Reliability Assessment of HVdc Systems Using Monte Carlo Simulation Technique

by

Wentian Hou

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University of Manitoba

Winnipeg

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Abstract

With the proliferation of HVdc systems around the world, the reliability performance of HVdc system and the impact of HVdc systems on the reliability performance of overall power systems is becoming an important issue. In the past, predominantly analytical techniques were used to assess the reliability of HVdc systems. One of the major disadvantages with analytical techniques is that the models used in the reliability evaluation of the HVdc systems are highly approximate. Also, analytical methods do not produce the probability distributions associated with the reliability indices, which can provide more detailed information on the reliability performance of power systems.

This thesis presents a method for the reliability evaluation of HVdc systems using the Monte Carlo technique, with the emphasis on the use of the reliability index distributions in HVdc system adequacy assessment to provide a complete picture of the reliability of power systems that contain HVdc links. The concept of developing distributions and the related analysis of reliability index distributions are illustrated in this thesis. Appropriate techniques are also developed to incorporate deterministic considerations into probabilistic evaluations to perform well-being analysis on power systems containing HVdc link. The well-being indices would provide additional and useful adequacy indices for system planning. The distribution of the wellbeing indices was also examined, and the comparison and analysis are presented for different deterministic criteria and different scenarios.

The models, techniques and results presented in this thesis would provide valuable methods and inputs for power system planners and operators.

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Abbreviations

A	Availability
BP	Bipole
BTB	Back-to-Back System
CT	Converter Transformer
DPLVC	Daily Peak Load Variation Curve
FACTS	Flexible AC Transmission System
LCC	Line-Commutated Converter
LLM	Loss of Load Method
LLU	Loss of the Largest Unit
LDC	Load Duration Curve
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
EUE	Expected Unserved Energy
HL	Hierarchical Levels
HL-I	Hierarchical Level-I
HL-II	Hierarchical Level-II
HL-III	Hierarchical Level-III
HVdc	High Voltage Direct Current
IEEE-RTS	IEEE-Reliability Test System

IGBT	Gate Bipolar Transistor
IGCTs	Integrated Gate-Commutated Thyristors
GTOs	Gate Turn-off Thyristors
MCS	Monte Carlo Simulation
MMC	Modular Multi-level Converter
MTTF	Mean Time to Failure
MTTR	Mean Time to Repair
MWh	Megawatt Hour
occ/yr	occurrences per year
PTP	point-to-point
PWM	Pulse Width Modulation
RBTS	Roy Billinton Test System
RC	Reserve Capacity
SP	Station Poles
SCR	Short Circuit Ratio
TP	Transmission Poles
THD	Total Harmonic Distortion
VG	Valve Group
VSC	Voltage Source Converter

Chapter 1 Introduction

1.1 Power System Reliability

The reliability associated with a power system is a measure of the overall ability of the system to perform its intended function [1]. Generally, power system reliability assessment can be broadly categorized into two aspects: system adequacy and system security. System adequacy relates to the existence of sufficient facilities within the system to satisfy the customer load demand while system security reflects the robustness of the system relative to various disturbances. The research described in this thesis falls into the domain of power system adequacy assessment using a probabilistic approach. Probabilistic adequacy assessment can be performed in different functional zones i.e., generation, transmission and distribution in a particular power system. The main focus of the research described in this thesis is to develop appropriate probabilistic models and techniques to evaluate the impacts of HVdc systems on generating system adequacy performance.

1.2 HVdc Systems

1.2.1 Historical Background

High voltage direct current (HVdc) system consist of power-electronic converters embedded into an ac system that are used to transfer electric power using high voltage and direct current from the rectifier station to the inverter station. In the early days of power distribution, there was considerable debate, primarily between the two giant personalities in the field- Edison,

who was a proponent of dc, and Westighouse, who was a proponent of ac distribution won this "War of Currents" [2], because of the simpler electric apparatus that it required and the ability provided via transformers to select appropriate and different voltage levels for the generation, transmission, distribution and end-use. However, with improvements in converter technology, it became possible to convert from ac to dc, and HVdc technology began to be a viable alternative particularly for underground cable transmission, where the ac alternative would require excessive charging current; and for long distance overhead line transmission, where the ac option would result in increased transmission losses. The Gotland HVdc link (1954) between the Swedish east coast and the island of Gotland was the first commercial HVdc project in the world and started the era of modern HVdc technology [3]. The Gotland HVdc link was commissioned in 1954 and was rated at 20 MW and ±100 kV. With the development of HVdc technology, the dc voltage has increased from 100 kV (1954, Sweden) to 1100 kV (2017, China), transmission distance has increased to 3333 km (2017, China), and capacity has increased to 10 GW (2017, China).

Compared to ac system, HVdc technology has its advantages in following applications:

Low cost for long-distance bulk power transmission: The converter cost is a big portion of the total HVdc cost. However, the dc transmission line costs are less due to the fewer number of conductors and towers of lower height as compared to ac transmission. Hence there is a break-even distance beyond which the dc option is economical as compared to the ac alternative to transfer the same amount of power at the same voltage level.

Asynchronous ac systems inter-connection: HVdc technology is the only option to inter-connect two asynchronous ac systems with different frequencies, such as 50/60Hz systems.

Power transmission over long cable: With the increasing length of the ac cable, the cable capacitance becomes larger. The cable capacitance requires a portion of the reactive power in the form of capacitance charging current. This portion becomes relatively large and reduces the cable power carrying capability because of the current limit is constant. For dc cable, it is only needed to be energized once during start-up. There is no charging current required in the steady state.

Limiting fault current in ac system: The fault current in an ac system is largely determined by the number of generators and the network configuration. HVdc links can interconnect two ac systems without increasing the fault current level of ac network at each terminal.

AC fault isolation: The HVdc links can prevent ac faults propagating through dc line and converter. The control and protection are designed to block or trip the converter immediately after detecting ac fault in ac system.

Historically, there were three stages in HVdc technology development:

In the first stage, the mercury-arc valve was used as commutation device for converting alternating current into direct current and vice versa. The largest mercury-arc converter was used in Bipole 1 HVdc of the Nelson River link in Manitoba, Canada. Each terminal has six 6-pulse converters in series and each converter is rated at 150 kV, 1.8 kA. The main disadvantages of mercury-arc converters are low liability, high cost and maintenance, environment risk. The advent of solid state semiconductor such as diode and thyristor leaded to the second stage of HVdc technology.

The first commercial thyristor based HVdc project was the Pacific dc intertie in USA. This HVdc link was commissioned in 1970 and rated at 1440 MW and ±400 kV at that time. Today, thyristor based HVdc technology is widely used in new HVdc projects all over the world. The exiting mercury-arc converters were gradually upgraded to thyristor converters. The largest mercury-arc converter, Bipole 1 of Manitoba Hydro, is completely converted to thyristor converter at end of 2004.

The third stage of HVdc technology starts from the commission of the Hellsjön-Grängesberg HVdc project in 1997. This is the first time that HVdc links use insulated Gate Bipolar Transistor (IGBT) in converter. This experimental HVdc project was rated at 3MW and ±10 kV [4]. In 1999, the first commercial IGBT converter based HVdc link was built to transfer wind power from south Gotland to the load centre of the island in Sweden, this dc line is rated at 50 MW and ±80 kV [5]. Unlike the thyristor, IGBT gate turn-off thyristors (GTOs) and integrated gate-commutated thyristors (IGCTs) can follow external control signals to turn on and turn off quickly. Due to the enhanced controllability of today's HVdc products, they are finding increasingly more use in today's power systems.

1.2.2 Basic Configurations

Depending on the configuration, HVdc can be divided into point-to-point (PTP) system and back-to-back system (BTB). In the PTP system, the rectifier station and inverter station are at different locations connected via overhead line or cable. BTB topology can be used for interconnections between adjacent asynchronous networks. In this case, there is no transmission line between the converter bridges and the connection can be monopolar or bipolar.

1.2.3 HVdc Technologies

Line-Commutated Converter (LCC)

The mercury-arc valve and thyristor valve only can be triggered to turn on externally while there is forward voltage at the valve terminals. Mercury arc and thyristor-based converters rely on the reverse voltage from the ac system to turn off the valves. Mercury arc valve-based systems are becoming obsolete, so they will not be discussed further. This type of converter is also called a line-commutated converter (LCC) [6]. The ac current always lags the ac voltage in the LCC converter which leads to a poor (low) power factor. This means the LCC converter requires a large amount of reactive power compensation. It also requires the ac system to have a large short circuit ratio (SCR). A schematic diagram of a LCC HVdc system is shown in Figure 1.1.

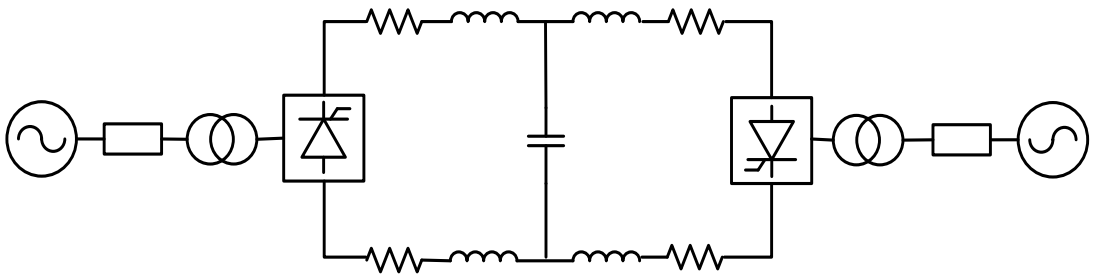

Figure 1.1: Structure of LCC-HVdc System

Voltage Source Converter (VSC)

Fully controllable semiconductor like IGBT, IGCT and GTO can turn on and, unlike the LCC, can also turn off according to an external control signal. This gives an additional degree of controllability to the IGBT (or IGCT, GTO) based converter. One terminal of such

an HVdc link is usually under constant dc voltage control mode and the dc system usually has a large capacitor to help smooth the dc voltage. Hence the dc voltage in such HVdc link is usually considered constant. Hence the IGBT (or IGCT, GTO) based converter is also known as Voltage Source Converter (VSC). Due to the two-degree freedom of the valve, the active power and reactive power of the converter can be controlled independently.

A. Two-level VSC Converter

The first VSC HVdc link, the Hellsjön-Grängesberg HVdc project, used a two-level VSC. The topology of a two-level converter is shown in Figure 1.2. Similar to the LCC converter, the two-level converter has 3 arms and each arm has two anti-parallel IGBT/Diode switches and has a connection to each phase of ac system. The dc system has large capacitors to smooth the dc voltage and buffer the unbalance of the power between the two ends. Pulse width modulation (PWM) is used to modulate the switching so that lower order harmonics are minimized [7], and only high frequency filters of small rating are required.

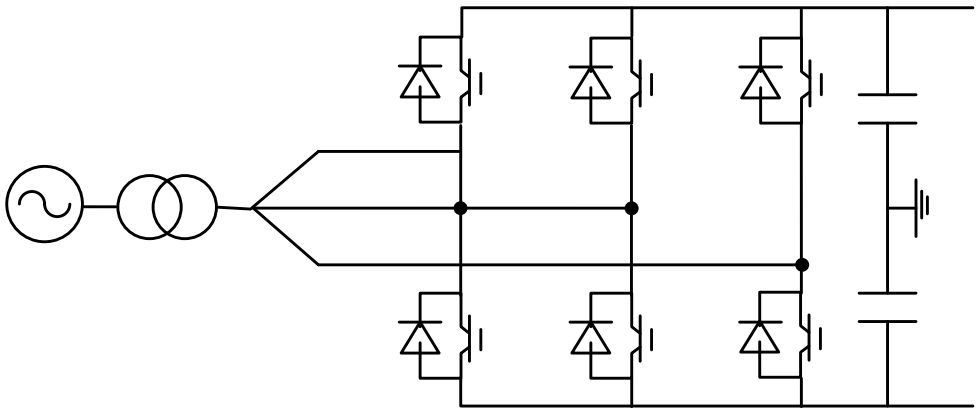

Figure 1.2: Three Phase, Two Level VSC

B. Modular Multi-Level Converters

The Modular multi-level Converter (MMC) is another type of topology for the multilevel VSC for HVdc transmission [8][9]. The topology of a typical MMC is shown in Figure 1.3. Each arm in the MMC consists of a series of identical sub-modules (SM). The capacitor in each SM can be selected individually to be switched into the system or be bypassed. By controlling the number of switched SM, the output waveform on each MMC arm can be designed to be closer to a sinusoidal waveform. Compared to a classic two-level or three-level VSC, the switching frequency and voltage change step of each semiconductor switch in MMC are significantly reduced. This also results in low switching loss in MMC converter. This configuration is adaptable to any voltage and power level by adjusting the number of stacked SM on each arm. With more levels, the output waveform of the MMC converter is close to a sine-wave and has a very low total harmonic distortion (THD).

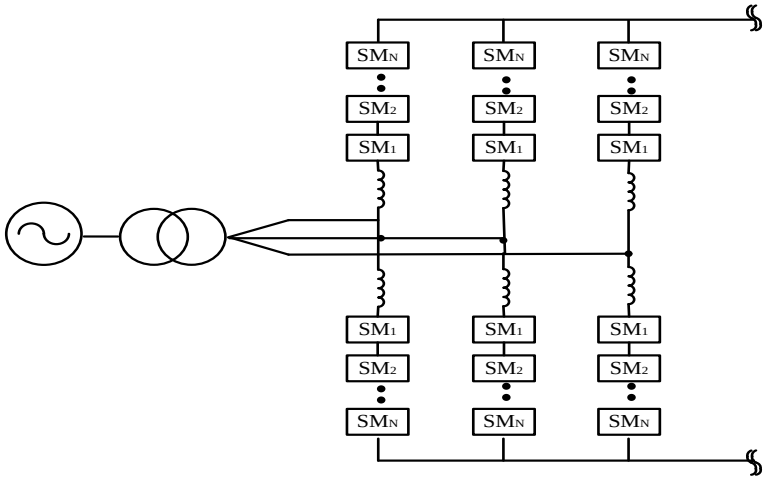

Figure 1.3: Topology of MMC

Currently, the practical HVdc project using MMC technology usually has 200-300 levels and operates without any filters. Similarly, to the VSC converter, its active power and reactive power output can be controlled independently using d-q decoupling control. However, the large number of SM will add to system complexity.

C. Multi-Terminal VSC Transmission

As noted earlier that HVdc technology has shown its advantages on long distance bulk power transmission, sea-crossing power transmission, ac system inter-connection and renewable energy integration. With the development of the renewable energy generation, the transmission of the large-scale power from wind farm or solar park to the remote loading center is becoming a challenge to the existing infrastructure. In Europe, there have been 117.3 GW of installed wind capacity (110.7 GW on shore and 6.6 GW off shore) by 2013 [10]. Usually wind farm or solar park is far from load center and generation center, and local existing ac network is too weak to support high power flow transmission. The fluctuating characteristic of renewable energy also requires the flexible power flow control, which is another challenge to the exiting power systems to accommodate those fluctuating sources.

One solution for this challenge is to use the multi-terminal VSC transmission (dc grid or super-grid) technology, which can integrate different types of renewable generations at different locations and transport bulk power over large geographic areas flexibly, effectively and efficiently. It has been proposed that the Super Grid [11], integrate off-shore wind power generation into the ac grid via a dc system in Europe. The DESERTEC concept [12] aims to promote solar and wind power generation in North Africa and transmit the power to European and African countries by a multi-terminal HVdc system. Perhaps linking these two concepts is

the Mediterranean Ring (Medring) proposed by the Med Grid group [13], which advocates a dc and ac grid linking the nations that border the sea. On the eastern seaboard of the USA, the Atlantic Wind Group [14] are proposing a submarine interconnector from New Jersey to Maryland and Deleware, which will also connect to multiple off-shore wind farms.

Compared to the ac grid, the dc grid has its own advantages. The power flow in multi-terminal VSC transmission system is controllable due to the independently controlled real power and reactive power at each VSC terminal. The VSC converter also can provide reactive power support to the local ac system. Also, compared with the LCC, it is easier to connect a VSC converter into an islanded system with very low short circuit capacity. The bidirectional power transmission ability provides the path to micro grid in the community or even in the individual house to exchange the energy with the dc system. This may lead to the future liberalization of the energy market and allow the use of the grid for energy trading among individuals, utility companies and even countries. However, there are some technical challenges need to be solved prior to build large scale dc grid. The dc resistance is much less than the fundamental impedance of an ac line. Hence a fault at the dc system has larger impact range than in an ac system. The mutli-terminal dc grid needs extremely short time (< 2ms) for the fault clearance. Fast dc circuit breakers are needed to isolate the fault. Currently, all converters in the grids being planned use the same dc voltage level for all converters there is only one dc voltage level at each terminal of the multi-terminal dc system. The future dc grid may use different voltage levels to generate, transmit and distribute power. A dc-dc converter is needed to realize the dc voltage transform. To develop such large scale, high voltage, and reliable device will be another challenge. Beside these challenges, there are still some technical details need to be looked into, such as the integration standards in dc grid, dc

grid control and protection system, the configuration of the dc grid, power flow control in dc grid, HVdc converter models in dc grid, impact of ac system on dc grid and HVdc grid operation voltage levels.

1.3 Reliability Considerations of HVdc Systems

The steady increase in utilization of HVdc technology around the world particularly in the recent past has created the need for comprehensive procedures to evaluate the reliability of power systems that contains HVdc facilities. For example, if the generation system is remote and it is connected to the load centre through HVdc links, transmission availability may have a significant impact on the overall system reliability performance. These impacts need to be quantified in order to ensure a reliable supply at an affordable cost. With increase in HVdc installations around the world more and more attention is given to the reliability aspects of these designs, and considerable effort has been devoted to developing models and methods for assessing the reliability impacts of HVdc systems [15-45].

Application of probabilistic methods in HVdc system reliability assessment started in late 60's [15] [16]. Availability and reliability prediction for a high-voltage direct-current terminal is presented in [15]. The assessment method is based on the system function and failure mode analysis. The application of a Markov model and the recursive approach to the analysis of single and multiple mercury arc bridge configurations is presented in [16]. As the number of states required for modeling a particular configuration increases rapidly with the number of bridges and the number of spare units, the state space representations of converter bridges become unmanageable. The proposed models described in [16] are, therefore, difficult

to be directly used in the reliability assessment of power systems containing HVdc sub-systems due to the model complexity. A model reduction approach is, therefore, proposed to reduce the complexity in LCC HVdc system modelling [17]. The applicability of the reduced models is also illustrated by examining the reliability of example systems [17]. A reliability cost-benefit analysis for HVdc transmission expansion planning is presented in [18]. The expected unserved energy for calculating the risk cost is estimated and outages of valve group, monopole and bipole system are modelled using an analytical approach. The configurations examined include group connected and conventional common collector systems. The enhancement options include increase of redundancy, improvement to component reliability, provision of spares for critical components, reduction of common cause and dependent failures and provision of reserve capability. A minimal cut set method is proposed for reliability analysis of HVdc systems [19]. The minimal cut set method is based on failure mode and effect analysis. The idea presented in [19] is simple but identification of the minimal cut set for a practical and complex power system is quite excessive. The minimal cut set method is later extended to evaluate the reliability of an autonomous power system considering interconnection to other system through an HVdc link [20]. This method seems not very efficient when evaluating the impacts of HVdc systems on overall power system reliability performance. Hence, a hybrid deterministic and probabilistic evaluation of HVdc transmission system reliability is proposed to evaluate healthy, marginal and risk state probabilities [21]. The hybrid technique is trying to alleviate some of the difficulties encountered in interpreting and accepting pure probabilistic indices such as the loss of load probability. The reliability impacts of an HVdc link on composite generation and transmission systems are quantified using several different techniques [22-26]. With the increasing

utilization of new HVdc and flexible ac transmission system (FACTS) technologies, recent papers focus on modelling VSC HVdc systems, Multi-terminal HVdc systems and hybrid VSC and LCC HVdc systems [27-29].

In the existing literature, the models and methods proposed in assessing HVdc system reliability are mainly based on the analytical approach. Relatively less work has, however, been done using Monte Carlo simulation technique to evaluate HVdc system reliability. This thesis presents a method for the reliability evaluation of HVdc systems using the Monte Carlo technique. The proposed technique is verified against some of the analytical technique described in the available literature. A comprehensive reliability assessment for a specific example system is performed to illustrate the usefulness of the method. The evaluations will mainly investigate the impacts of various system parameters on HVdc system reliability. These parameters include equipment forced outage rate, number of spare component, and system load variations. Most commonly used reliability indices such as the loss of load probability (LOLP), loss of load expectation (LOLE) and expected unserved energy (EUE) will be used to measure the reliability of the HVdc system under examination. One of the major advantages of the proposed method is to examine the HVdc reliability using not only the average or expected values but also using the distributions of reliability indices. The distributions of reliability indices are produced and used in the reliability evaluation of example systems.

The research described in this thesis also extends the system well-being assessment to consider HVdc links. The basic well-being analysis method was applied to electric power system assessment in recently years [30-32], it hasn't been applied in HVdc reliability

adequacy assessment yet. The analysis presented in this thesis is incorporated the deterministic criteria in probabilistic assessment of power systems that contain HVdc links.

1.4 Research Objectives and Outline of the thesis

The main objective of this research work is to develop appropriate models and techniques for evaluating the impacts of HVdc systems on power system reliability. It is expected that this research will help utilities make decisions in regard to optimum planning and operation of HVdc systems. Specific objectives of this research include:

A) Develop appropriate models and techniques for the reliability evaluation of power systems containing HVdc links based on the Monte Carlo simulation approach.

B) Develop an effective method to incorporate reliability index distributions in HVdc system reliability assessment.

C) Extend the conventional well-being analysis approach to power systems containing HVdc links.

D) Perform reliability analyses on example systems to illustrate the effectiveness and accuracy of the proposed models and techniques.

E) Identify potential future work for expanding the research on reliability modeling and evaluation of power systems with HVdc links.

This thesis contains six chapters and the contents of each chapter are briefly outlined as follows:

Chapter 1 provides an introduction to the thesis along with an overview of the application of the HVdc technology in power systems and a comprehensive review and evaluation of the existing literature on HVdc system reliability. Chapter 1 also outlines the scope and objectives of the thesis.

Chapter 2 introduces the basic concepts and techniques for power system reliability assessment. The commonly used reliability assessment methods of the analytical assessment and Monte Carlo Simulation are introduced in this chapter.

Chapter 3 presents a general adequacy evaluation approach using the sequential Monte Carlo simulation technique for power systems containing HVdc links. The basic HVdc reliability assessment models for a valve group, a pole and a bipole are proposed and discussed. A sequential Monte Carlo Simulation procedure for reliability assessment of power systems with HVdc links is proposed and presented in this chapter. Results obtained using an analytical technique and the proposed sequential Monte Carlo simulation method are compared in order to verify the Monte Carlo based simulation program developed during the course of this research.

Chapter 4 illustrates the application of the general evaluation models presented in Chapter 3 in HVdc system reliability assessment. A series of studies are performed to illustrate the proposed technique described in Chapter 3 using example systems. This chapter also evaluates the reliability of various scenarios using example systems to investigate the impacts of key system parameters on the reliability performance of HVdc systems using both the mean values and distributions of the reliability indices.

Chapter 5 presents a sequential Monte Carlo based simulation approach for the well-being analysis of power systems containing HVdc links. The proposed technique is illustrated and applied to different HVdc system cases. The effect on deterministic criteria and different HVdc system parameters are illustrated and the distribution associated with the wellbeing indices are also discussed in this chapter.

Chapter 6 summarizes the thesis and highlights the conclusions.

Chapter 2 Basic Concepts and Techniques for Power System Reliability Assessment

2.1 Introduction

The focus of the research described in this thesis is on the reliability assessment of power systems with HVdc links. Generally, a power system consists of three basic functional zones of generation, transmission and distribution as shown in Figure 2.1[1].

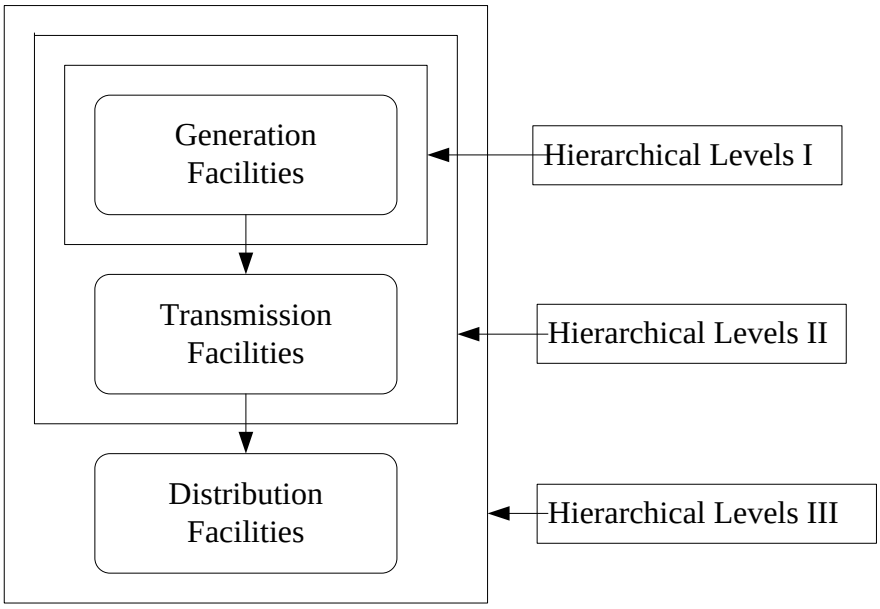

Figure 2.1: Hierarchical levels

Power system reliability evaluation can be performed in any of these three functional zones [1]. If the reliability assessment involves only generating facilities it is usually referred to as, Hierarchical Level I (or HL I) evaluation. Similarly, Hierarchical Level II (or HL II) evaluation includes both the generation and transmission sides while Hierarchical Level III

(or HL III) appraisal includes the distribution facilities in addition to the generation and transmission facilities to provide a complete system reliability assessment.

The scope of the research described in this thesis falls into HL I assessment and therefore a brief review of the basic concepts and techniques used in HL I assessment is provided in this chapter.

The main objective of HL I assessment is to evaluate the adequacy of a generating system to satisfy its load demand and therefore the system can be represented by a single bus connecting all generation and the load as shown in Figure 2.2 [1].

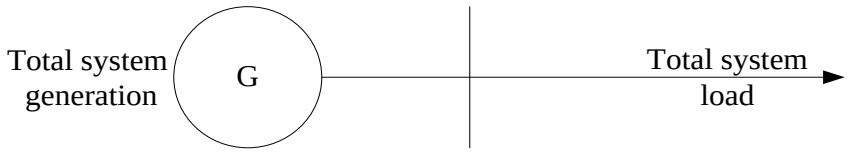

Figure 2.2:System Representation at HL-I

The basic approach for performing HL I evaluation is, therefore, to develop a risk model by suitably combining a generation model with an appropriate load model as shown in Figure 2.3 [1].

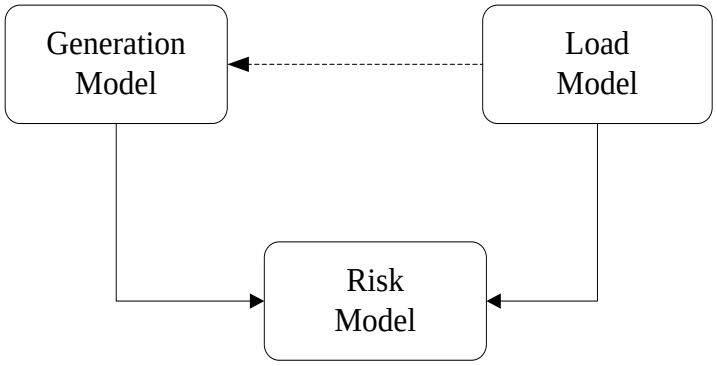

Figure 2.3: Conceptual Model in Adequacy Assessment at HLI

Traditionally transmission is not considered in the HL I assessment. However, if the impact of outlet transmission of a particular generating unit or a group of generating units is significant for example the Nelson River HVdc system in Manitoba, Canada, it should be incorporated in HL I evaluation. As noted earlier that the main objective of the research is to develop appropriate models and techniques to assess the impacts of HVdc component failures on the reliability performance of generating systems that are connected to HVdc transmission to supply energy in a particular power system. Theoretically, the impact of major transmission can be incorporated in the HL I evaluation by modifying either the generation model or the load model. It is, however, more accurate to modify the generation than to modify the load in incorporating the impacts of HVdc system on the generating system reliability. Chapter 3 will provide more detailed information on the modeling of HVdc systems in HL I assessment.

The fundamental approaches used in probabilistic assessment of electric power systems can be generally described as being either a direct analytical evaluation or a Monte Carlo simulation. Analytical techniques represent the system by analytical models and evaluate the system risk indices from these models using mathematical solutions [1]. Monte Carlo simulation, on the other hand, estimates the probabilistic risk indices by simulating the actual process and the random behavior of the system [46]. Both approaches have advantages and disadvantages, and each of them can be very powerful with proper application. In using these approaches to perform power system reliability assessment, the first step is to develop appropriate models for various components in the system of interest and therefore outage model of a typical power system component is generally described in the following section.

Outage Model of System Components

Accurate and consistent models to represent the true component behavior are the basis of power system reliability assessment using probabilistic approaches. A power system component can reside in several different states for example normal in-service, faulted, repair and maintenance states. Although a very detailed model could result in more accurate evaluation, a power system component is typically modeled as a two-state representation in probabilistic reliability assessment as shown in Figure 2.4. In this case, the component is considered to be either fully available (State 0) or totally out of service (State 1) [1].

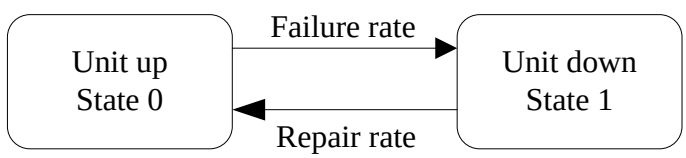

Figure 2.4: Two-state Model for A Power System Component

The availability (A) and unavailability (U) can be calculated using the following equations:

$$\text{Availability} = \text{A} = \frac{\mu}{\boldsymbol{\lambda} + \mu} = \frac{\text{m}}{\boldsymbol{r} + \text{m}} = \frac{\sum up\ time}{\sum down\ time + \sum up\ time} \tag{2.1}$$

$$\text{Unavailability(FOR)} = \text{U} = \frac{\boldsymbol{\lambda}}{\boldsymbol{\lambda} + \mu} = \frac{\boldsymbol{r}}{\boldsymbol{r} + \text{m}} = \frac{\sum down\ time}{\sum down\ time + \sum up\ time} \tag{2.2}$$

Where:

m: Mean Time to Failure

r: Mean Time to Repair

λ: Failure Rate

μ: Repair Rate.

$$\mathrm{MTTF} = 1/\boldsymbol{\lambda} \tag{2.3}$$

$$\mathrm{MTTR} = 1/\,\mu \tag{2.4}$$

It is quite often in power system reliability assessment to reduce a network to equivalent reliability assessment blocks based on the connection of power system components. From a reliability point of view, two components are in parallel if both must fail for system failure and they are in series if the failure of either one causes system failure. Figure 2.5 shows a two components series system and its equivalent system. The equivalent system capacity states and the associated probability can be calculated as shown in Table 2.1. In Table 2.1, C_i, A_i and U_i represent the capacity, availability and unavailability of Component i.

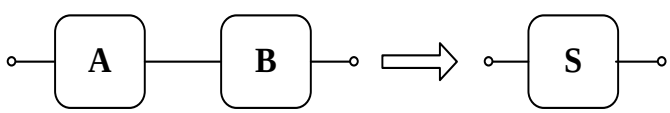

Figure 2.5: A Series Connected System with Two Components and Its Equivalent

Table 2.1: The Capacity and Probability Table for A Series System

Component State	Capacity	Probability (Availability)
a and b in up-state	Min $\{C_a, C_b\}$	Availability = $A_a \times A_b$
With failure of any one component	0	Availability = $U_a + U_b - U_a \times U_b$

Figure 2.6 shows a two components parallel system and its equivalent system. The equivalent system capacity states and the associated probability can be calculated as in Table 2.2.

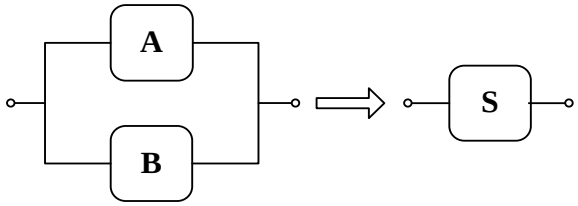

Figure 2.6: A Parallel Connected System with Two Components and Its Equivalent

Table 2.2: The Capacity and Probability Table for A Parallel System

Component State	Capacity	Probability (Availability)
Both a and b in up- state	C_a+C_b	Availability $=A_a \times A_b$
b failed	C_a	Availability $=A_a \times U_b$
a failed	C_b	Availability $=U_a \times A_b$
Both a and b failed	0	Availability $=U_a \times U_b$

There are two types of methods for generating capacity adequacy evaluation: analytical and simulation based. The analytical method tries to develop a mathematical expression for the reliability index such as the LOLE. The Monte Carlo methodsds estimate the reliability indices by simulating the actual process and random behaviour of the system [1]. Each method has its own advantages and disadvantages. If complex operating conditions such as loss of one transmission line requiring the tripping of one or several generators are not considered, and the system is relatively small, the analytical method is sufficient and easily applied. On the other hand, if the number of severe events is relatively large, or the system is complex, or the outrage rate of the component is not constant (e.g., a function of age), it is easier to use the Monte Carlo Simulation. The main advantages of Monte Carlo method are as follows: 1) When the system includes operational procedures, for example loss of a line may

requires trip of one or several generators. It is difficult to model this type of procedure in analytical evaluation but can be easily modeled in MCS. 2) The accuracy level of MCS is independent of the size of the system, and the formulation of the reliability indices is straightforward.

2.2 Analytical Methods

Analytical evaluation of generating system reliability produces system reliability information on the likelihood that the generation system (may include some transmission) will be unable to serve the forecast load. The typical results obtained in this evaluation are the expected values of the various adequacy indices as will be explained below. In an analytical evaluation, the generation model is normally in the form of an array of capacity levels and their associated probabilities. This representation is known as a capacity outage probability table (COPT) [1]. In this thesis, a two-state model (up or down) as described in Section 2.2 is assumed for each generating unit in the system. Alternatively, a multi-state model can be used if derated states for the generation need to be considered. The COPT can be constructed using various techniques such as the well-known recursive technique [1].

Usually, the load is represented by either the daily peak load variation curve (DPLVC) [1] or the load duration curve (LDC) [1] in HL I reliability assessment using an analytical technique. The DPLVC is the cumulative load model formed by arranging the individual daily peak loads in descending order [45]. The resultant model is known as the LDC when the individual hourly load values are used, and in this case the area under the curve represents the

energy required by the system in a given period. This is not the case with the DPLVC. The DPLVC is an approximate representation of the actual system load demand [45]. It is, however, used extensively mainly due to its simplicity. The LDC is a more realistic representation of the system load.

The generation model obtained from the COPT and an appropriate load model are combined to evaluate the risk indices in the analytical evaluation [1]. There are many methods available in combing the generation and the load models to calculate various reliability indices. The most commonly used one is the discrete convolution method often referred to as the loss of load method or loss of energy method depending on the load model used in the evaluation.

Loss of Load Expectation

The LOLE index can be calculated by combining the system COPT with either a DPLVC or a LDC. If the COPT is convolved with a DPLVC the unit of LOLE index is in days per year while the unit of the LOLE is in hours per year if an LDC is used.

Figure 2.7 shows the combination of a DPLVC with the COPT. When a capacity outage Q_k with a probability of p_k exceeds the reserve, a loss of load with a duration of t_k occurs. The LOLE index is the expected value of such t_k. It should be noted that any capacity outage less the reserves will not contribute to the LOLE. The LOLE index expressed in terms of days/period can be calculated using the following equation [1]:

$$LOLE = \sum_{k=1}^{n} \mathrm{p}_k \times t_k \tag{2.5}$$

Where

n: the number of capacity outage state in excess of the reserve

p_k: probability of the capacity outage Q_k.

t_k : the time for which load loss occur.

The p_k values in Equation 2.5 are the individual probabilities associated with COPT. And when applied the cumulative probabilities, the modified equation is as follows:

$$LOLE = \sum_{k=1}^{n} \mathrm{P}_k \times (t_k - t_{k-1}) \tag{2.6}$$

If the time t_k is expressed as a per unit value, the index is called as LOLP.

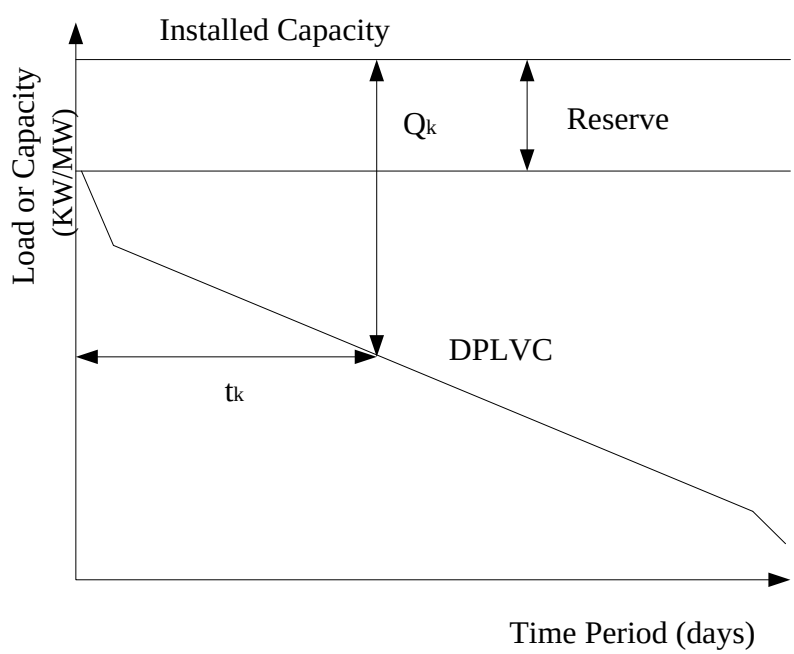

Figure 2.7: Evaluation of LOLE using DPLVC

<u>Expected unserved energy (EUE)</u>

Similarly, system COPT can be combined with a LDC to calculate a LOLE index expressed in hours per year. If the DPLVC in Figure 2.7 is replaced by a LDC as shown in Figure 2.8 the calculation of LOLE in hours per year is exactly the same as the calculation of LOLE in days per year as described previously. As noted earlier that the area under the LDC represents the energy utilized during the specified period. Therefore, it can be used to calculate an expected energy not supplied due to insufficient installed capacity [1]. Any outage of generating capacity exceeding the reserve will result in a curtailment of system load energy [1]. The EUE can be evaluated using.

$$EUE = \sum_{i=1}^{n} p_k \times E_k \tag{2.7}$$

Where E_k: the energy curtailment

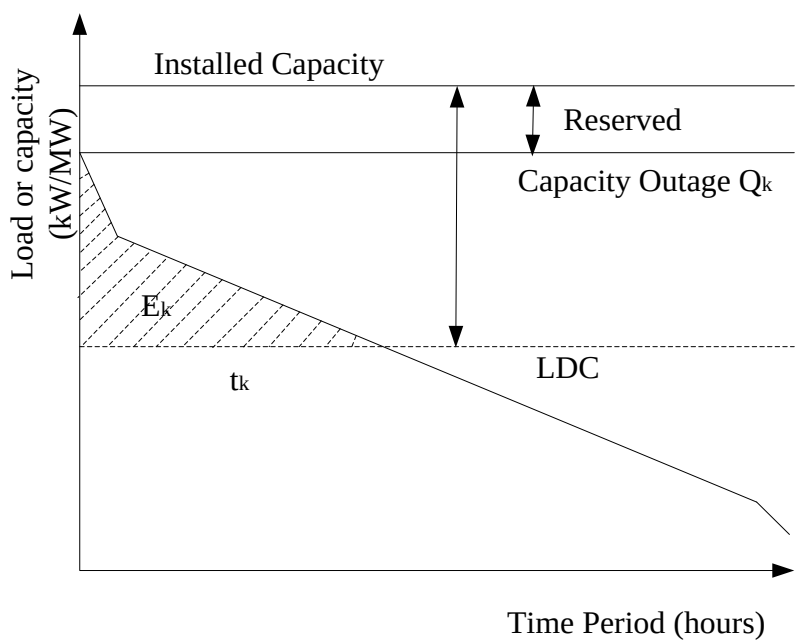

Figure 2.8: Evaluation of EUE using LDC

EUE index is very important because the future electric power systems may be energy limited rather than power or capacity limited with increased utilization variable energy sources.

2.3 Monte Carlo Simulation

In the past, predominantly analytical techniques were used to assess the reliability of power systems. One of the major disadvantages with analytical techniques is that they are unable to provide satisfactory solutions without excessive approximations in system modelling for example modelling a complex operating procedure. Also, analytical methods produce only the mean values of reliability indices but not the probability distributions associated with the reliability indices. Probability distributions of reliability indices can provide more detailed information on the reliability performance of power systems.

Monte Carlo simulation methods estimate the reliability indices by simulating the actual process and random behaviour of the system [1, 46]. There are two basic simulation methods commonly used in power system reliability assessment. These are state duration sampling (sequential) and state sampling (non-sequential) methods [46].

State Sampling

State sampling is a non-sequential approach and it is based on random sampling of generation and load states. This approach takes only the snap shot of the system state at various time, no time continuity is considered. This approach is therefore, often referred to as

the state sampling approach. For the generation side, at any time, the generation state of each unit can be sampled based on its state probability using a uniformly distributed random number. The system generation state can then be modeled by sampling all the generating unit states. The load is usually represented by a multi-step load model. Reliability indices can then be assessed based on the load and the generation status. The simulation is repeated for a large number of replications and statistics of the indices are collected and computed. The advantage of this method is that multi-state models can be incorporated without significant increase in computing time. The chronology of events is, however, not modeled. State sampling approach provides a good estimate of the LOLE indices, but this method is unable to provide any information on event frequency and duration.

State Duration Sampling

The state duration sampling approach simulates the system states in a time sequential manner. The generating unit is modeled with its various states and outage durations. The generating unit state is chronologically represented based on the samplings. The load is usually represented by a chronological hourly load or daily peak load variation profile. The system adequacy status or reliability indices can then be assessed by superimposing the generation model to the chronological load profile. This approach is often referred to as the sequential Monte Carlo simulation. The advantage of the sequential Monte Carlo simulation is that the operating cycles of generating units must be generated and combined with the rest of the units in the system to form a system capacity curve. It can also provide information of event frequency and duration.

The main parameters used to form an operational history for each unit are the failure rate and the repair rate as described in Section 2.2. Using these parameters and the random numbers between 0 and 1 a state history in the form of random up and down times for each generating unit as shown in Figure 2.9, can be produced over a large number of samples (typically 10,000 replications). Those state residence times are random variables and follow a particular probability distribution.

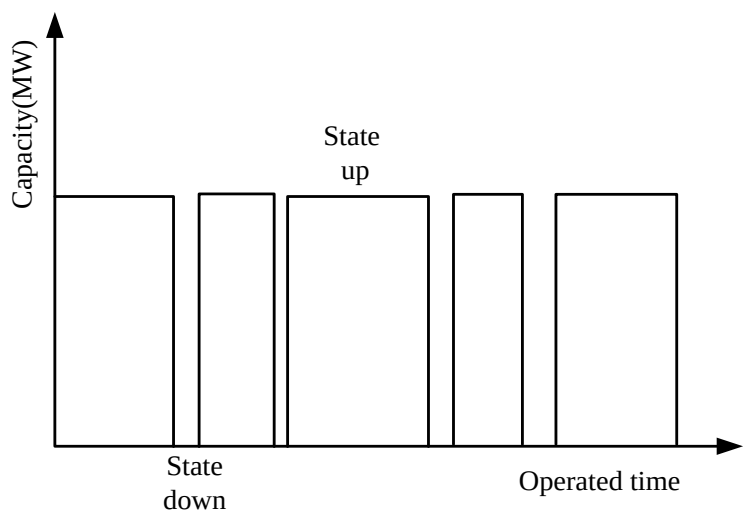

Figure 2.9: Operating History of A Generating Unit

If the state residence time is represented by an exponentially distributed random variable T, it has the following probability density function [1]:

$$f(t) = xe^{-xt} \tag{2.8}$$

The cumulative probability distribution function for exponential distribution is [1]

$$F(t) = 1 - e^{-xt} \tag{2.9}$$

Using the inverse transform method, the random variable T can be obtained as expressed in the following equation [1], where U is uniformly distributed random number between 0 and 1:

$$U = F(t) = 1 - e^{-xt} \tag{2.10}$$

$$T = F^{-1}(U) = -\frac{1}{x}\ln(1 - U) \tag{2.11}$$

Since 1-U is distributed uniformly in the same way as U in the interval [0,1], the random variable T can be expressed [1]:

$$T = -\frac{1}{x}\ln(U) \tag{2.12}$$

Consider a two-state generating unit, if the unit is in the up state, then x is the failure rate of the generating unit, which is the reciprocal of the MTTF [1]. If the unit is in the down state, x is the repair rate of the generating unit, which is the reciprocal of the MTTR [1].

The basic simulation procedure for evaluating power system reliability using the state duration sampling method can be briefly described as follows [46]:

1) Generate operating histories for each component in the system. The operating history of each component is then typically in the form of chronological up-down-up operating cycles as shown in Figure 2.9.
2) Obtain the available capacity of the system by combining the operating cycles of all components in the system as shown in Figure 2.10.

3) Superimpose the system available capacity obtained in Step 2 on the chronological load model to construct the system available margin model as shown in Figure 2.11

4) Estimate the desired reliability indices by observing the margin model constructed in Step 3 for a large number of samples.

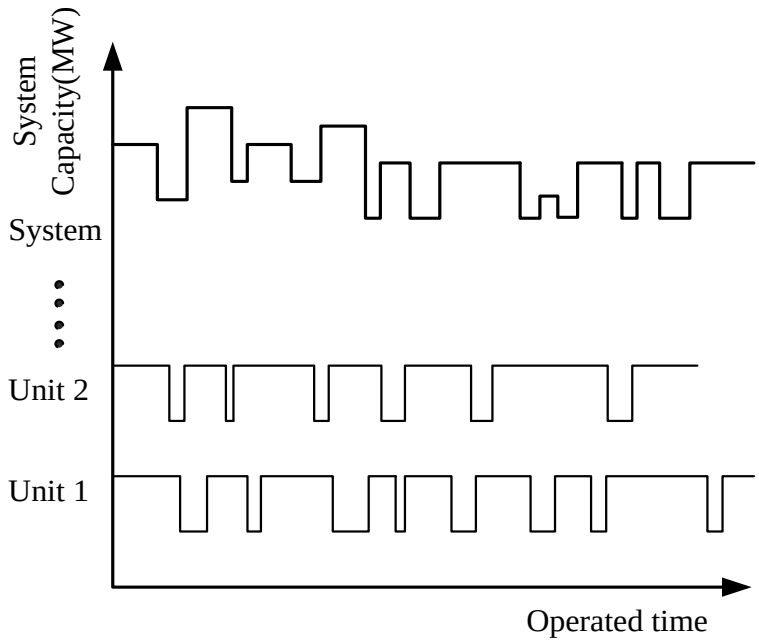

Figure 2.10: Operating History of Individual Generating Units and the Capacity States of the Overall System

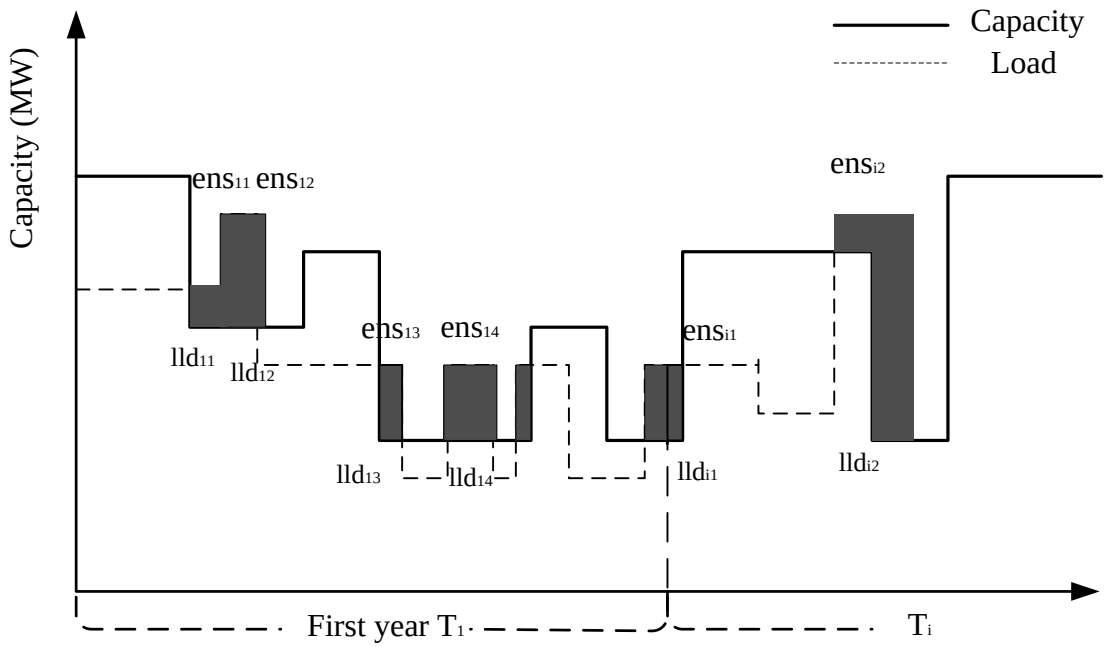

Figure 2.11: Superimposition of the Capacity States and the Chronological Load Pattern

Normally the sequential Monte Carlo simulation advances hourly and the reliability indices are evaluated on an annually basis. The reliability indices such as the LOLE can be evaluated by recording the loss of load duration in hours for each load curtailment, and the index of EUE can be evaluated based on the energy not supplied in MWh or kWh at each curtailment for a significant number of sample years. Estimates of the reliability indices for a number of sample years (N) can be obtained using the following equations.

<u>Loss of load Expectation</u>

$$\mathrm{LOLE} = \frac{\sum_{i=1}^{N} \mathrm{LLD_i}}{N} \tag{2.13}$$

Where $\mathrm{LLD_i}$ = the loss of load duration for the sampling year i

<u>Expected un-served energy</u>

$$\mathrm{EUE} = \frac{\sum_{i=1}^{N} \mathrm{ENS_i}}{N} \tag{2.14}$$

Where $\mathrm{ENS_i}$ = energy not supplied for the sampling year i

Simulation Convergence and Stopping criteria

Monte Carlo simulations require a large number of samples to obtain results that are statistically meaningful. The accuracy of the results provided by Monte Carlo simulation is improved by increasing the number of replications. It is, however, not practical to conduct the simulation by simply increasing the number of samples for achieving higher accuracy. The simulation can be controlled by setting appropriate rules to only improve the accuracy of the estimated indexes but also to avoid premature convenience. In this thesis, the stopping criterion is adopted in [33]. This criterion includes two parts:

1. Setting a minimum number of replications to avoid premature convergence for example 1000 replications and
2. Use a stopping criterion to monitor the reliability index of interest to control the simulation process. In this thesis study, the standard deviation of the reliability index has to be less than 1% in last 50 replications.

2.4 Summary

This chapter describes various methods used for generating capacity adequacy evaluation. Generating capacity adequacy evaluation involves the combination of a generation model with an appropriate load model to obtain a risk model. In general, there are two different approaches available as being analytical method and Monte Carlo simulation technique in the probabilistic power system reliability evaluation. Both methods have advantages and disadvantages. Analytical method can provide the expected index values in short computational time but one of the major disadvantages with analytical techniques is the excessive approximations to simplify the problem in reliability assessment, particularly when a complex operating procedure is needed to be modeled. Comparing with analytical method, the Monte-Carlo simulation approach requires longer computing time but can include all contingencies of the reliability model. More importantly, it also produces the probability distributions associated with the reliability indices, which can provide more detailed information on the reliability performance of power systems.

The sequential state duration sampling simulation technique is utilized in the research described in the following chapters in the reliability assessment of power systems containing HVdc links.

Chapter 3 Development of Evaluation Models for HVdc System Reliability Assessment

3.1 Introduction

As noted in Chapter I that considerable efforts have been devoted to developing probabilistic models and techniques for reliability assessment of HVdc systems. The outage models of system components are the basis for such reliability assessments. HVdc system reliability assessment involves the selection and evaluation of system states. The system states can be enumerated or determined using either an analytical method or a Monte Carlo simulation approach. Based on the literature review results, the analytical methods were more preferred over Monte Carlo simulation in the past. One of the major disadvantages with analytical techniques is, however, that the models for HVdc system reliability evaluation are approximate. On the other hand, analytical methods do not produce the probability distributions associated with the reliability indices. The probability distributions of reliability indices can, however, provide more detailed information on the reliability performance of power systems. This chapter presents a Monte Carlo simulation-based reliability evaluation technique that can be used to incorporate HVdc systems in HL I reliability evaluation. The technique involves the development of HVdc component, subsystem and overall system reliability models that are based on component failure mode and effect analysis and incorporation of these models into the overall system reliability simulation procedure.

3.2 HVdc System Reliability Assessment Models

The first step in HVdc system reliability assessment is to develop appropriate models for HVdc system components, subsystem and the overall system. Generally, HVdc system components can be broadly categorized into valve group (converter) related, pole related and bipole related components. Examples of valve group related components include valve group controls, converter transformers, valves and switching equipment. Examples of pole related components include pole control equipment, dc filters, smoothing reactors and dc transmission lines and examples of bipole related components include main station control, ac filters, reactive power supply equipment (such as synchronous condensers), transmission lines or ground electrode. Based on the failure mode and effect analysis, a model for HVdc system reliability assessment can be developed. In developing the reliability model, the following approach can be used:

1) Outages of valve group controls, converter transformers, valves and switching equipment that cause a loss of transmission capability equal to that of a valve group are combined into a single reliability block representing a valve group by suitably combining their individual reliability models using network reduction in reliability assessment described in Chapter 2.
2) Similarly, outages of pole control equipment, dc filters, smoothing reactors and transmission lines that result in a loss of capability equal to a pole capacity can be combined into a single pole element reliability model.

3) Failures of main station components, such as master controls, ac filters, reactive power supply equipment (such as synchronous condensers), transmission lines or ground electrode cause a loss of capability equal to that of a bipole can be lumped into a bipole reliability model.

Using the above described procedure, a reliability block diagram can be developed for HVdc system adequacy assessments. Figure 3.1 shows such a reliability block diagram developed for a generating system supplying a load through a bipolar HVdc system with two identical poles. In Figure 3.1, VG stands for valve groups, CT for converter transformers, SP for station poles, TP for transmission poles and BP for a bipole.

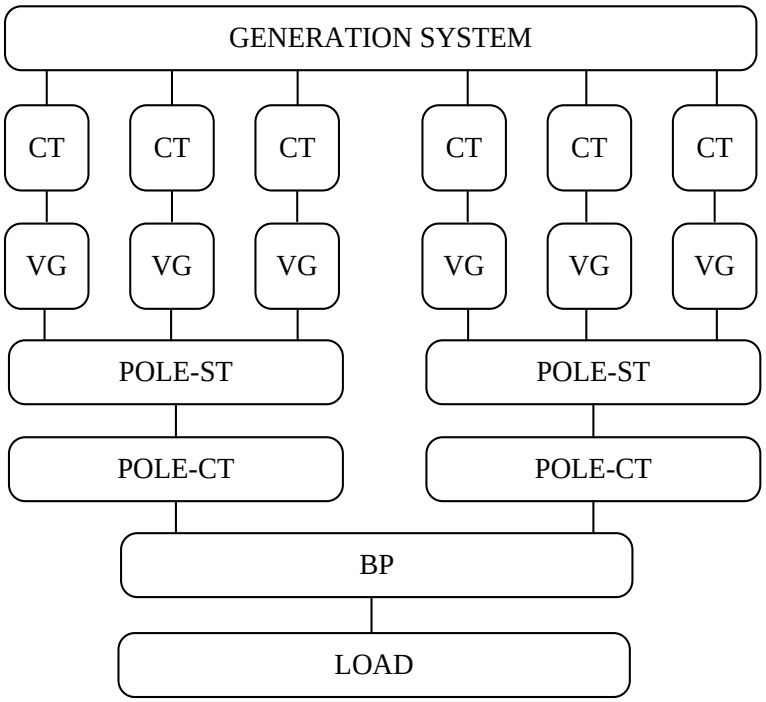

Figure 3.1: Reliability Block Diagram for a Bipolar System

If possible, the series/parallel components can be combined to their equivalents using the network reduction technique in order to increase the calculation efficiency and simplify the reliability diagram. For example, the valve group and converter transformer in Figure 3.1 can be equivalent to a VG, because transmission is lost if either fail, similarly the station pole and transmission pole can be combined to an equivalent Pole. The simplified reliability block diagram is shown as Figure 3.2.

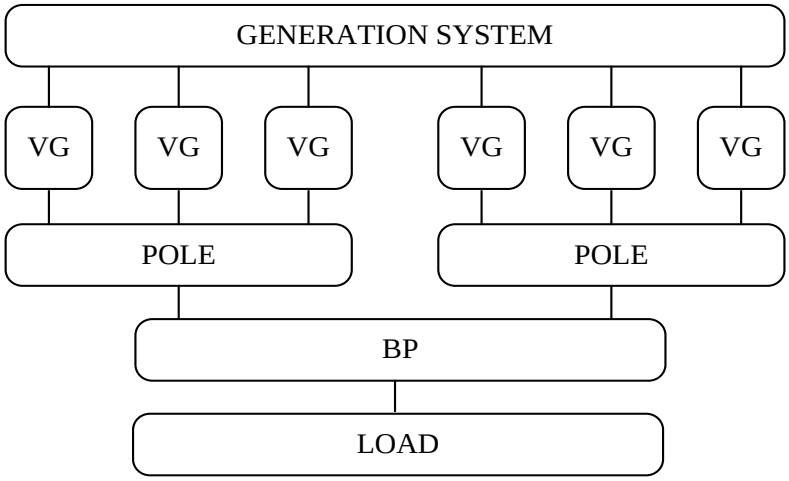

Figure 3.2: Simplified Reliability Block Diagram for the Model Shown in Figure 3.1

Once an HVdc reliability model like the one shown in Figure 3.2 is developed the generating model of the system that is connected to the HVdc system can be modified to incorporate the impacts of HVdc system in HL I reliability assessment. The modified generation model which includes the HVdc system then can be combined with an appropriate load model to evaluate various reliability indices.

3.3 Load Models

Different reliability indices can be evaluated using different load models for example the LOLE index in hours/year can be evaluated using hourly load values and similarly the LOLE index in days/year is evaluated using daily peak load values. As the research described in this thesis is based on the state duration sampling method a chronological load model is used. The IEEE reliability test system (IEEE-RTS) [34] is used. Figure 3.3 shows the chronological load variations of the IEEE-RTS load [34]. The load variation pattern shown in Figure 3.3 can be conveniently used in various reliability studies if there is no historical data to come up with a load curve model. This IEEE-RTS load model is, therefore, used in most of the studies presented in this thesis unless otherwise specified.

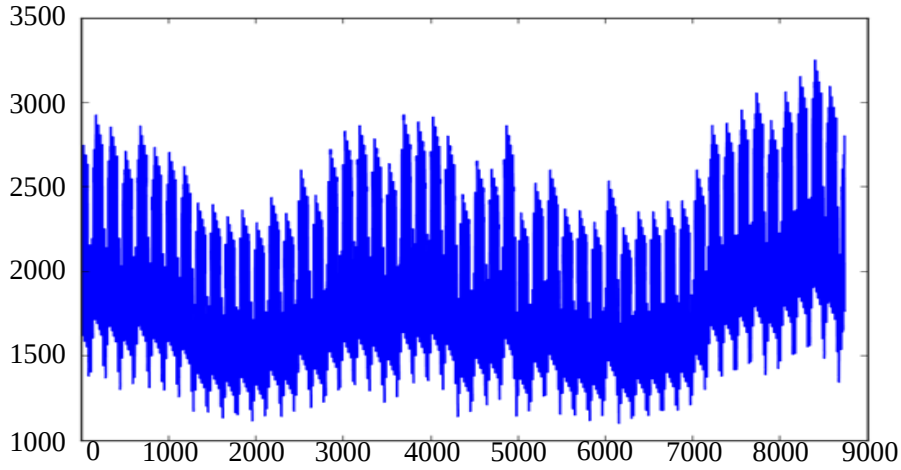

Figure 3.3: IEEE-RTS Chronological Load Model

3.4 Overall System Reliability Assessment Model

The reliability of HVdc system can be evaluated with the help of reliability block diagrams as shown in Figures 3.1 and 3.2 based on either an analytical or a Monte Carlo simulation technique. A sequential Monte Carlo based technique for the reliability assessment of HVdc system is proposed in this research. In the sequential Monte Carlo simulation, operating history of each component is created. The basic procedure of the proposed simulation technique is briefly described as below and graphically shown in Figure 3.4. Generate operating histories for each component in the reliability block diagram. The operating history of each component is then in the form of chronological up-down-up or up-derate-down-up operating cycles.

1) Obtain the system available capacity by combining the operating cycles of all components in the system.
2) Superimpose the system available capacity obtained in Step 2 on the chronological load model to construct the system available margin model.
3) Estimate the desired reliability indices by observing the margin model constructed in Step 3 over a long-time period.

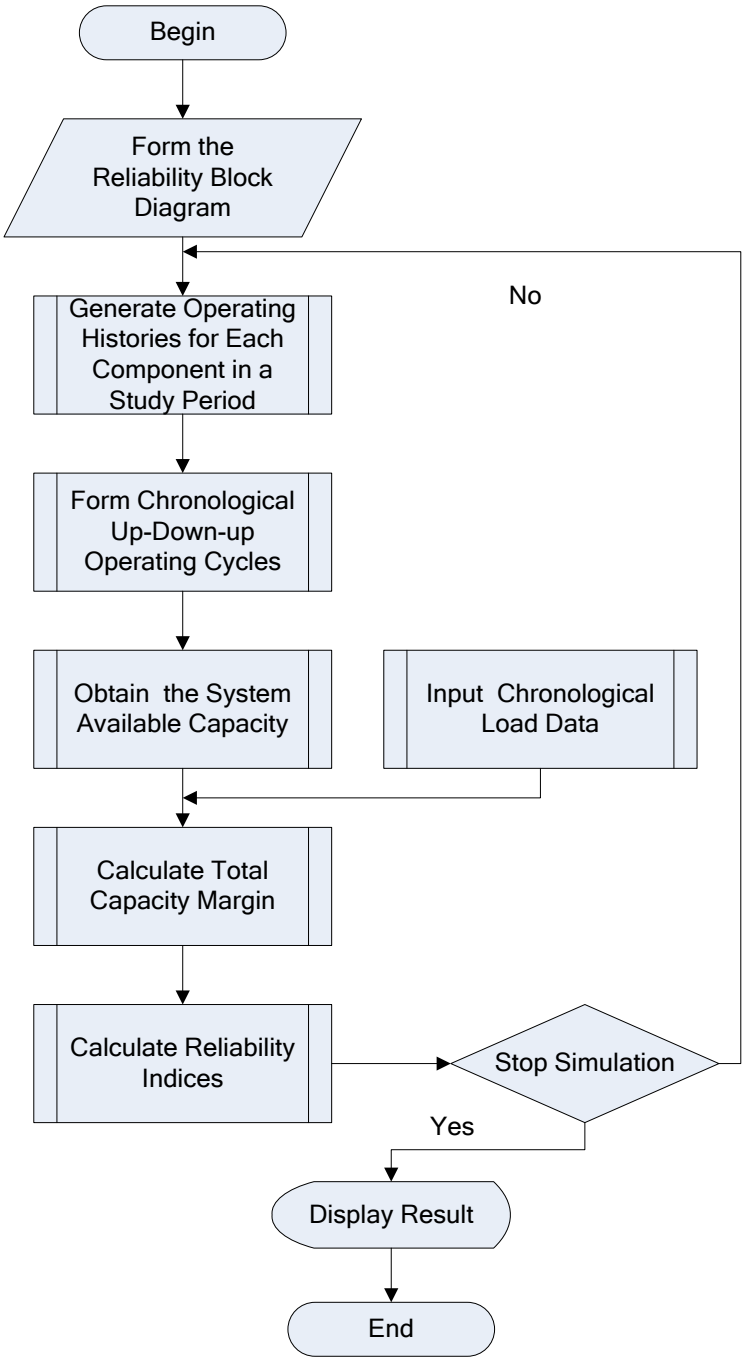

Figure 3.4: The Proposed Simulation Technique

A simulation program was developed based on the above flow chart using Python language. The major inputs and outputs of the simulation program are briefly described in the following subsections.

Input data There are three major inputs to the simulation program. These are simulation parameters, system component data and load information.

(1) **Simulation parameters:** The simulation parameters include the minimum number of replications, the stopping criterion, the interval width for producing histograms of reliability index distributions and the deterministic criterion for performing wellbeing analysis. The minimum number of replications is set for avoiding any premature convergence of the simulation and it is typically set to 1000 unless otherwise specified.

When the simulation is reached the minimum number of replication and the selected index coefficient of variation is less than a pre-determined value, the simulation stops. A class interval needs to be specified for a particular reliability index such as the LOLE, EUE for producing its distribution histogram from the simulation. A deterministic criterion is needed to perform wellbeing analysis as described in Chapter 5 of this thesis.

(2) **Component data:** System component data include the capacity, failure rate and average repair duration for each generating unit and each HVdc component.

(3) **Load Information:** Load information includes the peak load level and the chronological load variation profile.

Output data the major outputs from the simulation program include, but are not limited to, the mean values of various reliability indices including wellbeing indices such as

the LOLE and EUE, information on simulation progress and convergence, the distribution histograms of reliability indices.

3.5 Model Verification

The developed models and procedure are validated by comparing reliability indices calculated using an analytical method and the proposed sequential simulation approach. The example system used in the calculation is similar to the existing Nelson River Bipolar HVdc transmission system located in Manitoba, Canada. The reliability diagram developed for the example system is shown in Figure 3.5.

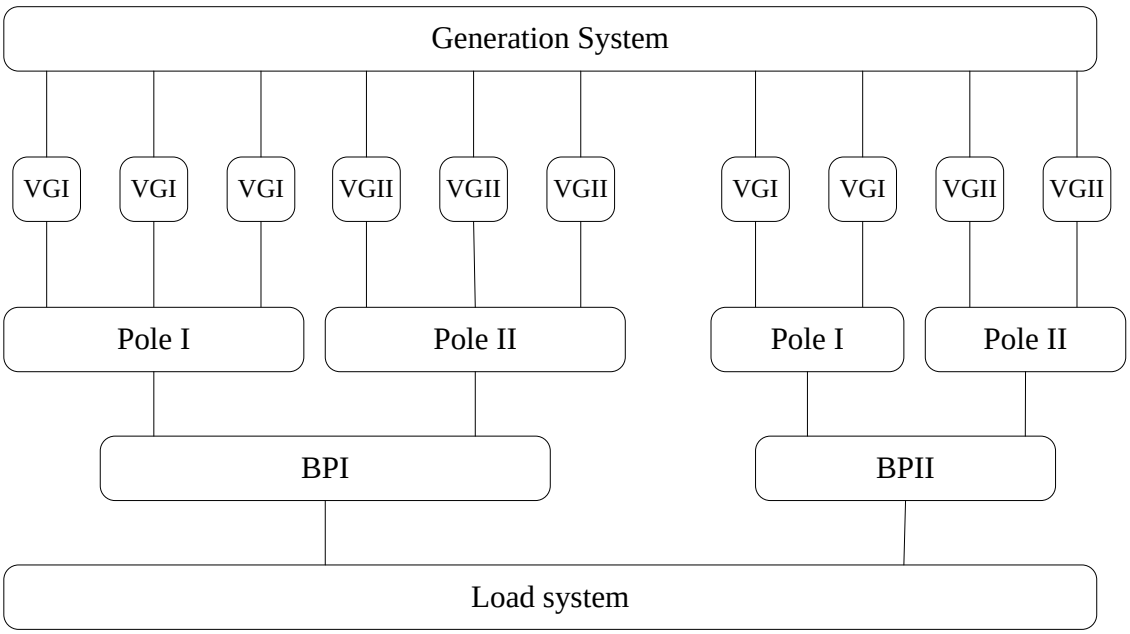

Figure 3.5: Reliability Diagram Developed for the Example System

The HVdc system shown in Figure 3.5 consists of 2 bipolar transmissions called Bipole I and Bipole II. This Bipolar system is a typical LCC-HVdc system. Bipole I has six

valve groups (VG), each of 309 MW capacity, which gives a single pole capacity of 927 MW and a bipolar capacity of 1854 MW. The capacity of each of the four Bipole II valve group is 500 MW, which gives a single pole capacity of 1000 MW and a bipolar capacity of 2000 MW. The component outage statistics used in the calculations are provided in Table 3.1. It is assumed that the generating system connected to the HVdc transmission is 100% reliable. The load variation pattern is the same as IEEE-RTS load with a peak value of 3854 MW.

Table 3.1: HVdc System Outage Statistics Used in the Model Validation

Bipole	Component	Failure/year	Average Repair Duration (h)
Bipole I	BPI Pole I VG	5.2222	6.4747
	BPI Pole I CT	0.034	24 months wo s/12 days w s
	BPI Pole II VG	5.1515	6.0805
	BPI Pole II CT	0.034	24 months wo s/12 days w s
	BPI Pole I SP	4.7143	1.9781
	BPI Pole I TP	1.0952	0.2645
	BPI Pole II SP	3.3636	2.327
	BPI Pole II TP	0.1818	0.15
	BPI Bipole	0.3333	2.5833
Bipole II	BPII Pole I VG	7.1379	5.2100
	BPII Pole I CT	0.034	24 months wo s/12 days w s
	BPII Pole II VG	7.1379	6.0805
	BPII PoleII CT	0.034	24 months wo s/12 days w s
	BPII Pole I SP	3.7414	2.3290
	BPII Pole I TP	1.6897	1.2221
	BPII Pole II SP	3.7414	2.3290
	BPII Pole II TP	1.6897	1.2221
	BPII Bipole	0.6552	2.3272

In the analytical calculation, the COPT developed for the HVdc system assuming that the generating system is 100% reliable is convolved with the system load duration curve. In the Monte Carlo Simulation, the available capacity from the HVdc system that is obtained by combining the operating history of all components shown in Figure 3.5 is superimposed with the chronological load model to calculate the reliability indices. The Monte Carlo Simulation runs for 10,000 replications. To validate results obtained from the Monte Carlo Simulation, they are compared with the analytical results. The LOLE and EUE indices obtained using the two methods are compared in Table 3.2. It can be seen from Table 3.2 that the two methods produce virtually the same results.

It should be noted that the simulation approach can also generate more detailed information such as reliability index distributions that are very useful in understanding the reliability performance of a power system. The construction and the use of the reliability index distributions in HVdc system reliability assessment will be discussed in detail in Chapter 4 of this thesis.

Table 3.2: Comparison of Results Obtained Using Analytical and Simulation Techniques

Reliability Index	**LOLE(hours/y)**	**EUE (MWh/y)**
Analytical	32.70	6789.31
Monte Carlo Simulation	32.24	6784.1

3.6 Summary and Conclusions

A Monte Carlo simulation-based approach for the reliability evaluation of HVdc system is proposed in this chapter. The proposed approach consists of two parts. These are the development of a reliability model for a particular HVdc system of interest and incorporation of such model into the overall system reliability assessment. The proposed approach uses a sequential simulation method to mimic the operating history of the main components that have significant impact on the reliability performance of HVdc systems for example valve groups, poles and bipoles. The reliability model developed for the HVdc system is used to modify the capacity model in evaluating the overall system reliability. The simulation program developed based on the proposed approach was described in detail and the major inputs and outputs to the program were presented. The proposed method is validated against the results obtained from the analytical method. The validation results show that the two methods produce essentially the same results.

Chapter 4 Reliability Assessment of HVdc Systems

4.1 Introduction

The basic concepts, models and techniques for the generating capacity adequacy evaluation incorporating HVdc systems are discussed in Chapter 3. This chapter presents the application of the models and method described in Chapter 3 in reliability evaluation of power systems containing HVdc links. A hypothetical example system is chosen to perform reliability studies. Several cases are examined and compared for illustrating the applications of the proposed models, method and the algorithms. A Monte Carlo simulation program was developed based on the flow chart shown in Figure 3.4 for facilitating the reliability evaluation of the example scenarios. A range of sensitivity analyses is performed by changing some of the key parameters to investigate the impacts of these parameters on the reliability performance of the example cases. The HVdc system reliability is examined using not only the traditional mean values of reliability indices, but also a number of visual illustrations of the distributional variations of these reliability indices. The traditional mean values are important and are the primary indices in power system reliability assessment. For example, a planning engineer may prefer to have several short duration outages rather than a few very large duration outages even though the two scenarios may have the same LOLE index. Nevertheless, the use of the reliability index distributions in HVdc system reliability assessment is a valuable extension to the current industry practice and therefore the applications of these distributions are discussed in detail in this chapter.

4.2 Input Data and Study Scenarios

The reliability block diagram used for the studies described in this chapter is as shown in Figure 3.5 of Chapter 3. The capacity of each component shown in Figure 3.5 was also presented in Section 3.5. The outage statistics assumed for each component in Bipole I and Bipole II for the reliability assessment of various cases were presented in Table 3.1. The hourly chronological load model of the IEEE-RTS with a peak load of 3254 MW is used in most of the analysis presented in this chapter unless otherwise specified. It is assumed in the studies described in this chapter that the generation system feeding into the HVdc transmission system is 100% reliable with a capacity equal to the maximum capacity of the HVdc system.

The following cases are examined using the proposed method:

A. Base Case

The base case assumes that there are no available spare converter transformers for Bipole I and Bipole II. The component outage statistics used in the base case simulation are, therefore, those shown in Table 3.1 for the "without spare" scenario.

B. Spare Converter Transformer (Spare CT)

This case assumes that spare converter transformers are available to both Bipole I and Bipole II. The net reliability effect of the spare converter transformers are modeled approximately by reducing the repair time. The repair times for Bipole I and Bipole II with

spare converter transformers are also shown in Table 3.1. Other system and component parameters are the same as those in the base case.

C. Refurbishment of Valve Groups (Refurbishment)

The outage rates of Bipole I and Bipole II valve groups assumed in the base case are decreased by 15% in this case to examine the impact of VG refurbishment on the HVdc system reliability. Other system and component parameters are the same as those in the base case.

D. Addition of a New Bipole

In this case, a 2000 MW new Bipole is added to the system and the topology, component capacity and its reliability performance are assumed to be identical to that of Bipole II. Other system and component parameters are the same as those in the base case.

4.3 Base Case Results

Evaluation of the LOLE and EUE for the base case yields values of 32.24 hours/year and 6784.1MWh/year respectively. These reliability indices are obtained by averaging the simulation results from 12,000 samples. These results constitute a reference set of basic adequacy indices for the example systems considered.

Figure 4.1 shows the convergences of LOLE and EUE indices for 12, 000 replications. It can be seen from Figure 4.1 that the convergence of the LOLE is better than that of the EUE. The reason is that the EUE, which is a composite of the duration and magnitude of load loss,

makes it difficult to converge than the LOLE index. The reliability indices LOLE and EUE are widely used by utilities as the basic generating capacity adequacy indices. However, they are simply the average values and do not contain any information on the distribution of these indices.

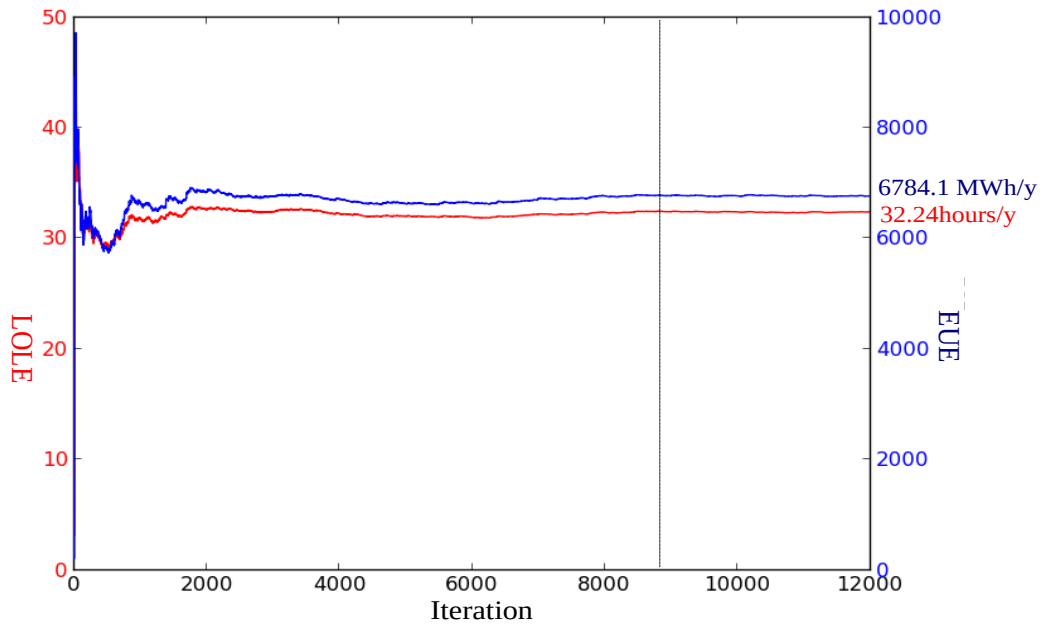

Figure 4.1: Simulation Convergence of LOLE and EUE

One of the advantages of Monte Carlo simulation is that it can produce not only the mean values but also the probability distributions of various reliability indices. The variation of reliability indices around their mean values provides more detailed information on the reliability performance of power systems. A range of distributional variations associated with the LOLE and EUE indices are presented below. The reliability index frequency distributions are constructed by recording the values of interest in the simulation and grouping the observations into frequency distributions. In constructing the frequency distributions, class intervals of 5 hour/year for LOLE and 1 GWh/year for EUE are selected.

Figure 4.2 and Figure 4.3 show the distributions of the loss of load duration and loss of energy for the base case. It can be seen from Figures 4.2 (first bar) that there is a chance of approximately 0.052 in a given year for the system to experience no loss of load event. Additional information on the load loss and energy loss can be obtained using the distributions in shown in Figure 4.2 and 4.3. For example, the 2nd, 3rd and 4th bars in Fig. 4.2 yield relative frequencies of 12.1%, 10.80%, 9.31% respectively for a 0-5 hours loss, a 5-10 hours loss and a 10-15 hours loss. The distributions provide more detailed information compared to a single averaged index. Reliability index distributions can be used in power system planning for example comparison of alternatives with very close average values of LOLE and EUE but with different distributions.

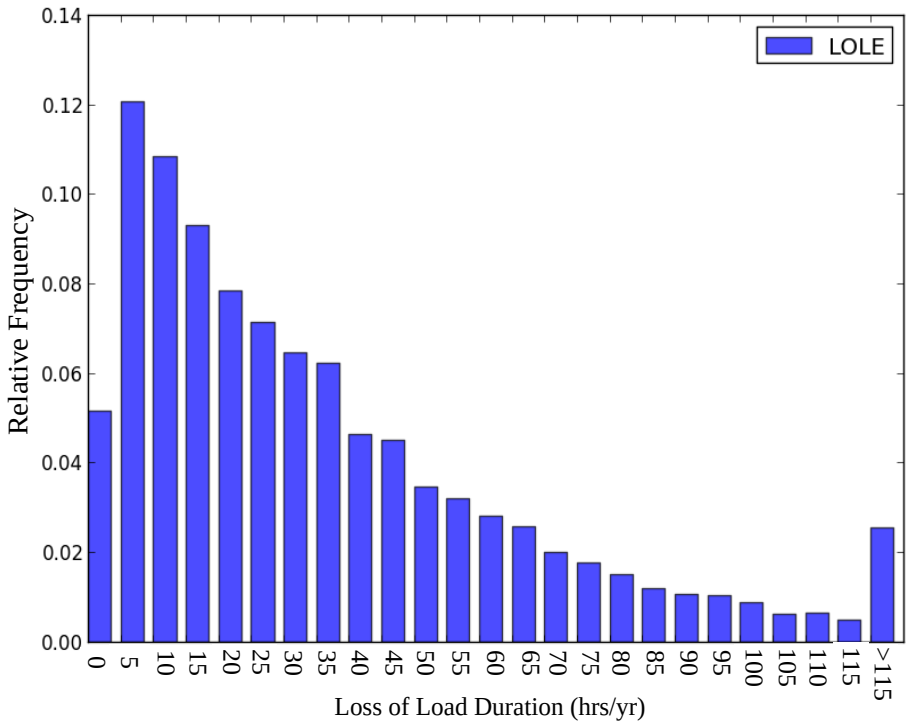

Figure 4.2: Probability Distribution of the LOLE Index (Base case)

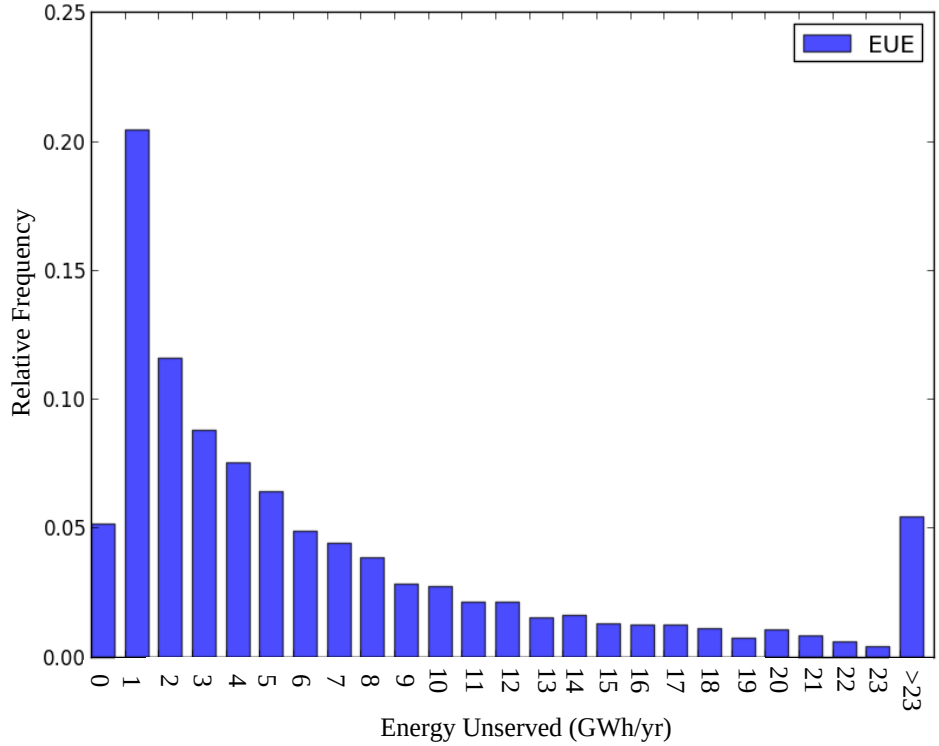

Figure 4.3: Probability Distributions of the EUE Index (Base case)

4.4 Sensitivity Analysis

Several scenarios as described in Section 4.2 were investigated. In each of these scenarios, a modification made to the assumptions of the base case (A), and the sensitivity of the modification to the final result was investigated. These modifications included (B) reduction of failure rate due to refurbishment, (C) availability of a spare transformer in BP1 and BP II and (D) addition of a new Bipole.

Table 4-1 shows the results of these sensitivity cases as discussed in Section 4.2 obtained using the Monte Carlo simulation. It can be seen from Table 4-1 that providing spare converter transformer enhances system overall reliability while refurbishing the valve group marginally

improves the reliability performance of the system under study as compared to the base case results. Addition of a new bipole, however, has significant impact and the reliability indices calculated for this scenario are very favorable.

Table 4.1: Basic Reliability Indices for the Sensitivity Cases

Cases	**LOLE(hour/year)**	**EUE(MWh/year)**
Refurbishment	22.40	4511.56
Spare CT	1.42	616.93
New Bipole	0.02	3.58

Figures 4.4 to 4.6 respectively show the distributions of the annual loss of load duration for the sensitivity cases of the Refurbishment, Spare CT and New Bipole cases. It can be seen from these figures that the shapes of the distributions are very different for these cases. The probability of a zero value in each reliability index distribution is an important reliability parameter. It quantifies the likelihood of a no loss of load event and therefore it is desirable to plan a system with high value of this probability. For example, the LOLE distribution for the refurbished VG (Fig. 4.4) indicates a zero loss of load with a probability of 0.08, which means that in 8% of the cases, a capacity reduction in the HVdc system due to equipment failures will not result in a loss of load. With a spare transformer (Fig. 4.5), this is improved to 51.6%. The LOLE probability with zero value for the addition of a new bipole (Fig. 4.6) is the highest and it is approximately 0.985, i.e., in 98.5% of the HVdc capacity reduction due to equipment failures, there is no loss of load.

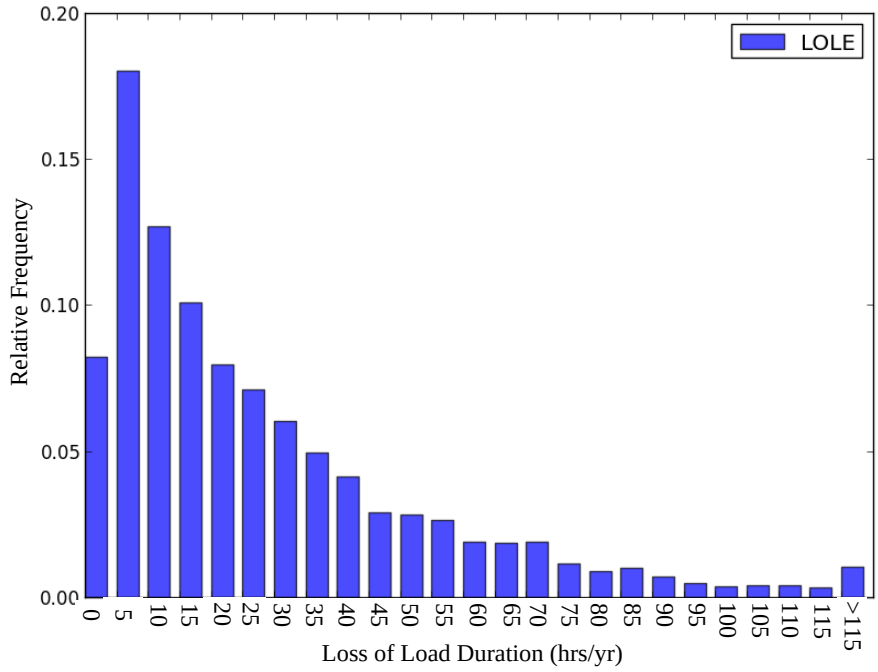

Figure 4.4: Probability Distribution of the LOLE Index (Refurbishment)

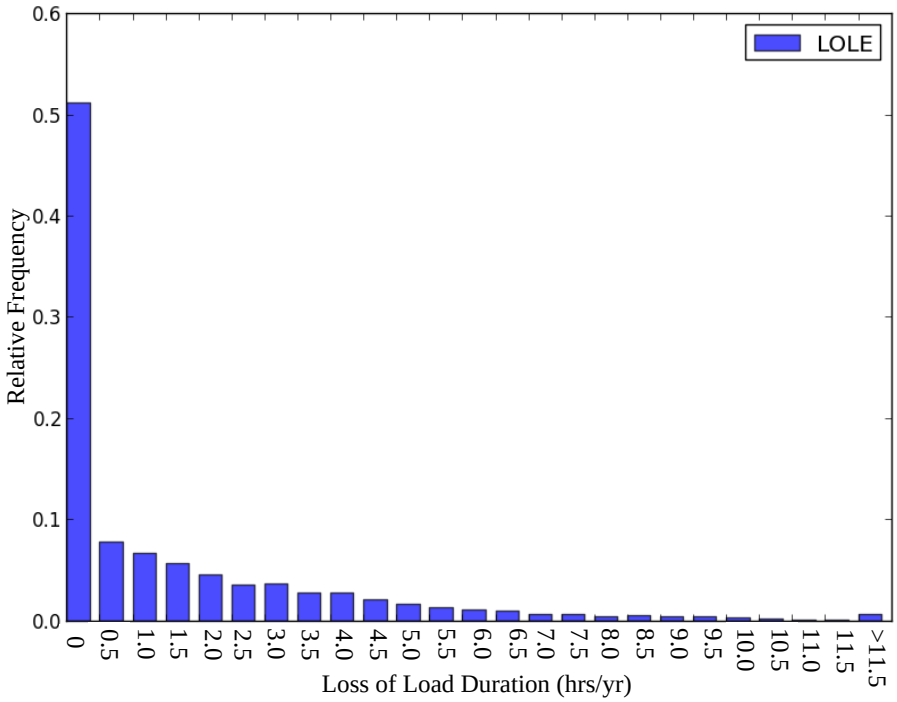

Figure 4.5: Probability Distribution of the LOLE Index (Spare CT)

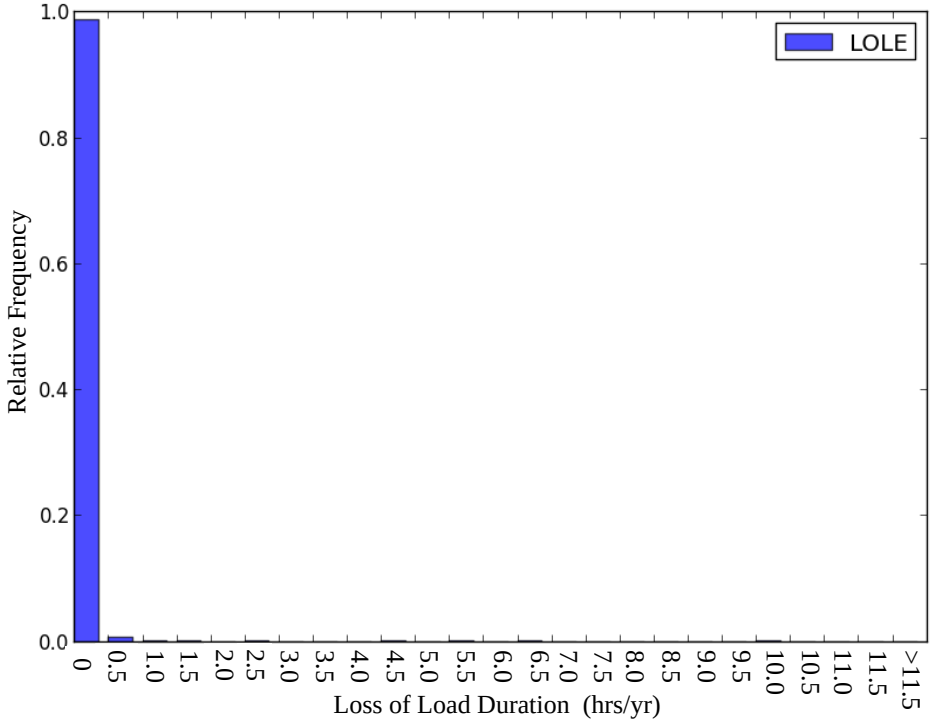

Figure 4.6: Probability Distribution of the LOLE Index (New Bipole)

The probability histograms of the energy not supplied by the system for the three sensitivity cases are shown in Figures 4.7-4.9. The shape of these distributions is similar to that of the corresponding distribution of the annual loss of load duration. The probability associated zero values is also very similar to that of the corresponding distribution of the annual loss of load duration.

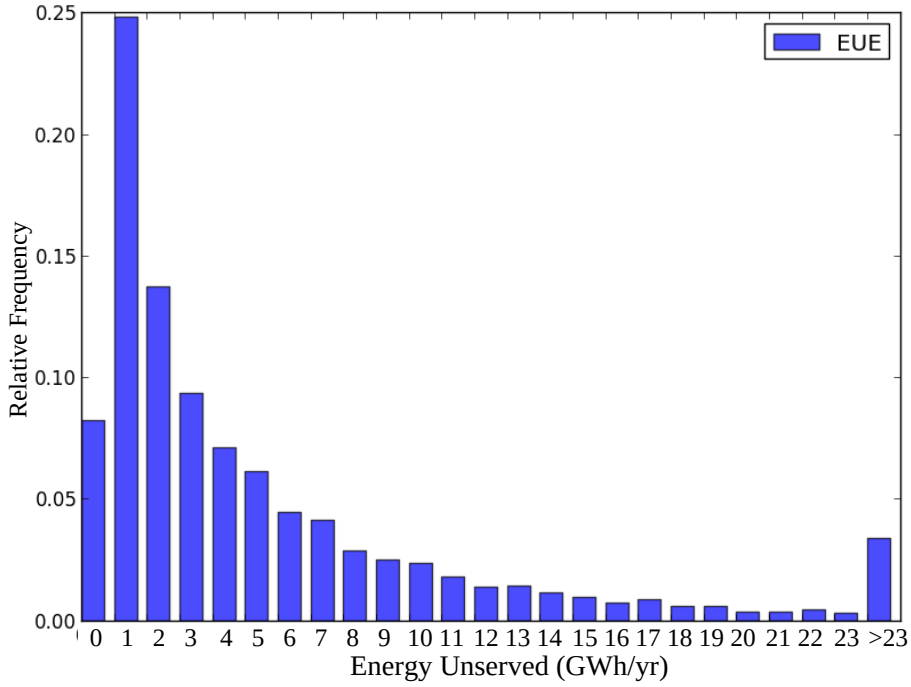

Figure 4.7: Probability Distribution of the EUE Index (Refurbishment)

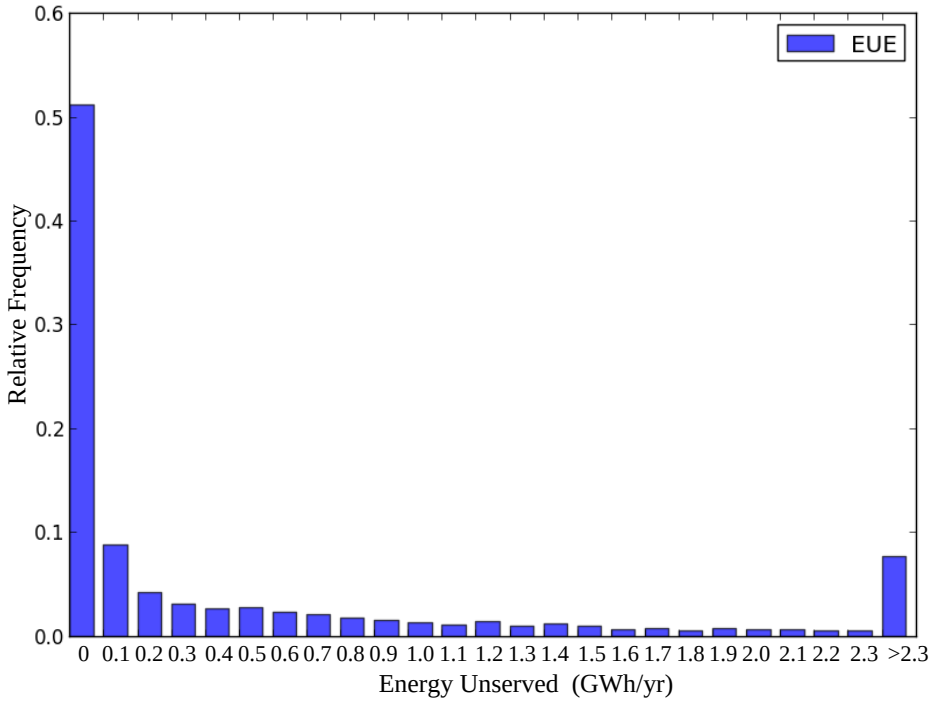

Figure 4.8: Probability Distribution of the EUE Index (Spare CT)

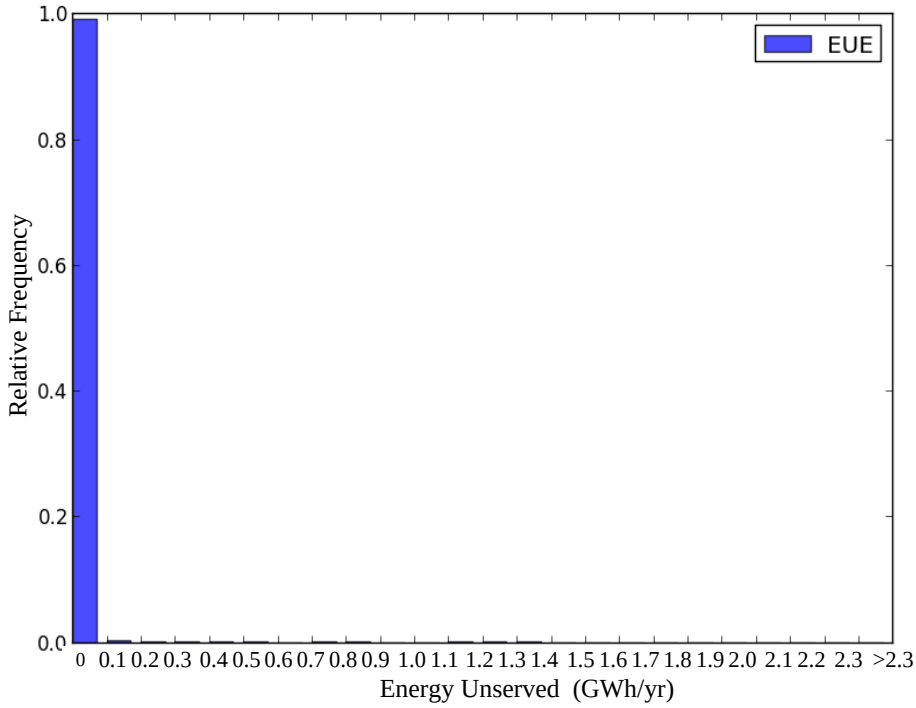

Figure 4.9: Probability Distributions of the EUE Index (New Bipole)

Further studies are performed to examine the impacts of some of the parameters on the reliability performance of HVdc systems. These studies and the results are discussed in the following subsections.

4.4.1 Effect of Peak Load

Normally, system peak load increases with time and it can have significant impact on the reliability performance of a power system. A sensitivity analysis is conducted to examine the impact of system peak load for four different load levels varied from 3254 MW to 3854 MW for a 200 MW step increase while maintaining the basic shape of the load curve. Figure 4.10 shows

the LOLE for the four cases as a function of the maximum annual peak load. For the base case, the LOLE indices are 32.1, 68.2, 134,7 and 253.5 hours/year respectively for the peak load levels of 3254, 3454 3654 and 3854 MW. It can be seen from these results that the system risk increases with peak load in all of these cases but not to the same degree. Figure 4.10 shows that system risk variation for the Base, Spare CT and Refurbishment cases is similar. Due to the significant increase of system redundancy as a result of the addition of third bipole, the system reliability is still high even for a 600 MW load increase.

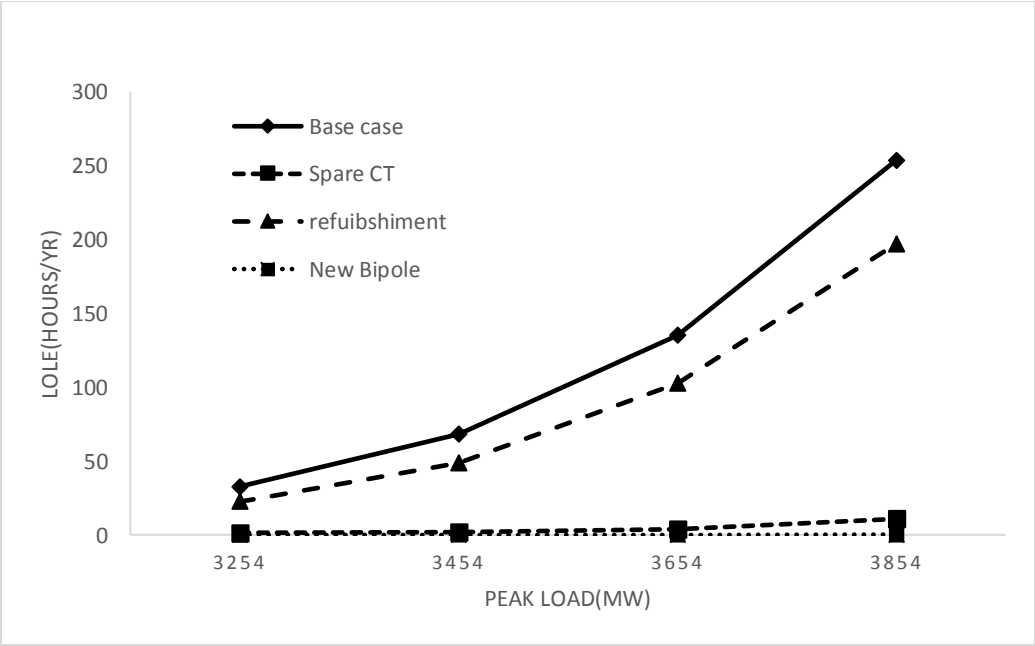

Figure 4.10: Effect of Peak Load on LOLE

The change in the probability distributions of the loss of load duration with peak load (Base Case) is shown in Figure 4.11. A class interval width of 20 hours/year is used in producing the histograms shown in Figure 4.11. The last class interval contains the loss of load durations greater than 460 hours/year. It can be seen from Figure 4.11 that the shape of the loss of load

duration distribution changes with increase in peak load. The probability of no loss of load decreases rapidly with the peak load increases. The probability of loss of load with longer duration increases with increase of peak load.

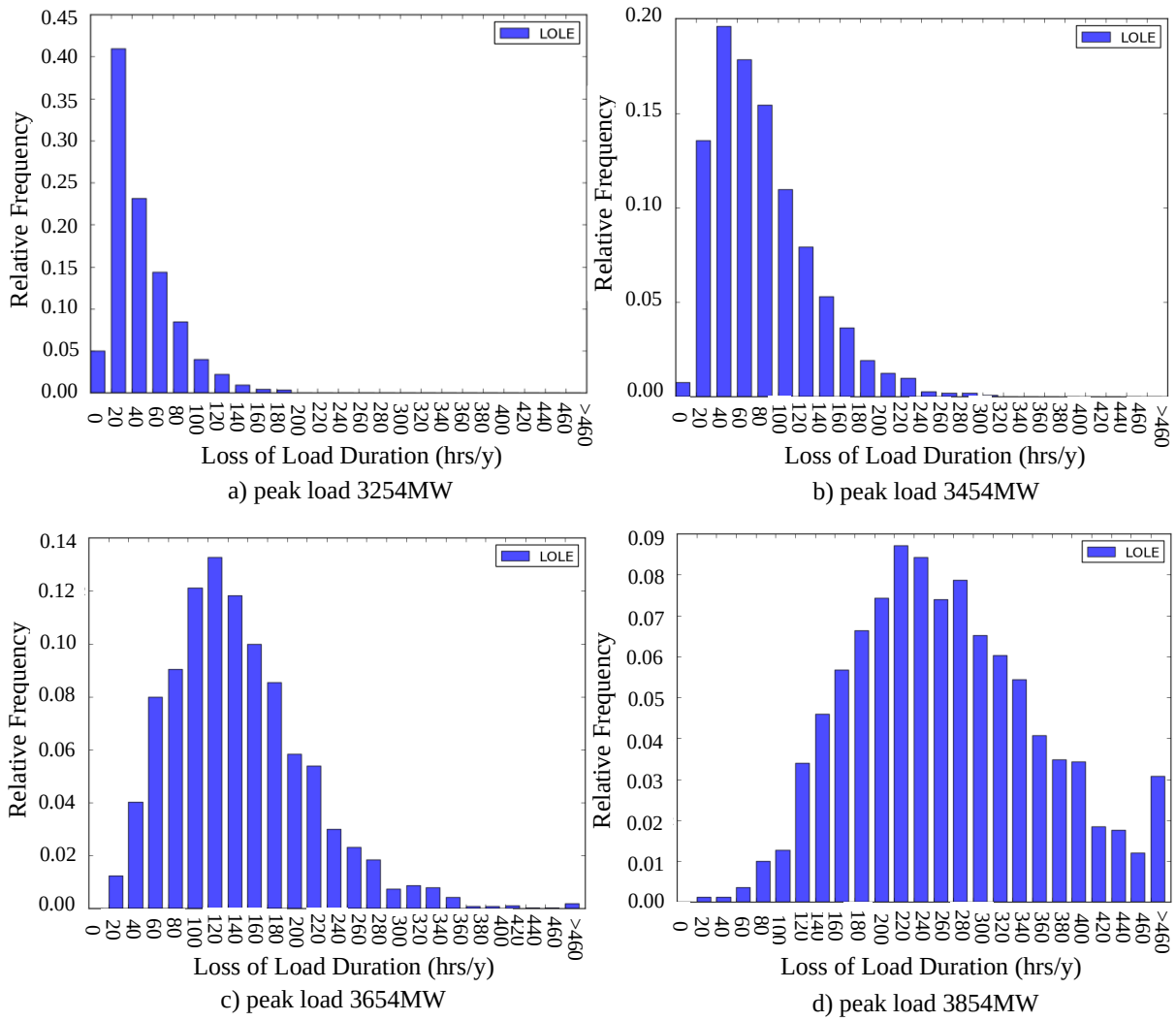

Figure 4.11: Probability Distributions of the LOLE for Different Peak Load (Base Case)

Figure 4.12 shows the EUE for the four cases as a function of the maximum annual peak load. For the base case, the EUE indices are 6789,14767,30959,63477 MWh/year respectively for the peak load levels of 3254, 3454 3654 and 3854 MW.

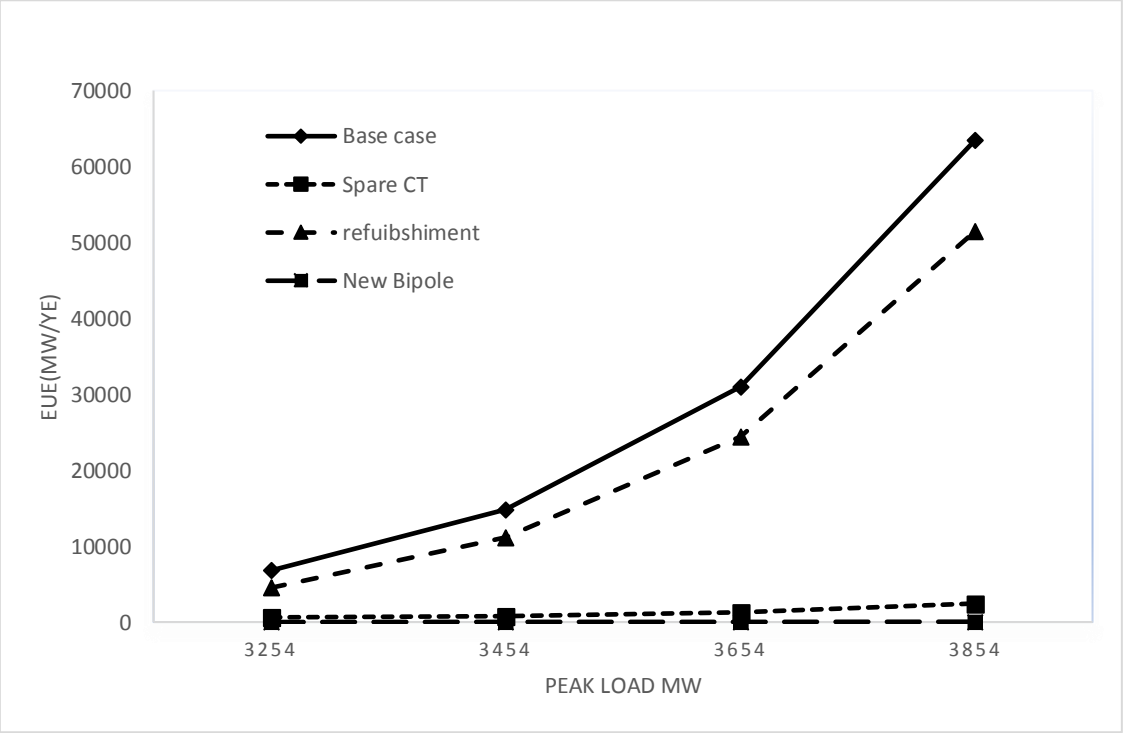

Figure 4.12: Effect of Peak Load on EUE

Figure 4.13 shows the distributions of the loss of energy for four different peak load scenarios for the Base Case. It can be seen from Figure 4.13 that the shape of the distribution also changes with increase of peak load and the distributions extend further to the right as the peak load increases. It can be also seen from Figure 4.13 that the chance of zero loss of energy at a peak load level of 3254 MW is approximately 5.2% and this probability decreases to essentially zero with the increase in load, as seen in the graphs for load values of 3654 MW and 3854 MW. If system load increases to 3854 MW the events associated with larger loss of energy becomes most dominant with a 22.6 % chance of having 92 GWh/yr or larger of unserved energy. From these unserved energy distributions, the need for additional capital investment to improve the system reliability can be identified.

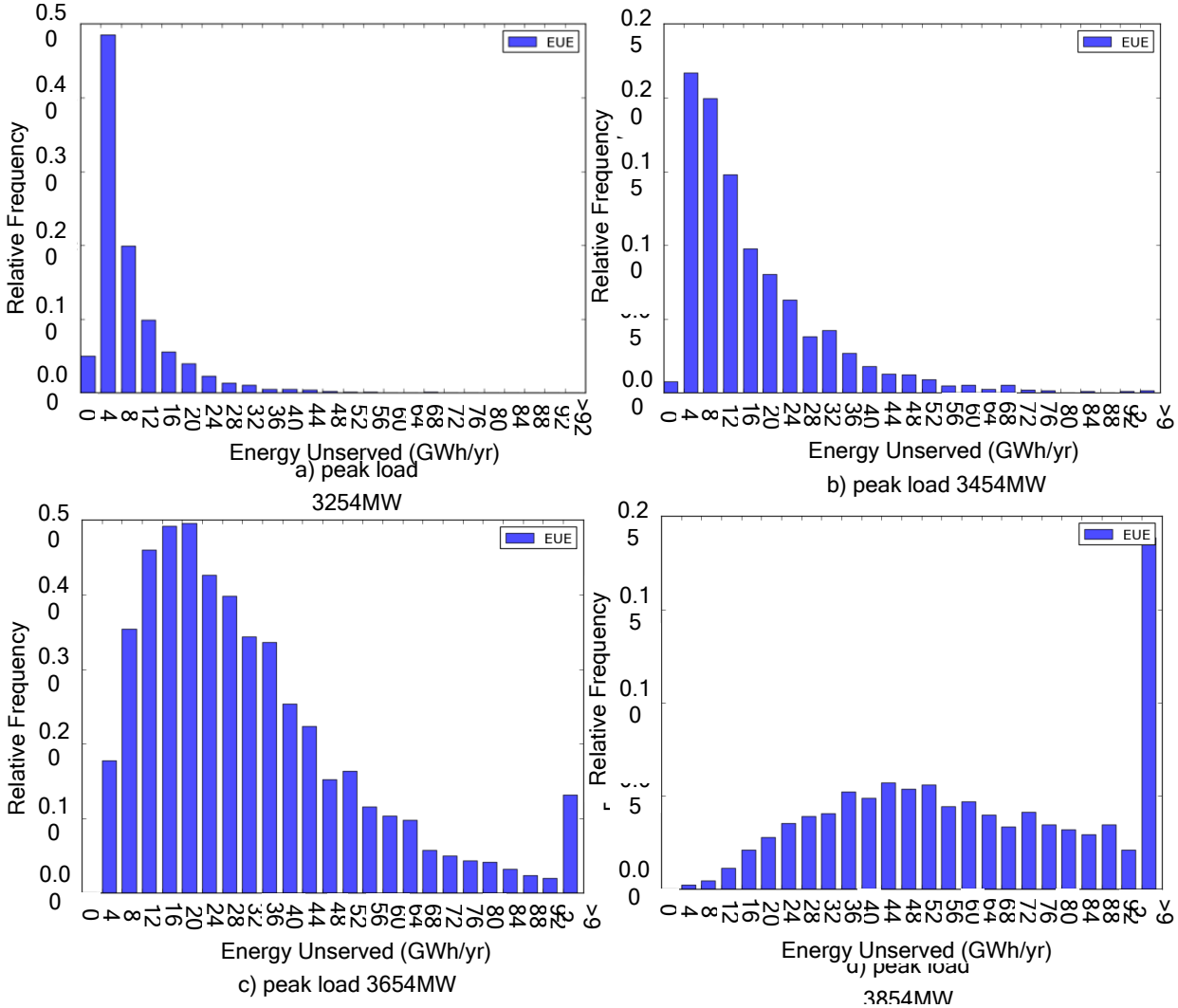

Figure 4.13: Probability Distributions of the EUE for Different Peak Load (Base Case)

4.4.2 Effect of VG Failure Rate

Statistics show that the majority of power interruptions for HVdc systems are due to valve group failures and therefore the reliability of an HVdc system can be strongly influenced by the valve group forced outage rate. The effects of valve group failure rate on HVdc system reliability performance are examined by increasing the base case valve group failure rate in a 25% increment. Figure 4.14 and Figure 4.15 shows the influence of the failure rate on the LOLE and

EUE. It can be seen that the system LOLE and EUE increases as the failure rate of the valve group increases and they are not in the same rate.

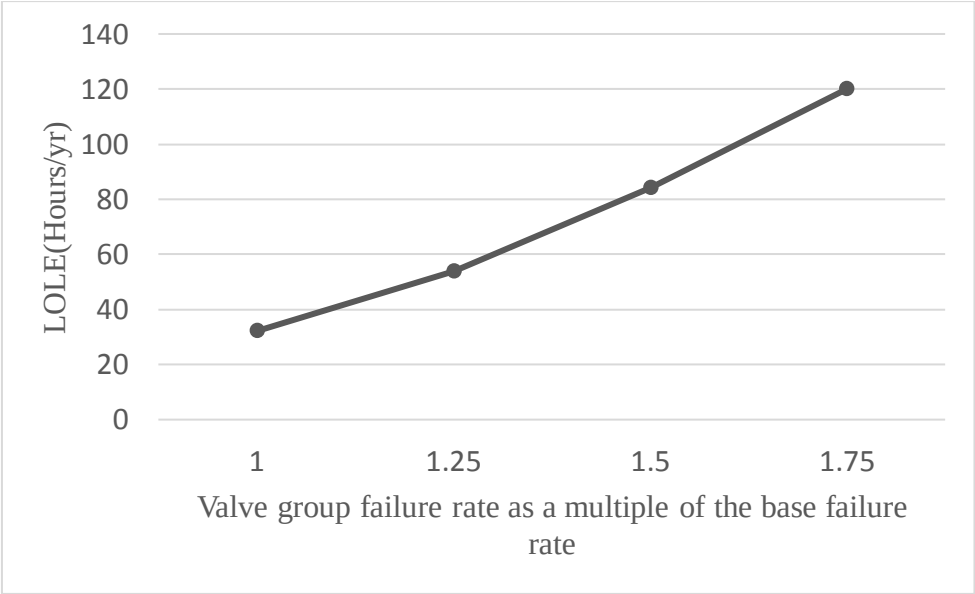

Figure 4.14: Effect of Change in VG Failure Rate on LOLE (Base Case)

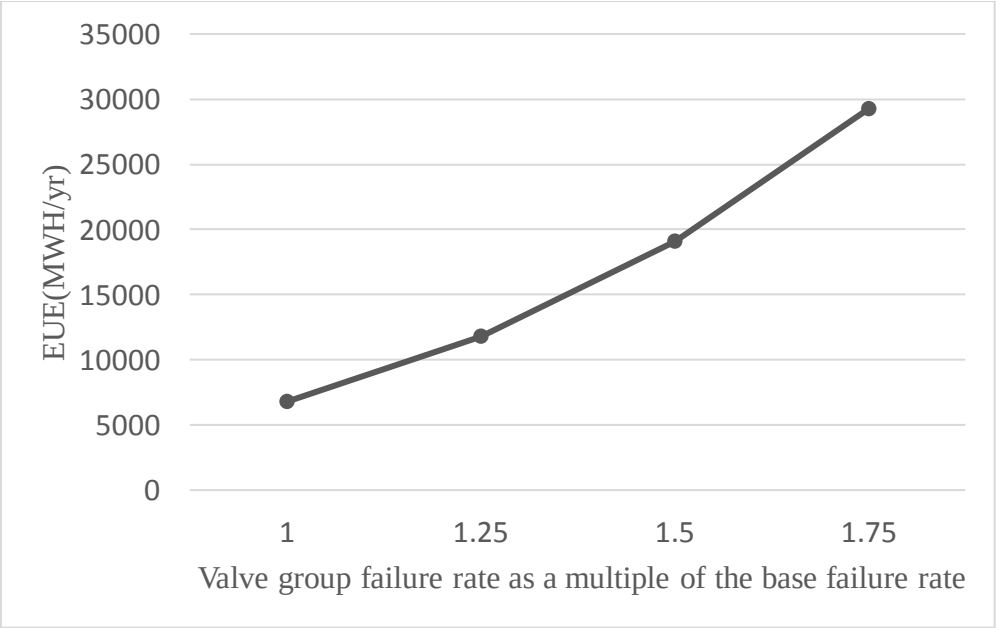

Figure 4.15: Effect of Change in VG Failure Rate on EUE (Base Case)

As before, information that is more meaningful is obtained by considering the distribution of the LOLE index rather than a single average value. The change in the probability distributions of the loss of load duration with VG failure rate is shown in Figure 4.16. A class interval width of 20 hours/year is used in producing the histograms shown in Figure 4.16. It can be seen from Figure 4.16 that the loss of load duration distribution is skewed towards the lower LOLE values. The following observations can be made:

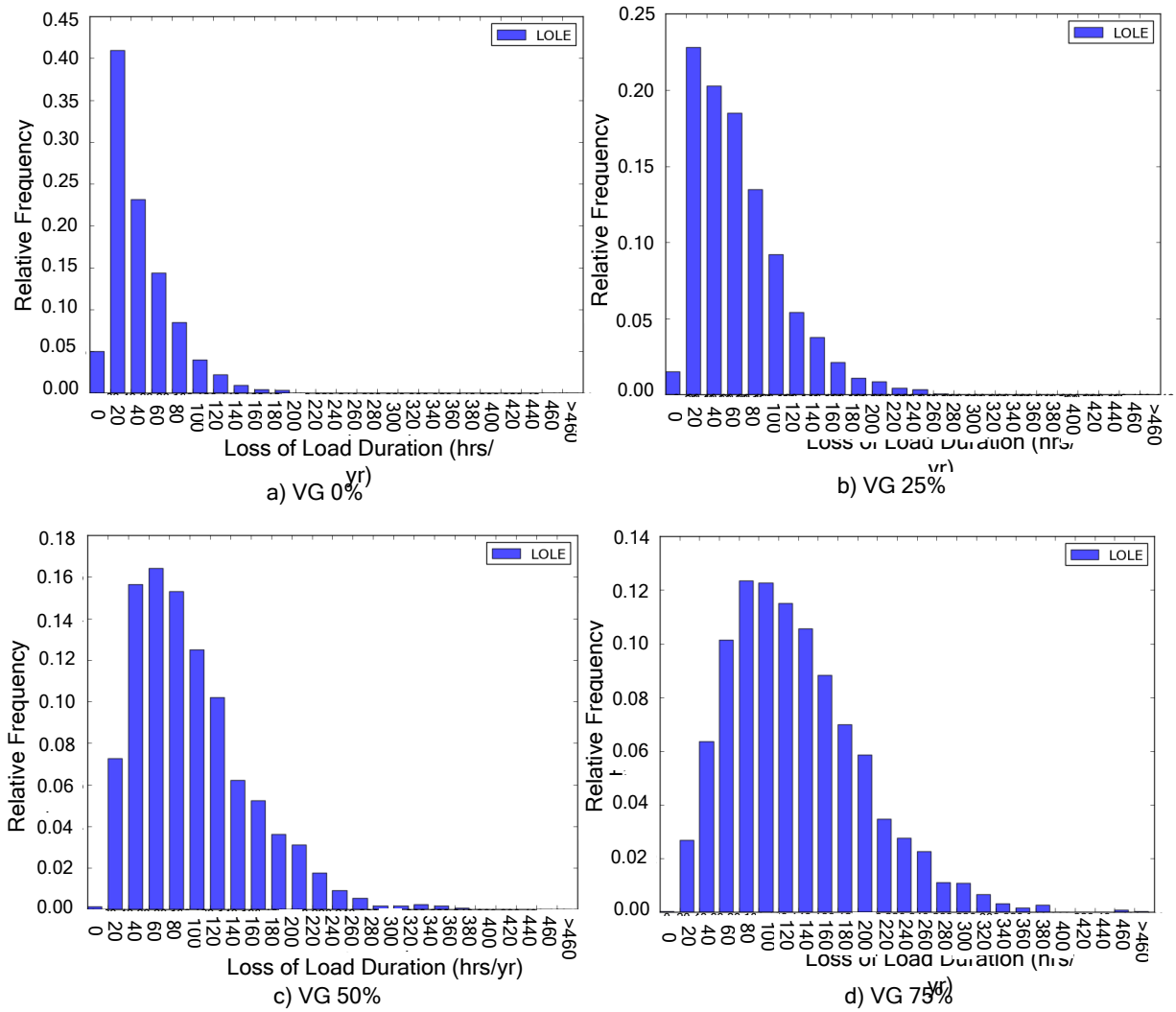

Figure 4.16: Probability Distributions of the LOLE Index for Different VG Failure Rate

With increase in VG failure rate, the relative frequency of zero value decreases. For example, the relative frequency of zero value is 5.2% for the base case but it decreases to 1.6%, 0.5% and 0.1% with the increase in VG failure rate by 25%, 50% and 75% respectively. With increase in VG failure rate, the probability of loss load event with larger duration also increases.

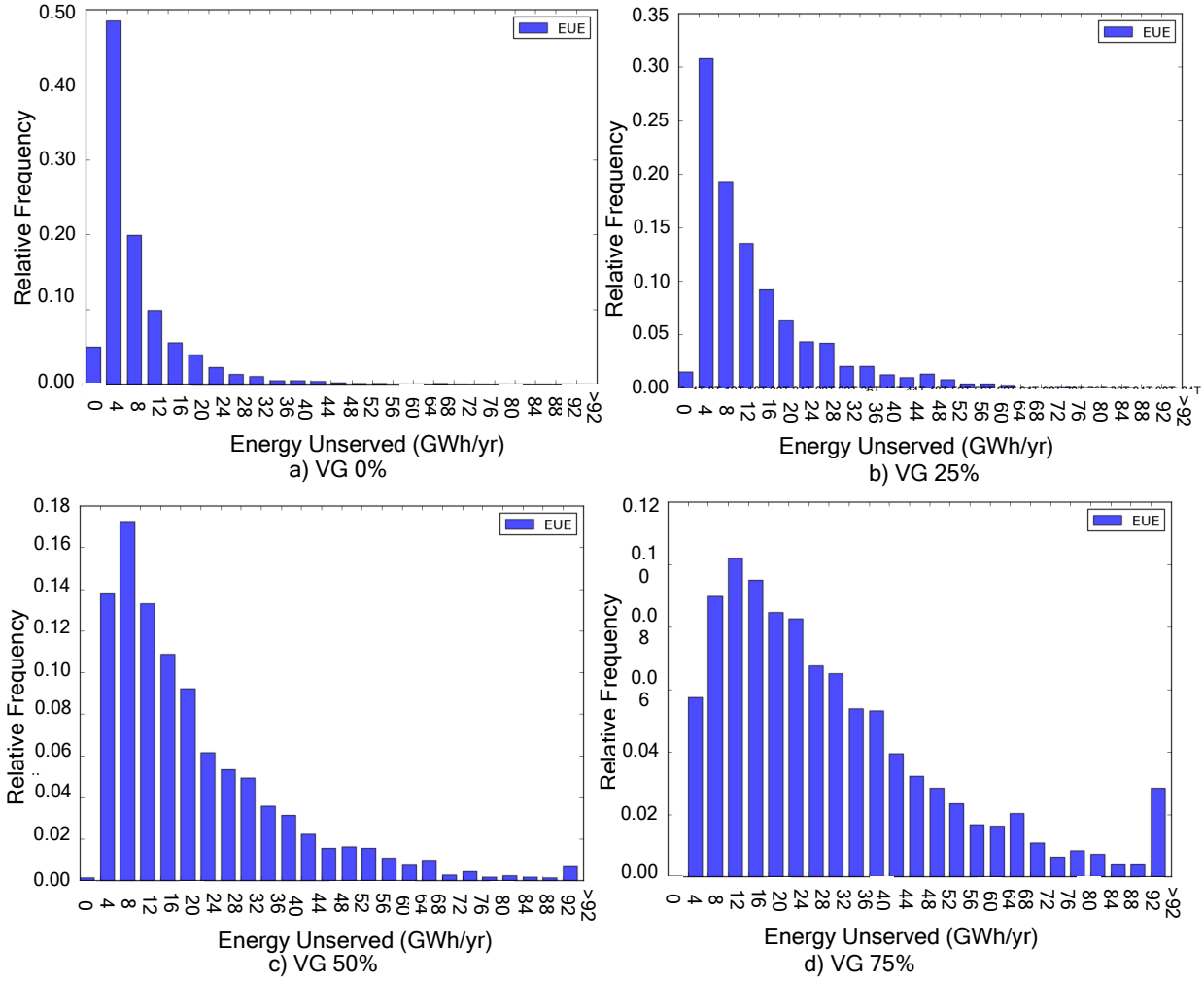

Figure 4.17: Probability Distributions of the EUE Index for Different VG Failure Rate

The change in the probability distributions of the loss of energy with VG failure rate is shown in Figure 4.17. A class interval width of 4000 MWh /year is used in producing the

histograms shown in Figure 4.17. It can be seen from Figure 4.17 that the shape of the loss of energy distribution changes with increase in VG failure rate. The mean value and standard deviation of the loss of energy in hours/year increase as the VG failure rate increases and the distributions shown in Figure 4.17 move to the right. The relative frequency of having a year with non-loss of energy are 1.6%, 0.5% and 0.1% respectively with the increase in VG failure rate by 0%, 25%, 50% and 75% respectively. The relative frequencies of having unserved energy greater than 92 GWh/year for the increase in VG failure rate by 0%, 25%, 50% and 75% are 0%, 0.02% ,0.7% and 3% respectively.

4.5 Summary and Conclusions

A series of studies is performed to examine the reliability performance of an example HVdc system. The reliability performance of the example system is evaluated not only using the traditional mean values of reliability indices but also using more detailed information of reliability index distributions. The mean values of reliability indexes will continue to be the main stream measures for power system reliability. It can be seen from the analysis presented in this section that reliability index distributions can provide very useful additional information on the reliability performance of a particular system. The effect of parameter variations on system reliability performance can be more physically appreciated by analyzing the reliability index distributions.

HVdc system reliability can be enhanced by providing spare components, improving component reliability performance by making appropriate refurbishment and increasing

system redundancy by adding additional components/subsystem. The variations of annual loss of load duration distributions show that the chance of no loss of load increases while the probability associated with longer loss of load duration decreases with enhancement in system reliability.

Both system peak load and different failure rate of valve group effect the reliability index distributions. Increase in system peak load or component unavailability negatively impacts the reliability performance of HVdc systems. The annual loss of load duration is very sensitive to load growth. The probability of uninterrupted load in the entire year, i.e., zero value for the annual loss of load duration decreases as the system peak load increases. The probability of longer loss of load durations increases with increase in valve group failure rate.

Chapter 5 Incorporation of Deterministic Criterion into Probabilistic Assessment

5.1 Introduction

Chapter 4 presents the reliability index distributions of the HVdc system which shows the HVdc system reliability performance in detail. In order to form a uniform set of guidelines for regulators, managers and system planners, incorporation of deterministic criteria into the probabilistic framework is considered and a wellbeing framework for HVdc system is proposed. The advantage of system wellbeing analysis is providing the system designers and operators of the wellbeing status in the forms of healthy and marginal state, not just the risk index.

The basic well-being analysis method was proposed in [35] and the states of the system well-being are illustrated in Figure 5.1. The system well-being state is identified as healthy, marginal and at-risk by considering deterministic criteria in a probabilistic assessment. The accepted deterministic criteria recommend the reserve margin be sited well to meet the reliability requirement. Reserve margin is the sufficient capacity which should be scheduled in order that the system has the capacity to handle a specified deviation of load and the possible loss of a specified operating generation unit.

In the healthy state, the system meets the deterministic criteria such as tripping of the largest generation unit or adequate reserve margin. The system is in marginal state when the

system does not meet the deterministic criteria but also does not have loss of load. The system is in at-risk state if the capacity of the system supply is lower than the load demand.

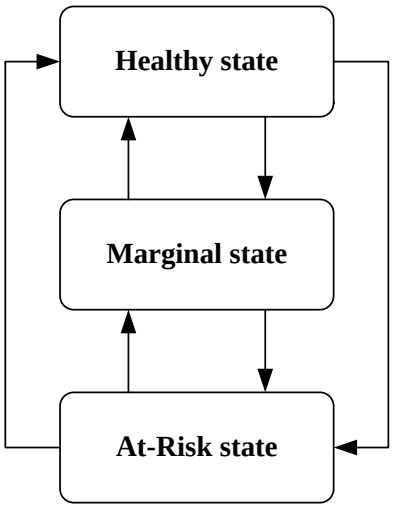

Figure 5.1:Model for System Well-Being Analysis

The deterministic criterion to define an acceptable level of system reliability varies. The classic criterion is the N-1 security criterion, which requires that the power system is able to withstand the loss of any one element of the system (line, transformer, generator, HVdc valve etc.) without loss of any load [36]. This deterministic technique does not provide an assessment of the actual system reliability, such as it does not incorporate the probabilistic or stochastic nature of the system behavior and component failures. The deterministic criteria of the loss of the largest unit (LLU) [32] is also frequently used in generating system planning. The more consistent and realistic approach is the one which recognizes the stochastic nature of system components and incorporates these factors in the assessment in a consistent way. The deterministic criterion of loss of one of the largest valve group or pole is used in the analysis presented in this chapter.

The IEEE-RTS system was used to illustrate the applications of the proposed well-being framework. The hypothetical example systems described in Chapter 4 are used to perform well-being analysis. A range of sensitivity analyses are also performed by changing some of the key parameters to investigate the impacts of these parameters on the well-being indices. The HVdc system well-being is examined using not only the mean values of well-being indices, but also the distributional variations of these indices.

5.2 Well-being Framework for HVdc Systems

The extension of the conventional well-being approach to be used in the power systems containing HVdc links is proposed in this chapter. Rather than focusing on loss of load expectation, well-being analysis classifies the network condition into healthy, marginal and at-risk state probabilities. The well-being analysis is further enhanced by presenting distributions of the duration and frequency of each state. Rather than providing a single well-being figure, different operating choices may provide different distributions for duration and frequency of the marginal state. For example, two alternatives could have very close mean values for economic or reliability indices, but significantly different distributions. Using distributions, a planning engineer can determine which alternative is more suitable, e.g., is it better to have several short marginal durations or is it better to have a few very large marginal durations.

The Monte Carlo simulation technique is used to calculate the well-being indices. Figure 5.2 graphically shows the combination of generation model with the load model for

different time intervals. The state can change over time and the well-being indices can be evaluated by simulating the system from a large number of samples.

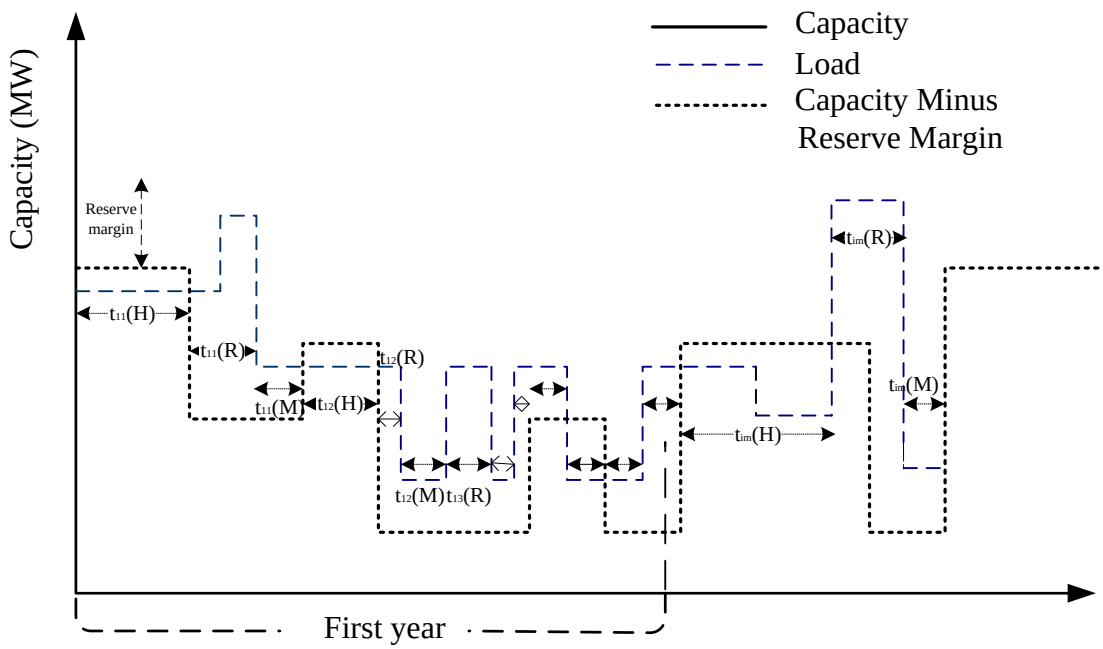

Figure 5.2: Graphical illustration of Performing System Well-being Analysis

The total system capacity available in each hour is superimposed with the chronological load (measured) as shown in Figure 5.2. When the system load is less than or equal to the capacity minus reserve margin, the system state is healthy and the duration $t_{ij}(H)$ for this state is recorded. On the other hand, when the load is less than the system capacity, but greater than the capacity minus reserve margin, a marginal state is indicated. When the load is greater than the system capacity, it denotes an at-risk state. The corresponding durations for the marginal and at-risk states, $t_{ij}(M)$ and $t_{ij}(R)$ are calculated respectively. The basic well-being indices can be obtained by recording the appropriate time duration T_i

shown in Figure 5.2. The corresponding duration T_i is defined mathematically in following Equation:

$$\mathrm{T}_i(\mathrm{H}) = \sum_{j=1}^{n(H)} t_{ij}(H) \qquad \text{when } SC_{ij} > ML_{ij} + L_{ij} \quad (5.1)$$

$$\mathrm{T}_i(\mathrm{M}) = \sum_{j=1}^{n(M)} t_{ij}(M) \qquad \text{when } ML_{ij} + L_{ij} > SC_{ij} > L_{ij} \quad (5.2)$$

$$\mathrm{T}_i(\mathrm{R}) = \sum_{j=1}^{n(R)} t_{ij}(R) \qquad \text{when } SC_{ij} < L_{ij} \quad (5.3)$$

Where: SC_{ij} is the system capacity. ML_{ij} is the reserve margin. L_{ij} is the load demand. T_i is the corresponding duration in each year. $n(H), n(M)$ and $n(R)$ are the number of occurrences of the healthy, marginal and at-risk states respectively.

Using the above definition, the following basic well-being indices can be evaluated:

Healthy State Probability:

$$\mathrm{p(H)} = \frac{1}{8736*\mathrm{N}} \sum_{i=1}^{\mathrm{N}} T_i(H) \quad (5.4)$$

Marginal State Probability:

$$\mathrm{p(M)} = \frac{1}{8736*\mathrm{N}} \sum_{i=1}^{N} T_i(M) \quad (5.5)$$

Risk State Probability:

$$\mathrm{p(R)} = \frac{1}{8736*\mathrm{N}} \sum_{i=1}^{N} T_i(R) \quad (5.6)$$

Additional well-being indices can also be defined if required. The healthy state duration (HSD) defined below, measures the average duration of the system in the healthy state. A high value of HSD represents a more comfortable system as it implies that the system

resides in the healthy state longer. Marginal (MSD) state duration is similarly defined as the average duration of the system in the marginal state. A similar index is not required for the At-risk state as it simply corresponds to the loss of load period.

Healthy state duration:

$$\mathrm{HSD} = \frac{1}{\mathrm{N}} \sum_{i=1}^{N} T_i(H) \tag{5.7}$$

Marginal state duration:

$$\mathrm{MSD} = \frac{1}{\mathrm{N}} \sum_{i=1}^{N} T_i(M) \tag{5.8}$$

The frequency of healthy, margin and risk measure the expected number of times that the corresponding state is encountered by the system in a year. In other words, the frequency of healthy states is the number of occurrences in which the system has enough reserve capacity to satisfy the deterministic criterion. The frequency of risk represents the number of occurrence when the system cannot satisfy the system demand.

Frequency of health:

$$F(H) = \frac{\sum_{i=1}^{N} \mathrm{n}(H)}{N} \tag{5.9}$$

Frequency of margin:

$$F(M) = \frac{\sum_{i=1}^{N} \mathrm{n}(M)}{N} \tag{5.10}$$

Frequency of Risk:

$$F(R) = \frac{\sum_{i=1}^{N} \mathrm{n}(R)}{N} \tag{5.11}$$

Where: N is the total number of replications in the Monte Carlo simulation.

As noted earlier the most commonly used deterministic criterion is the N-1 security criterion which requires the system is able to withstand the loss of any one component in the system without loss of load. In the following analysis, a deterministic criterion similar to the traditional N-1 security criterion is used. It is assumed that in the healthy state the HVdc system capacity is able to cover all the load demand with a reserve capacity that is equal or greater than the capacity of the largest valve group or pole in the system. Any other deterministic criterion can easily be incorporated in the well-being analysis using the proposed approach.

5.3 Case Studies

Case studies for well-being analysis used the exactly the same information provided in Chapter 4 for the base case and the sensitivity cases. The hourly chronological load uses the IEEE-RTS profile with a peak load of 3254MW. The length of the time step is 1 hour and there were 8736 samples in each time series. The maximum number of replications is set to be 10,000. The largest VG capacity is 500 MW and therefore the deterministic criterion of reserve capacity is 500 MW.

Table 5.1 shows the basic well-being indices calculated for the four cases described in Chapter 4. It can be seen from Table 5.1 that the healthy state probability is high and marginal

and risk state probabilities are small for all cases examined. Due to the addition of the third bipole, the healthy state probability is virtually 1 for the New Bipole case indicating that loss of a 500 MW capacity has no impact on the reliability performance of the system.

Table 5.1: Basic Well-being Indices Calculated for the Four Cases Described in Chapter 4

CASE	P(H)	P(M)	P(R)
Base	0.9670	0.0263	0.0037
Refurbishment	0.9989	0.00095	0.00013
Spare CT	0.9840	0.01460	0.00149
New Bipole	0.99996	2.8176e-05	1.917e-06

5.4 Evaluation of Well-being Index Distributions

Figure 5.3 shows the distributions of HSD of the four cases examined. The class internal used in the Base and Refurbishment cases is 30 hours, and the range of HSD varies between 8100 hours and 8736 hours. The class internal for the Spare CT and New Bipole cases is 2 hours and the range of HSD is between 8694 hours to 8736 hours. It can be seen from Figure 5.3 that the shapes of the distributions are different and the distribution of HDS moves to the right side of the figure as the system reliability is enhanced.

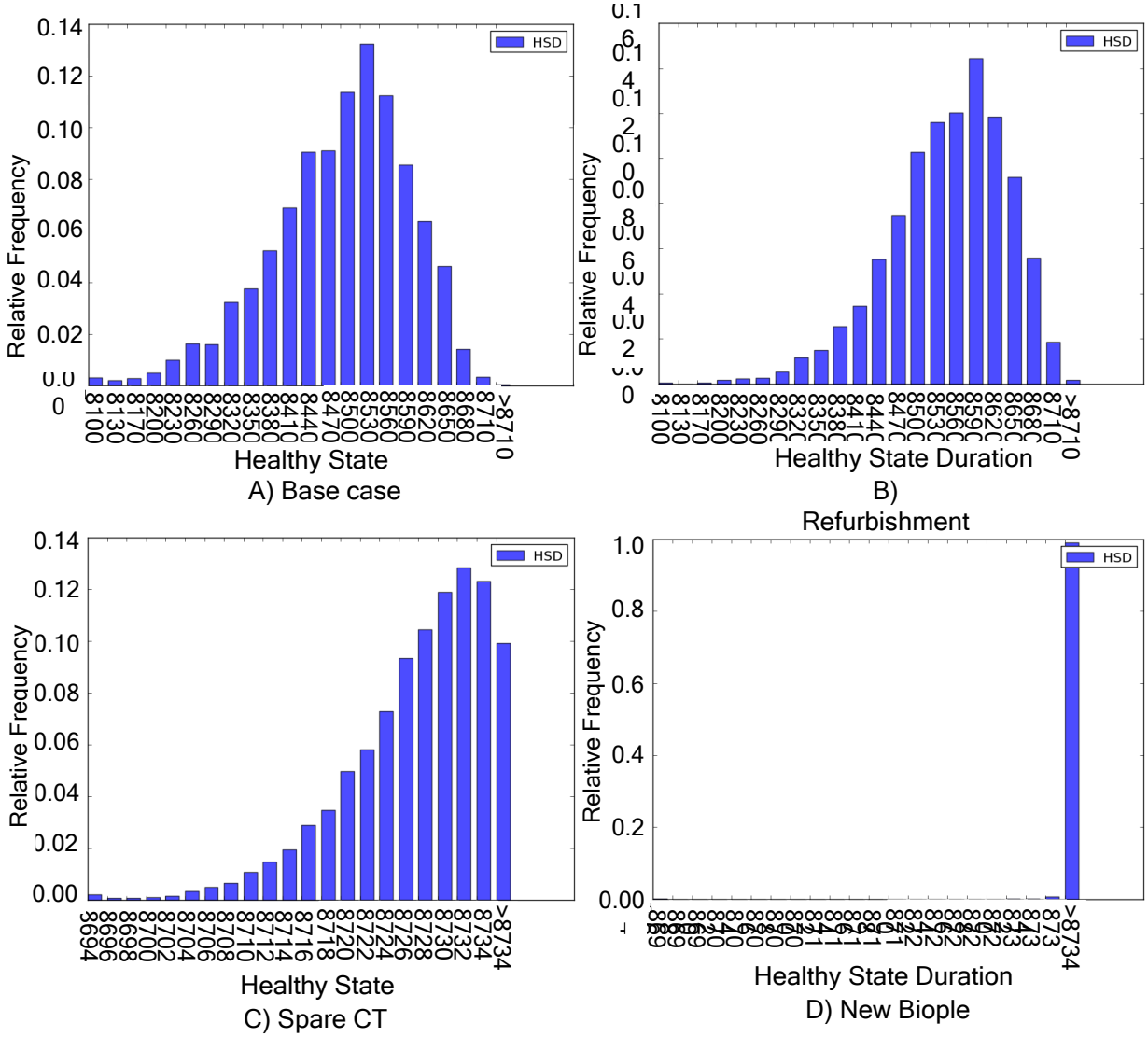

Figure 5.3: Healthy State Duration Distributions

Figure 5.4 shows the MSD of four cases. The class internals used in the Base Case and Refurbishment cases are 25 hours, and the range of MSD is from 50 hours to 550 hours. The class internals for the Spare CT and New Bipole cases are 2 hours and the MSD ranges from 0 to 40 hours. It can be seen from Figure 5.4 that the shapes of the distributions are also different for these cases and the distribution of MSD moves to the left side of the figure as the system reliability is enhanced.

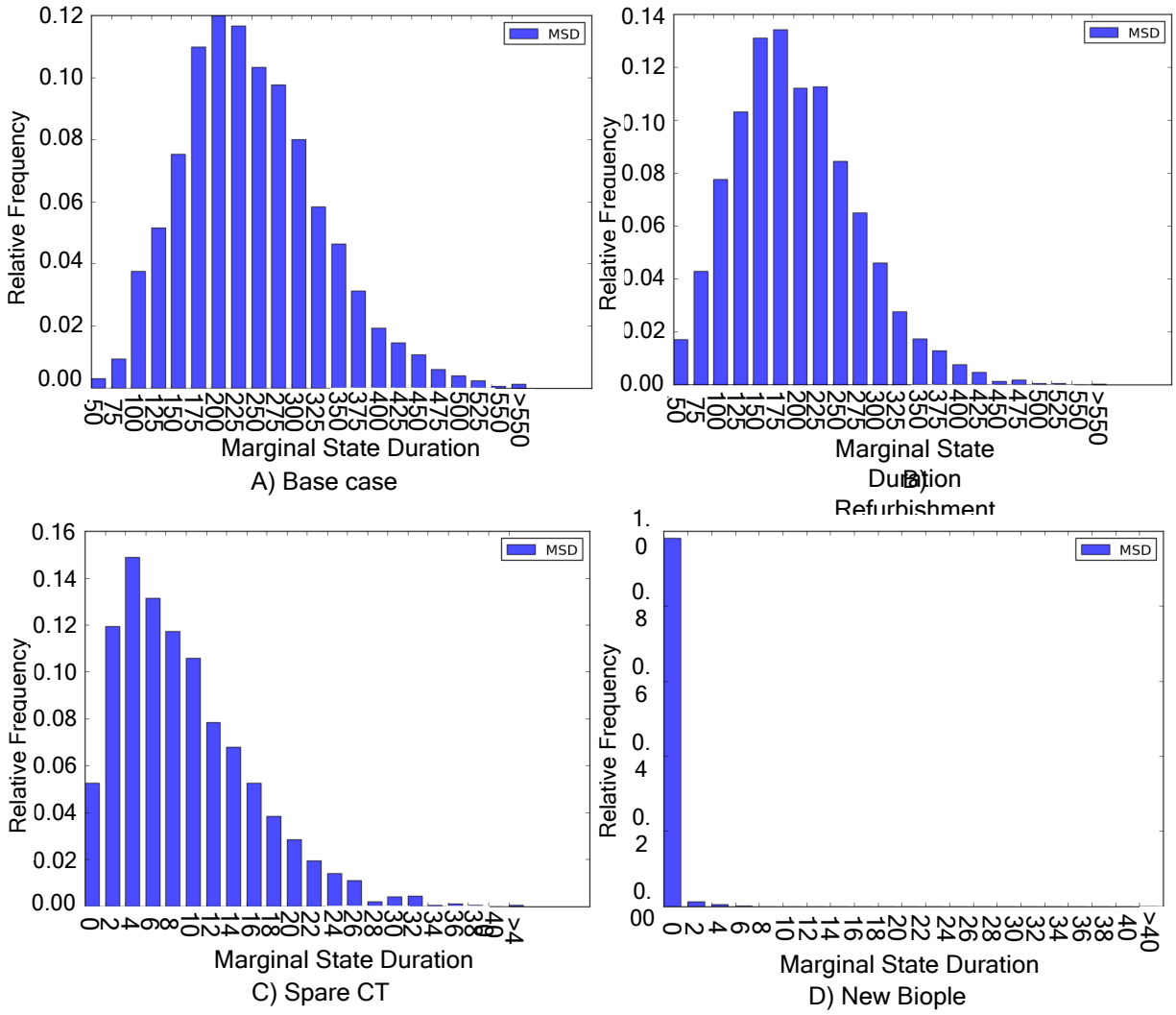

Figure 5.4: Marginal State Duration Distributions

Similarly, the distributions associated with any well-being indices can easily be produced and compared if necessary. The information on reliability index distribution is very useful particularly when comparing alternatives. For example, three alternatives are very competitive in terms of economics and reliability based on the mean values. It is, therefore, difficult to recommend any of the three options. In this case, reliability index distributions can

be produced and compared so that one of the alternatives could be preferred over the other two.

5.5 Effect of deterministic criteria on system well-being

As discussed earlier deterministic criteria play vital role in the well-being analysis. The impact of the reserve margins on the system healthy, marginal and risk states can be determined using deterministic indices for Healthy, Marginal or At-risk states. Different reserve margin criteria have been used to calculate well-being indices. These include the preciously examined criterion for the reserve margin, i.e., providing a reserve equal to the capacity of the largest VG (e.g., 500 MW in the example discussed in Section 3.5) or a reserve which is equal to the largest pole capacity (1000 MW). Table 5.2 shows the variation in the system health, margin and risk probabilities with the different deterministic criterion for the base case. It can be seen from Table 5.2 that the healthy state probability decreases, the marginal state probability increases, and the risk state probabilities remains the same when the required reserve margin changes from 500 MW to 1000 MW.

Table 5.2 : Impact of Deterministic Criterion on System Well-being

CASE	P(H)	P(M)	P(R)
500 MW Reserve	0.9670	0.0263	0.0037
1000MW Reserve	0.85018	0.14607	0.0037

The healthy and marginal state duration distributions obtained using the two different deterministic criteria are shown in Figures 5.5 and 5.6 respectively. The interval width is set

at 100 hrs/yr and the range of HSD is between 6636 hours to 8736 hours and the range of MSD is between 50 hours to 2300 hours.

It can be seen from Figure 5.5 that the largest relative frequency is 37% and the corresponding duration falls in the range of [8436, 8536] hours if a 500 MW deterministic criterion is used. In this case, the healthy state duration distribution as shown in Figure 5.5 A). If a 1000 MW deterministic criterion is used the peak relative frequency is 17.8 % and its duration falls in the range of [7436, 7536] hours because the more demanding the deterministic criterion, the distribution moves to the left side of the graphic as shown in Figure 5.5-B.

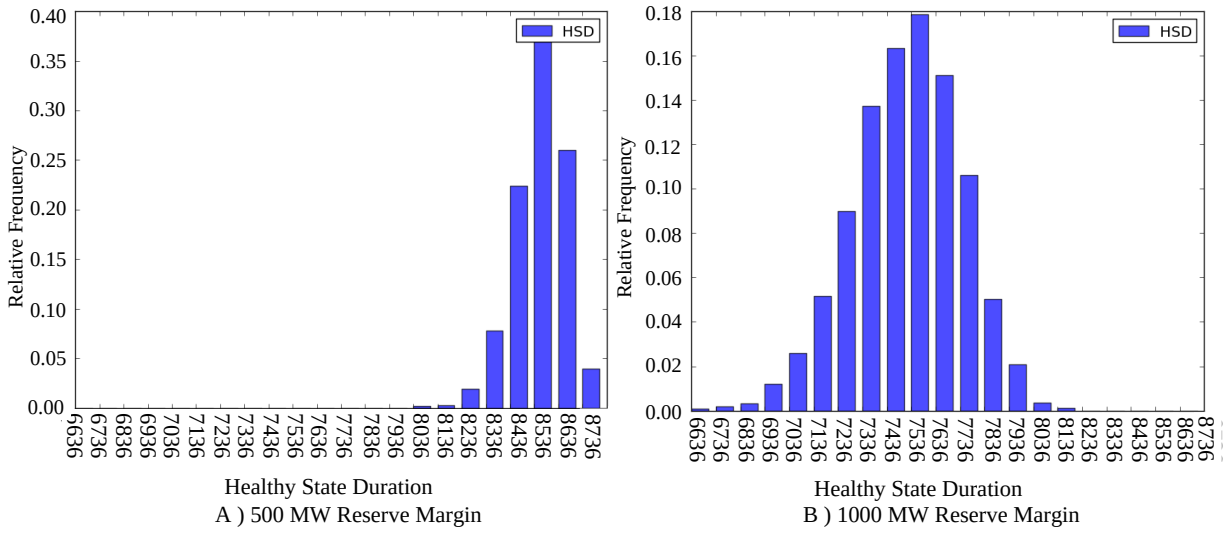

Figure 5.5: Healthy State Duration Distributions (Effect of Deterministic Criterion)

The distributions of the marginal state duration are different from those of the healthy state duration. If a 500 MW deterministic criterion is used, the marginal state duration is biased more towards the left side as shown in Figure 5.6 A. The largest relative frequency is

51% shown (Figure 5.6 A) and the corresponding duration is 175 to 300 hours. If a 1000 MW deterministic criterion is used the distribution is displaced to the right side of the graph as shown in Figure 5.6 A. The more demanding the deterministic criterion, the more possibility the system operates in the margin state resulting in the reduction in the anticipant duration of residing in the health state.

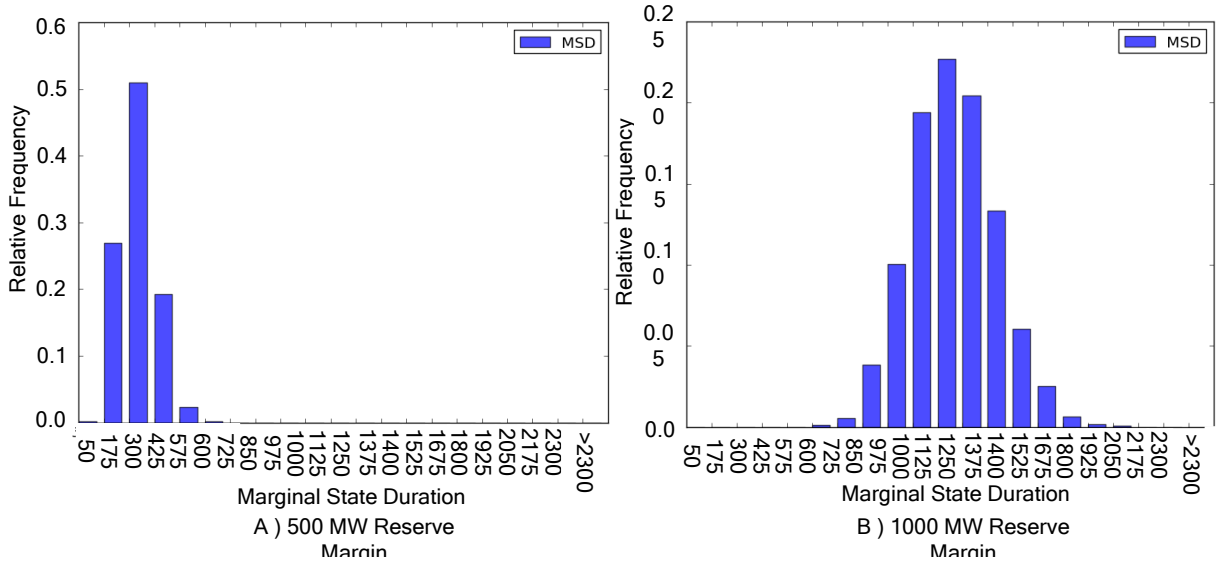

Figure 5.6: Marginal State Duration Distributions (Effect of Deterministic Criterion)

Figures 5.7 and 5.8 show the distributions of marginal state and risky state frequency obtained using the two different deterministic criteria. The marginal state frequency distribution is similar to the marginal state duration distribution, as the more demanding the deterministic criterion, the marginal state frequency distribution displaced to the right side of the graphic. If a 500 MW deterministic criterion is used, the marginal state frequency mainly falls in the range of 10-120 occurrences/year. If the deterministic criterion is changed to 1000MW, the distribution mainly falls in the range of 100-220 occurrences /year. It can be

seen from Figure 5.8 that the distribution of the risk state frequency will not change with the change in the deterministic criterion used in the analysis.

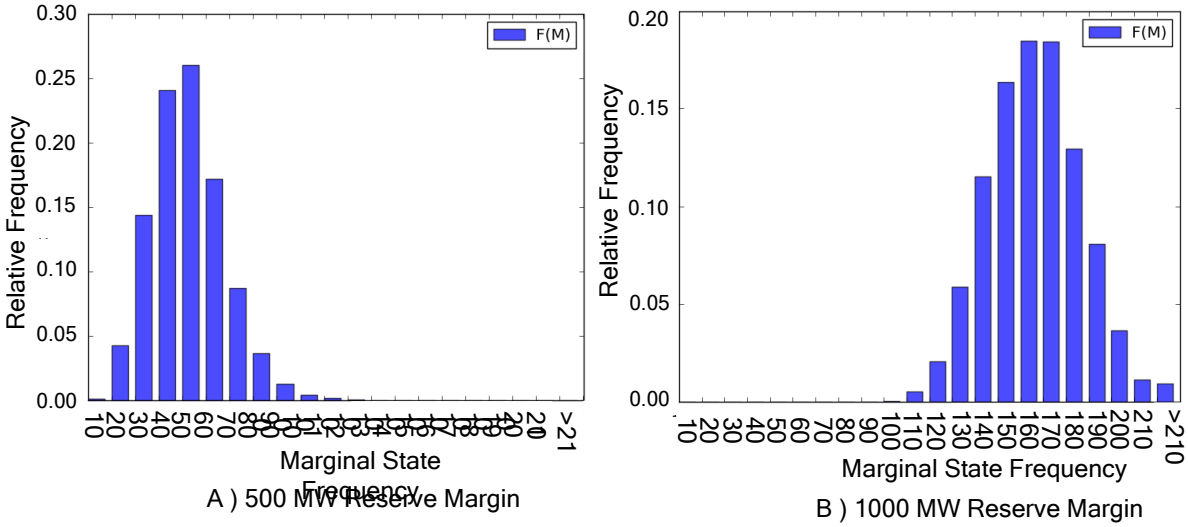

Figure 5.7: Marginal State Frequency Distribution (Effect of Deterministic Criterion)

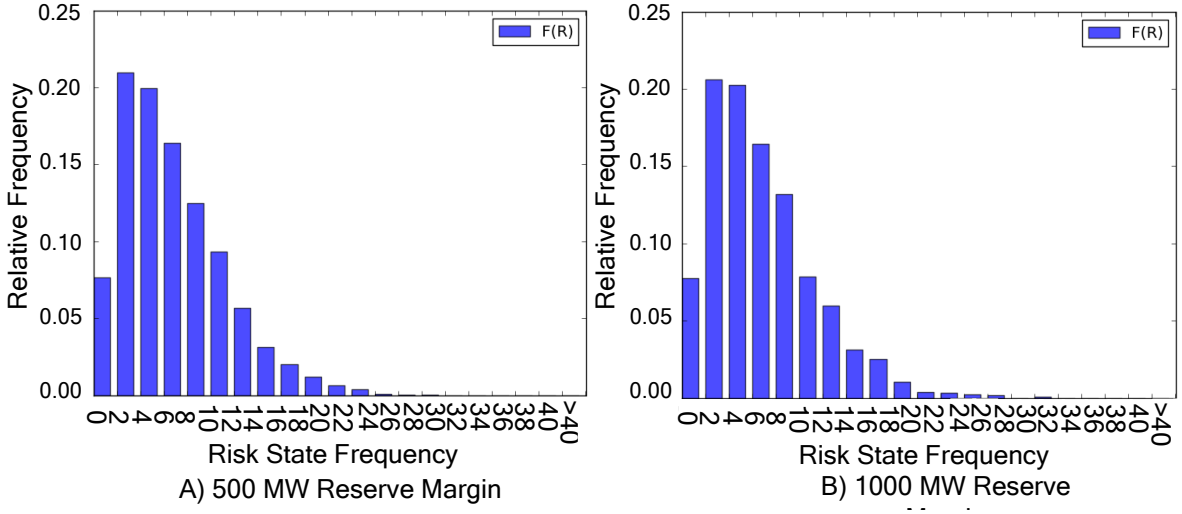

Figure 5.8: Risk State Frequency Distribution (Effect of Deterministic Criterion)

5.6 Summary and Conclusions

A well-being framework for power systems containing HVdc links is proposed. Generally, the system well-being is defined in terms of three different states; namely healthy state, marginal state and at-risk state. The healthy state is defined by considering an accepted deterministic criterion. A number of wellbeing indices such as the state probabilities, the state duration and the state frequency are used to evaluate and compare the reliability performance of the example system.

The technique is illustrated in this chapter using the four different cases. The relative distribution of wellbeing indices is also produced and analyzed. The results obtained from the well-being analysis are consistent with those obtained using the traditional reliability indices. The well-being indices associated with the healthy and marginal states are directly affected by the deterministic criteria, although the risk state indices are not impacted by the deterministic criteria. The healthy state probability decreases, the marginal state probability increases, and the risk state probability remains the same when the required reserve margin changes from small to large. The analysis of the distributions of well-being indices can provide more detailed and useful information that can be used in power system planning. The less dispersed the distribution of the state duration, the healthier is the system state.

Chapter 6 Summary and Conclusions

6.1 Summary and Conclusions

Reliability evaluation of power systems containing HVdc schemes is attracting more and more attention with the proliferation of HVdc technology around the world. The research described in this thesis focuses on developing appropriate models and techniques for evaluating the impacts of HVdc systems on power system reliability.

The research described in this thesis falls into the domain of generating capacity adequacy evaluation. Generating capacity adequacy evaluation involves the combination of a generation model with an appropriate load model to obtain a risk model [1]. Literature review shows that there are two different approaches for power system reliability evaluation; namely, analytical methods and Monte Carlo simulation. A comprehensive literature review shows that the approaches used in reliability assessment associated with HVdc systems are predominantly analytical.

A new Monte Carlo simulation-based approach for the reliability evaluation of HVdc systems is proposed in this thesis. Monte Carlo Simulation is used in the research in this thesis because of the two distinctive advantages: (1) it avoids using excessive approximations in system modelling (2) it provides the probability distribution of reliability indices in addition to mean values of reliability indices. The proposed new approach involves the development of a reliability model for a particular HVdc system of interest and incorporation of such model into the overall system reliability assessment. The reliability model for a particular HVdc system is

developed based on the identification of failure modes considering the major components that have significant impact on the reliability performance of the HVdc system such as valve groups, poles and bipoles. The reliability model developed for the HVdc system is then used to modify the capacity model in evaluating the overall system reliability. The proposed method is validated against the results obtained from the analytical method for a base system for which an analytical model was constructible. The validation results show that the two methods produce essentially the same results. The Monte Carlo approach was then extended to study the distribution of reliability indices, which cannot be done analytically. The development of the extended comprehensive simulation approach for the reliability assessment of power systems containing HVdc links is one of the major contributions of the research described in this thesis.

The proposed approached was used to perform a series of studies to examine the reliability performance of an example HVdc system. A range of sensitivity analysis studies was also conducted to investigate the impacts of key parameters on the reliability performance. The reliability analysis of the example systems uses not only the traditional mean values of reliability indices such as the LOLE and EUE but also the more detailed information of reliability index distributions. A method for producing distributions of various reliability indices was developed and incorporated into the overall Monte Carlo simulation procedure. Study results show that the reliability index distributions can provide considerable additional information and a more physical appreciation of the reliability performance of the system under study and the effects of parameter variations. The utilization of reliability index distributions in HVdc system reliability assessment is a relatively new approach. This technique enhances and complements the conventional expected values-based reliability assessment. Rather than provide a single Loss of

Load Expectation figure, different operating choices may provide different distributions for the loss of load. The development of an effective method to incorporate reliability index distributions and the use of the reliability index distributions in HVdc system reliability assessment are also the major contributions of the research described in this thesis.

The research described in this thesis also extends the conventional well-being approach to be used in the power systems containing HVdc links. Rather than focusing on the loss of load expectation, well-being analysis classifies the network condition into healthy, marginal and at-risk state probabilities. The well-being analysis is further enhanced by presenting distributions of the duration and frequency of each state. Results show that the well-being indices associated with the healthy and marginal states are directly affected by the deterministic criteria, whereas risk state indices are not impacted by the deterministic criteria. The healthy state probability decreases, the marginal state probability increases, and the risk state probabilities remains the same when a more demanding deterministic criterion is used in the analysis. The analysis of the distributions of well-being indices can also provide more detailed and useful information that can be used in power system planning. Extension of the conventional well-being analysis approach to power systems containing HVdc links is also one of the major contributions of the research described in this thesis.

6.2 Publications

Several major contributions as described previously are made during the courses of this research. The general models, the proposed simulation technique and some of the study results

are published in the proceeding of an academic conference as listed in the following in order to share the new knowledge obtained through the research described in this thesis.

1. W. Hou, B. Bagen and Aniruddha Gole, "Including Reliability Index Distributions in HVdc System Adequacy Assessment Using Monte Carlo Simulation", a paper presented at the 13th International Conference on AC and DC Power Transmission, Manchester, UK, February 14-16, 2017.

The new knowledge associated with reliability index distributions and the extension of the well-being approach will be reported in the form of technical papers to share the new findings and advance the industry knowledge in the area in the near future.

6.3 Future Extension of the Research

One of the major advantages of the Monte Carlo simulation is its ability to model a complex operating procedure that may have significant reliability impact on the system under study. The approach proposed in this thesis does not consider such an operating procedure. Future research may need to be performed to model various operating procedures so that all of the major influencing factors can be captured in the Monte Carlo simulation.

A range of reliability distributions is produced and evaluated in the studies presented in this thesis. One of the observations is that the shapes of these distributions look very similar to known distributions for example exponential, Poisson or normal. More examinations are needed to understand if any general conclusions can be made from the distributions of these reliability indices.

Extension of the well-being approach to HVdc system reliability evaluation is one of the major contributions. In the proposed well-being framework, the system state is divided into three parts as being healthy, marginal and at-risk. In order to obtain more detailed information on the reliability performance of the system it may be beneficial to further divide the marginal or the healthy states. For example, the marginal state may be described as safe marginal, medium marginal and close to risk. Further studies are needed to understand necessity and applicability of detailed division of system states.

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