University of Strathclyde
Engineering

# Generation System Reliability Evaluations with Intermittent Renewables

*A Thesis submitted in partial fulfilment for the requirement of degree in*
***Master of Science in Energy Systems and the Environment,***
*University of Strathclyde*

*by*
***Hee Yau, Phoon***

September 2006

COPYRIGHT DECLARATION

ACKNOWLEDGEMENTS

First of all I want to express my appreciation to all individuals who have in one way or the other contributed to the completion of this project. I would like to thank my supervisors Dr. Graham Ault and Dr. Ian Elders for the guidance and support they have offered throughout the project.

I would also like to thank the UK Government especially the Foreign and Commonwealth Office and University of Strathclyde for the British Chevening Scholarship Partnership Award, and the British Council and Tenaga Nasional Berhad for supporting me in this masters degree programme. Not forgetting is my family, relatives and friends for their undivided support and love during the whole duration and to the completion of this thesis and course.

# TABLE OF CONTENT

# FIGURES

# TABLES

# List of Abbreviations

| | |
|---|---|
| BWEA | British Wind Energy Association |
| CC | Capacity Credit |
| COPT | Capacity Outage Probability Table |
| DTI | Department of Trade and Industry (UK) |
| EENS | Expected Energy Not Served |
| ELCC | Effective Load Carrying Capability |
| FOR | Forced Outage Rate |
| GB | Great Britain |
| IEEE | Institute of Electrical and Electronic Engineering |
| LOEE | Loss of Energy Expectation |
| LOEP | Loss of Energy Probability |
| LOLE | Loss of Load Expectation |
| LOLD | Loss of Load Duration |
| LOLF | Loss of Load Frequency |
| LOLP | Loss of Load Probability |
| LPT | Load Probability Table |
| RE | Renewable Energy |
| RTS | Reliability Test System |
| SMST | System Margin State Table |
| UK | United Kingdom |

# ABSTRACT

Generation system reliability is an important aspect in the planning for future system capacity expansion to make sure that the total installed capacity is sufficient to provide adequate electricity when needed. The planning process utilizes reliability indices as criteria to decide on new investments in new generation capacities. With the emergence of renewable energy as the promising future generating options, system planners now face the issue of integrating large amount of renewable resources, namely wind, solar, wave and tidal energy which are intermittent in nature. The intermittency of these resources contributes little to the electricity system reliability.

This research will particularly focussed on evaluating how intermittent wind generation contributes to the generation system adequacy and affects system reliability. This project aims to analyse the capacity contribution of wind from different sites using a methodology and programme developed for this purpose. Different factors of wind characteristics that impact the reliability of electricity system are also analysed.

A generation system reliability model and calculation tool was developed using MS Excel and the Visual Basic Editor based on the analytical method and was referred to as the System Reliability Evaluation Programme (SREP) in the thesis. Data from the IEEE Reliability Test System '96 was used in the modelling and evaluation. Wind data obtained from various wind farms across Scotland was used and modelled using three selected approaches; two approaches based on retrospective analysis – Firm Capacity Method / Effective Load Carrying Capability and Effective Capacity Method, and the Reliability Curve Method. These approaches modelled the wind data as load-modifier and the capacity credits evaluated were compared with the wind capacity factor. Among all the four methods, the Effective Capacity Method gives the value closest to the average of all the methods and a better representation of the capacity credit and therefore is recommended to be used for future generation capacity adequacy study with intermittent wind generation.

Four case studies were carried out to examine the effect that intermittent wind generation had on system reliability. The first case study concludes that the rate of system reliability improvement is nonlinear to wind generation capacity addition or wind penetration. The second case study found that the dispersed nature of wind provides a good reason and incentive for wind farms to be installed at different locations with varying wind profile. In Case Study 3 and 4, it was also found that the capacity credit depends on the amount of correlations that the wind data had with the peak demand when wind is modelled as load-modifier.

From the results and contribution, this work provides another reference for generation system planners in choosing a suitable evaluation methodology when considering intermittent renewable wind generation. It is sufficient to mention that this project has contributed to the ongoing research on the study of intermittency of renewable generation particularly wind generation and capacity credit in and for the UK.

# Chapter 1

*"Is it a fact – or have I dreamt it – that, by means of electricity, the world of matter has become a great nerve, vibrating thousands of miles in a breathless point of time? Rather, the round globe is a vast head, a brain, instinct with intelligence! Or, shall we say, it is itself a thought, nothing but thought, and no longer the substance that we dreamed it?"*

**Nathaniel Hawthorne**
The House of Seven Gables
1851

## INTRODUCTION

Electricity has been the driving force for economies of the world and provides day-to-day necessity for the population in the world. The generation, transmission and retailing of electricity have existed hundreds of years in providing the much needed electricity. Due to the nature of electricity systems, the variable demand at every moment needs to be met by consistent electricity supply in making sure the continuous availability of the resources. Not meeting the demand in any case will lead to a huge loss of income to the generators as well as to the consumers. The reliability of the generation, transmission and distribution of electricity in this sense is crucial for the continuous supply of electricity to meet the demand.

A modern power system is complex, highly integrated and very large. Fortunately, the system can be divided into appropriate subsystems or functional areas that can be analysed separately (Billinton and Allan, 1996). These functional areas are generation, transmission and distribution. The function of the generation system is to make sure enough capacity is available to meet the load/demand at any time. Transmission and distribution systems need to be reliable in making sure the electricity generator can be delivered to the consumers. System planners have been assigned the role of planning for forecasting the load into the future and plant capacity addition to meet the load and provide a level of reliability in case some of the plants are out on maintenance or breakdown. Probabilistic method is often used to determine the system reliability and the system reliability can be summed up into a single value, the reliability indices. Reliability studies are conducted for two purposes. Long-term evaluations are performed to assist in system planning and short-term evaluations to assist in day to day operating decisions. In short, these reliability indices (for long-term evaluations) are used by system planners and the authorities to decide on and advice for new investments in building new generation capacities.

In recent years, renewable technologies have been in the limelight and became highly favourable generation resources due to the rising of oil prices, uncertainty of fossil fuel or security of supplies in the future and concerns on the environmental impact due to the over consumption of fossil resources. With that, renewables look promising as the fuel that are almost non-depletable, available at the local level, green to the environment and increasingly cost competitive with technology maturity and rising fossil fuel prices. However, one of the main barriers of integrating large amount of renewable resources, namely wind, solar, wave and tidal energy are the variability of the natural resources. This variability of the renewable resources is also known as intermittency of the resources.

In the UK, the Renewable Obligations was introduced as a policy to promote and make sure the UK will have at least 10% of it’s generation from renewable energy sources by 2010, and 15% by 2015. The increasing amount of renewables which are intermittent or uncontrolled generation will be a major challenge for the operators to meet variable demand and ensure secure and reliable operation of the electricity systems of the future. This intermittency affects the planning and operation of the supply of electricity.

System operator has been relying on the highly dependable conventional plants to generate power to meet demand at anytime. However, the variability of the renewable resources acts as a challenge for system operator to make sure enough capacity is available to meet the load at every instance. This making sure of available capacity at all times to meet the load is called system balancing.

Another important effect on intermittency is the planning for generation system adequacy. Most utilities do give the intermittent renewables energy credit but not capacity credit. This is because system planners seemed to disagree that these intermittent renewables can be relied upon to contribute to the system reliability. However, some studies have concluded that these intermittent renewables do contribute a certain amount to system reliability and should not be discounted.

The context of this study will cover the system reliability evaluations for generation system capacity adequacy considering conventional and intermittent generation. This study will not include the analysis on operational issues i.e. system balancing of intermittent generation as well as transmission and distribution system reliability impact.

This research will particularly focussed on how intermittent wind generation contributes to the generation system adequacy planning and the effects on system reliability. The focus on wind is chosen because wind offers the greatest potential for expansion in the United Kingdom among all renewable technologies in the short to medium term, both on and off shore. According to Nedic et. al (2005) it is expected that wind power will play a key role to achieve 2010/2020 targets for renewable generation.

## 1.1 Specific objectives

The objectives of this thesis are to:

1. Establish a generation system reliability calculation tool to evaluate conventional generation systems reliability based on the analytical method
2. Evaluate different modelling methodologies for intermittent renewable generating units
3. Apply chosen methodologies and integrate into the reliability evaluation tool to evaluate intermittent wind generation effect on capacity credit
4. Propose an evaluation method to be used for generation capacity adequacy planning
5. Examine the effect of wind penetration level, diversity, inter-annual data variation and application of GB demand profile.

## 1.2 Project aims

This project aims to analyse the capacity contribution of wind from different sites and the impact that has on system reliability. Besides, it is hoped that the methodology and tools developed can be useful for future study in planning for capacity expansion using intermittent renewable generation.

## 1.3 Thesis Outline

In Chapter 2, the background on generation system reliability, load and conventional generators modelling and description of the various reliability indices frequently used by utilities are discussed. All subsequent sections provide the current modelling approach and descriptions of intermittent renewable generators and the discussed the factors that causes intermittency.

Chapter 3 provides a description of the methodology and common assumptions. There are two parts in the methodology; (1) the conventional system reliability modelling and (2) the intermittent wind generation reliability modelling.

In Chapter 4, the process of modelling the conventional generation system reliability based on the analytical method is described. This will cover the computer model developed using MS Excel and the built-in Visual Basic Editor [for Applications] to calculate reliability indices; Loss of Load Probability (LOLP) and Loss of Load Expectation (LOLE) of conventional generation system using the *Load Probability Table* (LPT), *Capacity Outage Probability Table* (COPT) and the *System Margin State Table* (SMST). A test case and data from the IEEE Reliability Test System (RTS) is used to evaluate the computer model developed and the reliability results obtained will be compared to various references.

After verifying the working of the model, the computer model will be extended to include intermittent renewable wind generators in the reliability evaluation which will be described in Chapter 5. Four different methods of approximation and evaluations of capacity credit will be used and the results will be compared.

Further case studies were conducted to evaluate the effect of intermittent wind penetration on system reliability, diversity of wind, inter-annual variation and reliability effect of using Great Britain (GB) load profile. These case studies will be elaborated in Chapter 6.

Chapter 7 will give a detail discussion and interpretation of results obtained and the contribution that this thesis has provided to the study of intermittency in system capacity adequacy evaluations.

The last chapter will conclude the whole thesis, reviewing the objectives and what this project has achieved. Further recommendation in this field as well as possible further work that can and should be carried out will also be listed.

# Chapter 2

## GENERATION SYSTEM RELIABILITY – BACKGROUND

*Generation system reliability is an important aspect in the planning for future system capacity expansion. It provides a measurement of reliability or adequacy to make sure that the total generation system capacity is sufficient to provide adequate electricity when needed.*

*This chapter provides a background of generation system reliability and its evaluation methods and gives a detail description of the load modelling and generating unit modelling process. Various reliability indices commonly used in the planning process will then be presented. The chapter will conclude with the detailed discussion of the characteristics of the various intermittent generation models (wind, solar, wave and tidal stream), reliability model and the effects of the intermittency on system reliability.*

## *2.1 Generation system reliability*

Reliability has been and always is one of the major factors in the planning, design, operation, and maintenance of electric power system. Generation system reliability focuses on the reliability of generators in the whole electric power system where electric power is produced from the conversion process of primary energy (fuel) to electricity before transmission. The generation system is an important part of the electricity supply chain and it is crucial that enough electricity is generated at every moment to meet the demand. Generating units will occasionally fail to operate and the system operator has to make sure that enough reserve is available to be operated when this situation happens.

Reliability of the generation system is divided into adequacy and security. System adequacy relates to the existence of sufficient generators within the system to satisfy the consumer load demand or system operational constraints. System adequacy is associated with static conditions of the system and do not include system disturbances. System security on the other hand relates to the ability of the system to respond to disturbances arising within the system. Therefore system security is associated with the response of the system to whatever perturbation it is subjected to. In this study, the reliability evaluations will be focused on the generation system adequacy and will not take into account system security.

According to Endrenyi (1978, p.109), if an improvement in system reliability is required, it can be affected by using either better components or a system design incorporating more redundancy. Redundancy in generation system means the installation of more generating capacity than normally required which will incur more cost for the added reliability since the additional capacity added will only be needed in times of emergency.

In a generation system study, the total system generation is examined to determine its adequacy to meet the total system load requirement. This activity is usually termed “generating system adequacy assessment”. The transmission system is ignored in generating system adequacy assessment and is treated as a load point. The main idea of the generating system adequacy assessment is to estimate the generating capacity required to meet the system demand and to have excess capacity to cater for planned and forced outage events.

The most basic conventional technique used to determine the capacity requirement was the percentage reserve or reserve margin method. This technique will be explained in detail in section 2.4.1. Another conventional method used is a reserve equal to one or more of the largest units in the system. These two deterministic approaches have now been replaced by probabilistic methods which respond to and reflect the actual factors that influence the reliability of the system (Billinton and Allan 1984).

The basic modelling approach for the generating system adequacy assessment consists of three parts as shown in Figure 2-1. The generation and load models are convolved to form an appropriate risk model where the element of interest is the risk of generation capacity less than the load. In short, adequacy evaluation of generation systems consists of three general steps:

1. Create a generation capacity model based on the operating characteristics of the generating units
2. Build an appropriate load model
3. Combined the generation capacity model with load model to obtain a risk model

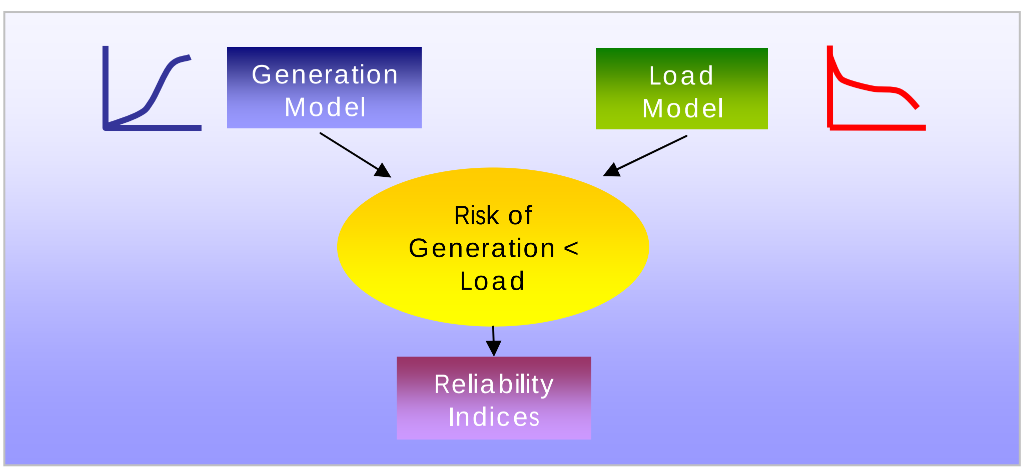


**Figure 2-1: Elements of generation reliability evaluation**

Analytical methods or Monte Carlo simulation can be used to calculate the reliability indices. Analytical techniques represent the system by analytical models and evaluate the indices from these models using mathematical solutions. Monte Carlo simulations, on the other hand estimate the indices by simulating the actual process and random behaviour of the system, treating the problem as a series of experiments. The reliability indices obtained indicate the ability of the generating facilities to meet the system demand.

In the analytical method, the generating system model used for generation capacity adequacy assessment is a *Capacity Outage Probability Table* (COPT) which can be created using the recursive technique which will be explained later in this chapter. As for the load model, the daily peak load or hourly load for a period of one year is normally used to form the *Load Probability Table* (LPT).

According to Wang and McDonald (1994, p.107) the process of evaluation of power system reliability starts by creating a mathematical model of a system or a subsystem and then proceeding with a numerical solution, summarized in the following general steps:

1. Define the boundary of the system and list all the components included.
2. Provide reliability data such as failure rate, repair rate, repair time, scheduled maintenance time, etc., for every component.
3. Establish reliability models for every component.
4. Define the mode of system failure, or define the criterion for normal and faulty systems.
5. Establish a mathematical model for the system reliability and its basic assumptions.
6. Select an algorithm to calculate the system reliability indices.

Reliability models can be constructed and evaluated using the process shown in Figure 2-2.

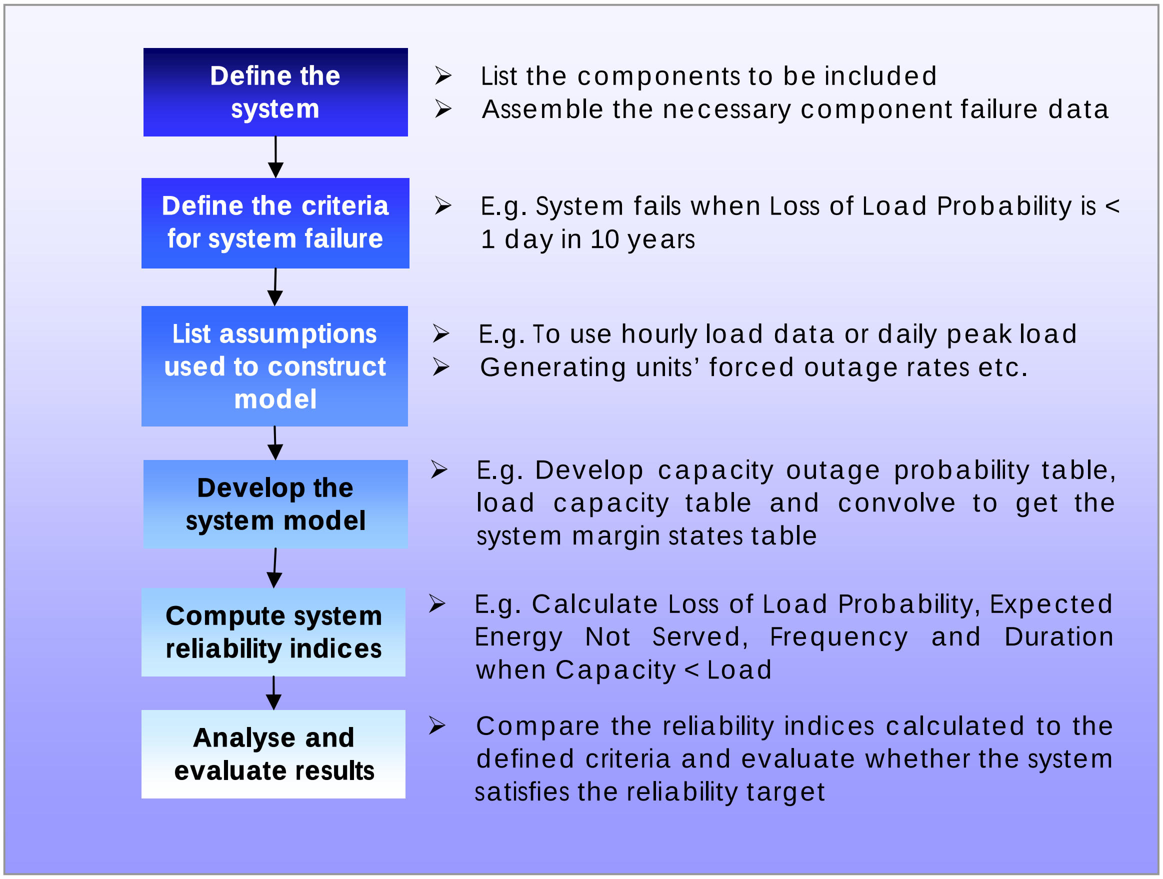


**Figure 2-2: Reliability models construction process**

## *2.2 Load model and representation*

The load in a power system in any time period is a stochastic process, which is difficult to describe with a simple mathematical formula. Different models are created, starting from primary load data and according to the need to calculate reliability.

Primary load data will provide a minimum amount of data that is needed to establish an hourly chronological load profile. Most primary load data consist of the percentage of maximum monthly load or weekly load in a year, the load in 24 hours in a typical day in each season and the maximum load in each day in a week. With the percentages of these data available and the annual peak load known, the hourly chronological load profile can be established.

In other circumstances, daily peak load for a year (365 days) are sufficient when the modelling uses the daily peaks. However, these daily peaks are assumed to occur over the entire duration of the day.

## 2.3 Conventional generating unit reliability model

The most important input quantities required in generation system reliability analysis are the capacity and the failure probabilities of individual generating units.

If a simple two-state model is assumed for the operation of a unit, its failure probability is given by its unavailability $U$, which can be expressed in terms of the unit failure rate $\lambda$ and repair rate $\mu$ in Equation 2.1.

$$U = \frac{\lambda}{\lambda + \mu} \qquad \text{Where} \quad \begin{array}{l} U = \text{unit unavailability} \\ \lambda = \text{unit failure rate} \\ \mu = \text{unit repair rate} \end{array} \tag{2.1}$$

Unit unavailability is also known conventionally as "forced outage rate" (*FOR*), although the value is not a rate. The *FOR* is defined in Equation 2.2 below.

$$FOR = \frac{\textit{Forced outage hours}}{\textit{In-service hours} + \textit{Forced outage hours}} \tag{2.2}$$

The *FOR* calculated for a long period of time (e.g. 365 days), is the same index as the unavailability defined in Equation 2.1. The *FOR* is a good approximation for the 2 state approximations.

The next step in building a generation model is to combine the capacity and availability of the individual units to estimate available generation in the system. The result of this combination will be a capacity model, where each generating unit is represented by its nominal capacity, $C_i$ and its unavailability, $U_i$ (or *FOR*). The capacity or the outage capacity, $X$ is considered to be a random variable in power system reliability analysis.

The capacity or outage capacity is discrete and obeys an exponential distribution. The unit model is the probability table of a generator unit's capacity state.

The probability model of a two-state generator model has only two states; in operation or on outage. There are $2^n$ possible different capacity states. The individual state probability can be described in Equation 2.3.

$$P(X = x_i) = \begin{cases} 1 - q & x_i = C_i \\ q & x_i = 0 \end{cases} \tag{2.3}$$

The cumulative state probability (the distribution function) can be obtained by summing up the individual state probability for all capacity less than $x_i$. Equation 2.4 gives the cumulative state probability.

$$P(X = x_i) = \begin{cases} 0 & x_i < 0 \\ q & 0 \le x_i \le C_i \\ 1 & x_i \ge C_i \end{cases} \tag{2.4}$$

There will be a forced outage rate for every capacity $C_i$, and the individual state probability and cumulative state probability are summarized in Equation 2.5 and 2.6 respectively.

$$P\ (X = x_i) = p\ (x_i) \qquad \text{where } i = 0, 1, 2, \ldots \tag{2.5}$$

$$P\ (x_k) = P\ (X \ge x_k) = \sum_{i \ge k} p\ (x_i) \tag{2.6}$$

From these equations, the *Capacity Outage Probability Table* (COPT) that represents the probability of different capacity outages of the system can be generated.

## 2.4 Generation system reliability indices

The quantification of reliability is an important aspect of generation system reliability assessment. The measurement used to quantify reliability of a generation system is given by various reliability indices. These reliability indices are used to assess the reliability performance of a generation system against some predetermined minimum requirements or reliability standards, compare alternative designs, identify weak spots and determine ways for correction in the generation system and to be integrated with costs and performance considerations for decision making. These indices are better understood as estimates of system-wide generation adequacy and not as absolute measures of system reliability.

Basically, system reliability evaluations can be divided into deterministic and probabilistic. The most common deterministic indices are the Reserve Margin and the largest set in the system. An important shortcoming of these methods is that they do not account for the stochastic nature of system behaviour.

Probabilistic methods can provide more meaningful information to be used in design and resource in planning and allocation (Prada 1999, pp.14). There are two approaches that use probabilistic evaluation. The analytical methods and Monte Carlo simulation as can be seen from Figure 2-3. The analytical methods represent the system by mathematical models and use direct analytical solutions to evaluate reliability indices from the model. As for the Monte Carlo simulation, reliability indices are estimated by simulating the actual random behaviour of the system. So of the commonly used probabilistic reliability indices are Loss of Load Probability (LOLP), Loss of Load Expectation (LOLE), Loss of Energy Probability (LOEP), Loss of Energy Expectation (LOEE), Expected Energy Not Served (EENS), and Loss of Load Frequency (LOLF) and Loss of Load Duration (LOLD). Most of these indices are basically expected values of a random variable. Expectation indices provide valid adequacy indicators which reflect various factors such as system component availability and capacity, load characteristics and uncertainty, system configurations and operational conditions, etc. (Billinton and Li 1994, p.22).

Typical reliability indices used in power system evaluations and their categorising is shown in Figure 2-3.

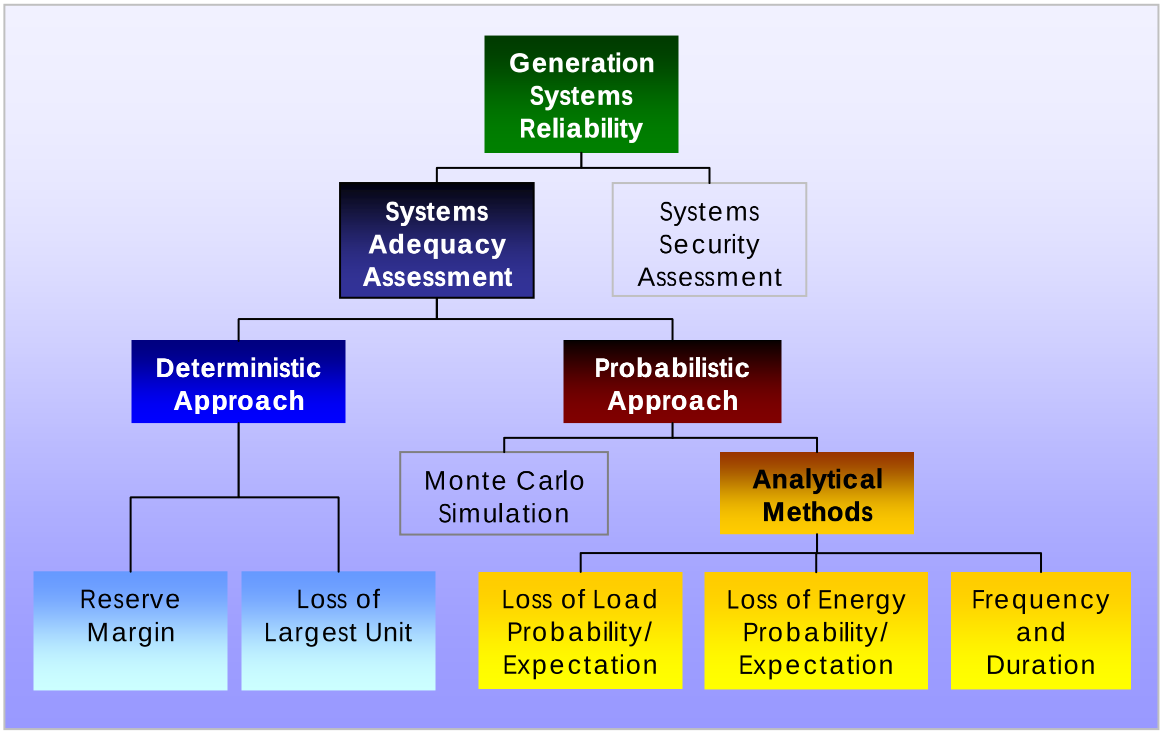


**Figure 2-3: Generation system reliability assessment indices category**

### 2.4.1 Reserve margin

Reserve Margin is the percentage of additional installed capacity over the annual peak demand. It is a deterministic criteria used to evaluate system reliability by defining a target generation margin. The formula to calculate the reserve margin is shown in Equation 2.7.

$$\text{Reserve Margin} = \frac{\text{Installed Capacity (MW) - Peak Demand (MW)}}{\text{Peak Demand (MW)}} \text{ X } 100\% \quad (2.7)$$

The forecasted peak demand and the expected capacity in planning need to be extracted from planning data to calculate the future system Reserve Margin. The assumptions used in the calculation of Reserve Margin is that Installed Capacity or the Nameplate Capacity is used instead of Derated Capacity, and therefore does not give a true representation of the actual available margin the system will operate with. This method compares the adequacy of reserve requirements in totally different systems on the sole basis of their peak load, mainly used in the past for generation system expansion planning of small and established systems. Based on past experience, a certain percentage of reserve is set to be available to meet the peak demand, usually ranges from 15% to 20%. Plant addition is done when the Reserve Margin goes below the expected level. This method is very easy to use and understand in quantifying reliability and generation system adequacy.

However, as the electricity system grows in sizes and complexities, Reserve Margin alone is not sufficient to provide the reliability assessment. The basic weakness of Reserve Margin is that it does not respond to, nor reflect, the probabilistic or stochastic nature of system behaviour, of customer demands, or of component failure. For example, it does not consider the failure rate of different plant types and sizes. Deterministic analysis using just Reserve Margin calculation could lead to overinvestment in generation expansion or insufficient system reliability. Therefore, most of the utilities and system planner have been using the probabilistic indices rather than the Reserve Margin criteria.

### 2.4.2 Loss of load

Loss of load occurs when the system load exceeds the generating capacity available for use. Loss of Load Probability (LOLP) is a projected value of how much time, in the long run, the load on a power system is expected to be greater than the capacity of the available generating resources. It is defined as the probability of the system load exceeding the available generating capacity under the assumption that the peak load of each day lasts all day (Endrenyi 1978).

LOLP is based on combining the probability of generation capacity states with the daily peak probability so as to assess the number of days during the year in which the generation system may be unable to meet the daily peak (Khatib 1978).

LOLP can be calculated considering the daily peak loads for 1 year duration or sometimes on each hour's load for a 24 hours day. Therefore, the same system may have two or more values of LOLP depending on how the calculation is being done.

The mathematical formula for calculation of LOLP is shown in Equation 2.8.

$$\text{LOLP} = \sum_j P\,[\,C_A = C_j\,]\,.\,P\,[\,L > C_j\,] = \sum_j \frac{p_j\,.\,t_j}{100} \tag{2.8}$$

where

| | | |
|---|---|---|
| where | $P$ | the probability of |
| | $L$ | expected load |
| | $C_A$ | available generation capacity |
| | $C_j$ | remaining generation capacity |
| | $p_j$ | probability of capacity outage |
| | $t_j$ | percentage of time when the load exceeds $C_j$ |

Alternatively, a load duration curve consists of daily peak loads arranged in descending order can be used to measure LOLP for long term generation capacity evaluation. The assumption used in this case is that the peak load of the day would last all day. The LOLP calculation is illustrated with a daily peak load curve in Figure 2-4.

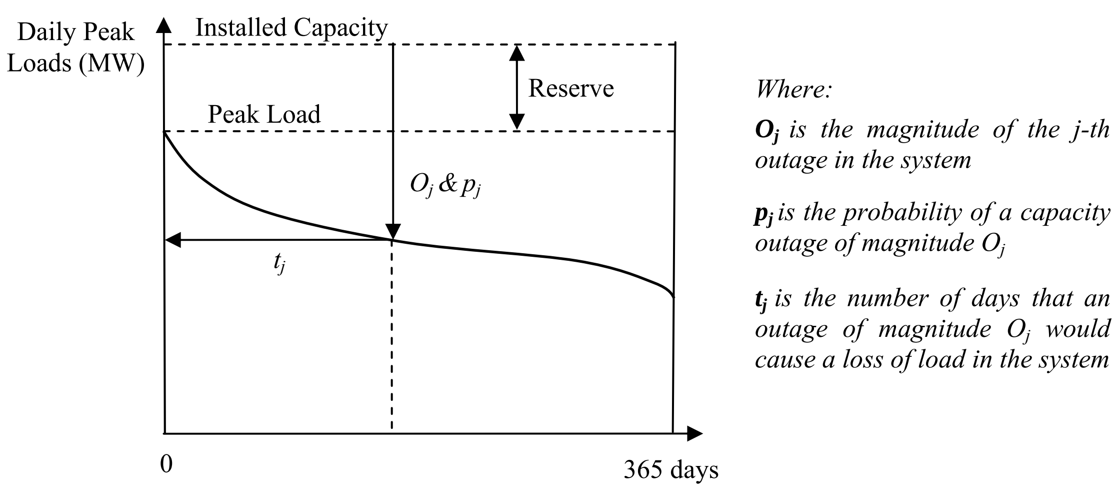


**Figure 2-4: LOLP Calculation using Load Duration Curve**

Capacity outage less than the amount of reserves will not contribute to a loss of load. When a particular capacity outage is greater than the reserve, the risk in this case will be $p_j$ x $t_j$.

It must be noted that an LOLE expectation index is more often used than the LOLP probability index in practical applications. The relationship between LOLE and LOLP is shown in Equation 2.9.

$$\text{LOLE} = \text{LOLP} \times T \tag{2.9}$$

where

- $T$ = 365 days (if the load model is an annual continuous load curve with day maximum load; the LOLE unit is in days per year)
- $T$ = 8760 hours (if the load model is an hourly load curve; the LOLE unit is in hours per year)

A level of LOLP is normally set and to be use as a reliability criteria for generation capacity planning. A common practice was to plan the power system to achieve an LOLP of one-day-in-ten-years or less. This does not mean a full day of shortages once every 10 years, but refers to the total accumulated time of shortages that should not exceed one day in 10 years or equivalently 0.0274% of a day. It is expected that a system having an LOLP value lower than the criteria set can withstand expected forced outages, anticipated peak loads and contingencies. A central utility is responsible for planning and making sure the availability of generation, energy purchases, load management and other system balancing mechanisms so as to ensure the resulting system LOLP will be at or below the set criterion. LOLP is used to characterize the adequacy of generation to serve the load on the bulk power system; it does not model the reliability of the power delivery system – transmission and distribution – where the majority of outages actually occur (Kueck et al. 2004).

The LOLP is like a rule of thumb to give an indication of the reserve margin of 20% or 25%. But it gives a better indication or measure of reliability than the reserve margin index as it takes into account system characteristics such as individual generator reliability, load unpredictability, and unit derations. For example where one utility might function acceptably with 25% reserve margin, another might be having the same LOLP with just a 20% reserve margin. In short, if utilities were planned so that they maintain an appropriate reserve margin, different utilities should have different reserve margins because the same reserve margin in different utilities would result in different levels of reliability (Kueck et al. 2004).

The LOLP index has gained recognition and became a widely used probabilistic index for generation reliability assessment. This is because it provides a probabilistic figure which can be relatively simple to compute and employed in generation capacity planning. It gives a simplified comparison of reliability.

There are several problems with the use of the LOLP for power system reliability evaluations.

- LOLP does not provide any indication of the frequency or duration of shortages and the extent of load shedding in MW or severity of potential shortages which are important reliability measures. As an expected value, it does not differentiate between one large shortfall and several small, brief ones.
- Different LOLP calculation techniques can result in different indices for the same system. Some utilities calculate LOLP based on the hour of each day's peak load (i.e., 365 computations), while others model every hour's load (i.e., 8760 computations (Kueck et al. 2004).
- LOLP does not include additional emergency support that one control area or region may receive from another, or other emergency measures that control area operators can take to maintain system reliability (Kueck et al. 2004, pp.7).
- Major loss-of-load incidents usually occur as a result of contingencies not modelled by the traditional LOLP calculation. Often, a major bulk power outage event is precipitated by a series of incidents, not necessarily occurring at the time of system peak (when the calculated risk is greatest) (Kueck et al. 2004, pp.7).

- The LOLP, in days per year, mainly indicates the number of days in the year in which the generation system would not be able to meet the load. The frequency of load shedding may be higher than this figure in case of double peaked daily load curves and in systems which employ units with higher failure rates but short repair duration (Khatib 1978, p.46).
- Since the load model used in the loss-of-load method is most often the cumulative curve of daily peak loads, the variations of load within a day are not recognized in it. This makes the LOLP value obtained by that method a rather crude approximation of the true system failure probability, and prevents the calculation of the system failure frequency (Endrenyi 1978, p.124).
- It is not very useful for comparing the reliabilities of different utilities or national systems, particularly if they have different shapes of the load curve and peak duration (Khatib 1978, p.46).
- It is argued that for the same system the use of the LOLP index would be adequate and correct for investigating different expansion plans and annual maintenance scheduling. This is only correct if the duration peak demand is static over years of the study. This is not the case in many systems with the continuous increase in the middle of the day load being experienced in most cases, particularly in developing countries (Khatib 1978, p.46).
- The vertically structured utility will build generation or enter into power purchase agreements to achieve the required LOLP, but LOLP is not necessarily an accurate predictor of the resulting incidence of electricity shortages (Kueck et al. 2004, pp.7).

### 2.4.3 Loss of energy

Loss-of-energy method is another measure for generation reliability assessment. The measure of interest in this case is the ratio of the expected energy not served (EENS) during some long period of observation to the total energy demand during the same period.

A mathematical formula for the Loss of Energy Probability (LOEP) calculation is shown in Equation 2.10.

$$\text{LOEP} = \sum_{k} \frac{E_k \cdot p_k}{E} \tag{2.10}$$

where $E_k$ is the energy not supplied due to a capacity outage $O_k$

$p_k$ is the probability of the capacity outage $O_k$

$E$ is the total energy demand during the period of study

The value obtained will have a unit of MWh/year and is also known as the Loss of Energy Expectation (LOEE) since it is an expected value rather than a probability.

Similar to the loss-of-load method, a load duration curve can be used to determine the LOEP for installed capacity evaluation. Figure 2-5 shows the load duration curve used for determining the LOEP.

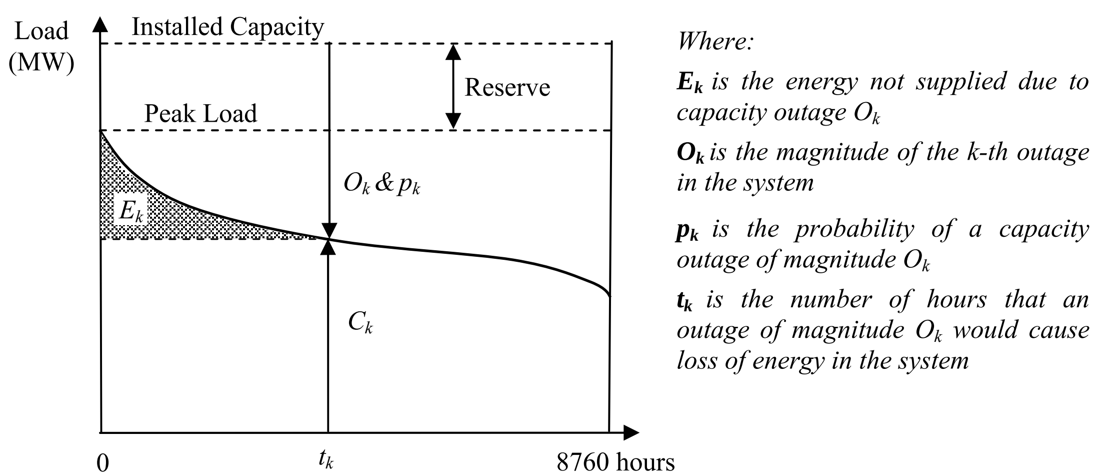


**Figure 2-5: LOEP Calculation using Load Duration Curve**

Any capacity outage exceeding the reserve will result in load interruption and energy curtailment. The energy not served, $E_k$, is the shaded area shown under the load duration curve in Figure 2-5. LOEP can be calculated from Equation 2.10 with $E_k$ and $E$ represented as in Equation 2.11.

$$E_k = \int_0^{t_k} (L - C_k)\, dt \qquad and \qquad E = \int_0^{8760} L\, dt \tag{2.11}$$

In some ways, the loss of energy index gives a more real representation of the system than the LOLP index. It will show the severity of an event by giving a higher value for more serious events than for marginal failures, even if their probabilities and frequencies are the same.

However, the true loss of energy cannot be accurately computed on the basis of the cumulative curve of daily peaks (Endrenyi 1978, p.123).

As a result, the LOEP index is seldom used for reliability evaluations of for generation capacity planning.

### 2.4.4 Frequency and duration

The frequency and duration (FAD) method is another set of reliability indices useful when the frequency of power interruption over a certain period of time is of interest. It is a helpful way to evaluate customer point reliability.

The FAD method applies the state-space approach to the set of units present in the system and uses the transition rate parameters $\lambda$ and $\mu$ of generation units. This means that each possible combination of units in up and down states defines a capacity state of the system. The resulting states are characterized by their available capacity, the associated state probabilities and the transition rates. The process of a frequency and duration analysis are as described follows (Prada 1999, pp.30):

1. The capacities $C_j$ and the probabilities $p_j$ of each state are calculated for the system capacity outage distribution.
2. The frequency of encountering a state $j$, $f_j$, is the expected number of stays in (or arrivals into, or departures from) $j$ per unit time, computed over a long period.
3. The frequency of state $j$ is $f_j = p_j$ x $(\lambda_{j+} + \lambda_{j-})$, where $\lambda_{j+}$ is the transition rate from state $j$ to higher capacity states and the $\lambda_{j-}$ transition rate to lower capacity states.
4. The average state duration $T_j$ is defined by the relation $p_j = f_j$ x $T_j$.

This representation is combined with a load model to identify marginal states, that is states where a transition to a lower capacity state results in a generation deficit ($C_j < L$). A chronological load curve is needed in this case. Then, cumulative probabilities and frequencies are computed for the marginal states and suitable indices are derived.

According to Billinton and Li (1994, p.24), the frequency and duration indices can be calculated using the Equation 2.12 and 2.13 respectively.

$$\text{Loss of Load Frequency, LOLF (occ./year)} = \sum_{j\,\varepsilon\, S} (F_j - f_j) \tag{2.12}$$

where $F_j$ is the frequency of departing system state $j$ and $f_j$ is the portion of $F_j$ which corresponds to not going through the boundary wall between the loss-of-load state set and the no-loss-of-load state set.

$$\text{Loss of Load Duration, LOLD (hr/disturbance)} = \frac{LOLE}{LOLF} \tag{2.13}$$

Frequency and duration are a basic extension of the LOLE index in that they identify the expected frequency of encountering a deficiency and the expected duration of load deficiencies. Both indices contain additional physical characteristics which make them sensitive to additional generation system parameters. However, the criterion has not been used very widely in generation system reliability analysis.

### 2.4.5 The common practice and application of reliability indices

Different countries and utilities employ different reliability standards for their specific and unique electricity system. This is because all systems are different from one another and therefore, the reliability criteria are also different. The last security standard employed in the UK by the Central Electricity Generating Board (CEGB) proposed that interruptions of supply should not occur more than 9 winters in 100. So the risk of having supply deficits cannot be larger than 9% (Nedic et al. 2005, pp.18). Added Nedic et. al (2005) based on probabilities of plant failures from the 1980s the standard would require a capacity margin of about 24%, where the capacity margin is defined as the percentage difference between total system generation capacity and peak system load with respect to the former.

As for the adequacy standard in Ireland, the authority proposes that an expectation of failure should not be larger than 8 hours per year LOLE (Nedic et al. 2005, pp.18). For France, the level of supply deficits accepted as stated in the Generation Adequacy Report is a mathematical expectation of less than three hours per year (LOLE < 3 hours) added Nedic et al. (2005, pp.19) in the report.

It has been a common practice in some of the advanced countries to adopt in electricity supply an arbitrary reliability target, such as one-day-in-ten-years LOLP (Pillai 2002). This does not mean a full day of shortages once every ten years; rather, it refers to the total accumulated time of shortages that should not exceed one day in 10 years, or, equivalently, 0.03 per cent of a day. Other developing countries in Asia would employ LOLP criteria of 1 day per year for the planning of generation capacity adequacy.

## *2.5 Intermittent generation reliability model*

Conventional generating unit runs of fossil fuel that are consistently made available all the time except during fuel curtailments. Renewable generation units like wind, solar PV, wave and tidal relies on the availability of natural resources as their “fuel” to generate power. These renewable “fuels” fluctuates all the time and according to the time of the day and different seasons of the year. The fluctuations or variability are intermittent in nature and cannot be controlled. Hence, these resources are labelled intermittent generation and are considered separately from the conventional generating units in reliability modelling. The following Figure 2.6 shows the variability and predictability of various renewable energy sources.

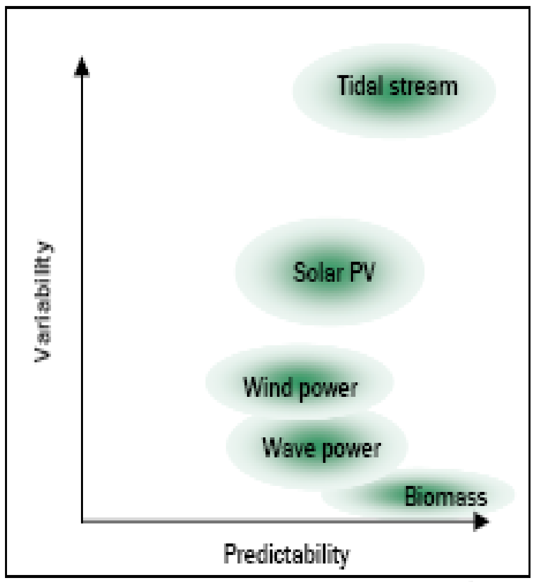


**Figure 2-6: Variability and predictability of RE sources (Source: Sinden, 2005)**

Intermittent generators can provide energy, have zero fuel costs and can reduce emissions (Gross et al. 2006, pp.14). With these advantages over all conventional plants, intermittent generators are usually ranked high up in the merit order and ideally should be operated whenever they are available. However, depending upon technology, location and timing of demand peaks, intermittent generators’ output may or may not be available during peak demand periods, therefore, causing lower contribution to reliability than similar capacity conventional generators. There are some different factors that cause the intermittency of renewable generations. These factors will be discussed in detail in the individual renewable technology section later in this chapter.

Intermittent renewable generators are usually thought to have clean energy value but not to carry any capacity value as in the system planner and operator's point of view. This is because the intermittent nature of the resources cannot guarantee available capacity when the system needs it during high demand period. However, there is one terminology that is often used to provide an estimation of a capacity value for these intermittent sources; it is called the *capacity credit*.

### 2.5.1 Capacity Credit

Capacity credit (CC) is a measure of contribution that intermittent generation can make to reliability (% of installed capacity of intermittent generation). It is the fraction of installed capacity by which the conventional power generation capacity can be reduced without affecting the loss of load probability (LOLP). According to Ford and Milborrow (2005), capacity credit here is defined as the ratio (capacity of thermal plant displaced)/(rated output of wind plant). One commonly used and well accepted measure of capacity credit is effective load carrying capability (ELCC). The advantages and good quality capacity credit modelling is simple and straightforward. Because it is based on empirical data that reflects actual performance, it is very much data-driven. Besides, it is independent of the order in which generators are evaluated.

Almost every authoritative utility study of wind energy has concluded that wind can provide firm capacity - roughly equal, in northern Europe, to the capacity factor in the winter quarter (Milborrow, 1996). This implies that if, say, 1000 MW of wind plant was operating on the UK network, it might be expected to displace around 350 MW of thermal plant considering wind power has a capacity factor of around 35%. Ford and Milborrow (2005) states that the capacity credit of solar plant in the UK would be very low, and that of tidal barrage plant is lower than the average capacity factor.

Capacity credit can be used as a guide of the capacity contribution from intermittent renewables in generating capacity planning to make sure the system reliability will be maintained when introducing intermittent renewable generations to meet future electricity demand.

### 2.5.2 Wind generation

In recent years, considerable attention has been given to the development of renewable wind generation due to concerns with dwindling fossil fuel reserves and the potential impact of conventional energy systems on the environment. Wind is a non-depletable and environmentally friendly source of energy. In the UK, wind generation will be the leading source of renewable energy in the few decades to come.

Energy from wind is a form of energy transmitted from the sun. An estimated 1 to 3% of energy from the Sun that hits the earth is converted into wind energy (Wikipedia contributors. *Wind power, 2006*). Winds are turbulent masses of air movement resulting from the differential pressure at different locations in the surface of the earth. Wind is highly variable, site and terrain specific. Its variations spans from instantaneous, hourly, diurnal to seasonal. Wind power is directly proportional to the cube of the wind speed. The theoretical wind power - wind speed relationship is describe in Equation 2.14 below.

$$\text{Wind power output, } P = \tfrac{1}{2} \rho A V^3 \tag{2.14}$$

where

$P$ = Power output (Watts)

$\rho$ = Air density (about 1.225 kg/m$^3$ at sea level, less higher up)

$A$ = turbine rotor swept area, exposed to the wind (m$^2$)

$V$ = Wind speed (m$^3$/second)

Equation 2.14 yields the power in a free flowing stream of wind. However, it is impossible to extract all the power from the wind because some flow must be maintained through the rotor and to take into consideration the generator and bearings efficiency. Therefore, a more practical equation for a wind turbine is Equation 2.15.

$$\text{Wind turbine power, } P = \tfrac{1}{2}\, \rho\, A\, C_p\, V^3 \,.\, \eta_g \,.\, \eta_b \qquad (2.15)$$

where

$C_p$ = Coefficient of performance (.59 {Betz limit} is the maximum theoretically possible, 0.35 for a good design)

$\eta_g$ = generator efficiency (50% for car alternator, 80% or possibly more for a permanent magnet generator or grid-connected induction generator)

$\eta_b$ = gearbox/bearings efficiency (could be as high as 95% if good)

It is observed from the equation that a small increase in wind speed, $V$ will produce a large increase in power, $P$.

The amount of electricity generated by a wind turbine at a specific site depends on many factors. These factors include the wind speed conditions at the site and the characteristics of the wind turbine generator. Typical wind turbine generators generate power based on the availability of wind, and the power generated is a function of the wind speed. A typical wind power output curve as a function of wind speed is illustrated in Figure 2-7. The wind power curve shows the cut-in, rated and cut-out wind speed. It can be observed from Figure 2-7 that the power output of a wind generator does not vary linearly with the wind speed. A wind generator is designed not to generate power when the wind speed is below the cut-in speed and to shut down for safety reasons if the wind speed is higher than the cut-out or storm protection speed. The power output of a wind generator increases with the wind speed between the cut-in speed and the rated wind speed, and after reaching the rated speed remains constant while generating the rated power.

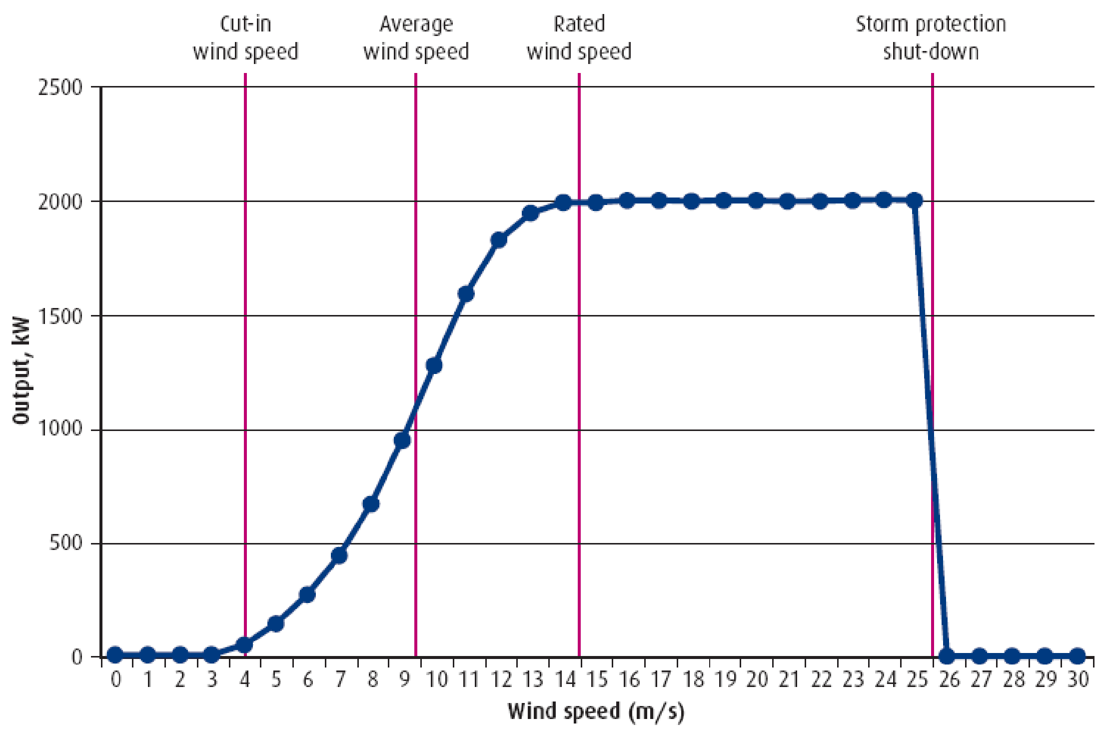


**Figure 2-7: Wind turbine power curve (Source: Winkelman, 1992)**

A major problem and barrier to effectively utilize the wind resource is the fact that it is both intermittent and diffuse in nature. Wind generators typically have very high mechanical availability which exceeds 95% in many instances. This means that the forced outage rate is often below 5% and requires very little maintenance throughout the year. However, wind generators experience 'fuel' shortages when the wind does not blow, thus causing the wind generators to be unavailable to generate power. This 'fuel' shortages for wind generators can be regarded as the forced outage rates which are much higher when taking into account the intermittency of wind.

In addition to that, wind's contribution to meeting the electricity demand may also vary. As mentioned by Milligan and Parsons (1999), the output from some wind generators may have a high correlation with load and thereby can be seen as supplying capacity when it is most needed. When this happened, a wind generating plant should have a relatively high capacity credit. The output from other wind generating plants may not be as highly correlated with system load, and therefore would have a lower value to the electric system and should receive a lower capacity credit, added Milligan and Parsons (1999). The correlation of wind generation with system load, along with the wind generator's outage rate, will determine how much capacity credit a wind generator will receive (Milligan and Porter 2005).

According to Chen (2000, pp.58) at the present time, many utilities are prepared to give an energy credit to a wind facility but are reluctant to assign it a capacity credit. However, numerous studies of the UK network have concluded that wind plant has a capacity credit. An early study (Farmer et al., 1980) concluded: -
"*If a definition of capacity credit is adopted, that maintains the existing level of security of supply, it can be shown that for low levels of wind-power penetration, a substantial proportion of the output can be ascribed as firm power…even at higher levels of penetration, the capacity credit could approach 20% of the rated output*".

In addition to the variability, wind has a highly diffuse characteristic and is not a concentrated source of energy. In order to generate a significant amount of power, a wind farm must harvest a large cross-sectional area of wind. The wind at any point in time may be insufficient to operate a wind system, as wind power depends upon climatic and weather conditions. Wind energy therefore is a non-dispatchable or intermittent resource (Chen pp. 60).

There are various factors that cause the intermittent nature of wind generation. These are directly related to the characteristics of the wind resource. As the fuel for wind-generated electricity, the strength, presence, absence and variability of the wind determines not only how much electricity can be generated, but also how reliable electricity from the wind will be in meeting electricity demand patterns (Sinden, 2005). The factors below directly cause the variability of wind resources.

1. meteorological conditions
2. daily/seasonal variations of wind speed (monthly, diurnal)
3. specific site and height
4. geographic dispersion of wind plant

The fluctuations in wind speed are dependent on different meteorological conditions. This means that wind resources vary between locations and countries, therefore, each country's wind characteristics should be analysed differently.

Besides, wind speed variations may follow a generally daily or seasonal pattern with inter-annual variability. Wind speed in the UK vary from summer and winter months as well as contain the element of diurnal variability where wind resource shows a clear pattern of higher wind power output during daylight hours in comparison to overnight.

Besides the diurnal, seasonal and inter-annual variations, wind speed at a specific site dictates the amount of energy that can be extracted from the wind technology characteristics. The availability of wind generation depends on the wind speed at the specific location where the wind generators are installed as well as the height of the installation as wind speed varies with height from ground. Figure 2-8 shows the annual mean wind speed in the mainland of the UK while Figure 2-9 shows the wind resources offshore.

Geographic dispersion of the wind plant will also affect the variability of wind power output. The variability of wind is not a fixed property, as different geographic locations will experience different wind conditions at any given time. Therefore, it is advantageous to locate wind turbines in a range of locations, rather than being concentrated in one place.

From the observation of the various factors that affect the availability of wind resources, it is important to find out how much capacity can be replaced by intermittent wind plant without compromising system reliability. This is determined by the probability of intermittent wind generation providing electricity at periods when demand is high. Quantifying this depends upon the behaviour of demand, conventional stations and intermittent wind generators during the times of the year when demand is at its highest level. In order to do that, the information required is listed as follows.

1. The timing and duration of demand peaks
2. The variability of demand during peak periods
3. The expected output and possible range of outputs from conventional stations during peak periods
4. The range of possible outputs from intermittent wind stations during peak periods

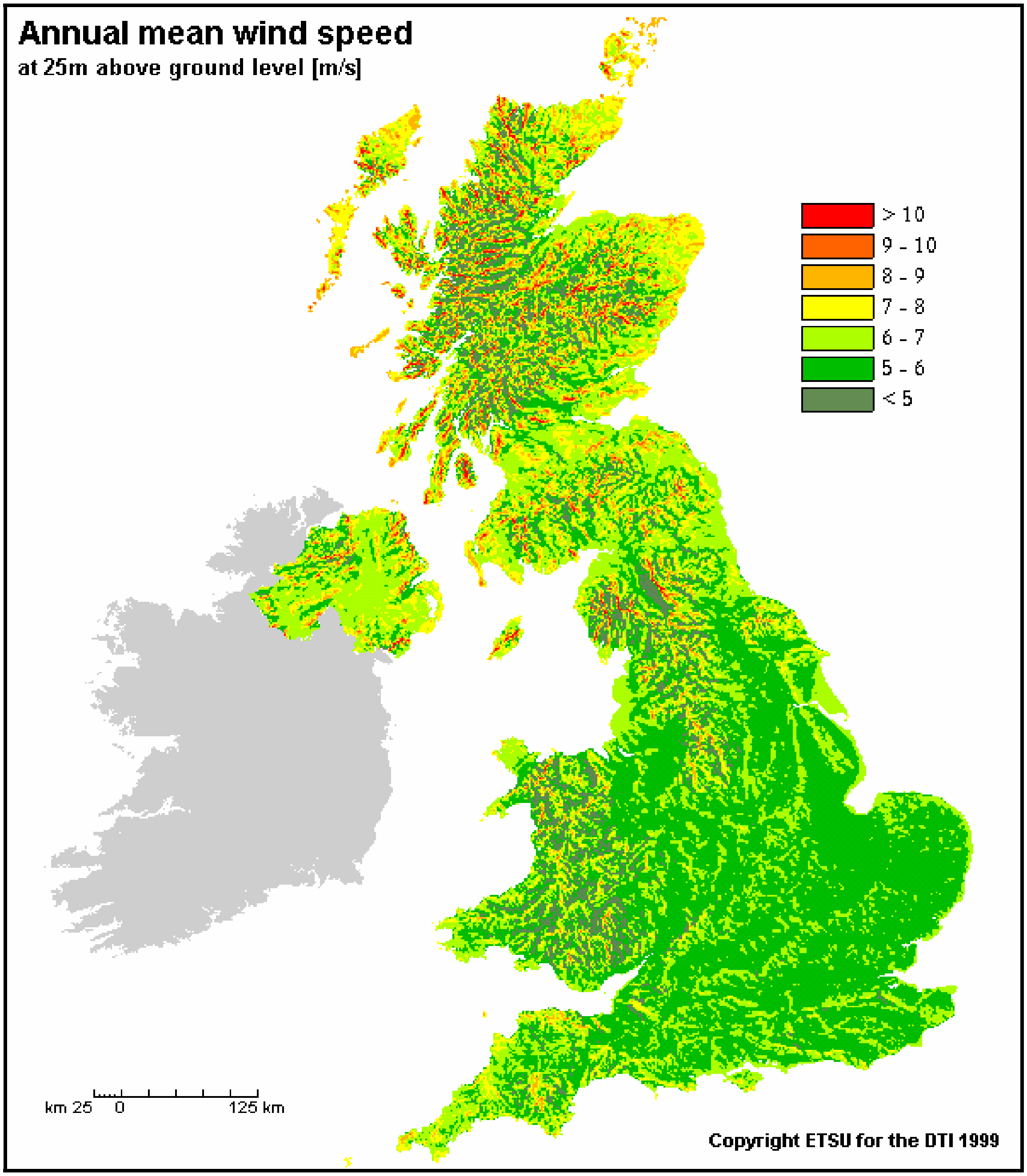


**Figure 2-8: Annual mean wind speed of the UK mainland (Source: BWEA website)**

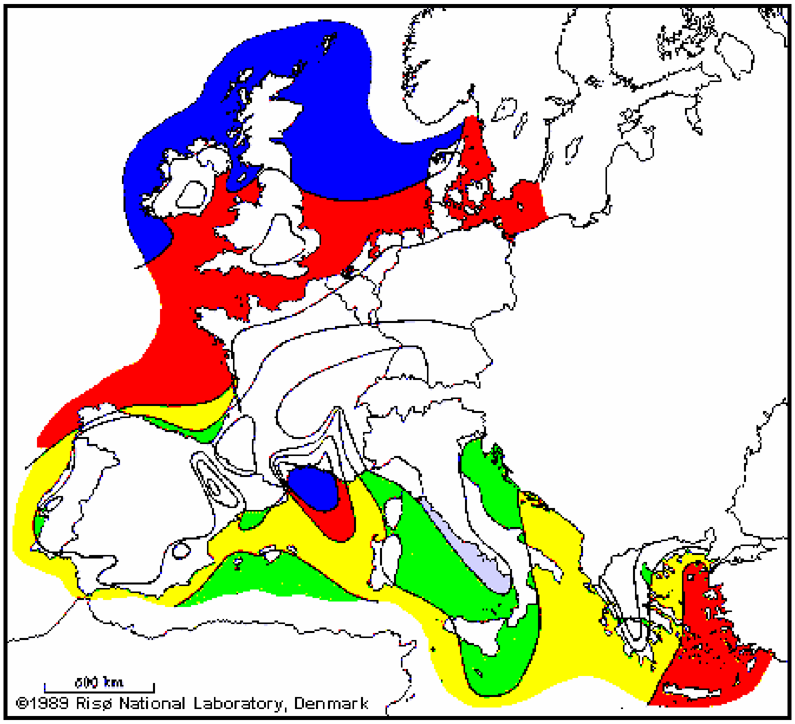


**Figure 2-9: Wind resource over offshore (Source: BWEA website)**

**Wind resources over open sea (more than 10 km offshore) for five standard heights** ($ms^{-1}$ + $Wm^{-2}$)

| | 10m | 25m | 50m | 100m | 200m |
|---|---|---|---|---|---|
| | > 8.0<br>> 600 | > 8.5<br>> 700 | > 9.0<br>> 800 | > 10.0<br>> 1100 | > 11.0<br>> 1500 |
| | 7.0-8.0<br>350-600 | 7.5-8.5<br>450-700 | 8.0-9.0<br>600-800 | 8.5-10.0<br>650-1100 | 9.5-11.0<br>900-1500 |
| | 6.0-7.0<br>250-300 | 6.5-7.5<br>300-450 | 7.0-8.0<br>400-600 | 7.5-8.5<br>450-650 | 8.0-9.5<br>600-900 |
| | 4.5-6.0<br>100-250 | 5.0-6.5<br>150-300 | 5.5-7.0<br>200-400 | 6.0-7.5<br>250-450 | 6.5-8.0<br>300-600 |
| | < 4.5<br>< 100 | < 5.0<br>< 150 | < 5.5<br>< 200 | < 6.0<br>< 250 | < 6.5<br>< 300 |

This particular study excluded all the following areas from the resource assessment:
* everything closer to the shore than 5 km
* shipping lanes
* military exercise areas
* regions where dredging concessions existed
* known dumping grounds for ammunition, explosives and other hazardous materials
* any areas where the sea depth was less than 10m or greater than 50m

There are various modelling approaches that have been proposed by many literatures to evaluate the capacity credit of wind generators/farms. Some of the more frequently used and widely known approaches are described below.

**1. Retrospective analysis**

Wind plants are modelled as load modifiers, where the hourly wind generation capacity is deducted from the expected demand. This approach, according to Milligan and Porter (2005), can best be accomplished by using hourly wind generation data along with actual load data in the reliability model. This provides the most accurate fidelity for a backward-looking evaluation, and is relatively simple to accomplish in most modelling frameworks, added the two authors. For this approach, the hourly wind generation is subtracted from the hourly load, and the reliability calculation can then be conducted to determine the LOLP by applying this net equivalent load to the hourly load probability table. Milligan and Porter (2005) also suggest that as additional wind production data becomes available over time, a multi-year analysis that pairs actual wind and load data is possible, and it can provide significant insights into inter-annual variability and ELCC over time.

The advantage of modelling the wind plant as a load-modifier is that it takes into account the detailed chronological variation of the wind plant output. However, the setback of this method according to Milligan (1996a) is that it does not allow the variance of the wind plant output to be captured and quantified into the LOLP calculation.

There are two ways to represent the capacity credit of a wind generator using this approach. They are the firm capacity method and the equivalent capacity method.

***Firm capacity method / Effective Load Carrying Capability (*ELCC*) method*** – The firm capacity/ELCC method is based on the LOLP measure of system reliability, and incorporates LOLP calculations in such a way that adding a new generator (for example a wind plant) is benchmarked against an *ideal, perfectly reliable unit* with 100% availability (Milligan, 2005).

Many studies that incorporate the use of electric utility reliability and production cost models characterize wind plants by the load-modification technique and measure capacity as measured with the effective load-carrying capacity (ELCC) (Milligan, 1996a). ELCC can discriminate among generators with differing levels of reliability, size and on-peak vs. off-peak delivery. It effectively rewards plants that are consistently able to deliver during periods of high demand, and it ranks less reliable plants by calculating a lower capacity credit. For intermittent wind generators, this method can discriminate between wind regimes that consistently deliver during high-risk periods, sometimes deliver during high-risk periods, or never deliver during high-risk periods. In fact, added Milligan (1996a), ELCC can provide for a continuum of capacity values over these potential outcomes. In order to calculate ELCC, a database is required that contains

- hourly load requirements
- conventional generator characteristics such as rated capacity, forced outage rates, and specific maintenance schedules
- Intermittent wind power output data (at least 1 year of hourly power output is required, but more data is always better)

Although there are some variations in the approach, ELCC can be calculated in several steps as described by Milligan and Porter (2005) as below.

1. The system is modelled without the intermittent generator of interest. (e.g. a wind generator)
2. The loads are adjusted to achieve a given level of reliability. (This reliability level is often equated to a loss of load expectation (LOLE) of 1 day in 10 years.)
3. Once the desired LOLE target is achieved, the renewable generator is added to the system and the model is re-run.
4. The new, lower LOLE (higher reliability) is noted, and the generator is removed from the system.

5. Then the benchmark unit is added to the system in small incremental capacities until the LOLE with the benchmark unit matches the LOLE that was achieved with the renewable generator.
6. The capacity of the benchmark unit is then noted, and that becomes the ELCC of the renewable generator. (It is important to note that the ELCC documents the capacity that achieves the same risk level as would be achieved without the renewable generator.)

To fully measure the long-term capacity credit of an intermittent power plant, Milligan and Parsons recommend using the standard ELCC measure and a full complement of reliability model runs.

***Equivalent capacity method*** – This method substitutes an alternative unit (for example a natural gas unit) instead of the ideal unit which is sized so that the LOLP calculation is the same as that calculated with a wind plant instead of the gas plant. This method provides a more practical value of capacity credit than using *the ideal, perfectly reliable unit* in the firm capacity/ELCC method as it refers the wind capacity to a gas plant with the same amount of forced outage rates.

### 2. Prospective analysis

A prospective analysis (Milligan and Porter, 2005) of how wind may affect future system reliability may involve modelling wind in a probabilistic way. The approach modelled wind plants with a capacity level and effective FOR that takes into accounts both mechanical and fuel (wind) availability. Wind availability can be captured in the reliability models by applying the forced outage rate to account for the lack of "fuel" when the wind does not blow, just as mechanical outages are treated with conventional units. The details of this approach will depend on the capabilities of the reliability model. However, Milligan and Porter (2005) suggested that the approach generally involves modelling wind as a multi-block conventional generator. Several levels of wind output can be calculated and matched with the probability of obtaining that output. These values are then converted into the form that is acceptable by the reliability model so that these capacities and probabilities look like forced outage rates at different output levels (Milligan and Porter, 2005). It is critical that these probabilities represent the diurnal and seasonal characteristics of the wind resource. This approach is discussed further in Milligan (Wind Energy Journal Part 2).

### 3. Reliability Curves

Similar to the methods in the retrospective approach, where wind plant is modelled as load modifier, different reliability indices (LOLE) can be obtained by varying the annual peak load. The LOLE can be plotted against the system load for two cases; without wind generation and with wind generation. The two curves can be plotted as shown in an example in Figure 2-10 and this curves show the relationship between a risk index (LOLE) and the annual peak load before and after adding the wind generator. For a predetermined level of reliability, 0.1 days per year in this case, the ELCC for the wind plant can be evaluated by taking the difference between load values at the reliability level for the two curves.

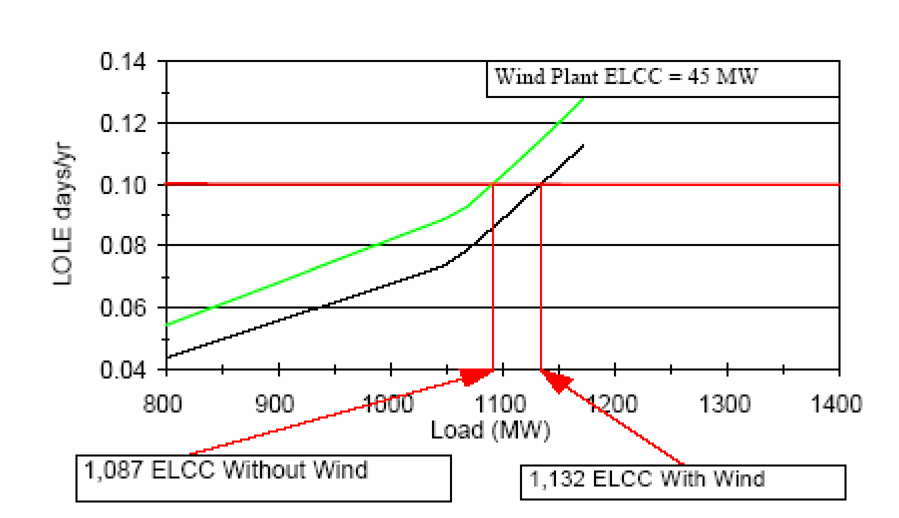


**Figure 2-10: Reliability curves for calculating ELCC of a wind plant (Chen, pp. 89)**

## 4. Advanced techniques

Most of the reported work done on modelling wind power generation and on the use of such models for generating system adequacy evaluation is in the analytical domain. Analytical methods usually create separate generation models for the conventional unit and intermittent unit group. According to Chen (pp. 59) the most obvious deficiency of analytical methods is that the chronological characteristics of the wind velocity and its effects on wind power output cannot be considered. A sequential Monte Carlo approach, on the other hand, is capable of incorporating such considerations in an adequacy assessment of a generating system containing wind generators (Chen pp.59).

***Sequential Monte Carlo (SMC) –*** While the load-modifier method is easy to use and understand, it is at best a single draw from a random variable (in statistical sense). According to Marnay and Strauss (1989) cited in Milligan (2005), repeated Monte Carlo simulations can be more accurately used to represent outages by selecting the available generation in each hour based on drawing from the probability distribution that describes its availability.

The SMC is a collective method taking a broader perspective on wind variability. The technique develops a probabilistic model of the underlying wind speed or wind power data. According to Milligan (2001), a number of techniques can be used for this, and examples include the auto-regressive integrated moving average approach applied by Billinton et. al. (1996) and the Markov modelling applied by Milligan (1996b) and Milligan and Graham (1997). These methods involve extensive computational time and effort, mentioned Milligan (2001), but produced probabilistic estimates of a number of parameters related to wind-power production. The issues related to inter-annual variations in wind generation can be assessed by using this probability distribution. Besides, the expected wind-induced variation in reliability could be estimated.

***Sliding window technique*** – This method was proposed by Milligan (2001) where it is designed to retain the hourly variability in wind power output, while retaining an assessment of the probability that the actual wind power production will be either above or below the expected level. It uses the hourly variation of wind power to calculate an effective forced-outage rate for wind power plant. According to Milligan (2001), it is an extension of the convolution procedure that is applied to conventional generators. The main part of these new methods is in assessing an effective FOR for the wind plant that changes through time. The advantage of this approach is that it retains the diurnal and seasonal characteristics of the wind generation and explicitly convolves alternative wind power output levels and their probabilities into the LOLP calculation. The effective FOR is not a true representation of mechanical reliability, but a statistical expectation that the wind plant will be on outage over a specified period of time. More detailed discussion of the sliding window approach can be found in Milligan (2001).

### 5. Approximation Methods (Milligan and Porter, 2005)

In cases in which ELCC cannot be calculated because of data or other limitations, approximation methods can be useful. Three different approximation methods will be described here.

***Capacity factor*** – The capacity factor of the wind plant can be used to approximate the capacity credit. From a planning perspective, one could interpret the capacity factor as the ratio of statistically expected output divided by annual energy output (Milligan, 2001). Because planning often focuses on the "reasonably expected future", this measure can be viewed as a first-stage approximation to overall capacity credit (Milligan, 2001). Capacity factor of the wind plant can be easily calculated when the hourly wind generation data is available. The capacity factor (defined as the ratio of the average output to the total output) can be calculated for the entire duration of the period in consideration, hours during the utility system peak or for the hours in which the risk of not meeting the load is highest. This factor indicates the potential wind energy production capability at a wind site. It is, however, not related to the system capacity composition, the chronological load and wind profiles, and the accepted system risk level.

***Risk-Based Simple Methods*** - Risk-based categories develop an approximation to the utility's LOLP curve throughout the year. Risk-based methods utilize hourly LOLP information either from an actual reliability model run or as an approximation.

***Time-Period-Based Methods*** – This is another approximation method attempt to capture risk indirectly, by assuming a high correlation between hourly demand and LOLP. To avoid using a reliability model altogether, it is possible to collect only hourly load and wind data for at least one year and use these data to calculate an approximation to ELCC. This approach is appealing in its simplicity, but it does not capture the potential system risks that are part of the other methods discussed above.

### 2.5.3 Solar generation

Solar radiation from the sun is the greatest energy source that our planet earth receives and known to man at the moment. Photovoltaic (PV) was invented in 1954 and by 1970s, arrays of photovoltaic cells were used to convert the solar radiation into DC electricity (Kreith 1997, p.969). Solar PV uses high-tech solar cells usually made from silicon to produce electricity directly from sunlight. Direct sunlight is not necessary and the cells can produce electricity even during cloudy conditions, however, at a reduced rate. These cells are normally grouped and form solar panels that can be fitted to absorb heat from the Sun. PV has no mechanical or moving parts and requires no other fuels than the sunlight. Therefore, they require very little operation and maintenance effort. Besides, PV system runs quietly and cleanly without emissions which cause little or no pollution to the environment. With the hype of growing concerns regarding the sustainability of energy supply and the energy crisis the world is facing when the fossil fuel runs out, PV has emerged as one of the feasible technology in harnessing a renewable resource, the solar energy.

The basic requirement of harvesting the solar energy is having sufficient irradiance from the sun and large enough surface area of the PV cells to capture the irradiance. The efficiency of the PV system that only produces DC electricity will be enhanced by incorporating a solar thermal system as a hybrid. A PV Cell current-voltage characteristic curve is shown in Figure 2-11. The area under the curve is the power output that can be harnessed from the PV panel.

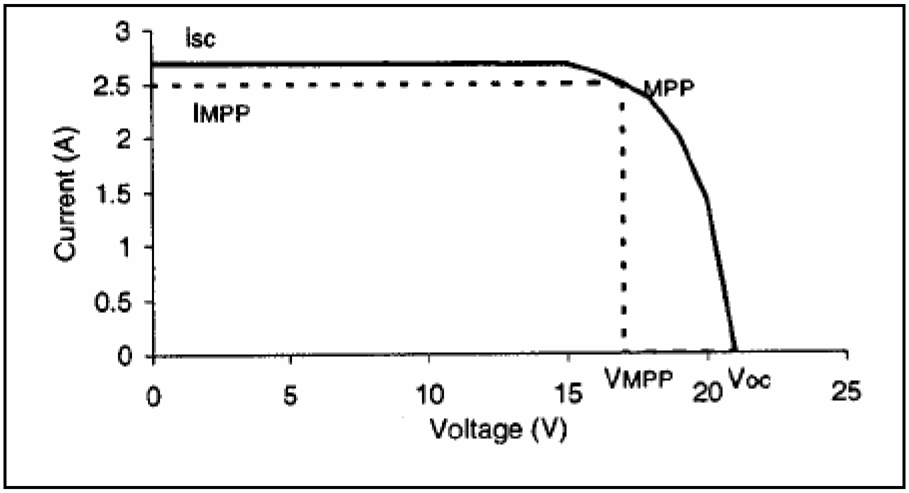


**Figure 2-11: PV Cell Current-Voltage characteristics curve**

PV modules are normally sized to provide enough energy during the time of lowest sunlight availability and taking into consideration the predicted load for a peak day. This is to ensure that the building will have a reasonable supply from its PV hybrid system during the period of low resources availability as well as period of high local demand. The period of the lowest sunlight availability will normally be during the winter season with very little direct incident solar radiation or insolation.

In order to maximize the energy delivery of a PV hybrid system, PV panels will be best located on the roof of a building without shades from tall trees and tall buildings in the surroundings. Besides, the area should be exposed to the sunlight for a minimum of 6 hours in a typical day (Southface Energy Institute, n.d.). This is to maximize the amount of direct and diffused insolation to the PV panel. A typical residential PV system which produces about 2 kilowatts (2kW) requires an area of about 8 feet by 25 feet to accommodate solar panels (Southface Energy Institute, n.d.). According to Solar Century, the minimum required area for a solar electric system and solar thermal system is approximately $10m^2$ and $4m^2$ respectively.

In the UK, the orientation of the panels will be maximized when it is installed at a tilted angle between 30º - 40º from horizontal, facing south, south-east or south-west (Solar Century, n.d.). In addition, the west-facing roof should give the module to more exposure of the hot afternoon sun. This is important because this is when most, if not all utility experiences peak demand. However, the efficiency of the PV system will be reduced by 40% with a north-facing panel compared to a south-facing one. The panel orientation actually depends on the location of the installation of the PV panels. And this orientation applies to the UK due to its location in the northern hemisphere on the earth.

Solar energy is so abundant in most areas of the world, although highly dispersed in nature. This resource if harnessed by the current technology in PV hybrid system could provide a significant amount of savings in terms of the capital expenditure of building new centralized power plants to meet the growing electricity demand. Large scale applications of PV hybrid system will also reduce the dependency of the electricity supply from the grid, which means a reduction in the reliance on the depleting fossil fuels resources and environmental impact of greenhouse gases.

However, there are still barriers in the widespread implementation which is yet to be resolved. There are a few reasons that solar generation is intermittent in nature. The factors that cause intermittency and the inconsistent generation are listed below.

1. solar insolation/intensity
2. time of the day and day of the year
3. water content in the air
4. cloud coverage
5. location

Solar energy is in a sense less random than wind, as the underlying seasonal and diurnal trends are accurately predictable. Randomness is, however, introduced by the variations in cloud cover and water content in the air. This random coverage of clouds effect makes short-term variations of solar energy difficult to forecast.

Besides these temporal variations, solar resources vary spatially like wind do, and the output from the same intermittent technologies could vary from site to site. The amount of solar intensity at a particular site dictates the power output of a PV system. Recorded solar radiation data are not available for many locations around the world. It is necessary to generate synthetic hourly data for satisfactory evaluation of PV power generation for reliability studies.

The capacity credit of solar photovoltaic installations in the UK is likely to be very low, given that the output from PV plant around the times of peak demand – generally 17:30 on a January weekday – may confidently be stated to be zero (Ford and Milborrow, 2005).

One of the models proposed by Ehnberg (2003) is for simulating six-minute mean values of global solar radiation without any geographical restrictions and a method of generating cloud coverage data by using a discrete Markov model. This model according to Ehnberg (2003) only uses the geographical coordinates of the location and cloud coverage data as input.

There are several models proposed previously for generation of the random nature of global radiation but the way of implementing are very different. Amato et. al (1986), Albizzatia et. al (1997), and Blouktsis and Tsalides (1988) model daily global solar radiation (thus the yearly variations) but a higher resolution of the simulation is needed for photovoltaic power generation in an autonomous electric power system. Such model would be applicable in a system with a storage capability higher than the daily load demand.

The transmittivity of solar radiation in the atmosphere depends on various factors, for example humidity, air pressure and cloud type. A factor that has a great impact on the transmissivity is the cloud coverage (Albizzatia et. al, 1997). By assuming a deterministic relation between cloud coverage and hourly global solar radiation, the need for measurement of the latter disappears according to Ehnberg (2003). Cloud observations can be used in this sense because of the simplicity of measuring and there is no need of expensive equipment. The level of cloudiness is expressed in Oktas. This divides the sky into eight parts and can be used to describe the range of the sky that is covered with clouds. Ehnberg (2003) even suggested that by combining the solar radiation model with a model of simulating cloud coverage the simulation method could be even more suitable. In reliability simulations for power systems without storage capacity, simulation data with higher resolution than one hour is needed in some cases added Ehnberg (2003). Detailed modelling of the solar generation model can be found in Ehnberg's thesis (2003).

### 2.5.4 Wave and tidal stream generation

Wave and tidal stream generation would be expected to make significant contributions in the UK in the coming few decades as the technology matures. The UK is blessed with some of the largest wave and tidal power resources in the world (Butler, 2001). A recent report by the House of Commons Select Committee acknowledged the high capital costs and need for further R & D and highlighted that energy from waves and tides was predictable and reliable, added Butler (2001). At the moment, these technologies are still in the phase of trial and development. Therefore, there are not much research and literature that has considered the intermittent nature of both resources for system reliability evaluations. The resources of these two renewable energy are intermittent but predictable with a very high degree of accuracy, far into the future.

Waves transmit large volumes of energy from windy conditions far out from sea to the shore. Here the energy can be used to generate electricity and a variety of technologies are being developed to do this. The potential of wave energy in the UK is large due to the extensive coastline. Figure 2-12 presents the annual mean wave height around the UK coast. The light colours show the potential of harnessing wave energy for electricity generation.

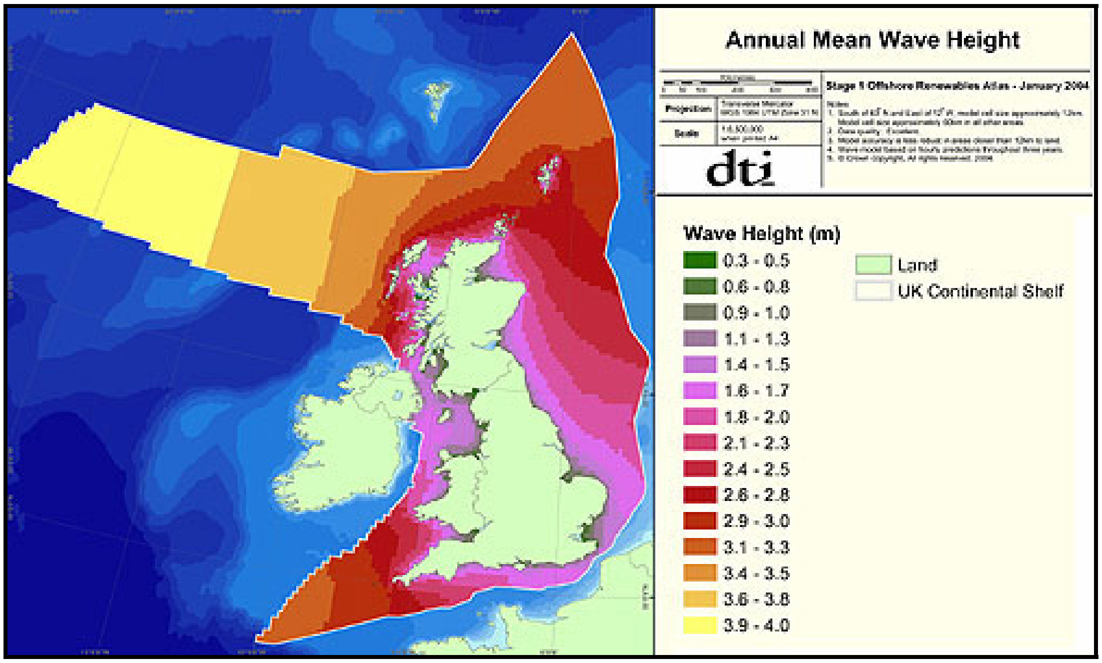


**Figure 2-12: Annual mean wave height of the UK coast (Source: DTI website)**

Wave energy is random in nature, although there are frequently seasonal and diurnal trends. The random nature of wave is both temporal and spatial although the movement of large-scale weather systems may mean that there are often underlying trends over a wide geographical area (Ford and Milborrow, 2005). The factors that cause intermittency for wave generation are listed below.

1. sea state
2. location
3. typical period

Though intermittent, electrical output from wave energy is more predictable than wind power output, as sea states or waves are more predictable than wind. Wave energy is largely immune to short-term, local climatic effects (Imperial College and E4Tech, 2003). This means that when the waves are created, it will continue to transmit energy for some time and distance. The power output from a wave energy plant can be accurately predicted at least 6 hours in advance (Imperial College and E4Tech, 2003).

As for tidal stream generation, the energy is in a unique category as it is related to the Lunar, rather than the solar cycle. Tidal currents flow according to a predictable diurnal pattern. It is highly predictable but the peak generation from a tidal scheme will rarely coincide with peak demand on an electricity system. Overall, the resource is likely to be smaller than that for the offshore wind and wave energy, but has advantages in terms of predictability, and possibly, engineering feasibility (Imperial College and E4Tech, 2003).

Tidal currents are relatively predictable where tides vary by day and month. One tide with a period of about 12.4 hours represents the diurnal ebb and flow cycle, and the other the 28 day spring-neap period. In UK waters the maximum spring current velocity is approximately twice the minimum mean neap tide velocity (Imperial College and E4Tech, 2003). Therefore, the times of peak power vary from day to day not following the 24 hour cycle. Although this cycling of available power is predictable, it may not coincide with the time of peak demand.

Figure 2-12 presents the average annual tidal power around the UK coastline. The light colours show the high potential of harnessing tidal stream energy for electricity generation. As can be observed from the Figure 2-12, there are certain areas marked in deep red that shows massive potential for development of tidal streams generation.

Despite very large resources, tidal energy has not been successfully exploited on a wide scale. Tidal produced electricity is generated by making use of tidal water flows. It can be done by constructing a tidal barrage in an estuary and operating this like a conventional hydro dam – however, the environmental impacts are often prohibitive. Alternatively, turbines can be placed underwater in the tidal stream – these produce power from both in and out flows. Other variations are also possible. Tidal power is gaining increased interest in the UK, with a number of projects at demonstration and testing stage.

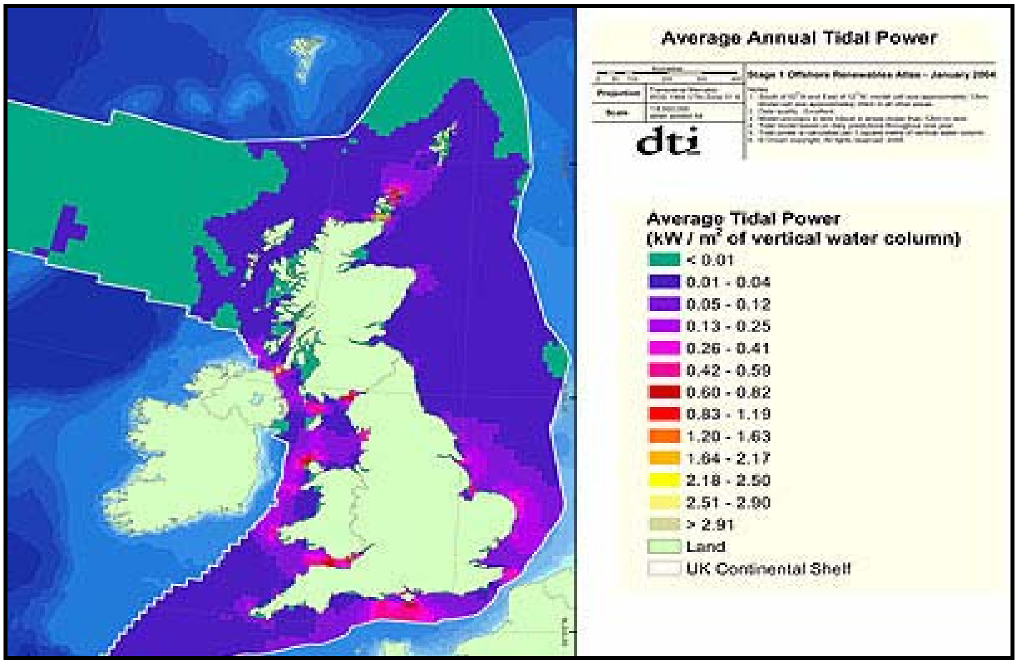


**Figure 2-13: Average Annual Tidal Power off UK coastline (Source: DTI website)**

The factors that cause the variation of power output from tidal stream are due to the moon's gravity and have a predictable diurnal pattern. Although these technologies cannot be controlled and be relied upon to deliver power during peak demand period most of the time, their predictability is a very good indication to system planners and operators to make available backup capacity.

### 2.5.5 Impacts of intermittent generation to system reliability

Intermittent and variable output must be considered in relation to the role the generation source is providing. Butler (2001) suggest that intermittent and variable generation sources may not be best suited as base-load plant, but contributing more to ancillary services, peak demand and seasonal variations, e.g. higher demand for electricity in the winter when the wind speed tends to be higher.

Besides, the right mix and location of intermittent renewable generation with appropriate aggregation may provide opportunities for the provision of base-load output. Added

Butler (2001), certain renewable energy sources show a degree of inverse correlation that may help flatten and ease the predictability of output, e.g. low winds on sunny days and high winds on overcast days. By using combinations of different variable source, hydro, storage and/or trade (interconnectors), there seems no technical reason why large systems should not derive well over half their power from variable sources (Grubb, 1997).

At high levels of intermittent generation in the system (perhaps over 20%), the effects of intermittency will be more noticeable. Back-up facilities and/or electricity storage have been highlighted as potential technologically and economically necessary responses to such effects (Anderson and Leach, 2001). But, although increased generation from variable renewable sources may increase the value of storage and vice versa, storage is in no sense the only answer (Grubb, 1997).

# Chapter 3

## RELIABILITY EVALUATION METHODOLOGY

*The first section of this chapter describes the method of approach that is used in this project. The work focuses on two parts of system reliability modelling. The first part will focus on the development of a computer programme that will model and simulate an existing conventional generation system with load and generating plants and calculate the reliability indices; the Loss of Load Probability (LOLP) and Loss of Load Expectation (LOLE) of the system being studied. The second part of the project consist of modelling and integrating the intermittent wind generation into the existing model and to study the effect of intermittent wind generation on system reliability.*

*The second section will describe the sources of data that is used in the modelling and study. The data used in this study are the IEEE 1996 RTS, 2001 and 2002 wind power plant hourly output from wind farms across Scotland and 2002 England and Wales electricity demand profile. These data will be used in part of the study.*

## *3.1 Method of approach*

The first part of the research will describe the whole process of modelling the conventional generation system reliability based on the analytical method. A computer programme called "*System Reliability Evaluation Programme*" or SREP is developed using MS Excel together with the built-in Visual Basic Editor. This programme will be used to model and simulate conventional generation system with load and generating plants, and calculate the reliability indices; the Loss of Load Probability (LOLP) and Loss of Load Expectation (LOLE) of the system being studied. The analytical method adopted to determine the reliability indices will be to establish the *Load Probability Table* (LPT) and *Capacity Outage Probability Table* (COPT) using the IEEE RTS data and then convolving the two tables to form a *System Margin State Table* (SMST). The SMST will then provide the evaluation of the reliability indices, namely the LOLP and LOLE. Data from the IEEE Reliability Test System (RTS) is used to evaluate the computer model developed and the reliability indices result obtained will be compared to various references.

The second part of the project consist of modelling and integrating the intermittent wind generation into the existing model and to study the effect of intermittent wind generation on system reliability. A wind model is developed based on the load-modifying method as described in Chapter 2. The total amount of hourly wind generation will then be deducted from the hourly load profile and the 'new' modified load profile will be used together with the existing generating units to determine the reliability of the system with intermittent wind effect integrated into the load model. Using the Reliability Curve Method and the Retrospective Approach, the capacity credit of the wind generation will be evaluated and compared between the different approaches.

Further case studies were also conducted based on the wind modelling approach created to assess the effect of integrating intermittent wind generation into the conventional generation system in terms of wind penetration level, diversity of wind, inter-annual variation and the impact on capacity credit using the GB load profile. The flow chart of the project methodology is summarized in Figure 3-1.

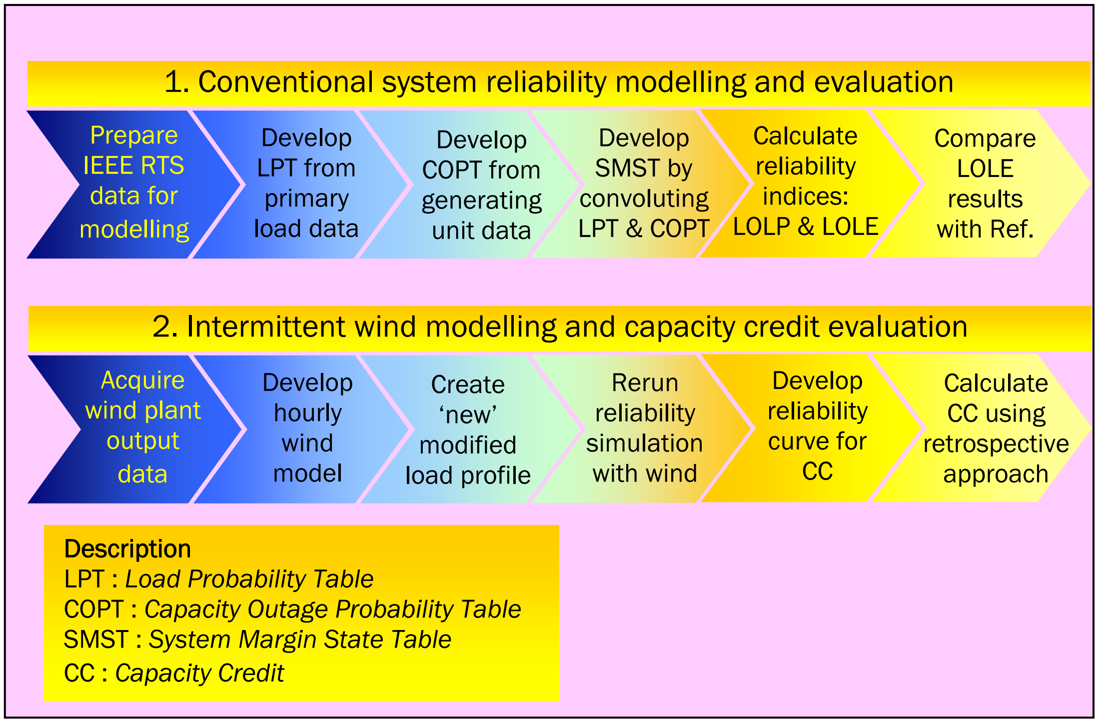


**Figure 3-1: Reliability assessment methodologies utilised in this research**

## 3.2 *Sources of Data*

The data used for the initial modelling of the SREP computer programme is the Institute of Electrical and Electronic Engineer's Reliability Test System 1996 (IEEE RTS). This reliability test system is developed by the Reliability Test System Task Force for use in bulk power system reliability evaluation studies. The value of the test system is that it will permit comparative and benchmark studies to be performed on new and existing reliability evaluation techniques (IEEE RTS Task Force of APM Subcommittee, 1999). This test system was an updated version of the original IEEE RTS developed in 1979 (referred to as RTS79). It was designed and used as a reference system that contains the core data and system parameters necessary for composite reliability evaluation methods.

According to the IEEE RTS Task Force of APM Subcommittee (1999), in 1986 a second version of the RTS was developed (RTS-86) and published with the objective of making the RTS more useful in assessing different reliability modelling and evaluation methodologies. The advantage of the RTS-86 is that it presented the system reliability indices derived through the use of rigorous solution techniques without any approximations in the evaluation process. These exact indices can then be used to compare with results obtained from other methods.

It is important to note that the various parameters in RTS-96 is not a representative of any particular power system and is merely a reference for testing the impact of different evaluation techniques on diverse applications and technologies.

The load and generating units data of the IEEE RTS 96 is summarized in Appendix A. Table A-1 in Appendix A shows the weekly peak loads in percent of the annual peak. This seasonal load profile can be used to adapt to any system peaking season one desires to model. Table A-2 in Appendix A shows the assumed daily peak load in percent of the weekly peak; while Table A-3 shows the hourly load in percent of the daily peak. The week numbers corresponding to the seasons of the year can be reassigned depending on the climate zone that one wishes to model. The peak demand of this load profile is 2850 MW.

The combination of 52 weekly peak loads, 7 daily peak loads and 24 hourly peak loads, all as fractions, in combination with the annual peak load, results in an hourly load model for a year consisting of 8736 hours.

Table A-4 in Appendix A shows the generating units data with the unit unavailability.
Besides the IEEE RTS-96 data, the wind hourly power output data was also used in the intermittent wind reliability modelling study. Three sets of hourly data for year 2001 and 2002 wind power output are obtained from three different wind farms location across Scotland. The three wind farms are located in the northern isles, northern mainland and the west of Scotland. These are the actual power output of the respective wind farms

recorded at site. The three sets of data will be used in Chapter 5 and Chapter 6 for the modelling of the wind reliability system as well as for the case studies.

In addition to the wind data, a 2002 England and Wales electricity demand profile which will be called the 2002 GB demand profile is used in one of the case study in Chapter 6.

# Chapter 4

## GENERATION SYSTEM RELIABILITY MODELLING AND EVALUATIONS

*Generation system reliability indices have been traditionally used as a standard for measuring system reliability. The amount, type and availability of generating plants in the system is required to provide the capacity sufficient to meet the electricity demand and to provide a certain level of reliability.*

*In order to evaluate the reliability indices of a generation system, a computer model is created using MS Excel. This model will be called the System Reliability Evaluation Programme (SREP) and utilizes the Load Probability Table (LPT), Generation Capacity Outage Probability Table (COPT) and the System Margin State Table (SMST) to evaluate the reliability indices; the Loss of Load Probability (LOLP) and Loss of Load Expectation (LOLE) in units of days per year and hours per year.*

*This chapter will discuss about the input data requirements, the modelling process of the IEEE RTS load data into LPT, the modelling process of the IEEE RTS generating units' data into COPT and the convolution of the two tables to obtain the SMST. Then the calculation of the reliability indices (LOLE & LOLP) and the model evaluation will be discussed.*

## 4.1 Background

Generating capacity adequacy assessment involves the creation of a capacity model and the convolution of this model with a suitable load model (Chen 2000, pp.77). Based on the analytical method, the capacity model is normally referred to as a *Capacity Outage Probability Table* (COPT). This COPT provides the probability of existence of each possible outage capacity level considering all generating plants that is available in the system. On the other hand, the load model is a chronological hourly load profile. The available system reserve at a point in time is the difference between available capacity and the load. This system reserve can be obtained by convoluting the COPT and the load model in the LPT to obtain a SMST. A negative margin state which can be found from the SMST denotes a load loss situation. The system reliability indices can be evaluated by observing the available system reserve profile over a sufficiently long time period.

According to Wang and McDonald (1994, p.129), the calculation procedure for Generating System Reliability Evaluation can be described as follows:

1. Compile the generating unit's reliability data table. Indicate the generator type: hydroelectric, fossil fuel, nuclear, pump and reservoir, etc. For hydroelectric generators, output power should be determined according to the flow capacity and the reservoir discharge, etc.
2. Arrange a maintenance program. The unit under scheduled maintenance during a certain period should be withdrawn from the system and the reliability calculations.
3. Create the generator unit's outage capacity model – probability and frequency tables – using the recurrence formulae.
4. Compile the load's primary date table.
5. Create the load outage capacity model – probability and frequency tables.
6. Calculate the system margin state table using the parallel formulae.
7. Calculate the system's reliability indices.

The power generating system reliability evaluation calculation procedure can be summarised in Figure 4-1.

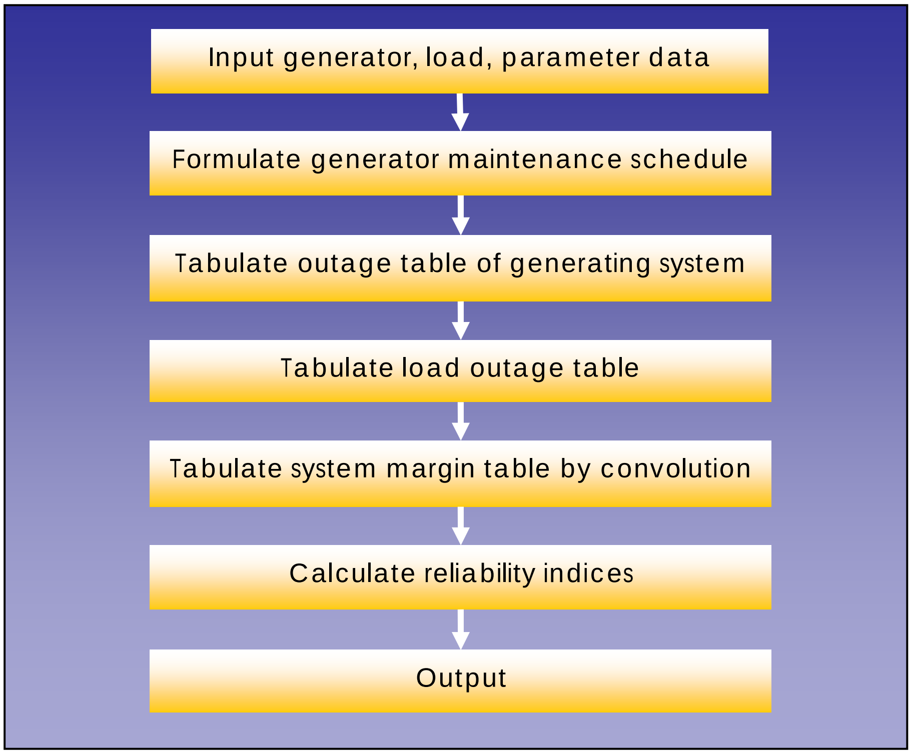


**Figure 4-1: Flowchart for generating system reliability calculation (Source: Wang & McDonald, 1994)**

A computer model is created using MS Excel based on the procedure presented and will use the analytical method to evaluate the system reliability indices.

## *4.2 Input data*

Before the start of developing the programme, the input data required needs to be determined. This model requires data for the annual demand or load profile of the system and also the generator unit parameters such as the effective capacity, number of similar units and the forced outage rates.

For the load data, the hourly chronological load is required. This chronological load can be sourced directly from the system operator or can be combined and modelled using primary load data. In the latter case, three sets of data will be required. They are the:

1. Maximum weekly load in a year (52 weeks in a year)
2. Maximum load in each day in a week (7 days in a week)
3. Hourly load in a typical day in each season (24 hours a day)

By modelling the load curve using the primary load data, the total number of hours in a year will be 52 weeks x 7 days x 24 hours which is equal to 8736 hours rather than 8760. These primary load data can be combined to form a chronological hourly load.

IEEE RTS data will be used to generate and later evaluate the SREP. The IEEE RTS primary load data with a maximum load of 2850MW can be found in Appendix A. The load factor for the IEEE RTS load data is 61.4% with a daily peak variation curve shown in Figure 4-2.

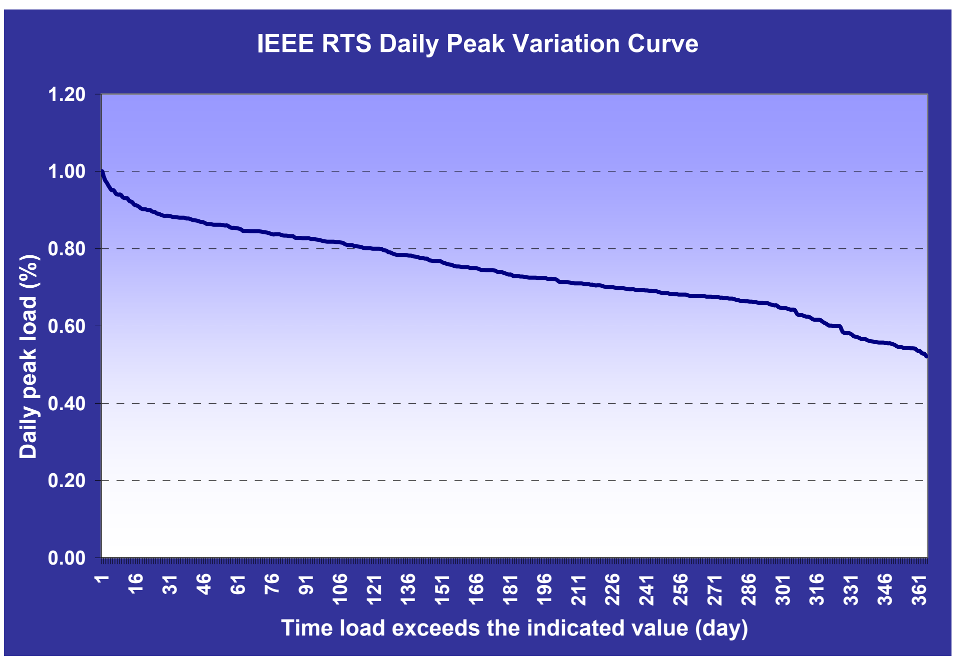


**Figure 4-2: IEEE RTS Daily Peak Variation Curve**

The data required to establish a *Capacity Outage Probability Table* (COPT) for generating units are:

1. number of identical generator units in the system
2. effective capacity of generator units
3. forced outage rates
4. duration for scheduled maintenance in a year
5. mean time to failure (MTTF) and
6. mean time to repair (MTTR)

These data can be obtained from individual generating stations or from the system operator. In this study, the IEEE RTS data of generating systems are used to generate the COPT and can be found in Table A-4 in Appendix A. The system consists of conventional oil, coal, nuclear and hydro units with different unit sizes ranging from 12MW to 400MW. The total system capacity of the RTS generating system is 3405MW which give a percentage reserve or reserve margin of 19.5% with a peak load of 2850MW.

The IEEE RTS load and generating system data are used in the next part of this chapter to model the system reliability evaluation programme which consists of the LPT, COPT and the SMST.

## *4.3 Load Probability Table (LPT)*

This LPT is one of many load models that can be used for system reliability study. Using the primary load data, the hourly chronological load is calculated for the whole year and then converted to a percentage figure of the annual peak demand.

The probability of a load increase from every load level can be calculated using Equation 4-1.

$$P\,(L_i) = \sum_j \frac{t_{ij}}{T} \tag{4.1}$$

where

$t_{ij}$ is the number of hours or days the load is at load level $L_i$

$T$ is the total number of hours or days in the examination period ($\sum t_j$)

This calculation can use a built in function in MS Excel called "*frequency*". This "*frequency*" function calculates how often values occur within a range of values, and then returns a vertical array of numbers. Because "*frequency*" returns an array, it must be entered as an array formula in MS Excel. The load level is arranged in descending order from 100% or peak to 0% and the corresponding "*frequency*" of the hourly or daily peak load will be calculated. The value obtained from the calculation is the exact probability of the number of occurrence of the corresponding load level. Then the cumulative probability of each load level will be calculated based on Equation 4-2.

$$P\,(l \geq L_i) = \sum_{k \geq i} p\,(L_k) \tag{4.2}$$

This is a cumulative distribution function and is shown in Figure 4-3.

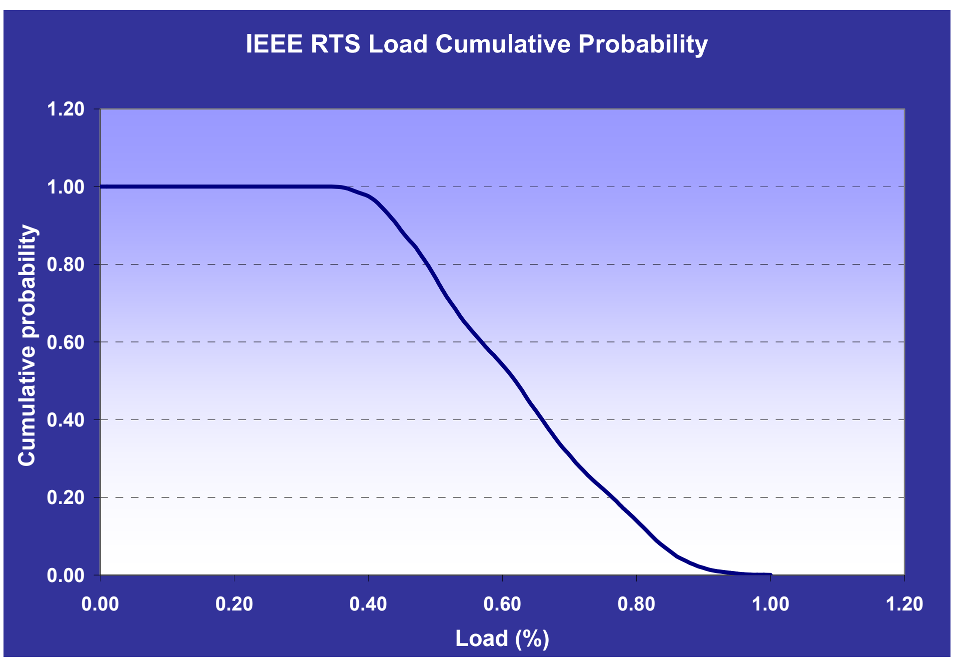


**Figure 4-3: IEEE RTS Load Cumulative Probability Curve**

Details of the load model in the System Reliability Evaluation Programme for the IEEE RTS are shown in Table 4-1, Table 4-2 and Table 4-3.

***Reliability Test System (RTS) - 1996***

The 1996 version of the Reliability Test System was published in Grigg, C., "The IEEE reliability test system: 1996", Paper 96 WM 326-9 PWRS, IEEE Winter power meeting

**Maximum Load in system:** **2850** **MW**

**Table 2 - Weekly Peak Load in Percent of Annual Peak (Source: IEEE RTS)**

| Index | Week | Peak Load (%) | Peak Load (MW) |
|---|---|---|---|
| | 1 | 86.2 | 2456.7 |
| | 2 | 90.0 | 2565.0 |
| | 3 | 87.8 | 2502.3 |
| | 4 | 83.4 | 2376.9 |
| | 5 | 88.0 | 2508.0 |
| | 6 | 84.1 | 2396.9 |
| | 7 | 83.2 | 2371.2 |
| | 8 | 80.6 | 2297.1 |
| | 9 | 74.0 | 2109.0 |
| | 10 | 73.7 | 2100.5 |
| | 11 | 71.5 | 2037.8 |
| | 12 | 72.7 | 2072.0 |
| | 13 | 70.4 | 2006.4 |
| | 14 | 75.0 | 2137.5 |
| | 15 | 72.1 | 2054.9 |
| | 16 | 80.0 | 2280.0 |
| | 17 | 75.4 | 2148.9 |
| | 18 | 83.7 | 2385.5 |
| | 19 | 87.0 | 2479.5 |
| | 20 | 88.0 | 2508.0 |
| | 21 | 85.6 | 2439.6 |
| | 22 | 81.1 | 2311.4 |
| | 23 | 90.0 | 2565.0 |
| | 24 | 88.7 | 2528.0 |
| | 25 | 89.6 | 2553.6 |
| | 26 | 86.1 | 2453.9 |
| | 27 | 75.5 | 2151.8 |
| | 28 | 81.6 | 2325.6 |

**Table 4-1: Part of "LoadModel" MS Excel spreadsheet input data**

**Calculated Hourly Peak Load**

| Week No. | Hour / Day | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Monday | 1531 | 1439 | 1371 | 1348 | 1348 | 1371 | 1691 | 1965 | 2170 | 2193 | 2193 | 2170 | 2170 |
| 1 | Tuesday | 1646 | 1548 | 1474 | 1449 | 1449 | 1474 | 1818 | 2113 | 2334 | 2358 | 2358 | 2334 | 2334 |
| 1 | Wednesday | 1613 | 1517 | 1445 | 1420 | 1420 | 1445 | 1782 | 2071 | 2287 | 2311 | 2311 | 2287 | 2287 |
| 1 | Thursday | 1580 | 1486 | 1415 | 1391 | 1391 | 1415 | 1745 | 2028 | 2241 | 2264 | 2264 | 2241 | 2241 |
| 1 | Friday | 1547 | 1455 | 1386 | 1362 | 1362 | 1386 | 1709 | 1986 | 2194 | 2217 | 2217 | 2194 | 2194 |
| 1 | Saturday | 1475 | 1362 | 1286 | 1248 | 1211 | 1230 | 1248 | 1324 | 1513 | 1665 | 1702 | 1721 | 1702 |
| 1 | Sunday | 1437 | 1327 | 1253 | 1216 | 1179 | 1198 | 1216 | 1290 | 1474 | 1621 | 1658 | 1677 | 1658 |
| 2 | Monday | 1598 | 1503 | 1431 | 1407 | 1407 | 1431 | 1765 | 2051 | 2266 | 2290 | 2290 | 2266 | 2266 |
| 2 | Tuesday | 1719 | 1616 | 1539 | 1513 | 1513 | 1539 | 1898 | 2206 | 2437 | 2462 | 2462 | 2437 | 2437 |
| 2 | Wednesday | 1684 | 1584 | 1508 | 1483 | 1483 | 1508 | 1860 | 2162 | 2388 | 2413 | 2413 | 2388 | 2388 |
| 2 | Thursday | 1650 | 1551 | 1477 | 1453 | 1453 | 1477 | 1822 | 2118 | 2339 | 2364 | 2364 | 2339 | 2339 |
| 2 | Friday | 1615 | 1519 | 1447 | 1423 | 1423 | 1447 | 1784 | 2074 | 2291 | 2315 | 2315 | 2291 | 2291 |
| 2 | Saturday | 1541 | 1422 | 1343 | 1304 | 1264 | 1284 | 1304 | 1383 | 1580 | 1738 | 1778 | 1797 | 1778 |
| 2 | Sunday | 1501 | 1385 | 1308 | 1270 | 1231 | 1250 | 1270 | 1347 | 1539 | 1693 | 1731 | 1751 | 1731 |
| 3 | Monday | 1559 | 1466 | 1396 | 1373 | 1373 | 1396 | 1722 | 2001 | 2211 | 2234 | 2234 | 2211 | 2211 |
| 3 | Tuesday | 1677 | 1576 | 1501 | 1476 | 1476 | 1501 | 1852 | 2152 | 2377 | 2402 | 2402 | 2377 | 2377 |
| 3 | Wednesday | 1643 | 1545 | 1471 | 1447 | 1447 | 1471 | 1815 | 2109 | 2330 | 2354 | 2354 | 2330 | 2330 |
| 3 | Thursday | 1609 | 1513 | 1441 | 1417 | 1417 | 1441 | 1778 | 2066 | 2282 | 2306 | 2306 | 2282 | 2282 |
| 3 | Friday | 1576 | 1482 | 1411 | 1388 | 1388 | 1411 | 1741 | 2023 | 2235 | 2258 | 2258 | 2235 | 2235 |
| 3 | Saturday | 1503 | 1387 | 1310 | 1272 | 1233 | 1252 | 1272 | 1349 | 1541 | 1696 | 1734 | 1753 | 1734 |
| 3 | Sunday | 1464 | 1351 | 1276 | 1239 | 1201 | 1220 | 1239 | 1314 | 1501 | 1652 | 1689 | 1708 | 1689 |
| 4 | Monday | 1481 | 1393 | 1326 | 1304 | 1304 | 1326 | 1636 | 1901 | 2100 | 2122 | 2122 | 2100 | 2100 |
| 4 | Tuesday | 1593 | 1497 | 1426 | 1402 | 1402 | 1426 | 1759 | 2044 | 2258 | 2282 | 2282 | 2258 | 2258 |
| 4 | Wednesday | 1561 | 1467 | 1398 | 1374 | 1374 | 1398 | 1724 | 2003 | 2213 | 2236 | 2236 | 2213 | 2213 |
| 4 | Thursday | 1529 | 1438 | 1369 | 1346 | 1346 | 1369 | 1689 | 1962 | 2168 | 2191 | 2191 | 2168 | 2168 |
| 4 | Friday | 1497 | 1408 | 1341 | 1318 | 1318 | 1341 | 1653 | 1921 | 2123 | 2145 | 2145 | 2123 | 2123 |
| 4 | Saturday | 1428 | 1318 | 1245 | 1208 | 1171 | 1190 | 1208 | 1281 | 1464 | 1611 | 1647 | 1665 | 1647 |
| 4 | Sunday | 1390 | 1284 | 1212 | 1177 | 1141 | 1159 | 1177 | 1248 | 1426 | 1569 | 1604 | 1622 | 1604 |
| 5 | Monday | 1563 | 1469 | 1399 | 1376 | 1376 | 1399 | 1726 | 2006 | 2216 | 2239 | 2239 | 2216 | 2216 |
| 5 | Tuesday | 1680 | 1580 | 1505 | 1480 | 1480 | 1505 | 1856 | 2157 | 2383 | 2408 | 2408 | 2383 | 2383 |
| 5 | Wednesday | 1647 | 1548 | 1475 | 1450 | 1450 | 1475 | 1819 | 2114 | 2335 | 2360 | 2360 | 2335 | 2335 |
| 5 | Thursday | 1613 | 1517 | 1445 | 1421 | 1421 | 1445 | 1782 | 2071 | 2287 | 2311 | 2311 | 2287 | 2287 |
| 5 | Friday | 1580 | 1485 | 1415 | 1391 | 1391 | 1415 | 1745 | 2027 | 2240 | 2263 | 2263 | 2240 | 2240 |
| 5 | Saturday | 1506 | 1390 | 1313 | 1275 | 1236 | 1255 | 1275 | 1352 | 1545 | 1699 | 1738 | 1757 | 1738 |
| 5 | Sunday | 1467 | 1354 | 1279 | 1241 | 1204 | 1223 | 1241 | 1317 | 1505 | 1655 | 1693 | 1712 | 1693 |
| 6 | Monday | 1493 | 1404 | 1337 | 1315 | 1315 | 1337 | 1650 | 1917 | 2118 | 2140 | 2140 | 2118 | 2118 |
| 6 | Tuesday | 1606 | 1510 | 1438 | 1414 | 1414 | 1438 | 1774 | 2061 | 2277 | 2301 | 2301 | 2277 | 2277 |
| 6 | Wednesday | 1574 | 1480 | 1409 | 1386 | 1386 | 1409 | 1738 | 2020 | 2231 | 2255 | 2255 | 2231 | 2231 |
| 6 | Thursday | 1542 | 1450 | 1381 | 1358 | 1358 | 1381 | 1703 | 1979 | 2186 | 2209 | 2209 | 2186 | 2186 |
| 6 | Friday | 1510 | 1419 | 1352 | 1329 | 1329 | 1352 | 1667 | 1938 | 2140 | 2163 | 2163 | 2140 | 2140 |
| 6 | Saturday | 1440 | 1329 | 1255 | 1218 | 1181 | 1200 | 1218 | 1292 | 1476 | 1624 | 1661 | 1679 | 1661 |
| 6 | Sunday | 1402 | 1294 | 1222 | 1186 | 1150 | 1168 | 1186 | 1258 | 1438 | 1582 | 1618 | 1636 | 1618 |
| 7 | Monday | 1477 | 1389 | 1323 | 1301 | 1301 | 1323 | 1632 | 1896 | 2095 | 2117 | 2117 | 2095 | 2095 |
| 7 | Tuesday | 1589 | 1494 | 1423 | 1399 | 1399 | 1423 | 1755 | 2039 | 2253 | 2276 | 2276 | 2253 | 2253 |
| 7 | Wednesday | 1557 | 1464 | 1394 | 1371 | 1371 | 1394 | 1720 | 1998 | 2208 | 2231 | 2231 | 2208 | 2208 |
| 7 | Thursday | 1525 | 1434 | 1366 | 1343 | 1343 | 1366 | 1685 | 1958 | 2163 | 2185 | 2185 | 2163 | 2163 |
| 7 | Friday | 1493 | 1404 | 1337 | 1315 | 1315 | 1337 | 1649 | 1917 | 2117 | 2140 | 2140 | 2117 | 2117 |
| 7 | Saturday | 1424 | 1315 | 1242 | 1205 | 1169 | 1187 | 1205 | 1278 | 1461 | 1607 | 1643 | 1661 | 1643 |
| 7 | Sunday | 1387 | 1280 | 1209 | 1174 | 1138 | 1156 | 1174 | 1245 | 1423 | 1565 | 1601 | 1618 | 1601 |
| 8 | Monday | 1431 | 1346 | 1282 | 1260 | 1260 | 1282 | 1581 | 1837 | 2029 | 2051 | 2051 | 2029 | 2029 |
| 8 | Tuesday | 1539 | 1447 | 1378 | 1355 | 1355 | 1378 | 1700 | 1976 | 2182 | 2205 | 2205 | 2182 | 2182 |
| 8 | Wednesday | 1508 | 1418 | 1351 | 1328 | 1328 | 1351 | 1666 | 1936 | 2139 | 2161 | 2161 | 2139 | 2139 |
| 8 | Thursday | 1477 | 1389 | 1323 | 1301 | 1301 | 1323 | 1632 | 1896 | 2095 | 2117 | 2117 | 2095 | 2095 |
| 8 | Friday | 1447 | 1360 | 1296 | 1274 | 1274 | 1296 | 1598 | 1857 | 2051 | 2073 | 2073 | 2051 | 2051 |
| 8 | Saturday | 1380 | 1274 | 1203 | 1167 | 1132 | 1150 | 1167 | 1238 | 1415 | 1557 | 1592 | 1610 | 1592 |
| 8 | Sunday | 1344 | 1240 | 1172 | 1137 | 1103 | 1120 | 1137 | 1206 | 1378 | 1516 | 1551 | 1568 | 1551 |

**Table 4-2: "*LoadModel*" in MS Excel spreadsheet for the hourly peak load**

**Calculated Hourly Peak Load in Percentage of Maximum Demand**

| Week No. | Hour / Day | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Monday | 0.54 | 0.51 | 0.48 | 0.47 | 0.47 | 0.48 | 0.59 | 0.69 | 0.76 | 0.77 | 0.77 | 0.76 | 0.76 |
| 1 | Tuesday | 0.58 | 0.54 | 0.52 | 0.51 | 0.51 | 0.52 | 0.64 | 0.74 | 0.82 | 0.83 | 0.83 | 0.82 | 0.82 |
| 1 | Wednesday | 0.57 | 0.53 | 0.51 | 0.50 | 0.50 | 0.51 | 0.63 | 0.73 | 0.80 | 0.81 | 0.81 | 0.80 | 0.80 |
| 1 | Thursday | 0.55 | 0.52 | 0.50 | 0.49 | 0.49 | 0.50 | 0.61 | 0.71 | 0.79 | 0.79 | 0.79 | 0.79 | 0.79 |
| 1 | Friday | 0.54 | 0.51 | 0.49 | 0.48 | 0.48 | 0.49 | 0.60 | 0.70 | 0.77 | 0.78 | 0.78 | 0.77 | 0.77 |
| 1 | Saturday | 0.52 | 0.48 | 0.45 | 0.44 | 0.43 | 0.43 | 0.44 | 0.47 | 0.53 | 0.58 | 0.60 | 0.60 | 0.60 |
| 1 | Sunday | 0.50 | 0.47 | 0.44 | 0.43 | 0.41 | 0.42 | 0.43 | 0.45 | 0.52 | 0.57 | 0.58 | 0.59 | 0.58 |
| 2 | Monday | 0.56 | 0.53 | 0.50 | 0.49 | 0.49 | 0.50 | 0.62 | 0.72 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| 2 | Tuesday | 0.60 | 0.57 | 0.54 | 0.53 | 0.53 | 0.54 | 0.67 | 0.77 | 0.86 | 0.86 | 0.86 | 0.86 | 0.86 |
| 2 | Wednesday | 0.59 | 0.56 | 0.53 | 0.52 | 0.52 | 0.53 | 0.65 | 0.76 | 0.84 | 0.85 | 0.85 | 0.84 | 0.84 |
| 2 | Thursday | 0.58 | 0.54 | 0.52 | 0.51 | 0.51 | 0.52 | 0.64 | 0.74 | 0.82 | 0.83 | 0.83 | 0.82 | 0.82 |
| 2 | Friday | 0.57 | 0.53 | 0.51 | 0.50 | 0.50 | 0.51 | 0.63 | 0.73 | 0.80 | 0.81 | 0.81 | 0.80 | 0.80 |
| 2 | Saturday | 0.54 | 0.50 | 0.47 | 0.46 | 0.44 | 0.45 | 0.46 | 0.49 | 0.55 | 0.61 | 0.62 | 0.63 | 0.62 |
| 2 | Sunday | 0.53 | 0.49 | 0.46 | 0.45 | 0.43 | 0.44 | 0.45 | 0.47 | 0.54 | 0.59 | 0.61 | 0.61 | 0.61 |
| 3 | Monday | 0.55 | 0.51 | 0.49 | 0.48 | 0.48 | 0.49 | 0.60 | 0.70 | 0.78 | 0.78 | 0.78 | 0.78 | 0.78 |
| 3 | Tuesday | 0.59 | 0.55 | 0.53 | 0.52 | 0.52 | 0.53 | 0.65 | 0.76 | 0.83 | 0.84 | 0.84 | 0.83 | 0.83 |
| 3 | Wednesday | 0.58 | 0.54 | 0.52 | 0.51 | 0.51 | 0.52 | 0.64 | 0.74 | 0.82 | 0.83 | 0.83 | 0.82 | 0.82 |
| 3 | Thursday | 0.57 | 0.53 | 0.51 | 0.50 | 0.50 | 0.51 | 0.62 | 0.73 | 0.80 | 0.81 | 0.81 | 0.80 | 0.80 |
| 3 | Friday | 0.55 | 0.52 | 0.50 | 0.49 | 0.49 | 0.50 | 0.61 | 0.71 | 0.78 | 0.79 | 0.79 | 0.78 | 0.78 |
| 3 | Saturday | 0.53 | 0.49 | 0.46 | 0.45 | 0.43 | 0.44 | 0.45 | 0.47 | 0.54 | 0.60 | 0.61 | 0.62 | 0.61 |
| 3 | Sunday | 0.51 | 0.47 | 0.45 | 0.44 | 0.42 | 0.43 | 0.44 | 0.46 | 0.53 | 0.58 | 0.59 | 0.60 | 0.59 |
| 4 | Monday | 0.52 | 0.49 | 0.47 | 0.46 | 0.46 | 0.47 | 0.57 | 0.67 | 0.74 | 0.75 | 0.75 | 0.74 | 0.74 |
| 4 | Tuesday | 0.56 | 0.53 | 0.50 | 0.49 | 0.49 | 0.50 | 0.62 | 0.72 | 0.79 | 0.80 | 0.80 | 0.79 | 0.79 |
| 4 | Wednesday | 0.55 | 0.52 | 0.49 | 0.48 | 0.48 | 0.49 | 0.61 | 0.70 | 0.78 | 0.79 | 0.79 | 0.78 | 0.78 |
| 4 | Thursday | 0.54 | 0.50 | 0.48 | 0.47 | 0.47 | 0.48 | 0.59 | 0.69 | 0.76 | 0.77 | 0.77 | 0.76 | 0.76 |
| 4 | Friday | 0.53 | 0.49 | 0.47 | 0.46 | 0.46 | 0.47 | 0.58 | 0.67 | 0.75 | 0.75 | 0.75 | 0.75 | 0.75 |
| 4 | Saturday | 0.50 | 0.46 | 0.44 | 0.42 | 0.41 | 0.42 | 0.42 | 0.45 | 0.51 | 0.57 | 0.58 | 0.58 | 0.58 |
| 4 | Sunday | 0.49 | 0.45 | 0.43 | 0.41 | 0.40 | 0.41 | 0.41 | 0.44 | 0.50 | 0.55 | 0.56 | 0.57 | 0.56 |
| 5 | Monday | 0.55 | 0.52 | 0.49 | 0.48 | 0.48 | 0.49 | 0.61 | 0.70 | 0.78 | 0.79 | 0.79 | 0.78 | 0.78 |
| 5 | Tuesday | 0.59 | 0.55 | 0.53 | 0.52 | 0.52 | 0.53 | 0.65 | 0.76 | 0.84 | 0.85 | 0.85 | 0.84 | 0.84 |
| 5 | Wednesday | 0.58 | 0.54 | 0.52 | 0.51 | 0.51 | 0.52 | 0.64 | 0.74 | 0.82 | 0.83 | 0.83 | 0.82 | 0.82 |
| 5 | Thursday | 0.57 | 0.53 | 0.51 | 0.50 | 0.50 | 0.51 | 0.63 | 0.73 | 0.80 | 0.81 | 0.81 | 0.80 | 0.80 |
| 5 | Friday | 0.55 | 0.52 | 0.50 | 0.49 | 0.49 | 0.50 | 0.61 | 0.71 | 0.79 | 0.79 | 0.79 | 0.79 | 0.79 |
| 5 | Saturday | 0.53 | 0.49 | 0.46 | 0.45 | 0.43 | 0.44 | 0.45 | 0.47 | 0.54 | 0.60 | 0.61 | 0.62 | 0.61 |
| 5 | Sunday | 0.52 | 0.48 | 0.45 | 0.44 | 0.42 | 0.43 | 0.44 | 0.46 | 0.53 | 0.58 | 0.59 | 0.60 | 0.59 |
| 6 | Monday | 0.52 | 0.49 | 0.47 | 0.46 | 0.46 | 0.47 | 0.58 | 0.67 | 0.74 | 0.75 | 0.75 | 0.74 | 0.74 |
| 6 | Tuesday | 0.56 | 0.53 | 0.51 | 0.50 | 0.50 | 0.51 | 0.62 | 0.72 | 0.80 | 0.81 | 0.81 | 0.80 | 0.80 |
| 6 | Wednesday | 0.55 | 0.52 | 0.50 | 0.49 | 0.49 | 0.50 | 0.61 | 0.71 | 0.78 | 0.79 | 0.79 | 0.78 | 0.78 |
| 6 | Thursday | 0.54 | 0.51 | 0.48 | 0.48 | 0.48 | 0.48 | 0.60 | 0.69 | 0.77 | 0.78 | 0.78 | 0.77 | 0.77 |
| 6 | Friday | 0.53 | 0.50 | 0.47 | 0.47 | 0.47 | 0.47 | 0.59 | 0.68 | 0.75 | 0.76 | 0.76 | 0.75 | 0.75 |
| 6 | Saturday | 0.51 | 0.47 | 0.44 | 0.43 | 0.41 | 0.42 | 0.43 | 0.45 | 0.52 | 0.57 | 0.58 | 0.59 | 0.58 |
| 6 | Sunday | 0.49 | 0.45 | 0.43 | 0.42 | 0.40 | 0.41 | 0.42 | 0.44 | 0.51 | 0.56 | 0.57 | 0.57 | 0.57 |
| 7 | Monday | 0.52 | 0.49 | 0.46 | 0.46 | 0.46 | 0.46 | 0.57 | 0.67 | 0.74 | 0.74 | 0.74 | 0.74 | 0.74 |
| 7 | Tuesday | 0.56 | 0.52 | 0.50 | 0.49 | 0.49 | 0.50 | 0.62 | 0.72 | 0.79 | 0.80 | 0.80 | 0.79 | 0.79 |
| 7 | Wednesday | 0.55 | 0.51 | 0.49 | 0.48 | 0.48 | 0.49 | 0.60 | 0.70 | 0.78 | 0.78 | 0.78 | 0.78 | 0.78 |
| 7 | Thursday | 0.54 | 0.50 | 0.48 | 0.47 | 0.47 | 0.48 | 0.59 | 0.69 | 0.76 | 0.77 | 0.77 | 0.76 | 0.76 |
| 7 | Friday | 0.52 | 0.49 | 0.47 | 0.46 | 0.46 | 0.47 | 0.58 | 0.67 | 0.74 | 0.75 | 0.75 | 0.74 | 0.74 |
| 7 | Saturday | 0.50 | 0.46 | 0.44 | 0.42 | 0.41 | 0.42 | 0.42 | 0.45 | 0.51 | 0.56 | 0.58 | 0.58 | 0.58 |
| 7 | Sunday | 0.49 | 0.45 | 0.42 | 0.41 | 0.40 | 0.41 | 0.41 | 0.44 | 0.50 | 0.55 | 0.56 | 0.57 | 0.56 |
| 8 | Monday | 0.50 | 0.47 | 0.45 | 0.44 | 0.44 | 0.45 | 0.56 | 0.65 | 0.71 | 0.72 | 0.72 | 0.71 | 0.71 |
| 8 | Tuesday | 0.54 | 0.51 | 0.48 | 0.48 | 0.48 | 0.48 | 0.60 | 0.69 | 0.77 | 0.77 | 0.77 | 0.77 | 0.77 |
| 8 | Wednesday | 0.53 | 0.50 | 0.47 | 0.47 | 0.47 | 0.47 | 0.59 | 0.68 | 0.75 | 0.76 | 0.76 | 0.75 | 0.75 |
| 8 | Thursday | 0.52 | 0.49 | 0.46 | 0.46 | 0.46 | 0.46 | 0.57 | 0.67 | 0.74 | 0.74 | 0.74 | 0.74 | 0.74 |
| 8 | Friday | 0.51 | 0.48 | 0.46 | 0.45 | 0.45 | 0.46 | 0.56 | 0.65 | 0.72 | 0.73 | 0.73 | 0.72 | 0.72 |
| 8 | Saturday | 0.48 | 0.45 | 0.42 | 0.41 | 0.40 | 0.40 | 0.41 | 0.43 | 0.50 | 0.55 | 0.56 | 0.57 | 0.56 |
| 8 | Sunday | 0.47 | 0.44 | 0.41 | 0.40 | 0.39 | 0.39 | 0.40 | 0.42 | 0.48 | 0.53 | 0.54 | 0.55 | 0.54 |

**Table 4-3: "*LoadModel*" in MS Excel spreadsheet for the hourly peak load in %**

From the "*frequency*" calculation and thus the exact and cumulative probability can be obtained. The results can then be presented in the LPT and is shown in Table 4-4 below with the hourly load and the daily peak load. It is important to note that the total number of hours and days in the hourly load and daily peak load is 8736 hours and 365 days.

| % Peak Load | Peak Load (MW) | Frequency | Exact Probability | Cumulative Probability |
|---|---|---|---|---|
| 100 | 2850.0 | 2 | 0.000229 | 0.000229 |
| 99 | 2821.5 | 1 | 0.000114 | 0.000343 |
| 98 | 2793.0 | 2 | 0.000229 | 0.000572 |
| 97 | 2764.5 | 3 | 0.000343 | 0.000916 |
| 96 | 2736.0 | 10 | 0.001145 | 0.002060 |
| 95 | 2707.5 | 12 | 0.001374 | 0.003434 |
| 94 | 2679.0 | 19 | 0.002175 | 0.005609 |
| ⋮ | ⋮ | ⋮ | ⋮ | ⋮ |
| 68 | 1938.0 | 188 | 0.021520 | 0.349931 |
| 67 | 1909.5 | 210 | 0.024038 | 0.373970 |
| 66 | 1881.0 | 218 | 0.024954 | 0.398924 |
| 65 | 1852.5 | 209 | 0.023924 | 0.422848 |
| 64 | 1824.0 | 205 | 0.023466 | 0.446314 |
| 63 | 1795.5 | 237 | 0.027129 | 0.473443 |
| 62 | 1767.0 | 217 | 0.024840 | 0.498283 |
| 61 | 1738.5 | 198 | 0.022665 | 0.520948 |
| ⋮ | ⋮ | ⋮ | ⋮ | ⋮ |
| 40 | 1140.0 | 101 | 0.011561 | 0.975504 |
| 39 | 1111.5 | 57 | 0.006525 | 0.982028 |
| 38 | 1083.0 | 53 | 0.006067 | 0.988095 |
| 37 | 1054.5 | 56 | 0.006410 | 0.994505 |
| 36 | 1026.0 | 35 | 0.004006 | 0.998512 |
| 35 | 997.5 | 11 | 0.001259 | 0.999771 |
| 34 | 969.0 | 2 | 0.000229 | 1.000000 |
| 33 | 940.5 | 0 | 0.000000 | 1.000000 |
| 32 | 912.0 | 0 | 0.000000 | 1.000000 |
| 31 | 883.5 | 0 | 0.000000 | 1.000000 |
| ⋮ | ⋮ | ⋮ | ⋮ | ⋮ |

**(with hourly load)**

| % Peak Load | Frequency | Exact Probability | Cumulative Probability |
|---|---|---|---|
| 100 | 1 | 0.002747 | 1.000000 |
| 99 | 0 | 0.000000 | 0.997253 |
| 98 | 1 | 0.002747 | 0.997253 |
| 97 | 1 | 0.002747 | 0.994505 |
| 96 | 3 | 0.008242 | 0.991758 |
| 95 | 1 | 0.002747 | 0.983516 |
| 94 | 4 | 0.010989 | 0.980769 |
| ⋮ | ⋮ | ⋮ | ⋮ |
| 68 | 20 | 0.054945 | 0.291209 |
| 67 | 11 | 0.030220 | 0.236264 |
| 66 | 9 | 0.024725 | 0.206044 |
| 65 | 8 | 0.021978 | 0.181319 |
| 64 | 1 | 0.002747 | 0.159341 |
| 63 | 6 | 0.016484 | 0.156593 |
| 62 | 5 | 0.013736 | 0.140110 |
| 61 | 4 | 0.010989 | 0.126374 |
| ⋮ | ⋮ | ⋮ | ⋮ |
| 40 | 0 | 0.000000 | 0.000000 |
| 39 | 0 | 0.000000 | 0.000000 |
| 38 | 0 | 0.000000 | 0.000000 |
| 37 | 0 | 0.000000 | 0.000000 |
| 36 | 0 | 0.000000 | 0.000000 |
| 35 | 0 | 0.000000 | 0.000000 |
| 34 | 0 | 0.000000 | 0.000000 |
| 33 | 0 | 0.000000 | 0.000000 |
| 32 | 0 | 0.000000 | 0.000000 |
| 31 | 0 | 0.000000 | 0.000000 |
| ⋮ | ⋮ | ⋮ | ⋮ |

**(with daily peak load)**

**Table 4-4: IEEE RTS Load Probability Table**

## 4.4 Generating Units Capacity Outage Probability Table (COPT)

This section will present a detailed discussion of the creation of the outage table for the multi-generating unit table. A power system normally consists of hundreds or thousands of generating units of different types, capacity, and reliability in parallel operations. With each units assumed to have dual states, a system with $n$ units has $2^n$ capacity states. This will prove too much for any manual calculations to be conducted. At present, the recurrent algorithm based upon discrete distribution is used by all (Wang and McDonald 1994, p.123).

The process of using the recurrent algorithm starts off with creation of a capacity table for a single generating unit as of Table 4-5.

| **Available capacity, MW** | **Outage capacity, MW** | **Exact probability, $P_i$** | **Cumulative probability, $P$** |
|---|---|---|---|
| $c$ | 0 | $1- q$ | 1 |
| 0 | $c$ | $q$ | $q$ |

**Table 4-5: Probability model for a single generating unit**

Where

$c$ is the generating unit's effective capacity

$q$ is the forced outage rate (FOR)

Then, the table is revised as units are added one after another until the last generating unit and the capacity outage probability table for the whole generating system is completed. To add on generating units into the table, the recurrent formula provides a means to do that using a computer algorithm. First of all, suppose the capacity outage table for $n-1$ generating units has been formed as in Table 4-5 and the outage capacity $X$ is a random variable with a discrete distribution and an exact probability of $p_{n-1}(X)$. When the $n$th new unit is added with effective capacity $C_n$ and forced outage rate $q_n$, the exact probability of the system outage capacity $p_n(X)$ can be directly obtained by using the convolution formula in Equation 4.3.

$$p_n(X) = p_{n-1}(X) \,.\, p(0) + p_{n-1}(X - C_n) \,.\, p(C_n) \tag{4.3}$$

According to the two states generation model, the exact probability of no outage is $p(0) = 1 - q$ and the exact probability of full outage is $p(C_n) = q_n$. When substituted into Equation 4.3, the recurrence formula is obtained:

$$p_n(X) = p_{n-1}(X) \,.\, (1 - q) + p_{n-1}(X - C_n) \,.\, q_n \tag{4.4}$$

Equation 4.4 can be used for iterative calculations of both the exact state probability and the cumulative state probability $P_n(X)$, changing only $p_{n-1}(X)$ and $p_{n-1}(X - C_n)$ to the corresponding cumulative state probabilities. However, the initial conditions are different. When $X \leq C_n$, it can be stipulated that $p_{n-1}(X - C_n) = 0$ for the exact probability and $P_{n-1}(X - C_n) = 1$ for the cumulative probability.

It is important to note that when using the recurrence formula to calculate the cumulative probability and cumulative frequency of a generating system, a certain increment of the outage capacity is used as the step, not the unit capacity. The size of the step increment can be determined by the largest common divisor of the various types of assembly capacity, the scale of the system and the needed calculation accuracy. The discussion of the addition of individual units can be found in (Wang and McDonald 1994, p.124).

For the purpose of this study, a computer code is written for the calculation of the outage table using the recursive formula in Equation 4.4 for the IEEE RTS generating system. The details of the computer code can be found in Appendix B, Table B-1. The "*PlantData*" MS Excel spreadsheet in the *System Reliability Evaluation Programme* (SREP) is where the characteristics of the generating units in a system can be modelled.

Figure 4-4 shows the IEEE RTS model in "*PlantData*". The blue cells denote user input cells and the user can add on lines of generating units.

***Reliability Test System (RTS) - 1996***

The 1996 version of the Reliability Test System was published in Grigg, C.,"The IEEE reliability test system: 1996", Paper 96 WM 326-9 PWRS, IEEE Winter power meeting 1996.

**Table 6 - Generator Reliability Data (Source: IEEE RTS)**

| | |
|---|---|
| **Total number of groups:** | **9** |
| **Total System Capacity:** | **3405** |

| Index | Unit Group | Unit Type | No. of Units | Unit Size, C (MW) | Forced Outage Rate, U | MTTF (m=1/λ) (Hour) | MTTR (r=1/μ) (Hour) | Scheduled Maintenance Weeks/year |
|---|---|---|---|---|---|---|---|---|
| 1 | U12 | Oil/Steam | 5 | 12 | 0.02 | 2940 | 60 | 2 |
| 2 | U20 | Oil/CT | 4 | 20 | 0.10 | 450 | 50 | 2 |
| 3 | U50 | Hydro | 6 | 50 | 0.01 | 1980 | 20 | 2 |
| 4 | U76 | Coal/Steam | 4 | 76 | 0.02 | 1960 | 40 | 3 |
| 5 | U100 | Oil/Steam | 3 | 100 | 0.04 | 1200 | 50 | 3 |
| 6 | U155 | Coal/Steam | 4 | 155 | 0.04 | 960 | 40 | 4 |
| 7 | U197 | Oil/Steam | 3 | 197 | 0.05 | 950 | 50 | 4 |
| 8 | U350 | Coal/Steam | 1 | 350 | 0.08 | 1150 | 100 | 5 |
| 9 | U400 | Nuclear | 2 | 400 | 0.12 | 1100 | 150 | 6 |
| | | **Total units** | **32** | | | | | |

**Figure 4-4: "*PlantData*" worksheet for generating system input**

The generation system reliability and modelling is conducted in the "*COPT*" worksheet. A step increment is required from the user in the input cells of the "*COPT*" worksheet. By simulating the computer code "*COPT*( )", each generating units in Figure 4-4 will be added unit by unit into the "*COPT*" worksheet based on the recursive formula of Equation 4.4 to obtain the exact and cumulative probability for each outage capacity level. The summarized *Capacity Outage Probability Table* for the IEEE RTS is shown in Table 4-7.

**Capacity Outage Probability Table Calculation**

**Step increment** 1

| Outage Capacity (MW) | Available Capacity (MW) | Pn-1 (X) | X - c | Pn-1 (X - c) | Exact probability, pn (X) | Cumulative probability, Pn (X) |
|---|---|---|---|---|---|---|
| 0 | 3405 | 1.000000 | -400 | 1.000000 | 2.363951E-01 | 1.000000E+00 |
| 1 | 3404 | 0.731369 | -399 | 1.000000 | 0.000000E+00 | 7.636049E-01 |
| 2 | 3403 | 0.731369 | -398 | 1.000000 | 0.000000E+00 | 7.636049E-01 |
| 3 | 3402 | 0.731369 | -397 | 1.000000 | 0.000000E+00 | 7.636049E-01 |
| 4 | 3401 | 0.731369 | -396 | 1.000000 | 0.000000E+00 | 7.636049E-01 |
| 5 | 3400 | 0.731369 | -395 | 1.000000 | 0.000000E+00 | 7.636049E-01 |
| 6 | 3399 | 0.731369 | -394 | 1.000000 | 0.000000E+00 | 7.636049E-01 |
| 7 | 3398 | 0.731369 | -393 | 1.000000 | 0.000000E+00 | 7.636049E-01 |
| 8 | 3397 | 0.731369 | -392 | 1.000000 | 0.000000E+00 | 7.636049E-01 |
| 9 | 3396 | 0.731369 | -391 | 1.000000 | 0.000000E+00 | 7.636049E-01 |
| 10 | 3395 | 0.731369 | -390 | 1.000000 | 0.000000E+00 | 7.636049E-01 |
| 11 | 3394 | 0.731369 | -389 | 1.000000 | 0.000000E+00 | 7.636049E-01 |
| 12 | 3393 | 0.731369 | -388 | 1.000000 | 2.412195E-02 | 7.636049E-01 |
| 13 | 3392 | 0.703958 | -387 | 1.000000 | 0.000000E+00 | 7.394829E-01 |
| 14 | 3391 | 0.703958 | -386 | 1.000000 | 0.000000E+00 | 7.394829E-01 |
| 15 | 3390 | 0.703958 | -385 | 1.000000 | 0.000000E+00 | 7.394829E-01 |
| 16 | 3389 | 0.703958 | -384 | 1.000000 | 0.000000E+00 | 7.394829E-01 |
| 17 | 3388 | 0.703958 | -383 | 1.000000 | 0.000000E+00 | 7.394829E-01 |
| 18 | 3387 | 0.703958 | -382 | 1.000000 | 0.000000E+00 | 7.394829E-01 |
| 19 | 3386 | 0.703958 | -381 | 1.000000 | 0.000000E+00 | 7.394829E-01 |
| 20 | 3385 | 0.703958 | -380 | 1.000000 | 1.050645E-01 | 7.394829E-01 |
| 21 | 3384 | 0.584566 | -379 | 1.000000 | 0.000000E+00 | 6.344184E-01 |
| 22 | 3383 | 0.584566 | -378 | 1.000000 | 0.000000E+00 | 6.344184E-01 |
| 23 | 3382 | 0.584566 | -377 | 1.000000 | 0.000000E+00 | 6.344184E-01 |
| 24 | 3381 | 0.584566 | -376 | 1.000000 | 9.845694E-04 | 6.344184E-01 |
| • | • | • | • | • | • | • |
| • | • | • | • | • | • | • |
| • | • | • | • | • | • | • |
| 3381 | 24 | 0.000000 | 2981 | 0.000000 | 2.900311E-44 | 2.934375E-44 |
| 3382 | 23 | 0.000000 | 2982 | 0.000000 | 0.000000E+00 | 3.406446E-46 |
| 3383 | 22 | 0.000000 | 2983 | 0.000000 | 0.000000E+00 | 3.406446E-46 |
| 3384 | 21 | 0.000000 | 2984 | 0.000000 | 0.000000E+00 | 3.406446E-46 |
| 3385 | 20 | 0.000000 | 2985 | 0.000000 | 4.348654E-47 | 3.406446E-46 |
| 3386 | 19 | 0.000000 | 2986 | 0.000000 | 0.000000E+00 | 2.971580E-46 |
| 3387 | 18 | 0.000000 | 2987 | 0.000000 | 0.000000E+00 | 2.971580E-46 |
| 3388 | 17 | 0.000000 | 2988 | 0.000000 | 0.000000E+00 | 2.971580E-46 |
| 3389 | 16 | 0.000000 | 2989 | 0.000000 | 0.000000E+00 | 2.971580E-46 |
| 3390 | 15 | 0.000000 | 2990 | 0.000000 | 0.000000E+00 | 2.971580E-46 |
| 3391 | 14 | 0.000000 | 2991 | 0.000000 | 0.000000E+00 | 2.971580E-46 |
| 3392 | 13 | 0.000000 | 2992 | 0.000000 | 0.000000E+00 | 2.971580E-46 |
| 3393 | 12 | 0.000000 | 2993 | 0.000000 | 2.959501E-46 | 2.971580E-46 |
| 3394 | 11 | 0.000000 | 2994 | 0.000000 | 0.000000E+00 | 1.207960E-48 |
| 3395 | 10 | 0.000000 | 2995 | 0.000000 | 0.000000E+00 | 1.207960E-48 |
| 3396 | 9 | 0.000000 | 2996 | 0.000000 | 0.000000E+00 | 1.207960E-48 |
| 3397 | 8 | 0.000000 | 2997 | 0.000000 | 0.000000E+00 | 1.207960E-48 |
| 3398 | 7 | 0.000000 | 2998 | 0.000000 | 0.000000E+00 | 1.207960E-48 |
| 3399 | 6 | 0.000000 | 2999 | 0.000000 | 0.000000E+00 | 1.207960E-48 |
| 3400 | 5 | 0.000000 | 3000 | 0.000000 | 0.000000E+00 | 1.207960E-48 |
| 3401 | 4 | 0.000000 | 3001 | 0.000000 | 0.000000E+00 | 1.207960E-48 |
| 3402 | 3 | 0.000000 | 3002 | 0.000000 | 0.000000E+00 | 1.207960E-48 |
| 3403 | 2 | 0.000000 | 3003 | 0.000000 | 0.000000E+00 | 1.207960E-48 |
| 3404 | 1 | 0.000000 | 3004 | 0.000000 | 0.000000E+00 | 1.207960E-48 |
| 3405 | 0 | 0.000000 | 3005 | 0.000000 | 1.207960E-48 | 1.207960E-48 |
| 3406 | -1 | 0.000000 | 3006 | 0.000000 | 0.000000E+00 | 0.000000E+00 |

**Table 4-6: “*COPT*” worksheet for COPT with 1 step increment**

| *Outage Capacity (MW)* | *Available Capacity (MW)* | *Exact probability, pn (X)* | *Cumulative probability, Pn (X)* |
|---|---|---|---|
| 0 | 3405 | 2.363951E-01 | 1.000000E+00 |
| 12 | 3393 | 2.412195E-02 | 7.636049E-01 |
| 20 | 3385 | 1.050645E-01 | 7.394829E-01 |
| 24 | 3381 | 9.845694E-04 | 6.344184E-01 |
| 32 | 3373 | 1.072087E-02 | 6.334339E-01 |
| 36 | 3369 | 2.009325E-05 | 6.227130E-01 |
| 40 | 3365 | 1.751075E-02 | 6.226929E-01 |
| 44 | 3361 | 4.375864E-04 | 6.051822E-01 |
| 48 | 3357 | 2.050332E-07 | 6.047446E-01 |
| 50 | 3355 | 1.432698E-02 | 6.047444E-01 |
| 52 | 3353 | 1.786811E-03 | 5.904174E-01 |
| 56 | 3349 | 8.930335E-06 | 5.886306E-01 |
| 60 | 3345 | 1.297093E-03 | 5.886216E-01 |
| 62 | 3343 | 1.461936E-03 | 5.873245E-01 |
| 64 | 3341 | 7.293107E-05 | 5.858626E-01 |
| 68 | 3337 | 9.112587E-08 | 5.857897E-01 |
| 70 | 3335 | 6.367545E-03 | 5.857896E-01 |
| 72 | 3333 | 1.323564E-04 | 5.794220E-01 |
| 74 | 3331 | 5.967087E-05 | 5.792897E-01 |
| 76 | 3329 | 1.929905E-02 | 5.792300E-01 |
| 80 | 3325 | 3.603072E-05 | 5.599310E-01 |
| 82 | 3323 | 6.497495E-04 | 5.598949E-01 |
| 84 | 3321 | 5.402301E-06 | 5.592452E-01 |
| 86 | 3319 | 1.217773E-06 | 5.592398E-01 |
| 88 | 3317 | 1.969154E-03 | 5.592386E-01 |
| 90 | 3315 | 1.061258E-03 | 5.572694E-01 |
| 92 | 3313 | 3.676566E-06 | 5.562082E-01 |
| 94 | 3311 | 2.652039E-05 | 5.562045E-01 |
| 96 | 3309 | 8.576804E-03 | 5.561780E-01 |
| 98 | 3307 | 1.242625E-08 | 5.476012E-01 |
| 100 | 3305 | 2.999156E-02 | 5.476011E-01 |
| 120 | 3285 | 1.332958E-02 | 5.120591E-01 |
| 140 | 3265 | 2.221597E-03 | 4.956939E-01 |
| 160 | 3245 | 1.645628E-04 | 4.508122E-01 |
| 180 | 3225 | 4.571234E-06 | 4.250724E-01 |
| 200 | 3205 | 1.286656E-03 | 3.813281E-01 |
| 250 | 3155 | 7.583947E-05 | 3.427983E-01 |
| 300 | 3105 | 1.942785E-05 | 3.206538E-01 |
| 350 | 3055 | 2.073959E-02 | 3.110565E-01 |
| 400 | 3005 | 6.572831E-02 | 2.618734E-01 |
| 450 | 2955 | 6.538536E-03 | 1.451702E-01 |
| 500 | 2905 | 8.337769E-03 | 1.225162E-01 |
| 550 | 2855 | 6.040126E-04 | 9.640123E-02 |
| 600 | 2805 | 3.576919E-04 | 6.211286E-02 |
| 650 | 2755 | 2.240030E-05 | 4.941866E-02 |
| 700 | 2705 | 2.126892E-05 | 4.246135E-02 |
| 750 | 2655 | 5.657307E-03 | 3.849087E-02 |
| 800 | 2605 | 4.741340E-03 | 2.471940E-02 |
| 850 | 2555 | 9.842072E-04 | 1.473085E-02 |
| 900 | 2505 | 6.010407E-04 | 1.160785E-02 |
| 950 | 2455 | 6.430599E-05 | 7.491953E-03 |
| 1000 | 2405 | 2.578254E-05 | 4.340874E-03 |
| 1200 | 2205 | 2.413207E-05 | 7.912523E-04 |
| 1400 | 2005 | 1.279622E-07 | 1.017231E-04 |
| 1600 | 1805 | 5.279730E-08 | 8.039633E-06 |
| 1800 | 1605 | 1.259345E-10 | 2.912056E-07 |
| 2000 | 1405 | 9.129184E-11 | 7.246199E-09 |
| 2200 | 1205 | 4.200399E-13 | 9.270183E-11 |
| 2400 | 1005 | 7.999056E-16 | 4.697177E-13 |
| 2600 | 805 | 5.087922E-19 | 6.256599E-16 |
| 2800 | 605 | 7.491658E-23 | 1.424674E-19 |
| 3000 | 405 | 3.105126E-28 | 9.826054E-25 |
| 3200 | 205 | 6.887710E-44 | 3.324452E-32 |
| 3400 | 5 | 0.000000E+00 | 1.207960E-48 |
| 3405 | 0 | 1.207960E-48 | 1.207960E-48 |

**Table 4-7: IEEE RTS Capacity Outage Probability Table (COPT)**

## *4.5 System Margin State Table (SMST)*

The next step in the evaluation of reliability indices of a system is the formation of the *System Margin State Table* (SMST). The generation and load models can be easily combined on the basis that the events in the two are independent and, therefore, the event probabilities in any one of them will remain the same while changes occur in the other (Endrenyi 1978, p.125). The combination of discrete level of available capacity and discrete level of system demand creates a set of discrete system margins, $M_k$. The system margin is defined as the difference between the available capacity and the system load. A cumulative margin state contains all states with the specified margin or less. For example, a margin state of 100 MW contains all states with 100MW and less. A margin state $M_k$ is the combination of the load state $L_i$ and capacity state $C_n$ where $M_k = C_n - L_i$ .

According to Billinton and Allan (1996, p.97), the transition from one margin state to another can be made by a change in load or a change in capacity but not by both simultaneously. The probability of the margin state is the product of the capacity state and load probabilities as shown in Equation 4.5.

$$p\,(M_k) = p(C_n)\,.\,p\,(L_i) \qquad (4.5)$$

Having obtained the individual probability of the margin states, the cumulative values can be obtained. Different combinations of capacity and load states can result in identical margin states. These identical states are independent of each other and can be combined by summing up all the individual exact probability using Equation 4.6. For a given margin state $M_k$ made up of $S$ identical margin states:

$$p_k = \sum_{i=1}^{S} p_i \qquad (4.6)$$

The most useful single index is the cumulative probability of the first negative margin.

The cumulative probability can be used to obtain the LOLE value:

LOLE (in hours per year) = [Cumulative probability of the first negative margin] x 8760

LOLE (in days per year) = [Cumulative probability of the first negative margin] x 365

For computer application, the cumulative probability of the associated margin states can be calculated by the *Formula method* using Equation 4.7.

$$P\,(M) = \sum_{j=1}^{N} p\,(L_j)\,.\,P\,(X_j) \qquad (4.7)$$

On the other hand, the system margin state probability table can be obtained by convoluting the generator *Capacity Outage Probability Table* (COPT) and the *Load Probability Table* (LPT) by applying the parallel calculation formula.

The parallel calculation formula for calculating the margin state cumulative probability through parallel convolution is shown in Equation 4.8.

$$P_c\,(X_k) = \sum_{j=0}^{N_b} P_a\,(X_k - X_j)\,.\,[P_b\,(X_j)\,.\,P_b\,(X_{j+1})] \qquad (4.8)$$

where

$P_a\,(X_i)$ = generating unit's cumulative probability (for $i = 0, 1, 2, \ldots, N_a$)

$P_b\,(X_i)$ = load cumulative probability (for $i = 0, 1, 2, \ldots, N_b$)

$P_c\,(X_k)$ = system margin cumulative probability

$X_k$ = Margin state (MW) (can be negative as well as positive)

A computer algorithm was written to use the parallel calculation formula to generate the system margin state probability table (SMST) by convolution of the COPT and the LPT. The computer algorithm can be found in Appendix B, Table B-2. In the application of the parallel calculation formula, a step increment of the system margin, maximum and minimum margin state need to be specified in the input cells. The "*COPT*" worksheet of the system margin evaluation is shown in Figure 4-5. Two system margin state cumulative probabilities are calculated using the parallel calculation formula using two different load models, the hourly load and the daily peak load. The maximum margin state is set to 3400MW and the minimum margin state to -2850MW.

**Margin States Table Calculation**

| | | | | |
|---|---|---|---|---|
| Step increment | 1 | | Capacity (MW) | 3405 |
| Last Load State | 100 | | Peak Load (MW) | 2850 |
| Max. Margin States | 3400 | | | |
| Min. Margin States | -2850 | | | |

| States | Margin state (MW) | Cumulative Margin Probability for hourly load | Cumulative Margin Probability for daily peak load | Margin in % of Peak Load |
|---|---|---|---|---|
| 0 | 3400 | 0.000000E+00 | 0.000000E+00 | 119.3% |
| 1 | 3399 | 0.000000E+00 | 0.000000E+00 | 119.3% |
| 2 | 3398 | 0.000000E+00 | 0.000000E+00 | 119.2% |
| 3 | 3397 | 0.000000E+00 | 0.000000E+00 | 119.2% |
| 4 | 3396 | 0.000000E+00 | 0.000000E+00 | 119.2% |
| 5 | 3395 | 0.000000E+00 | 0.000000E+00 | 119.1% |
| 6 | 3394 | 0.000000E+00 | 0.000000E+00 | 119.1% |
| 7 | 3393 | 0.000000E+00 | 0.000000E+00 | 119.1% |
| 8 | 3392 | 0.000000E+00 | 0.000000E+00 | 119.0% |
| 9 | 3391 | 0.000000E+00 | 0.000000E+00 | 119.0% |
| 10 | 3390 | 0.000000E+00 | 0.000000E+00 | 118.9% |
| 11 | 3389 | 0.000000E+00 | 0.000000E+00 | 118.9% |
| 12 | 3388 | 0.000000E+00 | 0.000000E+00 | 118.9% |
| 13 | 3387 | 0.000000E+00 | 0.000000E+00 | 118.8% |
| 14 | 3386 | 0.000000E+00 | 0.000000E+00 | 118.8% |
| 15 | 3385 | 0.000000E+00 | 0.000000E+00 | 118.8% |
| 16 | 3384 | 0.000000E+00 | 0.000000E+00 | 118.7% |
| 17 | 3383 | 0.000000E+00 | 0.000000E+00 | 118.7% |
| 18 | 3382 | 0.000000E+00 | 0.000000E+00 | 118.7% |
| 19 | 3381 | 0.000000E+00 | 0.000000E+00 | 118.6% |
| 20 | 3380 | 0.000000E+00 | 0.000000E+00 | 118.6% |
| 21 | 3379 | 0.000000E+00 | 0.000000E+00 | 118.6% |
| 22 | 3378 | 0.000000E+00 | 0.000000E+00 | 118.5% |
| 23 | 3377 | 0.000000E+00 | 0.000000E+00 | 118.5% |
| 24 | 3376 | 0.000000E+00 | 0.000000E+00 | 118.5% |
| 25 | 3375 | 0.000000E+00 | 0.000000E+00 | 118.4% |
| 26 | 3374 | 0.000000E+00 | 0.000000E+00 | 118.4% |
| 27 | 3373 | 0.000000E+00 | 0.000000E+00 | 118.4% |
| 28 | 3372 | 0.000000E+00 | 0.000000E+00 | 118.3% |
| 29 | 3371 | 0.000000E+00 | 0.000000E+00 | 118.3% |
| 30 | 3370 | 0.000000E+00 | 0.000000E+00 | 118.2% |
| 31 | 3369 | 0.000000E+00 | 0.000000E+00 | 118.2% |
| 32 | 3368 | 0.000000E+00 | 0.000000E+00 | 118.2% |
| 33 | 3367 | 0.000000E+00 | 0.000000E+00 | 118.1% |
| 34 | 3366 | 0.000000E+00 | 0.000000E+00 | 118.1% |
| 35 | 3365 | 0.000000E+00 | 0.000000E+00 | 118.1% |
| 36 | 3364 | 0.000000E+00 | 0.000000E+00 | 118.0% |
| 37 | 3363 | 0.000000E+00 | 0.000000E+00 | 118.0% |
| 38 | 3362 | 0.000000E+00 | 0.000000E+00 | 118.0% |
| 39 | 3361 | 0.000000E+00 | 0.000000E+00 | 117.9% |
| 40 | 3360 | 0.000000E+00 | 0.000000E+00 | 117.9% |
| 41 | 3359 | 0.000000E+00 | 0.000000E+00 | 117.9% |
| 42 | 3358 | 0.000000E+00 | 0.000000E+00 | 117.8% |
| 43 | 3357 | 0.000000E+00 | 0.000000E+00 | 117.8% |
| 44 | 3356 | 0.000000E+00 | 0.000000E+00 | 117.8% |
| 45 | 3355 | 0.000000E+00 | 0.000000E+00 | 117.7% |

**Figure 4-5: System margin state probability calculation in "*COPT*" worksheet**

Table 4-8 shows the *System Margin State Probability Table* (SMST) obtained using a 10 MW step increment while Table 4-9 shows the SMST using a 1 MW step increment.

| Margin state (MW) | Cumulative Margin Probability for hourly load | Cumulative Margin Probability for daily peak load | Margin in % of Peak Load |
|---|---|---|---|
| 3400 | 0.000000E+00 | 0.000000E+00 | 119.3% |
| 3390 | 0.000000E+00 | 0.000000E+00 | 118.9% |
| 3380 | 0.000000E+00 | 0.000000E+00 | 118.6% |
| • | • | • | • |
| • | • | • | • |
| • | • | • | • |
| 2460 | 0.000000E+00 | 0.000000E+00 | 86.3% |
| 2450 | 0.000000E+00 | 0.000000E+00 | 86.0% |
| 2440 | 0.000000E+00 | 0.000000E+00 | 85.6% |
| 2430 | 1.748180E-04 | 0.000000E+00 | 85.3% |
| 2420 | 1.692955E-04 | 0.000000E+00 | 84.9% |
| 2410 | 1.450169E-04 | 0.000000E+00 | 84.6% |
| • | • | • | • |
| • | • | • | • |
| • | • | • | • |
| 1920 | 1.456545E-01 | 0.000000E+00 | 67.4% |
| 1910 | 1.411554E-01 | 0.000000E+00 | 67.0% |
| 1900 | 1.356254E-01 | 0.000000E+00 | 66.7% |
| 1890 | 1.521239E-01 | 6.293447E-03 | 66.3% |
| 1880 | 1.471193E-01 | 6.094640E-03 | 66.0% |
| 1870 | 1.420331E-01 | 5.220609E-03 | 65.6% |
| • | • | • | • |
| • | • | • | • |
| • | • | • | • |
| 30 | 1.475925E-03 | 4.972414E-03 | 1.1% |
| 20 | 1.373205E-03 | 4.662643E-03 | 0.7% |
| 10 | 1.281644E-03 | 4.367324E-03 | 0.4% |
| 0 | 1.190567E-03 | 4.074197E-03 | 0.0% |
| -10 | 1.112620E-03 | 3.830233E-03 | -0.4% |
| -20 | 1.038466E-03 | 3.613263E-03 | -0.7% |
| -30 | 9.553825E-04 | 3.332802E-03 | -1.1% |
| -40 | 8.975253E-04 | 3.149478E-03 | -1.4% |
| -50 | 8.255385E-04 | 2.889731E-03 | -1.8% |
| • | • | • | • |
| • | • | • | • |
| • | • | • | • |
| -2800 | 8.544929E-45 | 1.025387E-43 | -98.2% |
| -2810 | 3.345126E-46 | 4.014149E-45 | -98.6% |
| -2820 | 6.718031E-48 | 8.061471E-47 | -98.9% |
| -2830 | 6.803069E-50 | 8.163683E-49 | -99.3% |
| -2840 | 2.765475E-52 | 3.318570E-51 | -99.6% |

**Table 4-8: System Margin State Probability Table (SMST) with 10 MW step increment**

With a 10 MW step increment, the first negative margin state will be the margin state of -10 MW which gives a cumulative margin probability of 0.00111262 with the hourly load model and 0.003830233 with the daily peak load model. This cumulative margin probability is the *Loss of Load Probability* (LOLP) indices. These LOLP indices are equivalent to 9.72 hours per year LOLE and 1.398 days per year LOLE respectively by multiplying the LOLP with 8736 hours and 365 days respectively.

| Margin state (MW) | Cumulative Margin Probability for hourly load | Cumulative Margin Probability for daily peak load | Margin in % of Peak Load |
|---|---|---|---|
| 3400 | 0.000000E+00 | 0.000000E+00 | 119.3% |
| 3399 | 0.000000E+00 | 0.000000E+00 | 119.3% |
| 3398 | 0.000000E+00 | 0.000000E+00 | 119.2% |
| • • • | • • • | • • • | • • • |
| 2439 | 0.000000E+00 | 0.000000E+00 | 85.6% |
| 2438 | 0.000000E+00 | 0.000000E+00 | 85.5% |
| 2437 | 0.000000E+00 | 0.000000E+00 | 85.5% |
| 2436 | 2.289377E-04 | 0.000000E+00 | 85.5% |
| 2435 | 1.748180E-04 | 0.000000E+00 | 85.4% |
| 2434 | 1.748180E-04 | 0.000000E+00 | 85.4% |
| • • • | • • • | • • • | • • • |
| 1897 | 1.352779E-01 | 0.000000E+00 | 66.6% |
| 1896 | 1.343997E-01 | 0.000000E+00 | 66.5% |
| 1895 | 1.342502E-01 | 0.000000E+00 | 66.5% |
| 1894 | 1.537085E-01 | 6.293447E-03 | 66.5% |
| 1893 | 1.532373E-01 | 6.293447E-03 | 66.4% |
| 1892 | 1.531173E-01 | 6.293447E-03 | 66.4% |
| • • • | • • • | • • • | • • • |
| 3 | 1.222795E-03 | 4.191935E-03 | 0.1% |
| 2 | 1.214986E-03 | 4.162698E-03 | 0.1% |
| 1 | 1.208410E-03 | 4.145666E-03 | 0.0% |
| 0 | 1.203435E-03 | 4.132627E-03 | 0.0% |
| -1 | 1.190522E-03 | 4.071471E-03 | 0.0% |
| -2 | 1.177503E-03 | 4.037028E-03 | -0.1% |
| -3 | 1.174513E-03 | 4.028263E-03 | -0.1% |
| -4 | 1.168224E-03 | 4.006809E-03 | -0.1% |
| -5 | 1.163974E-03 | 3.990197E-03 | -0.2% |
| • • • | • • • | • • • | • • • |
| -2845 | 2.765475E-52 | 3.318570E-51 | -99.8% |
| -2846 | 2.765475E-52 | 3.318570E-51 | -99.9% |
| -2847 | 2.765475E-52 | 3.318570E-51 | -99.9% |
| -2848 | 2.765475E-52 | 3.318570E-51 | -99.9% |
| -2849 | 2.765475E-52 | 3.318570E-51 | -100.0% |

**Table 4-9: System Margin State Probability Table (SMST) with 1 MW step increment**

With 1 MW step increment, the first negative margin state will be the margin state of -1 MW which gives a cumulative margin probability of 0.001191 with the hourly load model and 0.004071 with the daily peak load model. This cumulative margin probability is again the *Loss of Load Probability* (LOLP) indices. These LOLP indices are equivalent to 10.4 hours per year LOLE and 1.486 days per year LOLE respectively by multiplying the LOLP with 8736 hours and 365 days respectively.

## 4.6 Reliability indices and model evaluations

From the *System Margin State Probability Table* (SMST), the LOLP of the respective load model can be determined just by observing the probability of the first negative margin state. The respective LOLE then can be calculated by multiplying the LOLP value with the total number of hours or days in a year as described in Chapter 2.

Besides, the LOLE value can also be calculated using the *Formula method* using Equation 4.7. The computer algorithm that calculates the LOLE using this method can be found in Appendix B, Table B-3.

Even though with the same COPT and LPT, the step increment used to establish the *System Margin State Table* can vary the LOLE value obtained. Using the SREP model, step increments of 1 MW, 10 MW and 20 MW was evaluated and the results obtained for the first negative margin state were recorded. These values are then compared to the values obtained from other literatures that model the same IEEE RTS. The comparisons of the values obtained to a few references are shown in Table 4-10.

<table>
<tr><th rowspan="2">Step Increment</th><th colspan="5">LOLE (hours/year)</th><th rowspan="2">Difference btw SREP & Ref. 1</th></tr>
<tr><th>SREP Model</th><th>LOLE Formula</th><th>Reference 1</th><th>Reference 2</th><th>Reference 3</th></tr>
<tr><td>1</td><td>10.4004</td><td rowspan="3">10.516</td><td>9.3550</td><td></td><td rowspan="3">9.3716</td><td>11.2%</td></tr>
<tr><td>10</td><td>9.7817</td><td>9.3609</td><td>8.996</td><td>4.5%</td></tr>
<tr><td>20</td><td>9.1268</td><td>9.4482</td><td></td><td>-3.4%</td></tr>
</table>

**Table 4-10: Comparison of LOLE from SREP model and other references**

Where

Reference 1 value are obtained from (Singh, 1996)

Reference 2 value are obtained from (Wang and McDonald, 1994)

Reference 3 value are obtained from (Billinton and Li, 1994)

The results obtained for the LPT and COPT are exactly similar to the table in Wang and McDonald (1994). However, there are some differences in the values obtained for the *System Margin State Probability Table* (SMST) and therefore, giving a different value for the LOLE with the same 10 MW step increment. Even the LOLE values obtained from different references vary by about 4.2%.

The percentage difference in the value obtained from the SREP model and *Reference 1* is shown in the same table. The inconsistency of the value obtained is due to the step increment used. The smaller the step increment, the more accurate the results should be.

The LOLE using a 1 MW step increment from the *System Margin State Probability Table* gives a very close value to the LOLE obtained from the *Formula method*. This shows that the 1 MW step increment gives a more precise estimation of the LOLE than with a 10 MW or 20 MW step increment.

The possible discrepancies in the reliability indices according to Billinton and Allan (1996, p.37) are because there are a number of possible load models which can be used and therefore there are a number of risk indices which can be produced.

From the observation, a 1 MW step increment is selected to be used in the subsequent reliability studies. In order to reduce the simulation time, the maximum and minimum margin states of 410 MW and -60 MW are selected and fixed since the important value is the first negative margin state which is -1 MW. With this *System Reliability Evaluation Programme* (SREP), further analysis with integration of intermittent wind renewable energy modelling and other sensitivity analysis could be carried out and evaluated. This will be the discussed and elaborated in detail in the next two chapters.

# Chapter 5

## INTERMITTENT WIND GENERATION RELIABILITY MODEL

*Wind generation is currently one of the emerging and proven renewable technologies in the UK and in countries with the availability of useful wind resources. It is anticipated that wind power, despite its current modest contribution towards meeting the UK electricity demand of 0.49% (DUKES, 2005 cited in Sinden, 2005), will be the dominant source of renewable electricity by 2010 (Mott Macdonald, 2003 cited in Sinden, 2005). With the high growth of wind generation compared to other types of intermittent renewables, it is vital to focus the reliability study on intermittent wind generation and to examine the different factors of wind characteristics that will impact the reliability of electricity system.*

*In this chapter, intermittent wind generation will be modelled and integrated into the system reliability evaluation programme and the capacity credit obtained from various modelling methods will be analysed and compared.*

## 5.1 Selection of modelling approach

Chapter 2 of the Literature review have introduced the various approaches that can be used for calculating the capacity credit of wind generation for generation capacity planning. There is currently no one single approach which is commonly accepted for determining the capacity contribution for system reliability from wind generation.

The most simple and straightforward method is using the approximation technique where the capacity credit of wind generation is estimated using the capacity factor of the wind farm. However, this approach should only be used as a first approximation before conducting further detail capacity credit evaluations. The capacity factor of all the wind regions studied will be used for comparison purpose only.

The second method selected to be used in determining the capacity credit is the reliability curve method. This method, based on the graphical approach, uses the system reliability curve for a range of load level to evaluate the capacity credit of wind generation.

The retrospective or Effective Load Carrying Capability (ELCC) approach is selected as another approach to determine the capacity credit of wind generation. This approach consists of two similar but slightly different methods. The first is known as the *Firm Capacity Method* that compares the wind generation with an *ideal, perfectly reliable unit* and the second, an alternate *Effective Capacity Method* that compares the wind generation with a typical conventional generating unit (normally a gas turbine unit) in determining the capacity credit of specific wind generation.

These methods were chosen due to the availability of hourly chronological wind power output data which is required by those techniques. Besides, these data can be easily integrated into the system reliability evaluation program that has been developed earlier as discussed in Chapter 4. Another reason is that the calculation of capacity credit using the load-modifying (retrospective) approach is well known and has been widely used in the modelling of capacity credit in many existing utilities. The limitation of this approach is that the probabilistic effect of wind availability is not taken into account.

## *5.2 Data requirements, assumptions and limitation of the selected approach*

In addition to the data required for modelling of the conventional system reliability, the required data for wind generation reliability modelling is the hourly wind speed (meteorological) or hourly wind power output (actual generation capacity) data for at least a year.

The annual hourly data used in this study is obtained from actual wind farms at various locations across Scotland. Three sets of annual hourly wind power output data are selected from the measured power output of wind farms of the West, Northern Mainland and Northern Isles of Scotland. The hourly chronological wind power output data for year 2001 are used for the base case of this study. Data for year 2002 are used later in Chapter 6; Case Study 3 to examine the effect of inter-annual variation of wind power output on system reliability and Case Study 4 to compare the effect on using the Great Britain (GB) 2002 demand profile with the IEEE RTS.

Since these wind data are actual measured values, the data already in-built the element of planned and forced outages of the individual wind generators, the effect of array efficiency and other technical and operational efficiencies. Besides, by using the chronological hourly data, the effect of the diurnal and seasonal variation of wind across the three regions will be taken into consideration.

By using only one year hourly chronological wind power output data in the modelling, it is assumed that there is no inter-annual variation of wind. This means that the wind profile and demand profile is assumed to be the same for all the year of study. However, this effect of inter-annual variation of wind generation will be analysed and discussed in Chapter 6 and will be presented as an independent case study.

For all the three approaches, the hourly chronological wind power output is modelled as a load-modifier into the system reliability evaluation programme. The amount of wind generation capacity at the respective time and day is deducted from the corresponding hourly chronological load based on the amount of wind capacity specified and the combination of wind regions. The "*WindModel*" worksheet in the programme calculates the combined percentage of wind data from the wind regions, which will then be deducted from the "*LoadModel*" worksheet to give the new modified hourly load data.

## *5.3 The capacity factor approximation*

The capacity factor of the wind data can be used to give a crude approximation of the capacity credit of the wind generation from the region. From a planning perspective, one could interpret the capacity factor as the ratio of statistically expected output divided by annual energy output (Milligan, 2001). Because planning often focuses on the "reasonably expected future", this measure can be viewed as a first-stage approximation to overall capacity credit (Milligan, 2001).

This method calculates the capacity factor of the hourly chronological wind power output by taking the sum of all hourly wind generation capacity divided by the maximum wind generation capacity in the year multiplied by total number of hours in the whole year. The chronological wind power output data for year 2001 is used in this case and the capacity factor for all the three regions were calculated based on Equation 5.1.

$$\text{Capacity factor} = \frac{\text{Sum of annual hourly wind power output (MW)}}{\text{Maximum wind power output (MW)} \times 8736} \qquad (5.1)$$

The total number of hours in the whole year is assumed to be 8736 due to the assumption that there are 24 hours x 7 days x 52 weeks in a year. The capacity factor calculated using Equation 5.1 for all the three regions are listed in Table 5-1.

| Wind Region | Capacity factor (%) |
|---|---|
| 1 | 25.7% |
| 2 | 25.6% |
| 3 | 35.4% |

**Table 5-1: Capacity factor of the three wind regions based on 2001 wind data**

## *5.4 The reliability curve method*

Another approach that can be used to assess the capacity credit of wind generation from the hourly chronological wind power output is by using the reliability curve method. The process of modelling starts from calculating the system reliability indices, i.e. the LOLE without the wind generation for a range of annual peak load using the developed system reliability evaluation programme. The reference curve generated without wind generation is plotted in a graph. Then, the effect of wind generation is taken into consideration by deducting the chronological hourly wind power output from the hourly load data. The wind generation capacity required is scaled up to the required level. In this case, the "new" hourly load profile is scaled to the different load level, and the system reliability indices (LOLE) is calculated for the different load level as in the reference case. The new reliability curve for the wind generation of LOLE vs. Annual Peak Load is plotted in the same graph. For a required reliability level, the difference of the annual peak load of the curve for wind generation and the reference curve gives the ELCC or the capacity credit for the respective amount of wind generation.

Figure 5-1 shows the reliability curves of Wind Region 1 with 100, 200 and 300 MW wind capacity level together with the reference reliability curve without wind generation.

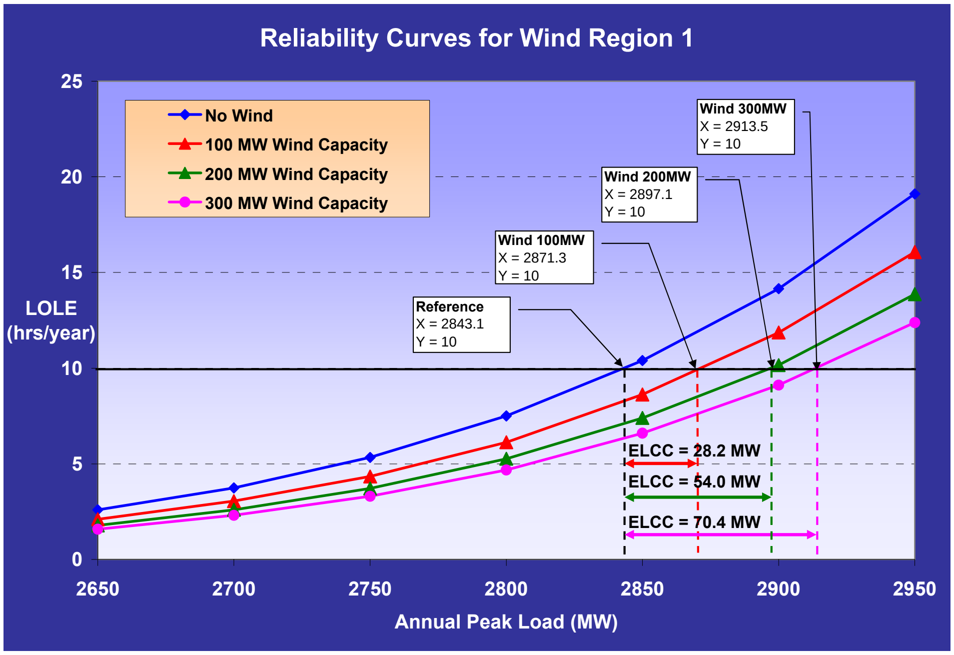


**Figure 5-1: Region 1 capacity credit evaluation using reliability curves**

By assuming that the reliability level of 10 hours/year LOLE is required, the capacity credit of the 100 MW installed wind capacity in Region 1 can be assessed by taking the difference between the load level of that curve that gives 10 hours/year LOLE and the load level of the reference curve at 10 hours/year. The effective load carrying capability of a 100 MW wind generation in Region 1 therefore is 28.2 MW which is equivalent to a capacity credit of 28.2%.

With a 200 MW installed wind capacity in the same region, the effective load carrying capability is 54 MW which is equivalent to a capacity credit of 27%. For a 300 MW installed wind capacity, the ELCC obtained is 70.4 MW which gives a 23.5% capacity credit. The summary of capacity credit for the respective installed wind capacity of Region 1 is presented in Table 5-2.

| No. | Installed wind capacity level (MW) | Capacity credit (%) |
|---|---|---|
| 1. | 100 | 28.2% |
| 2. | 200 | 27.0% |
| 3. | 300 | 23.5% |

**Table 5-2: Capacity credit of respective installed wind capacity for Region 1**

Figure 5-2 and Figure 5-3 shows the same reliability curves for Wind Region 2 and Wind Region 3 respectively. The effective load carrying capability of the respective installed wind generation capacity level is shown in the graph and the respective capacity credit is tabulated in Table 5-3 and Table 5-4.

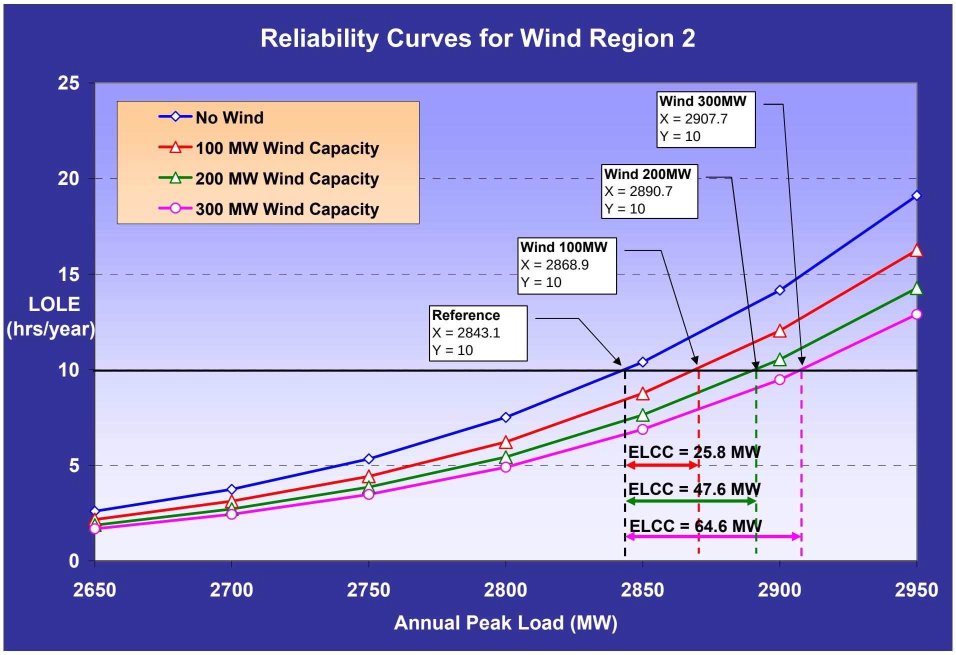


**Figure 5-2: Wind Region 2 capacity credit evaluation using reliability curves**

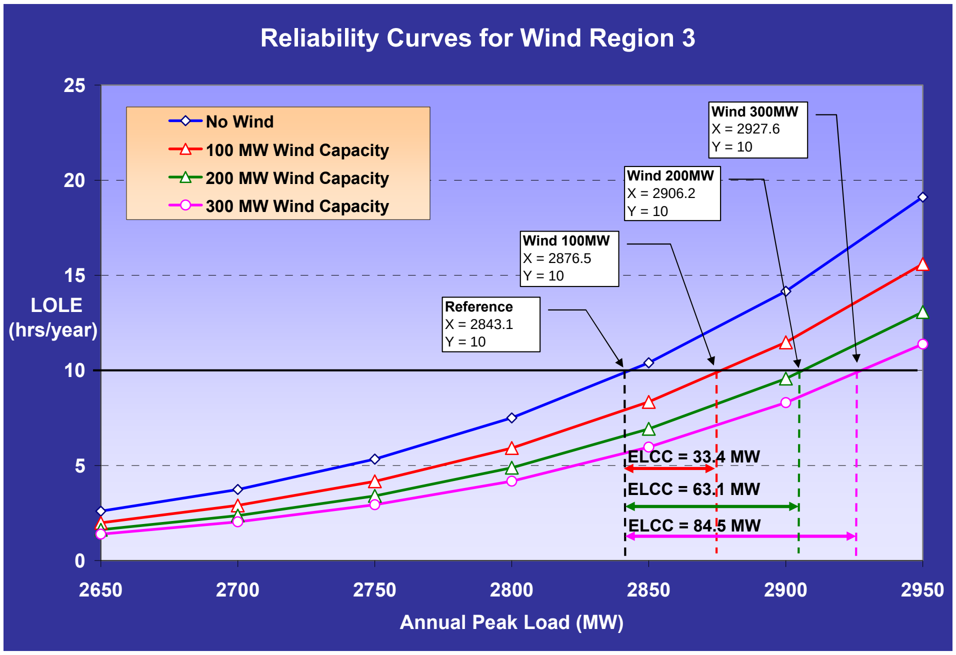


**Figure 5-3: Wind Region 3 capacity credit evaluation using reliability curves**

| No. | Installed wind capacity level (MW) | Capacity credit (%) |
|---|---|---|
| 1. | 100 | 25.8% |
| 2. | 200 | 23.8% |
| 3. | 300 | 21.5% |

**Table 5-3: Capacity credit of respective installed wind capacity for Wind Region 2**

| No. | Installed wind capacity level (MW) | Capacity credit (%) |
|---|---|---|
| 1. | 100 | 33.4% |
| 2. | 200 | 31.5% |
| 3. | 300 | 28.2% |

**Table 5-4: Capacity credit of respective installed wind capacity for Wind Region 3**

Figure 5-4 shows the summary of the capacity credit obtained for all three regions in a capacity credit versus installed wind capacity graph. It is observed that the capacity credit decreases with higher installed wind capacity within the same region and Region 3 has the highest capacity credit while Region 2 has the lowest capacity credit among the three regions.

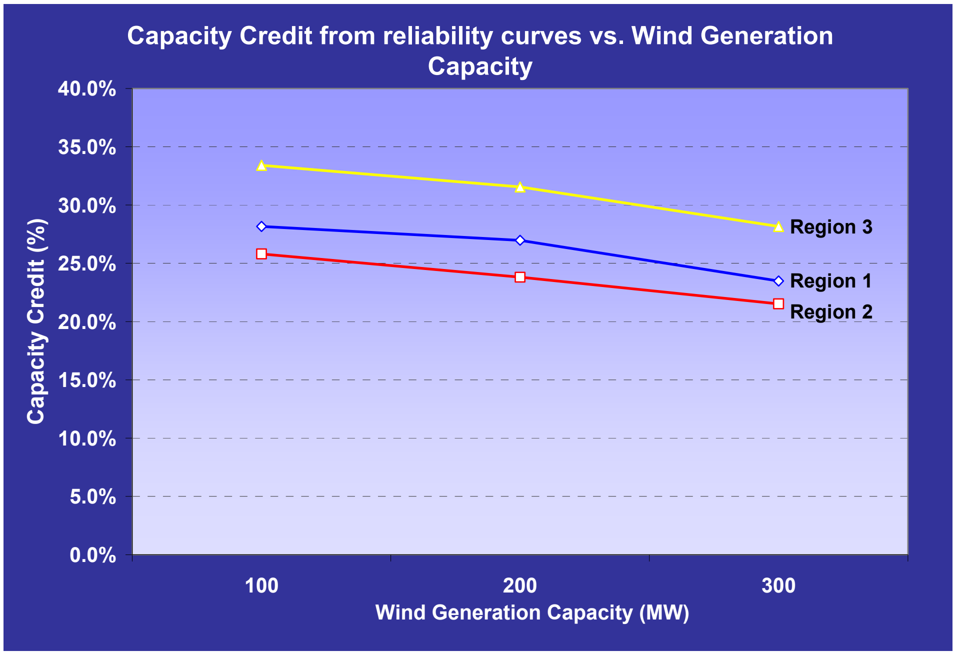


**Figure 5-4: Capacity credit with different wind generation capacity**

## 5.5 *The retrospective approach*

Using the retrospective approach, wind plants can be modelled as load modifiers where the hourly generation capacity of the wind is deducted from the expected hourly system demand. The advantage of modelling the wind plant as a load-modifier is that it takes into account the detailed chronological variation of the wind plant output.

The two slightly similar methods in the retrospective approach are used to assess the capacity credit. They are:

1. Firm Capacity Method, and
2. Effective Capacity Method

The ***Firm Capacity Method*** is based on the LOLE measure of system reliability, and incorporates LOLE calculations in such a way that adding a new wind plant is benchmarked against an ***ideal, perfectly reliable unit*** with 100% availability.

The ***Effective Capacity Method*** on the other hand substitutes an ***alternative unit*** (for example a natural gas unit with typical forced outage rates) instead of the ideal unit which is sized so that the LOLE calculation is the same as that calculated with a wind plant.

These two methods can be used to effectively evaluate the ELCC and the capacity credit using at least one year of hourly wind power output data. The following steps listed below explain the whole calculation procedure.

1. The system is modelled without the wind plant or wind region of interest
2. The loads are adjusted to achieve a reliability level (In this study, 10 hours per year LOLE is chosen)
3. Once the desired LOLE target is achieved, the wind generation is added to the system and the model is re-run
4. The new, lower LOLE with wind generation is noted, and the wind generation is removed from the system
5. Then the benchmark unit (*ideal and perfectly reliable unit* for the *Firm Capacity Method* or *a gas turbine unit* for the *Effective Capacity Method*) is added to the system in small incremental capacities until the LOLE with the benchmark unit matches the LOLE that was achieved with the wind generation obtained in (4)
6. The capacity of the benchmark unit is then noted, and that becomes the ELCC of the wind generation

The ELCC documents the capacity that achieves the same risk level as would be achieved without the wind generation.

Three sets of chronological wind power output were modelled into the *system reliability evaluation programme* as "*Wind1*", "*Wind2*" and "*Wind3*" worksheets. Subsequent wind regions' chronological data can be added accordingly if more were to be analysed. These three worksheets contain the percentage of the hourly wind generation output over the annual maximum output. It is modelled in such a way as to provide the flexibility and option to scale up the wind output as needed when running simulations.

The "*WindModel"* worksheet is then used to sum up the different amount of wind capacity contribution chronologically for each hour of the year, depending on the wind regions to be considered. This hourly wind capacity contribution will then be deducted from the "*LoadModel"* worksheet's hourly load to form a reduced hourly load model. The *Load Probability Table* (LPT) will be calculated automatically and will depict the chronological contribution from wind generation as load modifier.

Further calculations of *Capacity Outage Probability Table* (COPT) and the *System Margin State Table* (SMST) can be conducted by following the similar steps as the conventional reliability indices simulation described in Chapter 4 previously.
The amount of wind generation will be deducted from the load, leaving the remaining capacity to be met by conventional generation systems. The process of calculating the capacity credit is conducted for Wind Region 1, Wind Region 2 and Wind Region 3.

The calculation process using the *Firm Capacity Method* with *ideal, perfectly reliable unit* for Wind Region 1 is displayed in Table 5-5.

| STEPS | PROCESS | Annual Peak Load (MW) | Wind Capacity (MW) | Ideal Unit Capacity (MW) | LOLE (hrs/yr) | LOLE % Diff. compare to (3) |
|---|---|---|---|---|---|---|
| 1 | Reference Without Wind | 2850 | 0 | - | 10.4004 | - |
| 2 | Annual Peak Load adjusted to give 10 hours per year LOLE | 2843 | 0 | - | 10.0280 | - |
| 3 | Add wind generation of 100 MW from Region 1 | 2843 | 100 | - | ***8.30513*** | - |
| 4 | Remove wind unit and add 20 MW *ideal, perfectly reliable unit* | 2843 | 0 | 20 | 8.60139 | 3.57% |
| 5 | Increase the *ideal, perfectly reliable unit* capacity to 22 MW | 2843 | 0 | 22 | 8.48114 | 2.12% |
| 6 | Increase the *ideal, perfectly reliable unit* capacity to 25 MW | 2843 | 0 | ***25*** | 8.30081 | -0.05% |
| 7 | The ELCC for 100 MW of Wind Region 1 is 25MW based on an *ideal, perfectly reliable unit* | | | | | |

**Table 5-5: Firm capacity method for a 100 MW capacity from Wind Region 1**

The *ideal, perfectly reliable unit* with 25 MW will give an almost equivalent LOLE results to the LOLE with a 100 MW installed wind capacity. This means that the 100 MW installed wind capacity in Region 1 provide the same level of system reliability as with a 25 MW of *ideal, perfectly reliable unit*. The process is repeated using the *Effective Capacity Method* by substituting the *ideal, perfectly reliable unit* with a *gas turbine unit* with a FOR of 4% and presented in Table 5-6.

| STEPS | PROCESS | Annual Peak Load (MW) | Wind Capacity (MW) | GT Unit Capacity (MW) | LOLE (hrs/yr) | LOLE % Diff. compare to (3) |
|---|---|---|---|---|---|---|
| 1 | Reference Without Wind | 2850 | 0 | - | 10.4004 | - |
| 2 | Annual Peak Load adjusted to give 10 hours per year LOLE | 2843 | 0 | - | 10.0280 | - |
| 3 | Add wind generation of 100 MW from Region 1 | 2843 | 100 | - | ***8.30513*** | - |
| 4 | Remove wind unit and add 25 MW *GT unit* with 4% FOR | 2843 | 0 | 25 | 8.36990 | 0.78% |
| 5 | Increase the *GT unit* capacity to 26 MW | 2843 | 0 | 26 | 8.33994 | 0.42% |
| 6 | Increase the *GT unit* capacity to 27 MW | 2843 | 0 | **27** | 8.31000 | 0.06% |
| 7 | The ELCC for 100 MW of Wind Region 1 is 27MW based on a *gas turbine unit with 4% FOR* | | | | | |

**Table 5-6: Effective capacity method for a 100 MW capacity from Wind Region 1**

The GT unit with a 27 MW capacity will give an almost equivalent LOLE results to the LOLE with a 100 MW installed wind capacity. This means that the 100 MW installed wind capacity in Region 1 provide the same level of system reliability as with a 27 MW gas turbine power plant. The calculation process is repeated for Wind Region 2 and Wind Region 3 and the results are summarized in Table 5-7.

| No. | Installed wind generation capacity level (MW) | ELCC based on *Firm Capacity Method* | ELCC based on *Effective Capacity Method* |
|---|---|---|---|
| 1. | 100 MW Wind Region 2 | 22 MW | 23 MW |
| 2. | 100 MW Wind Region 3 | 30 MW | 32 MW |

**Table 5-7: Results of ELCC calculated for Wind Region 2 and 3**

## *5.6 Comparison and discussion of results*

The capacity credit results obtained from all the three different methods and the capacity factor approximation are summarized and presented in Figure 5-5.

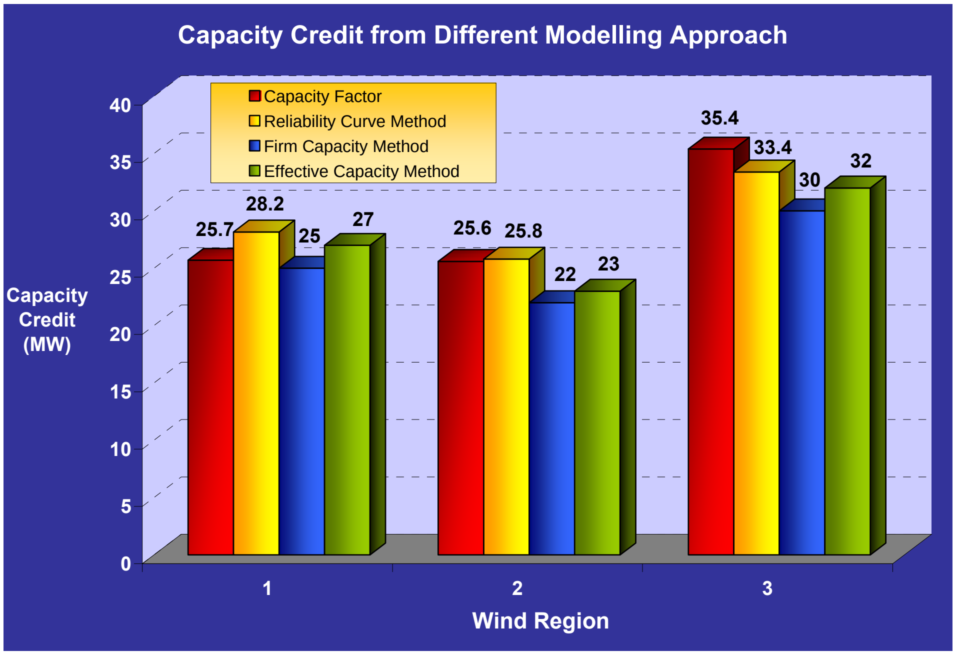


**Figure 5-5: Capacity credit from different modelling approach**

The standard deviation of the capacity credit for Wind Region 1, 2 and 3 (in % capacity credit) is 1.4%, 1.9% and 2.3% respectively. From the graph, it is observed that the capacity factor of Wind Region 1 and 2 gives a close first hand approximation of the capacity credit but over estimated the capacity credit for Wind Region 3. It is also found that the capacity factor did not give a consistent trend of estimating the capacity credit of the wind regions as compared to the other methods. Comparing to the capacity credit evaluated from the Reliability Curve Method, the capacity factor is lower for wind in Region 1, almost similar for wind in Region 2 and much higher for wind in Region 3. The other three methods give a consistent trend of capacity credit where the *Reliability Curve Method* will give a slightly optimistic upper value while the *Firm Capacity Method* is a little pessimistic in giving the lowest capacity credit value due to the comparison to the *ideal and perfectly reliable unit*.

The average capacity credit value of all the four methods for the three regions are 26.5%, 24.1% and 32.7%. Among all the four methods, the *Effective Capacity Method* gives the value closest to the average capacity credit and therefore is recommended to be used for future generation capacity adequacy planning with intermittent wind generation.

# Chapter 6

## EFFECT OF INTERMITTENT WIND GENERATION ON SYSTEM RELIABILITY

*Integrating large amount of wind generation into the electricity system requires careful planning and evaluation of the impact on system reliability. There are many aspects of intermittent wind integration have on system reliability. The percentage wind penetration, diversity of wind generation and inter-annual variation of wind power output on system reliability are a few that is of interest for generation capacity planning. These will be examined in detail in three separate case studies. The fourth case study will examine the effect of using the Great Britain's (GB) historical demand profile instead of the IEEE RTS demand profile in the evaluation of wind generation capacity credit. This will provide an indication of the effect that the actual GB system has on the capacity credit of the wind generation.*

## 6.1 *Case Study 1: Wind penetration effect on system reliability*

Wind power development need to be integrated into the electricity system to meet the future demand of electricity. With this, the development of wind power will result in a reduced need for conventional capacity. However, the amount of conventional capacity that can be replaced by wind generation will not be a 1 MW wind for 1 MW conventional in order to maintain the required level of system reliability. The amount of intermittent wind generation capacity in a system will affect the system reliability compared to having the same amount of capacity from conventional plants.

This study is conducted to examine the effect of wind penetration on system reliability. A 5% increment on total system capacity for wind power was analysed using the wind generation and system reliability evaluation model developed earlier. The system reliability (LOLE) resulted from the additional wind generation capacity in the system will be calculated for different installed wind capacity. The chronological hourly wind generation capacity data for all the three regions were analysed and the results obtained is presented in Figure 6-1.

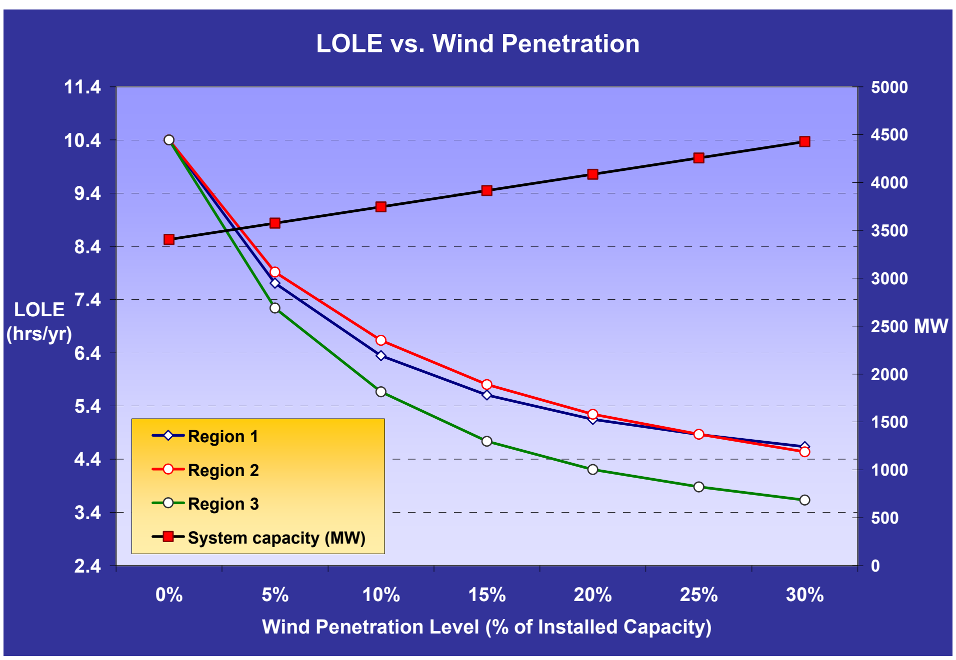


**Figure 6-1: The effect of wind penetration on system reliability**

It can be seen from the results that with system capacity increases due to the addition of wind generation capacity, the system reliability reduces exponentially. Wind Region 3 show a much lower loss of load expectation (better system reliability) for the respective penetration level since it has a higher capacity credit as found in Chapter 5 previously.

The rate of system reliability improvement is nonlinear, showing that system reliability does not improve with respect to wind generation capacity addition. Besides, after about 30% of penetration level, there will not be much improvement in system reliability. This means that even if investments are made to install more wind generators and wind farms to cater for the capacity and reserve requirements with 30% of wind generation capacity already in the system, the system reliability or the loss of load expectation in this case will not be improved further. This will give the system planner a clear indication for proposing other power generation resources to meet demand and system reliability.

## *6.2 Case Study 2: Diversity effect on system reliability and capacity credit*

Besides being intermittent, wind resources are diffused in nature. Wind resources vary between locations and countries and therefore, it is not possible to generalize the characteristics of a single site. Even wind in the Northern Isles of Scotland will be different than wind in the Northern Mainland of Scotland. The advantage of a diversified system is that the wind turbines at different regions will be exposed to a range of wind conditions at the same time. If taken as a whole, the contribution from all the wind regions to the whole system will minimize the no-wind condition. This study is conducted to examine the effect of diversity on system reliability.

The wind data used in this case is from three different wind farms in different areas of Scotland. Wind Region 1 data is from the Northern mainland, Wind Region 2 data is from West while Wind Region 3 data is from the Northern isles of Scotland. The wind model and the conventional reliability system model developed in Chapter 4 and 5 are again used to conduct the analysis. Four scenarios were analysed and super-imposed on to the three wind penetration reliability curve for the individual regions of Figure 6-1. The four scenarios analysed were:

1. The combination of Wind Region 1 and 2
2. The combination of Wind Region 1 and 3
3. The combination of Wind Region 2 and 3
4. The combination of all three regions

All the combined regions are assumed to contribute equally the amount of wind capacity, presented as the penetration level. Figure 6-2 shows the results obtained from the combination effect or the diversity effect with respect to system reliability.

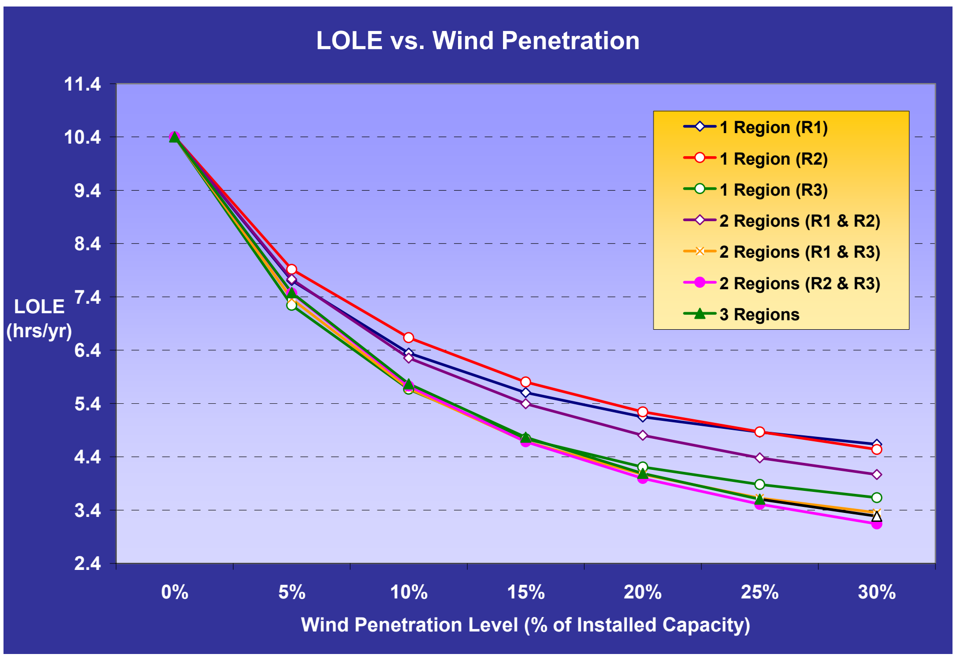


**Figure 6-2: Effect of diversity on system reliability**

It is observed that by distributing the same amount of wind capacity among Region 1 and Region 2, the effective system reliability is equal to the reliability brought about by the lower individual region reliability (Region 1 at 5% penetration level) or better for higher penetration level as can be seen from the 2 regions curve (R1 & R2). This trend can also be seen from the other 2-regions curves and the combination of all three regions curve.

The trend of system reliability improvement is similar to that of the individual regions, but the system reliability improvement is clear with the added diversity effect. This means that while having more wind farms and thus capacity can improve system reliability, the location of the wind farms and the distance between them can make a difference to the amount of reliability contribution to the system.

Figure 6-3 gives the capacity credit calculated using the *Reliability Curves Method* for the combination of regions.

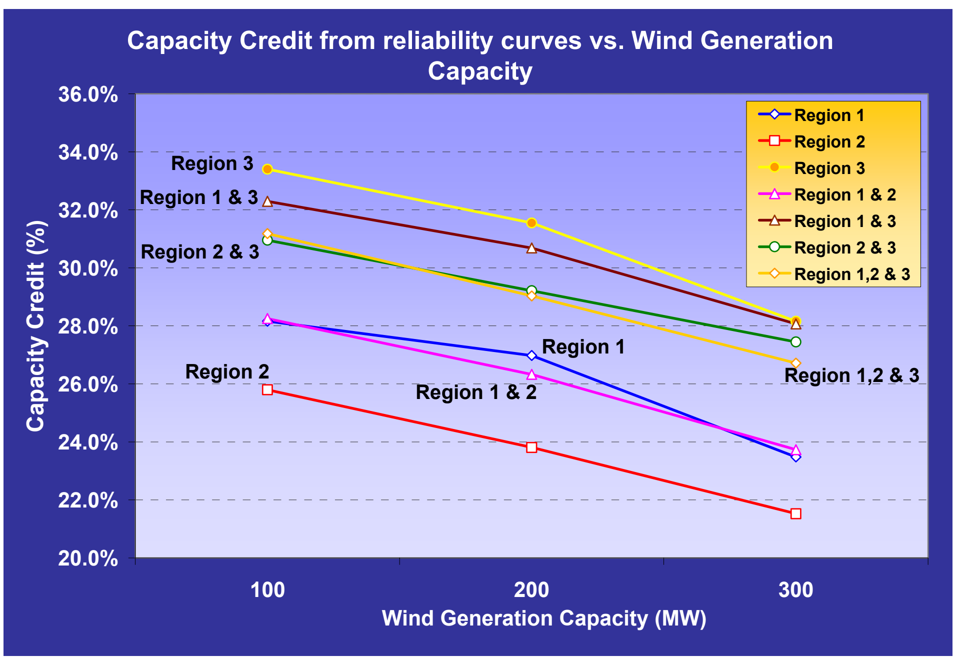


**Figure 6-3: Capacity credit effect from combination of regions**

It is observed that the capacity credit of the combined regions fall between the capacity credit of the individual regions. This means that with the introduction of diversity, the capacity credit obtained will be somewhat better than the average of the capacity credit obtained from individual regions; higher than the lower regions but lower than the higher ones. The advantage of the diversity is that it improves the capacity credit contribution of the lower region but penalise the capacity contribution from the higher region.

Developers always want to build their wind farms in regions that will have a high capacity credit. However, from the system planner point of view, it would be better if the next wind farm is located in another region which will improve the system reliability as according to Figure 6-2.

This diversity effect can provide an avenue for identifying and giving incentives to wind farm developers to build in different regions (even with lower wind resources) so as to benefit from the additional system reliability as a result of diversity.

## *6.3 Case Study 3: Inter-annual wind power output variation*

Wind speed and thus wind generation varies between day and night and between seasons. This can be found from many studies and is known as the diurnal and seasonal variation of wind. The UK wind resource has strong seasonal patterns of availability, together with daily patterns of lighter and stronger winds (Sinden, 2005). Diurnal and seasonal variation has been taken into account with the modelling method using the hourly chronological wind power output. Besides the diurnal and seasonal pattern, another element that is important when looking at intermittent wind generation effect on system reliability is the inter-annual variation. The inter-annual variation of wind means that the wind condition this year is not the same as last year or the year after. This case study will look at the effect of inter-annual variation using wind generation data of the same location from another year.

The current wind generation capacity data for all three regions used are from year 2001. The wind generation capacity data for year 2002 will be analysed and the capacity credit results from both years will be compared.

Year 2002 hourly wind power output data is modelled into the wind model similar to the process as described in Chapter 5 previously. The method selected to assess the capacity credit in this case is the *Effective Capacity Method* in addition to the capacity factor approximation. The results of both years are then compared. The capacity factor of the wind generation capacity data for year 2001 and 2002 is shown in Figure 6-4.

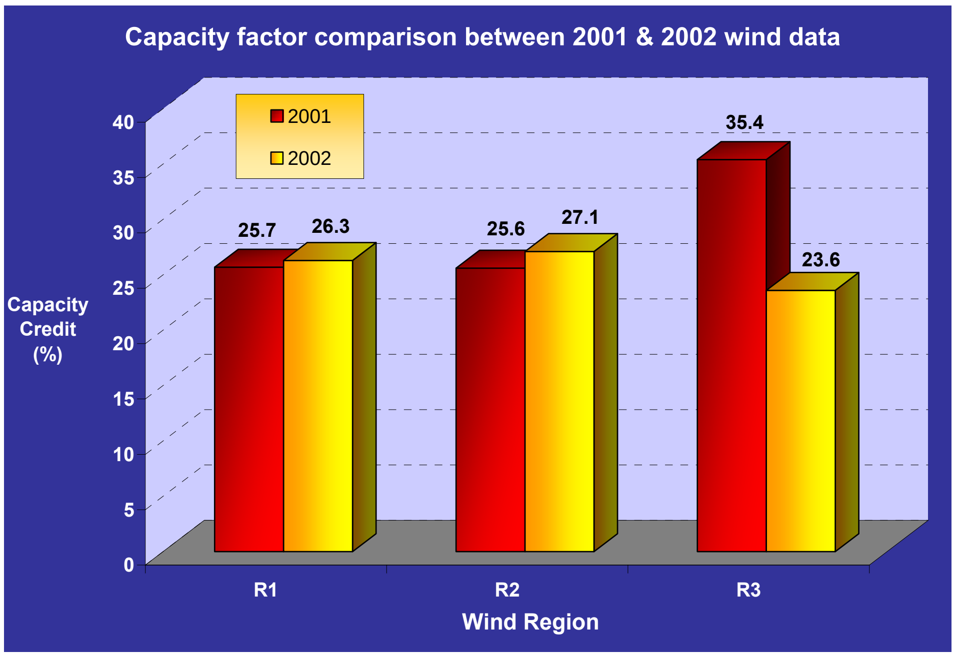


**Figure 6-4: Capacity factor of wind generation capacity data for 2001 and 2002**

Table 6-1 shows the percentage difference between the 2001 and 2002 capacity factor value.

| Wind Region | Capacity factor variation between 2001 and 2002 wind power output (% difference) |
|---|---|
| 1 | 2% |
| 2 | 6% |
| 3 | -33% |

**Table 6-1: Capacity factor difference between 2001 and 2002 wind power output**

It is observed that there is a high variation of wind resources in Region 3. The comparison of the capacity credit obtained from the *Effective Capacity Method* for all the three regions 2001 and 2002 data is shown in Figure 6-5.

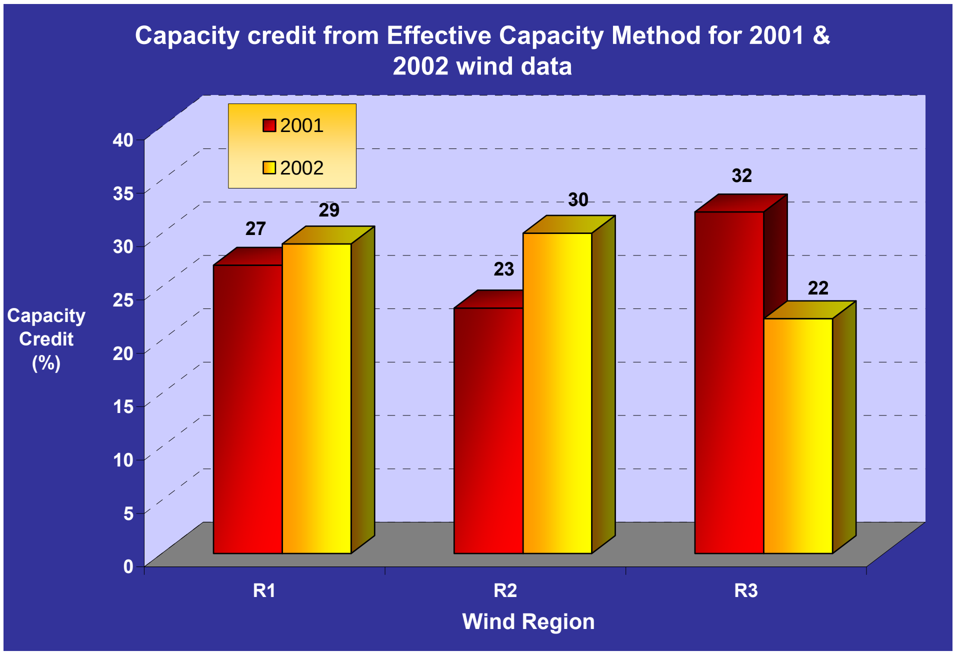


**Figure 6-5: Capacity credit comparison with inter-annual wind data variation**

Table 6-2 list the difference between the capacity credits of the two years for all the three regions.

| Wind Region | Capacity credit from *Effective Capacity Method* annual variation (% difference) |
|---|---|
| 1 | 7% |
| 2 | 30% |
| 3 | -31% |

**Table 6-2: Difference between *CC* using 2001 and 2002 wind generation data**

It is observed from Figure 6-5 that the capacity credit value of the 2002 wind generation capacity data is higher than the 2001 value for Wind Region 1 and 2 by 7% and 30%

respectively. The capacity credit value for 2002 is lower for Wind Region 3 by 31%. The region with the highest wind capacity potential in year 2001 becomes one of the lowest among the three in 2002. This variation occurs for a number of reasons and one of the main reasons is because LOLE measures are weighted heavily on the peak hours of the year, and if full wind power output is attained during the peak hours for a given year, wind will compare favourably with its alternative. On the other hand, if in another year wind power output is low during system peak times, LOLE based measure will find wind much less favourable, and thus giving a lower value for the capacity credit.

The inter-annual variation of wind power output makes it a challenge to accurately predict the capacity credit of a wind region, especially when using methods that model the wind plant as a load-modifier. Therefore, in order to accurately assess the capacity credit of a wind region, more years of hourly wind data need to be modelled or as suggested by Milligan (2005), using some other form of repeated sampling of the wind probability distribution.

## *6.4 Case study 4: GB demand profile and capacity credit*

The current demand profile using the IEEE RTS gives a load factor of 61.4% and the day hourly profile for a typical winter week where the peak demand occurs is shown in Figure 6-6. It is observed that the peak demand period of the IEEE RTS demand profile is between 0900 to 2100 hours. The load profile is rather flat in this case and occurs during weekdays.

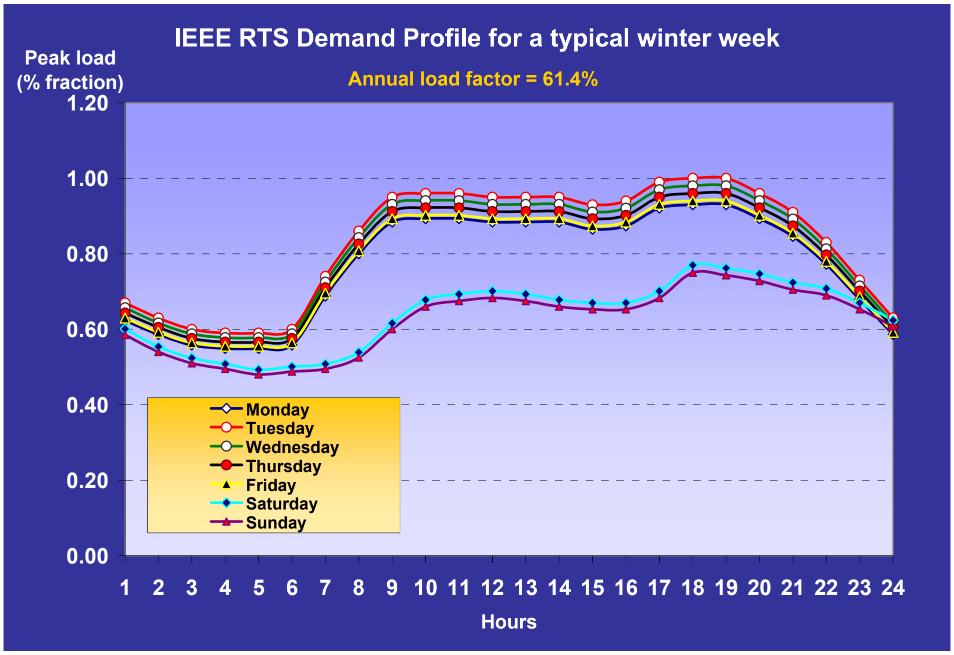


**Figure 6-6: IEEE Reliability Test Systems demand profile for a typical winter week**

The time of occurrence of the peak demand is crucial in the study of using intermittent wind generation to meet the peak demand. This is especially true when the hourly chronological wind power output is modelled as a load modifier in the retrospective approach.

In this case study, the GB (England and Wales, year 2002) demand profile is examined in place of the IEEE RTS demand profile. The purpose of this study is to examine how the GB demand profile will affect the capacity credit contribution of the wind generation capacity data compared with the IEEE RTS demand profile.

This GB 2002 demand profile has a load factor of 62.9%; 1.5% higher than the IEEE RTS load factor. The GB 2002 hourly demand profile for a typical winter week is shown in Figure 6-7.

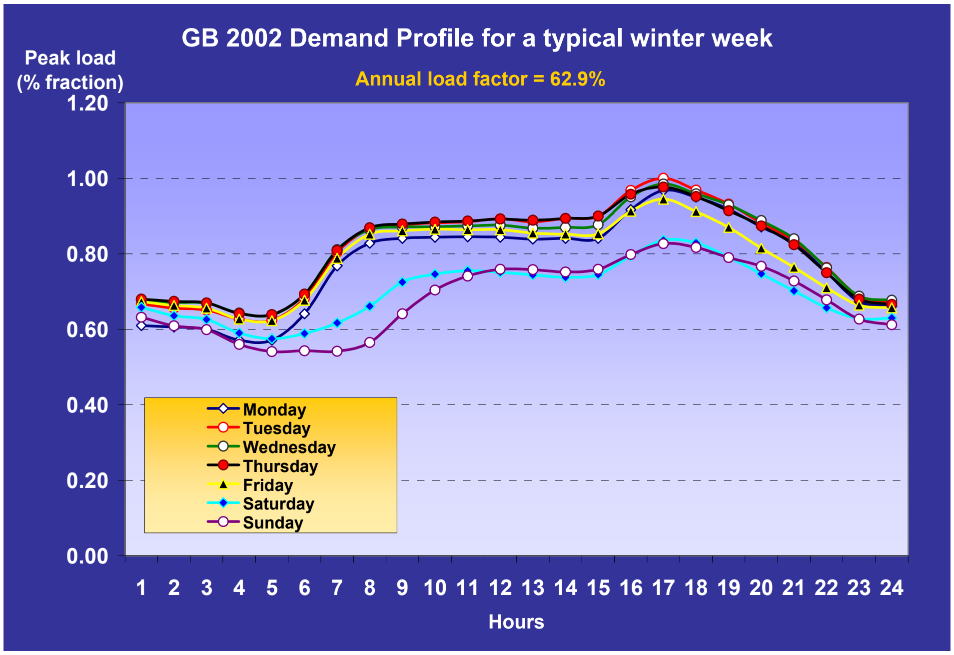


**Figure 6-7: GB 2002 demand profile for a typical winter week**

The GB 2002 demand profile also gives a different cumulative load and probability curve which is shown in Figure 6-8 and Figure 6-9.

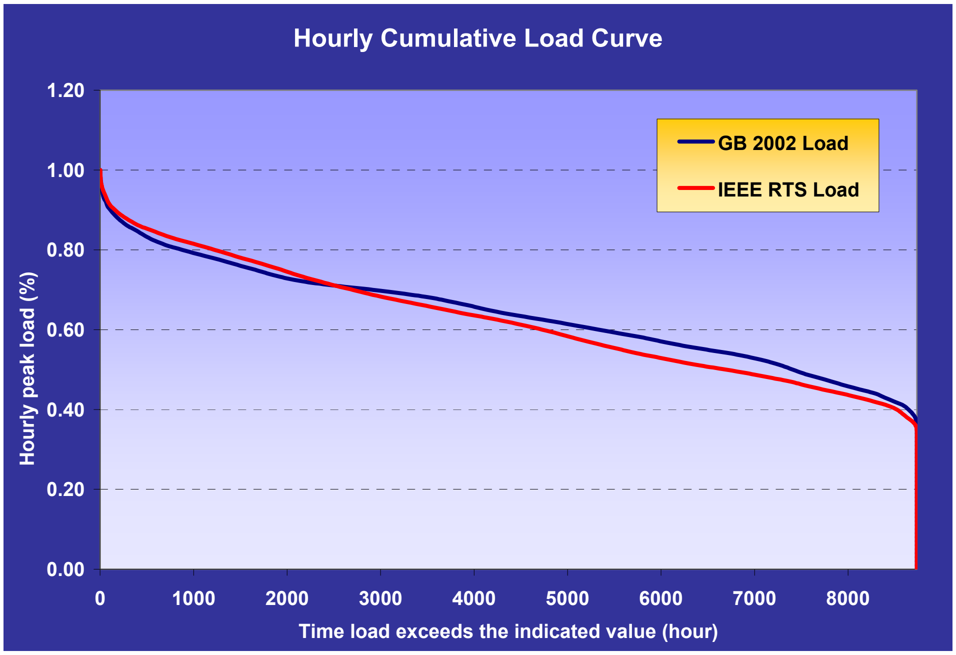


**Figure 6-8: Hourly load duration curve comparison**

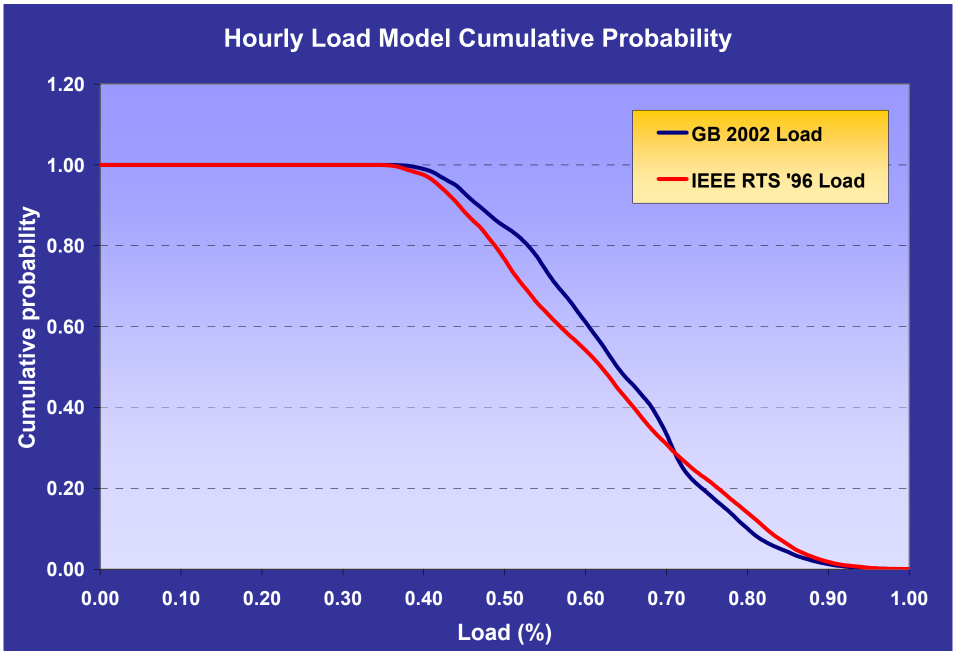


**Figure 6-9: Hourly load cumulative probability curve comparison**

The GB 2002 demand profile is modelled into the *system reliability evaluation programme*, taking each hour load as a percentage of the peak load (2850 MW as of the IEEE RTS). The total system capacity as well as the generation units is assumed to be the same as the IEEE RTS. The simulation is conducted using wind data of year 2002 for the three regions and the capacity credits are evaluated using the *Reliability Curve Method* and the two retrospective methods. The results of the capacity credit assessed are shown in Figure 6-10.

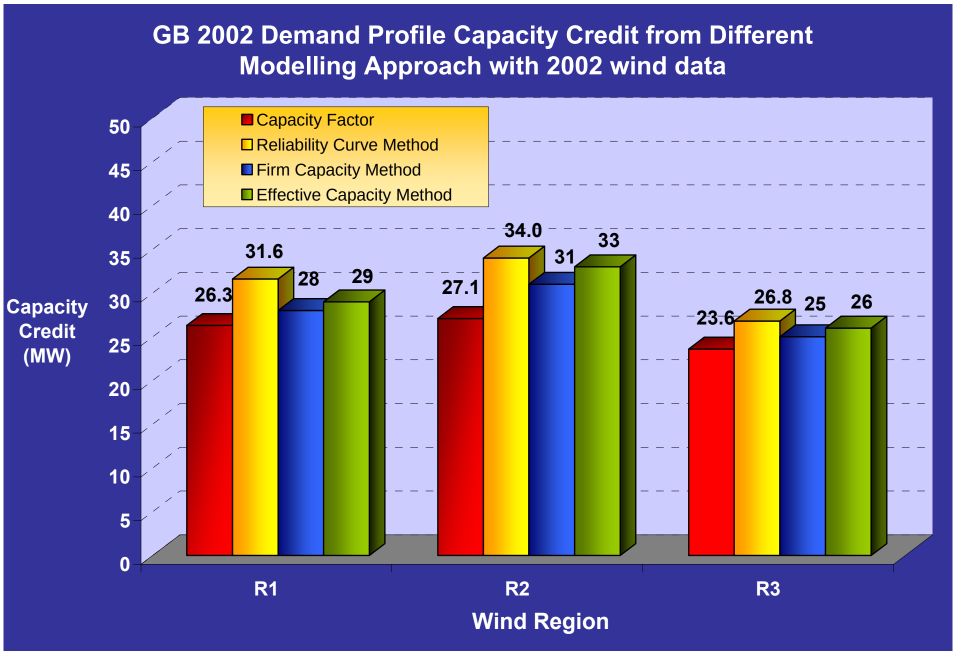


**Figure 6-10: Capacity credit for GB 2002 demand and 2002 wind data**

It is observed that the capacity factor of the three wind regions give a lower value than the capacity credit obtained from all other methods. The capacity credit for the three regions displayed a consistent trend among the methods. Table 6-3 shows the comparison between the capacity credit value obtained from the GB 2002 demand profile and the IEEE RTS demand profile for 2002 wind data using the retrospective – *Effective Capacity Method*.

| Wind Region | RTS '96 Capacity credit | GB 2002 Capacity credit | % Difference |
|---|---|---|---|
| 1 | 29% | 29% | 0% |
| 2 | 30% | 33% | 10% |
| 3 | 22% | 26% | 18% |

**Table 6-3: Capacity Credit from Effective Capacity Method based on 2002 wind generation data**

Wind Region 1 has the same capacity credit for the two demand profile while Wind Region 3 gives the highest percentage difference. This result shows that difference in the demand profile will have implication on capacity credit value calculated for a wind region. Therefore, capacity credit has to be calculated based on the relevant system demand profile. This means that the contribution of capacity credit from wind generation has to be identified based on the actual system peak demand profile.

The results also show that the capacity credit evaluated for the three regions are higher for the GB 2002 demand profile. It can be summarized that the wind profile is more correlated to the demand profile of the GB 2002 than the IEEE RTS.

# Chapter 7

## DISCUSSION, INTERPRETATION AND CONTRIBUTION

*This chapter discusses and interpret the results obtained from all the modelling and case studies of the project. In addition to that the contribution that this project has done to the ongoing research in the area of intermittency of renewable generations is also discussed. It is hoped that the results of this work can provide another means to conduct generation capacity adequacy evaluation and to evaluate the capacity credit of different wind profile with respect to the generation and load system.*

The discussion of the work done can be divided into different parts, the modelling of the conventional system reliability and evaluations, modelling of the intermittent wind generation, and the case studies.

In the modelling part of the conventional system reliability and evaluations, the modelling of reliability indices from SMST is best simulated using 1MW incremental step as the results obtained would give a more accurate results. In order to reduce the time of simulation, the maximum and minimum margin states of 410 MW and -60 MW are selected and fixed for all simulation runs since the value of interest in the SMST is the first negative margin state, which is -1 MW. With this *System Reliability Evaluation Programme* (SREP), further analysis with integration of intermittent wind renewable energy modelling and other sensitivity analysis could be carried out and evaluated. However, one of the inadequacies of this model is that it does not give any indication of the frequency of the occurrences of insufficient capacity in meeting demand and the duration for which they are likely to occur. Besides, the impact of the capacity shortages cannot be determined.

With the potential high growth of wind generation compared to other types of intermittent renewables in the UK, it was decided that intermittent wind generation will be the focus of this study and different factors of wind characteristics that impacts the reliability of electricity system will be analysed. In the modelling of wind, 3 sets of wind data were used from 3 different regions in Scotland. These data are the actual hourly power output of wind farms and the data are net off planned and forced outages of individual wind generators, the effect of array efficiency and other technical and operational efficiencies. The load-modifier modelling approach although looked simple and straightforward, has its advantages and disadvantages. The advantages are that it takes into account the effect of the time (diurnal and seasonal) variation of wind across the three regions and matching the wind power availability to the occurrence of peak demand. The disadvantages of this method are that it does not take into account the probability of the occurrence of wind and assumes wind will be available at the particular hour. Besides, by using only one year hourly chronological wind power output data in the modelling, it is assumed that there is no inter-annual variation of wind. This means that the wind profile and demand profile is assumed to be the same for all the year of study.

In the evaluation of capacity credit, it was found that the capacity factor gives an inconsistent approximation of the capacity credit. Figure 7-1 which is the same as Figure 5-5 in Chapter 5 shows that the capacity factor of Wind Region 1 and 2 gives a close first hand approximation of the capacity credit but over estimated the capacity credit for Wind Region 3. It is also found that the capacity factor did not give a consistent trend of estimating the capacity credit of the wind regions as compared to the other methods. Comparing to the capacity credit evaluated from the Reliability Curve Method, the capacity factor is lower for wind in Region 1, almost similar for wind in Region 2 and much higher for wind in Region 3. The other three methods give a consistent trend of capacity credit where the Reliability Curve Method will give a slightly optimistic upper value while the Firm Capacity Method is a little pessimistic by giving the lowest capacity credit value due to the comparison to the *ideal and perfectly reliable unit*.

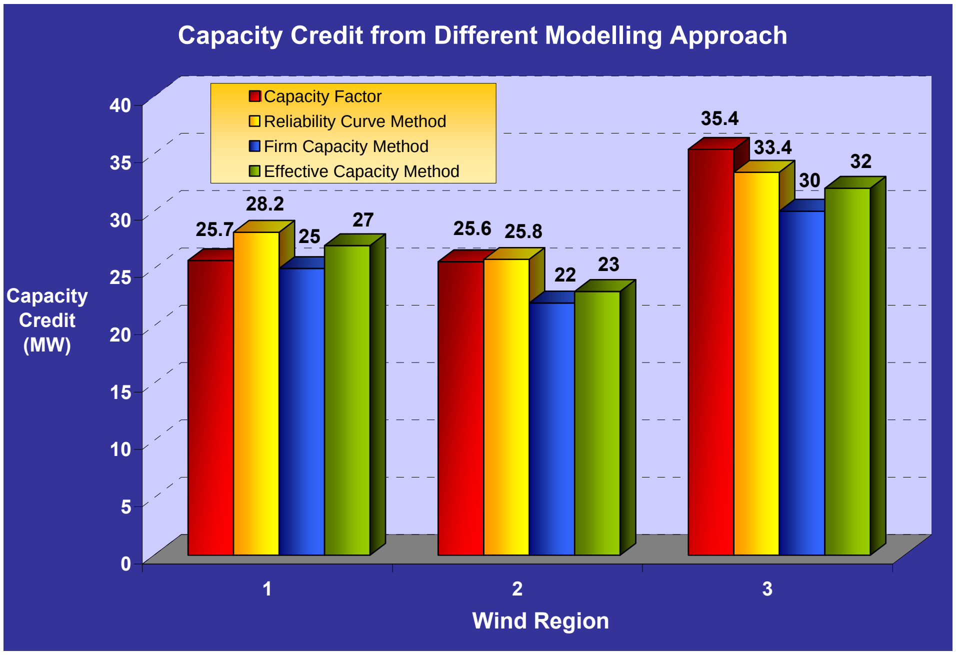


**Figure 7-1: Capacity credit from different modelling approach**

Among all the four methods, the *Effective Capacity Method* gives the value closest to the average capacity credit and therefore is recommended to be used for future generation capacity adequacy study with intermittent wind generation.

Turning to the case study of wind penetration effect on system reliability, it is observed that the rate of system reliability improvement is nonlinear, showing that system reliability does not improve with respect to wind generation capacity addition. Besides, after about 30% of penetration level, there will not be much improvement in system reliability. This means that even if investments are made to install more wind generators and wind farms to cater for the capacity and reserve requirements with 30% of wind generation capacity already in the system, the system reliability or the loss of load expectation in this case will not be improved further. This will give the system planner a clear indication for proposing other power generation resources to meet demand and system reliability.

Besides being intermittent, wind resources are diffused in nature. In the case study on diversity effect on system reliability, it is observed that by distributing the same amount of wind capacity among Region 1 and Region 2, the effective system reliability is equal to the reliability brought about by the lower individual region reliability (Region 1 at 5% penetration level) or better for higher penetration level. This trend of system reliability improvement is similar to that of the individual regions, but the system reliability improvement is clear with the added diversity effect. This means that while having more wind farms and thus capacity can improve system reliability, the location of the wind farms and the distance between them can make a difference to the amount of reliability contribution to the system. Besides, in the same case study, it is observed that the capacity credit of the combined regions fall between the capacity credit of the individual regions. This shows that with the introduction of diversity, the capacity credit obtained will be somewhat better than the average of the capacity credit obtained from individual regions; higher than the lower regions but lower than the higher ones. The advantage of the diversity is that it improves the capacity credit contribution of the lower region but penalise on the capacity contribution from the higher region.

Following the two case studies, the third case study looks at the effect of inter-annual variation of wind power output. By using wind data of different years, this case study was conducted to analyse the effect of inter-annual variation using wind generation data of the same location. It is observed that there is a high variation of wind resources in Region 3. The capacity credit value evaluated from the 2002 wind generation capacity data is higher than for the 2001 value for Wind Region 1 and 2. It is the other way around for Wind Region 3. The region with the highest wind capacity potential in year 2001 becomes one of the lowest among the three in 2002. This variation occurs for a number of reasons and one of the main reasons is because LOLE measures are weighted heavily on the peak hours of the year, and if full wind power output is attained during the peak hours for a given year, wind will compare favourably with its alternative. On the other hand, if in another year wind power output is low during system peak times, LOLE based measure will find wind much less favourable, and thus giving a lower value for the capacity credit.

The inter-annual variation of wind power output makes it a challenge to accurately predict the capacity credit of a wind region, especially when using methods that model the wind plant as a load-modifier. Therefore, in order to accurately assess the capacity credit of a wind region, more years of hourly wind data need to be modelled or as suggested by Milligan (2005), using some other form of repeated sampling of the wind probability distribution.

The time of occurrence of the peak demand is crucial in the study of using intermittent wind generation to meet the peak demand. This is especially true when the hourly chronological wind power output is modelled as a load modifier in the retrospective approach. In the GB demand profile and capacity credit case study, it is observed that the capacity factor of the three wind regions give a lower value than the capacity credit obtained from all other methods. With the use of the GB demand profile and the same wind generation profile, the capacity credit in Region 3 is 18% above the capacity credit obtained from the IEEE RTS demand profile. This shows that the peak demand in the GB demand profile does correlate better with the Region 3 wind power output pattern than when using the IEEE RTS demand profile. Wind Region 1 has the same capacity credit for the two demand profile. These results show that demand profile will have implication on capacity credit value calculated for a wind region. Therefore, capacity credit has to be calculated based on the relevant system demand profile. This means that the contribution of capacity credit from wind generation has to be identified based on the actual system peak demand profile.

The results also show that the capacity credit evaluated for the three regions are higher for the GB 2002 demand profile. It can be summarized that the wind profile is more correlated to the demand profile of the GB 2002 than the IEEE RTS.

There are a few important assumptions to note where the modelling and case studies did not take into considerations. The frequency of the loss of load in the reliability evaluations is not calculated due to errors occurring in the algorithm while establishing the COPT. However, the frequency of a load loss does not affect the results on the system reliability and the capacity credit evaluated for the wind generations. It will, however, if available, give another good reliability measure when evaluating the wind generation system reliability.

Derated states and the segregation of peaking and base load unit model are not considered when modelling the conventional generation system and the generation model is limited to the 2-state unit. These assumptions simplify the modelling process and provide a shorter simulation time for calculating the reliability indices. However, if the derated states are modelled and considered for the conventional generation systems, the use of another wind generation modelling approach (Prospective approach where wind plants are modelled with a capacity and an effective FOR) can be easily adopted and the results obtained could be compared with the current results.

It must be noted that the IEEE RTS data used are generic and does not depict any typical countries or electricity systems. Each system, for example the GB electricity system is unique and has its own characteristics. The reliability level required will also be different considering the size, composition and the profile of the system demand and supply. With that, the capacity credit obtained for the wind regions are not representative to the actual capacity contribution to the GB system. However, Case Study 4 in Chapter 6 introduces the load profile of the GB system to study the differences with load profile. Further study need to be conducted with actual GB system demand profile and the existing generating units and the available wind generation.

Even though some of the results in this study has been mentioned and concluded in other literatures, this work provides another reference and supporting document for generation system planners in choosing a suitable evaluation methodology when considering intermittent renewable wind generation. It is sufficient to mention that this project has contributed to the ongoing research on the study of intermittency of renewable generation particularly wind generation and capacity credit for the UK.

# Chapter 8

## CONCLUSION

*This final chapter provides a summary and conclusion of the work done in the evaluation of intermittent generation effect on system reliability and provides a list of suggested further work that can be carried out, building on the foundation that this work has laid down.*

### *8.1 Summary*

Generation system reliability is an important aspect of planning for the future development of the electricity system. Reliability evaluation methodologies for conventional generation systems which encompassed large and reliable fossil-fuel units have been developed and matured over many decades. Most if not all utilities in the world have operated successfully and reliably with the use of these methods. With the hype and focus turning to renewable energy generation and with many plants expected to be commissioned in the coming decades, there are concerns that the intermittent nature of renewable resources will have a huge impact on the system reliability.

The aim of this research is to analyse and look into the effect of intermittent renewable generation, especially wind, on system reliability and determine how much capacity credit that wind can carry.

In this project, a generation system reliability model and calculation tool was developed using MS Excel and the Visual Basic Editor. The tool was used to evaluate the reliability of conventional generation systems based on the analytical method and was referred to as the System Reliability Evaluation Programme (SREP) in the thesis. Data from the IEEE Reliability Test System '96 was used in the system modelling so that evaluation of the SREP could be carried out. The SREP was evaluated and the results obtained were compared with other references. These were discussed and presented in Chapter 4.

The next part of the project was to include the model for intermittent renewable generation into the SREP so that reliability analysis could be conducted. Wind generation was chosen because of the promising future it has in the UK and due to the time constraint of the project, other renewables were not included in the study. Wind data obtained from various wind farms across Scotland was used and modelled using three selected approaches; two approaches based on retrospective analysis – Firm Capacity Method/ELCC and Effective Capacity Method, and the Reliability Curve Method. These approaches modelled the wind data as load-modifier and the capacity credit obtained from every methods were compared with the wind capacity factor as another approximation method of capacity credit. The comparisons were presented and discussed in Section 5.6. The three modelling approaches were compared and the retrospective analysis – Effective Capacity Method was proposed to be used as the main evaluation method for generation capacity adequacy planning because it gives a better understanding and representation of the capacity credit. The capacity credit obtained from this method portrays the amount of capacity that can be contributed by the wind generation that could provide the same reliability level as a conventional gas turbine plant with a 4% forced outage rate.

In summary, it can be concluded that the rate of system reliability improvement is nonlinear to wind generation capacity addition or wind penetration. This means that there will be a saturation point where having a higher amount of wind generation in the system will not provide added reliability to the system. When this happens, system planners should look to other alternative generation sources for reliability improvement.

Besides, the dispersed nature of wind provides a good reason and incentive for wind farms to be installed at different locations with varying wind profiles. This is because diversity will provide added improvement on system reliability as observed from the results of Case Study 2 in Chapter 6. Developers always want to build their wind farms in regions that will offer a high capacity credit and load factor. However, from the system planner point of view, it would be better if the next wind farm is located in another region with a different wind profile, which will provide an added improvement to system reliability. This diversity effect can provide an avenue for identifying and giving incentives to wind farm developers to build in different regions (even with lower wind resources) so as to benefit from the additional system reliability as a result of diversity.

The results obtained from the study of the effect of inter-annual variation of wind power output in Case Study 3 shows that more years of wind power output need to be analysed to accurately predict the capacity credit of a wind region, especially when using methods that model the wind plant as a load-modifier. This is because the capacity credit depends on the amount of correlations that the wind data had with the peak demand.

This conclusion was further reinforced by evaluating the wind capacity credit with the GB demand profile in Case Study 4 later. The results in the study shows that the time of occurrence of the peak demand is crucial in the study of using intermittent wind generation when using hourly chronological wind power output modelled as a load modifier. These results show that capacity credit has to be calculated based on the relevant system demand profile and will be different if the demand profile changes.

## *8.2 Further work*

This research was started with the intention of providing a means to quantify the reliability of intermittent renewables in the future GB electricity generation system. The idea was to develop reliability models for the four emerging intermittent renewable generation sources, namely wind, solar, wave and tidal stream and to use the models to evaluate the reliability of the future GB electricity industry scenarios. However, this ambitious plan was not realised due to the time constraint as well as the amount of modelling work and evaluations that need to be carried out to ensure the credibility of the results. Nevertheless, this thesis has provided a foundation and starting point to the initial idea. The following further works are suggested:

1. Development of reliability models for solar, wave and tidal stream generation and to integrate the models into the existing System Reliability Evaluation Programme (SREP)
2. Conduct reliability study using SREP on the GB system by using demand profile and existing generating plants data of the GB system
3. Conduct reliability study using SREP with the other three intermittent generation models for the future electricity industry scenarios in GB and determine the suitable level of reserve margin that provide the same level of system reliability
4. Use of other more advanced wind modelling approaches in verifying the capacity credit results (e.g. Prospective approach – EFOR, Sliding window approach and Sequential Monte Carlo technique)
5. Conduct economic or system cost evaluations on the additional reserves needed with high penetration of intermittent renewables

In conclusion, it is hoped that the research conducted in this thesis will provide an added resource in the betterment of the future electricity supply system and the advancement of mankind.

# REFERENCES

Albizzatia, D., G. Rossetti, and O. Alfano. (1997) *Measurements and predictions of solar radiation incident on horizontal surfaces at Santa Fe, Argentina (31± 39'S, 60± 43'W)* Renewable Energy, vol. 11, no. 4, pp. 469-478.

Anderson, D. and Leach, M. (2001) *Intermittency of Generation within Large Energy Systems*, Imperial College of Science, Technology and Medicine, UK.

Amato, U., A. Andretta, B. Bartoli, B. Coluzzi, V. Cuomo, F. Fontana, and C. Serio (1986) *Markov processes and fourier analysis as a tool to describe and simulate daily solar irradiance.* Solar energy, vol. 37, no. 3, pp. 179-194.

Balouktsis, A. and P. Tsalides (1988) *On stochastic simulation of hourly total solar radiation sequences.* International Journal of Energy Systems, vol. 8, no. 3, pp. 1121-1125.

Billinton, R. and Allan, R.N. (1984) *Reliability Evaluation of Power Systems*. New York: Plenum.

Billinton, R. and Allan, R.N. (1996) *Reliability Evaluation of Power Systems*. Plenum Press, New York, NY.

Billinton, R. and Li, W. (1994) *Reliability Assessment of Electric Power Systems Using Monte Carlo Methods*. New York: Plenum.

Billinton, R., Chen, H. and Ghajar, R. (1996) *A Sequential Simulation Technique for Adequacy Evaluation of Generating Systems Including Wind Energy*. IEEE/PES Winter Meeting. Baltimore, Maryland.

Butler, S. (2001) *The nature of UK electricity transmission and distribution networks in an intermittent renewable and embedded electricity generation future*. [Online] Imperial College of Science, Technology and Medicine, Centre for Environmental Technology. In collaboration with Parliamentary Office of Science and Technology (POST).
Available from: http://www.parliament.uk/post/e5.pdf
[cited 14 September 2006]

Chen, H. (2000) *Generating System Reliability Optimization*. [Online] Thesis for the Doctor of Philosophy, University of Saskatchewan, Canada.
Available from : http://library.usask.ca/theses/available/etd-10212004-002514/unrestricted/NQ63854.pdf
[cited 15 August 2006]

DUKES (2005) *Digest of UK Energy Statistics*. Department of Trade and Industry.

Ehnberg, J. (2003) *Generation Reliability for Isolated Power Systems with Solar, Wind and Hydro Generation*. [Online] Thesis for the Degree of Licentiate of Engineering, Chalmers University of Technology. Goteborg, Sweden.
Available from:
http://www.elteknik.chalmers.se/Publikationer/EKS.publ/Abstract/2003/ehnbergLic.pdf
[cited 14 September 2006]

Endrenyi, J. (1978) *Reliability Modelling in Electric Power Systems*. John Wiley & Sons.

Farmer, E. D., Newman, V. G. and Ashmole, P. H. (1980) *Economic and operational implications of a complex of wind-driven power generators on a power system*. IEE Proc A, Vol 127, No 5.

Ford, R. and Milborrow, D. (2005) *Integrating renewables*. British Wind Energy Association.
Available from: http://www.britishwindenergy.co.uk/pdf/RAEIntegrationfinal.pdf
[cited 5 September 2006]

Giorsetto, P. and Utsurogi, K.F. (1983) *Development of a New Procedure for Reliability Modeling of Wind Turbine Generators*. IEEE Transactions on Power Apparatus and Systems. Vol. 102, No. 1. pp. 134- 143.

Gross, R. et al. (2006) *The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generations on the British electricity network*. [Online] UK Energy Research Centre (UKERC).
Available from : http://www.ukerc.ac.uk/content/view/258/852
[cited 15 August 2006]

Grubb, M. with Vigotti, R. (1997) *Renewable Energy Strategies for Europe Volume II: Electricity Systems and Primary Electricity Sources.* The Royal Institute of International Affairs Energy and Environmental Programme, Earthscan Publications Ltd, London.

IEEE RTS Task Force of APM Subcommittee (1999) *The IEEE Reliability Test System – 1996.* IEEE Transactions on Power Systems, Vol. **14**, NO. 3.
Available from:
http://ieeexplore.ieee.org/xpl/freeabs_all.jsp?isnumber=16941&arnumber=780914&type=ref
[cited 15 August 2006]

Imperial College and E4Tech Consulting (2003) *The UK Innovation Systems for New and Renewable Energy Technologies.* [Online] A report to the DTI Renewable Energy Development and Deployment Team.
[cited 14 September 2006]

Khatib, H. (1978) *The Economics of Reliability in Electrical Power Systems*. England: Technicopy Ltd.

Kreith, F. and Ronald E. W. (1997) *CRC Handbook of Energy Efficiency.* CRC Press.

Kueck, J.D. et al. (2004) *Measurement Practices for Reliability and Power Quality – A toolkit of Reliability Measurement Practices*. [Online] Oak Ridge National Laboratory, U.S. Department of Energy. Report No. ORNL/TM-2004/91.
Available from: http://www.ornl.gov/~webworks/cppr/y2001/rpt/122366.pdf
[cited 14 August 2006]

Marnay, C. and Strauss, T. (1989) *Chronological Model Comparison*. Sacramento, California: California Public Utility Commission.

Milborrow, D. J. (1996) *Capacity credits - clarifying the issues*. [Online] British Wind Energy Association, 18th Annual Conference, Exeter, 25-27 September, 1996. MEP Ltd, London
[cited on 12 September 2006]

Milligan, M. (1996a) *Measuring Wind Plant Capacity Value*. [Online] National Renewable Energy Laboratory, U.S. Department of Energy.
Available from:
http://arc.cs.odu.edu:8080/dp9/getrecord/oai_dc/1525835101/oai:dlnet:EE/DLNET-12-30-2002-0111
[cited 16 August 2006]

Milligan, M. (1996b) *Variance Estimates of Wind Plant Capacity Credit*. Wind Power '96. Denver, CO: American Wind Energy Association.
Available from: http://www.nrel.gov/docs/legosti/fy96/21311.pdf
[cited 16 August 2006]

Milligan, M. (2001) *A Sliding Window Technique for Calculating System LOLP Contributions of Wind Power Plants*. [Online] U.S. Department of Energy, National Renewable Energy Laboratory.
Available from: www.nrel.gov/docs/fy01osti/30363.pdf
[cited 14 September 2006]

Milligan, M. and Graham, M. (1997) *An Enumerative Technique for Modelling Wind Power in Production Costing*. 5th International Conference on Probabilistic Methods Applied to Power Systems. Vancouver, BC, Canada: International PMAPS Committee, BC Hydro.
Available from: http://www.nrel.gov/docs/legosti/fy97/22868.pdf
[cited 14 September 2006]

Milligan, M. and Porter, K. (2005) *Determining the Capacity Value of Wind: A Survey of Methods and Implementation*. [Online] Conference Paper: NREL/CP-500-38062. National Renewable Energy Laboratory, U.S. Department of Energy.
Available from: www.nrel.gov/docs/fy05osti/38062.pdf
[cited 15 August 2006]

Mott Macdonald (2003) *Renewables network impact study – Annex 4: intermittency literature survey and roadmap*. The Carbon Trust.

Nedic, Dusko et al. (2005) *Security assessment of future UK electricity scenarios*. [Online] Tyndall Centre Technical Report 30.
Available from: www.tyndall.ac.uk/research/theme2/final_reports/t2_24.pdf
[cited 14 August 2006]

Pillai, N. V. (2002) *Reliability and rationing cost in a power system*. [Online] Centre for Development Studies, Thirivananthapuram, India. Working paper No. 325.
Available from: http://ideas.repec.org/p/ind/cdswpp/325.html
[cited 14 August 2006]

Prada, J. F. (1999) *The Value of Reliability in Power Systems – Pricing Operating Reserves*. [Online] EL99-005 WP. MIT Energy Laboratory.
Available from:
http://lfee.mit.edu/metadot/index.pl?id=2667&isa=Item&field_name=item_attachment_file&op=download_file
[cited 14 August 2006]

Sinden, G. (2005) *Characteristics of the UK wind resource: Long-term patterns and relationship to electricity demand.* [Online] Environmental Change Institute, Oxford University Centre for the Environment.
Available from: http://www.eci.ox.ac.uk/lowercf/renewables/UKWindResource-EnergyPolicyPaper.pdf
[cited 24 August 2006]

Sinden, G. (2005) *Wind power and the UK wind resource*. [Online] The Environmental Change Institute, University of Oxford.
Available from: http://www.eci.ox.ac.uk/renewables/UKWind-Report.pdf
[cited 27 August 2006]

Singh, C. and Gubbala, N.V. (1996) *An alternative approach to rounding off generation models in power system reliability evaluation*. [Online] Electric Power Systems Research. Elsevier B.V. Pub. Volume 36, Number 1, pp. 37-44(8).
Available from:
http://www.sciencedirect.com/science?_ob=MImg&_imagekey=B6V30-3VTSVY2-6-1&_cdi=5716&_user=875629&_orig=search&_coverDate=01%2F31%2F1996&_qd=1&_sk=999639998&view=c&_alid=442246971&_rdoc=1&wchp=dGLzVlz-zSkzS&md5=52e33e8db2f43319957fd0e68753ca6b&ie=/sdarticle.pdf
[cited 1 September 2006]

Southface Energy Institute (n.d.) *Residential PV Options.* [Online]
Available from: http://www.southface.org/solar/solar-roadmap/residential/residential_pv_options.htm
[cited 15 July 2006]

Voorspools, K. R. and D'haeseleer, W. D. (2006) *An analytical formula for the capacity credit of wind power*. [Online] Renewable Energy 31. pp.45–54
Available from: http://www.sciencedirect.com/science?_ob=ArticleURL&_udi=B6V4S-4GC1R8C-2&_coverDate=01%2F31%2F2006&_alid=450333542&_rdoc=1&_fmt=&_orig=search&_qd=1&_cdi=5766&_sort=d&view=c&_acct=C000050221&_version=1&_urlVersion=0&_userid=10&md5=1585acb5f2a81025dac7bfeef417d48f
[cited 15 August 2006]

Wang, X. and McDonald, J. R. (1994) *Modern Power System Planning*. McGraw-Hill International (UK) Ltd.

Wikipedia contributors. *Wind power* [Internet]. Wikipedia, The Free Encyclopedia; 2006 Sep 13, 19:18 UTC.
Available from:
http://en.wikipedia.org/w/index.php?title=Wind_power&oldid=75558339.
[cited 13 September 2006]

Winkelman, J.E. (1992.) *The impact of the Sep wind park near Oosterbierum (Fr.), the Netherlands, on birds*. 4: Disturbance. DLO-Institut voor Bos-en Naluuronderzoek, Arnehem, RIN-rapport 92/5. Cited in Phillips 1994.

## Internet source

Solar Century (n.d.) Available from: www.solarcentury.co.uk

# APPENDIX A

# IEEE RELIABILITY TEST SYSTEM ’96

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

Table A-1: Weekly Peak Load in Percent of Annual Peak

| No. | Day | Peak Load (%) |
|---|---|---|
| 1 | Monday | 93 |
| 2 | Tuesday | 100 |
| 3 | Wednesday | 98 |
| 4 | Thursday | 96 |
| 5 | Friday | 94 |
| 6 | Saturday | 77 |
| 7 | Sunday | 75 |

Table A-2: Daily load in Percent of Weekly Peak

| Time | Hour | Winter weeks 1 - 8 & 44 - 52 | | Summer weeks 18 - 30 | | Spring / fall weeks 9 - 17 & 31 - 43 | |
|---|---|---|---|---|---|---|---|
| | | Wkdy | Wknd | Wkdy | Wknd | Wkdy | Wknd |
| 1 | 12 - 1 am | 67 | 78 | 64 | 74 | 63 | 75 |
| 2 | 1 - 2 am | 63 | 72 | 60 | 70 | 62 | 73 |
| 3 | 2 - 3 am | 60 | 68 | 58 | 66 | 60 | 69 |
| 4 | 3 - 4 am | 59 | 66 | 56 | 65 | 58 | 66 |
| 5 | 4 - 5 am | 59 | 64 | 56 | 64 | 59 | 65 |
| 6 | 5 - 6 am | 60 | 65 | 58 | 62 | 65 | 65 |
| 7 | 6 - 7 am | 74 | 66 | 64 | 62 | 72 | 68 |
| 8 | 7 - 8 am | 86 | 70 | 76 | 66 | 85 | 74 |
| 9 | 8 - 9 am | 95 | 80 | 87 | 81 | 95 | 83 |
| 10 | 9 - 10 am | 96 | 88 | 95 | 86 | 99 | 89 |
| 11 | 10 - 11 am | 96 | 90 | 99 | 91 | 100 | 92 |
| 12 | 11 - noon | 95 | 91 | 100 | 93 | 99 | 94 |
| 13 | Noon - 1 pm | 95 | 90 | 99 | 93 | 93 | 91 |
| 14 | 1 - 2 pm | 95 | 88 | 100 | 92 | 92 | 90 |
| 15 | 2 - 3 pm | 93 | 87 | 100 | 91 | 90 | 90 |
| 16 | 3 - 4 pm | 94 | 87 | 97 | 91 | 88 | 86 |
| 17 | 4 - 5 pm | 99 | 91 | 96 | 92 | 90 | 85 |
| 18 | 5 - 6 pm | 100 | 100 | 96 | 94 | 92 | 88 |
| 19 | 6 - 7 pm | 100 | 99 | 93 | 95 | 96 | 92 |
| 20 | 7 - 8 pm | 96 | 97 | 92 | 95 | 98 | 100 |
| 21 | 8 - 9 pm | 91 | 94 | 92 | 100 | 96 | 97 |
| 22 | 9 - 10 pm | 83 | 92 | 93 | 93 | 90 | 95 |
| 23 | 10 - 11 pm | 73 | 87 | 87 | 88 | 80 | 90 |
| 24 | 11 - 12 am | 63 | 81 | 72 | 80 | 70 | 85 |

Table A-3: Hourly Peak Load in Percent of Daily Peak

| Unit Group | Unit Type | No. of Units | Unit Size, C | Forced Outage Rate, U | MTTF (m=1/λ) | MTTR (r=1/μ) | Scheduled Maintenance |
|---|---|---|---|---|---|---|---|
| | | | (MW) | | (Hour) | (Hour) | Weeks/year |
| U12 | Oil/Steam | 5 | 12 | 0.02 | 2940 | 60 | 2 |
| U20 | Oil/CT | 4 | 20 | 0.10 | 450 | 50 | 2 |
| U50 | Hydro | 6 | 50 | 0.01 | 1980 | 20 | 2 |
| U76 | Coal/Steam | 4 | 76 | 0.02 | 1960 | 40 | 3 |
| U100 | Oil/Steam | 3 | 100 | 0.04 | 1200 | 50 | 3 |
| U155 | Coal/Steam | 4 | 155 | 0.04 | 960 | 40 | 4 |
| U197 | Oil/Steam | 3 | 197 | 0.05 | 950 | 50 | 4 |
| U350 | Coal/Steam | 1 | 350 | 0.08 | 1150 | 100 | 5 |
| U400 | Nuclear | 2 | 400 | 0.12 | 1100 | 150 | 6 |

Table A-4: Generator Reliability Data

# APPENDIX B

# SYSTEM RELIABILITY EVALUATION PROGRAMME (SREP)

```
Sub COPT( )

Sheets("COPT").Select
Range("A10:H5000").ClearContents
SysCap = Sheets("PlantData").Cells(7, 4)
For Row1 = 10 To SysCap + 11
   For Col1 = 4 To 8
      Cells(Row1, Col1) = 0
   Next Col1
Next Row1
Application.ScreenUpdating = False
Dim n, C, U As Double

Step = Sheets("COPT").Cells(5, 3)                ' A certain increment of the outage capacity to be used as step
TotCap = 0

Dim Msg, Style, Title, Response
Msg = "You have chosen " & Step & " step increment." & Chr(13) & "Your calculation is going to take a while." & Chr(13) &
"Do you want to continue?"                       ' Define message.
Style = vbYesNo + vbQuestion + vbDefaultButton2  ' Define buttons.
Title = "Capacity Outage Probability Calculation"   ' Define title.
Response = MsgBox(Msg, Style, Title)

If Response = vbYes Then                         ' User chose Yes.
For i = 11 To Groups + 10
   n = Sheets("PlantData").Cells(i, 4)           ' Assign number of generating units
   C = Sheets("PlantData").Cells(i, 5)           ' Assign generating unit capacity
   U = Sheets("PlantData").Cells(i, 6)           ' Assign forced outage rate
   Sheets("COPT").Select
   For j = 1 To n
       TotCap = TotCap + C
       Pn = 1
       X = 0
      Do While Pn > 0
         Cells(10 + X, 1) = X                    ' To index the states
         Cells(10 + X, 2) = TotCap - X           ' To display the available capacity
         Cells(10 + X, 3) = X                    ' To display the outage capacity
         If Cells(10 + X, 3) = 0 Then
            Cells(10 + X, 4) = 1
         Else
            Cells(10 + X, 4) = Cells(10 + X, 8)
         End If
         Cells(10 + X, 5) = X - C
         If Cells(10 + X, 5) <= 0 Then
            Cells(10 + X, 6) = 1
         Else
            Cells(10 + X, 6) = Application.WorksheetFunction.VLookup(Cells(10 + X, 5), Range("C10:D5000"), 2)
         End If
         Cells(10 + X, 8) = Cells(10 + X, 4) * (1 - U) + Cells(10 + X, 6) * U
         Pn = Sheets("COPT").Cells(10 + X, 8)
         If X = 0 Then
         Else
            Cells(10 + X - 1, 7) = Cells(10 + X - 1, 8) - Cells(10 + X, 8)
         End If
         X = X + Step
     Loop
   Next j
Next i
   Sheets("COPT").Range("A1").Select
   MsgBox ("Well done! " & X - 1 & " capacity outage states are calculated.")

Else                                             ' User chose No.
   MsgBox ("You have terminated the calculation.")
End If

End Sub
```

Table B-1: Calculation algorithm for *Capacity Outage Probability Table* (*COPT*)

```
Sub Margin( )

Sheets("COPT").Select
Application.ScreenUpdating = False
Step = Sheets("COPT").Cells(5, 12)                    ' Step increment for margin states
Nb = Sheets("COPT").Cells(6, 12)                      ' Number of load states with capacity > 0
Nk = Sheets("COPT").Cells(7, 12)                      ' Maximum margin state
Np = Sheets("COPT").Cells(8, 12)                      ' Mininum margin state
MaxC = Sheets("COPT").Cells(10, 2)
Dim pLj, Lj, Ljd, pLjd, Ljm, Ljmd, PXj, PXjd As Double
Cells(21, 23) = 0
Cells(24, 23) = 0
Range("J10:P5000").ClearContents

For k = 1 To (Nk - Np + 1) / Step                     ' Iterate for all margin states with step increment

  Cells(k + 9, 10) = k – 1                            ' For the first column, to specify margin states

  If k = 1 Then                                       ' For the second column, to specify margin
    Cells(k + 9, 11) = Nk
  Else
    Cells(k + 9, 11) = Cells(k + 8, 11) - Step
  End If
  Cells(k + 9, 12) = 0
  Cells(k + 9, 13) = 0

  For j = 0 To Nb                                     ' For the third column, to calculate margin cumulative probability
    Lj = Sheets("LoadData").Cells(917 + j, 3) * Sheets("LoadData").Cells(914, 4)
    Ljd = Sheets("LoadData").Cells(917 + j, 12) * Sheets("LoadData").Cells(914, 4)
    pLj = Sheets("LoadData").Cells(917 + j, 5)
    pLjd = Sheets("LoadData").Cells(917 + j, 14)
    Ljm = CInt(Sheets("COPT").Cells(k + 9, 11) + Lj)
    Ljmd = CInt(Sheets("COPT").Cells(k + 9, 11) + Ljd)

    If Ljm > MaxC Then
      PXj = 0
    ElseIf Ljm < 0 Then
      PXj = 0
    Else
      PXj = Application.WorksheetFunction.VLookup(Ljm, Range("B10:H5000"), 7, False)
    End If

    If Ljmd > MaxC Then
      PXjd = 0
    ElseIf Ljmd < 0 Then
      PXjd = 0
    Else
      PXjd = Application.WorksheetFunction.VLookup(Ljmd, Range("B10:H5000"), 7, False)
    End If

    Cells(k + 9, 12) = Cells(k + 9, 12) + (pLj * PXj)
    Cells(k + 9, 13) = Cells(k + 9, 13) + (pLjd * PXjd)

  Next j
  Cells(k + 9, 14) = Cells(k + 9, 11) / Cells(6, 15)  ' For the fifth column, to calculate margin in % of Peak
  Cells(21, 23) = Cells(21, 23) + Cells(k + 9, 16) * 365
  Cells(24, 23) = Cells(24, 23) + Cells(k + 9, 15) * 8736

Next k

  Cells(20, 23) = Application.WorksheetFunction.VLookup(-Step, Range("K10:M5000"), 3, False) ' For LOLP in days per year
  Cells(23, 23) = Application.WorksheetFunction.VLookup(-Step, Range("K10:L5000"), 2, False) ' For LOLP in hours per year
  Call LOLE
  MsgBox ("" & k - 1 & " margin states calculated")

End Sub
```

Table B-2: Calculation algorithm for *System Margin State Table* (*SMST*)

```
Sub LOLE( )

Sheets("COPT").Select
Dim LOLE, P, CjLj, LOLEh, Ph, CjLjh
LOLE = 0
LOLEh = 0

For i = 0 To 100

    ' Calculate LOLE in days per year
    CjLj = Sheets("COPT").Cells(10, 2) - Sheets("LoadData").Cells(917 + i, 12) * Sheets("LoadData").Cells(914, 4)
    P = Application.WorksheetFunction.VLookup(CjLj, Range("C10:H5000"), 6) ' Search 5000 lines below
    LOLE = LOLE + Sheets("LoadData").Cells(917 + i, 13) * P

    ' Calculate LOLE in hours per year
    CjLjh = Sheets("COPT").Cells(10, 2) - Sheets("LoadData").Cells(917 + i, 3) * Sheets("LoadData").Cells(914, 4)
    Ph = Application.WorksheetFunction.VLookup(CjLjh, Range("C10:H5000"), 6) ' Search 5000 lines below
    LOLEh = LOLEh + Sheets("LoadData").Cells(917 + i, 4) * Ph

Next i

Cells(11, 23) = LOLE
Cells(14, 23) = LOLEh

End Sub
```

Table B-3: Calculation algorithm for *LOLE using formula*

```
Sub COPTident( )

Sheets("COPTi").Select
k = Cells(5, 3) + 1
Range("A10:D1000").ClearContents
factn = Application.WorksheetFunction.fact(Cells(5, 3))

For i = 1 To k

    Cells(i + 9, 1) = i - 1
    Cells(i + 9, 2) = Cells(6, 3) * (i - 1)

    Pb = Cells(7, 3) ^ (i - 1) * (1 - Cells(7, 3)) ^ (Cells(5, 3) - i + 1)

    If i = 1 Then
        Cells(i + 9, 3) = Pb
    ElseIf i = k Then
        Cells(i + 9, 3) = Pb
        MsgBox "Your calculation has been completed successfully!"
    Else
        factk = Application.WorksheetFunction.fact(i - 1)
        factn_k = Application.WorksheetFunction.fact(Cells(5, 3) - i + 1)
        Cells(i + 9, 3) = Pb * (factn / (factk * factn_k))
    End If

Next i

For j = 1 To k
    Cells(10 + k - j, 4) = Cells(10 + k - j, 3) + Cells(11 + k - j, 4)
Next j

End Sub
```

Table B-4: Calculation algorithm for *identical units' Capacity Outage Probability Table*