designated as security constrained adequacy evaluation. In this case, adequacy assessment includes the margins needed for secure system operation.

In order to include security constraints in an adequacy evaluation of a composite system, the total power network can be divided into several states in terms of the degree to which the adequacy and security constraints are satisfied. Reference 71 presents a classification of a system which includes normal, alert, emergency, extreme emergency and restorative states. A modified state framework is shown in Figure 3.3. The state definitions [71] are as follows.

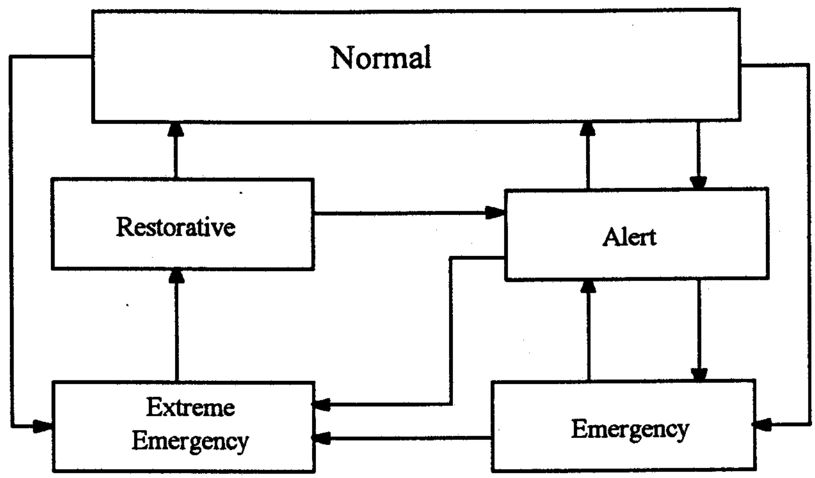


Figure 3.3: System operating states.

The definition of the normal state is:

> In the normal state, all equipment and operation constraints are within limits, including that the generation is adequate to supply the load (total demand), with no equipment overloaded. In the normal state, there is sufficient margin such that the loss of any element, specified by some criteria, will not result in a constraint being violated. The particular criteria, such as all single elements, will depend on the planning and operating philosophy of a particular utility.

From the definition it is clear that the system is both adequate and secure in the normal state. This means that the system is adequate to supply the load and has sufficient margin to withstand specified criteria.

The alert state is defined as:

> If a system enters a condition where the loss of some elements covered by the operating criteria will result in a current or voltage violation, then the system is in the alert state. The alert state is similar to the normal state in that all constraints are satisfied, but there is no longer sufficient margin to withstand an outage (disturbance). The system can enter the alert state by the outage of equipment, by a change in generation schedule, or a growth in the system load.

In the alert state the system no longer has sufficient margin to satisfy the security constraints. Preventive control actions can restore the system to the normal operating state from the alert state. This may involve undesirable actions, such as non-economic generation dispatch or customer load curtailment (or other emergency action). Therefore, a utility or operator may decide to remain in the alert state.

The emergency state is defined as:

> If a contingency occurs or the generation and load changes before corrective action can be (or is) taken, the system will enter the emergency state. No load is curtailed in the emergency state, but equipment or operating constraints have been violated. If control measures are not taken in time to restore the system to the alert state, the system will suffer from emergency state to extreme emergency state.

In this state both adequacy and security constraints are violated. This is a temporary state which requires operator action because equipment operating constraints have been violated. The first objective will be to remove the equipment operating constraints without load curtailment, by such means as phase shift adjustment, redispatch, or startup of additional generation. If successful, this could lead to the alert state, where further actions would be still necessary to achieve the normal state. Such actions could include voltage reduction and even controlled load curtailment. On the other hand, once the alert state is reached, it may be decided to take no further control action as described previously. A single control action could conceivably also lead directly to the normal state.

If use of available facilities can not achieve the alert or normal states, the operator again faces the choice of load curtailment or continued operation in the existing state. However, in this case, continued operation involves operation of equipment outside limits. This would normally not be allowed.

The extreme emergency state is defined as follows:

> In the extreme emergency state, the equipment and operating constraints are violated and load is not supplied.

In this state, load has to be curtailed in a specific manner in order to return from this state to another state.

The restorative state is defined as follows:

> To transfer out of the extreme emergency state, the system must enter the restorative state to reconnect load and resynchronize the network. The loop can then be closed by either entering the alert state or the normal state.

The system can be returned to the normal state from the alert state by using preventive action. Restoration from the emergency state to the alert state can be achieved by using corrective action. The system can be returned to the restorative state from the extreme emergency state by means of emergency action. The system can return to the alert state or to the normal state from the restorative state by using the restorative action.

The probability and frequency of each operating state are used as basic reliability indices in this research project. It is expected that these reliability indices will prove to be intuitively appealing to both power system planners and operators and will form the basis of new system reliability criteria.

3.5. Composite System Operating State Risk Index

Security constrained adequacy of a composite generation and transmission system can be expressed in terms of the probability and frequency of each operating state. These indices depend on many factors such as the amount of installed generation capacity, size of the various generating units and their availabilities, reliability parameters of the transmission facilities, system load, the acceptable voltage range at a load bus, the operating level of the generating units, the station configurations and their element parameters, etc. Both deterministic and probabilistic methods are used in an HL I study to determine the required system capacity reserve margins. The most commonly used deterministic criterion relates the reserve capacity margin to the size of the largest generating unit or to some percentage of the peak demand [70]. The most popular probabilistic criterion is the Loss Of Load Expectation (LOLE) index [70]. This section demonstrates the use of the normal and alert state probabilities to define a system risk index which can be used in HL II studies.

As noted in the operating state definitions, there is no constraint violations or load curtailed in the normal and alert states as the security and adequacy constraints are both satisfied in these two states. Therefore, the system is not in a state of risk if it lies in the normal or the alert state. The system risk can be represented by an index designated as the Composite System Operating State Risk (CSOSR) [72, 91] as shown in Equation 3.25,

$$CSOSR = 1.0 - P_n - P_a \,. \tag{3.25}$$

In this expression, P_n and P_a represent the probabilities of the system residing in the normal and alert states respectively. The summation of the two probabilities is an assessment of the favorable conditions associated with the system. The complement of the sum of these two probabilities quantifies the unfavorable conditions and constitutes the risk level for the system. The CSOSR is used in this thesis as the basic criterion for acceptable/unacceptable system performance.

3.6. Reliability Test Systems

Two reliability test systems have been used to examine composite system security constrained reliability assessment and to test the developed evaluation procedures. These two test systems are the modified Roy Billinton Test System (MRBTS) [90] and the IEEE Reliability Test System (IEEE-RTS) [41].

3.6.1. The Modified RBTS

The RBTS [90] is a small composite power system which can be used to conduct a large number of reliability studies with relatively low computation time. This system is utilized extensively in power system reliability studies conducted at the University of Saskatchewan. The MRBTS single line diagram is shown in Figure 3.4 and the associated reliability data are given in Appendix A. The total installed capacity is 240 MW and the system peak load is 185 MW.

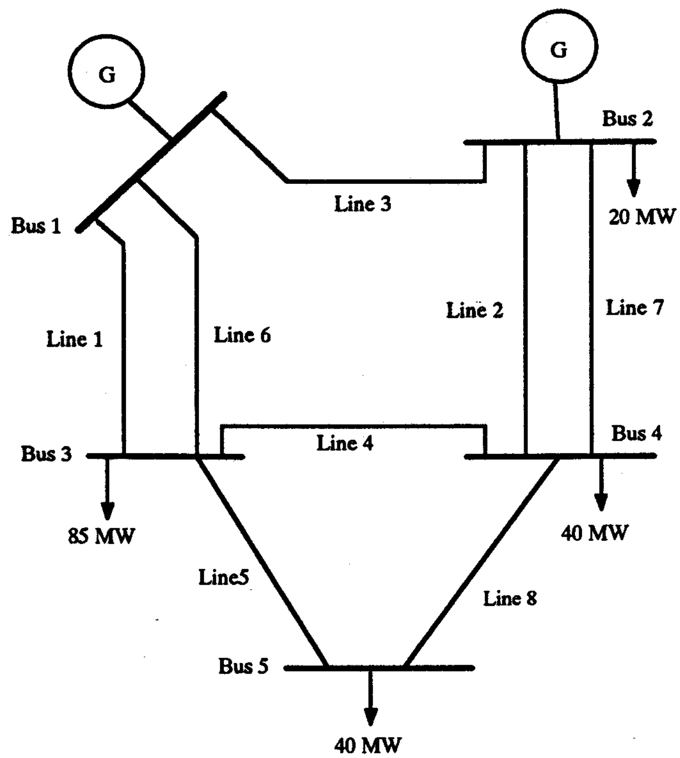


Figure 3.4: Single line diagram of the MRBTS.

3.6.2. The IEEE-RTS

The IEEE-RTS was established by an IEEE task force in 1979 [41]. This test system is relatively complex and is used extensively as a reference network to test and develop different methods of power system reliability evaluation. The single line diagram is shown in Figure 3.5 and the reliability data of this system are given in Appendix B. It can be seen from this single line diagram that the outage of Line 11 will cause the complete isolation of Bus 7. The probability of the normal system state will be zero using the criterion that in this state the loss of any single element will not result in a limit being violated or load curtailment. Outage of Line 11, therefore, has been considered as a special case which does not violate the normal state definition in the studies performed in this thesis. The total installed capacity is 3405 MW and the system peak load is 2850 MW.

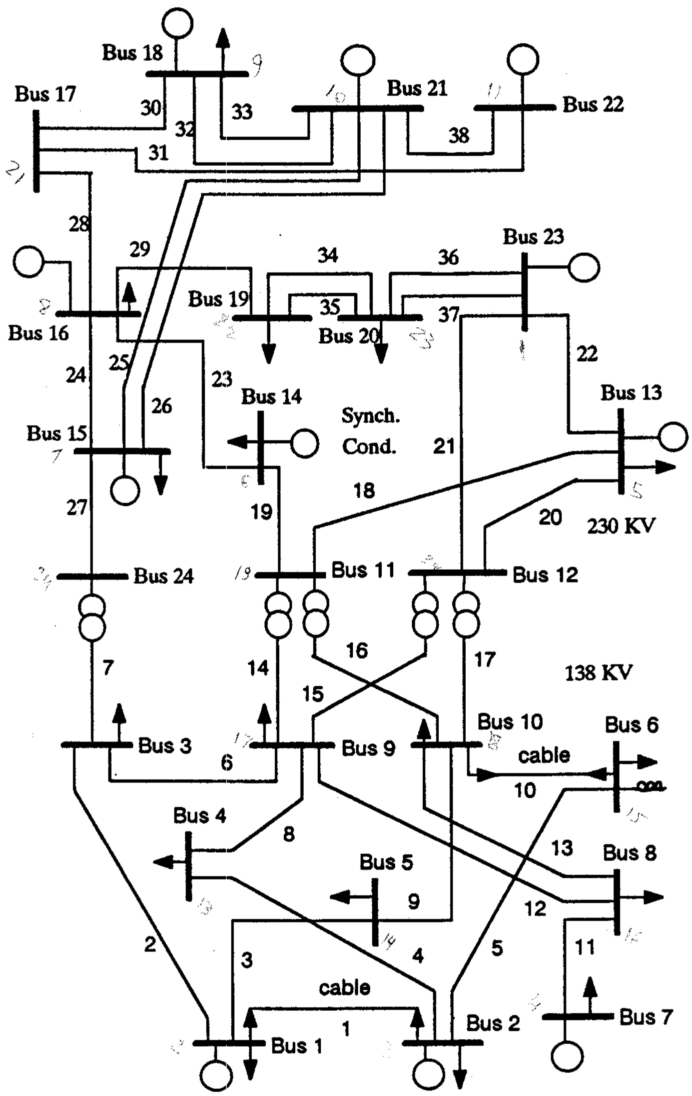


Figure 3.5: Single line diagram of the IEEE-RTS.

3.7. Study Results

A digital computer code was developed [72] to conduct security constrained adequacy evaluation of composite systems. The security constraints considered in this program include two groups, voltage violation (Set I) and overload (Set II) problems. The overload problem is associated with real power generation and thermal transmission line flow. The voltage violation problem is concerned with the voltage at a load bus and the reactive power generation. The developed program can be utilized to consider either the overload or voltage violation or both. The basic flow chart of this program is illustrated in Figure 3.6.

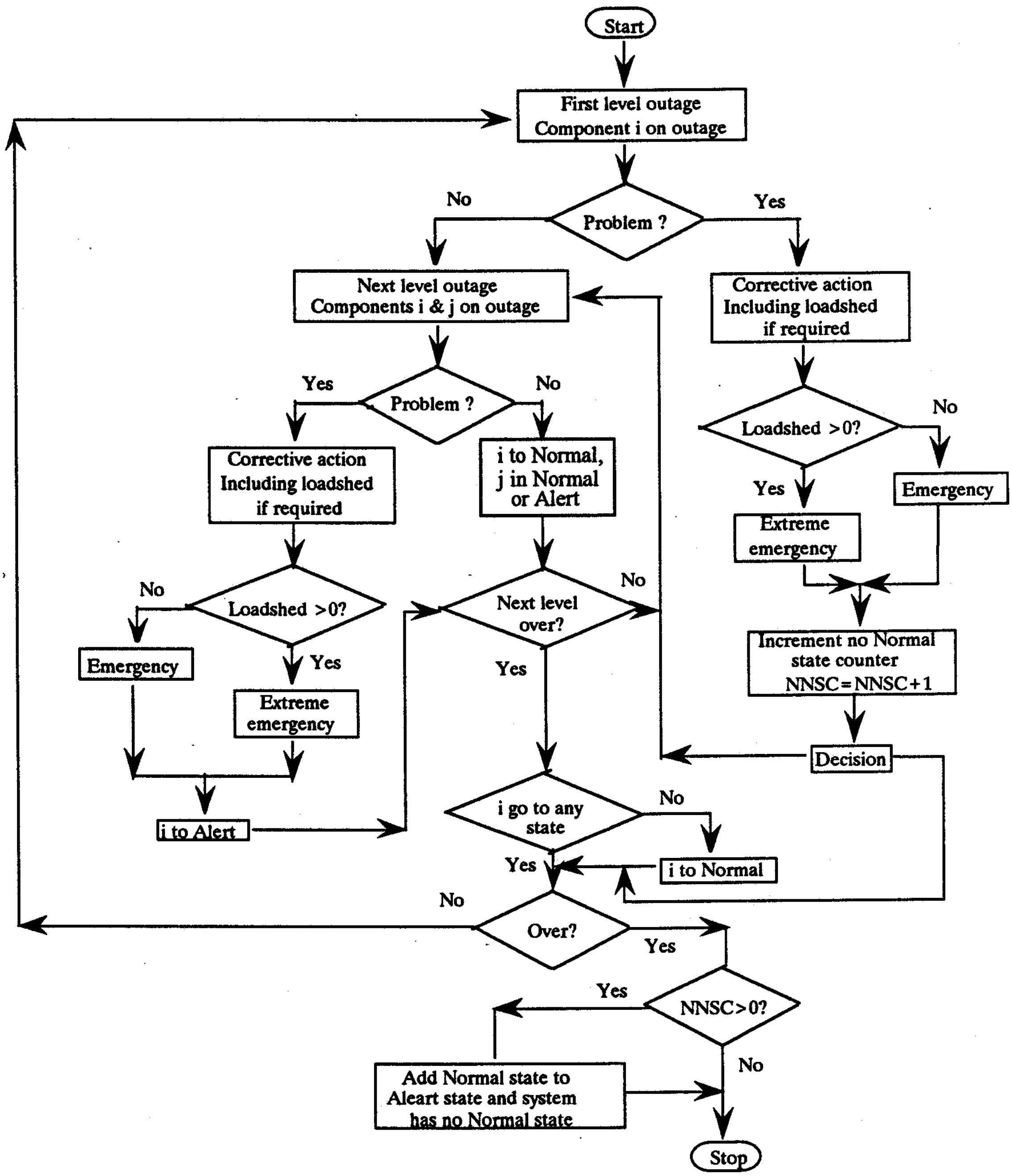


Figure 3.6: Flow chart for detecting different operating states.

3.7.1. Operating State Indices for the MRBTS

Tables 3.1 and 3.2 show the probabilities and frequencies of different operating states for the MRBTS. The results presented consider up to 4th order outages of generators, 3rd order line outages and 3rd order combination outages of generators and transmission lines. The voltage at generating buses in the MRBTS is assumed to be 1.05 p.u. Load bus voltages ranging from 0.97 p.u. to 1.05 p.u. are considered to be acceptable. Tables 3.1 and 3.2 present the reliability indices for the two different constraint sets and for the combination. It can be seen from Table 3.1 that the total probability captured by the outages considered are 0.999975 for the MRBTS. The studies were conducted at the system peak load of 185 MW. The system risk index (CSOSR) is also shown in Table 3.1 for the different constraint sets.

Table 3.1: Operating state probabilities - MRBTS.

State	Set I	Set II	Set I+II
Normal	0.841951	0.828712	0.828712
Alert	0.149725	0.162608	0.162608
Emergency	0.000000	0.000074	0.000074
Ex.Emerg.	0.008299	0.008580	0.008580
Total	0.999975	0.999974	0.999974
CSOSR	0.008324	0.008680	0.008680

Table 3.2: Operating state frequencies - MRBTS.

State	Set I	Set II	Set I+II
Normal	67.397499	54.988461	54.988461
Alert	42.341648	54.271660	54.271660
Emergency	0.000000	0.135101	0.135101
Ex.Emerg.	3.638682	3.982606	3.982606

3.7.2. Operating State Indices for the IEEE-RTS

Tables 3.3 and 3.4 show the probabilities and frequencies of the different operating states in the IEEE-RTS. The CSOSR indices are presented in Table 3.3. Contingencies were considered up to 4th order outages of generators, 3rd order line outages and 3rd order combination outages of generators and transmission lines. The generating bus voltages in the IEEE-RTS were assumed to be 1.02 p.u. Load bus voltages ranging from 0.95 p.u. to 1.05 p.u. were considered to be acceptable. The reliability indices for the different constraint sets are presented in Tables 3.3 and 3.4. It can be seen from Table 3.3 that the total probability captured by the contingencies considered is 0.985617. It can also be seen that the probability and frequency of the normal operating state is zero if the voltage constraint set is included. The reason for this is that at system peak load, there are three single line outages (Lines 4, 10 and 27) which create voltage problems and require VAR injection or raising of the voltage at some generating buses in order to overcome this difficulty. The results are for the system peak load of 2850 MW.

Table 3.3: Operating state probabilities - IEEE-RTS.

State	Set I	Set II	Set I+II
Normal	0.000000	0.233535	0.000000
Alert	0.898146	0.665927	0.898145
Emergency	0.000264	0.000001	0.000265
Ex.Emerg.	0.087207	0.086155	0.087207
Total	0.985617	0.985618	0.985617
CSOSR	0.101854	0.100538	0.101855

Table 3.4: Operating state frequencies - IEEE-RTS.

State	Set I	Set II	Set I+II
Normal	0.000000	61.858276	0.000000
Alert	417.590820	357.024780	417.589691
Emergency	0.354380	0.001118	0.355480
Ex.Emerg.	54.868267	53.929287	54.868294

3.8. Operating State Indices at Different Load Levels

The reliability indices at the system peak load in the two test systems are presented in the previous section. System load varies normally with time for any specific system. Using the peak load as a constant value is pessimistic from a reliability point of view. The reliability indices calculated at the system peak load are called annualized indices [70]. System reliability indices obtained using the actual system load profile are known as annual system indices [70]. Reliability indices obtained at different load levels can be used to obtain the annual system indices by applying a load probability distribution. This is discussed in the next section.

Tables 3.5, 3.6 and 3.7, 3.8 show the probabilities and frequencies of the system operating states for the MRBTS and IEEE-RTS when both constraint sets are applied. In calculating these tables, the voltage at each generating bus was adjusted within the acceptable range in order to minimize the system operating risk. It can be seen from these tables that the system risk increases significantly as the system load increases. Some of the normal state probabilities and frequencies in Tables 3.7 and 3.8 are zero. This indicates that some voltage constraints are violated in these cases.

Table 3.5: Operating state probabilities at different load levels - MRBTS.

Load level	Probability of Normal	Alert	Emergency	Extreme emergency	CSOSR
40%	0.997595	0.002379	0.000000	0.000001	0.000026
50%	0.997577	0.002396	0.000000	0.000001	0.000027
60%	0.997325	0.002646	0.000000	0.000003	0.000029
70%	0.994166	0.005783	0.000001	0.000024	0.000051
80%	0.973718	0.025991	0.000080	0.000186	0.000291
90%	0.899920	0.097637	0.000077	0.002341	0.002443
100%	0.828712	0.162608	0.000074	0.008580	0.008680

Table 3.6: Operating state frequencies at different load levels - MRBTS.

Load level	Frequency of Normal	Alert	Emergency	Extreme emergency
40%	110.942863	2.432243	0.000013	0.002703
50%	110.921448	2.453592	0.000013	0.002774
60%	110.748116	2.625338	0.000106	0.004264
70%	108.741661	4.616448	0.002449	0.017269
80%	92.281883	20.838959	0.144879	0.112103
90%	71.571609	40.523109	0.139542	1.143568
100%	54.988461	54.271660	0.135101	3.982606

Table 3.7: Operating state probabilities at different load levels - IEEE-RTS.

Load level	Probability of				CSOSR
	Normal	Alert	Emergency	Extreme emergency	
40%	0.233143	0.752455	0.000005	0.000003	0.014402
50%	0.233143	0.752453	0.000007	0.000003	0.014404
60%	0.233143	0.752449	0.000011	0.000003	0.014408
70%	0.000000	0.985282	0.000321	0.000003	0.014718
80%	0.000000	0.983499	0.001115	0.000993	0.016501
90%	0.000000	0.972947	0.000275	0.012384	0.027053
100%	0.000000	0.898145	0.000265	0.087207	0.101855

Table 3.8: Operating state frequencies at different load levels - IEEE-RTS.

Load level	Frequency of			
	Normal	Alert	Emergency	Extreme emergency
40%	62.069893	410.720093	0.005095	0.004614
50%	62.069893	410.718445	0.006725	0.004613
60%	62.069893	410.714325	0.010855	0.004613
70%	0.000000	472.386475	0.407982	0.005228
80%	0.000000	471.231537	0.993490	0.574652
90%	0.000000	463.949341	0.372918	8.477441
100%	0.000000	417.589691	0.355480	54.868294

3.9. Annual Indices

Appendix C presents the Daily Peak Load Variation Curve (DPLVC) and the Load Duration Curve (LDC) data for the two test systems. Each curve is represented by 100 points. These data are illustrated graphically in Figure 3.7. These two curves can be used to calculate the annual system indices. Table 3.9 is obtained from Figure 3.7 and Tables C.4 and C.5 using a seven step approximation of the load model.

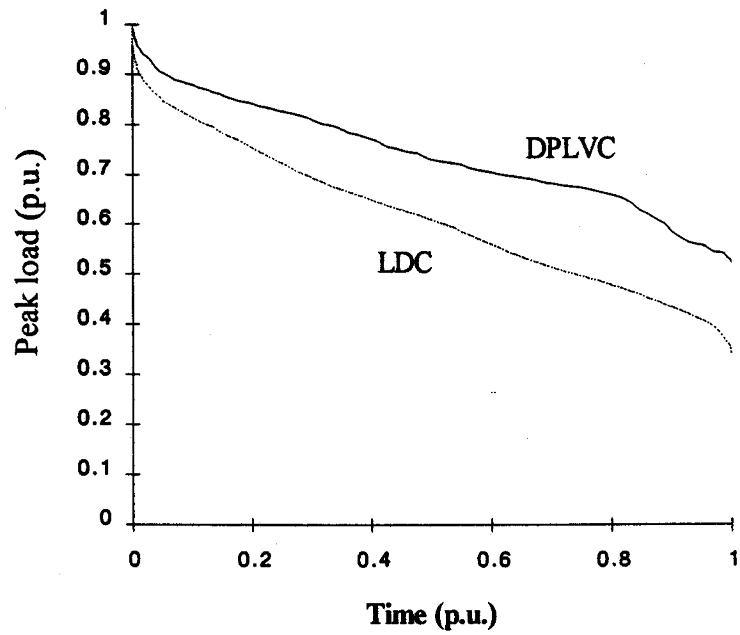


Figure 3.7: System load variation curves.

Table 3.9: Seven step load model probabilities.

Load level	Probability	
	DPLVC	LDC
40%	0.0000	0.0451
50%	0.0000	0.2331
60%	0.1242	0.2129
70%	0.2624	0.2316
80%	0.2971	0.1651
90%	0.2646	0.1022
100%	0.0517	0.0100

Tables 3.10 and 3.11 present the annual CSOSR values calculated using the DPLVC and the LDC for the MRBTS and the IEEE-RTS respectively. The annual risk contributions from the selected load levels are

also shown in these two tables. The annual HL II CSOSR values can be compared with the LOLE indices used in HL I evaluation [70, 128].

Table 3.10: Annual CSOSR contribution for the MRBTS.

Load	Basic value	DPLVC		LDC	
level	CSOSR (p.u.)	CSOSR (days/yr)	Contribution (%)	CSOSR (hrs/yr)	Contribution (%)
40%	0.000026	0.0000	0.0000	0.0103	0.2860
50%	0.000027	0.0000	0.0000	0.0551	1.5352
60%	0.000029	0.0013	0.3005	0.0541	1.5060
70%	0.000051	0.0049	1.1165	0.1035	2.8811
80%	0.000291	0.0316	7.2130	0.4209	11.7189
90%	0.002443	0.2359	53.9304	2.1871	60.9006
100%	0.008680	0.1638	37.4396	0.7604	21.1722
Total		0.4375	100.0000	3.5913	100.0000

Table 3.11: Annual CSOSR contribution of the IEEE-RTS.

Load	Basic value	DPLVC		LDC	
level	CSOSR (p.u.)	CSOSR (days/yr)	Contribution (%)	CSOSR (hrs/yr)	Contribution (%)
40%	0.014402	0.0000	0.0000	5.6899	3.8228
50%	0.014404	0.0000	0.0000	29.4123	19.7610
60%	0.014408	0.6532	7.7878	26.8710	18.0535
70%	0.014718	1.4096	16.8074	29.8601	20.0618
80%	0.016501	1.7894	21.3353	23.8650	16.0339
90%	0.027053	2.6128	31.1524	24.2198	16.2723
100%	0.101855	1.9221	22.9171	8.9225	5.9947
Total		8.3870	100.0000	148.8406	100.0000

3.10. Summary

The basic network solution approaches, system failure criteria and corrective actions utilized in traditional adequacy evaluation at HL II are briefly described in this chapter. These techniques can also be utilized in security constrained adequacy evaluation of composite systems. An approach to classify the system operating states, their definitions and a flow chart for detecting these operating states are presented in this chapter. Reliability indices calculated with the inclusion of security constraints are completely different from those obtained using the traditional composite system adequacy evaluation methods. The basic indices are the probabilities and frequencies of the system operating states. These indices can be more readily understood and appreciated by power system planners and operators than the conventional adequacy indices. It is believed that these indices overcome some of the concerns raised in the EPRI project survey [71], and will form the basis for new system reliability criteria. The Composite System Operating State Risk (CSOSR) is proposed as the system risk criterion and can be used to serve the same function as the basic index LOLE presently used in HL I studies. The annual system risk contributions for selected load levels are also presented in this chapter together with the calculated annual values. This information provides power system planners with an overall appreciation of the risk contributions at the selected system load levels and their effects on the annual system risk.

4. CONSIDERATION OF DEPENDENT OUTAGES IN SECURITY CONSTRAINED ADEQUACY EVALUATION OF COMPOSITE SYSTEMS

4.1. Introduction

One of the most essential elements in power system planning is the determination of how much generation capacity is required to give a reasonable assurance of satisfying the system load requirement. The basic concern in this case is to determine whether there is sufficient capacity in the system to generate the required energy to meet the system load. A second but equally important element in the planning phase is the development of a suitable transmission network to transfer the generated energy to the customer load points. Switching stations are used to connect the generating units and major transmission lines to form the bulk electricity system. Substations are then used to connect the bulk power system to the distribution network and the customer load points. Switching facilities and substations are essential and important configurations in an electric power system.

Independent outages of generating and transmission facilities in security constrained adequacy evaluation of composite systems have been illustrated in Chapter 3. This is the simplest consideration in the reliability evaluation of a composite system. Dependent outages of major components can, however, also contribute significantly to system unreliability [35 - 37]. This chapter focuses on the analysis and modeling of dependent generation and transmission outages in composite system evaluation. The term "dependent outages" as used in this thesis is considered to include both common mode failures of transmission lines [1, 70] and the station originated failures described in Chapter 2.

This chapter presents the modeling techniques used for common mode outages and station initiated outages. Reliability index expressions recognizing both independent and dependent outages are developed. The developed procedure is quantified and examined by application to the two reliability test systems and the impacts of dependent failures on the system indices are discussed. The annualized reliability indices for the system operating states are examined at different load levels. These values can be easily used to calculate the corresponding system annual values.

4.2. Effect of Common Mode Outages on Adequacy Indices

4.2.1. Modeling of Common Mode Outages

A common mode failure is defined as an event having a single external cause with multiple failure events which are not consequence of each other [1]. The most obvious example of a common cause event is the failure of a transmission tower supporting two or more transmission circuits. The basic transmission line model used is the simple two state representation in which a component is either available or forced out of service as shown in Figure 3.1. The model for two transmission lines is the same as that shown in Figure 3.2 when only independent outages of the two lines are considered.

Two transmission lines may be in a simultaneous outage state due to a common cause outage. The probability of this contingency arising due to a common mode outage can be considerably larger, in certain configurations, than the probability of two independent overlapping outages. The model shown in Figure 4.1 includes both independent and common mode outages of the two lines [70]. State 4 results from the overlapping of the two component independent outages. The probability of State 4 is the product of the individual outage probabilities when only independent outages are considered. This probability is extremely small when the two individual outage probabilities are small, as is generally the case for transmission facilities. State 5 is due to the common mode outage. The common mode failure and repair rates are represented by λ_c and μ_c respectively.

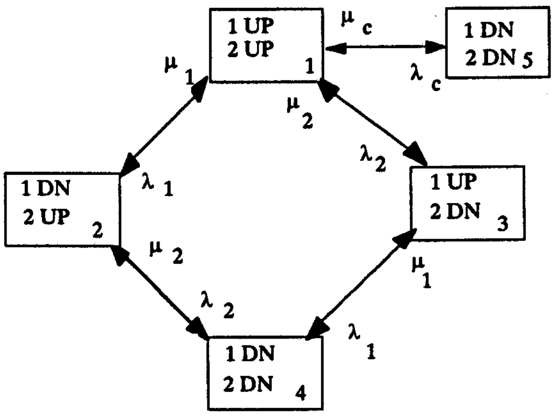


Figure 4.1: Two component common mode outage model.

The probability and frequency of each state can be obtained using the frequency and duration method [101] and are given by Equations 4.1, 4.2, 4.3, 4.4, 4.5 and 4.6,

$$P_1 = \frac{\mu_1 \mu_2 \mu_c}{\Delta}, \tag{4.1}$$

$$P_2 = \frac{\lambda_1 \mu_2 \mu_c}{\Delta}, \tag{4.2}$$

$$P_3 = \frac{\mu_1 \lambda_2 \mu_c}{\Delta}, \tag{4.3}$$

$$P_4 = \frac{\lambda_1 \lambda_2 \mu_c}{\Delta}, \tag{4.4}$$

$$P_5 = \frac{\mu_1 \mu_2 \lambda_c}{\Delta}, \tag{4.5}$$

$$f_i = P_i \cdot \lambda_+ , \tag{4.6}$$

where $\Delta = \mu_1\mu_2\mu_c + \lambda_1\mu_2\mu_c + \lambda_2\mu_1\mu_c + \lambda_1\lambda_2\mu_c + \lambda_c\mu_1\mu_2$ and
λ_+ -- summation of all the transition rates of departure from the studied state.

Both States 4 and 5 represent the two components in the outage state. One is caused by independent component outages and the other by a common mode failure event. The two states can be combined into one to simplify subsequent system analysis. The probability and frequency of the combined state are given by Equations 4.7 and 4.8 respectively,

$$P_{com} = P_4 + P_5 \ , \tag{4.7}$$

$$f_{com} = (\mu_1 + \mu_2) \cdot P_4 + \mu_c P_5 \ . \tag{4.8}$$

An alternative model to recognize common mode failures is shown in Figure 4.2 [1, 70]. In this model, the outage of two transmission lines due to a common mode outage and the overlapping of the two independent outages is represented by State 4. The corresponding probability of residing in each individual state and the frequency of departure from a state can be obtained using the frequency and duration method. The model shown in Figure 4.1 is utilized throughout this research project.

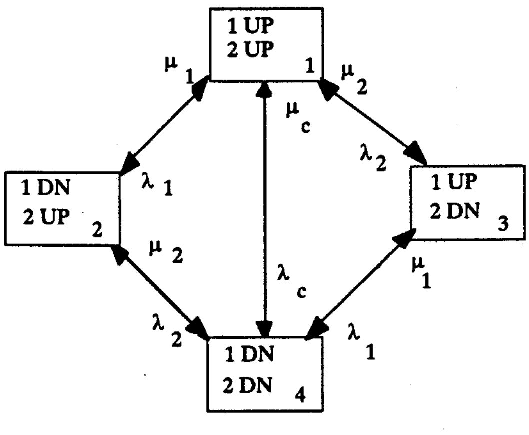


Figure 4.2: Alternative common mode outage model.

4.2.2. Adequacy Evaluation Including Common Mode Outages

The common mode outage data associated with the two test systems, the MRBTS and the IEEE-RTS, are given in Appendices A and B. The system operating state probabilities and frequencies, and the CSOSR are presented in this section for situations in which common mode outages of transmission lines are considered together with independent outages of the major components. The studies were conducted at system peak loads of 185

MW and 2850 MW for the MRBTS and the IEEE-RTS respectively. The three combinations of constraint sets I and II are illustrated in these studies.

4.2.2.1. Operating State Indices for the MRBTS

Tables 4.1 and 4.2 present the system operating state probabilities and frequencies for the MRBTS. It can be seen from Table 4.1 that the total probability captured is 0.999950 when only constraint set I is considered. This probability is less than that presented in Chapter 3 and all system conditions are identical except that common mode outages are included. This can be understood by comparing the differences between the two models with and without recognizing the common mode outage of two transmission lines. It can also be seen that the risk indices in Table 4.1 are larger than those shown in Table 3.1.

Table 4.1: Operating state probabilities - MRBTS (independent and common mode outages considered).

State	Set I	Set II	Set I+II
Normal	0.840962	0.827739	0.827739
Alert	0.150430	0.162432	0.162432
Emergency	0.000000	0.000873	0.000873
Ex.Emerg.	0.008558	0.008908	0.008908
Total	0.999950	0.999952	0.999952
CSOSR	0.008608	0.009829	0.009829

Table 4.2: Operating state frequencies - MRBTS (independent and common mode outages considered).

State	Set I	Set II	Set I+II
Normal	67.860222	55.461887	55.461887
Alert	42.943455	54.318455	54.318455
Emergency	0.000000	0.623965	0.623965
Ex.Emerg.	3.815507	4.216701	4.216701

4.2.2.2 Operating State Indices for the IEEE-RTS

The adequacy indices for the IEEE-RTS incorporating the effect of common mode outages of transmission lines are given in Tables 4.3 and 4.4. The probability captured, as shown in Table 4.3, is 0.983297 in the case of constraint set I. This is less than 0.985617 which is the captured probability when only independent outages of major components are included. It can also be seen that the probabilities and frequencies of the Emergency and Extreme emergency states shown in these two tables are larger than those shown in Tables 3.3 and 3.4. Recognizing only independent outages of major components can provide an optimistic assessment of system reliability in certain configurations.

Table 4.3: Operating state probabilities - IEEE-RTS (independent and common mode outages considered).

State	Set I	Set II	Set I+II
Normal	0.000000	0.232197	0.000000
Alert	0.895794	0.664741	0.895627
Emergency	0.000266	0.000142	0.000407
Ex.Emerg.	0.087237	0.086215	0.087263
Total	0.983297	0.983295	0.983297
CSOSR	0.104206	0.103062	0.104373

Table 4.4: Operating state frequencies - IEEE-RTS (independent and common mode outages considered).

State	Set I	Set II	Set I+II
Normal	0.000000	62.234795	0.000000
Alert	420.536469	359.440399	420.381317
Emergency	0.356735	0.129712	0.486100
Ex.Emerg.	55.306881	54.393101	55.332645

4.3. Effect of Station Originated Outages on Adequacy Indices

Stations can have a significant impact on the reliability indices of a composite system. It has been reported that station initiated failures cause more than 40 percent of the multi-line outages in the Commonwealth Edison Company's 345 KV power system [129]. Station originated failure events can also cause the outages of generating units and complete isolation of load feeders. The probability of these outages can be quite high in some cases and can contribute significantly to composite system adequacy indices [35, 37, 73 - 75]. There are two basic techniques for considering station element outage effects in composite system adequacy analysis. One technique involves the recognition and consideration of independent overlapping outages and station initiated common cause events. The outages resulting from station components are normally included by increasing the failure rates of the associated transmission lines and generating units by a fixed amount. This is a valid addition only for those terminal related failures which result in the outage of a single connection. Such treatment, however, can not recognize a situation in which a single event in the terminal station results in the outage of more than one connection. A more valid technique considers the failures in terminal stations to be separate and distinct events rather than attempting to include the effect of terminal stations by modifying the transmission line or generating unit reliability parameters. Reliability analysis of stations should be performed separately before commencing a composite system reliability study. This procedure provides a list of connection contingencies together with the probability and frequency of occurrence for each connection contingency. This information is then considered as input data and combined with the values of the corresponding component contingencies due to independent outages. This technique is utilized in this research project. The probability and frequency indices associated with the outage of connection sets can be obtained by the station reliability evaluation procedures described in Chapter 2.

4.3.1. Modeling of Station Originated Outages

Reliability evaluation of switching facilities and substations are described extensively in Chapter 2. As noted, two distinct groups of reliability indices can be obtained and used for quite different purposes. One group provides an estimate of load point reliability while the other provides input data for the reliability evaluation of composite systems. This second group is used in the security constrained adequacy analysis described in this chapter.

The outage of two or more transmission facilities not necessarily on the same right of way or the outage of two or more generating units can arise due to station initiated causes. Station initiated outages can occur due to a ground fault on a breaker, a stuck breaker condition, a bus fault, etc. or a combination of these faults. The modeling procedure is illustrated using the switching station shown in Figure 4.3. This figure shows a single line diagram of a ring type station including six breakers, six bus sections and three transformers. This station configuration has six connections which can be linked with generating units, transmission lines or load feeders. It can be seen from this configuration that a ground fault on Breaker 1 will open Breakers 2 and 6 and hence isolate two connections from the system. This type of event is not normally included in either generating capacity or composite system reliability studies.

Connection contingencies for lines, or lines and generators have been considered up to the third order level in this research work. Connection contingencies for generators have been considered up to the fourth order level. This corresponds to the contingency selection levels used for the major components. Figure 4.4 shows a station originated outage model for two connections, X and Y. The transition rates in this diagram originate from the associated components in the configuration under study.

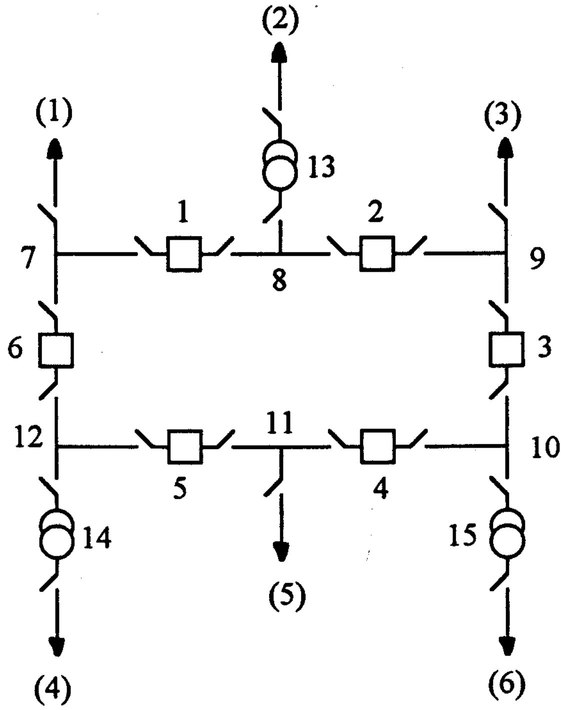


Figure 4.3: A ring bus station configuration.

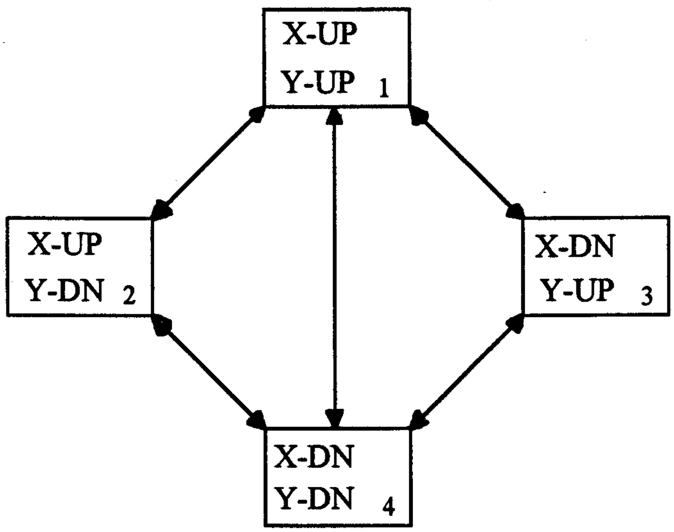


Figure 4.4: Two connection outage model.

4.3.2. Modeling Technique for Contingencies Caused by Major Component and Station Elements

Major components such as generators and transmission lines can be forced out of service due to their own outages and also due to related station element outages. The state probabilities and frequencies calculated using the models given in Figures 3.2 and 4.4 can be combined to consider the major component outages and station element failure effects. A four state space diagram can be used for this purpose. The summation of the probabilities of these states is shown in Equation 4.9. The probability and frequency of each state can be calculated using Equations 4.10, 4.11, 4.12, 4.13 and 4.14 ,

$$\sum_{i=1}^{i=4} P_i = (\sum_{i=1}^{i=4} A_i)\cdot(\sum_{j=1}^{j=4} B_j) \, , \tag{4.9}$$

$$P_1 = A_1 B_1 \, , \tag{4.10}$$

$$P_2 = A_1 B_2 + A_2 (B_1 + B_2) \, , \tag{4.11}$$

$$P_3 = A_1 B_3 + A_3 (B_1 + B_3) \, , \tag{4.12}$$

$$P_4 = A_4 + A_1 B_4 + A_2 (B_3 + B_4) + A_3 (B_2 + B_4) \, , \tag{4.13}$$

$$f_i = P_i \cdot \lambda_+ \, , \tag{4.14}$$

where P is the combined probability due to both independent and station originated outages. A is the probability due to major component independent outage events. B is the probability due to station element outage events. f is the state frequency. λ_+ is the summation of all the equivalent departure rates from the studied state. Subscript 1 indicates both components in the operating state. Subscript 2 indicates Component 1 in the operating state and Component 2 in the outage state. Subscript 3 represents Component 1 in the outage state and Component 2 in the operating state. Subscript 4 represents both components in the outage state.

In general, the probability of the two connections being in the up state due to station events, i.e. B_1, is almost equal to 1. Using this approximation, P_2, P_3, and P_4 can be calculated using Equations 4.15, 4.16 and 4.17 respectively,

$$P_2 = A_2 + A_1 \cdot B_2 \ , \tag{4.15}$$

$$P_3 = A_3 + A_1 \cdot B_3 \ , \tag{4.16}$$

$$P_4 = A_4 + A_1 \cdot B_4 \ . \tag{4.17}$$

These equations can be extended to calculate the probability and frequency of every event obtained in the contingency enumeration method for a system including N major components. The probability and frequency associated with contingency i, j, k can be calculated using Equations 4.18 and 4.19 respectively,

$$P_{i,j,k} = A_{i,j,k} + A_{all\ component\ up} \cdot B_{i,j,k} \ , \tag{4.18}$$

$$f_{i,j,k} = P_{i,j,k} \cdot \lambda_{i,j,k} \ , \tag{4.19}$$

where $P_{i,j,k}$, $f_{i,j,k}$ are the probability and frequency of Components i, j, k in the outage state and all other components in the operating state. $A_{i,j,k}$ is the probability of major components i, j, k in the outage state and all other major components in the operating state. $B_{i,j,k}$ is the probability of connections corresponding to major components i, j, k being in the outage state and all other connections in the operating state. $\lambda_{i,j,k}$ is the equivalent departure rate from the contingency i, j, k due to independent and dependent outages.

4.3.3. Development of a More Accurate Technique

The station connections link the generating units, transmission lines and load feeders. The previously developed equations assume that the load feeder isolation indices resulted from the station element failures are equal to the corresponding connection values multiplied by the probability of all major components in the operating state. This assumption is optimistic. A group of more realistic equations has been developed and is used in the security constrained adequacy evaluation procedure. When considering only major component outages, the total probability captured in the adequacy evaluation procedure is calculated using Equation 4.20,

$$P = A_0 + \sum A_{1i} + \sum A_{2i} + \sum A_{3i} + \sum A_{4i} \ , \qquad (4.20)$$

where subscripts *0, 1, 2,* etc. indicate the major component outage order of 0, 1, 2, etc. Equation 4.20 becomes Equation 4.21 when the station originated outages are included and the total summation of the station connection probabilities is unity,

$$P = (A_0 + \sum A_{1i} + \sum A_{2i} + \sum A_{3i} + \sum A_{4i})$$
$$\times (B_0 + \sum B_{1j} + \sum B_{2j} + \sum B_{3j} + \sum B_{4j} + \sum B_{lj} + \sum B_{hj}) \ , \qquad (4.21)$$

where the $\sum B_{lj}$ indicates the total probability of load feeder isolation caused by station element outages. $\sum B_{hj}$ represents the probability due to the higher order contingencies which are not enumerated.

In the case of load feeder isolation, the system will lie in the Extreme Emergency state as defined in Chapter 3 even if all of the major components are in the operating state. Therefore, Equation 4.21 has the following form where it is assumed that the total probability captured is approximately equal to 1 when only independent outages are considered:

$$P \approx \sum B_{lj} + \sum B_{hj} + A_0B_0 + A_0(\sum B_{1j} + \sum B_{2j} + \sum B_{3j} + \sum B_{4j})$$
$$+(\sum A_{1i})(B_0 + \sum B_{1j} + \sum B_{2j} + \sum B_{3j} + \sum B_{4j})$$
$$+(\sum A_{2i})(B_0 + \sum B_{1j} + \sum B_{2j} + \sum B_{3j} + \sum B_{4j})$$
$$+(\sum A_{3i})(B_0 + \sum B_{1j} + \sum B_{2j} + \sum B_{3j} + \sum B_{4j})$$
$$+(\sum A_{4i})(B_0 + \sum B_{1j} + \sum B_{2j} + \sum B_{3j} + \sum B_{4j}) . \tag{4.22}$$

It is assumed that in the case of a contingency caused by the major components, the effect of the station element outages on the contingency unavailability is negligible as the unavailability of the connections is much less than the probability of having all connections in the operating state. Equation 4.22 therefore simplifies to Equation 4.23,

$$P = \sum B_{lj} + \sum B_{hj} + A_0B_0 + A_0(\sum B_{1j} + \sum B_{2j} + \sum B_{3j} + \sum B_{4j})$$
$$+(1-\sum B_{lj} - \sum B_{hj})\sum A_{1i} + (1-\sum B_{lj} - \sum B_{hj})\sum A_{2i}$$
$$+(1-\sum B_{lj} - \sum B_{hj})\sum A_{3i} + (1-\sum B_{lj} - \sum B_{hj})\sum A_{4i} . \tag{4.23}$$

This equation can be used to calculate the probabilities of all the contingencies. The probability associated with contingency *i, j, k* can be calculated using Equation 4.24,

$$P_{i,j,k} = (1-\sum B_{lm} - \sum B_{hm})A_{i,j,k} + A_0B_{i,j,k} . \tag{4.24}$$

The difference between Equations 4.24 and 4.18 is that the probability $A_{i,j,k}$ in Equation 4.18 is multiplied by a system constant $1-\sum B_{lm} - \sum B_{hm}$ in Equation 4.24. The overall system risk obtained using Equations 4.23 and 4.24 is larger than that calculated using Equation 4.18. Equations 4.24 and 4.19 were utilized in the security constrained reliability evaluation procedure developed in this research project.

4.3.4. Adequacy Evaluation Including Station Originated Outages

Reliability evaluation including both independent and station originated outages was performed using the MRBTS and the IEEE-RTS. The extended single line diagrams of these systems together with their station configurations are shown in Figures 4.5 and 4.6. The reliability data for these two test systems including the station element reliability parameters are given in Appendices A and B. All the studies were conducted at system peak loads of 185 MW and 2850 MW for the MRBTS and IEEE-RTS respectively.

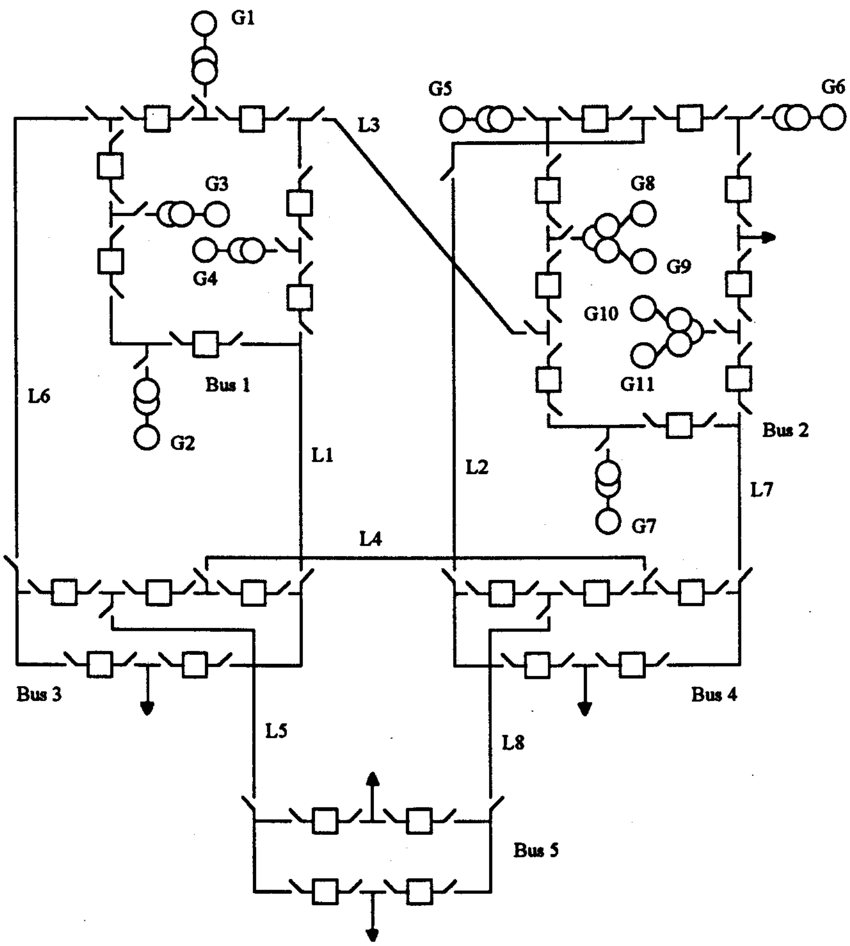


Figure 4.5: Extended single line diagram of the MRBTS.

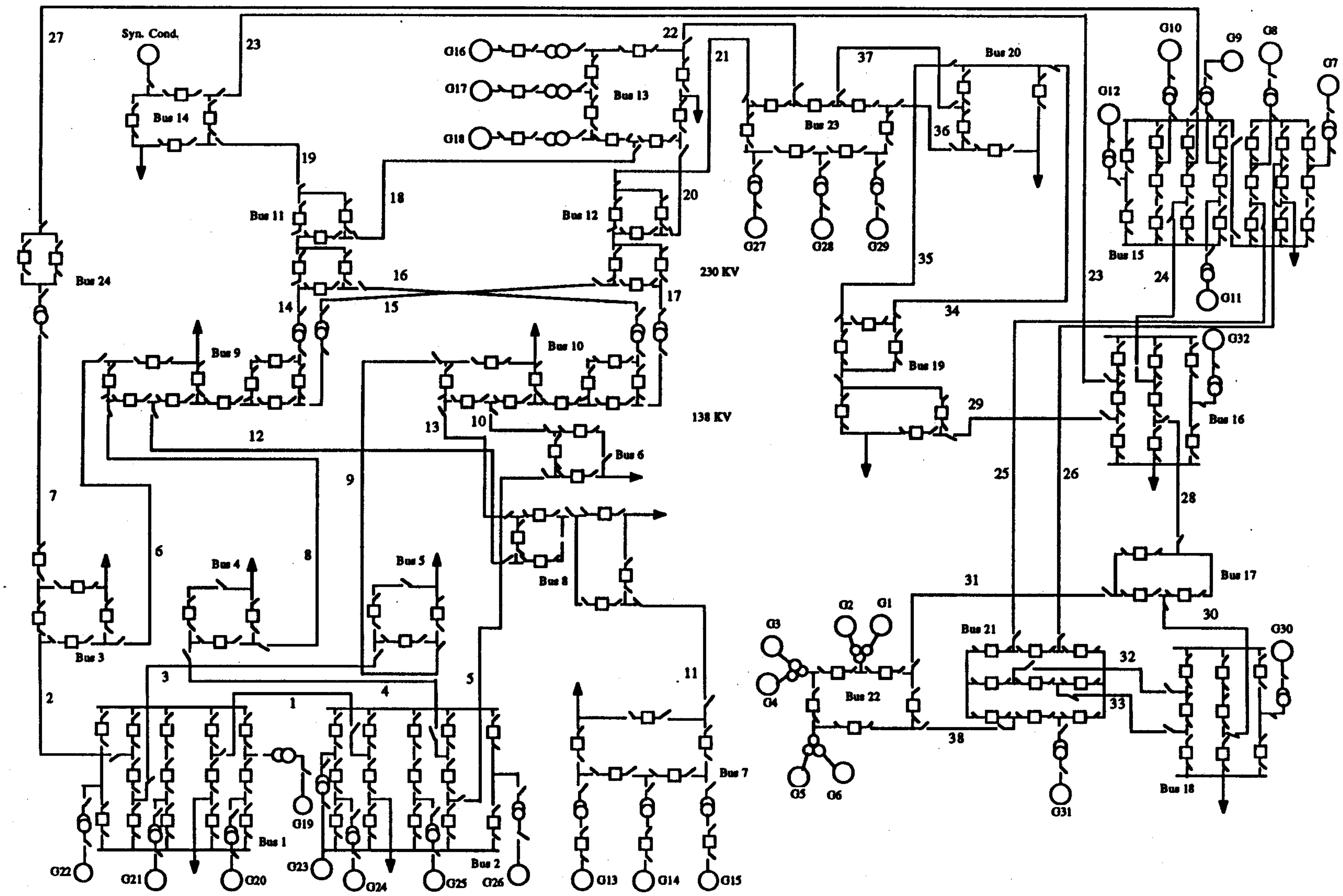


Figure 4.6: Extended single line diagram of the IEEE-RTS.

4.3.4.1. Operating State Indices for the MRBTS

The operating state probabilities and frequencies for the MRBTS are given in Tables 4.5 and 4.6. It can be seen from Table 4.5 that the total probability captured is 0.999932. This can be compared with the value of 0.999975 illustrated in Table 3.1. This difference is caused by the increased outage state probabilities. The system risk values are also higher in Table 4.5 compared with those presented in Table 3.1.

Table 4.5: Operating state probabilities - MRBTS (independent and station originated outages considered).

State	Set I	Set II	Set I+II
Normal	0.828962	0.814473	0.814473
Alert	0.161196	0.175323	0.175323
Emergency	0.000000	0.000075	0.000075
Ex.Emerg.	0.009774	0.010061	0.010061
Total	0.999932	0.999932	0.999932
CSOSR	0.009842	0.010204	0.010204

Table 4.6: Operating state frequencies - MRBTS (independent and station originated outages considered).

State	Set I	Set II	Set I+II
Normal	75.859482	61.947479	61.947479
Alert	48.250023	61.672478	61.672478
Emergency	0.000000	0.136427	0.136427
Ex.Emerg.	5.534911	5.888036	5.888036

4.3.4.2. Operating State Indices for the IEEE-RTS

Tables 4.7 and 4.8 present the operating state probabilities and frequencies for the IEEE-RTS. The total probability captured is 0.985581 which can be compared with the value of 0.985617 given in Chapter 3. The system risks shown in Table 4.7 are also higher than the corresponding values in Table 3.3.

Table 4.7: Operating state probabilities - IEEE-RTS (independent and station originated outages considered).

State	Set I	Set II	Set I+II
Normal	0.000000	0.212272	0.000000
Alert	0.892559	0.681640	0.892544
Emergency	0.000300	0.000015	0.000315
Ex.Emerg.	0.092722	0.091654	0.092722
Total	0.985581	0.985581	0.985581
CSOSR	0.107441	0.106088	0.107456

Table 4.8: Operating state frequencies - IEEE-RTS (independent and station originated outages considered).

State	Set I	Set II	Set I +II
Normal	0.000000	66.752960	0.000000
Alert	457.182129	392.011383	457.061798
Emergency	0.614211	0.120026	0.734135
Ex.Emerg.	61.349651	60.261608	61.350040

4.4. Security Constrained Adequacy Evaluation Including Dependent Outages

This section presents security constrained adequacy indices for the test systems including both independent and dependent outages. The required expressions for calculating the probability and frequency of every contingency are similar to those of Equations 4.24 and 4.19 but with the addition of major component common mode failures. The total probability captured in the analysis of the MRBTS or IEEE-RTS in this section is lower than that presented in Chapter 3 for the corresponding test system. The risk parameters, however, are much higher than those presented in Chapter 3.

4.4.1. Operating State Indices for the MRBTS

Tables 4.9 and 4.10 present the operating state reliability indices for the MRBTS. Table 4.9 can be compared with Tables 4.1 and 4.5 to see the differences caused by the dependent outage considerations. The total probability captured in this case is 0.999909.

Table 4.9: Operating state probabilities - MRBTS (independent and dependent outages considered).

State	Set I	Set II	Set I+II
Normal	0.827988	0.813516	0.813516
Alert	0.161886	0.175132	0.175132
Emergency	0.000000	0.000873	0.000873
Ex.Emerg.	0.010033	0.010388	0.010388
Total	0.999907	0.999909	0.999909
CSOSR	0.010126	0.011352	0.011352

Table 4.10: Operating state frequencies - MRBTS (independent and dependent outages considered).

State	Set I	Set II	Set I+II
Normal	76.300095	62.400120	62.400120
Alert	48.853134	61.712498	61.712498
Emergency	0.000000	0.631555	0.631555
Ex.Emerg.	5.712265	6.123163	6.123163

4.4.2. Operating State Indices for the IEEE-RTS

The system operating state probabilities and frequencies for the IEEE-RTS are given in Tables 4.11 and 4.12. The total probability captured in Table 4.11 is 0.983275. The small differences in probability between the different constraint sets is caused by the calculation precision and is negligible. The probabilities shown in Table 4.11 can be compared with

Tables 4.3 and 4.7 to appreciate the differences caused by the dependent outage considerations.

Table 4.11: Operating state probabilities - IEEE-RTS (independent and dependent outages considered).

State	Set I	Set II	Set I+II
Normal	0.000000	0.211056	0.000000
Alert	0.890223	0.680350	0.890042
Emergency	0.000302	0.000155	0.000456
Ex.Emerg.	0.092751	0.091713	0.092777
Total	0.983276	0.983274	0.983275
CSOSR	0.109777	0.108594	0.109958

Table 4.12: Operating state frequencies - IEEE-RTS (independent and dependent outages considered).

State	Set I	Set II	Set I+II
Normal	0.000000	67.028687	0.000000
Alert	459.918457	394.310791	459.638702
Emergency	0.615189	0.253110	0.867859
Ex.Emerg.	61.768951	60.707855	61.796032

4.5. Contribution of Dependent Outages to System Indices at Different Load Levels

Tables 4.13, 4.14, 4.15 and 4.16 show the operating state probabilities and frequencies at various load levels for the two test systems including station originated and common mode outages. The 100% load levels for the MRBTS and the IEEE-RTS are 185 MW and 2850 MW respectively. The operating state indices at each load level can be considered to be the system annualized values at that load level. The system annual indices can be calculated from these values using an appropriate load model. Tables 4.13 to 4.16 were obtained considering both voltage and capacity constraint sets (I & II).

4.5.1. Operating State Indices for the MRBTS

Table 4.13 presents the MRBTS operating state probabilities for the specified system conditions. The total probability captured is 0.999909 at 100% load level. The difference between the captured probabilities at the various load levels is caused by calculation precision. This difference is very small and is negligible. Table 4.13 can be compared with Table 3.5 in which the dependent outages are not considered. It can be seen from this comparison that the probabilities of the Emergency and Extreme emergency states in Table 4.13 are considerably larger than those shown in Table 3.5. One important phenomenon to note is that the relative contribution to the system risk of the dependent outages increases as the system load decreases. The frequencies of the system risk states also increase considerably when dependent outages are included. This can be seen by comparing Table 4.14 with Table 3.6.

Table 4.13: Operating state probabilities at different load levels - MRBTS.

Load level	Probability of				CSOSR
	Normal	Alert	Emergency	Extreme emergency	
40%	0.994059	0.004404	0.000000	0.001489	0.001537
50%	0.994042	0.004419	0.000000	0.001490	0.001539
60%	0.993776	0.004675	0.000005	0.001493	0.001549
70%	0.990166	0.008250	0.000019	0.001514	0.001584
80%	0.968823	0.028547	0.000904	0.001657	0.002630
90%	0.886165	0.108720	0.000893	0.004162	0.005115
100%	0.813516	0.175132	0.000873	0.010388	0.011352

4.5.2. Operating State Indices for the IEEE-RTS

The system conditions in the IEEE-RTS studies are the same as those for the MRBTS studies. The operating state reliability indices at different load levels are presented in Tables 4.15 and 4.16. The total probability captured in Table 4.15 is 0.983275 at the 100% load level. The reliability indices shown in Tables 4.15 and 4.16 can be compared with those given in Tables 3.7 and 3.8 where dependent outages are not included.

Table 4.14: Operating state frequencies at different load levels - MRBTS.

Load level	Frequency of			
	Normal	Alert	Emergency	Extreme emergency
40%	124.683968	4.361030	0.000042	2.040034
50%	124.662094	4.379160	0.000042	2.041941
60%	124.375656	4.656240	0.003501	2.045922
70%	121.860626	7.044246	0.117353	2.059089
80%	103.648232	24.613625	0.664218	2.149245
90%	79.825462	47.178379	0.650896	3.422040
100%	62.400059	61.710545	0.631556	6.122494

Table 4.15: Operating state probabilities at different load levels - IEEE-RTS.

Load level	Probability of				CSOSR
	Normal	Alert	Emergency	Extreme emergency	
40%	0.210942	0.765771	0.000038	0.006617	0.023287
50%	0.210942	0.765769	0.000040	0.006617	0.023289
60%	0.210942	0.765761	0.000050	0.006617	0.023297
70%	0.000000	0.976392	0.000362	0.006618	0.023608
80%	0.000000	0.974609	0.001163	0.007596	0.025391
90%	0.000000	0.964143	0.000324	0.018893	0.035857
100%	0.000000	0.890042	0.000456	0.092777	0.109958

4.6. Comparison of the Risk Contributions Due to Dependent Outages

The system risk is defined by the overall index CSOSR in Equation 3.25. This risk index can be used to compare the contribution of dependent outages to bulk power system inadequacy. The system risk at selected load levels for the two test systems is presented and compared in this section. Tables 4.17 and 4.18 present the CSOSR indices for the MRBTS and for the IEEE-RTS respectively. In the tables given in this section, Cases I, II, III and IV indicate the CSOSR values evaluated under conditions including only independent outages, independent and common mode outages, independent and station element outages, and independent and dependent outages respectively.

Table 4.16: Operating state frequencies at different load levels - IEEE-RTS.

Load level	Frequency of			
	Normal	Alert	Emergency	Extreme emergency
40%	67.598770	451.104523	0.074380	3.553960
50%	67.598770	451.102509	0.076482	3.553951
60%	67.598770	451.059082	0.120386	3.553942
70%	0.000000	518.230713	0.548230	3.554581
80%	0.000000	516.917236	1.252205	4.161787
90%	0.000000	508.998688	0.748224	12.577880
100%	0.000000	459.638702	0.867859	61.796032

Table 4.17: CSOSR at different load levels for the MRBTS.

Load level	CSOSR			
	Case I	Case II	Case III	Case IV
40%	0.000026	0.000053	0.001509	0.001537
50%	0.000027	0.000056	0.001509	0.001539
60%	0.000029	0.000066	0.001512	0.001549
70%	0.000051	0.000088	0.001547	0.001584
80%	0.000291	0.001148	0.001774	0.002630
90%	0.002443	0.003600	0.003960	0.005115
100%	0.008680	0.009829	0.010204	0.011352

Table 4.18: CSOSR at different load levels for the IEEE-RTS.

Load level	CSOSR			
	Case I	Case II	Case III	Case IV
40%	0.014402	0.017278	0.020429	0.023287
50%	0.014404	0.017280	0.020431	0.023289
60%	0.014408	0.017284	0.020440	0.023297
70%	0.014718	0.017593	0.020751	0.023608
80%	0.016501	0.019368	0.022543	0.025391
90%	0.027053	0.029859	0.033069	0.035857
100%	0.101855	0.104373	0.107456	0.109958

The actual CSOSR increase due to common mode outages of transmission facilities and station originated outages is shown in Tables 4.19 and 4.20 for the MRBTS and the IEEE-RTS respectively. The actual CSOSR increase is calculated using Equation 4.25,

$$CSOSR\ \ increase = CSOSR_{new} - CSOSR_{base}\ . \tag{4.25}$$

Table 4.19: CSOSR increase at different load levels for the MRBTS.

Load level	CSOSR		
	Case II	Case III	Case IV
40%	0.000027	0.001483	0.001511
50%	0.000029	0.001482	0.001512
60%	0.000037	0.001483	0.001520
70%	0.000037	0.001496	0.001533
80%	0.000857	0.001483	0.002339
90%	0.001157	0.001517	0.002672
100%	0.001149	0.001524	0.002672

Table 4.20: CSOSR increase at different load levels for the IEEE-RTS.

Load level	CSOSR		
	Case II	Case III	Case IV
40%	0.002876	0.006027	0.008885
50%	0.002876	0.006027	0.008885
60%	0.002876	0.006032	0.008889
70%	0.002875	0.006033	0.008890
80%	0.002867	0.006042	0.008890
90%	0.002806	0.006016	0.008804
100%	0.002518	0.005601	0.008103

It can be seen from Table 4.19 that the actual CSOSR increase caused by the inclusion of common mode outages increases as the load in the MRBTS increases. The contribution to the system risk due to the station initiated outages is almost constant at the seven selected load levels. The total contribution to the system risk caused by the dependent outages considered increases as the system load increases. It can be seen from Table 4.20 that the system risk contribution due to common mode outages is basically constant as the load in the IEEE-RTS increases. The CSOSR contribution from the station element outages is also basically constant as the system load increases. The small decrease in contribution at the higher load levels is due to the capture probability level. This is obviously a point of concern for large system analysis. The effect of dependent outages on the CSOSR for the MRBTS and for the IEEE-RTS is quite different. It can be concluded that detailed operating state reliability evaluation is necessary when planning a system. No general conclusions can be reached regarding the magnitude of the increase in system risk due to the dependent outages as this is a function of a wide range of system factors.

The relative contribution to the CSOSR caused by dependent outages can be clearly seen by considering the relative CSOSR increase obtained using Equation 4.26. The relative CSOSR increase is presented in Tables 4.21 and 4.22 for the MRBTS and for the IEEE-RTS respectively.

$$Relative\ CSOSR\ increase = \frac{CSOSR_{new} - CSOSR_{base}}{CSOSR_{base}} \times 100\% \qquad (4.26)$$

Table 4.21: Relative CSOSR increase at different load levels for the MRBTS.

Load level	CSOSR increase (%)		
	Case II	Case III	Case IV
40%	103.918	5706.536	5814.199
50%	107.477	5491.286	5602.542
60%	127.621	5114.375	5241.859
70%	72.597	2934.267	3006.877
80%	294.487	509.591	803.737
90%	47.358	62.096	109.372
100%	13.237	17.558	30.783

Table 4.22: Relative CSOSR increase at different load levels for the IEEE-RTS.

Load level	CSOSR increase (%)		
	Case II	Case III	Case IV
40%	19.969	41.848	61.693
50%	19.967	41.842	61.684
60%	19.961	41.865	61.694
70%	19.534	40.991	60.402
80%	17.375	36.616	53.875
90%	10.372	22.238	32.544
100%	2.472	5.499	7.955

It can be seen from Table 4.21 that the relative contribution to the CSOSR index due to dependent outages is very large at low system loads in the MRBTS. The CSOSR increase is approximately 30% at the 100% load level when both common mode and station element outages are included. The MRBTS is a small and quite reliable system and the CSOSR is relatively low when only independent outages are considered. Table 4.22 shows that the contribution of dependent outages to the CSOSR index for the IEEE-RTS is approximately 8% at the 100% load level when all three outage types are recognized and included. As the system load decreases, the relative contribution made by dependent outages becomes quite significant. The IEEE-RTS has relatively high system risk at the 100% load level due to the low generating reserve margin at this load level. The CSOSR is more directly related to the system load when the analysis includes only independent outages. The contribution to the CSOSR from recognized dependent outages is not a direct function of system load but is more related to the system configuration and its element parameters.

4.7. Summary

This chapter recognizes and includes the dependent outages of major components in security constrained adequacy evaluation of composite generation and transmission systems. The modeling techniques associated with station originated outages and common mode failures are described. The techniques presented are utilized to combine dependent failures with those of independent major component outages in the reliability assessment. The effects of dependent outages on the system operating state probabilities and frequencies are examined in some detail for the MRBTS and the IEEE-RTS. It can be seen that dependent events can prove to be extremely important in security constrained adequacy evaluation and should be carefully considered. The relative contribution to system risk from dependent events is very significant at low system load levels.

5. COMPOSITE SYSTEM RISK SENSITIVITY STUDIES

5.1. Introduction

Chapters 3 and 4 of this thesis present the basic concepts associated with security constrained adequacy evaluation in composite systems. These concepts include the development of operating state reliability indices. It is believed that these indices will provide power system managers, designers and planners with a better appreciation of the overall reliability of a composite system. Quantitative evaluation of the system operating state probabilities provides the ability to conduct sensitivity studies in which the relative effects of system design and parameter variations can be evaluated. This is illustrated in this chapter using the two test systems. In these studies, component parameters, such as the independent failure rates of generating units and transmission lines, the common mode failure rates of transmission facilities, the failure rates of circuit breakers, the failure rates of bus sections, etc. are varied and their effect on the system risk examined.

The CSOSR index is used as the system operation criterion in the sensitivity studies described in this chapter. Varying the repair durations associated with major component failures has the same effect on the system risk as varying the failure rates as both result in changes in component unavailability. This can be seen by considering the two state model given in Figure 3.1. The sensitivity studies described in this chapter were, therefore, performed by varying selected element failure rates. The results shown include both the capacity and voltage constraint sets.

5.2. System Risk Sensitivity Studies Based on Varying the Independent Failure Rates of Major Components

This section describes a series of system risk sensitivity studies in which the independent failure rates of transmission lines and generating units were varied. The failure rates of all the major components in the two test systems were increased in the same proportion. Table 5.1 shows the CSOSR variation as a function of the increased failure rates. The 1.0 multiplier values are the base values. A multiplier of 1.2 designates the case in which the failure rates are increased by twenty percent. The same procedure is used in the other tables in this chapter. This type of analyses can provide system planners with useful information on the impact of proposed transmission lines and generating units on the system risk. This type of analyses can also provide system planners with a more comprehensive understanding of their system when the available component reliability data are uncertain. The following symbols are utilized in the tables in this chapter and indicate different outage event considerations. In certain cases, additional explanations are provided.

(a) Only the independent outages of major components are included.
(b) Both the independent outages of major components and common mode outages of transmission lines are included.
(c) Both the independent outages of major components and station originated outages are included.
(d) The independent outages of major components together with the common mode outages of transmission lines and station initiated outages are included.

5.2.1. Transmission Line Failure Rate Variation

Tables 5.1 and 5.2 present the system risk indices for the MRBTS and the IEEE-RTS when the independent failure rates of transmission facilities are varied.

5.2.1.1. System Risk Values for the MRBTS

Table 5.1 presents the CSOSR values in the MRBTS for the four outage event cases. These results are also shown in Figure 5.1 in order to provide a more physical appreciation. These risk values were obtained at the system peak load of 185 MW. It can be observed from Table 5.1 that the increase in system risk is less than ten percent in the all four cases when the independent failure rates of the transmission lines are doubled. It can also be seen that the risk contributions arising from the events considered in case (d) are much greater than those resulting from a simple doubling of the independent failure rates.

Table 5.1: System risk (CSOSR) in the MRBTS (varying the independent failure rates of transmission facilities).

Multiplier	Conditions			
	(a)	(b)	(c)	(d)
1.0	0.008680	0.009830	0.010205	0.011352
1.2	0.008781	0.009929	0.010306	0.011451
1.4	0.008892	0.010037	0.010416	0.011559
1.6	0.009012	0.010154	0.010535	0.011676
1.8	0.009140	0.010281	0.010663	0.011802
2.0	0.009278	0.010416	0.010801	0.011937

5.2.1.2.System Risk Values for the IEEE-RTS

Table 5.2 shows the system risk for the IEEE-RTS. The system load utilized is 2850 MW. The indices in Table 5.2 for the four outage event cases are also illustrated in Figure 5.2. It can be seen from Table 5.2 and Figure 5.2 that the system risk increases by approximately 0.004 in each case when the transmission line failure rates are doubled. The basic system risk is quite high. It depends on the system size, transmission network, component reliability data and the system configuration. The total probability of the enumerated contingencies is much lower than unity and the probability not captured in the enumeration approach is considered as part of the system risk. The increase in risk due to varying the line failure rates is not small but on a relative scale is not particularly significant.

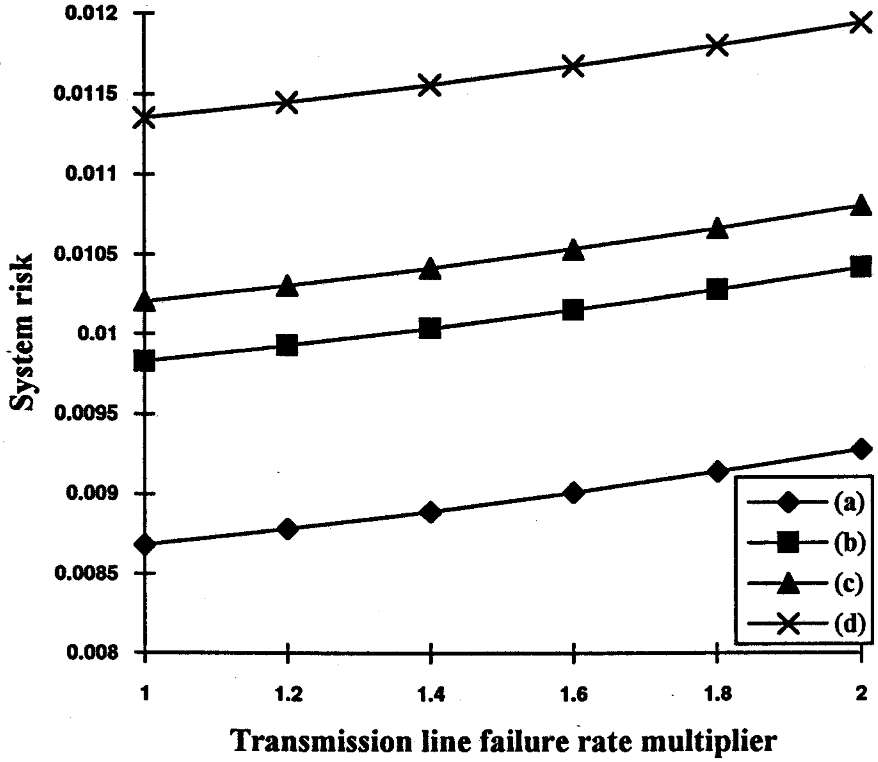


Figure 5.1: Sensitivity of system risk based on varying the transmission line failure rates -- MRBTS.

Table 5.2: System risk (CSOSR) in the IEEE-RTS (varying the independent failure rates of transmission facilities).

Multiplier	Conditions			
	(a)	(b)	(c)	(d)
1.0	0.101855	0.104373	0.107456	0.109958
1.2	0.102641	0.105163	0.108236	0.110742
1.4	0.103431	0.105956	0.109020	0.111528
1.6	0.104224	0.106753	0.109807	0.112319
1.8	0.105022	0.107554	0.110598	0.113114
2.0	0.105823	0.108358	0.111393	0.113911

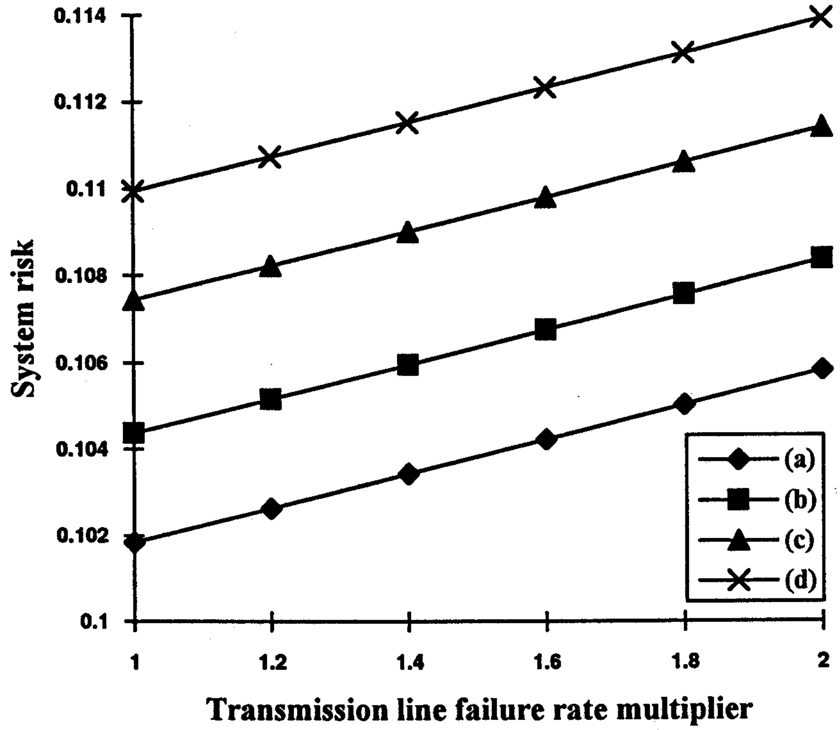


Figure 5.2: Sensitivity of system risk based on varying the transmission line failure rates -- IEEE-RTS.

5.2.2. Generating Unit Failure Rate Variation

The effect on the system risk index of varying the generating unit failure rates was examined and the results obtained are presented in Tables 5.3 and 5.4 for the MRBTS and the IEEE-RTS respectively.

5.2.2.1. System Risk Values for the MRBTS

The CSOSR values obtained when varying the generating unit outage rates in the MRBTS are presented in Table 5.3. It can be seen that the risk increases significantly in all four cases when the generating unit failure rates are increased by twenty percent. The unavailability of a generating unit is normally much greater than that of a transmission line. A twenty percent increase in this case is quite significant and the CSOSR is very sensitive to this increase. The probabilities presented in Table 5.3 are also presented graphically in Figure 5.3 in order to provide a physical appreciation of this phenomenon.

Table 5.3: System risk (CSOSR) in the MRBTS (generating unit failure rates varied).

Multiplier	Conditions			
	(a)	(b)	(c)	(d)
1.0	0.008680	0.009830	0.010205	0.011352
1.2	0.012123	0.013267	0.013641	0.014782
1.4	0.016055	0.017191	0.017564	0.018699
1.6	0.020440	0.021570	0.021941	0.023069
1.8	0.025246	0.026368	0.026738	0.027858
2.0	0.030442	0.031557	0.031924	0.033037

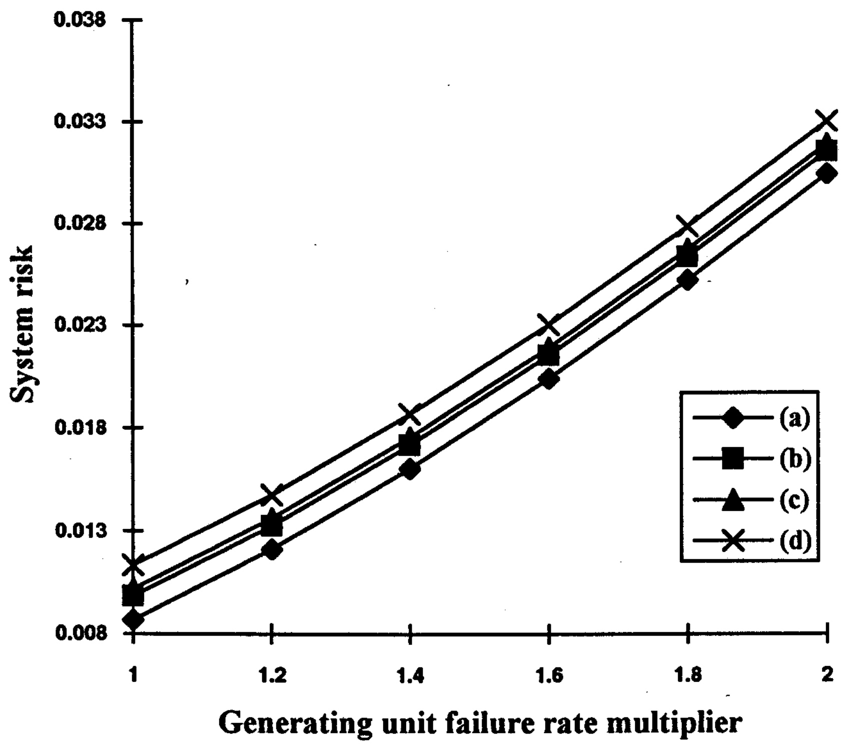


Figure 5.3: Sensitivity of system risk based on varying the generating unit failure rates -- MRBTS.

5.2.2.2. System Risk Values for the IEEE-RTS

Table 5.4 shows the system risk variation in the IEEE-RTS as a function of the generating unit failure rates. It can be seen from Table 5.4

that the system risk increases drastically when the failure rates of all generating units are increased. It can be concluded that the generating units contribute significantly to the system risk in this system. The risk indices presented in Table 5.4 are also illustrated in Figure 5.4 in order to provide a physical appreciation of this phenomenon.

Table 5.4: System risk (CSOSR) in the IEEE-RTS (generating unit failure rates varied).

Multiplier	Conditions			
	(a)	(b)	(c)	(d)
1.0	0.101855	0.104373	0.107456	0.109958
1.2	0.138328	0.141035	0.143634	0.146323
1.4	0.177815	0.180647	0.182827	0.185641
1.6	0.219482	0.222380	0.224204	0.227084
1.8	0.262564	0.265476	0.266999	0.269893
2.0	0.306370	0.309252	0.310521	0.313386

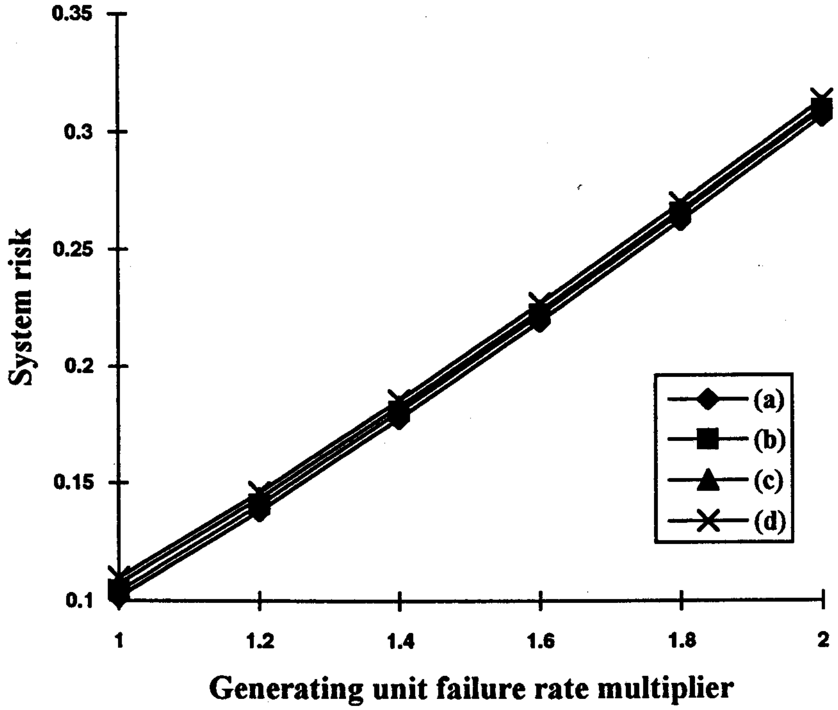


Figure 5.4: Sensitivity of system risk based on varying the generating unit failure rates -- IEEE-RTS.

5.3. System Risk Sensitivity Studies Based on Varying the Transmission Line Common Mode Failure Rates

Further risk sensitivity studies were conducted by varying the common mode failure rates of all associated transmission lines. The results shown in Figures 5.5 and 5.6 were calculated at the 185 MW and 2850 MW load levels for the MRBTS and the IEEE-RTS respectively. These figures show the results obtained for cases (b) and (d) when the common mode failure rates are varied. This type of analysis can provide system planners with useful information on the impact of moving to common tower facilities and the possible implications of the economies associated with constrained right of way utilization.

5.3.1. System Risk Values for the MRBTS

Figure 5.5 shows the risk values for the MRBTS. The risk is increased about two percent when the common mode failure rates are increased by twenty percent. The system risk will, however, increase by approximately ten percent when the common mode failure rates are doubled. This clearly shows that the risk contribution due to the common mode failures is not insignificant in this system.

5.3.2. System Risk Values for the IEEE-RTS

The IEEE-RTS risk values are shown in Figure 5.6. The risk increase is about 0.0025 when the common mode failure rates are doubled. This system has a relative high risk as it has low generation capacity reserve and a constrained transmission network. This system is relatively large and complex compared with the MRBTS.

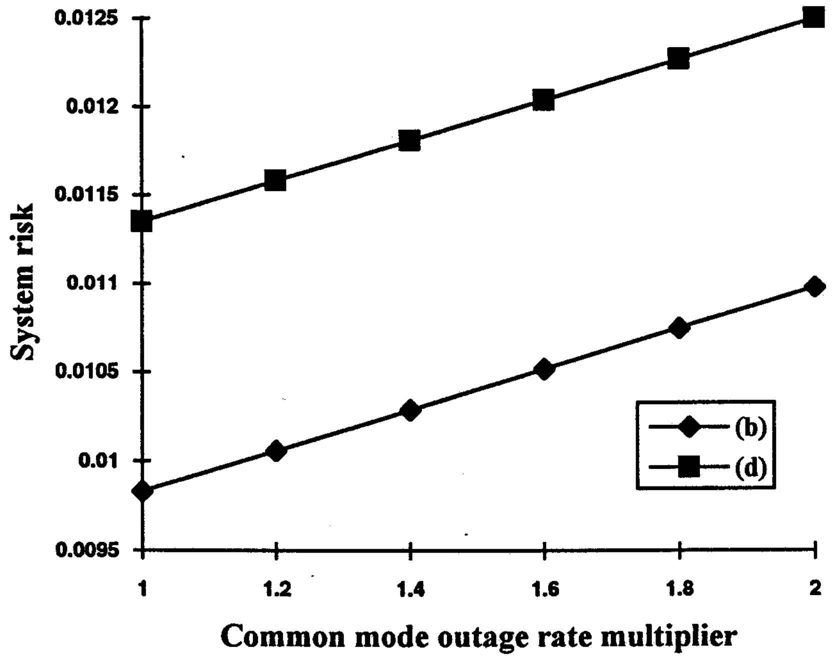


Figure 5.5: Sensitivity of system risk by varying the transmission line common mode failure rates -- MRBTS.

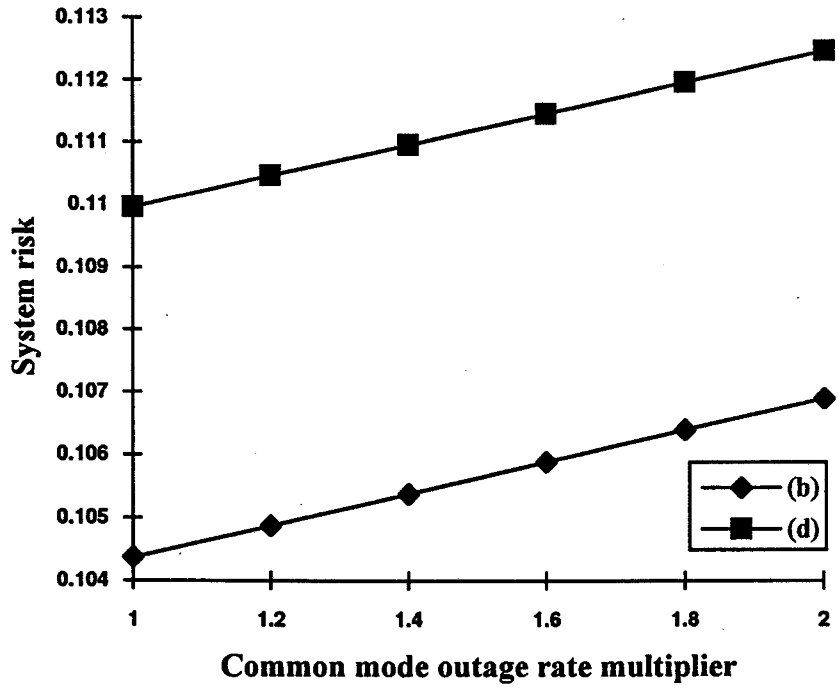


Figure 5.6: Sensitivity of system risk by varying the transmission line common mode failure rates -- IEEE-RTS.

5.4. System Risk Sensitivity Analyses Based on Varying System Load and the Independent Outage Rates of Major Components

Composite System Operating State Risk (CSOSR) depends on not only the system components and their performances, but also the system operating conditions. The most important operating condition is the system load [130]. In a reliability study, the system load is usually represented by its peak value or by a limited number of load steps. The system load in these studies was represented by a seven step model in which each step is ten percent of the system peak demand. The risk sensitivity studies were conducted using this assumed load model. The risk indices obtained can be used to calculate annual and annualized values. The reliability indices shown in this section were performed including both independent and dependent outage events. The failure rates were varied form one hundred to two hundred percent of their original values in twenty percent steps.

5.4.1. Variation of System Load and Transmission Line Independent Failure Rates

5.4.1.1. Study Results for the MRBTS

Figure 5.7 shows the MRBTS risk indices obtained when the system load and the failure rates of all transmission lines are varied. It can be seen from Figure 5.7 that the system risk changes very slightly at lower system load levels when the failure rates of transmission facilities are varied. The variation in system risk is greater when the system experiences full load. It can be concluded that variation in transmission line failure rates has only a very slight effect on system risk when the system load is relatively low. It can be also seen that the system risks when the load is equal to or lower than 70% of the peak value are much smaller than those at the peak load level.

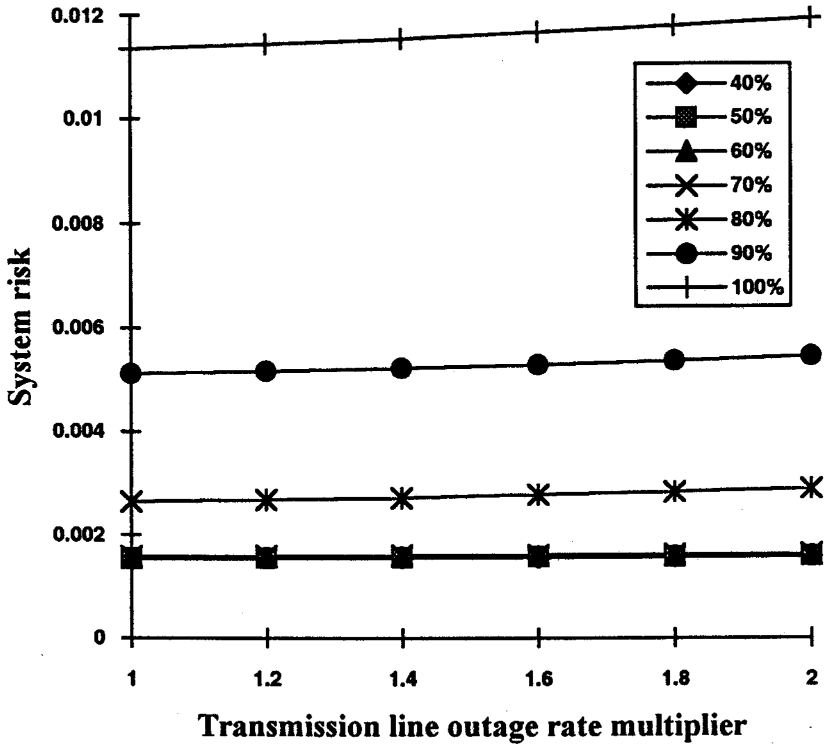


Figure 5.7: Sensitivity in system risk by varying transmission line failure rates and system load -- MRBTS.

5.4.1.2. Study Results for the IEEE-RTS

The risk values for the IEEE-RTS are shown in Figure 5.8. The system risk increases by approximately 0.0008 at all load levels when the line failure rates are increased by twenty percent. The risk in the IEEE-RTS is approximately ten times that in the MRBTS. The basic conclusion, however, is that the risk is not particularly sensitive in both cases to the variation in transmission line independent failure rates.

5.4.2. Variation of System Load and Generating Unit Failure Rates

5.4.2.1. Risk Values for the MRBTS

Figure 5.9 presents the MRBTS risk values when the system load and the generating unit failure rates are varied. It can be seen from Figure 5.9 that the system risk varies only slightly at the seventy percent load level while it changes drastically at the peak load level when the failure rates of the generating units are increased.

5.4.2.2. Risk Values for the IEEE-RTS

The risks in the IEEE-RTS by varying the system load and the generating unit failure rates are presented in Figure 5.10. It can be seen that the variation in system risk at all load levels is not insignificant when the generating unit failure rates are increased. The risk contribution is much larger at the system peak load level than at the lower load levels.

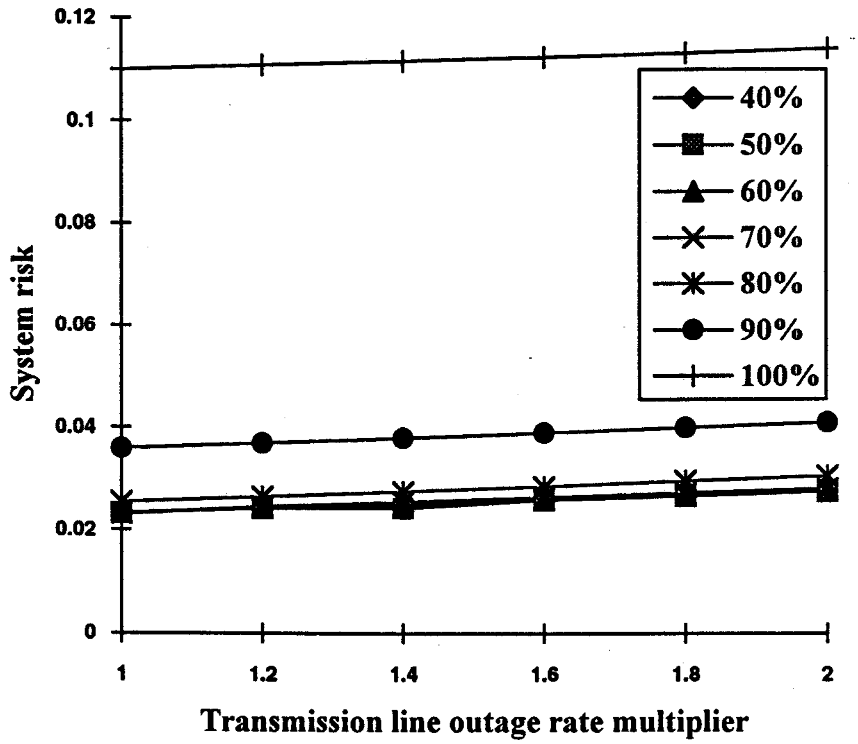


Figure 5.8: Sensitivity in system risk when varying transmission line failure rates and system load -- IEEE-RTS.

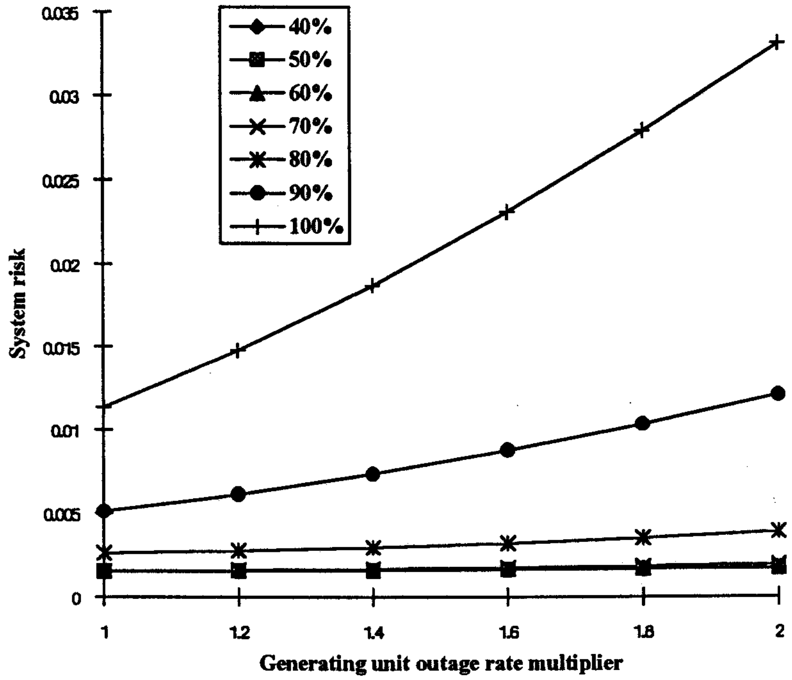


Figure 5.9: Sensitivity in system risk when varying generating unit failure rates and system load -- MRBTS.

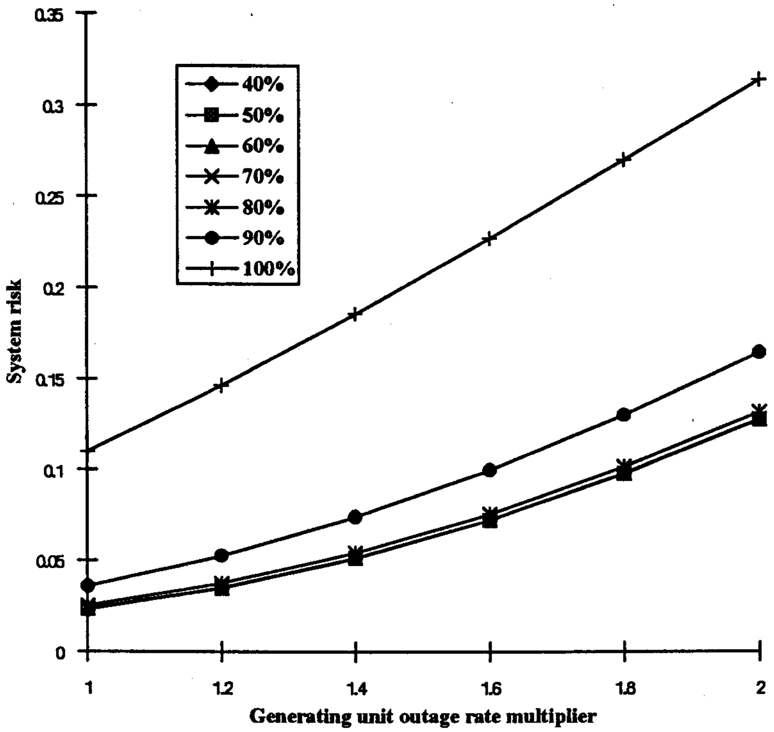


Figure 5.10: Sensitivity in system risk when varying generating unit failure rates and system load -- IEEE-RTS.

5.5. System Risk Sensitivity Analyses Based on Varying System Load and Transmission Line Common Mode Failure Rates

The sensitivity studies described in the previous section are focused on varying the system load and the independent failure rates of the major system components. Sensitivity studies were also performed by varying the system load and the dependent failure rates. Variations of the system load and the transmission line common mode failure rates are presented in this section.

5.5.1. Study Results for the MRBTS

Figure 5.11 shows the risks in the MRBTS when the system load and the transmission line common mode failure rates are varied. The general observation can be made that the change in risk is negligible at 70% or lower load levels and increases only slightly at higher load levels as the transmission line common mode failure rates increase. This conclusion is obviously system specific and depends on the number of transmission facilities vulnerable to common mode outages.

5.5.2. Study Results for the IEEE-RTS

A similar sensitivity study was performed for the IEEE-RTS. The results are shown in Figure 5.12 where it can be seen that the increase in risk at all load levels is relatively insignificant.

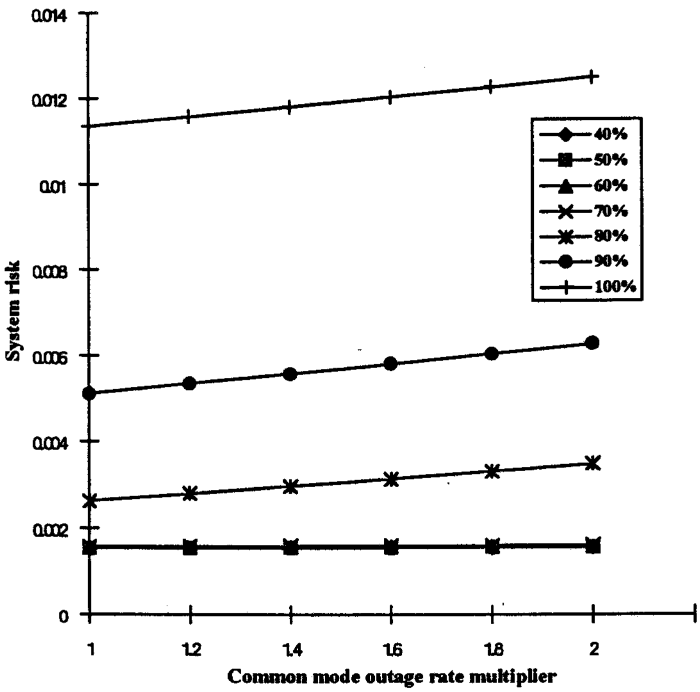


Figure 5.11: Sensitivity in system risk when varying common mode failure rates and system load -- MRBTS.

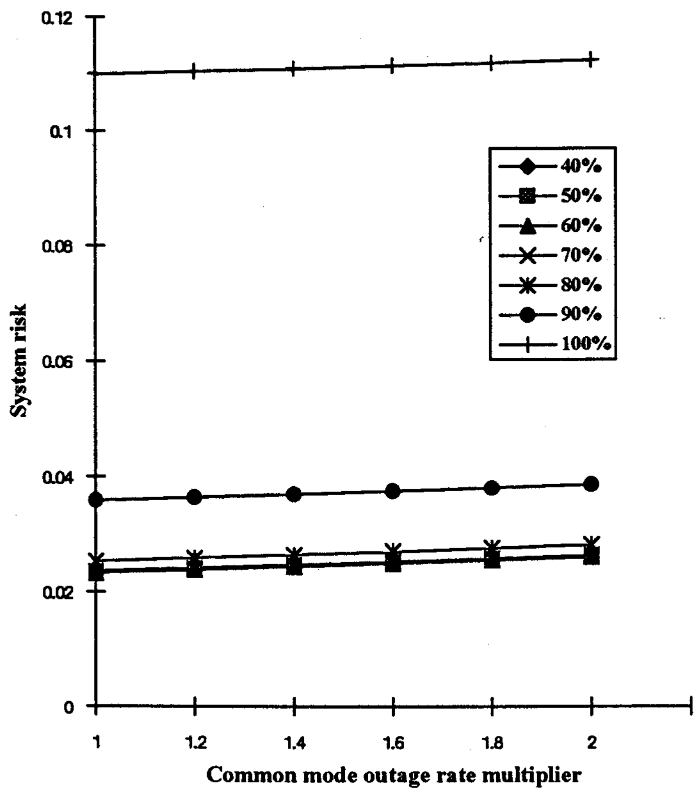


Figure 5.12: Sensitivity in system risk when varying common mode failure rates and system load -- IEEE-RTS.

5.6. Risk Sensitivity Studies of the MRBTS Varying the Station Element Failure Rates

The sensitivity studies described in this section are focused on the variation of station element failure rates in the MRBTS. The analysis was conducted by varying the failure rates of circuit breakers and bus sections. The single line diagram of the MRBTS showing these elements is given in Figure 4.5.

5.6.1. Breaker Failure Rate Variation

Tables 5.5 and 5.6 present the system risks obtained by varying the breaker failure rates. The results in Tables 5.5 and 5.6 were obtained by neglecting and including common mode failures respectively. Both the passive and active failure rates were changed in the same proportion. It can been seen from Tables 5.5 and 5.6 that the risk index increases by about 0.00004 at all load levels when the breaker failure rates are increased by twenty percent of their original values. This risk increase is quite small compared with the actual system risk. This type of analysis is very important as the circuit breaker failure rates are quite low and the available data may not be very accurate. It can be seen from these studies that uncertainty in breaker reliability data may not be too critical as the risk contribution due to this parameter variation is very small.

Table 5.5: CSOSR in the MRBTS without common mode failures.

Load	Multiplier				
level	1.2	1.4	1.6	1.8	2.0
40%	0.001550	0.001591	0.001632	0.001674	0.001716
50%	0.001550	0.001591	0.001632	0.001674	0.001716
60%	0.001552	0.001593	0.001634	0.001676	0.001718
70%	0.001590	0.001634	0.001678	0.001722	0.001767
80%	0.001815	0.001856	0.001897	0.001939	0.001981
90%	0.004000	0.004041	0.004082	0.004124	0.004166
100%	0.010245	0.010286	0.010327	0.010368	0.010410

Table 5.6: CSOSR in the MRBTS including common mode failures.

Load level	Multiplier 1.2	1.4	1.6	1.8	2.0
40%	0.001577	0.001618	0.001659	0.001701	0.001743
50%	0.001580	0.001621	0.001662	0.001704	0.001746
60%	0.001589	0.001630	0.001671	0.001713	0.001755
70%	0.001627	0.001671	0.001715	0.001759	0.001804
80%	0.002671	0.002712	0.002753	0.002795	0.002836
90%	0.005156	0.005196	0.005238	0.005279	0.005321
100%	0.011393	0.011434	0.011475	0.011516	0.011557

5.6.2. Bus Section Failure Rate Variation

Tables 5.7 and 5.8 present the system risks obtained by varying the system load and the bus section failure rates. The values shown in these two tables were obtained by neglecting and by including transmission line common mode failures. It can be seen from Tables 5.7 and 5.8 that the increase in risk is about 0.00013 at all load levels when the bus section failure rates are increased by ten percent. This increase is not small compared with the original system risk. Comparing the risk indices obtained by varying the breaker failure rates with those calculated by varying the bus section failure rates, it can be concluded that the risk contribution caused by an increase in the bus section failure rates is much larger than that caused by an increase in the breaker failure rates. This suggests that attention should be placed on collecting accurate bus section outage data.

Table 5.7: CSOSR in the MRBTS without common mode failures.

Load level	Multiplier				
	1.1	1.2	1.3	1.4	1.5
40%	0.001642	0.001774	0.001906	0.002039	0.002171
50%	0.001642	0.001774	0.001906	0.002039	0.002171
60%	0.001643	0.001776	0.001908	0.002040	0.002173
70%	0.001679	0.001811	0.001944	0.002077	0.002209
80%	0.001906	0.002039	0.002171	0.002304	0.002437
90%	0.004093	0.004226	0.004360	0.004493	0.004627
100%	0.010337	0.010470	0.010604	0.010737	0.010871

Table 5.8: CSOSR in the MRBTS including common mode failures.

Load level	Multiplier				
	1.1	1.2	1.3	1.4	1.5
40%	0.001669	0.001801	0.001933	0.002066	0.002198
50%	0.001671	0.001803	0.001936	0.002068	0.002201
60%	0.001680	0.001812	0.001945	0.002077	0.002210
70%	0.001716	0.001848	0.001981	0.002113	0.002246
80%	0.002762	0.002894	0.003027	0.003159	0.003292
90%	0.005248	0.005381	0.005515	0.005648	0.005782
100%	0.011485	0.011618	0.011751	0.011885	0.012018

5.7. Summary

This chapter illustrates the use of the Composite System Operating State Risk (CSOSR) index defined in Chapter 3 as the system risk criterion in sensitivity studies. The risk index is used to assess performance of the system due to variation in basic system component parameters. The sensitivity studies illustrate the system risk due to variations in the major component parameter and in the system load levels. System risk values are presented for selected load levels. The sensitivity studies were conducted considering the following basic phenomena: (1) varying the independent failure rates of major system components, (2) varying the common mode failure rates of associated transmission facilities, (3) varying the system load and the failure rates of major system components, (4) varying the system load and the associated transmission line common mode failure rates, (5) varying the system load and the station element failure rates. It is not possible to draw general conclusions from these studies regarding system risk variations for all composite systems. System risk assessment must be performed for each specific composite system in order to understand, examine and appreciate the impact on the system risk of generating unit, transmission line and station element parameter variations. The results shown, however, for the MRBTS and the IEEE-RTS provide a very useful indication of the expected implications associated with reliability parameter variations. The ability to perform risk sensitivity studies as illustrated in this chapter can provide power system planners and designers with useful information on the impacts on system risk of major system element unavailabilities.

6. SYSTEM FACILITIES AND THEIR EFFECT ON SECURITY CONSTRAINED ADEQUACY EVALUATION

6.1. Introduction

Security constrained adequacy evaluation using the two test systems has been described in detail in the previous chapters. As noted in Chapter 3, the system risk depends on many factors, such as the amount of installed generation capacity, the size of the various generating units and their availabilities, the capacity of the transmission facilities and their parameters, the system load, the acceptable voltage range at load buses, the output of each generating unit in terms of its real power and voltage, the station configurations and their element parameters, and the overall system topology, etc. The effect of some of these factors on system risk is examined extensively in the research work presented in Chapters 4 and 5. The effect on the MRBTS CSOSR index of load growth, generation capacity additions, generating unit replacement, transmission facility additions, the removal of transmission lines for maintenance, and the variation of station configurations is examined in this chapter.

It is noted in the previous chapters that the system risk contribution caused by dependent outages is not a direct function of system load but is more related to the system configuration and its element parameters. In the initial studies described in this chapter, only independent outages of major components are considered. Dependent considerations are added in subsequent studies. In general, overall system studies should be performed which include dependent outages as these can make a significant contribution to system risk in some configurations.

6.2. Generating Unit Addition

An existing power system may or may not meet the forecast load requirements at an acceptable reliability level unless additional facilities are added to the system. The addition of generating or transmission capacity will have a positive effect on the system operating risk. A major system planning task is to determine the most effective and economic facility addition to the system in order to maintain an acceptable risk level as the system load increases. The following sections briefly illustrate the impact on system risk of adding generation and transmission capacity to the base MRBTS. The acceptable system risk level in these studies is assumed to be 0.01 for the MRBTS, i.e. the system is considered to be adequate to supply the load demand when its CSOSR value is less than or equal to this value. This section illustrates the addition of generating unit(s) at different buses in the system. The reliability data for the additional generating units are given in Table 6.1.

Table 6.1: Additional generating unit data in the MRBTS.

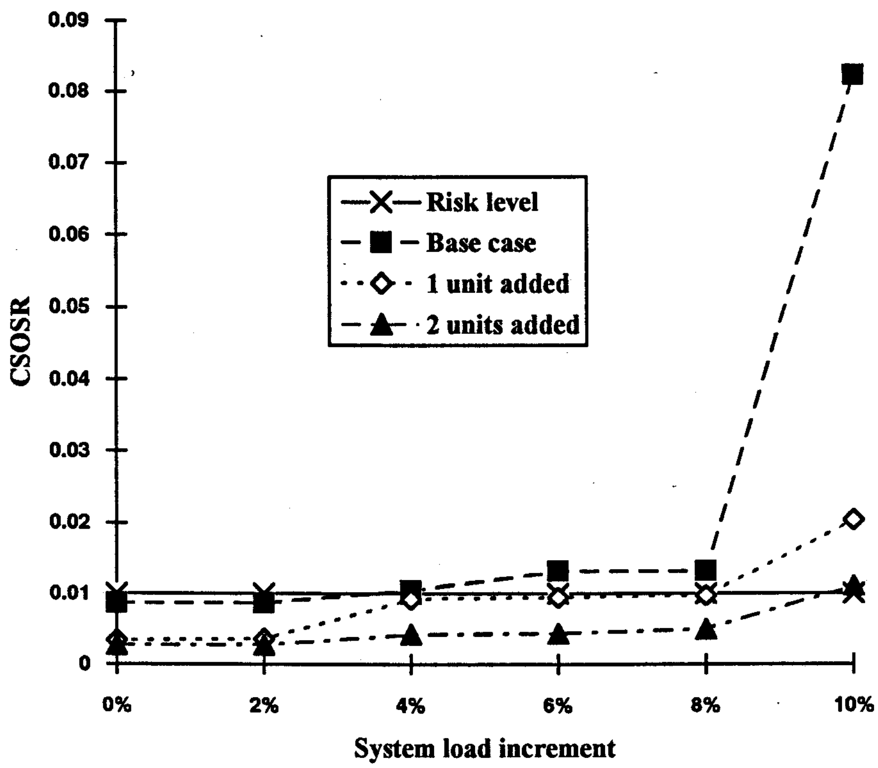
Capacity (MW)	FOR	λ (f/yr)	MTTR (hrs)
10	0.12	15.927	75

6.2.1. Generating Unit Location Selection

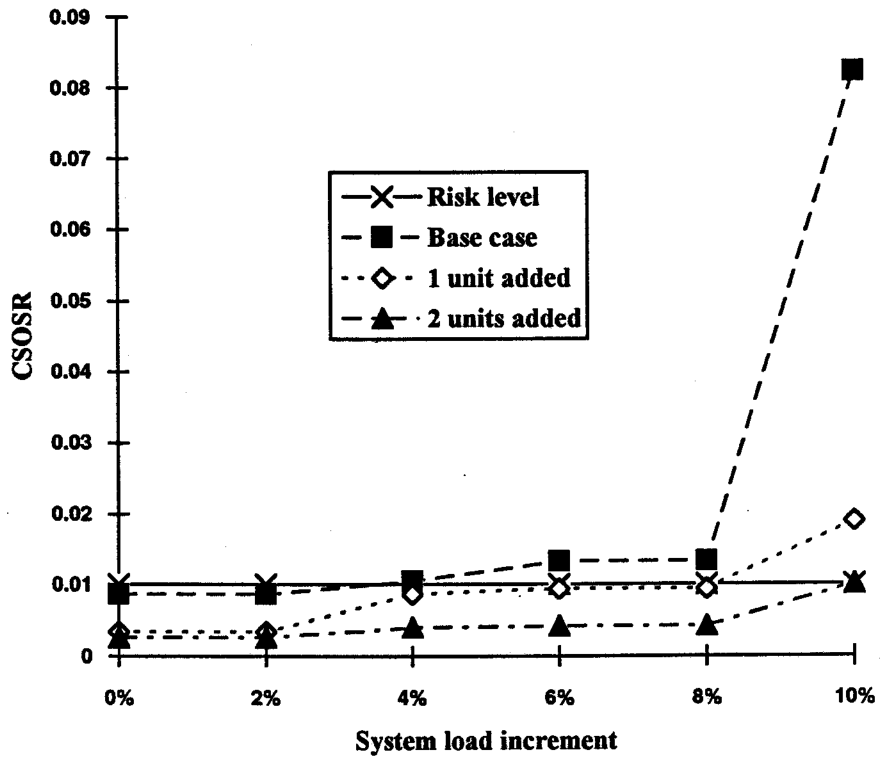
The objective in this type of study is to illustrates when and where the additional facilities must be added to the system as the load increases. The base load for this system is 185 MW. The calculated CSOSR is the annualized value at this load level. Table 6.2 shows the CSOSR indices for different unit additions and selected load increases. The base case values shown in Table 6.2 are for the original MRBTS with no additional facilities installed. The system load increments are 0, 2, 4, 6, 8, and 10 percent. Table 6.2 illustrates the system risk when one or two additional units are added at different buses in the system. In order to illustrate the effect, the CSOSR indices for generating unit additions at buses 2 and 5 are shown in Figures 6.1 (a) and (b) respectively.

Table 6.2: CSOSR indices with generating unit additions.

Bus No.	Units added	CSOSR at system load increase of 0%	2%	4%	6%	8%	10%
1	1	0.003609	0.003612	0.009545	0.010937	0.010939	0.020459
2	1	0.003459	0.003621	0.009224	0.009472	0.009739	0.020456
3	1	0.003446	0.003447	0.008709	0.009414	0.009414	0.018998
4	1	0.003447	0.003448	0.008710	0.009415	0.009416	0.018998
5	1	0.003446	0.003447	0.008709	0.009414	0.009414	0.018998
1	2	0.002916	0.002918	0.005197	0.006368	0.006370	0.012102
2	2	0.002749	0.002786	0.004270	0.004399	0.005035	0.011053
3	2	0.002659	0.002659	0.003990	0.004230	0.004230	0.009989
4	2	0.002669	0.002671	0.004051	0.004240	0.004244	0.010130
5	2	0.002659	0.002660	0.004041	0.004230	0.004230	0.010122
Base case		0.008680	0.008689	0.010478	0.013256	0.013260	0.082207



(a). Unit addition at Bus 2



(b). Unit addition at Bus 5

Figure 6.1: CSOSR indices with generating unit additions.

It can be seen from Table 6.2 and Figure 6.1 that the original system can only accommodate an approximate increase of 3% in system load without violating the acceptable risk level. Unit additions, as the load increases, at buses 3, 4 and 5 have approximately equal impacts on the system risk. The risk improvement achieved by the addition of generating unit(s) at these buses is greater than that obtained by the addition of unit(s) at bus 1 or bus 2. Table 6.2 also indicates that the system can tolerate a load increase of approximately 8 percent when one unit is added at bus 2, 3, 4, or 5. This system can accommodate an 8% load increment when two units are added at any individual bus. It can be seen from Table 6.2 that the addition of two units at any bus, other than bus 3, will not provide the required reliability for a load growth of 10%. This indicates that more generating or transmission facilities should be added to the system in order to meet a 10% or higher load increase. Similar studies can be conducted for multiple unit additions with single units added to individual buses.

6.2.2. CSOSR Values Including Dependent Outages

Table 6.2 shows that the MRBTS has improved system risk performance when the additional generating capacity is located at the three load buses. This analysis was performed without the inclusion of recognized dependent outages as discussed in Chapter 4. The system risk indices given in Table 6.2 are therefore optimistic as the calculated risk increases when dependent outages are included. Figure 4.5 shows the station configuration used at bus 5 in the MRBTS. In order to add generating units at this bus, the system configuration must be modified. Figures 6.2 and 6.3 present two station configurations used to replace the station configuration at bus 5 for one unit and two unit additions respectively. The contribution of dependent outages to the CSOSR values for the MRBTS are shown in Table 6.3 and Table 6.4 for the two cases. In these tables and in subsequent tables in this chapter, "All" indicates that both independent and recognized dependent outages are included, the designation "Base" implies that only independent outages are considered in the assessment.

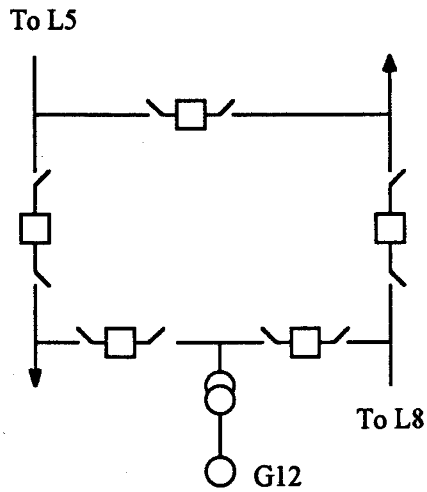


Figure 6.2: Five connection ring bus arrangement.

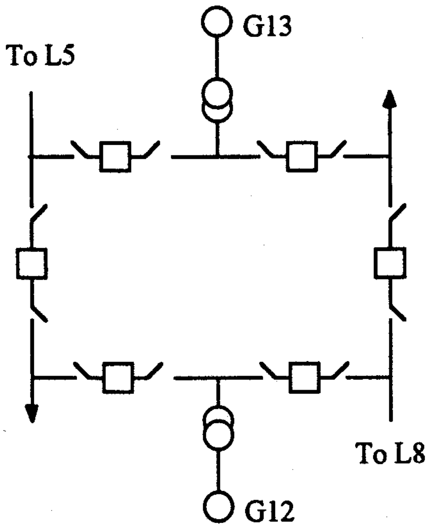


Figure 6.3: Six connection ring bus arrangement.

Table 6.3: CSOSR contributed by dependent outages -- one generating unit added at bus 5.

Load increment	CSOSR (All)	CSOSR (Base)	Increase	Contribution (%)
0%	0.006102	0.003446	0.002656	77.0749
2%	0.006103	0.003447	0.002656	77.0525
4%	0.011365	0.008709	0.002656	30.4972
6%	0.012070	0.009414	0.002656	28.2133
8%	0.012070	0.009414	0.002656	28.2133
10%	0.021682	0.018988	0.002694	14.1879

Table 6.4: CSOSR contributed by dependent outages -- two generating units added at bus 5.

Load increment	CSOSR (All)	CSOSR (Base)	Increase	Contribution (%)
0%	0.005133	0.002659	0.002474	93.0425
2%	0.005134	0.002660	0.002474	93.0075
4%	0.006716	0.004041	0.002675	66.1965
6%	0.006905	0.004230	0.002675	63.2388
8%	0.006905	0.004230	0.002675	63.2388
10%	0.012793	0.010122	0.002671	26.3881

It can be seen from Tables 6.3 and 6.4 that the highest relative CSOSR contribution caused by dependent outages is approximately 93 percent. This contribution is quite significant. The actual risk increase due to dependent outages is not negligible although the lowest relative contribution is only about 14 percent as the base risk index is very large in this case. It can also be seen from Tables 6.3 and 6.4 that the presumed acceptable CSOSR risk level used when considering only independent outages may not be suitable when dependent outages are included. Dependent outages can create a large increase in risk in some systems. These results shown clearly demonstrate that the risk contribution due to recognized dependent outages can be quite large and should be recognized in composite system reliability evaluation.

6.3. Generating Unit Replacement

6.3.1. Selection of Generating Units to be Replaced

Installation of additional generating capacity can reduce the composite system operating state risk. A similar reduction in risk can be obtained by replacing small capacity units by larger ones or refurbishing small units to increase their capacities. Table 6.5 shows the CSOSR values associated with increased unit capacities. In each case, a given unit has had its capacity increased by 10 MW. The results shown in Table 6.5 can be compared with those of Table 6.2 where an additional 10 MW was added to the system in the form of an additional generating unit. Table 6.5 shows six individual unit cases as the remaining units are identical. In order to illustrate the effect, the CSOSR values corresponding to the replacements of units 1 and 5 are shown graphically in Figure 6.4 together with the acceptable risk level and the CSOSR values in the base case.

Table 6.5: CSOSR of the MRBTS with generating unit capacity increase.

Unit replaced	CSOSR at system load increase of					
	0%	2%	4%	6%	8%	10%
1	0.005051	0.005053	0.009553	0.011447	0.011450	0.037328
3	0.002921	0.002922	0.010471	0.011834	0.011837	0.011844
4	0.004635	0.004636	0.009053	0.010469	0.010472	0.013123
5	0.002737	0.002919	0.008714	0.009468	0.009772	0.012549
7	0.004152	0.004341	0.009011	0.009438	0.009742	0.028830
8	0.003793	0.003930	0.008680	0.008788	0.009092	0.012724

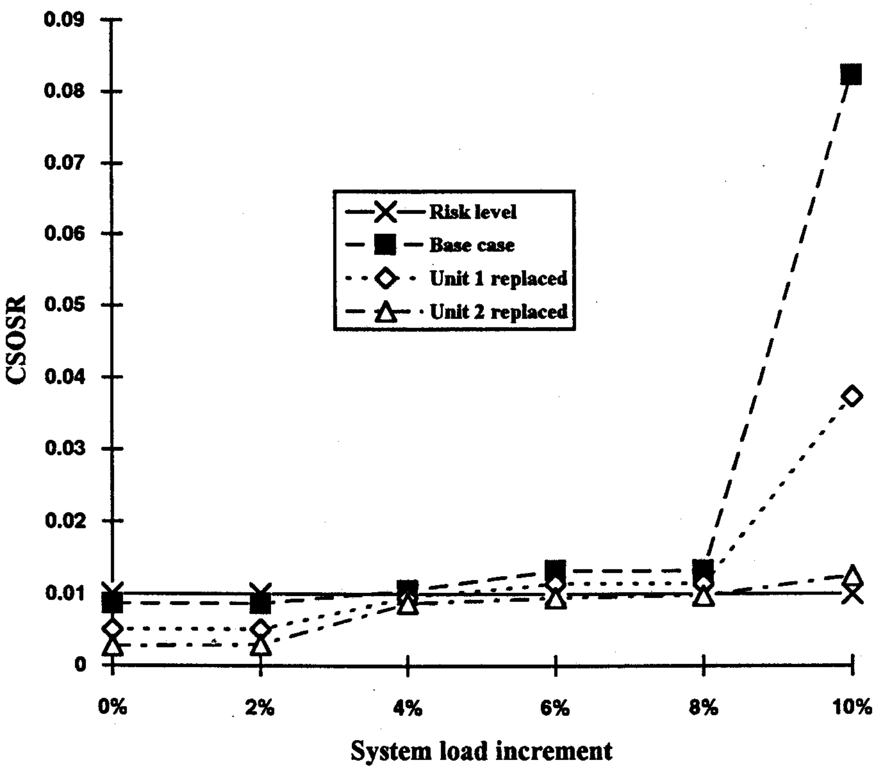


Figure 6.4: CSOSR indices with generating unit replacement.

Table 6.2 shows that the base system can only tolerate an approximate 3 percent increase in load without violating the allowable system risk. Table 6.5 shows the CSOSR for each of six individual generating unit selections. It can be seen from Table 6.5 that replacement of unit 8 will provide the best system performance compared with the other selections. Three of the six selections however, result in a system which can withstand a load increment of about 8 percent. It can be concluded that, in this system and for the reliability data used, replacing generating units at bus 1 will result in lower system risk performance than that obtained by adding an additional unit to this bus. The effect of replacing generating units at bus 2 on the system risk performance is similar to that obtained by adding an additional unit to this bus. These can be seen by comparing Table 6.5 with Table 6.2.

6.3.2. CSOSR Indices Including Dependent Outages

Table 6.6 shows the CSOSR indices for the MRBTS when dependent outages are included and unit 5 is replaced by a larger unit as discussed in the previous subsection. It can be seen from Table 6.6 that the largest increase in CSOSR contribution due to dependent outages is approximately 98 percent and the lowest about 25 percent. This type of study illustrates that composite system reliability evaluation should consider all realistic failure types and not just focus on independent events. It is obviously impossible to include every failure event in composite system reliability evaluation. Some factors have to be neglected in order to reduce the required computation time and the attendant data burden. Reasonable assumptions are very important and major factors should be considered and unimportant ones neglected. The results obtained should be both reasonable and practical.

Table 6.6: CSOSR contributed by dependent outages -- generating unit replaced.

Load increment	CSOSR (All)	CSOSR (Base)	Increase	Contribution (%)
0%	0.005438	0.002737	0.002701	98.6847
2%	0.005620	0.002919	0.002701	92.5317
4%	0.011404	0.008714	0.002690	30.8699
6%	0.012186	0.009468	0.002718	28.7072
8%	0.012561	0.009772	0.002789	28.5407
10%	0.015766	0.012549	0.003217	25.6355

6.4. Transmission Line Addition

6.4.1. Transmission Line Location Selection

Table 6.7 shows the CSOSR indices for the MRBTS with the addition of transmission facilities. The CSOSR associated with line additions between buses 1 and 3 and buses 2 and 4 is also shown in Figure 6.5. The maximum reduction in risk occurs due to the addition of a line between buses 1 and 3. The results for a line between buses 2 and 4 are very similar. With either of these additions, the system can effectively meet a 4% increase in load at the acceptable risk level of 0.01. It can be seen from Table 6.7 that the addition of a single line can not effectively reduce the system risk as the system load grows. Table 6.2 shows the CSOSR with the addition of generating capacity. The overall objective should be to optimally add both generation and transmission facilities to meet further load growth and maintain an acceptable risk level.

Table 6.7: CSOSR of the MRBTS with transmission facility addition.

Line added between buses	CSOSR at system load increase of					
	0%	2%	4%	6%	8%	10%
1 and 3	0.008403	0.008411	0.009838	0.011259	0.011266	0.080449
2 and 4	0.008390	0.008401	0.009999	0.011471	0.011471	0.080657
1 and 2	0.008968	0.010331	0.011760	0.013181	0.013206	0.082181
3 and 4	0.008680	0.008688	0.010178	0.011899	0.013261	0.082209
3 and 5	0.008679	0.008688	0.010478	0.013260	0.013260	0.082208
4 and 5	0.008679	0.008687	0.010177	0.011898	0.013260	0.082208

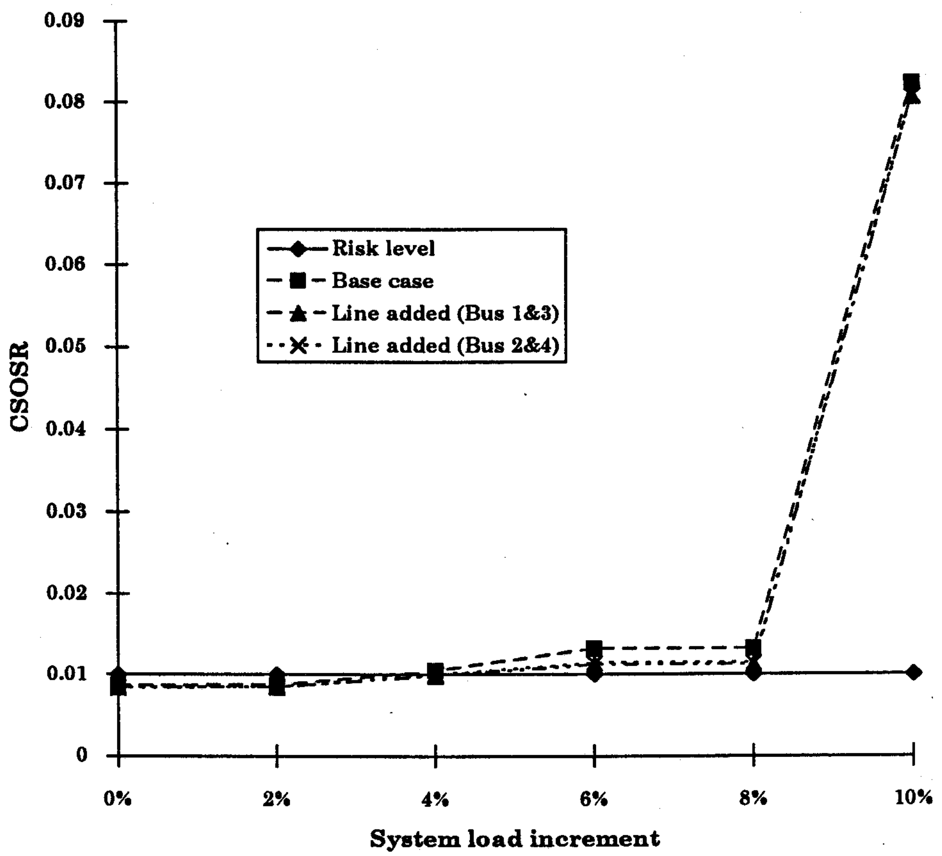


Figure 6.5: CSOSR indices with a transmission line addition.

6.4.2. CSOSR Indices With Dependent Outages

The CSOSR indices contributed by dependent outages at selected load levels are shown in Table 6.8. These indices are for the MRBTS with an additional line between buses 1 and 3. It can be seen from Table 6.8 that the system can not meet a risk level of 0.01 at any load level. It can also be seen from Table 6.8 that the highest relative CSOSR contribution caused by the recognizing dependent outages is about 28 percent. This amount is not negligible and it clearly indicates that these outages should be recognized and included in practical CSOSR evaluation.

Table 6.8: CSOSR contributed by dependent outages -- transmission facility added.

Load increment	CSOSR (All)	CSOSR (Base)	Increment	Contribution (%)
0%	0.010826	0.008403	0.002423	28.8349
2%	0.010834	0.008411	0.002423	28.8075
4%	0.012278	0.009838	0.002440	24.8018
6%	0.013771	0.011259	0.002512	22.3110
8%	0.014002	0.011266	0.002736	24.2855
10%	0.091252	0.080449	0.010803	13.4284

6.5. Transmission Line Maintenance

The studies presented in the previous sections can be used to determine when and where additional system facilities (generating units and transmission lines) should be added to the system in order to meet increased load demand at an acceptable risk level. Additional studies can also be conducted in order to determine the risk associated with removing a transmission line from service for maintenance. Table 6.2 shows that the system risk is 0.008680 at a system load of 185 MW when all generating units and transmission lines are in the system. This value is less than the defined system risk level and therefore the system is considered to be acceptable. The system risk exceeds 0.01 at the 100% load level (185 MW) when some transmission lines are removed from service. This is shown in Table 6.9. It is therefore important to select an appropriate time to conduct line maintenance. In general, the system load is a random function of time but the load curve can be predicted from previous history and experience. It is possible to perform the required maintenance at lower system load levels as under these conditions the system risk is less than 0.01 with some lines removed from service. Table 6.9 shows the system CSOSR values at seven selected load levels when an individual line is removed from service. The CSOSR values associated with six different line removals are presented as transmission lines 6 and 7 are identical to 1 and 2 respectively.

Table 6.9: CSOSR indices with line removals (only independent outages considered).

Load level	CSOSR with removal of line					
	1	2	3	4	5	8
40%	0.000050	0.000045	0.000056	0.000032	0.000261	0.000261
50%	0.000060	0.000048	0.000056	0.000032	0.000261	0.000261
60%	0.000098	0.000069	0.000061	0.000034	0.000263	0.000263
70%	0.000209	0.001059	0.001173	0.000132	0.000358	0.000361
80%	0.001497	0.001482	0.001549	0.000303	0.000526	0.000534
90%	0.009508	0.006025	0.004292	0.002483	0.002682	0.002710
100%	0.015873	0.012014	0.010288	0.008701	0.008913	0.008972

It can be seen from Table 6.9 that any single line can be removed for maintenance when the system load is less than or equal to 90% of 185 MW. The system risk is also quite small at low system load levels. It is therefore preferable that line maintenance be performed when the system risk is as low as possible. It can also be seen from Table 6.9 that the sensitivity of the CSOSR to load level variations is quite different for each line removal. These differences can prove important in the selection of lines for maintenance and in the overall maintenance schedule.

Table 6.10 shows the CSOSR values for the line maintenance cases when independent outages, common mode and station originated failures are all included. It can be seen from Table 6.10 that the CSOSR is less than 0.01 in five of the presented six cases when the system load is less than or equal to 90% of its peak load. The CSOSR indices presented in this table are larger than the corresponding ones shown in Table 6.9. This type of analysis provides useful information to system planners and operators when scheduling line maintenance.

Table 6.10: CSOSR indices at different load levels (independent and dependent outages considered).

Load level	CSOSR with removal of line					
	1	2	3	4	5	8
40%	0.001582	0.001537	0.002712	0.001546	0.001814	0.001815
50%	0.001591	0.001804	0.002712	0.001546	0.001814	0.001815
60%	0.002509	0.001825	0.002717	0.001596	0.001819	0.001865
70%	0.002623	0.002861	0.003861	0.002715	0.002722	0.002983
80%	0.003969	0.003230	0.004291	0.002901	0.002904	0.003184
90%	0.012499	0.008358	0.007070	0.005157	0.005393	0.005436
100%	0.018880	0.014365	0.013072	0.011389	0.011640	0.011700

6.6. The MRBTS With One and a Half Breaker Station Configurations

Security constrained adequacy assessment in the MRBTS has been illustrated in the previous sections of this chapter considering the addition of generating unit(s) and transmission facilities. Dependent outages were included in the evaluation as their effect on the indices is usually quite significant. Dependent outages resulting from station originated failures are obviously related to the station configurations used. The MRBTS including stations is shown in Figure 4.5. The effect of using different configurations has been examined. The element reliability data of the selected station arrangement are identical to those used earlier and are given in Appendix A. The MRBTS in which a one and a half breaker station configuration is used to replace the ring bus station configuration at each individual bus is shown in Figure 6.6. An important feature of a one and a half breaker station is that a main bus failure does not remove any load feeder from service.

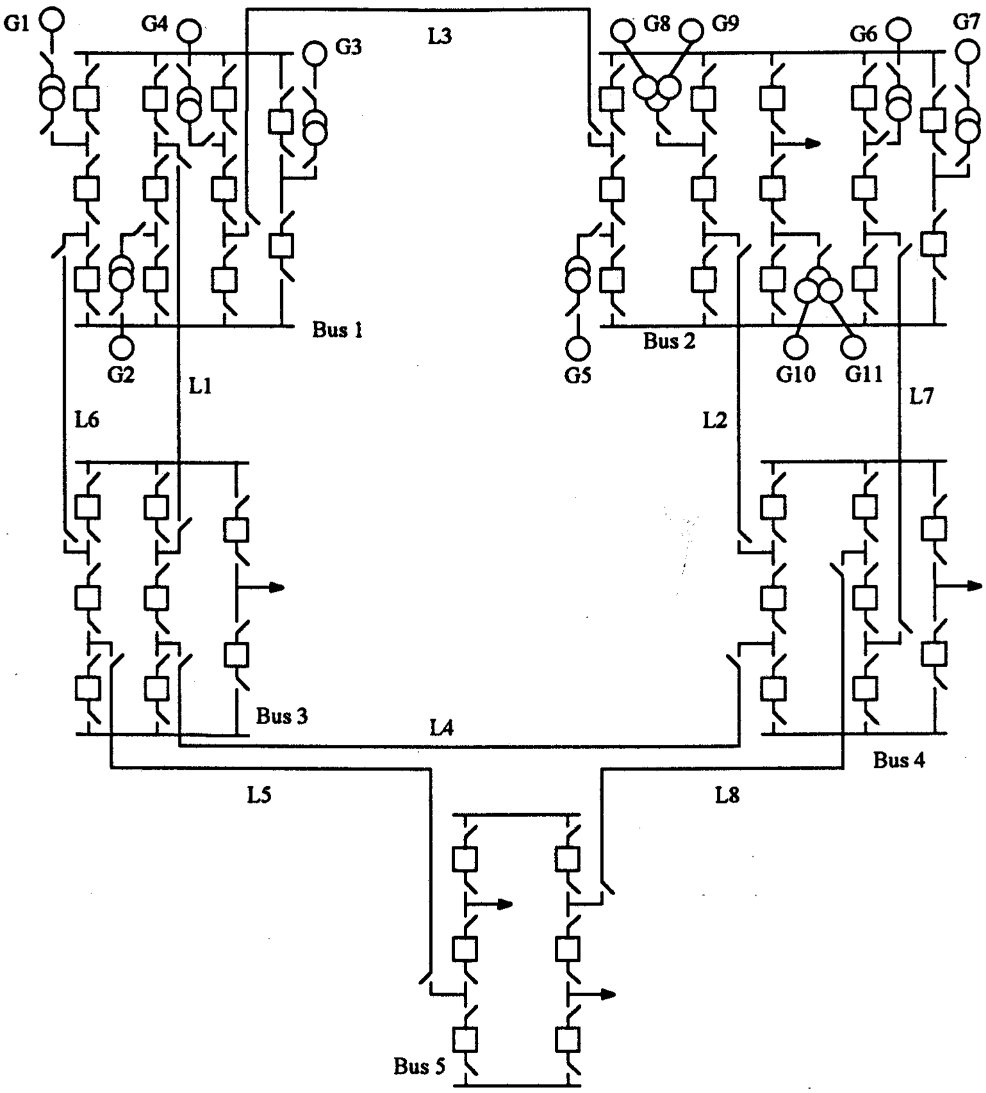


Figure 6.6: The single line diagram of the MRBTS with one and a half breaker stations.

Table 6.11 presents the operating state probabilities at seven load levels for the system shown in Figure 6.6. A comparison of these CSOSR values with those obtained in Chapter 4 is presented later in this chapter. The total probability captured at the 100% load level is 0.999933 and the corresponding CSOSR is 0.011373. This risk is almost identical to the value obtained for the MRBTS with ring bus stations. The difference between the individual state probabilities due to the application of these two station types can be appreciated by comparing Table 6.11 with Table 4.13.

Table 6.11: Operating state probabilities at selected load levels - MRBTS.

Load level	Probability of				CSOSR
	Normal	Alert	Emergency	Extreme emergency	
40%	0.994003	0.004441	0.000000	0.001508	0.001556
50%	0.993985	0.004456	0.000000	0.001509	0.001559
60%	0.993719	0.004713	0.000005	0.001513	0.001568
70%	0.990076	0.008334	0.000006	0.001534	0.001590
80%	0.968720	0.028630	0.000905	0.001676	0.002650
90%	0.885873	0.108992	0.000894	0.004182	0.005135
100%	0.813192	0.175435	0.000873	0.010433	0.011373

Table 6.12 presents the CSOSR values obtained by varying the circuit breaker failure rates and the system load. The breaker failure rates were varied from 1.2 to 2 times the base values. It can be seen from Table 6.12 that the CSOSR increase is about 0.000045 at any load level when the breaker failure rates are increased by twenty percent. This result further illustrates that the CSOSR contributed by station originated outages is not a direct function of the system load. Table 6.12 can be compared with Table 5.6 to contrast the effect of different station configurations on system risk. It can be seen that the corresponding CSOSR values in these two tables are virtually identical in these two cases.

Table 6.12: CSOSR of the MRBTS with one and a half breaker station configurations.

Load level	Multiplier				
	1.2	1.4	1.6	1.8	2.0
40%	0.001600	0.001645	0.001689	0.001735	0.001780
50%	0.001603	0.001647	0.001692	0.001737	0.001783
60%	0.001612	0.001656	0.001701	0.001746	0.001792
70%	0.001634	0.001679	0.001724	0.001769	0.001814
80%	0.002694	0.002738	0.002783	0.002828	0.002874
90%	0.005179	0.005224	0.005269	0.005314	0.005360
100%	0.011416	0.011461	0.011505	0.011550	0.011596

6.7. The MRBTS With Single Bus Station Configurations

Ring bus or one and a half breaker station arrangements generally provide low system risk and good system performance. They are, however, not used by all utilities as the initial cost associated with these stations is quite high. Some utilities prefer to use single bus station arrangements rather than utilize ring bus or one and a half breaker configurations. The most important feature of a single bus station arrangement is its relatively low initial cost. Figure 6.7 illustrates the MRBTS where single bus station configurations are used at all five buses.

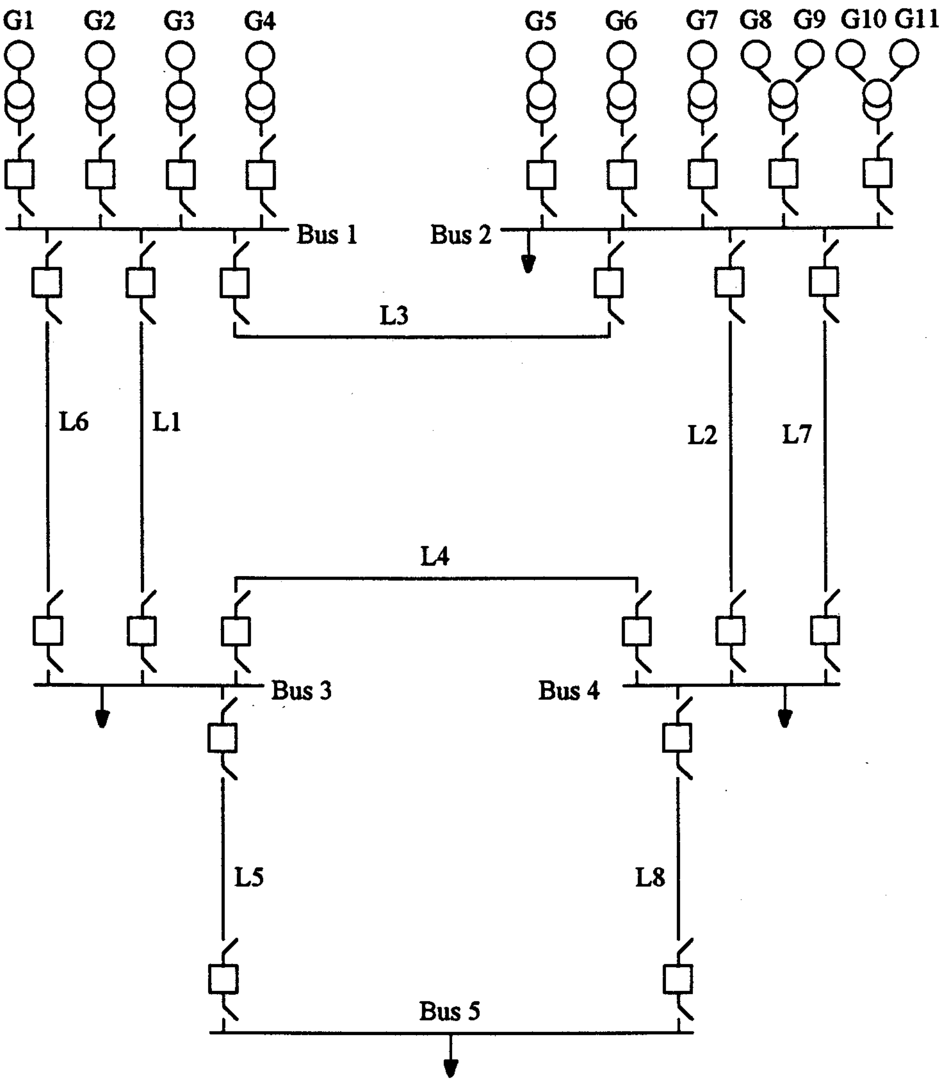


Figure 6.7: The single line diagram of the MRBTS with single bus station configurations.

The system operating state probabilities at different load levels are presented in Table 6.13. The element reliability data used in this study are identical to those used in obtaining Tables 4.13 and 6.11. The probabilities presented in Table 6.13 can be compared with those presented in Table 4.13 or Table 6.11 in order to appreciate the effect of different station configurations on the overall system risk. It can also be seen from Table 6.13 that the total probability captured at the 100% load level is 0.999927 and the corresponding CSOSR is 0.011443. The CSOSR in this case is higher than the values obtained for the other two station types.

Table 6.13: Operating state probabilities at selected load levels - MRBTS.

Load level	Probability of				CSOSR
	Normal	Alert	Emergency	Extreme emergency	
40%	0.992989	0.005403	0.000000	0.001560	0.001608
50%	0.992971	0.005418	0.000000	0.001562	0.001611
60%	0.992718	0.005662	0.000005	0.001565	0.001620
70%	0.988585	0.009773	0.000006	0.001586	0.001642
80%	0.966283	0.031014	0.000905	0.001723	0.002703
90%	0.881462	0.113336	0.000894	0.004245	0.005202
100%	0.808579	0.179978	0.000873	0.010497	0.011443

6.7.1. The CSOSR Values Varying Breaker Failure Rates

CSOSR sensitivity studies were performed by varying the circuit breaker failure rates and the system load for the MRBTS shown in Figure 6.7. The CSOSR values obtained are shown in Table 6.14. It can be seen from Table 6.14 that the actual CSOSR increase is about 0.00006 at any load level when the circuit breaker failure rates are increased by twenty percent. The results presented in Table 6.14 can be compared with Table 5.6 or Table 6.12 in order to examine the effect on the system risk.

Table 6.14: CSOSR of the MRBTS with single bus station configurations.

Load level	Multiplier				
	1.2	1.4	1.6	1.8	2.0
40%	0.001665	0.001723	0.001780	0.001838	0.001895
50%	0.001668	0.001725	0.001782	0.001840	0.001898
60%	0.001677	0.001734	0.001792	0.001849	0.001907
70%	0.001700	0.001757	0.001815	0.001872	0.001930
80%	0.002760	0.002818	0.002876	0.002934	0.002992
90%	0.005265	0.005329	0.005393	0.005457	0.005522
100%	0.011508	0.011573	0.011638	0.011704	0.011771

6.7.2. Effect of Bus Section Failure Rates on the CSOSR Values

The security constrained adequacy evaluation for the MRBTS illustrated previously assumes that the station element reliability data are identical for each of the different station arrangements. This assumption may be true for ring bus and one and a half breaker station configurations. It may not, however, be valid for the single bus station configurations, particularly with respect to the bus section failure rates. The bus sections in the single bus arrangements are usually considerable larger than in the other configurations. A CSOSR evaluation of the MRBTS was conducted in which the failure rates of the bus sections are varied. This study was conducted in four stages where the bus failure rates were assumed to be 1, 2, 3 and 4 times the initial values. The resulting CSOSR values are shown in Table 6.15. It can be seen from this table that the CSOSR increment is about 0.0013 at any selected load level when the initial bus failure rates are doubled. This value is not small compared with the overall system risk and indicates that the risk in the MRBTS with single bus station arrangements can be much higher than that shown in Table 6.13. It can clearly be seen that if the bus failure rates are considerably higher than the initial values, the system reliability will degrade quite significantly.

Table 6.15: CSOSR of the MRBTS with variation bus section parameter.

Load level	Multiplier			
	1.0	2.0	3.0	4.0
40%	0.001608	0.002896	0.004183	0.005472
50%	0.001611	0.002898	0.004186	0.005475
60%	0.001620	0.002907	0.004195	0.005484
70%	0.001642	0.002930	0.004218	0.005506
80%	0.002702	0.003988	0.005275	0.006562
90%	0.005202	0.006485	0.007768	0.009052
100%	0.011443	0.012718	0.013993	0.015269

6.8. CSOSR Comparison for the MRBTS With Different Station Configurations

Security constrained adequacy evaluation in the MRBTS was performed using different station configurations and a selection of sensitivity studies is presented in this chapter. The effect on the overall CSOSR of station arrangements and station element data is illustrated. Table 6.16 summarizes the CSOSR values at selected load levels in the MRBTS for the three different station arrangements. These results were obtained using the basic component data given in Appendix A. All the system constraints and element outages recognized in this thesis are included. It can be seen from Table 6.16 that the system risks are basically comparable for the ring bus or one and a half breaker configurations. The CSOSR is higher in the case of the single bus station arrangement and based on the results in Table 6.15 could be significantly higher.

Table 6.16: CSOSR indices of the MRBTS.

Load level	Ring bus station	One and a half breaker station	Single bus station
40%	0.001537	0.001556	0.001608
50%	0.001539	0.001559	0.001611
60%	0.001549	0.001568	0.001620
70%	0.001584	0.001590	0.001642
80%	0.002630	0.002650	0.002703
90%	0.005115	0.005135	0.005202
100%	0.011352	0.011373	0.011443

6.9. Summary

The effect on the CSOSR of system modifications and additions to the MRBTS is illustrated in this chapter. Generating unit and transmission line facilities were added and the station configurations modified. The studies illustrated in this chapter indicate that the addition of generating units at different buses or the addition of transmission lines between different buses have quite different effects on the CSOSR. These studies illustrate the impact of changes in system investment on the CSOSR and can be used to optimize the investment required to meet system load growth. The effect on the CSOSR of line removals for maintenance is illustrated at different load levels and provides useful information on the risk implications associated with preventive line maintenance. Common mode outages of transmission facilities and station originated outages have a significant effect on the system risk in the MRBTS. CSOSR sensitivity studies are presented in this chapter to illustrate the effect on system risk of circuit breakers and bus sections. The studies presented in this chapter are a small sample of the many possible sensitivity studies which could be performed.

7. COMPOSITE POWER SYSTEM HEALTH ANALYSIS USING A SECURITY CONSTRAINED ADEQUACY EVALUATION PROCEDURE

7.1. Introduction

Security constrained adequacy evaluation of composite generation and transmission systems is extensively illustrated in the previous chapters. The effects on the system reliability indices of system load demands, station configurations, facility additions, etc. have been examined in terms of the ability of the system to meet a specified operating risk criterion. The effect on the CSOSR of the system component reliability data was also examined and the study results show these effects. The results obtained from the security constrained adequacy evaluation procedure can provide an important knowledge base for power system engineers. The CSOSR index at HL II can be compared with conventional indices such as LOLP, LOLE, etc. used in HL I studies. The basic annualized and annual HL II risk indices presented in Chapter 3 can be used as new composite system operating risk criteria which include the ability to both generate sufficient energy and to deliver it to the major load points. The studies presented in Chapter 6 focus on composite system risk evaluation, the determination and utilization of the CSOSR. The operating state framework illustrated in Figure 3.3 also provides the opportunity to focus on the degree of system wellbeing in addition to the system risk. This is a new concept, which while complementing the risk evaluation approach, also provides important information to utility planners, operators and managers. This approach is presented in this chapter.

Most electric power utilities use deterministic techniques to incorporate reliability considerations in transmission system planning. Procedures such as ensuring that the system can withstand the loss of one or more transmission facilities without violating operating constraints or cutting load are usually used. There is also considerable interest in combining deterministic considerations with probabilistic indices to monitor the wellbeing of an electric power system. This combination can be achieved by appreciating that the system operating states created by recognizing the system deterministic criteria can be categorized as being healthy, marginal or at risk and quantified using probability theory. The concept of system health [93] and the margin from undesirable operating conditions involving load curtailment are illustrated in this chapter by application to the MRBTS.

7.2. Composite System Health, Margin and Risk

A power system operating state framework is presented in Reference 71. The modified framework is presented in Figure 3.3 where it can be seen that a system can transfer into the alert, emergency or extreme emergency states from the normal state due to individual system component outages or due to the overlapping of these individual events. The failed system elements may be generating units, transmission lines, or switching station and substation facilities. The concepts of system wellbeing and the impact of facility additions are examined in this chapter. The procedure is illustrated first by considering only independent outages and is extended to include dependent effects.

System wellbeing based on the accepted deterministic criteria can be categorized using the designations shown in Figure 7.1.

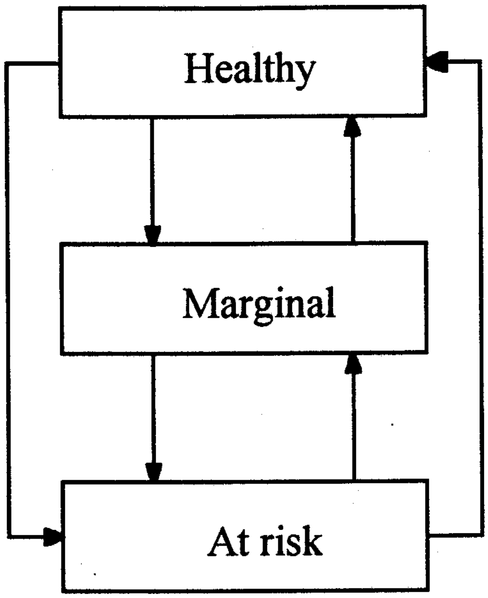


Figure 7.1: Simplified system operating states.

In the healthy state, all equipment is operating within constraints and the generation is sufficient to supply all the load demand. In this state, there is sufficient margin such that the loss of any major system component such as a generating unit or transmission line, as specified by an acceptable deterministic criterion, will not result in an operating limit being violated or load curtailed. The particular criterion will depend on the planning and operating philosophy of the utility in question.

In the marginal state, the system is operating within its limits but it no longer has sufficient margin to satisfy the specified deterministic criterion. The further loss of certain major components will result in a constraint violation or load curtailment. In the at risk state, equipment or system constraints are violated, and some load may be curtailed.

The composite system health, margin and risk designations can be illustrated using Figure 7.2. This figure contains three areas enclosed by circles C_1, C_2 and C_3 which identify the system domains for the outage events leading to the healthy, marginal and at risk states respectively. All possible system states will be located within the circle C_3. It is impossible to enumerate all system contingencies for a practical power system due to the enormous number of outage events. It is, however, not necessary to enumerate all the possible contingencies as the probability of individual high order events is usually quite small and these events can usually be considered as system risk cases. Therefore, only contingencies up to a certain order must be enumerated and the events leading to each of the operating states can be identified and calculated. Generating unit contingencies have been considered up to the fourth order level and those for transmission elements, or the combination of generating units and transmission facilities considered up to the third order level. The remaining higher order contingencies are considered as system risk states.

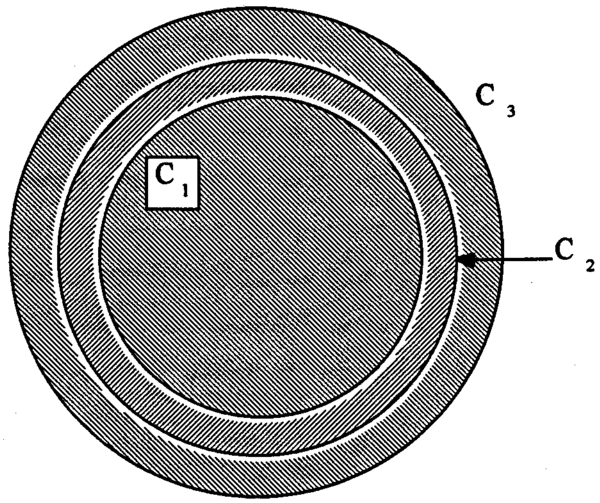


Figure 7.2: Healthy, marginal and at risk domains.

In Figure 7.2, a contingency event falls within C_1 when the system lies in the healthy state, lies between C_1 and C_2 when the system lies in the marginal state and is located between C_2 and C_3 when the system is in the risk state. Outage events enclosed by C_1 are acceptable and do not result in a system problem. In this domain, the system can also tolerate some further element failures defined by the specified deterministic criterion. The area within C_1 is designated as the system healthy domain. Outage events located between C_1 and C_2 are also acceptable but the system can not withstand further contingencies as prescribed by the specified deterministic criterion. The region between C_1 and C_2 is designated as the system marginal domain. A system is therefore both adequate and secure when its present state is located within the region enclosed by C_1. The system is liable to transfer into the risk domain when its current state is located within the region surrounded by C_1 and C_2. The system is in trouble when its current state is located outside C_2. The probabilities associated with the events located within C_1, between C_1 and C_2, outside C_2 are therefore defined as the probabilities of system health, system margin and system risk respectively. The probabilities of the healthy and marginal states provide an appraisal of system wellbeing. A Composite System Operating State Risk (CSOSR) index can be calculated by subtracting these values from unity. A system may be considered acceptable when the calculated CSOSR is less than or equal to a given risk level. The probabilities associated with the healthy and marginal states can also be used as system design criteria. The wellbeing of the system is increased when marginal state probabilities are transferred to the healthy state by system modification or improvement.

The individual contingency events and their probabilities also provide a system knowledge base. These indices can be used to examine the likelihood and severity of an outage contingency and its contribution to the probability of each operating state. A basic planning objective should be to design a system such that the probabilities of the healthy, marginal and risk states are at acceptable levels. These probabilities can be adjusted by optimizing the system operating conditions or installing additional facilities. The application of some of these techniques is illustrated in the following sections using the MRBTS.

7.3. Composite System Health Analysis

The single line diagram of the MRBTS is presented in Figure 3.4. it contains 5 buses, 11 generating units located at 2 buses, and 8 transmission lines. The system peak load is 185 MW. The system component reliability data are given in Appendix A.

Table 7.1 shows the study results for the MRBTS when the system load is 185 MW and all the system and equipment constraints are considered. This table shows the system health, system margin and system risk probabilities. Several system outage events are presented in this table for illustration. It is not possible to table all the system contingencies in this table even for such a small system but they can be easily stored in a computer data file. It can be seen from this table that the probability of system health is much larger than those of system margin and risk. An essential system planning objective is to maintain the probability of the healthy state as high as possible with a reasonable marginal state probability. The system risk is 0.008680. Assuming a criterion risk level of 0.01, the system is therefore acceptable. It can also be seen that this system has sufficient margin to tolerate any single major component outage, when all elements are initially in service, only line 4 is out of service, generating unit 3, 5, or 6 is in the outage state, and so on. The system state is considered to be marginal when line 1, 2, 3, or 6 or generator 1 or 2, etc. are in the outage state. This system is in the risk state when higher order contingencies such as lines 1 and 2, generating units 1 and 2, etc. exist. The probability of a single high order contingency is relatively small and its occurrence is, therefore, infrequent. The system risk can be compared with the Loss Of Load Probability (LOLP) and the Loss Of Load Expectation (LOLE) indices used in basic system planning studies [70]. The system risk probability of 0.008680 given above corresponds to a LOLE of 76.04 hrs/yr, assuming a constant system load level of 185 MW.

Table 7.1: System state probabilities and associated outage events.

<table>
<tr><td colspan="3">Probability in the state of</td></tr>
<tr><td>Health</td><td>Margin</td><td>Risk</td></tr>
<tr><td>0.828712</td><td>0.162608</td><td>0.008680</td></tr>
<tr><td colspan="3">Contingencies in the domain of</td></tr>
<tr><td>Health</td><td>Margin</td><td>Risk</td></tr>
<tr><td>0, L4, G3, G5,</td><td>L1, L2, L3,</td><td>L1 & L2,</td></tr>
<tr><td>G6, G3&L4,</td><td>L6, G1, G2,</td><td>G1 & G2,</td></tr>
<tr><td>......</td><td>......</td><td>......</td></tr>
</table>

Note: 0 -- no element out of service
G -- Generator out of service
L -- Line out of service

7.4. Effect of System Load

The probabilities of system health, margin and risk depend on many factors such as the system load, installed generating capacity, size of the various generating units and their availabilities, transmission line capabilities and availabilities, the acceptable load bus voltage levels, the overall system topology, etc. The studies illustrated in the last section are based on the original system and the forecast peak load. The system load varies with time and the utilization of the peak load as the single system load parameter provides a pessimistic appraisal of system performance. The probabilities of the three system states using a seven step load model are presented in Table 7.2 where 100% system load is 185 MW.

Table 7.2: System health at selected load levels.

Load level	Probability of		
	Health	Margin	Risk
40%	0.997595	0.002379	0.000026
50%	0.997577	0.002396	0.000027
60%	0.997325	0.002646	0.000029
70%	0.994166	0.005783	0.000051
80%	0.973718	0.025991	0.000291
90%	0.899920	0.097637	0.002443
100%	0.828712	0.162608	0.008680

The results presented in Table 7.2 show that the probability of system health decreases as the load increases and the system margin probability and system risk probability increase. Some probability associated with the healthy state at a low load level transfers to the marginal or risk state when the load increases. In other word, some contingencies located in the healthy region at low system load move to the marginal or risk domain as the load increases. The risk probabilities at the various load levels can be used to calculate the system annual risk and expressed as the composite system LOLE. The annual LOLE using the results given in Table 7.2 and the load model discussed in Chapter 3 is 3.59 hrs/yr for the MRBTS.

The system wellbeing shown in Table 7.2 is illustrated graphically in Figure 7.3, where the area enclosed by probability and load axes is divided into three regions of health, margin and risk. The graph shown in Figure 7.3 presents an intuitive appreciation of the effect of system load on system wellbeing.

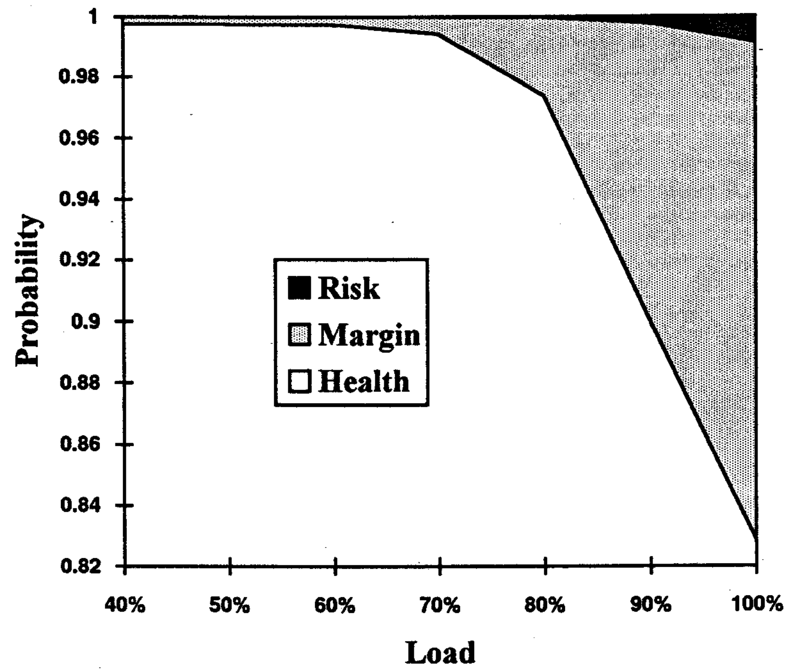


Figure 7.3: System wellbeing as a function of load demand.

7.5. Effect of Generating Unit Additions

The system health analyses described in the previous sections utilize the basic MRBTS. The existing system may or may not meet future increased load requirements at an acceptable risk level unless additional facilities are added to the system. The addition of generating or transmission capacity will have an impact on the system risk and a major system planning task is to determine the most effective and economic additions to the system in order to maintain an acceptable risk level as the system load increases. The following sections briefly illustrate the impact on system health, margin and risk of adding generation and transmission capacity to the base MRBTS. The acceptable system risk level in these studies is assumed to be 0.01 for the MRBTS, i.e. the system is considered to be adequate when its risk probability is less than or equal to 0.01. The attention is focused on not only the CSOSR values but also the system health and operating margin. This section illustrates the addition of generating units(s) at different buses in the system. The reliability data for the additional generating units are given in Table 6.1.

A composite system risk evaluation includes the entire system generation and transmission topology and therefore in addition to indicating when facilities should be added to the system also provides the opportunity to investigate where they should be added. In order to illustrate this, the load is increased by 5% to 194.25 MW. The study results are shown in Table 7.3 which presents the health, margin and risk probabilities for a single unit addition and a two unit addition at each of the five buses. Table 7.3 also shows the base case domain probabilities for the original MRBTS at a load of 194.25 MW.

Table 7.3: System health with generating unit additions.

Bus No.	Units added	Probability of		
		Health	Margin	Risk
1	1	0.825757	0.164696	0.009547
2		0.826558	0.164216	0.009226
3		0.826591	0.164549	0.008860
4		0.826575	0.164564	0.008861
5		0.826591	0.164549	0.008860
1	2	0.881514	0.113288	0.005198
2		0.881514	0.114214	0.004272
3		0.882520	0.113404	0.004076
4		0.881514	0.114400	0.004086
5		0.882520	0.113404	0.004076
Base	case	0.811019	0.178503	0.010478

It can be seen from Table 7.3 that the original system can not meet the presumed risk requirement for a 5% load increment as the risk index is 0.010478 and additional capacity is required. Table 7.3 shows that the addition of a unit at any of the five buses can result in an acceptable risk level. The addition of a unit at bus 3, 4, or 5 provides very similar results. If the new unit can only be added at one of the existing two generating buses, the addition of a unit at bus 2 provides better system performance. The probability of system health with a one unit addition at bus 2 is also higher than that with a one unit addition at bus 1. The results obtained by adding two units at each of the five buses are also shown in this table. The addition of two units at buses 3, 4 and 5 result in approximately equal system health, margin and risk indices and the addition of two units at bus 2 results in better system performance than that at bus 1. Similar studies can be performed for multiple unit additions with single units added at individual buses.

7.6. Effect of Line Additions

The effect on the composite system domain probabilities of transmission facility additions is examined in this section. The results are shown in Table 7.4 for a load demand of 194.25 MW. This table shows that only the line addition between bus 1 and bus 3 provides the required decrease in system risk to meet the assumed risk level of 0.01. It can be seen from Table 7.4 that the probability of system health is zero when a line is installed between bus 1 and bus 2. The results obtained with this line addition are worse than those calculated for the base case shown also in Table 7.4. This indicates that this system can not, in this condition, tolerate a single element outage without violating the healthy state condition. This violation is caused by the overload of line 1 or line 6 as power is transferred from bus 1 to bus 3 through one single line when one of lines 1 and 6 is out of service. The results shown in Table 7.4 indicate that the addition of a single line can not effectively reduce the system risk as the system load grows. Table 7.3 shows the system probabilities with the addition of generating capacity. The overall objective should be to optimally install both generation and transmission facilities to meet further load growth at an acceptable risk level.

Table 7.4: System health with transmission line addition.

Line between buses		Probability of		
		Health	Margin	Risk
1	3	0.814666	0.175495	0.009839
2	4	0.827546	0.162450	0.010004
1	2	0.000000	0.988240	0.011760
3	4	0.811907	0.177620	0.010473
3	5	0.811906	0.177616	0.010478
4	5	0.813721	0.175808	0.010471
Base	case	0.811019	0.178503	0.010478

7.7. Effect of Line Maintenance

Studies such as those illustrated in the previous sections can be used to determine when and where additional system facilities (generating units and transmission lines) should be added in order to meet increased load demand at an acceptable level of risk. Similar analyses can be performed in order to determine the system wellbeing when transmission elements are removed from service for maintenance. Table 7.2 shows that the system risk is 0.008680 at a load of 185 MW for the basic MRBTS. This value is less than the system risk criterion and therefore the system is acceptable in this condition. The system risk exceeds 0.01 at 100% load (185 MW) when certain transmission facilities such as lines 1, 2 and 3 are removed from service as illustrated in Table 6.9. It is important to select an appropriate time to conduct line maintenance. The system load varies with time and can be forecast with an acceptable accuracy. It is therefore possible to schedule the required maintenance at lower system load levels for which the system risk is less than 0.01 with the facilities removed from service. Table 7.5 shows the system state probabilities at a load level of 166.5 MW (90%) when individual lines are removed from the service. The system domain probabilities associated with six different line removals are presented in Table 7.5 as transmission lines 6 and 7 are identical to 1 and 2 respectively.

Table 7.5: System health with line removal.

Removal of line	Probability of Health	Probability of Margin	Probability of Risk
1	0.000000	0.990492	0.009508
2	0.000000	0.993975	0.006025
3	0.000000	0.995708	0.004292
4	0.899920	0.097597	0.002483
5	0.000000	0.997318	0.002682
8	0.000000	0.997290	0.002710

It can be seen from Table 7.5 that any single line can be maintained when the system load is less than or equal to 166.5 MW based on the risk domain probability. In all but one case, however the probability of system health is zero. This may not be acceptable and it may be therefore preferable that line maintenance be performed when the system has sufficient margin to withstand further element outage. In this case, the load level will have to be lower to accommodate line removal at an acceptable healthy state probability. It can be deduced from Tables 7.2 and 7.5 that the sensitivity of the system risk to load level variations will be quite different for each individual line removal. This difference can prove to be important in the selection of lines for preventive maintenance and in the determination of an overall maintenance schedule.

7.8. Effect of Specified Dependent Outages

Only the independent outages of generation and transmission facilities are considered in the system health studies presented in the previous sections of this chapter. As noted previously, both common mode and station originated outages should be considered in the reliability evaluation of composite systems. In the procedure developed to include dependent outages, the station elements are not considered as individual system major components within the deterministic criterion. The effect caused by station element outages is combined with those due to system major component independent outage events. The outage of those buses connected to the major load points will cause these points to be isolated from the bulk power supply. The probability of the healthy state is always zero when these bus sections are considered as major components in the deterministic criterion.

Table 7.6 presents the system health probabilities at selected load levels for the system shown in Figure 4.5. Table 7.6 can be compared with Table 7.2. It can be seen from Tables 7.2 and 7.6 that some of the probability in the healthy state is transferred to the marginal or at risk state when the dependent outages are included. This is caused by changes in the individual contingency probabilities while the major component contingency events located within each domain remain unchanged. The annual LOLE using the results given in Table 7.6 and the load model given in Chapter 3 is 19.23 hrs/yr. This index is much larger than the 3.59 hrs/yr value obtained earlier. The system wellbeing presented in Table 7.6 is shown graphically in Figure 7.4. The probabilities in the system health, margin and risk states are all a function of the system load.

Table 7.6: System health at selected load levels (dependent outages included).

Load level	Probability of Health	Probability of Margin	Probability of Risk
40%	0.994059	0.004404	0.001537
50%	0.994042	0.004419	0.001539
60%	0.993776	0.004675	0.001548
70%	0.990166	0.008250	0.001584
80%	0.968823	0.028547	0.002630
90%	0.886165	0.108720	0.005115
100%	0.813516	0.175132	0.011352

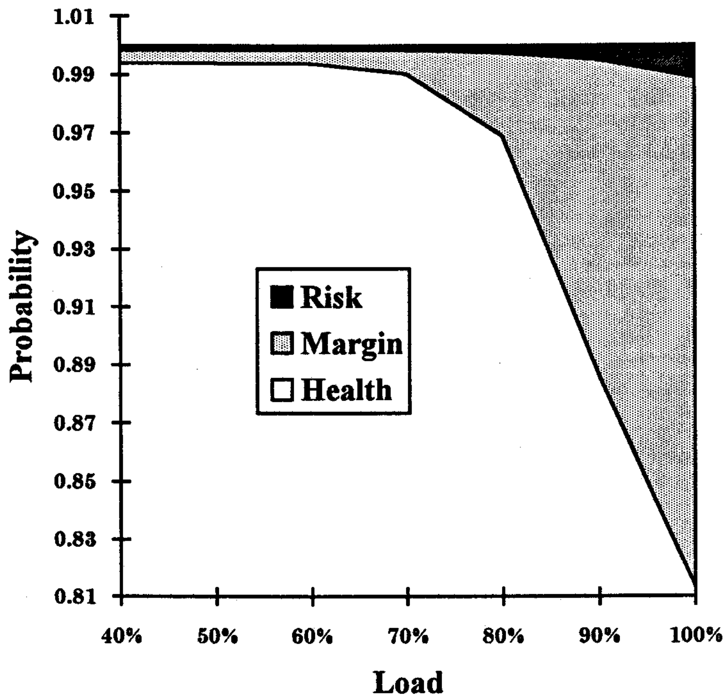


Figure 7.4: System wellbeing illustration.

7.9. Effect of Station Configurations

The studies described in the last section are based on ring bus arrangements in the MRBTS. As noted in the last chapter, utilities have their own rational in selecting station layouts which depend on many factors such as reliability, initial investment, flexibility, etc. A comparison of the effect on system health of selected station arrangements is both necessary and important in order to provide additional information in the planning process. The effect on the system wellbeing of using one and one half breaker arrangements and also single bus configurations is examined in this section.

7.9.1. One and a Half Breaker Arrangement

The system state probabilities at selected load levels are presented in Table 7.7 for the system shown in Figure 6.6. The CSOSR values for the one and a half breaker and ring bus configurations shown in Tables 7.7 and 7.6 respectively are quite close. This was also noted in Chapter 6. There is also no great difference in the healthy and marginal state probabilities, which indicates that the effect on the system wellbeing of these two station configuration types is almost similar. This conclusion is based on the results obtained and may not be true if the station element failure and repair rates are different in each configuration. The system wellbeing shown in Table 7.7 is also graphically illustrated in Figure 7.5.

Table 7.7: System health at selected load levels (dependent outages included).

Load	Probability of		
level	Health	Margin	Risk
40%	0.994003	0.004441	0.001556
50%	0.993985	0.004456	0.001559
60%	0.993719	0.004713	0.001568
70%	0.990076	0.008334	0.001590
80%	0.968720	0.028630	0.002650
90%	0.885873	0.108992	0.005135
100%	0.813192	0.175435	0.011373

7.9.2. Single Bus Arrangement

Table 7.8 shows the system state probabilities for the system shown in Figure 6.7 which utilizes single bus arrangements. This table can be compared with Tables 7.6 and 7.7 in order to appreciate the effect of the various station configurations on the system wellbeing. It can be seen from these three tables that the health state probability at a given load level is the lowest in Table 7.8. The marginal state probability at a given load level is the highest in Table 7.8 as a failure in a bus section will result in the system being in the risk state. Only one bus is utilized in each single bus station configuration while there are several buses in the other two station layouts. The bus outage rate in a single bus station should be larger than that in a ring bus or one and a half breaker station simply due to the length of the bus. The effect of bus failure rate on the CSOSR was illustrated in Chapter 6.

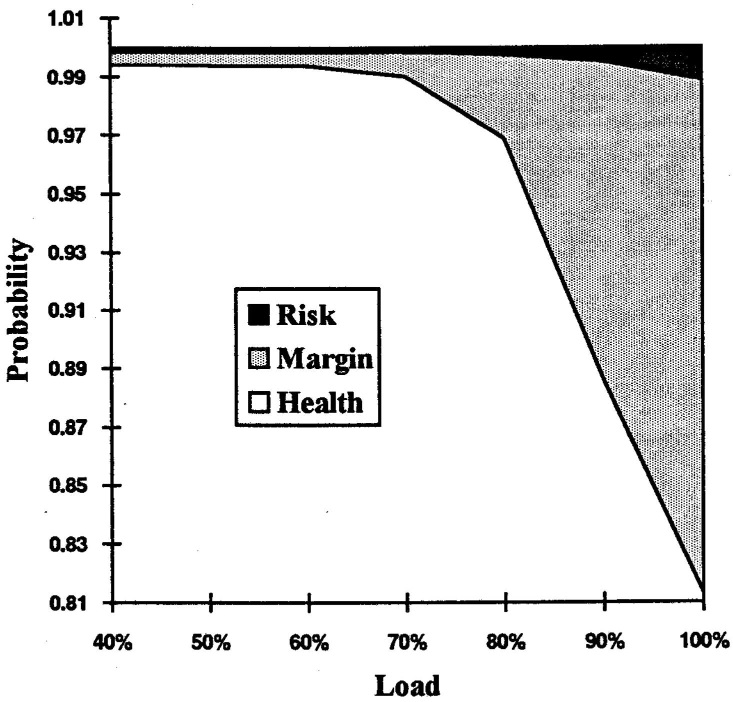


Figure 7.5: System wellbeing with one and a half breaker arrangements.

Table 7.8: System health at selected load levels (dependent outages included).

Load level	Probability of Health	Probability of Margin	Probability of Risk
40%	0.992989	0.005403	0.001608
50%	0.992971	0.005418	0.001611
60%	0.992718	0.005662	0.001620
70%	0.988585	0.009773	0.001642
80%	0.966283	0.031014	0.002703
90%	0.881462	0.113336	0.005202
100%	0.808579	0.179978	0.011443

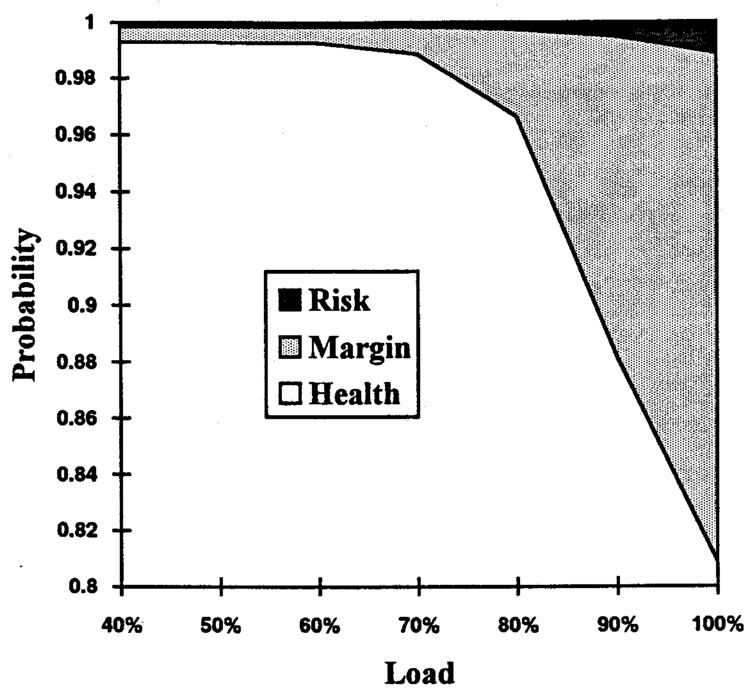


Figure 7.6: System wellbeing with single bus arrangements.

7.9. Summary

Composite system health, margin and risk domains are presented and quantified in this chapter by application to the MRBTS. The probabilities associated with these regions are used to calculate composite system operating limit and risk indices. The definition of these domains includes the deterministic criterion utilized by many utilities in planning and operating bulk power systems. Attention is normally focused on system risk rather than on the system wellbeing in the form of system health and margin under specified deterministic criteria. The approach presented in this chapter provides the ability to quantify the degree of wellbeing in addition to quantify the system risk. The study results presented illustrate the effect on the domain indices of generation and transmission facility additions. The studies also illustrate the utilization of the concepts of health and wellbeing in scheduling transmission line maintenance. The effect on the system wellbeing of dependent outages is also examined in this chapter. The procedure was extended to investigate the effect on system wellbeing of selected station configurations and provides further quantitative input to the system planning and decision making process.

8. GENERATING UNIT OPERATING RESERVE ASSESSMENT IN COMPOSITE GENERATION AND TRANSMISSION SYSTEMS

8.1. Introduction

Reliability evaluation of a power system can be conducted in the two distinct domains of system adequacy and security [1, 2]. Adequacy assessment is usually performed in the planning phase while security evaluation can be conducted in both the operating and planning phases. The operating phase can be divided into the two aspects of operational planning assessment and daily operation evaluation. Security assessment involves both steady state and transient analyses. The assessment of the operating reserve at any time of the day is a security problem. The load in a power system varies continuously and therefore it is not economical and practical to continuously operate all the generating units required to satisfy the peak load. Usually, units are placed into service at one point in time and removed from service or additional units are committed to the system at another point in time depending on the system load level. Generating units should be put into service for different segments of the scheduling period in such a way that the system operating cost is minimized and a satisfactory level of reliability is attained at all times.

There are a number of methods used in operating reserve assessment at HL I. The available techniques can be generally grouped into the two broad categories of deterministic and probabilistic approaches [5 - 7]. Deterministic criteria include considerations such as a percentage of system load or operating capacity, fixed capacity margins, and the largest unit loading. The assessment of the operating reserve risk can be conducted using a single technique or a combination of these techniques [94].

Deterministic approaches do not specifically recognize the probability of component failure, i.e. generating units, transmission lines, etc., in an assessment of the required operating reserve risk. A probabilistic approach can be used to recognize the stochastic nature of system components and to incorporate these phenomena in a consistent evaluation of the required operating reserve requirement. The magnitude of the operating reserve and the actual spinning requirement can be determined on the basis of system risk. This risk has been defined in HL I studies as the probability that the system will fail to meet the load or be able to just meet the load during a specified time in the future. This duration is known as the lead time and the failed generating unit(s) is normally considered to not be replaced or restored to service during this time [70].

The generating unit commitment risk assessment techniques presently used are focused only on the generating system functional zone (HL I). These approaches are relatively simple and can be easily understood and developed but they neglect the effect of other system components such as transmission facilities. They do not, therefore, incorporate the concept of delivering the generated energy to the major load points in the analysis. This chapter describes a probabilistic technique used to perform unit commitment risk assessment for composite generation and transmission systems (HL II). This application is therefore in the area of operational planning. In this method, outages of transmission lines and station elements are considered in addition to those of generating units. This technique is used in this chapter to examine the effect of recognized dependent outages on the operating reserve risk index.

8.2. Unit Commitment Risk Assessment in HL I Studies

In a conventional HL I operating capacity assessment, the committed units are assumed to be connected to a common bus and serve the total system load demand at that bus. System intra-connections are not normally considered in the assessment. Generating units are usually represented by a two state model as shown in Figure 3.1 which includes an operating state and a failed state. In this model, λ and μ are the unit failure and repair rates. It is also possible to include derated states in the model if desired or necessary [70]. The availability and unavailability of the generating unit at time t are given by Equations 8.1 and 8.2 respectively,

$$P_1(t) = \frac{\mu}{\lambda+\mu} + \frac{\lambda e^{-(\lambda+\mu)t}}{\lambda+\mu}, \tag{8.1}$$

$$P_2(t) = \frac{\lambda}{\lambda+\mu} - \frac{\lambda e^{-(\lambda+\mu)t}}{\lambda+\mu}. \tag{8.2}$$

If the lead time is sufficiently short, the repair process can be neglected and the probability of the generating unit being in the failed state during time T can be obtained using Equation 8.3. In general, the lead time T is relatively short and Equation 8.3 can be approximated by Equation 8.4. This probability is known as the Outage Replacement Rate (ORR) [70, 131].

$$P_2(T) = 1 - e^{-\lambda T}. \tag{8.3}$$

$$P_2(T) \approx \lambda T. \tag{8.4}$$

The individual unit ORRs can be used to create a system capacity outage probability table from which the operating risk can be determined [70]. The basic equation used in the development of a system capacity outage probability table is given by Equation 8.5,

$$P(X) = (1-ORR)P'(X) + P'(X-C)\cdot ORR, \tag{8.5}$$

where X -- capacity in outage,
C -- capacity of the generating unit to be added,
P -- cumulative state probability after a unit is added,
P' -- cumulative state probability before a unit is added, it is initialized by setting $P'(X)$=1.0 for X≤0 and P'(X)=0 otherwise,
ORR -- Outage Replace Rate of the generating unit to be added.

The operating risk can be reduced by committing more generating capacity for the same load demand. The selection of an acceptable risk level depends on the desired degree of reliability and the corresponding cost (benefit). The operating risk can be obtained using Equation 8.6,

$$U(t)=\sum_{i=1}^{N}P_i(t)Q_i(t), \tag{8.6}$$

where $U(t)$ -- system risk at time t,
$P_i(t)$ -- probability that the system is in state i at time t,
$Q_i(t)$ -- probability that the system load will be equal to or greater than the generation capacity in state i at time t,
N -- total number of system states.

This risk expression can be modified as shown in Equation 8.7 as $Q_i(t)$ is either 1 or 0 in the condition considered,

$$U(t)=\sum_{i=n}^{N}P_i(t), \tag{8.7}$$

where n is an integer such that the load is larger than or equal to the generating capacity at state *n* and the load is less than the capacity at state *n-1*. If R_S is the allowable system risk for a lead time T, then the risk index should be such that

$$U(t)\le R_s\,. \tag{8.8}$$

The basic operating reserve risk assessment approach has been utilized to study the two reliability test systems described in Chapter 3. Operating reserve risk assessment normally contains two basic aspects. The first is risk assessment for a given unit commitment and the second is the determination of the required number of committed units for a given system risk. Risk analysis of a given unit commitment is illustrated in this section and the determination of the required number of committed units for a given system risk is presented in next section.

8.2.1. Risk Assessment for the MRBTS

Table 8.1 shows the capacity outage probability table for the MRBTS for selected lead times. It is assumed that all of the 11 generating units are committed to service in order to satisfy the load demand and to meet the acceptable risk level. It can be seen from this table that the risk probabilities are 0.0000038, 0.000034 and 0.0000942 at the system load of 185 MW when the lead times are 1 hour, 3 hours, and 5 hours respectively. The risk at a lead time of 3 hours is about 9 times that for a lead time of 1 hour. The risk at a lead time of 5 hours is approximately 24 times larger than that at a lead time of 1 hour. This clearly shows that the system operating risk is a direct function of the generating unit lead times.

Table 8.1: Capacity outage probabilities in the MRBTS.

Capacity		Cumulative probability at lead time of		
out (MW)	in (MW)	1 hour	3 hours	5 hours
0.0	240.0	1.0000000	1.0000000	1.0000000
5.0	235.0	0.0042840	0.0128030	0.0212570
10.0	230.0	0.0038293	0.0114498	0.0190199
15.0	225.0	0.0033743	0.0100951	0.0167789
20.0	220.0	0.0033741	0.0100933	0.0167738
25.0	215.0	0.0017140	0.0051517	0.0086022
30.0	210.0	0.0017132	0.0051450	0.0085835
35.0	205.0	0.0017125	0.0051382	0.0085648
40.0	200.0	0.0017125	0.0051382	0.0085648
45.0	195.0	0.0000053	0.0000480	0.0001328
50.0	190.0	0.0000046	0.0000410	0.0001135
55.0	185.0	0.0000038	0.0000340	0.0000942
60.0	180.0	0.0000038	0.0000340	0.0000942
65.0	175.0	0.0000009	0.0000086	0.0000240
70.0	170.0	0.0000009	0.0000085	0.0000238
80.0	160.0	0.0000009	0.0000085	0.0000236
At the 185 MW load level				
Risk		0.0000038	0.0000340	0.0000942

8.2.2. Risk Assessment for the IEEE-RTS

The capacity outage probability table for the IEEE-RTS can be obtained using the same procedure illustrated for the MRBTS. The capacity outage probability table for this system is quite large and is not presented here. The system operating risk indices calculated for lead times of 1 hour, 3 hours and 5 hours are 0.0000158, 0.0001427 and 0.0003983 respectively when all the 32 generating units are committed and the system load is 2850 MW.

8.3. Effect of System Operating Conditions

System operating reserve risk is not only a direct function of generating unit lead time, but also a direct function of system load, the generating units committed, generating unit failure rates, etc. The risk assessment technique described in the previous section can be employed to determine the number of required generating units in order to supply the load demand at an acceptable risk level. This is illustrated in this section.

8.3.1. Unit Commitment at Selected Load Levels

Tables 8.2 and 8.3 present the required number of generating units at selected load levels for the MRBTS and the IEEE-RTS. The acceptable risk level is assumed to be 0.001, i.e. the unit commitment is acceptable when the calculated reserve risk is less than this value. The lead time for all committed generating units is identical and assumed to be 3 hours. The unit commitments for load levels ranging from 40% to 100% of the system peak load were determined for each system. Tables 8.2 and 8.3 show how the number of generating units required increases as the system load grows. The operating reserve risk is a direct function of the system load and the generating units committed. The actual system operating reserve risk for each load level is also presented in Tables 8.2 and 8.3.

Table 8.2: Unit commitment at selected load levels -- MRBTS.

Load level	Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
40%	74.0	0.001	3.0	4	0.00000717
50%	92.5	0.001	3.0	5	0.00000844
60%	111.0	0.001	3.0	5	0.00001685
70%	129.5	0.001	3.0	6	0.00002560
80%	148.0	0.001	3.0	7	0.00003260
90%	166.5	0.001	3.0	8	0.00003679
100%	185.0	0.001	3.0	9	0.00004099

Table 8.3: Unit commitment at selected load levels -- IEEE-RTS.

Load level	Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
40%	1140.0	0.001	3.0	8	0.00007963
50%	1425.0	0.001	3.0	10	0.00009737
60%	1710.0	0.001	3.0	12	0.00013121
70%	1995.0	0.001	3.0	13	0.00020458
80%	2280.0	0.001	3.0	16	0.00022396
90%	2565.0	0.001	3.0	19	0.00030504
100%	2850.0	0.001	3.0	28	0.00040673

8.3.2. Unit Commitment at Selected Lead Times

The required number of committed generating units for selected lead times is presented in Tables 8.4 and 8.5 for the MRBTS and the IEEE-RTS respectively. The load considered in the MRBTS is 60% (111 MW) of its peak value. The load in the IEEE-RTS is 70% (1995 MW). The acceptable risk level is again set at 0.001. Lead times ranging from 1 hour to 15 hours were studied. It can be seen from Table 8.4 that the number of required generating units in the MRBTS remains constant at this load level when the lead time varies. The actual calculated risk, however, changes quite considerably. The unit commitment is not a function of lead time in this case. This conclusion may not be valid when the acceptable risk level is changed or if the load level is different. It can be seen from Table 8.5 for the IEEE-RTS that the number of required units increases as the lead time increases. In general, the number of required generating units and the operating reserve risk are directly related to the generating unit lead times.

Table 8.4: Unit commitment for varied lead times -- MRBTS.

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
111.0	0.001	1.0	5	0.00000188
111.0	0.001	3.0	5	0.00001685
111.0	0.001	5.0	5	0.00004673
111.0	0.001	7.0	5	0.00009144
111.0	0.001	9.0	5	0.00015092
111.0	0.001	11.0	5	0.00022510
111.0	0.001	13.0	5	0.00031390
111.0	0.001	15.0	5	0.00041725

Table 8.5: Unit commitment for varied lead times -- IEEE-RTS.

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
1995.0	0.001	1.0	13	0.00002288
1995.0	0.001	3.0	13	0.00020458
1995.0	0.001	5.0	13	0.00056446
1995.0	0.001	7.0	14	0.00041085
1995.0	0.001	9.0	14	0.00068431
1995.0	0.001	11.0	15	0.00036670
1995.0	0.001	13.0	15	0.00053026
1995.0	0.001	15.0	15	0.00072963

8.3.3. Unit Commitment at Selected Risk Levels

The number of required generating units for a given load level and a given lead time is examined in this section by varying the acceptable risk level. It is assumed that a system is acceptable when its reserve risk is less than the specified values. The system loads for the MRBTS and the IEEE-RTS are 80% of their peak values, i.e. 148 MW and 2280 MW respectively. It can be seen from Tables 8.6 and 8.7 that the number of required generating units is also a function of the selected risk levels.

Table 8.6: Unit commitment for varied risk levels -- MRBTS.

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
148.0	0.001	5.0	7	0.00009032
148.0	0.003	5.0	7	0.00009032
148.0	0.005	5.0	7	0.00009032
148.0	0.007	5.0	7	0.00009032
148.0	0.008	5.0	7	0.00009032
148.0	0.009	5.0	6	0.00854781
148.0	0.011	5.0	6	0.00854781
148.0	0.012	5.0	5	0.01125268
148.0	0.013	5.0	5	0.01125268
148.0	0.015	5.0	5	0.01125268

Table 8.7: Unit commitment for varied risk levels -- IEEE-RTS.

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
2280.0	0.001	5.0	16	0.00061817
2280.0	0.003	5.0	16	0.00061817
2280.0	0.005	5.0	16	0.00061817
2280.0	0.007	5.0	16	0.00061817
2280.0	0.009	5.0	16	0.00061817
2280.0	0.010	5.0	15	0.00937031
2280.0	0.011	5.0	15	0.00937031
2280.0	0.013	5.0	15	0.00937031
2280.0	0.014	5.0	14	0.01393417
2280.0	0.015	5.0	14	0.01393417

8.4. System Risk Assessment at HL II

The HL I operating capacity risk assessment procedure described in this chapter is relatively straight forward [70] and provides a basic framework for the determination of unit commitment risk. In an actual power system, the generating capacities and loads are usually dispersed throughout the system and are not concentrated at a single bus. The power system operating risk, therefore, depends not only on the generation capacity in the system and the total load demand, but also on the associated transmission network. In a practical power system, the reliability of the transmission network depends on many factors. At the same time, the transmission network also creates many operational restrictions. The committed capacity should therefore satisfy not only the risk criterion at HL I but also that at HL II. Risk assessment at HL II can be conducted sequentially following basic unit commitment at HL I, and can consider a number of possible constraints, such as acceptable voltages at load buses, transmission line load carrying capabilities and real and reactive power considerations as described in Chapter 3. All of these constraints are included in the HL II studies described in this chapter. In these studies, load flow analysis was employed for every enumerated contingency associated with outages of generating units and/or transmission lines. Conventional HL I probabilistic operating reserve assessment does not normally include transmission facilities in the analysis. The approach illustrated in this chapter is a new technique [72] for operating reserve evaluation which includes the ability of the transmission system to deliver the generated energy to the major load points. This approach provides a more realistic appraisal of system risk than a basic HL I evaluation. The development structure of this procedure is similar to that used in the security constrained adequacy evaluation of composite systems described in Chapter 3.

Operating reserve risk assessment can be conducted in the areas of operational planning and daily operation analysis. In the operational planning phase, the Outage Replacement Rate (ORR) of generating units is used instead of their steady state unavailability while the steady state unavailability of transmission facilities is utilized. This is illustrated in this chapter. In the daily operation domain, the time dependent state probabilities of all associated system elements are considered and this is described in the next chapter. The procedure developed for security constrained adequacy evaluation was extended to conduct operating reserve assessment at HL II using the system operating states shown in Figure 3.3.

8.4.1. Risk Assessment for the MRBTS

Table 8.8 shows the operating state probabilities for the MRBTS at three selected lead times, 1 hour, 3 hours and 5 hours. In this procedure, all the capacity and voltage constraints are considered. All of the generating units are committed to the system and the system experiences its peak load demand of 185 MW.

Table 8.8: Operating state probabilities -- MRBTS.

State	Probability at lead time of		
	1 hour	3 hours	5 hours
Normal	0.975288	0.968713	0.962175
Alert	0.024577	0.031113	0.037580
Emergency	0.000083	0.000082	0.000082
Ex.Emerg.	0.000052	0.000092	0.000162
CSOSR	0.000135	0.000174	0.000244

As noted in the operating state definitions given in Chapter 3, there are no constraint violations and no load curtailed in the normal and alert states as the system is not in at risk when it lies in these states. The CSOSR in a security evaluation is calculated using Equation 3.25. Table 8.8 shows that the CSOSR of the MRBTS is 0.000135, 0.000174 and 0.000244 when the lead time is 1 hour, 3 hours and 5 hours respectively. These risk values are much larger than those given in Table 8.1, which indicates that the transmission network has a significant effect on the system operating reserve risk in the case studied.

8.4.2. Risk Assessment for the IEEE-RTS

Table 8.9 shows the operating state probabilities for the IEEE-RTS at three selected lead times, 1 hour, 3 hours and 5 hours. In this calculation, the system peak load of 2850 MW was used and all of the generating units were committed to the system. The system operating risk is 0.000168, 0.000433, and 0.000824 when the lead time is 1 hour, 3 hours, and 5 hours respectively.

Table 8.9: Operating state probabilities -- IEEE-RTS.

State	Probability at lead time of		
	1 hour	3 hours	5 hours
Normal	0.000000	0.000000	0.000000
Alert	0.999832	0.999567	0.999176
Emergency	0.000131	0.000249	0.000360
Ex.Emerg.	0.000021	0.000148	0.000402
CSOSR	0.000168	0.000433	0.000824

8.5. Effect of the System Operating Conditions

As illustrated for the HL I studies, the effect of the system load, generating unit lead time, acceptable risk level, etc. on the number of required generating units can be examined in the HL II analysis. This is illustrated in this section.

8.5.1. Unit Commitment at Selected Load Levels

Tables 8.10 and 8.11 present the study results for the MRBTS and the IEEE-RTS considering variations in system load. Tables 8.10 and 8.11 can be compared with Tables 8.2 and 8.3 respectively. It can be seen from Tables 8.2 and 8.10 that the number of required generating units is not equal at the 185 MW load level. The calculated risk at each load level as shown in Table 8.10 is much larger than the corresponding value shown in Table 8.2 for those cases when the number of required generating units is equal. It can be also seen that at low system load levels, the differences between the values given in Tables 8.2 and 8.10 is not very large, which indicates that the MRBTS transmission network has a high reliability at these low load levels. It can be seen from Tables 8.3 and 8.11 that the number of required units in the IEEE-RTS is unchanged for each individual load level while the calculated risk at each load level is quite different. Every risk value in Table 8.11 is much larger than the corresponding value shown in Table 8.3.

Table 8.10: Number of required generating units at different system load levels -- MRBTS.

Load level	Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
40%	74.0	0.001	3.0	4	0.000009
50%	92.5	0.001	3.0	5	0.000010
60%	111.0	0.001	3.0	5	0.000018
70%	129.5	0.001	3.0	6	0.000027
80%	148.0	0.001	3.0	7	0.000038
90%	166.5	0.001	3.0	8	0.000091
100%	185.0	0.001	3.0	11	0.000174

Table 8.11: Number of required generating units at different system load levels -- IEEE-RTS.

Load level	Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
40%	1140.0	0.001	3.0	8	0.000203
50%	1425.0	0.001	3.0	10	0.000155
60%	1710.0	0.001	3.0	12	0.000280
70%	1995.0	0.001	3.0	13	0.000292
80%	2280.0	0.001	3.0	16	0.000399
90%	2565.0	0.001	3.0	19	0.000490
100%	2850.0	0.001	3.0	28	0.000657

8.5.2. Unit Commitment at Selected Lead Times

The study results obtained by varying the generating unit lead times in the MRBTS and the IEEE-RTS are presented in Tables 8.12 and 8.13 respectively. Tables 8.12 and 8.13 can be compared with Tables 8.4 and 8.5 in which the studies were conducted at HL I. The number of required generating units shown in Table 8.12 or Table 8.13 is equal to that shown in Table 8.4 or Table 8.5 for every corresponding case. The risk values calculated in the HL II studies are, however, larger than those obtained in the HL I studies. These results are valid only for the particular system conditions studied and this conclusion may be different when some conditions are changed.

Table 8.12: Number of required generating units for varied lead times -- MRBTS.

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
111.0	0.001	1.0	5	0.000003
111.0	0.001	3.0	5	0.000018
111.0	0.001	5.0	5	0.000048
111.0	0.001	7.0	5	0.000093
111.0	0.001	9.0	5	0.000153
111.0	0.001	11.0	5	0.000227
111.0	0.001	13.0	5	0.000316
111.0	0.001	15.0	5	0.000419

Table 8.13: Number of required generating units for varied lead times -- IEEE-RTS.

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
1995.0	0.001	1.0	13	0.000092
1995.0	0.001	3.0	13	0.000292
1995.0	0.001	5.0	13	0.000669
1995.0	0.001	7.0	14	0.000540
1995.0	0.001	9.0	14	0.000833
1995.0	0.001	11.0	15	0.000536
1995.0	0.001	13.0	15	0.000724
1995.0	0.001	15.0	15	0.000949

8.5.3. Unit Commitment at Selected Risk Levels

A sensitivity study of the required number of generating units was conducted by varying the acceptable risk criterion. The results for the MRBTS and the IEEE-RTS are presented in Tables 8.14 and 8.15 which can be compared with Tables 8.6 and 8.7 respectively. It can be seen from these four tables that there is a small impact on the number of required units in the two hierarchical level studies for the two test systems. The actual calculated risk is, however, different. The actual impact will depend on the presumed conditions.

Table 8.14: Number of required units at selected risk levels -- MRBTS.

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
148.0	0.001	5.0	7	0.000098
148.0	0.003	5.0	7	0.000098
148.0	0.005	5.0	7	0.000098
148.0	0.007	5.0	7	0.000098
148.0	0.008	5.0	7	0.000098
148.0	0.009	5.0	6	0.008550
148.0	0.011	5.0	6	0.008550
148.0	0.012	5.0	5	0.011254
148.0	0.013	5.0	5	0.011254
148.0	0.015	5.0	5	0.011254

8.6. Effect of Common Mode Outages

In the HL II unit commitment risk assessments presented in the previous sections, only independent outages associated with transmission facilities and the generating units are considered. Transmission facilities can, however, experience common mode failures as discussed in Chapter 4. The modeling technique illustrated in Chapter 4 can also be applied to the HL II unit commitment problem.

Table 8.15: Number of required generating units at selected risk levels -- IEEE-RTS.

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
2280.0	0.001	5.0	16	0.000859
2280.0	0.003	5.0	16	0.000859
2280.0	0.005	5.0	16	0.000859
2280.0	0.007	5.0	16	0.000859
2280.0	0.009	5.0	16	0.000859
2280.0	0.010	5.0	15	0.009583
2280.0	0.011	5.0	15	0.009583
2280.0	0.013	5.0	15	0.009583
2280.0	0.014	5.0	15	0.009583
2280.0	0.015	5.0	14	0.014199

8.6.1. Risk Assessment in the MRBTS

Table 8.16 shows the risks for the MRBTS with lead times of 1 hour, 3 hours and 5 hours. All the generating units in the system are committed and the load level is 185 MW. It can be seen from Table 8.16 that the risk values (CSOSR) are 0.001309, 0.001348 and 0.001417 for the three different cases. It can also be seen that these values are much larger than those calculated at HL I and at HL II in the previous sections. The risk in the MRBTS under these conditions is dominated by the common mode outages of transmission facilities.

Table 8.16: Operating state probabilities -- MRBTS (independent and common mode outages included).

State	Probability at lead time of		
	1 hour	3 hours	5 hours
Normal	0.974142	0.967575	0.961045
Alert	0.024549	0.031077	0.037538
Emergency	0.000973	0.000969	0.000964
Ex.Emerg.	0.000335	0.000379	0.000452
CSOSR	0.001309	0.001348	0.001417

8.6.2. Risk Assessment in the IEEE-RTS

The operating state probabilities for the IEEE-RTS are presented in Table 8.17. In this table, all the generating units in the system are committed, the load level is 2850 MW and common mode transmission outages are included. The system risk values at the three lead times are presented in Table 8.17. The risks are 0.001383, 0.001667, and 0.002088 when the lead times are 1 hour, 3 hours and 5 hours respectively. The calculated risk values are again considerably larger than those presented in Table 8.9 in which the risk assessment only considered independent outages.

Table 8.17: Operating state probabilities -- IEEE-RTS (independent and common mode outages included).

State	Probability at lead time		
	1 hour	3 hours	5 hours
Normal	0.000000	0.000000	0.000000
Alert	0.998617	0.998333	0.997912
Emergency	0.000423	0.000537	0.000643
Ex.Emerg.	0.000928	0.001054	0.001305
CSOSR	0.001383	0.001667	0.002088

8.7. Effect of the Station Element Outages

It is noted in Chapter 4 that the risk contributions due to station originated outages can be quite large and should not be neglected in security constrained adequacy evaluation of a composite system. The relative risk contribution associated with station element outages is usually quite significant at low system load levels as the base risk is small at these low load levels and the risk contributed by the station elements is not a direct function of system load. In HL II operating reserve assessment, the risk due to only independent outages is usually relatively small. The contribution due to recognized dependent outages is usually very large and must be included. This is illustrated in this section.

8.7.1. Risk Indices for the MRBTS

Table 8.18 presents the operating state probabilities and the system risk for the MRBTS. These values can be compared with those obtained in the previous sections. They are much larger than those shown in Table 8.1 or 8.8 but are comparable with those shown in Table 8.16. This indicates that in the studied range of lead times, the risk contribution for the MRBTS due to the station element outages is comparable to that due to common mode failures.

Table 8.18: Operating state probabilities -- MRBTS (independent and station element outages included).

State	Probability at lead time of		
	1 hour	3 hours	5 hours
Normal	0.957907	0.951478	0.945085
Alert	0.040409	0.046799	0.053122
Emergency	0.000083	0.000083	0.000082
Ex.Emerg.	0.001546	0.001586	0.001656
CSOSR	0.001684	0.001723	0.001793

8.7.2. Risk Indices for the IEEE-RTS

Table 8.19 shows the operating state probabilities and the system risk values for the IEEE-RTS. The values shown in this table are much larger than those presented in Table 8.17. This indicates that the risk contribution due to the station initiated outages is much larger than that due to common mode failures for the IEEE-RTS. The station initiated outages dominate the system operating reserve risk.

It can be appreciated that the accepted risk criterion used in the previous section is obviously not applicable when common mode and station element outages are included in the reserve risk assessment procedure as it is not possible for the system to meet this risk requirement. The selection of an appropriate criterion must also include and recognize the factors incorporated in the calculation process. The following sections demonstrate the effect of recognized dependent outages on system operating reserve risk.

Table 8.19: Operating state probabilities -- IEEE-RTS (independent and station element outages included).

State	Probability at lead time of		
	1 hour	3 hours	5 hours
Normal	0.000000	0.000000	0.000000
Alert	0.992569	0.992382	0.992067
Emergency	0.000435	0.000535	0.000629
Ex.Emerg.	0.006427	0.006523	0.006748
CSOSR	0.007431	0.007618	0.007933

8.8. Effect of the Dependent Outages

Tables 8.20 and 8.21 present the operating state indices for the MRBTS and the IEEE-RTS respectively. In these two tables, recognized dependent outages, i.e. common mode and station originated outages are included. The other system operating conditions for each system are the same as those used in obtaining Tables 8.16 and 8.18 for the MRBTS or in Tables 8.17 and 8.19 for the IEEE-RTS. The risk values obtained in this case are larger than the corresponding values in the previous sections. A comparison of the risk contribution due to the various combinations of recognized outages is presented in the next section.

Table 8.20: Operating state probabilities -- MRBTS (independent and dependent outages included).

State	Probability at lead time of		
	1 hour	3 hours	5 hours
Normal	0.956782	0.950360	0.943975
Alert	0.040361	0.046745	0.053061
Emergency	0.000972	0.000968	0.000964
Ex.Emerg.	0.001829	0.001873	0.001946
CSOSR	0.002857	0.002895	0.002964

Table 8.21: Operating state probabilities -- IEEE-RTS (independent and dependent outages included).

State	Probability at lead time of		
	1 hour	3 hours	5 hours
Normal	0.000000	0.000000	0.000000
Alert	0.991369	0.991163	0.990818
Emergency	0.000723	0.000819	0.000910
Ex.Emerg.	0.007326	0.007422	0.007643
CSOSR	0.008631	0.008837	0.009182

8.9. Comparison of the Obtained Risk Indices

The abbreviations used in the tables presented in this section are described below.

Base case -- risk indices obtained at HL I,

Case I -- risk indices obtained at HL II with only the independent outages of major components considered,

Case II -- risk values obtained in HL II studies with the inclusion of independent and common mode failures,

Case III -- risk probabilities obtained at HL II with the inclusion of independent and station originated outages,

Case IV -- risk values obtained at HL II with the inclusion of independent and dependent outages.

8.9.1. Basic CSOSR Indices

The basic risk indices for the MRBTS and the IEEE-RTS were calculated using the different outage groupings noted above and are given in Tables 8.22 and 8.23.

Table 8.22: Operating reserve risk indices -- MRBTS.

Case	Risk indices at lead time of		
	1 hour	3 hours	5 hours
Base	0.0000038	0.0000340	0.0000942
I	0.0001350	0.0001740	0.0002440
II	0.0013090	0.0013480	0.0014170
III	0.0016840	0.0017230	0.0017930
IV	0.0028570	0.0028950	0.0029640

Table 8.23: Operating reserve risk indices -- IEEE-RTS.

Case	Risk indices at lead time of		
	1 hour	3 hours	5 hours
Base	0.0000158	0.0001427	0.0003983
I	0.0001680	0.0004330	0.0008240
II	0.0013830	0.0016670	0.0020880
III	0.0074310	0.0076180	0.0079330
IV	0.0086310	0.0088370	0.0091820

8.9.2. CSOSR Increase

The actual differences between the risk in each case and the base value are given in Tables 8.24 and 8.25 for the two test systems at selected lead times. These differences were calculated using Equation 4.25. The risk contributions due to the various outage event groupings can be appreciated from Tables 8.24 and 8.25.

Table 8.24: Risk increase -- MRBTS.

Case	Actual risk increase at lead time of		
	1 hour	3 hours	5 hours
I	0.0001312	0.0001400	0.0001498
II	0.0013052	0.0013140	0.0013228
III	0.0016802	0.0016890	0.0016988
IV	0.0028532	0.0028610	0.0028698

Table 8.25: Risk increase -- IEEE-RTS.

Case	Actual risk increase at lead time of		
	1 hour	3 hours	5 hours
I	0.0001522	0.0002903	0.0004257
II	0.0013672	0.0015243	0.0016897
III	0.0074152	0.0074753	0.0075347
IV	0.0086152	0.0086943	0.0087837

8.9.3. Relative CSOSR Increase

Tables 8.26 and 8.27 present the relative risk contributions due to the various outage event groupings. These two tables were calculated from Tables 8.22 and 8.23 using Equation 4.26.

Table 8.26: Relative risk increase -- MRBTS.

Case	Relative risk increase at lead time of		
	1 hour	3 hours	5 hours
I	34.526316	4.117647	1.590234
II	343.473684	38.647059	14.042463
III	442.157895	49.676471	18.033970
IV	750.842105	84.147059	30.464968

It can be seen from Table 8.26 that the risk increases for the four cases are approximately 34, 343, 442 and 750 times larger than the base value from an HL I study when the lead time is 1 hour. The relative differences decrease as the lead time increases but are still very significant. It can be concluded that the operating reserve risk calculated at HL I is a much more optimistic value than that obtained at HL II. One reason that the risk increase at the selected cases decreases as the lead time increases is that the risk contributions due to the outages of transmission facilities are not a function of lead time as their availabilities are used in this calculation process. As the lead time increases, the risk contributed by the generating units increases and therefore the relative contribution of the transmission facilities decreases.

Table 8.27: Relative risk increase -- IEEE-RTS.

Case	Relative risk increase at lead time of		
	1 hour	3 hours	5 hours
I	9.632911	2.034338	1.068792
II	86.531646	10.681850	4.242280
III	469.316456	52.384723	18.917148
IV	545.265823	60.927120	22.052975

It can be seen from Table 8.27 that the risk increases for the four selected cases are approximately 9, 86, 469 and 545 times larger than the base value from an HL I study when the lead time is 1 hour. The basic conclusions for the IEEE-RTS are the same as those for the MRBTS.

8.9.4. Risk Comparison

Risk comparison can be performed from another aspect. The risk values at a lead time of 1 hour were considered to be the base values and the risks obtained at longer lead times compared with the corresponding base values and expressed in percent. The relative values for the selected cases are presented in Tables 8.28 and 8.29 for the MRBTS and the IEEE-RTS respectively.

Table 8.28: Relative risk increase -- MRBTS.

Case	Relative risk (%) at lead time of		
	1 hour	3 hours	5 hours
Base	100.0000	894.7368	2478.9474
I	100.0000	128.8889	180.7407
II	100.0000	102.9794	108.2506
III	100.0000	102.3159	106.4727
IV	100.0000	101.3301	103.7452

It can be seen from Table 8.28 that in the MRBTS, the operating reserve risk for the base case increases drastically as the lead time increases as the system risk is a direct function of the generating unit lead times. In Case I, the risk does not increase as quickly as in the base case which indicates that the risk is not only influenced by the generating units, but also by the transmission facilities. The risk increases very slowly in the remaining cases with the lead time, as the common mode and station originated outages dominate the risk.

Table 8.29: Relative risk increase -- IEEE-RTS.

Case	Relative risk (%) at lead time of		
	1 hour	3 hours	5 hours
Base	100.0000	903.1646	2520.8861
I	100.0000	257.7381	490.4762
II	100.0000	120.5351	150.9761
III	100.0000	102.5165	106.7555
IV	100.0000	102.3867	106.3840

It can be seen from Table 8.29 that the general conclusions for the IEEE-RTS are the same as those drawn for the MRBTS.

8.10. Summary

The procedure for operating reserve risk assessment at HL I is relatively straightforward and has existed for some time [6, 7, 70]. Risk evaluation at HL I does not include transmission system considerations and therefore does not recognize system limitations incurred by outages in these facilities. An operating reserve risk assessment procedure is presented in this chapter which includes transmission elements. The developed risk evaluation procedure can be used to conduct operating reserve assessments in operational planning. This procedure is utilized in this chapter to illustrate the effects on the system operating reserve risk of common mode and station originated outages. The study results show that a bulk power system risk assessment procedure should include all the major elements such as generating units, transmission lines and station facilities in an overall assessment at HL II. The procedure illustrated in this chapter is more complete than a conventional HL I assessment and it is believed that this approach can provide power system planners and operators with a very useful tool to plan, design, and operate power systems.

9. OPERATING UNIT COMMITMENT IN COMPOSITE SYSTEMS

9.1. Introduction

Generating unit operating reserve assessment at HL I and HL II is introduced in the previous chapter. In the studies described, dependent outages such as common mode and station initiated failures were recognized and included in the analysis. In these studies, generating units are modeled using their outage replacement rates (ORR) [70, 131] and the transmission facilities are represented by their steady state availabilities. This representation is suitable for operational planning in which decisions are made considerably in advance. In the hourly commitment of generating units, it is also necessary to represent the transmission facilities with time dependent probabilities. Chapter 8 illustrates that composite system operating reserve risk is significantly affected by dependent outages, particularly station originated failures. These effects are considered in this chapter with respect to hourly unit commitment.

Recognition of system component state probabilities as a function of lead time is a significant extension of the risk analysis described in the previous chapter and can be used to evaluate composite system operating reserve risk in the intermediate future, e.g. for daily operation. In the composite system operating reserve risk assessment procedure illustrated in this chapter, time dependent representations are used for both generation and transmission facilities. The calculated risk depends on many factors such as the lead time, the total amount of committed generating capacity, the size of the various committed generating units, reliability parameters of all of the components considered, the system load, generating unit outputs in terms of active power and voltage, the system topology, etc. A matrix multiplication method [101] is used in this chapter to obtain the time dependent state probabilities associated with common mode and station initiated outages of system elements and the risk evaluation procedure is illustrated by application to the MRBTS.

In the basic approach to operating capacity reserve assessment illustrated in the last chapter, each generating unit is represented by a two state model as shown in Figure 3.1 which has an operating state and an outage state. In this model, λ and μ are the unit failure and repair rates respectively. It is also possible to include derated states in the model if desired or necessary [70]. The repair process is normally neglected in creating the capacity outage probability table as the lead time is usually much shorter than the generating unit repair times. The Outage Replacement Rates (ORR) [70, 131] of the individual generating units are used instead of their time dependent state probabilities. Repair processes should be considered when the lead time is relatively long or when the repair times are relatively short. In these situations, the time dependent generating unit availabilities and unavailabilities are used to create the capacity outage probability table. The availability and unavailability of a generating unit at any time t are given by Equations 8.1 and 8.2 respectively. The model of Figure 3.1 and Equations 8.1 and 8.2 are also used to represent transmission facilities when independent events are considered. The recognition of both independent and dependent outages are illustrated in this chapter by application to the MRBTS.

9.2. Unit Commitment in a Composite System

As noted earlier, composite system operating reserve risk depends on many factors. The effect on unit commitment of the system load, the lead time and the acceptable risk level is described in this chapter. In this section, only independent outages of the generating units and transmission lines are considered. The effect of dependent outages on system operating reserve risk is illustrated in subsequent sections.

9.2.1. Unit Commitment at Selected Load Levels

The required number of committed generating units at selected load levels is presented in Table 9.1. The acceptable risk level is assumed to be 0.001 which is the same as that used in the last chapter. A unit commitment is considered to be acceptable when the calculated operating risk is less than or equal to this value. The lead time for all committed generating units is assumed to be 5 hours. The actual risk at each load level is also shown in Table 9.1. These risk values are larger than would be obtained in a conventional operating capacity reserve study including only generation facilities as described in the last chapter.

Table 9.1: Unit commitment at selected load levels (only independent outages considered).

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
74.0	0.001	5.0	4	0.000018
92.5	0.001	5.0	5	0.000021
111.0	0.001	5.0	5	0.000042
129.5	0.001	5.0	6	0.000064
148.0	0.001	5.0	7	0.000084
166.5	0.001	5.0	8	0.000106
185.0	0.001	5.0	9	0.000131

9.2.2. Unit Commitment at Selected Lead Times

The required number of committed generating units for selected lead times is shown in Table 9.2. The load considered in this table is 166.5 MW or 90% of the system peak value. The acceptable risk level is 0.001. In this case, the required number of generating units remains constant for the studied lead times, which may not be the case when the acceptable risk level is changed or when a different load level is considered.

Table 9.2: Unit commitment at selected lead times (only independent outages considered).

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
166.5	0.001	1.0	8	0.000005
166.5	0.001	5.0	8	0.000106
166.5	0.001	9.0	8	0.000307

9.2.3. Unit Commitment at Selected Risk Levels

Sensitivity studies of the required number of committed generating units were performed by varying the acceptable system risk level. This is shown in Table 9.3. The system load considered is 166.5 MW and the generating unit lead time is considered to be 5 hours. As expected, the required number of generating units decreases as the acceptable risk criterion increases.

Table 9.3: Unit commitment at selected risk levels (only independent outages considered).

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
166.5	0.001	5.0	8	0.000106
166.5	0.008	5.0	8	0.000106
166.5	0.009	5.0	7	0.008130
166.5	0.013	5.0	7	0.008130
166.5	0.014	5.0	6	0.013363
166.5	0.015	5.0	6	0.013363

9.3. Sensitivity of Unit Commitment to Major Component Failure Rates

An important factor in composite system operating reserve risk is the time dependent availability of all the associated system components. This availability depends on the system lead time and the failure and repair rates of the associated facilities. The effect on the system operating risk of variability in component independent failure rates was examined and is presented in this section. This type of analysis can be used to demonstrate the importance of accurate data collection.

9.3.1. Generating Unit Failure Rates

Table 9.4 presents unit commitment results with variation in the generating unit failure rates. The base failure rate values are given in Appendix A. Tables 9.4 and 9.5 show the variations from the base values. Independent outages of generating and transmission facilities are considered in Table 9.4 and dependent outages are not included. It can be seen from Table 9.4 that the number of required generating units is constant but the calculated risk values change considerably. Table 9.4 shows that the reliability of the generating facilities has a significant impact on the system risk.

Table 9.4: Generating unit commitment with variation in the generating unit failure rates (only independent outages considered).

Load (MW)	Acceptable risk	Lead time	Variation (%)	Units required	Actual risk
185	0.001	5.0	-30	9	0.000076
185	0.001	5.0	-20	9	0.000093
185	0.001	5.0	-10	9	0.000111
185	0.001	5.0	0	9	0.000131
185	0.001	5.0	10	9	0.000153
185	0.001	5.0	20	9	0.000178
185	0.001	5.0	30	9	0.000204

9.3.2. Transmission Line Failure Rates

Table 9.5 presents unit commitment results with variation in the transmission line independent failure rates. It can be seen from Table 9.5 that the effect on the system risk of the transmission line failure rate variation is observable but not as significant as the generating unit effect.

Table 9.5: Generating unit commitment with variation in the transmission line failure rates (only independent outages considered).

Load (MW)	Acceptable risk	Lead time	Variation (%)	Units required	Actual risk
185	0.001	5.0	-30	9	0.000118
185	0.001	5.0	-20	9	0.000122
185	0.001	5.0	-10	9	0.000127
185	0.001	5.0	0	9	0.000131
185	0.001	5.0	10	9	0.000136
185	0.001	5.0	20	9	0.000142
185	0.001	5.0	30	9	0.000147

9.4. Inclusion of Common Mode Outages

Unit commitments incorporating independent outages of generation and transmission facilities are illustrated in the previous sections. Transmission line and generating unit performance can also be affected by dependent outages. As noted previously, the dependent events recognized in this research work include common mode outages of transmission facilities and station initiated outages which can cause the removal of both generating units and transmission lines and can also result in complete isolation of load points from the bulk power supply.

The model for two transmission lines with the inclusion of common mode outages is shown in Figure 4.1. The two transmission components can be in the outage state due to the overlapping of their independent outages or due to a common cause failure event. The steady state probabilities were evaluated using the frequency and duration method and have been utilized in the previous chapters. The time dependent state probabilities were calculated and have been included in the composite system unit commitment analysis illustrated in this section.

9.4.1. A Matrix Multiplication Method

There are several methods which can be used to evaluate the time dependent state probabilities of Figure 4.1. The most obvious is to simply solve the required differential equations. This can be illustrated using the following procedure. The continuous Markov model of Figure 4.1 can be described by a group of differential equations, which are presented in matrix form in Equation 9.1,

$$P'(t) = P(t) \cdot A, \tag{9.1}$$

where *P(t)* with dimension of 1×5 indicates the state probabilities at time t. Coefficient matrix A with dimension 5×5 represents the transition rates between states. Transition matrix A is given in Equation 9.2,

$$A = \begin{bmatrix} -(\lambda_1+\lambda_2+\lambda_c) & \lambda_1 & \lambda_2 & 0 & \lambda_c \\ \mu_1 & -(\lambda_2+\mu_1) & 0 & \lambda_2 & 0 \\ \mu_2 & 0 & -(\lambda_1+\mu_2) & \lambda_1 & 0 \\ 0 & \mu_2 & \mu_1 & -(\mu_1+\mu_2) & 0 \\ \mu_c & 0 & 0 & 0 & -\mu_c \end{bmatrix}. \tag{9.2}$$

It can be appreciated that it is not practical in a general sense to solve the equations in Equation 9.1 using the differential equation method, particularly when the model becomes somewhat more complicated than that of Figure 4.1. This continuous Markov model can, however, be solved using other methods. The continuous model can be represented as a discrete process moving in small steps. In this case, the transition matrix A associated with the continuous Markovian process is converted to a transitional probability matrix. This transitional probability matrix is given in Equation 9.3,

$$A = \begin{bmatrix} 1-(\lambda_1+\lambda_2+\lambda_c)\Delta t & \lambda_1\Delta t & \lambda_2\Delta t & 0 & \lambda_c\Delta t \\ \mu_1\Delta t & 1-(\lambda_2+\mu_1)\Delta t & 0 & \lambda_2\Delta t & 0 \\ \mu_2\Delta t & 0 & 1-(\lambda_1+\mu_2)\Delta t & \lambda_1\Delta t & 0 \\ 0 & \mu_2\Delta t & \mu_1\Delta t & 1-(\mu_1+\mu_2)\Delta t & 0 \\ \mu_c\Delta t & 0 & 0 & 0 & 1-\mu_c\Delta t \end{bmatrix}. \tag{9.3}$$

The state probabilities at time Δt can be therefore calculated using this transitional probability matrix A. These probabilities are given in Equation 9.4,

$$P(\Delta t) = P(0)\cdot A, \tag{9.4}$$

where *P(0)* is a row vector and contains the initial state probabilities.

The state probabilities at any time T can be calculated using the similar procedure. The time duration from $t = 0$ to $t = T$ is divided into many small time intervals such that the probability of two or more transitions occurring in this time interval is negligible. The state probabilities at time T are given in Equation 9.5,

$$P(T) = P(0)\cdot A^N, \tag{9.5}$$

where N is an integer which is equal to the time duration T divided by the time interval Δt.

It can be seen that the matrix multiplication method can be easily used to calculate the required time dependent state probabilities [101]. This method was utilized in the operating reserve risk assessment studies described in this chapter. This is a very powerful method for obtaining time dependent probabilities of complex systems.

9.4.2. Effect of Common Mode Outages

The calculated state probabilities at lead time T associated with common mode outages can be incorporated with the independent probabilities obtained using Equations 8.1 and 8.2 in order to conduct composite system operating reserve risk assessment. Unit commitment with the inclusion of the transmission facility common mode outages is presented in Tables 9.6, 9.7 and 9.8 for different system operating conditions. The common mode outage data are given in Appendix A. These three tables can be compared with Tables 9.1, 9.2 and 9.3. It can be seen from Tables 9.1 and 9.6 that the required number of generating units is unchanged at all the selected load levels. It can also be seen from these two tables that the effect on the unit commitment of common mode outages is not significant as the transmission system is basically quite reliable and the common mode failure rates are relatively small compared with the independent event values. In addition, only a few lines are exposed to common mode events in this system. The unit commitments shown in Tables 9.2 and 9.7, and Tables 9.3 and 9.8, are also unchanged although the risk clearly increases when common mode events are recognized.

Table 9.6: Unit commitment at selected load levels (independent and common mode outages included).

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
74.0	0.001	5.0	4	0.000019
92.5	0.001	5.0	5	0.000022
111.0	0.001	5.0	5	0.000044
129.5	0.001	5.0	6	0.000066
148.0	0.001	5.0	7	0.000085
166.5	0.001	5.0	8	0.000180
185.0	0.001	5.0	9	0.000449

Table 9.7: Unit commitment at various lead times (independent and common mode outage included).

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
166.5	0.001	1.0	8	0.000021
166.5	0.001	5.0	8	0.000180
166.5	0.001	9.0	8	0.000426

Table 9.8: Unit commitment at different risk levels (independent and common mode outages included).

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
166.5	0.001	5.0	8	0.000180
166.5	0.008	5.0	8	0.000180
166.5	0.009	5.0	7	0.008203
166.5	0.013	5.0	7	0.008203
166.5	0.014	5.0	6	0.013436
166.5	0.015	5.0	6	0.013436

9.5. Effect of Station Originated Outages

Station element models are presented in Chapter 2. The element models used in this chapter are somewhat simpler than those presented in Chapter 2 as the maintenance of station elements was neglected in the operating reserve risk evaluation. The station element time dependent state probabilities can be calculated using the matrix multiplication approach illustrated earlier. The study results presented in this chapter are based on the MRBTS single line diagram shown in Figure 4.5 and the reliability data given in Appendix A.

Tables 9.9, 9.10 and 9.11 present the unit commitment with the inclusion of station element outages for the selected system operating conditions. Tables 9.9, 9.10 and 9.11 can be compared with Tables 9.1, 9.2 and 9.3, as well as Tables 9.6, 9.7 and 9.8 in order to appreciate and understand the risk contribution due to the station originated outages. It can be seen from Tables 9.1 and 9.9 that the required number of committed generating units is unchanged at the selected load levels. The risk values shown in Table 9.9 are however much higher than those presented in Table 9.1. This conclusion may be changed when the acceptable risk level or some system operating conditions are changed.

Table 9.9: Unit commitment at selected load levels (independent and station element outages included).

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
74.0	0.001	5.0	4	0.000749
92.5	0.001	5.0	5	0.000753
111.0	0.001	5.0	5	0.000774
129.5	0.001	5.0	6	0.000795
148.0	0.001	5.0	7	0.000825
166.5	0.001	5.0	8	0.000847
185.0	0.001	5.0	9	0.000872

Table 9.10: Unit commitment at different lead times (independent and station element outages included).

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
166.5	0.001	1.0	8	0.000189
166.5	0.001	5.0	8	0.000847
166.5	0.001	6.0	9	0.000914
166.5	0.001	7.0	11	0.001057

Table 9.11: Unit commitment at various risk levels (independent and station element outages included).

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
166.5	0.001	5.0	8	0.000847
166.5	0.009	5.0	8	0.000847
166.5	0.010	5.0	7	0.009456
166.5	0.014	5.0	7	0.009456
166.5	0.015	5.0	6	0.014809

Table 9.10 shows that the number of required generating units for a load of 166.5 MW is 9 when the lead time is 6 hours and station outages are included. The risk at this load level exceeds the operating risk criterion of 0.001 when the lead time is 7 hours although all of the 11 units in the system are committed. This indicates that the lead time should be less than 7 hours if the acceptable risk level is set at 0.001. The lead time should be less than 6 hours if the system load is higher than 166.5 MW. The impact of station element outage events on unit commitment can be seen by comparing Table 9.3 and 9.11 in which the number of required units increases at certain specified risk levels.

9.6. Sensitivity of Unit Commitment to Dependent Failure Rates

The effect of the variation in dependent failure rates on composite system unit commitment was examined and is presented in this section. In the studies illustrated in this section, only the major system component independent failures and the common mode outages are considered or only the independent outages and the station originated outages are considered. In the tables shown in this section, the element failure rates were calculated using the same method as utilized in Tables 9.4 and 9.5.

9.6.1. Common Mode Failure Rates

Table 9.12 presents unit commitment with variation in transmission line common mode failure rates. It can be seen from Table 9.12 that the system operating reserve risk changes considerably when the common mode failure rates are changed from 70% to 130% of their original values. This indicates that these data are important in the study cases. It can be concluded by comparing Tables 9.6 and 9.12 that the operating reserve risk contribution due to the variation in common mode failure rates is not as serious at the low system load levels.

Table 9.12: Generating unit commitment with variation in the common mode failure rates (independent outages and common mode outages considered).

Load (MW)	Acceptable risk	Lead time	Variation (%)	Units required	Actual risk
185	0.001	5.0	-30	9	0.000353
185	0.001	5.0	-20	9	0.000385
185	0.001	5.0	-10	9	0.000417
185	0.001	5.0	0	9	0.000449
185	0.001	5.0	10	9	0.000480
185	0.001	5.0	20	9	0.000512
185	0.001	5.0	30	9	0.000544

9.6.2. Station Element Failure Rates

9.6.2.1. Circuit Breaker

Unit commitment considering circuit breaker failure rate variations is presented in Table 9.13. It can be calculated from this table that the risk increases or decreases only about 4% when the circuit breaker failure rates increase or decrease by 30%. This risk variation is not significant.

Table 9.13: Generating unit commitment with circuit breaker failure rate variations (independent outages and station originated outages considered).

Load (MW)	Acceptable risk	Lead time	Variation (%)	Units required	Actual risk
185	0.001	5.0	-30	9	0.000838
185	0.001	5.0	-20	9	0.000850
185	0.001	5.0	-10	9	0.000861
185	0.001	5.0	0	9	0.000872
185	0.001	5.0	10	9	0.000884
185	0.001	5.0	20	9	0.000895
185	0.001	5.0	30	9	0.000906

9.6.2.2. Bus Section

Unit commitment considering the variation in bus section failure rates is presented in Table 9.14. It can be seen from this table that the system risk exceeds 0.001 at the 185 MW load level when the bus section failure rates increase by 30 percent. The bus sections therefore can have a significant impact on the system operating performance.

Table 9.14: Generating unit commitment with bus section failure rate variations (independent outages and station originated outages considered).

Load (MW)	Acceptable risk	Lead time	Variation (%)	Units required	Actual risk
185	0.001	5.0	-30	9	0.000684
185	0.001	5.0	-20	9	0.000747
185	0.001	5.0	-10	9	0.000810
185	0.001	5.0	0	9	0.000872
185	0.001	5.0	10	9	0.000935
185	0.001	5.0	20	9	0.000998
185	0.001	5.0	30	11	0.001033

9.7. Overall Effect of Dependent Outages

The effects on unit commitment of both common mode and station element outages have been illustrated by considering these phenomena separately. These events are generally categorized as dependent outages and both should be recognized and included in the operating reserve risk analysis and unit commitment. Unit commitment including both independent and dependent outages is presented in Tables 9.15, 9.16 and 9.17.

Table 9.15: Unit commitment at selected load levels (independent and dependent outages included).

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
74.0	0.001	5.0	4	0.000750
92.5	0.001	5.0	5	0.000754
111.0	0.001	5.0	5	0.000775
129.5	0.001	5.0	6	0.000797
148.0	0.001	5.0	7	0.000827
166.5	0.001	5.0	8	0.000921
185.0	0.001	5.0	11	0.001162

Table 9.16: Unit commitment at selected lead times (independent and dependent outages included).

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
166.5	0.001	1.0	8	0.000206
166.5	0.001	5.0	8	0.000921
166.5	0.001	6.0	11	0.001280

Table 9.17: Unit commitment at selected risk levels (independent and dependent outages included).

Load (MW)	Desired risk	Lead time (hours)	No. of units required	Actual risk
166.5	0.001	5.0	8	0.000921
166.5	0.009	5.0	8	0.000921
166.5	0.010	5.0	7	0.009529
166.5	0.014	5.0	7	0.009529
166.5	0.015	5.0	6	0.014882

It can be seen from Table 9.15 that the system can meet the acceptable risk level of 0.001 for a load of 166.5 MW at a lead time of 5 hours. The calculated system risk at a lead time of 5 hours is larger than 0.001 at a load of 185 MW although all the eleven units are committed. The lead time associated with the system or the acceptable risk criterion must therefore be changed if the system is not modified. Table 9.16 indicates that the system can meet the required risk level at the system load of 166.5 MW when the lead time is less than or equal to 5 hours. Table 9.17 shows the unit commitment at selected risk levels. This table can be compared with Tables 9.3, 9.8 and 9.11. The impact of dependent outages on operating reserve risk and therefore on unit commitment is dependent on a wide range of system factors. These impacts can only be determined by performing a detailed analysis for the system in question.

9.8. Summary

A composite system operating reserve risk assessment procedure is described in this chapter. This procedure was utilized to conduct composite system unit commitment analysis. This is a significant extension of the analysis usually performed in generating capacity reserve assessment as it includes both generation and transmission facilities. This procedure is also a significant extension of the studies illustrated in the last chapter. In addition to the incorporation of independent transmission element outages, this chapter illustrates the inclusion of dependent events associated with common mode and station originated outages. The study results show that dependent outages can contribute significantly to system operating reserve risk. The effect of these dependent outages on the unit commitment was studied and is illustrated in this chapter. The studies are extended to analyze the effect of variation in system component reliability data on composite system operating reserve risk and unit commitment. It is believed that the risk assessment procedure illustrated in this chapter overcomes some of the disadvantages associated with considering only the generating facilities in operating reserve risk assessment. The basic procedure presented provides system planners and operators with a useful tool to conduct operating reserve risk analysis and unit commitment in daily system operation.

10. SUMMARY AND CONCLUSIONS

The basic objective of the research work described in this thesis was to examine the effect of common mode and station originated outages on the reliability of composite generation and transmission systems. The approach presented incorporates generating units and transmission facilities and their protection and control elements such as circuit breakers, bus sections and transformers. The studies described in this thesis investigate the area of security constrained reliability evaluation using the system operating state framework. The original work associated with this area is described in References 72 and 89. The significant extensions to this technique which have been developed in this research work are presented in Chapters 4 to 9. The extended techniques were utilized to conduct composite system risk assessment, composite system wellbeing analysis and composite system unit commitment. These studies are illustrated by application to both the Modified Roy Billinton Test System (MRBTS) and the IEEE Reliability Test System (IEEE-RTS).

The previously published literature on power system reliability evaluation methods was reviewed and identified in Chapter 1. These publications show that the techniques associated with power system reliability assessment can be classified in terms of being either deterministic or a probabilistic. Probabilistic reliability assessment of composite power systems originated about 30 years ago. This assessment can be conducted in the two major domains of system adequacy and system security. The development of system adequacy evaluation has been well documented [8 - 40]. The demerits of the available techniques are identified in Reference 71 where a framework is presented. An approach to quantify this framework is presented and implemented in References 72 and 89. Chapter 1 also clearly describes the objectives of the research work covered in this thesis.

Chapter 2 of this thesis discusses the analytical and simulation techniques used in switching facility and substation reliability evaluation and the basic concepts, indices and procedures developed for station evaluation are presented. The reliability indices obtained by both the analytical and simulation approaches can be used to conduct customer load point analysis and as input to composite system evaluation. The results presented clearly show that the developed simulation method can provide acceptable indices when compared with those obtained using the basic analytical approach. The studies also show that the simulation approach can provide important system information in addition to the average values. Probability distributions associated with the outage events and outage durations are presented in Chapter 2 where it is shown that these data can be used to conduct station reliability worth evaluation using composite customer damage functions [109].

Some important mathematical methods used in the composite system adequacy evaluation are presented and examined in Chapter 3. The modeling techniques for single component, two components and multiple components are also presented. It is important to note that only independent outages of system major components such as generating units and transmission facilities are considered in these models. Security constrained adequacy evaluation is illustrated based on the concepts presented in References 71, 72 and 82. This technique should alleviate some of the stated utility concerns [71], as this approach includes realistic consideration of system operating constraints. This approach is illustrated in Chapter 3 by application to both the MRBTS and the IEEE-RTS. Composite system operating state risk (CSOSR) indices obtained for both annualized and annual load models are compared with the loss of load expectation (LOLE) index commonly used in HL I studies. The study results presented in Chapter 3 involve only independent outages of generating units and transmission lines.

System major components can be removed from services due not only to their own independent outages but also due to common mode outages associated with transmission facilities and station initiated failures associated with generating units and transmission lines. These two types of outages are designated as dependent outages in this thesis. The effect of dependent outages on composite system operating state indices is extensively examined in Chapter 4 and a new approach associated with the incorporation of dependent outages with independent outages is developed and utilized. This procedure is also applied in the studies presented in the latter chapters. The effect on the composite system operating state indices of different combinations of recognized dependent outages and independent outages is examined. The study results clearly show that the relative risk contribution due to common mode and station originated outages can be quite significant at low system load levels. They also indicate that the inclusion of dependent outages can improve the accuracy of predicted reliability indices as the evaluation incorporates practical and realistic system conditions.

The composite system operating state risk (CSOSR) depends on many factors such as the system load, the amount of installed generation capacity, the size of the various generating units and their availabilities, reliability parameters of the transmission facilities, the acceptable voltage range at load bus, the output of generating units in terms of their voltage and active and reactive power generation, the system topology, station configurations and their element parameters, etc. Chapter 5 presents system risk sensitivity studies in which the system load and reliability parameters associated with system major components and station elements are varied. It is concluded that it is not possible to draw general conclusions associated with system risk variation for all composite systems when component parameters or system operating conditions are varied. System risk evaluation must be conducted for any given composite system in order to understand, examine and appreciate the impact on the system risk of generating unit, transmission line and station element parameter variations. The results shown, however, for the MRBTS and the IEEE-RTS provide a useful indication of the expected implications of reliability parameter variations. The ability to perform risk sensitivity studies as illustrated in this chapter can provide power system planners and designers with useful information regarding the impact on system risk of major system element unavailabilities.

One objective of this research work was to examine the effects on the composite system operating state risk (CSOSR) of additions to system facilities and modifications of system configurations. This is illustrated in Chapter 6. The system facility additions illustrated in this chapter include the addition of generating units and transmission lines in the MRBTS. These studies illustrate the impact of changes in system investment on the CSOSR and can be used to optimize the investment required to meet system load growth. Studies are presented in this chapter to illustrate the risk reduction due to increasing the capacity of a generating unit by refurbishing it or by replacing a generating unit with one of larger capacity. Increases in calculated risk due to the inclusion of dependent outages are illustrated in Chapter 6. System risk analysis associated with line removal as illustrated in this chapter can provide system managers and planners with a useful tool to schedule transmission line maintenance. Composite system risk is very dependent on the investment in station facilities and on the configurations. In addition to ring bus station configurations, one and a half breaker station configurations and single bus station arrangements are utilized in Chapter 6 to examine the impact of station configurations on composite system risk.

The studies presented in Chapter 6 are focused on composite system risk evaluation and system risk reduction due to the addition of system facilities. Utilities are concerned not only with system operating risk but also the degree of system wellbeing. The concept of system health, margin and risk are described in Chapter 7 where the contingency domains associated with these system operating states are presented. The associated contingencies and the domain indices provide a knowledge base for power system planners and operators. System wellbeing represented by the system healthy, marginal and at risk probabilities is examined in this chapter. The effect on composite system wellbeing of system load variations, system configuration modifications, addition of generating and transmission facilities and the removal of transmission lines for maintenance is also examined in this chapter. The developed technique combines both deterministic considerations and probabilistic indices to describe the system wellbeing of an electric power system.

Generating unit commitment analysis is often based on a presumed to be acceptable risk level and the predicted system load. This analysis is usually performed at HL I where only the generating capacity is considered. Chapter 8 presents an HL II generating unit commitment technique in which the unit commitment is made considering both generating and transmission facilities and their auxiliary elements. Unit commitment in this chapter is performed using a security constrained reliability evaluation procedure. Operating reserve risk assessment at HL I and HL II and for various system considerations is also performed and compared. It is noted in Chapter 8 that the operating reserve risk contribution due to dependent outages can be quite significant when the system lead time is short. In the studies conducted in this chapter, the outage replacement rate (ORR) of individual generating units is utilized together with the steady state probabilities of other considered components or elements. This formulation provides a valuable technique for operational planning.

Composite system operating reserve risk assessment in hourly operation should be performed utilizing component time dependent state probabilities rather than steady state values. Time dependent state probabilities can be obtained using either the differential equation method or a matrix multiplication technique. The solution of these probabilities using a differential equation method is tedious and difficult when the component models become complicated. In the case of the two transmission facility common mode outage model shown in Figure 4.1, a solution for a fifth order set of differential equations is required. A matrix multiplication technique can be used for this purpose with acceptable precision. This method is utilized in Chapter 9 for the time dependent state probabilities associated with common mode outage and station element models. Unit commitment and composite system operating reserve risk assessment has been performed for different system considerations and operating conditions. It is shown that the matrix multiplication technique can be used to satisfy the solution requirements of accuracy, speed and simplicity. Chapter 9 also illustrates that the developed technique can provide a useful tool for power system planners and operators in unit commitment at both HL I and HL II.

Dependent outages associated with common mode and station originated failures have been analyzed in depth in this research work and the effect of these outages on composite system operating state risk, composite system wellbeing and composite system unit commitment are presented in this thesis. The effect of system security constraints and operating conditions on composite system reliability is analyzed and described. System operating conditions involve many factors such as system load, installed generating capacity, size of generating units, load carrying capability of transmission facilities, generating unit actual output, station configurations, reliability parameters of the system and its components, overall system topology, etc. The concepts and techniques presented in this thesis provide useful tools for power system managers, planners, designers and operators by expanding their ability to perform system risk assessment, wellbeing analyses and unit commitment studies.

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A. DATA OF THE MRBTS

Base value = 100 MVA

Table A.1: Bus data.

Bus	Load (p.u.)		P_G	Q_{Max}	Q_{Min}	V_0	V_{Max}	V_{Min}
	Active	Reactive						
1	0.000	0.000	1.000	0.50	-0.40	1.05	1.05	0.97
2	0.200	0.000	1.200	0.75	-0.40	1.05	1.05	0.97
3	0.850	0.000	0.000	0.00	0.00	1.00	1.05	0.97
4	0.400	0.000	0.000	0.00	0.00	1.00	1.05	0.97
5	0.400	0.000	0.000	0.00	0.00	1.00	1.05	0.97

Table A.2: Line data.

Line No.	Buses		R	X	B/2	Tap	Current rating	Failures per year	Repair time (hrs)
	I	J							
1	1	3	0.0342	0.1800	0.0106	1.00	0.85	1.500	10.00
2	2	4	0.1140	0.6000	0.0352	1.00	0.71	5.000	10.00
3	1	2	0.0912	0.4800	0.0282	1.00	0.71	4.000	10.00
4	3	4	0.0228	0.1200	0.0071	1.00	0.71	1.000	10.00
5	3	5	0.0228	0.1200	0.0071	1.00	0.71	1.000	10.00
6	1	3	0.0342	0.1800	0.0106	1.00	0.85	1.500	10.00
7	2	4	0.1140	0.6000	0.0352	1.00	0.71	5.000	10.00
8	4	5	0.0228	0.1200	0.0071	1.00	0.71	1.000	10.00

Table A.3: Common mode data.

Lines exposed common cause		Failures per year	Repair time (hours)
1	6	0.150	16.00
2	7	0.500	16.00

Table A.4: Generator data.

Unit No.	Bus No.	Rating (MW)	Failures per year	Repair time (hrs)
1	1	40.00	6.0000	45.00
2	1	40.00	6.0000	45.00
3	1	10.00	4.0000	45.00
4	1	20.00	5.0000	45.00
5	2	5.00	2.0000	45.00
6	2	5.00	2.0000	45.00
7	2	40.00	3.0000	60.00
8	2	20.00	2.4000	55.00
9	2	20.00	2.4000	55.00
10	2	20.00	2.4000	55.00
11	2	20.00	2.4000	55.00

Table A.5: Station element reliability data.

Component	λ_a f/yr	λ_p f/yr	r hrs	r_{sw} hrs	μ_m occ/yr	r_m hrs
Breaker	0.066	0.005	72.0	1.0	0.2	108.0
Bus section	0.22		10.0			
Transformer	0.02		768.0	1.0	0.2	72.0

Table A.6: Priority loading order list of generating units.

Priority order	Generator number	Capacity (MW)	Type	Connected at bus
1	7	40	hydro	2
2	8	20	hydro	2
3	9	20	hydro	2
4	1	40	thermal	1
5	2	40	thermal	1
6	4	20	thermal	1
7	3	10	thermal	1
8	10	20	hydro	2
9	11	20	hydro	2
10	5	5	hydro	2
11	6	5	hydro	2

B. DATA OF THE IEEE-RTS

Base value = 100 MVA

Table B.1: Bus data.

Bus	Load (p.u.)		P_G	Q_{Max}	Q_{Min}	V_0	V_{Max}	V_{Min}
	Active	Reactive						
1	1.080	0.220	1.720	1.20	-0.75	1.02	1.05	0.95
2	0.970	0.200	1.720	1.20	-0.75	1.02	1.05	0.95
3	1.800	0.370	0.000	0.00	0.00	1.00	1.05	0.95
4	0.740	0.150	0.000	0.00	0.00	1.00	1.05	0.95
5	0.710	0.140	0.000	0.00	0.00	1.00	1.05	0.95
6	1.360	0.280	0.000	0.00	0.00	1.00	1.05	0.95
7	1.250	0.250	3.000	2.70	0.00	1.02	1.05	0.95
8	1.710	0.350	0.000	0.00	0.00	1.00	1.05	0.95
9	1.750	0.360	0.000	0.00	0.00	1.00	1.05	0.95
10	1.950	0.400	0.000	0.00	0.00	1.00	1.05	0.95
11	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95
12	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95
13	2.650	0.540	5.500	3.60	0.00	1.02	1.05	0.95
14	1.940	0.390	0.000	3.00	-0.75	1.02	1.05	0.95
15	3.170	0.640	2.100	1.65	-0.75	1.02	1.05	0.95
16	1.000	0.200	1.450	1.20	-0.75	1.02	1.05	0.95
17	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95
18	3.330	0.680	4.000	3.00	-0.75	1.02	1.05	0.95
19	1.810	0.370	0.000	0.00	0.00	1.00	1.05	0.95
20	1.280	0.260	0.000	0.00	0.00	1.00	1.05	0.95
21	0.000	0.000	3.500	3.00	-0.75	1.02	1.05	0.95
22	0.000	0.000	2.500	1.45	-0.90	1.02	1.05	0.95
23	0.000	0.000	6.600	4.50	-1.75	1.02	1.05	0.95
24	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95

Table B.2: Line data.

Line No.	Buses I	Buses J	R	X	B/2	Tap	Current rating	Failures per year	Repair time (hrs)
1	1	2	0.0026	0.0139	0.2306	1.00	1.93	0.240	16.00
2	1	3	0.0546	0.2112	0.0286	1.00	2.08	0.510	10.00
3	1	5	0.0218	0.0845	0.0115	1.00	2.08	0.330	10.00
4	2	4	0.0328	0.1267	0.0172	1.00	2.08	0.390	10.00
5	2	6	0.0497	0.1920	0.0260	1.00	2.08	0.480	10.00
6	3	9	0.0308	0.1190	0.0161	1.00	2.08	0.380	10.00
7	3	24	0.0023	0.0839	0.0000	1.00	5.10	0.020	768.00
8	4	9	0.0268	0.1037	0.0141	1.00	2.08	0.360	10.00
9	5	10	0.0228	0.0883	0.0120	1.00	2.08	0.340	10.00
10	6	10	0.0139	0.0605	1.2295	1.00	1.93	0.330	35.00
11	7	8	0.0159	0.0614	0.0166	1.00	2.08	0.300	10.00
12	8	9	0.0427	0.1651	0.0224	1.00	2.08	0.440	10.00
13	8	10	0.0427	0.1651	0.0224	1.00	2.00	0.440	10.00
14	9	11	0.0023	0.0839	0.0000	1.00	6.00	0.020	768.00
15	9	12	0.0023	0.0839	0.0000	1.00	6.00	0.020	768.00
16	10	11	0.0023	0.0839	0.0000	1.00	6.00	0.020	768.00
17	10	12	0.0023	0.0839	0.0000	1.00	6.00	0.020	768.00
18	11	13	0.0061	0.0476	0.0500	1.00	6.00	0.400	11.00
19	11	14	0.0054	0.0418	0.0440	1.00	6.00	0.390	11.00
20	12	13	0.0061	0.0476	0.0500	1.00	6.00	0.400	11.00
21	12	23	0.0124	0.0966	0.1015	1.00	6.00	0.520	11.00
22	13	23	0.0111	0.0865	0.0909	1.00	6.00	0.490	11.00
23	14	16	0.0050	0.0389	0.0409	1.00	6.00	0.380	11.00
24	15	16	0.0022	0.0173	0.0364	1.00	6.00	0.330	11.00
25	15	21	0.0063	0.0490	0.0515	1.00	6.00	0.410	11.00
26	15	21	0.0063	0.0490	0.0515	1.00	6.00	0.410	11.00
27	15	24	0.0067	0.0519	0.0546	1.00	6.00	0.410	11.00
28	16	17	0.0033	0.0259	0.0273	1.00	6.00	0.350	11.00
29	16	19	0.0030	0.0231	0.0243	1.00	6.00	0.340	11.00
30	17	18	0.0018	0.0114	0.0152	1.00	6.00	0.320	11.00
31	17	22	0.0135	0.1053	0.1106	1.00	6.00	0.540	11.00
32	18	21	0.0033	0.0259	0.0273	1.00	6.00	0.350	11.00
33	18	21	0.0033	0.0259	0.0273	1.00	6.00	0.350	11.00
34	19	20	0.0051	0.0396	0.0417	1.00	6.00	0.380	11.00
35	19	20	0.0051	0.0396	0.0417	1.00	6.00	0.380	11.00
36	20	23	0.0028	0.0216	0.0228	1.00	6.00	0.340	11.00
37	20	23	0.0028	0.0216	0.0228	1.00	6.00	0.340	11.00
38	21	22	0.0087	0.0678	0.0712	1.00	6.00	0.450	11.00

Table B.3: Generator data.

Unit No.	Bus No.	Rating (MW)	Failures per year	Repair time (hrs)
1	22	50.00	4.4200	20.00
2	22	50.00	4.4200	20.00
3	22	50.00	4.4200	20.00
4	22	50.00	4.4200	20.00
5	22	50.00	4.4200	20.00
6	22	50.00	4.4200	20.00
7	15	12.00	2.9800	60.00
8	15	12.00	2.9800	60.00
9	15	12.00	2.9800	60.00
10	15	12.00	2.9800	60.00
11	15	12.00	2.9800	60.00
12	15	155.00	9.1300	40.00
13	7	100.00	7.3000	50.00
14	7	100.00	7.3000	50.00
15	7	100.00	7.3000	50.00
16	13	197.00	9.2200	50.00
17	13	197.00	9.2200	50.00
18	13	197.00	9.2200	50.00
19	1	20.00	19.4700	50.00
20	1	20.00	19.4700	50.00
21	1	76.00	4.4700	40.00
22	1	76.00	4.4700	40.00
23	2	20.00	19.4700	50.00
24	2	20.00	19.4700	50.00
25	2	76.00	4.4700	40.00
26	2	76.00	4.4700	40.00
27	23	155.00	9.1300	40.00
28	23	155.00	9.1300	40.00
29	23	350.00	7.6200	100.00
30	18	400.00	7.9600	150.00
31	21	400.00	7.9600	150.00
32	16	155.00	9.1300	40.00

Table B.4: Common mode data.

Lines exposed common cause		Failures per year	Repair time (hours)
12	13	0.500	16.00
18	20	0.500	16.00
25	26	0.150	16.00
31	38	0.500	16.00
32	33	0.500	16.00
34	35	0.500	16.00
36	37	0.500	16.00

Table B.5: Station element reliability data.

Component	λ_a f/yr	λ_p f/yr	r hrs	r_{sw} hrs	μ_m occ/yr	r_m hrs
Breaker	0.066	0.005	72.0	1.0	0.2	108.0
Bus section	0.22		10.0			
Transformer	0.02		768.0	1.0	0.2	72.0

Table B.6: Priority loading order list of generating units.

Priority order	Generator number	Capacity (MW)	Type	Connected at bus
1-4	1-4	50	hydro	22
5	30	400	nuclear	18
6	31	400	nuclear	21
7	29	350	thermal	23
8-10	16-18	197	thermal	13
11	12	155	thermal	15
12-13	27-28	155	thermal	23
14	32	155	thermal	16
15-17	13-15	100	thermal	7
18-19	21-22	76	thermal	1
20-21	25-26	76	thermal	2
22-26	7-11	12	thermal	15
27-28	19-20	20	thermal	1
29-30	23-24	20	thermal	2
31-32	5-6	50	hydro	22

C. LOAD MODELS

Table C.1 presents the annual load model in terms of the weekly peak loads as a percentage of the annual peak load. If Week 1 is taken as the first week in January, the load model represents a winter peaking system. A summer peaking system can be created by taking a suitable time for Week 1.

Table C.1: Weekly peak load as a percent of annual peak.

Week	Peak load (%)	Week	Peak load (%)	Week	Peak load (%)	Week	Peak load (%)
1	86.2	14	75.0	27	75.5	40	72.4
2	90.0	15	72.1	28	81.6	41	74.3
3	87.8	16	80.0	29	80.1	42	74.4
4	83.4	17	75.4	30	88.8	43	80.0
5	88.0	18	83.7	31	72.2	44	88.1
6	84.1	19	87.0	32	77.6	45	88.5
7	83.2	20	88.0	33	80.0	46	90.9
8	80.6	21	85.6	34	72.9	47	94.0
9	74.0	22	81.1	35	72.6	48	89.0
10	73.7	23	90.0	36	70.5	49	94.2
11	71.5	24	88.7	37	78.0	50	97.0
12	72.7	25	89.6	38	69.5	51	100.0
13	70.4	26	86.1	39	72.4	52	95.2

Table C.2 presents the daily peak load cycle, as a percentage of the weekly peak. The same weekly peak load cycle is assumed to apply for all times of the year. The data in Tables C.1 and C.2 defines a daily peak load model of 364 days with Moday as the first day of the year.

Table C.2: Daily peak load as a percentage of weekly peak.

Day	Peak load (%)
Moday	93
Tuesday	100
Wednesday	98
Thursday	96
Friday	94
Saturday	77
Sunday	75

Table C.3 gives weekday and weekend hourly load data for each of three seasons. Combining the data given in Tables C.1 to C.3 defines an hourly load model of 8736 hours.

Table C.3: Hourly peak load as a percentage of daily peak load.

	Winter weeks 1-8 & 44-52		Summer weeks 18-30		Spring/Fall weeks 9-17 & 31-43	
Hour	Wkdy	Wknd	Wkdy	Wknd	Wkdy	Wknd
12-1am	67	78	64	74	63	75
1-2	63	72	60	70	62	73
2-3	60	68	58	66	60	69
3-4	59	66	56	65	58	66
4-5	59	64	56	64	59	65
5-6	60	65	58	62	65	65
6-7	74	66	64	62	72	68
7-8	86	70	76	66	85	74
8-9	95	80	87	81	95	83
9-10	96	88	95	86	99	89
10-11	96	90	99	91	100	92
11-noon	95	91	100	93	99	94
noon-1pm	95	90	99	93	93	91
1-2	95	88	100	92	92	90
2-3	93	87	100	91	90	90
3-4	94	87	97	91	88	86
4-5	99	91	96	92	90	85
5-6	100	100	96	94	92	88
6-7	100	99	93	95	96	92
7-8	96	97	92	95	98	100
8-9	91	94	92	100	96	97
9-10	83	92	93	93	90	95
10-11	73	87	87	88	80	90
11-12	63	81	72	80	70	85

Table C.4 presents 100 point daily peak data calculated from Tables C.1 and C.2. They are obtained from 364 daily peak load points. These data are used to represent the daily peak load curve for the studied systems.

Table C.4: 100 point daily peak load data.

Peak load (p.u.)	Study period (p.u.)	Peak load (p.u.)	Study period (p.u.)	Peak load (p.u.)	Study period (p.u.)	Peak load (p.u.)	Study period (p.u.)
1.0000	0.0000	0.9985	0.0002	0.9978	0.0003	0.9971	0.0004
0.9956	0.0006	0.9942	0.0008	0.9927	0.0010	0.9891	0.0015
0.9826	0.0024	0.9777	0.0034	0.9755	0.0040	0.9689	0.0058
0.9624	0.0076	0.9606	0.0081	0.9550	0.0100	0.9506	0.0137
0.9437	0.0160	0.9403	0.0189	0.9352	0.0239	0.9306	0.0290
0.9230	0.0333	0.9127	0.0401	0.9051	0.0464	0.9022	0.0517
0.8957	0.0614	0.8879	0.0718	0.8850	0.0823	0.8820	0.0906
0.8791	0.1004	0.8731	0.1122	0.8682	0.1254	0.8633	0.1353
0.8613	0.1452	0.8545	0.1574	0.8499	0.1704	0.8453	0.1823
0.8441	0.1918	0.8413	0.2005	0.8370	0.2114	0.8340	0.2232
0.8319	0.2339	0.8274	0.2436	0.8253	0.2561	0.8219	0.2670
0.8184	0.2773	0.8156	0.2909	0.8091	0.3030	0.8020	0.3163
0.8000	0.3300	0.7941	0.3448	0.7840	0.3616	0.7804	0.3769
0.7738	0.3934	0.7674	0.4094	0.7560	0.4260	0.7520	0.4420
0.7456	0.4591	0.7424	0.4771	0.7332	0.4932	0.7277	0.5089
0.7251	0.5242	0.7228	0.5390	0.7203	0.5501	0.7139	0.5625
0.7101	0.5742	0.7076	0.5869	0.7050	0.5992	0.7009	0.6134
0.6982	0.6265	0.6950	0.6415	0.6929	0.6544	0.6899	0.6706
0.6841	0.6881	0.6812	0.7043	0.6777	0.7218	0.6752	0.7410
0.6715	0.7603	0.6643	0.7810	0.6600	0.7992	0.6532	0.8158
0.6453	0.8302	0.6280	0.8473	0.6201	0.8599	0.6086	0.8758
0.6000	0.8880	0.5815	0.9029	0.5710	0.9159	0.5621	0.9293
0.5575	0.9420	0.5551	0.9549	0.5465	0.9647	0.5432	0.9721
0.5428	0.9783	0.5417	0.9827	0.5400	0.9867	0.5356	0.9905
0.5286	0.9949	0.5269	0.9977	0.5235	0.9991	0.5213	1.0000

Table C.5 presents 100 point hourly load data. They are obtained from the 8734 point hour load curve. They are used to represent the load duration cuves in this thesis.

Table C.5: 100 point hourly load data.

Peak load (p.u.)	Study period (p.u.)	Peak load (p.u.)	Study period (p.u.)	Peak load (p.u.)	Study period (p.u.)	Peak load (p.u.)	Study period (p.u.)
1.0000	0.0000	0.9933	0.0002	0.9866	0.0003	0.9800	0.0004
0.9733	0.0006	0.9666	0.0008	0.9599	0.0010	0.9532	0.0015
0.9466	0.0024	0.9399	0.0034	0.9332	0.0040	0.9265	0.0058
0.9199	0.0076	0.9132	0.0081	0.9065	0.0100	0.8998	0.0137
0.8931	0.0160	0.8865	0.0189	0.8798	0.0239	0.8731	0.0290
0.8664	0.0333	0.8597	0.0401	0.8531	0.0464	0.8464	0.0517
0.8397	0.0614	0.8330	0.0718	0.8264	0.0823	0.8197	0.0906
0.8130	0.1004	0.8063	0.1122	0.7996	0.1254	0.7960	0.1353
0.7863	0.1452	0.7796	0.1574	0.7729	0.1704	0.7662	0.1823
0.7596	0.1918	0.7529	0.2005	0.7462	0.2114	0.7395	0.2232
0.7329	0.2339	0.7262	0.2436	0.7195	0.2561	0.7128	0.2670
0.7061	0.2773	0.6995	0.2909	0.6928	0.3030	0.6861	0.3163
0.6794	0.3300	0.6727	0.3448	0.6661	0.3616	0.6594	0.3769
0.6527	0.3934	0.6460	0.4094	0.6394	0.4260	0.6327	0.4420
0.6260	0.4591	0.6193	0.4771	0.6126	0.4932	0.6060	0.5089
0.5993	0.5242	0.5926	0.5390	0.5859	0.5501	0.5792	0.5625
0.5726	0.5742	0.5659	0.5869	0.5592	0.5992	0.5525	0.6134
0.5459	0.6265	0.5392	0.6415	0.5325	0.6544	0.5259	0.6706
0.5191	0.6881	0.5125	0.7043	0.5058	0.7218	0.4991	0.7410
0.4924	0.7603	0.4857	0.7810	0.4791	0.7992	0.4724	0.8158
0.4657	0.8302	0.4590	0.8473	0.4523	0.8599	0.4457	0.8758
0.4390	0.8880	0.4323	0.9029	0.4256	0.9159	0.4190	0.9293
0.4123	0.9420	0.4056	0.9549	0.3989	0.9647	0.3922	0.9721
0.3856	0.9783	0.3789	0.9827	0.3722	0.9867	0.3655	0.9905
0.3588	0.9949	0.3522	0.9977	0.3455	0.9991	0.3388	1.0000