Future Great Britain Generation System Reliability Evaluations in the Presence of Intermittent Renewables

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Copyright Declaration

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LIST OF ABBREVIATIONS

AWR	Advanced Gas-Cooled Reactor
BETTA	British Electricity Trading and Transmission Arrangements
BMRA	Balancing Mechanism Reporting Agent
CCGT	Combine Cycle Gas Turbine
GB	Great Britain (England, Scotland and Wales)
GBSREP	Great Britain System Reliability Evaluation Programme
GW	Gigawatt (10^9 W)
MW	Megawatt (10^6 W)
OCGT	Open Cycle Gas Turbine
PWR	Pressurised Water Reactor
SREP	System Reliability Evaluation Programme
SYS2007	Seven Year Statement 2007

Abstract

One of the key elements of generation expansion planning in any electricity system, the GB system inclusive, is system reliability. Various methods and indices have been established to evaluate this particular criterion in the past for the conventional generation technologies. Nevertheless, rising concern on exhaustible fossil fuels, increase in oil prices and the environmental impact of fossil fuel generation has led to the introduction and integration of renewable generations, especially wind generation, into the system. Unfortunately, unlike fossil fuels, renewable resources, namely wind, solar, wave and tidal energy, are variable and in the case of wind, unpredictable. This variability of renewables is known as intermittency. As a result, new means of evaluating future system reliability have to be developed in order to incorporate the intermittency of the renewable resources.

Hence, to investigate the system reliability in the presence of intermittent renewable generation, a model based on the analytical reliability assessment method is developed using MS Excel and the Visual Basic Editor. This model is referred to as the Great Britain System Reliability Evaluation Programme or GBSREP throughout this thesis. GBSREP is the customised and improved model of System Reliability Evaluation Programme (SREP), which was developed for a thesis, entitled Generation System Reliability Evaluations with Intermittent Renewables (Phoon, 2006). The same thesis is used as the starting point and foundation to this research.

The SREP model was developed using data from the IEEE Reliability Test System '96, which has a peak demand of 2850 MW and generation capacity of 3431 MW only. Meanwhile, the GBSREP is tailored to the GB system with peak demand of approximately 60GW and supplied through a generation capacity of around 78 GW, inclusive of imports through interconnectors. Due to time constraint, limitation of data and present GB system, only wind generation is modelled. In GBSREP wind generation is modelled as a load-modifier for all case studies.

Four case studies were carried out on the present GB electricity system to study the effect of interconnection with external systems, diversity of wind generation capacity and geographical location and plant availabilities on the system reliability. Two more case studies were also conducted to evaluate the future GB system reliability under various generation mix scenarios, which includes intermittent wind generation.

Generally, this project is meant to contribute to the ongoing research on the study of intermittent renewable generation, in particular wind generation, in the UK. Meanwhile, specifically, results and findings of this research is intended to be a source of reference for generation system planners in determining the most suitable generation mix in the future GB system and also other studies of similar nature.

Chapter 1 Introduction

Ever since its discovery, electricity has evolved from being a luxury to an integral part of the various aspects of daily lives. Absence or even a glitch in electricity supply spells chaos and monetary loss. Therefore, it is vital to ensure a reliable supply at all times. Nevertheless, making sure that the lights are on round the clock can be quite tricky due to the unique physical properties of electricity. According to Stoft (2002), electricity can only be stored in the system for less than a tenth of a second. As a result, supply must be consumed as soon as it is produced and hence, generated there and then whenever there is demand. In order to materialise a reliable supply, a reliable electric system must first be established. Thus, studies on system reliability are an absolute essential when it comes to planning, designing and operating a power system.

Due to the complexity of the electric system, the system is divided into functional areas namely generation, transmission and distribution. Reliability of each functional area is usually analysed separately for more thorough evaluation and eventually combined to produce the system reliability. However, it is the intention of this thesis to only focus on the generation reliability.

In GB, the generation system is formed by a combination of various conventional generation technologies such as thermal plants, Combine Cycle Gas Turbines (CCGTs), nuclear reactors, and coal plants as base load plants and Open Cycle Gas Turbines (OCGTs), hydro and pumped storage as intermediate and peaking plants. The generation is also supported through two interconnections, which are the French and Moyle Interconnector. To date, this recipe has proven to be extremely dependable provided there are no interruptions to the fuel supply.

Nevertheless, global concern on the issue of exhaustible fossil fuel, rising oil prices, and the effect of hazardous greenhouse gasses emitted by the conventional plants on the environment, with exception of hydro and pumped storage, has propelled the switch to more environmental friendly methods of generation. Renewable generation meets this criterion as it fully utilises the natural undepletable resources such as wind, tidal and solar, while at the same time produces clean energy. Although the renewable generation cost is still higher relative to conventional plants, it is becoming more cost competitive as the technology matures. As a result, recent years have born witness to the emergence and integration of these renewables into the GB system.

Furthermore, in 1997, under the Kyoto Protocol, the UK government has accepted a legally binding target to reduce greenhouse gas emissions by 12.5 percent by 2008-2012, as compared to its 1990 levels. For this purpose, the UK government has set a target of 20 percent reduction in carbon dioxide (CO_2) by 2010, relative to emissions in 1990. In order to achieve further reductions, the Government has drafted a ‘Climate Change Programme’. A key policy of this programme is the ‘Renewables Obligation’. This particular policy aimed to produce 10 percent of the UK's electricity from renewable sources by 2010 (Butler, 2001a).

Looking at GB alone, in 2006/07, renewables accounts for 2.3 percent of total electricity generated. 97.5 percent of this portion is contributed by wind generation. Renewable generation penetration in the GB electricity system is expected to grow rapidly over the next fifty years and this forms the underlying assumption to this thesis.

However, renewable generations have some setbacks. Despite the abundance and inexhaustible fuel sources, the sources are variable and this is known as intermittency. Being intermittent, renewable generation may not be available when there is demand and more importantly, maximum availability of renewable resources does not coincide with the system peak demand. Fortunately, availability tidal sources are predictable. Wave and wind availability on the other hand is unpredictable. Yet, wind generation is the most mature technology and fastest growing in the GB system due to the high potential especially in Scotland. In fact, wind generation is expected to play a key role to achieve the 2010/2020 targets for renewable generation (Nedic et. al, 2005).

At lower penetration of wind generation, the effect of the intermittency is minimal. Nevertheless as more wind generation is integrated into the system, the impact on system reliability becomes more significant. Hence, incorporating generation system reliability study in future generation expansion planning is very important as it is the key component in the supply and demand equation. Usually, generation reliability is evaluated using various reliability indices such as loss of load or energy, obtained through probabilistic method. The outcome is then used to assist in the daily operation in the short term and provides input for investments in building new generation capacities.

This thesis investigates the present and future reliability of GB generation system in the presence of intermittent renewables. Due to time constraints and lack of credible data for other renewable energy sources, the analysis in this thesis is limited to integration of wind energy only. Several sensitivity analyses are carried out on the present GB electricity system to assist in understanding the effect of different factors such as plant availability, diversity of wind farm geographical location and the importance of interconnections on the reliability of the system. Meanwhile, the evaluation of future GB electricity systems is carried out to obtain a general outlook on the system reliability under different generation mix scenarios.

1.1 Project Aims

The project aims to study and evaluate the impact of higher penetration levels of intermittent renewables on system reliability. For this purpose, the project looks at the current and future generation system reliability of Great Britain. It is hoped that the findings and tools developed for this project would be useful in any future study pertaining to generation capacity expansion involving intermittent renewables.

1.2 Specific Project Objectives

A number of tasks are required to address the aims of the thesis. Therefore, the objectives of this thesis are to:-

1. Adapt and improve the System Reliability Evaluation Programme (SREP) to carry out study with Great Britain profiles.
2. Establish and incorporate current load and generation profiles for Great Britain into the system reliability evaluation tool.
3. To use the modified evaluation tool to examine the effect of interconnections with external systems, geographical location of wind farm and conventional plant availability on GB system reliability.
4. To study system reliability under the future Great Britain generation scenarios.

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1.3 Structure of the Thesis

Following this introduction, the thesis is structured as follows:

Chapter 2 provides the necessary background of the GB electric system to assist in understanding the remainder of the thesis. This chapter starts with an overview of the GB electric system. Then there are three sections which focus on the existing GB load demand and generation capacity. The final section looks at the future system as outlined in the Seven Year Statement 2006/07 by National Grid.

In Chapter 3, background material regarding generation reliability assessment is covered. The two main focuses of this chapter are the reliability models for conventional and intermittent renewable generation available in the literature. Nevertheless, as only wind generation is modelled into the reliability model developed for this study, no modelling material is covered for other intermittent generation technologies.

Chapter 4 details the methodology and main assumptions adopted in conducting the generation system reliability evaluation. This chapter also discusses the type of data required for the analysis and the sources for the data.

Chapter 5 explains the application of the reliability methodology in building the evaluation tool. It also describes the customisation of the models to represent the GB electric system. The computer model developed to calculate the reliability indices is also discussed in this chapter.

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Chapter 6 is a collection of case studies whereby the description of the different case studies together with the assumptions is elaborated. Results and findings of the sensitivity analysis and different scenarios are also presented in this chapter.

Chapter 7 is dedicated to discussions and interpretation of results obtained through the various case studies and how they contribute to the study of intermittency in system reliability evaluations.

Chapter 8 summarises the salient findings and concludes the whole thesis. In addition, this chapter also reviews the project aims and objectives and comment on the achievements of the project. The chapter ends with observations and recommendations for further work that could and should be carried out to enhance the findings of this project.

Chapter 2 GB Electric System

This chapter aims to assist readers in understanding the thesis by giving sufficient information on one of the two main aspects of the thesis which is the Great Britain (GB) electric system. First, an overview of the existing system is given followed by description of the load and generating capacity of the GB electric system presently and in the future so that the characteristics and size of the system can be appreciated.

2.1 Overview

The GB electricity system is a very large and complex system. Functionally, the system can be divided into three zones, which are generation, transmission and distribution Electricity is generated at the power stations at low voltages and then stepped up to high voltages of 400kV, 275kV and 132kV to be transmitted via transmission lines or underground cables.

Power is transmitted at high voltages to reduce losses during the transmission over long transmission lines. Before power is supplied to the customers, the voltages are stepped down back progressively to 33kV, 11 kV and eventually 240V. Transmission of power is carried out using Alternating Current (AC) system with the frequency of supply used in GB is 50 Hz. A typical GB power system is illustrated by Figure 1 (Cruden, 2003).

Meanwhile on a national basis, GB is connected to continental Europe via a high voltage direct current (HVDC) link to France and another to Northern Ireland. HVDC is adopted for connections between the different systems as HVDC commonly improves power flow control, no requirement to synchronise the systems and it is also more economical to transmit power over large distances or via subsea cables using HVDC.

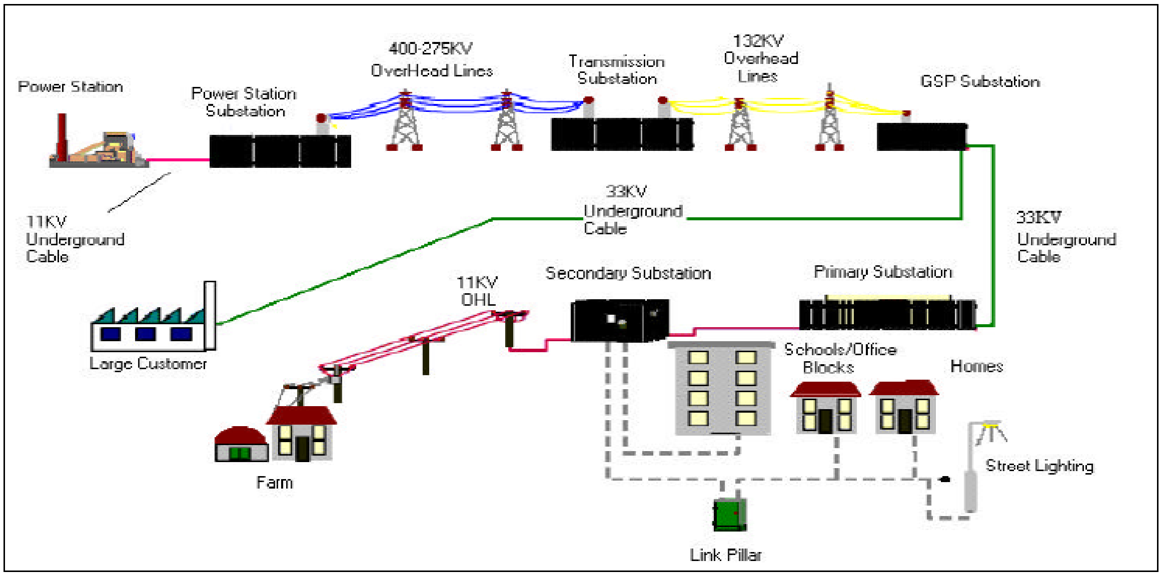


Figure 1 - Typical GB Power System Configuration

Presently, the GB electricity system is operated in a free market concept overseen by Ofgem, the government regulator. Effective 1 April 2005, British Electricity Trading and Transmission Arrangements (BETTA) was introduced to the system. Under BETTA, National Grid is given the role as Great Britain System Operator (GBSO). As GBSO, National Grid do not only owns and maintains the high voltage electricity transmission system in England and Wales, but also operates the system across GB by balancing supply with demand on minute by minute basis (National Grid, 2007).

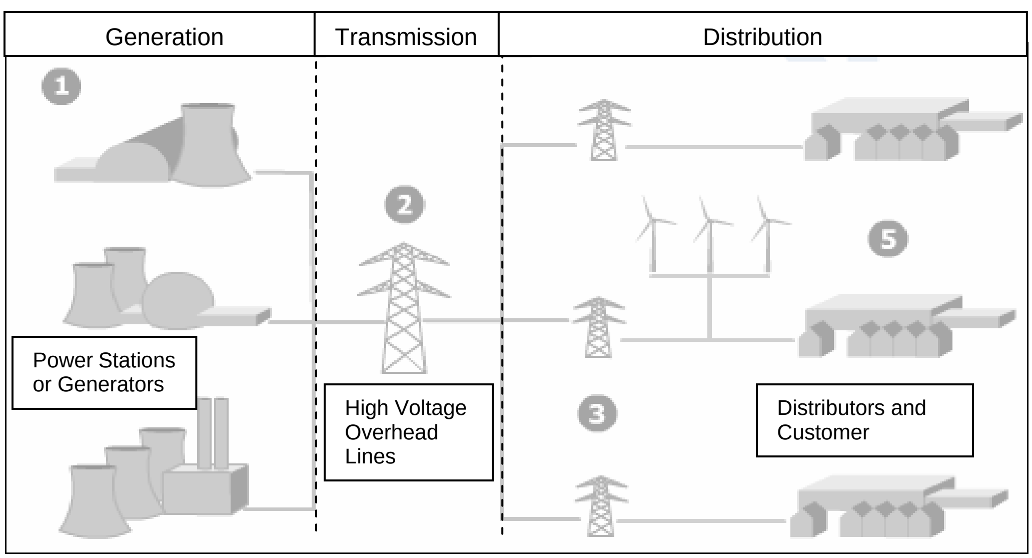
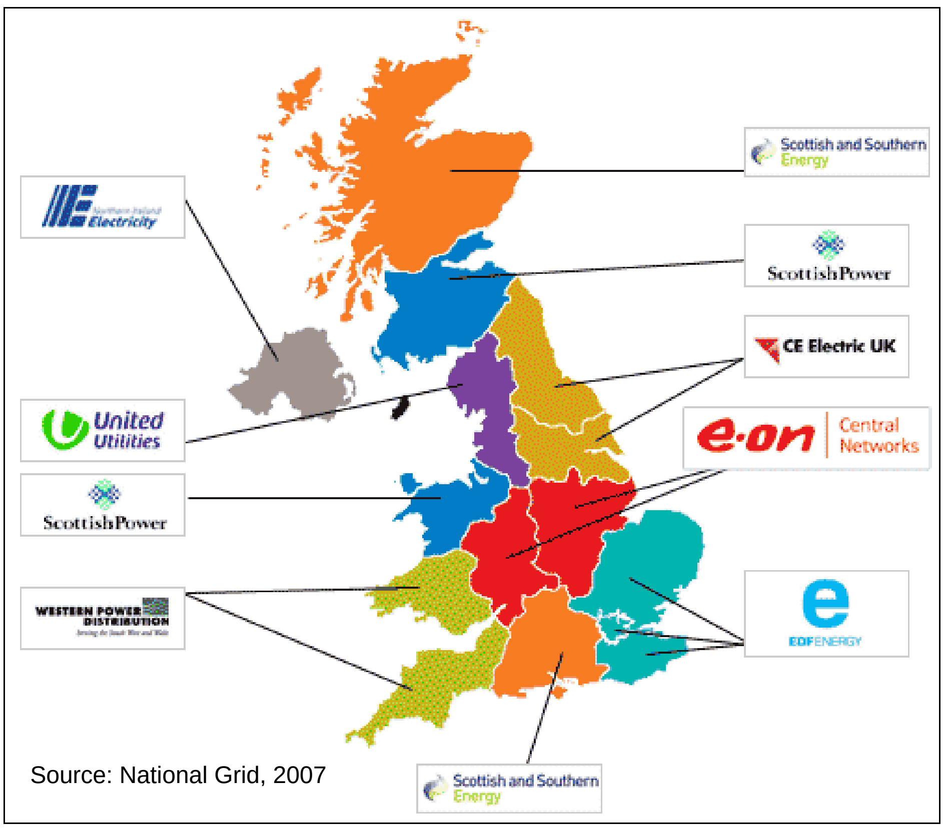


Figure 2 - Generation, Transmission and Distribution Zones in Electric System

Basically, the system consists of five main components as shown in Figure 2 (BWEA, 2007). They are:

1. Generators
2. The National Grid
3. Distribution companies
4. Supply companies
5. Consumers

The main stakeholders in the electricity industry however are only the generators, distributors and suppliers. The generators are responsible for generating power and feeding it into the National Transmission Network to meet the system electricity demand. Meanwhile, the distributors are the owner and operators of towers and cables that brings electricity from the National Transmission Network to the customers.



Source: National Grid, 2007

Figure 3 - Electricity Distributor Companies in GB

However, the end users do not buy electricity from the distributors (National Grid, 2007). Instead, electricity is supplied by the suppliers. Hence, suppliers are not shown in Figure 2.2 as the supply companies do not own towers or generators, they only buy and sell electricity (BWEA, 2007). Figure 3 shows the different distributors in different parts of GB and Table 1 lists the companies according to the area (National Grid, 2007).

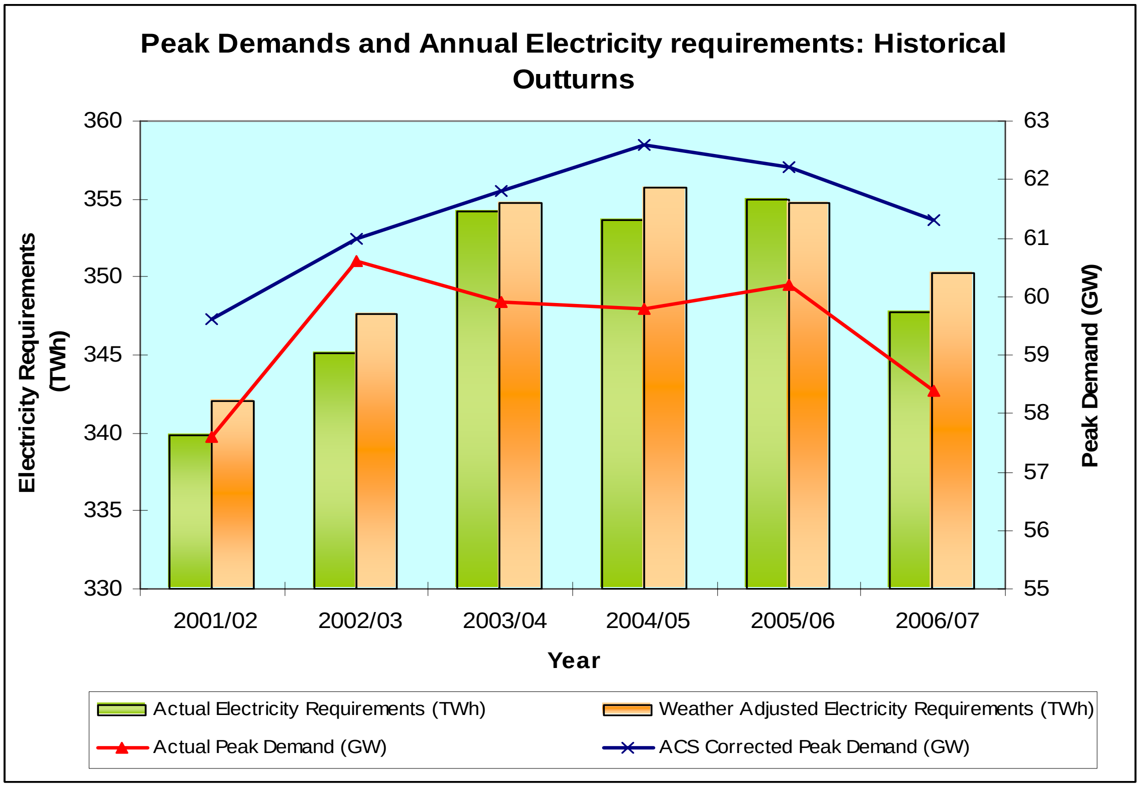
Area	Company
North Scotland	SSE Power Distribution
South Scotland	SP Power Systems
North East England	CE Electric (NEDL)
North West	United Utilities
Yorkshire	CE Electric (YEDL)
East Midlands	Central Networks
West Midlands	Central Networks
Eastern England	EDF Energy
South Wales	Western Power Distribution
Southern England	SSE Power Distribution
London	EDF Energy
South East England	EDF Energy
South West England	Western Power Distribution
North Wales, Merseyside and Cheshire	SP Manweb

Table 1 - Electricity distributor companies in GB according to area

2.2 GB Electricity Demand

As a developed country, GB has been observing a steady electricity demand for the past five years, from year 2001/02 to 2006/07. The electricity demand for GB within this period fluctuated between 57GW and 61GW as shown in Graph 1. In 2001/02, GB recorded a peak demand of 57.6GW. The GB peak demand then increased by 5.2 percent to 60.6 GW in the following year, which is the highest peak demand recorded in the five year period. The next couple of years witnessed a decline in peak demand. GB peak demand in 2003/04 is only 59.9 GW, a decrease of 0.7 GW from the previous year. Meanwhile, the peak demand in 2004/05 dropped by a further 0.2 percent to 59.8 GW.

Year 2005/06 saw a slight increase of 0.7 percent in peak demand, resulting in peak demand of 60.2GW. However, GB peak demand dropped again in 2006/07 to 58.4 GW.



Graph 1 - GB annual historical peak demands and electricity requirements

Peak demand gives a good overview of the existing GB electricity demand and hence the generation capacity requirement to meet the highest demand. Nevertheless, another indication of the electricity consumption in GB can be obtained from the annual electricity requirements. Contrary to the peak demand, which is only a snapshot of the system at its peak, the electricity requirement is in a way more representative of the system demand as it is the total energy used throughout the year. Hence, it is not surprising when the observed trend for the electricity requirements differs slightly from that of the peak demand.

Unlike the peak demand, the electricity requirement for GB has rose steadily from 2001/02 to 2003/04 with average growth rate of 2.1 percent per annum from 339.9 TWh to 354.2 TWh as shown in Table 2. The GB electricity consumption then remained constantly high at about 355TWh before experiencing a sudden drop of 2.1 percent to about 348 TWh in 2006/07, consistent with the recorded peak demand for the respective year.

Year	Actual Peak Demand (GW)	% Change in Actual Peak Demand	Actual Electricity Requirements (TWh)	% Change in Actual Electricity Requirements
2001/02	57.6	-	339.9	-
2002/03	60.6	5.2%	345.1	1.5%
2003/04	59.9	-1.2%	354.2	2.6%
2004/05	59.8	-0.2%	353.7	-0.1%
2005/06	60.2	0.7%	355.0	0.4%
2006/07	58.4	-3.0%	347.7	-2.1%

Table 2 - Annual historical peak demands and electricity requirements

Typically, peak demand occurs during winter period where heating load is at its height. This indicates that the recorded peak demand is highly influenced by the weather conditions. Hence, weather is a key factor in determining the energy demand. Unfortunately, weather conditions are unpredictable and inconsistent from one year to another, resulting in fluctuating peak demand and misleading trends. Therefore, to obtain a more representative demand data, a condition known as the Average Cold Spell Condition (ACS) is introduced into the actual peak demands.

ACS condition is a specific combination of weather elements that gives rise to a level of peak demand within a year, whereby it has a 50 percent chance of being exceeded as a result of weather variation alone (National Grid, 2007). ACS corrected peak demands are then used in studies in the generation and transmission system planning.

Table 3 shows that unlike the actual peak demand, the highest ACS corrected peak demand observed was in 2004/05 instead of 2003/04. Prior to this, the annual ACS corrected peak demand increased progressively with average growth rate of 1.7 percent per annum. Correspondingly, the ACS corrected peak demand rose from 59.6 GW in 2001/02 to 62.6 GW in 2004/05. Adjusted peak demand then dropped slightly to 62.2 GW in 2005/06 and later by another 1.4 percent in 2006/07.

Year	ACS Corrected Peak Demand (GW)	% Change in ACS Corrected Peak Demand	Weather Adjusted Electricity Requirements (TWh)	% Change in Weather Adjusted Electricity Requirements
2001/02	59.6	-	342.0	-
2002/03	61.0	2.3%	347.6	1.6%
2003/04	61.8	1.3%	354.7	2.0%
2004/05	62.6	1.3%	355.7	0.3%
2005/06	62.2	-0.6%	354.7	-0.3%
2006/07	61.3	-1.4%	350.3	-1.2%

Table 3 - GB historical ACS peak demands and weather adjusted electricity requirements

Similarly, the electricity requirements for 2001/02 to 2006/07 are adjusted to include the effect of the weather. The adjusted electricity requirement increased from 342 TWh in 2001/02 to 355.7 TWh in 2004/05 with average growth rate of 1.3 percent per annum. However, in 2005/06 the electricity consumption decreased by about 1 TWh and the trend follows into the 2006/07 whereby the electricity requirement dropped a further 4.4 TWh to just 350.3 TWh.

Understanding the trend in peak demands and energy requirements is very important as they are the starting point to the planning for supply and demand balance and also the reliability studies. The next section details the existing GB generation capacity used to meet the peak demand.

2.3 GB Generation Capacity

The basic function of a modern electric power system is to satisfy the system load requirements as economically as possible and with a reasonable assurance of continuity and quality. This purpose is fulfilled by the existing GB Electricity System. In 2006/07, total generation capacity for GB is approximately 76.4 GW, which is about 18GW than the peak demand in the corresponding year (SYS2007, 2007). Reserve margin in 2006/07 excluding external interconnections is therefore about 23.5 percent. Figure 4 shows the generation capacity mix for GB system in for 2006/07.

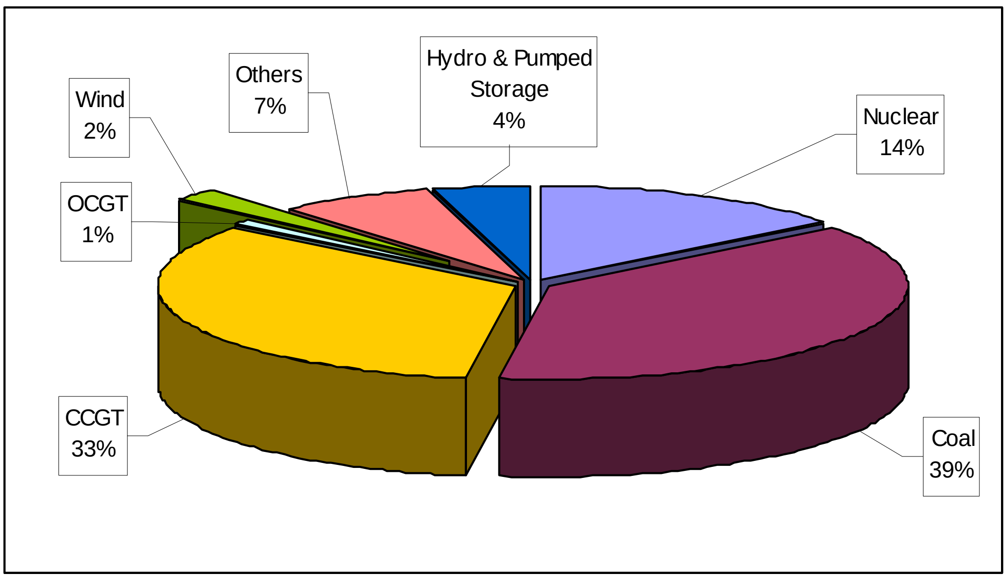


Figure 4 - GB generation capacity mix according to plant type 2006/07

The bulk of the generation capacity comes from the coal plant with 28.9 GW, followed quite closely by the CCGTs with 25.5 GW. The nuclear plants are next with 11 GW. 76 percent of the nuclear generation capacity is contributed by AGR reactor type, 13.1 percent by Magnox Reactors and the remaining 10 percent is from PWR reactors. Meanwhile, capacity of hydro and pump storage plants combined together is about 3.3 GW only. Other plant types that contribute to the generation capacity mix are CHP, OCGT, Oil and Wind with 1.7 GW, 0.6 GW, 3.5 GW and 1.7 GW respectively. Table 4 summarises the existing capacity according to plant type (SYS2007, 2007).

Plant Type	Number of Plant	Capacity (MW)
Nuclear	12	11,005
Coal	17	28,912
CCGT	41	25,532
CHP	12	1,741
Oil	3	3,496
OCGT	6	589
Hydro	34	1,028
Pumped Storage	4	2,300
Wind	37	1,737
Biomass	1	45
Total	**167**	**76,386**

Table 4 - Summary of existing power stations in GB for 2006/07

Generation capacity in GB is further enhanced through the French and Moyle interconnectors with a total import capacity of 2068 MW.

French Interconnector

The UK and French are linked by an electrical connection known as "Interconnexion France-Angleterre 2000" (IFA2000) or more commonly known as the French Interconnector. The French Interconnector is approximately 70km in length and has a capability of 2000MW export and 1988 MW for import. Interconnection is served via four pairs of HVDC subsea cables running across the Channel. It was officially intended to meet a target of 95 percent availability (Derdevet et. al, 2006). Nevertheless, the availability of this interconnection has consistently exceeded 97 percent per year (National Grid, 2007).

Moyle Interconnector

The interconnection between Northern Ireland and GB through Scotland is carried out using dc submarine cables through two circuits. The cables operate at 250kV DC as two monopolar HVDC two monopolar HVDC transmission systems rated at 250MW per pole, thus providing 500MW transfer capability (SONI, 2007). Nevertheless, presently, the interconnector is contracted for import to GB for 80 MW only (National Grid, 2007).

Dispatch Order

In the GB Electricity System, nuclear and interconnectors are operated as the base load plants. Base load plants are plants that run continuously throughout the year with exception of repairs and scheduled maintenance (Diesendorf, 2007). These plants generate a steady flow of power and not dependent on the load level in the system. Meanwhile the intermediate plants are coal and CCGTs. The order that they are dispatched however depends on the fuel price with the lower one being dispatched first.

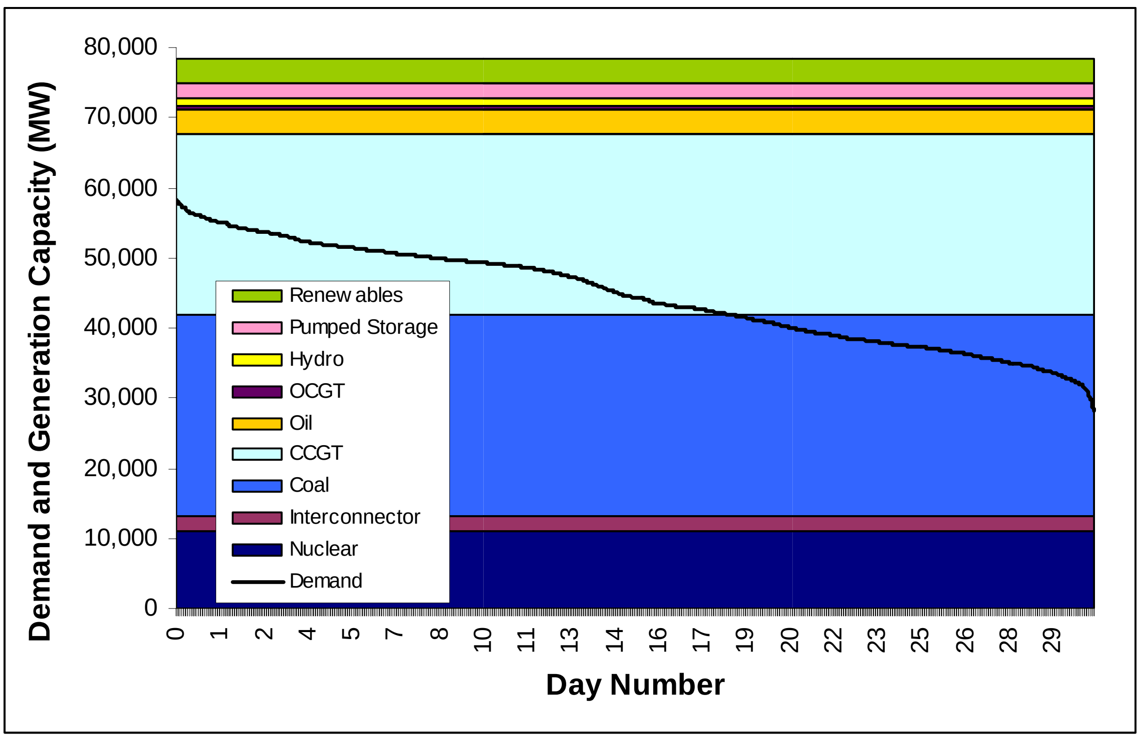


Figure 5 - GB Generation dispatch order according to plant type in 2006/07

The remaining of the plants are used as load-follower or peaking plants. These plants are only operated at peak hours to meet the high demand and are subjected to high number of start-stop operation. Figure 5 shows the GB Generation Dispatch Order according to plant type in 2006/07 and the load duration curve for month of January where peak demand for 2006/2007 occurred.

Looking at the demand and supply balance, GB has adequate generation to meet the electricity demand on day to day basis. Nevertheless, the reliability of the system is yet to be investigated and this will be elaborated more in Chapter 3 under the heading Generation System Reliability.

2.4 Future GB Electricity Demand and Generation Capacity

The GB electricity system is expected to continue expanding for the next seven years at least. Based on published SYS2007, the ACS peak demand is forecasted to grow annually with average growth rate of 1.38 percent. The forecasted ACS Peak Demand shown in Table 5 is the net GB peak demand, which excludes the station demands and also the projected export to Northern Ireland via Moyle Interconnector. Station demand is assumed to be 0.3 GW whereas export to Northern Ireland is taken to be 0.6 GW. The highest increase in peak demand is predicted to be from 2007/08 to 2008/09 with 1.8 percent. Meanwhile, the smallest increment in peak demand is expected to be from 2012/13 to 2013/14 with only 0.6 GW.

Year	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
ACS Forecasted Peak Demand (GW)	61.2	62.3	63.3	64.3	65.1	65.9	66.5
% change from previous year	1.32	1.80	1.61	1.58	1.24	1.23	0.91

Table 5 - Forecasted GB ACS Peak Demand inclusive of station demands but excluding projected export to Northern Ireland

In terms of generation, some changes are expected due to plant commissioning and decommissioning. In total, GB generation capacity increases by approximately 30 percent from 76.3 GW in 2007/08 to 98.6 GW in 2013/14. All type of plants increases in capacity at the end of the seven year period with the exception of nuclear. Planned shut down of a Magnox plant in stages between 2007/08 to 2010/11, reduces the total capacity of nuclear plants from 11 GW in 2007/08 to about 9.56 GW only in 2013/14.

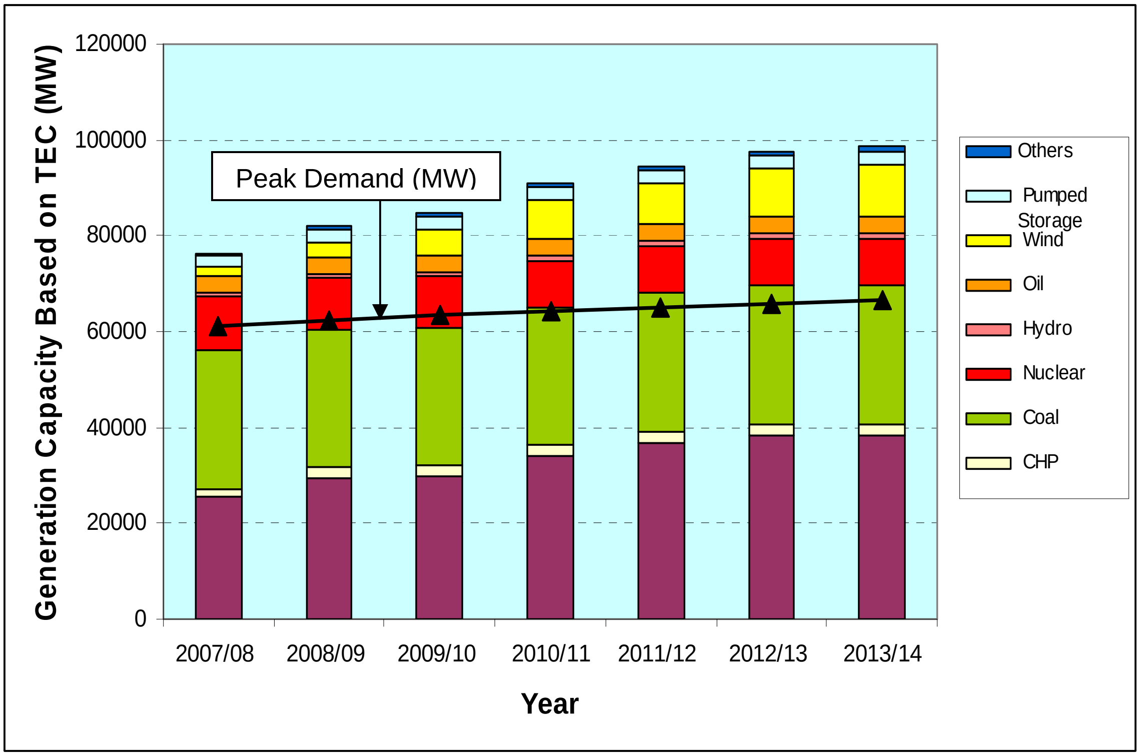


Figure 6 - GB generation capacity according to plant type (2007/08-2013/14)

The biggest contributor to the expansion comes from CCGT plants with almost 13 GW additions. This is followed by the wind turbine generators with 9.27 GW. 74 percent of the increase in wind generation will come from onshore wind farms and the rest is from offshore wind farms. Meanwhile, oil, OCGT and coal plants remain the same throughout the same period. Figure 6 shows the changes in Transmission Entry Capacity (TEC) from 2007/08 to 2013/14.

Looking at the generation mix in Table 6, coal plants will be replaced CCGTs in being the biggest contributor to the total generation capacity by 2013/14. Meanwhile, contribution of wind generation to the total generation capacity increases significantly from 2.3 percent in 2007/08 to about 11.2 percent in 2013/14.

Plant Type	2007/08 Generation Mix (%)	2013/14 Generation Mix (%)
Biomass	0.06	0.40
CCGT	33.43	**39.00**
CHP	2.26	2.36
Coal	**37.86**	29.32
Nuclear	14.41	9.69
OCGT	0.77	0.60
Hydro	1.35	1.15
Oil	4.58	3.55
Pumped Storage	3.01	2.78
Wind	2.09	8.54
Offshore Wind	0.18	2.63

Table 6 - Generation mix according to plant type for 2007/08 to 2013/14

Based on the ACS forecasted demand and expected generation capacity for 2007/08 to 2013/04, the capacity margin can be calculated. Calculation method used to obtain the capacity margin is covered in Chapter 3 of this thesis. During the seven year period, capacity margin for GB appears to be very adequate. The GB capacity margin is projected to grow from almost 20 percent to approximately 32.6 percent as tabulated in Table 7.

Year	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
ACS Forecasted Peak Demand (MW)	61200	62300	63300	64300	65100	65900	66500
Total Generation (MW) (excl. Interconnectors)	76370	82127	84634	90787	94360	97356	98614
Capacity Margin (MW)	15170	19827	21334	26487	29260	31456	32114
Capacity Margin (%)	19.86	24.14	25.21	29.17	31.01	32.31	32.57

Table 7 - GB capacity Margin (2007/08 -2013/14)

The higher capacity margin is expected as there is a higher penetration of wind generation, which is intermittent in nature and have a capacity factor of about 30 percent only. This makes the capacity margin effectively lower in reality. Nevertheless, the adequacy of the system is enhanced by the interconnections with external systems.

Interconnections with External Systems

Presently, GB Electric System has two interconnections with external systems, the French Interconnector with France and the Moyle Interconnector with Northern Ireland, to contribute to system generation capacity. In 2006/07, import capabilities through these interconnectors are 1988 MW and 80 MW respectively. Based on the SYS2007, additional capacities through the two interconnections will remain the same but only up to 2009/10 before increasing in the following years.

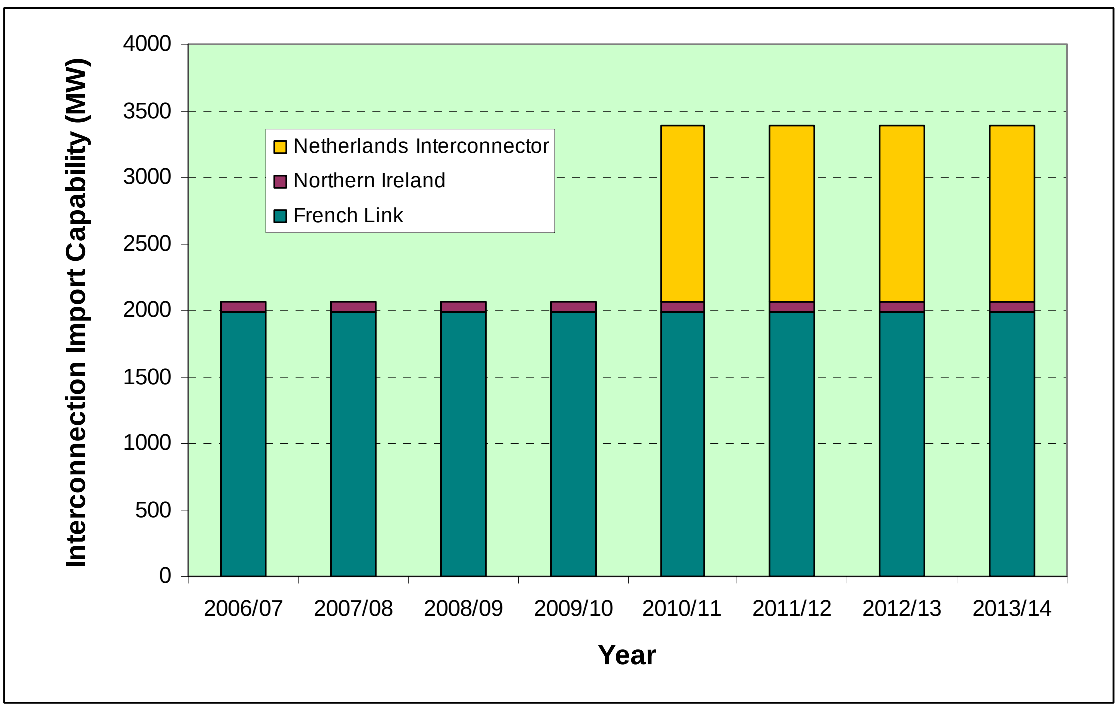


Figure 7 - GB interconnections import capabilities for 2006/07 to 2013/14

This is because a new connection is expected to be operational by late 2010/11 between GB and the Netherlands. This new connection will have a capacity up to 1320 MW, which brings the total import capacity through external interconnectors to 3388 MW. A summary of interconnection capacities (both export and import) for 2006/07 to 2013/14 is shown as Figure 7.

Theoretically, the generation capacity in GB is more than sufficient to cater for its demand. Nevertheless, there are factors that can affect the reliability of the supply. From the published SYS2007, the next seven years will see a large increase in wind generation penetration level and higher dependence on interconnections with external system on top of the existing conventional plants. In order to find out the effect of this, generation system reliability studies must be carried out. Chapter 3 elaborates on what generation system reliability is all about and how an electricity system can be modelled in order to calculate the relevant reliability indices.

Chapter 3 Generation System Reliability & Modelling

This chapter is dedicated to providing relevant background literature on generation system reliability modelling and evaluation. Firstly, generation system reliability is introduced followed by an explanation of how the power system can be modelled to carry out reliability evaluation where conventional and intermittent generation are present. This chapter also describes the common reliability indices used in reliability assessments.

3.1 Generation System Reliability

Modern power systems in developed countries, GB inclusive, are usually very large, highly integrated and complex. The numerous numbers of components and the complex interrelations between them makes evaluation of the overall system extremely tricky as it would require very complicated analytical models. These models are not impossible to build but they are extremely difficult to develop and would require excessive computing time. Furthermore, the results obtained are likely to be so vast that meaningful interpretation will be difficult, if not impossible (Billinton and Allan, 1996).

Due to these characteristics, systems are normally divided into three main functional zones, namely generation, transmission and distribution system. Typically, the zones are evaluated separately for better measures of reliability in terms of making appropriate assumptions and flexibility in failure criteria selection. They can then be combined into higher hierarchical levels to convey a more wholesome performance of the system. This thesis however, only addresses a portion of the system reliability which is the generation system reliability.

Generation system reliability concentrates on the performance of the generators where fuel is converted to white goods, the electricity before entering the transmission system. Generators are subjected to forced outages or reduction in available capacity, which can affect the system reliability and hence must be evaluated. System reliability is commonly interpreted as the probability of that system staying in the operating state, performing its intended purpose adequately for a period of time without failures under required conditions (Singh et. al, 1977, and Endrenyi, 1978). System reliability is made up of two main components, security and adequacy (Figure 8).

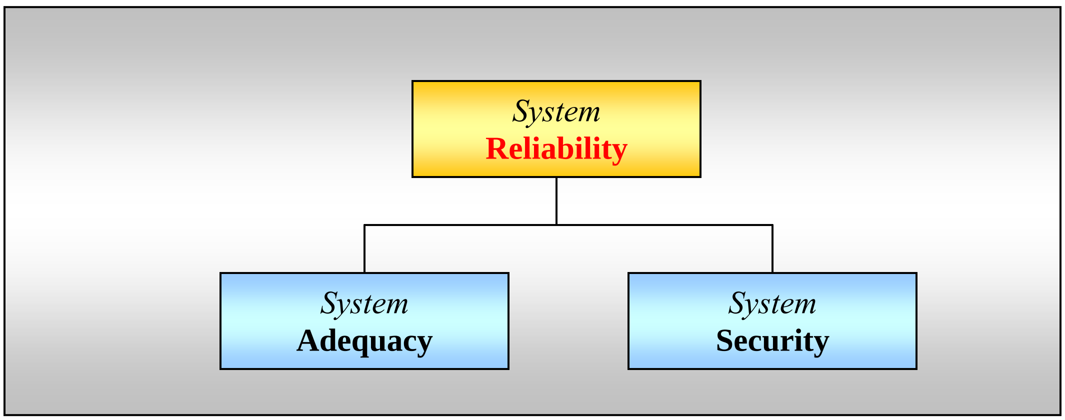


Figure 8 - Components of system reliability

Security relates to the ability of the system to withstand sudden disturbances such as faults and loss of system elements (Stoft, 2002). Generally, generation system security is the capability of the generators in enduring unexpected contingencies involving frequency and voltage any time during system operation. Security is a dynamic measure of response to the unforeseen events.

Adequacy on the other hand, considers the system in static conditions and does not fluctuate from one minute to another as it does not include system disturbances (Billinton and Allan, 1996). It is the property of having enough capacity to remain secure almost all the time. In terms of generation, an adequate generation system is a matter of installed capacity and ability to meet the annual peak demand with this capacity under normal operating conditions, taking into account scheduled and reasonably forced outages of generators (Stoft, 2002).

Together, adequacy and security provides the overall reliability description of the generation system, which can be broadly described as the ability to supply the quantity and quality of electricity desired by the customer when it is needed. Nevertheless, the scope of this study only covers the generation system adequacy and not system security. It is however assumed that the security requirements will be met if the system has adequate capacity reserves.

A shortage of installed generating capacity causes unreliable system operation. One way to improve system reliability is by installing new and better components or through incorporation of more redundancy in the system design. In generation system, redundancy is achieved by installing more generating capacity than normally required (Endrenyi, 1978).

Nevertheless, redundancy comes with a massive price tag. Furthermore, as there is excess generation, most of the generation units on reserve are kept on standby or mothballed. Therefore, a balance between reliability and cost must be found in order to have the most cost effective system with optimum reliability. Output of generation system reliability study such as the reliability indices would be a very significant input to finding the balance. Generation system study and reliability indices are elaborated further in sections 3.2 and 3.4 respectively.

3.2 Generation System Reliability Studies

In generation system, the reliability study of interest is usually termed as generating system adequacy assessment. For this exercise, the models develop do not represent the entire power system. It only includes the generating units whereas the rest of the system is assumed to be perfectly reliable as long as there is sufficient power generation available to meet the demand (Endrenyi, 1978). Therefore, transmission system which is directly connected to the generation system is ignored and treated merely as a load point as shown in Figure 9.

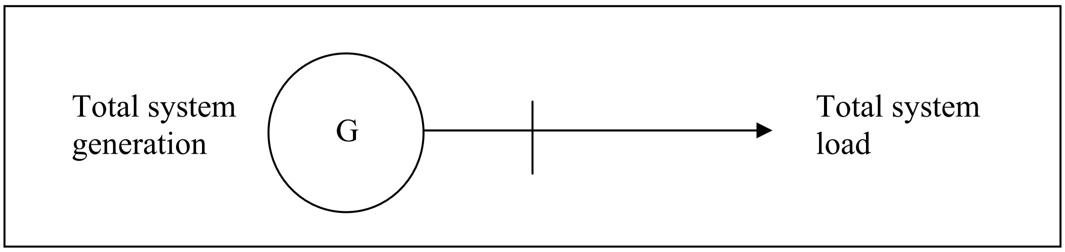


Figure 9 - Conventional system model

This particular study examines the total generation in the system in order to determine its adequacy in meeting the system demand. The system is adequate if it is able to meet the system load requirement and at the same time have excess capacity to cater for planned and forced outage events. Planned or scheduled outage is an outage that resulted from a generator being deliberately taken out of service at a predetermined time for the purpose of maintenance or repair. Meanwhile, forced outage is when a generator of the system has to be taken out of service as a result of emergency conditions.

Conventionally, deterministic approaches are used in determining the capacity requirement of the system. The most basic technique used was through the percentage reserve or reserve margin method. Alternatively, a reserve of equal to one or more of the largest units in the system was used. Nevertheless, these deterministic approaches have now been substituted by probabilistic methods. The probabilistic methods have an advantage over the deterministic techniques as they respond to and reflect the actual factors that influence the system reliability (Billinton and Allan, 1984).

Presently, there are two methods of investigating power system reliability, which are analysis and analogy. In the analytical method, a mathematical model is first created then the reliability indices are evaluated through numerical computation. Using these methods accurate results can be obtained given a good set of assumptions. United States, Canada and the UK are using this method for reliability assessment (Billinton and Allan, 1996).

Meanwhile for the analogous method, the system is divided into many components and their characteristics are estimated through probability distribution studies and other statistics related to each component. This method is also known as the Monte Carlo method. It requires extensive sample data to be collected and analysed. The indices are estimated by treating the problem as a series of experiment through simulation of actual process and random behaviour of the system. The fact that it is a statistical experiment, the results are not as accurate as the analytical method despite the excessive computation time required to analyse it. However, this method is more flexible and could be the only way to solve some difficult problems. Monte Carlo method is widely used in West Europe Countries (Billinton and Allan, 1996).

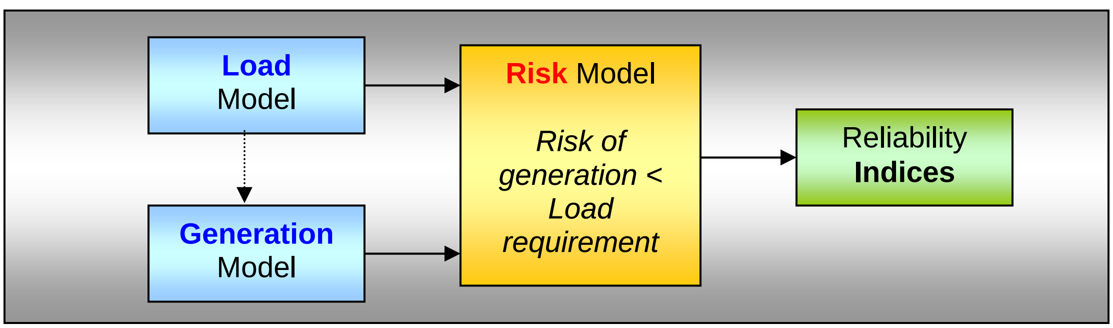


Figure 10 – Elements of Generating System Adequacy Assessment

The most recent trend, however, is to combine both analytical and analogous methods in order to exploit the best features of each method for more accurate results. For the analytical method, the available generation is contrasted with the load demand. Hence, the various techniques of evaluation used in the assessment require two types of mathematical models. They are the load generation model to represent the load variations and the generation model for the states of generation in the system (Endrenyi, 1978). The two models are then convolved or merged to form a suitable risk model (Billinton and Allan, 1996). In this case, the element of interest is when the generating capacity does not meet the load demand. Combination of these models results in an overall system model whose solution provides the required reliability indices. Figure 10 shows the three main elements of generating system adequacy assessment.

The load model used for generation system reliability assessment is in the form of ***Load Probability Table (LPT)***. LPT is usually created by utilising the hourly or daily peak load for a period of one year. The corresponding generation model adopted is the ***Capacity Outage Probability Table (COPT).*** The convolved model of LPT and COPT then forms a model known as the ***System Margin States Table (SMST)***. LPT and COPT are elaborated further in later sections of this chapter. Endrenyi (1978) summarises the main steps in constructing and evaluating reliability models in an actual reliability study as follows:

1. **Define the system** by making a list of the components to be included and assemble the necessary component failure data.
2. Define the **criteria for system failure**, such as LOLP < 1 day in 10 years.
3. List down the **assumptions** to be used in constructing the model such as annual availability of the generators and type of load data to be used (hourly or daily peak). This includes what effects, quantities or states than can be neglected for example load data on 29 February on leap years.
4. **Develop the system model** to realise the physical system, incorporating LPT and COPT to form SMST.
5. Perform failure effect analysis and **compute the system reliability indices** such as LOLP, LOLE, EENS and frequency and duration when load exceeds generating capacity.
6. **Analyse and evaluate** the results based on the indices and make judicial conclusion whether the system satisfies the reliability criteria set for the system.

3.3 Load Model and Representation

The load demand in power systems is stochastic in nature. There is no one unique profile or mathematical equation that can be adopted to represent the load profile for all types of reliability studies. However, different models can be created from primary data such as in the RTS 1996 and customised to the requirement of the study. Primary load data normally includes the maximum monthly or weekly load in a year, the typical hourly load in a day in each season and maximum load in each day in a week (McDonald and Wang, 1994). All the data is given as percentages of the annual, weekly and daily peak. With the knowledge of the annual peak demand, the primary data is the minimum amount of data needed to establish an hourly chronological load profile.

Load models are typically formed by using the daily peak load or the hourly peak load in a year. The former assumes that the peak load occurs through out the day and therefore consists of 365 data, one for each day of the day. Hence, although it is sufficient to conduct reliability studies, it is not very accurate. Meanwhile, the hourly peak is more accurate as it maps the hourly variation and has more data (8760 data).

Ideally, for a specific study, actual load data of the system should be used (such as for the GB system in this thesis). Historical and current load profiles generate more accurate reliability indices when conducting studies on the existing system. They can also be used to form the primary data in creating future chronological hourly load profile for evaluation of future GB generation systems.

3.4 Conventional Unit Reliability Models

In building the generation reliability model, the two main inputs required are the capacity and the failure probabilities of every generating unit present in the system. If the most basic two-state system 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, λ and repair rate, μ as in equation 3.1 (Endrenyi, 1978).

$$U = \frac{\lambda}{\lambda + \mu} \tag{3.1}$$

Alternatively, unit unavailability can also be obtained from the availability factor of the generating unit. Unit availability is equivalent to the number of hours in a year that it is available to be despatched regardless of whether they are utilised or not. In a simple two state system, availability and unavailability are related by equation 3.2.

$$Unavailability = 1 - Availability \tag{3.2}$$

Traditionally, unit unavailability is known as 'forced outage rate' (FOR). FOR data are usually collected by utilities and in some cases even published. The FOR is defined as equation 2.3 (Endrenyi, 1978). The FOR when calculated for a long period of time (e.g. 365 days), is the same index as the unavailability defined in Equation 3.3.

$$FOR = \frac{Forced\ outage\ hours}{In-service\ hours + forced\ outage\ hours} \tag{3.3}$$

In the case of partial outages, they are accounted for by increasing the forced outage hours by an appropriate amount of time termed 'equivalent forced outage hours' (EFOH). This duration is obtained using equation 3.4.

$$EFOH = Actual\ partial\ outage\ hours * fractional\ capacity\ reduction \tag{3.4}$$

Based on this approach, an equivalent forced outage rate (EFOR) can be defined as equation 3.5. With the introduction of EFOR, the model for a generating unit with partial outages is reduced to a simple two state model with full outages.

$$EFOR = \frac{forced\ outage\ hours + EFOH}{in - service\ hours + forced\ outage\ hours} \quad \textbf{(3.5)}$$

With the knowledge of unavailability in hand, the next step in developing the generation model is to match and combine the capacity and availability of every individual unit to form a capacity model. This is done to estimate the available generation capacity in the system. In a capacity model, each generating unit is represented by two main parameters, its nominal capacity, C_i and its unavailability, U_i (or *FOR*). In reality, the system loses generation capacity with a certain probability when the generating unit has to be forced to stop due to random failures. Hence, the capacity or the outage capacity, X is considered to be a random variable, discrete and obeys an exponential distribution in power system reliability analysis. The unit model is the probability table of a generator unit's capacity state (McDonald and Wang, 1994).

The probability model of a two-state generator model assumes that a generator unit only has two states. It is either in operation or repair (on outage) state. This results in 2^n different possible capacity states. Equation 3.6 describes the individual state probability in terms of FOR, q (McDonald and Wang, 1994).

$$P(X = x_i) = \begin{cases} 1 - q & x_i = C_i \\ q & x_i = 0 \end{cases} \quad \textbf{(3.6)}$$

Meanwhile, the cumulative state probability or the distribution function can be obtained by summing up the individual state probability for all capacity less than x_i. The cumulative state probability is given by Equation 3.7.

$$P(X = x_i) = \begin{cases} 0 & x_i < 0 \\ q & 0 \le x_i \le C_i \\ 1 & C_i \le x_i \end{cases} \quad \textbf{(3.7)}$$

Then there is a forced outage rate for every capacity C_i. Equation 3.8 gives the individual state probability for this and the cumulative state probability is shown by Equation 3.9.

$$P(X = x_i) = p(x_i) \qquad where \ \ i = 0,1,2... \tag{3.8}$$

$$P(x_k) = P(x_k \le X) = \sum_{k \le i} p(x_i) \tag{3.9}$$

These equations are fundamental in generating the *Capacity Outage Probability Table* (COPT) that represents the probability of different capacity outages of the system.

3.5 Generation System Reliability Indices

Reliability has always been a subject of concern to power system planners. Previously, the approach taken in addressing reliability were based on either intuitive or based on 'rule of thumb' criteria that were derived from experience with similar systems (Singh et. al, 1977). Nevertheless, intuitive methods become inadequate and outdated as the system increases in size and complexity. Recent years have seen quantitative evaluation and indices replacing qualitative analysis in evaluating reliability. Quantitative analysis is achieved by building mathematical equations or models to mimic the physical system and manipulating those models to obtain suitable indices and measures of reliability.

A number of indices have been introduced in reliability studies over the past years to assist reliability evaluations and predictions. Reliability indices are extremely useful as it quantifies the reliability of the system, hence making the assessment more meaningful. They are used to assess the reliability performance of a generation system against some predetermined criteria of reliability standards.

For the deterministic approach, two indices were used which are reserve margin or loss of largest unit in the system. Probabilistic approaches, however, have more indices.

According to Endrenyi (1978), the indices can generally be categorised as follows (Table 8):

No	Index Category	Example
1	Probabilities	The reliability or the availability (probability of success)
2	Frequencies	The average number of failures per unit time
3	Mean durations	The mean time to the first failure (MTTF), The mean time between failures (MTBF), The mean duration of failures
4	Expectations	The average number if days in a year when a system failure occurs. The average curtailment of energy per unit time as a result of power systems failure.

Table 8 - Indices categories

In generation system reliability, common indices used are:

1. Loss of Load Probability (LOLP)
2. Loss of Load Expectations (LOLE)
3. Loss of Energy Probability (LOEP)
4. Loss of Energy Expectations (LOEE)
5. Expected Energy Not Served (EENS)
6. Loss of Load Frequency (LOLF)
7. Loss of Load Duration (LOLD)

Most of these indices are expected values of random variable. They provide valid adequacy indicators that reflect the various factors such as system component availability and capacity, load characteristics and uncertainty, system configurations and operational conditions, etc. (Billinton and Li, 1994). Therefore, the indices are best understood as the system-wide generation adequacy and not the absolute measures of reliability (Phoon, 1996).

Figure 10 summarises the typical indices used in power system evaluations according to the approaches taken (Phoon, 1996).

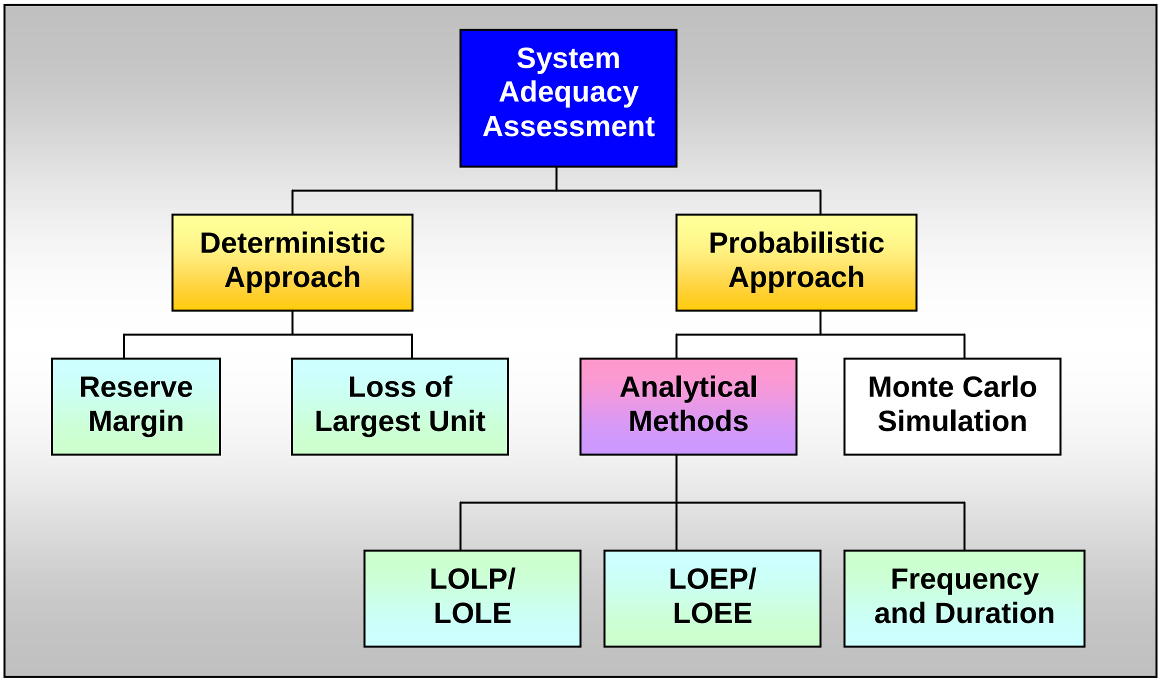


Figure 10 - Typical generation reliability assessment indices category

3.5.1 Reserve Margin

Reserve margin is defined as the percentage of excess installed capacity (inclusive of interconnection capacities) over the annual peak demand (Figure 11). It is a measure used in the deterministic approach in evaluating system reliability. This method compares the adequacy of reserve requirements in totally different systems solely based on the system peak load. Equation 3.10 gives the formula to calculate the reserve margin of a power system.

$$Reserve\ Margin = \frac{Installed\ Capacity\,(MW) - Peak\ Demand\,(MW)}{Peak\ Demand\,(MW)}\ X\ 100\% \qquad \textbf{(3.10)}$$

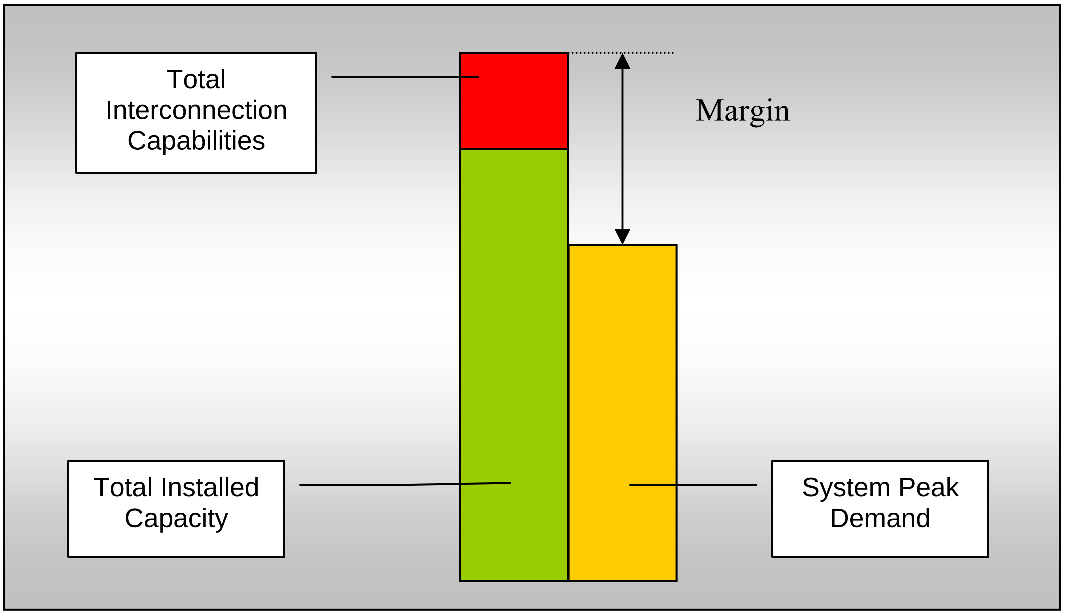


Figure 11 - Definition of reserve margin

In the past, reserve margin was normally used as a target for generation margin in generation system expansion planning exercises for small and established systems. A certain percentage is set to be available in order to meet the system peak demand based on previous experiences. Typically, the reserve margin used ranges from15 percent to 20 percent. Plant additions are made only when the reserve margin drops below the target level (Phoon, 2006). Reserve margin is therefore the easiest to understand and used in quantifying generation system adequacy.

Nevertheless, in the reserve margin calculation, installed capacities are used. Installed Capacity is defined as the maximum possible capacity. Typically, they are assumed to be the same as the nameplate ratings. Although this capacity might be accurate during the early years of the operation, the total output generated by each unit decreases with service time due to wear and tear. The actual capability of a unit is given by derated capacity, which is defined as the maximum capacity of a plant that can be obtained as a result of plant deterioration over the operating years. Therefore, reserve margin is often an overestimate of the available margin in the system and does not reflect the true margin. Hence, in large systems, reserve margin alone is not sufficient to provide a reflective reliability assessment. Moreover, it measures the system statically causing the stochastic nature of demand, component failures and system behaviour to be excluded from the evaluation. As a result, reliability analysis based solely on reserve margin could cause insufficient generation and underinvestment in generation expansion. Therefore, most utilities have shifted to probabilistic analysis as it takes into account the failure rate of different plant and sizes, thus represents the system better. Reserve margin is however still quoted in reliability analysis as the first indication to the system adequacy state.

3.5.2 Loss of Largest Unit

This method simply compares system peak demand with the generation capacity when the largest generation unit is unavailable. In larger system however, more than one generating unit is assumed to be unavailable when carrying out the reliability study. The remaining capacity after the loss of the largest generating unit is then known as the firm capacity and this can be given by Equation 3.11.

$$Firm\,Capacity = \sum_{I} C_i - C_1 \qquad \textbf{(3.11)}$$

Where $C_l \geq C_i$ and $i = 2,\ldots,I$

This method suffers from many drawbacks. Firstly, it does not take into account the probability availability of the generating units. It also takes no account of the actual size of the system as it treats the units in sets depending on their capacity. Last but not least, any new additions of larger unit(s) only mean that the firm capacity increases by the size of the largest set before the capacity expansion (Khatib, 1978).

As a result, the loss of largest unit approach is very inadequate and can be misleading. It is however used in some developing countries. A better indicator of system reliability is can be obtained from indices generated through probabilistic analysis such as loss-of-load, loss-of-energy and frequency and duration methods.

3.5.3 Loss of Load Method

Loss of load occurs when the system demand exceeds the available generating capacity in the system during operation. The probability of this happening is called the loss of load probability (LOLP). Endrenyi (1978) and Voorspools et. al (2004) define loss of load probability as the probability of the system load exceeding available generating capacity under the assumption that the peak load of each day lasts all day. Meanwhile, definition given by McDonald and Wang (1994) for LOLP is the probability of the effective system capacity not meeting the load demand, which can be written as Equation 3.12.

$$LOLP = P\ (X>R) \qquad \textbf{(3.12)}$$

Where X = System Outage Capacity

C = System Effective Capacity

L = Maximum Load

R = C-L = System Reserve Capacity

Generally, LOLP is obtained by combining the probability of generation capacity states with the daily or hourly peak demand probability. The number of days in a year whereby the daily peak load is unmet by the generation system is then assessed (Khatib, 1978). Alternatively, the hourly peak which is the peak load for each of the 24 hours a day is used instead of the daily peak, producing a more accurate representation of the stochastic nature of demand in the system. Consequently, the same system could be described by two or more values of LOLP, depending on how the calculation is done (Kueck et. al, 2004).

The overall LOLP of a system can be calculated using Equation 3.13.

$$LOLP = \sum_j P[C = C_j]P[L > C_j] = \sum_j \frac{p_j t_j}{100} \qquad \textbf{(3.13)}$$

Where:

Where:	P	is the probability of
	L	is the expected load
	C	is the available generation capacity
	C_j	is the remaining generation capacity
	p_j	is the probability of capacity outage
	t_j	is the percentage of time when the load exceeds C_j

The percentage of time when the load exceeds the remaining generation capacity can be obtained from the load model. The load model used utilises a simple cumulative load curve, as shown by Figure 12, which is known as the load duration curve. It can be constructed using hourly peaks. However, usually, it is assembled using daily peaks with the abscissa indicating the percentage of days when the peak exceeds the amount of load shown by the ordinate. With this approach, the peak load of the day lasts for the entire day (Endrenyi, 1978).

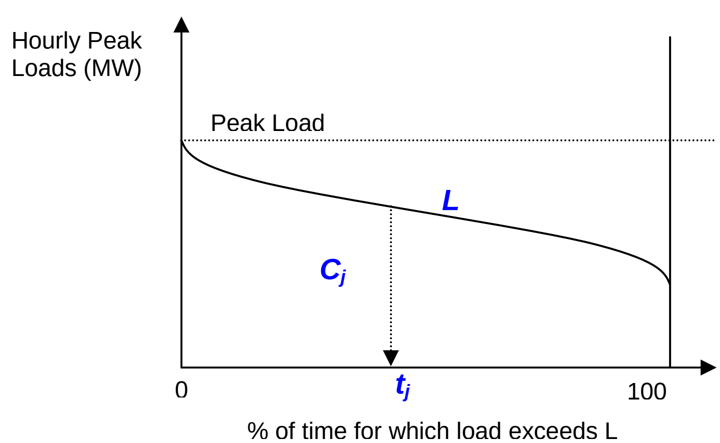
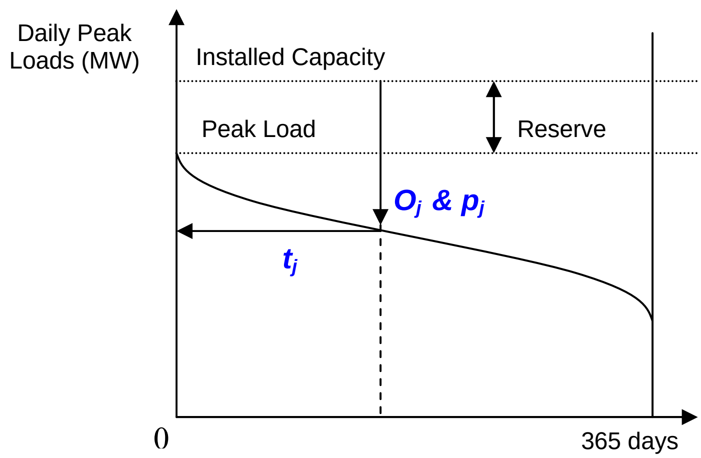


Figure 12 –A cumulative load curve

Alternatively, a load duration curve formed by arranging the daily peak loads in descending order can be used to measure LOLP for long term generation capacity assessment. Again, the peak load is assumed to last the whole day. LOLP calculation using this approach is shown by Figure 13. It must be noted that only capacity outages more than the amount of reserves contribute to a loss of load. The risk of this happening is then given by p_j x t_j (Phoon, 2006).



Where:

$\boldsymbol{O_j}$ *is the magnitude of the j-th outage in the system*

$\boldsymbol{p_j}$ *is the probability of a capacity outage of magnitude* $\boldsymbol{O_j}$

$\boldsymbol{t_j}$ *is the number of days that an outage of magnitude* $\boldsymbol{O_j}$ *would cause a loss of load in the system*

Figure 13 - LOLP calculation using load duration curve

Nevertheless, normally, it is not the probability indices but expectations that are used in generation reliability studies. This is known as the loss of load expectations or in short, LOLE. LOLE is the expected number of days or number of hours in the period investigated when the maximum load exceeds the system effective capacity (McDonald and Wang, 1994). LOLE can be derived from LOLP using the formula given in Equation 3.14.

$$\text{LOLE} = \text{LOLP X } T \quad \textit{where } T = \text{investigated period} \qquad \textbf{(3.14)}$$

If the load model is an annual continuous load curve formed by the daily peak demand, the period T is therefore 365 days. For this load curve, the unit for LOLE is in days per year. Meanwhile, of the load model is constructed using the hourly peak demand, then the value of T is 8760 hours and the unit for LOLE is hours per year (McDonald and Wang, 1994).

Usually, most literature does not make strict distinction to the difference between LOLP and LOLE (McDonald and Wang, 1994). Consequently, the LOLP index is quoted is actually the LOLE Index. In practice, a specific value of LOLP is set as a target and used as a reliability criterion in carrying out generation expansion planning. A common aim for LOLP is 0.0274 percent of a day or less, which is equivalent to LOLE of one day in ten years or less. This figure is a cumulative value and hence does not mean that one outage lasted for one whole day in the ten year period nor it is one outage incident in every ten years (Kueck et. al, 2004).

The rationale behind setting a target for LOLP is that, a system with LOLP or LOLE less then the targeted value is expected to be able to withstand any expected forced outages, forecasted peak loads and contingencies. Hence, utilities are expected to plan such that the LOLP of their system is below the set reliability criterion so as generation reliability is ensured. In some ways, the LOLP criterion can be seen like a rule of thumb, similar to the preset reserve margin of 20 or 25 percent to be maintained. However, it provides a better measure of reliability than reserve margin index because it takes into account the system characteristics. This includes the reliability of different generator types and sizes, load volatility, and deration of generating capacity as a result of plant deterioration.

Hence, two systems with similar LOLP targets do not necessarily have the same reserve margin since the amount of additional capacity needed to maintain the LOLP is different. Whereas two systems operated at the same reserve margin will end up with different levels of reliability (Kueck et. al, 2004).

Ever since its introduction, LOLP index has gained recognition and is widely used as a reliability criterion as well as a measure to reliability of a system. Its popularity is contributed by the fact that it is relatively easy to compute and it also provides simplified comparison of reliability (Phoon, 2006). Nonetheless, it must be highlighted that even though LOLP and LOLE can be used to describe the adequacy of generation in a bulk power system, it cannot be used as the sole measure of power system reliability. This is because, calculation of LOLP does not include a model of the reliability of the power delivery system, namely transmission and distribution, where the majority of outages actually occurs (Kueck et. al, 2004). Furthermore, there are several shortcomings with the use of LOLP in reliability evaluations.

Firstly, the LOLP provides no indication of the severity of load shedding either in MW or in percentage terms. It also does not give indication of its duration or frequency of shortfalls, which are important parameters in quantifying reliability. Instead, LOLP, given in days per year, mainly indicates the number of days in a year that the generation system will not be able to meet the system demand. As a result, 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). As an expected value, LOLP is also not able to differentiate between a large supply shortage and several small and brief ones (Kueck et. al, 2004).

Moreover, as the load model used in LOLP derivation is often the cumulative curve of daily peak loads, the variations of load within a day are not recognised. Consequently, the LOLP value produced is rather a crude approximation of the actual system failure probability. Apart from that, this type of load model prevents the calculation of the system failure frequency (Endrenyi, 1978). Besides that, LOLP also does not include additional emergency support that is available to one area from another or emergency measures that can be taken by the control area operators in order to maintain system reliability (Kueck et. al, 2004).

In the past, major loss of load incidents occurred as a result of contingencies that are not modelled by the traditional LOLP calculations. In fact, a major bulk power outage is often precipitated by a series of incidents, which does not necessarily occur when the calculated risk is the greatest that is during system peaks (Kueck et. al, 2004). It is however argued that the use of LOLP index for the same system would be adequate when investigating various expansion plans and annual maintenance scheduling. But, this is only true if the duration of peak load remain static over the study period. Unfortunately, in most cases, especially in developing countries, the system load experiences continuous increase during the middle of the day (Khatib, 1978).

LOLP is not very useful when it comes to comparing the reliability of different utilities or systems, particularly if they have different shapes of the load curve and peak duration (Khatib, 1978). It is also not necessarily an accurate predictor of the resulting incidence of electricity shortages (Kueck et. al, 2004). Nevertheless, LOLP is still an important reliability index and is useful in providing the first estimation of the generation system reliability.

3.5.4 Loss of Energy Methods

An alternative to the loss of load method in generation capacity reliability assessment is the loss of energy methods. The loss of energy can be quantified using the Expected Energy Not Served (EENS). McDonald and Wang (1994) define EENS as the expectation of energy loss at the customer end cased by insufficient power generation. The mathematical formula used to obtain EENS is given by Equation 3.15.

$$EENS = \sum_{R-X>0} (X-R)p(R)t \quad MWh \qquad \textbf{(3.15)}$$

Where X = System Outage Capacity

R = System Reserve Capacity

If the load model is based on hourly peak, then *p*(R) =1/8760 hours and the corresponding *t* = 8760 hours. EENS value is important as it is usually used in calculating the cost of power interruptions (McDonald and Wang, 1994).

The measure of interest in loss of energy however is the ratio, *E,* of EENS during a specified period of observation to the total energy demand during the same period (Endrenyi, 1978). The loss of energy probability (LOEP) can be calculated using the mathematical formula given by Equation 3.16 and 3.17.

$$LOEP = \sum_{k} \frac{E_k . p_k}{E} \qquad \text{MWh/year} \qquad \textbf{(3.16)}$$

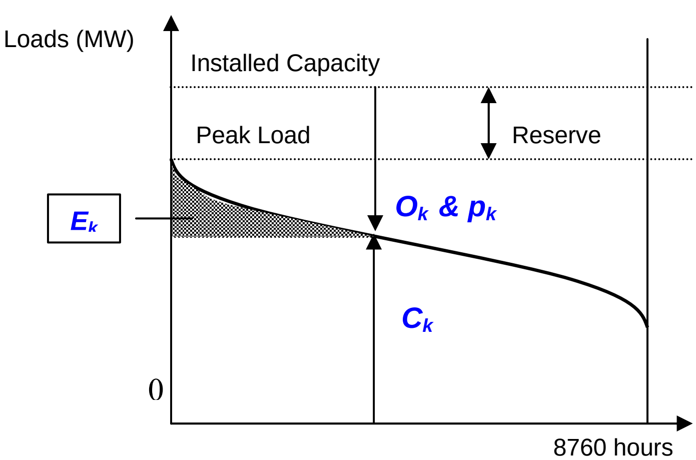
Where E_k is the energy not supplied due to a capacity outage O_k

p_k is the probability of capacity outage O_k

E is the total energy demand during the period of study

$$E_k = \int_0^{t_k} (L - C_k)\, dt \quad and \quad E = \int_0^{8760} L\, dt \qquad \textbf{(3.17)}$$

LOEP is also known as the Loss of Energy Expectation (LOEE) as it is an expected value rather than a probability (Phoon, 2006). Similar to loss of load method, LOEP can be determined using a load duration curve and this curve is illustrated by Figure 14. The energy not served as a result of insufficient generation capacity is shown as the shaded area under the load duration curve.



Where:

E_k *is the magnitude of the j-th outage in the system*

O_k *is the magnitude of the k-th outage in the system*

p_k *is the probability of a capacity outage of magnitude* ***O_j***

t_j *is the number of hours that an outage of magnitude* ***O_j*** *would cause a loss of energy in the system*

Figure 14 - LOEP calculation using load duration curve

In some ways, the loss of energy index has more physical significance than the loss-of-load indices. This is because it is able to show the severity of an event even if the probabilities and frequencies are the same. A higher value of loss-of-energy index is obtained for the more serious events than for the marginal failures (Endrenyi, 1978). Hence, it can measure the amount of inconvenience and loss to the customer (Khatib, 1978).

Nevertheless the true loss of energy cannot be accurately computed on the basis of the cumulative load curve of daily peaks. As a result, loss-of-energy index is seldom used in generation reliability studies for long term planning exercises. It is however used in several production cost evaluation programs using suitable load models (Endrenyi, 1978).

3.5.5 Frequency and Duration (F&D) Method

The F&D method produces a set of useful reliability indices when the frequency of interruption over a specified period is of interest. This is because it provides a reliability indication for specific customers or load points.

A state-space approach is applied to the sets of units present in the system in the reliability evaluation using the F&D method. This method also adopts the transition rate parameters λ and μ of generating units. This means that each possible combination of units in up or down states defines a capacity state of the system, which are then classified according to their available capacity, the relevant state probabilities and of course their transition states. The steps in an F&D analysis are as described below (Phoon, 2006):

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 state j is $f_j = p_j$ x $(\lambda_{j+} + \lambda_{j-})$, where λ_{j+} is the transition rate from state j to higher capacity states and the λ_{j-} transition rate to lower capacity states.
3) The average state duration T_j is defined by the relation $p_j = f_j$ x T_j.

This representation is then combined with a load model, which is a chronological load curve, to identify marginal states. Marginal states are where the transition to a lower capacity state will result in insufficient generating capacity ($C_j < L$). Cumulative probabilities and frequencies are then computed for the marginal states and relevant indices such as Loss of Load Frequency (LOLF) and Loss of Load Duration (LOLD) are generated. These indices can be calculated using the mathematical formula shown as Equation 3.18 and 3.19 respectively (Billinton and Li, 1994).

$$LOLF = \sum_{j \varepsilon S} (F_j - f_j) \qquad \text{times/year} \tag{3.18}$$

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

$$LOLD = \frac{LOLE}{LOLF} \qquad \text{hour/disturbance} \tag{3.19}$$

The frequency and duration method can be regarded as the basic extension to the LOLE index. This is because they identify the expected frequency and duration of load deficiency. Theoretically, both frequency and duration indices are more sensitive to the addition of generation system parameters as they contain additional physical characteristics. Nevertheless, they are still not widely used for generation system reliability assessments yet.

3.6 Reliability Indices in GB

Every country has a unique system with different levels of reliability standards imposed on the utilities responsible in operating the system. In GB, the last security standard employed by the Central Electricity Generating Board (CEGB) proposed that interruptions of supply should not occur more than 9 winters in 100. Hence, the risk of having supply deficits must not be larger than 9% (Nedic, 2005). According to the same source, this criterion corresponds to a capacity margin of about 24 percent. It is important to note that capacity margin and reserve margin are quite similar but not the same. Definition of reserve margin is given by Equation 3.10. Meanwhile, the capacity margin can be calculated based on Equation 3.20.

$$Capacity\ Margin = \frac{Installed\ Capacity\,(MW) - Peak\ Demand\,(MW)}{Installed\ Capacity\,(MW)}\ X\ 100\% \qquad \textbf{(3.20)}$$

However, the reliability criterion of interruptions not to exceed 1 in 10 winters is very vague and depending on how this is derived and interpreted, can produce different values of reliability indices even when the exact same system is studied. Unfortunately, no other literature was found to establish the actual reliability indices in GB. Hence, the LOLP, LOLE and EENS figures produced through this study are hoped to provide comparison to other studies relating to generation system reliability in GB.

3.7 Intermittent Generation and Reliability Models

Conventional plants with the exception of hydro, run on fossil fuels such as oil, gas, coal and nuclear. These fuel sources are always available with exception of during curtailments due to interrupted fuel supplies. Fuel curtailment is still rare in the present day. However, the security of fossil fuel supply is highly threatened in the future as fossil fuels are exhaustible resources and with the continuous increase in demand, they are fast running out of supply. As a result of this, the price of fossil fuel is also affected severely, especially oil prices, making system operation using fossil fuels less economical. Nevertheless, utilities around the world still operate conventional plants due to their dependability in terms of reliability and relatively low cost of operation.

Nevertheless, rising concern on the contribution of greenhouse gases (GHG) emissions through fossil fuel generation, which contributes to global warming, has cause the utilities to look into alternative fuel sources. The six GHG listed under the Kyoto Protocol are as listed below:

i) Carbon Dioxide (CO_2)
ii) Nitrous Oxide (NO_2)
iii) Hydrofluorocarbons (HFCs)
iv) Methane (CH_4)
v) Perfluorocarbons (PFCs)
vi) Sulphur Hexafluoride (SF_6)

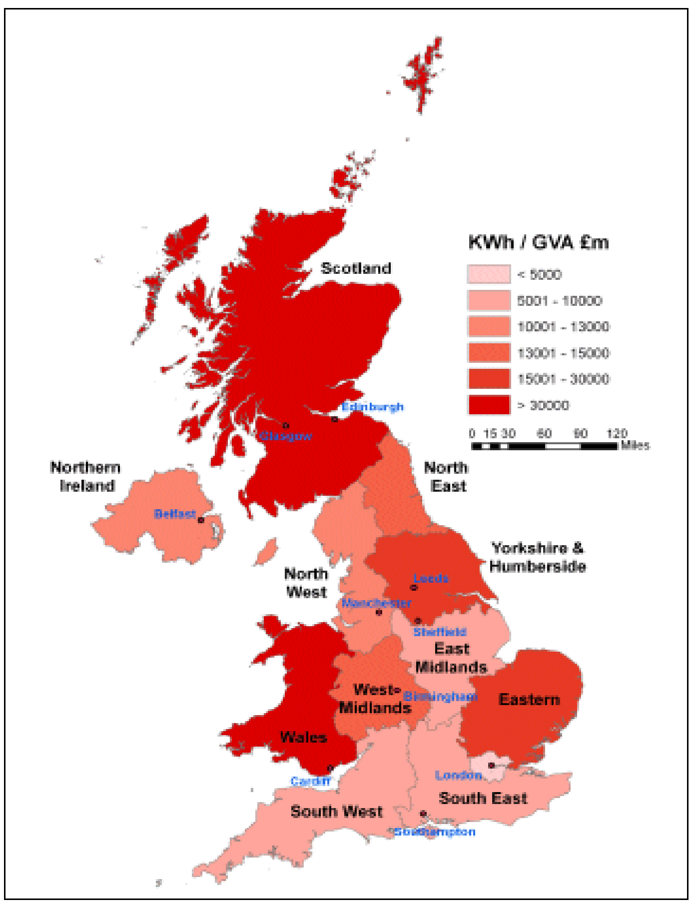


Figure 15 - Map of density of renewables generation in GB (Source: RESTATS, 2005)

The current trend is to venture into the renewable resources namely wind, solar, wave and tidal, which are known as renewable resources. These resources, unlike fossil fuels, are undepletable. Furthermore, renewable generation can provide energy at virtually zero fuel cost and at the same time, reduce emissions of the GHG (Gross et. al, 2006). In GB, serious development of renewable generation is being carried out throughout the country. Figure 15 shows the density of renewables generation in terms of kWh generated and gross value added in GB for 2005.

The advantages offered by renewable generation over conventional plants make them favourites when it comes to the despatch merit order. Ideally, renewable generation units are run whenever there is resource availability so as to maximise the renewable potential.

Unfortunately, renewable generation does not come without a price. They are intermittent in nature as they are dependent on the availability of the natural resources, which is continuously fluctuating and are unpredictable. As a result, depending on the technology, geographical location and time of occurrence of peak demand, there are instances when the intermittent generation is unavailable during peak periods when the supply is most needed.

Hence, in terms of reliability, the contribution of intermittent renewable generation is lower relative to that of conventional generating units. This means that even though the addition of intermittent generation theoretically contributes to the reserve margin, in the eyes of the operators and system planners, they do not carry real available capacity value. Estimation of the contribution of intermittent generation to the system reliability in terms of capacity value can, however, be made using the terminology capacity credit.

Capacity credit is defined by Ford and Milborrow (2005) as the ratio of capacity of thermal plant displaced over the rated output of wind plant. Meanwhile, Voorspools and D'haeseleer (2005) interpreted capacity credit as how much conventional power can be avoided or replaced by wind power. It is basically the fraction of installed capacity of renewable generation by which the conventional power generating capacity can be reduced without affecting the value of LOLP. There are a few ways to measure capacity credit but the most commonly used us the effective load carrying capability (ELCC).

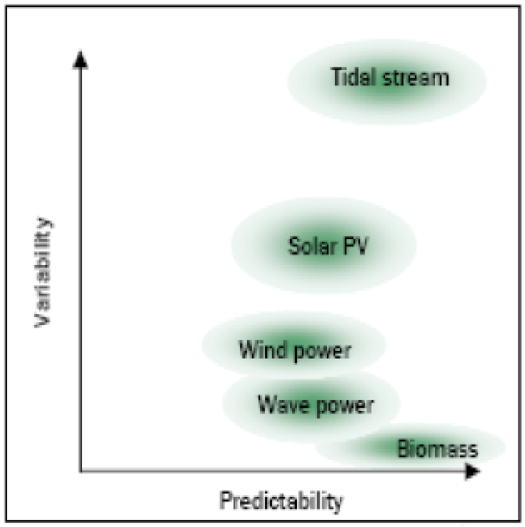


Figure 16 - Variability and predictability of RE sources (Source: Phoon)

Due to the intermittency of renewable generation, they cannot be modelled in the same way as the conventional plants when it comes to generation reliability assessment. The intermittency is, however, predictable to a certain extent. Figure 16 shows the variability and predictability of various renewable energy sources.

3.7.1 Wind Generation

Utilisation of the wind for electric power generation is increasingly being considered as a possible alternative to conventional generation due to the rising interest in renewable and green energy. In addition, uncertain global economic and political conditions are driving the countries to be more dependent on their own natural resources and hence rely less on imported fuels.

Wind is a turbulent mass of air movement resulting from the differential pressure at different locations on the earth surface. It is a clean, abundant and inexhaustible source of energy. Recent years have seen tremendous growth of wind generation globally generally and in GB specifically as a result of the UK commitment to the Kyoto Protocol 1997. This trend is expected to continue for decades to come. The integration of a large number of wind farms, however, will have a significant impact on the reliability performance of electric generation systems.

One of the main characteristics of wind is that it is highly variable and its properties vary from one location to another. The variation of wind spans from instantaneous, hourly, diurnal and seasonal. Annual variation also exists, but it is not as significant. Factors causing the variability of wind resources can generally be summarised as follows:

1) Meteorological conditions
2) Daily/seasonal variations of wind speed (monthly/diurnal)
3) Specific site and height from the ground
4) Geographic dispersion of wind plant

The wind property of interest when it comes to power generation is the wind speed and availability. This is because theoretically, the wind power output, P, harnessed from the wind is directly proportional to the cube of the wind speed. The relationship is given by equation 3.21. A small increase in wind speed, *V*, will therefore result in large increase in power, *P*.

$$P = \frac{1}{2}\rho A V^3 \qquad \textbf{(3.21)}$$

Where: P = Power output in Watts

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

A = turbine rotor swept area that is exposed to the wind (m^3)

V = wind speed (m/s)

Nevertheless, it is impossible to extract all the power from the wind. Hence, a more realistic mathematical representation after taking into account the losses and generator and bearings efficiency is given by Equation 3.22.

$$P = \frac{1}{2} C_p \rho A V^3 . \eta_g . \eta_b \quad \textbf{(3.22)}$$

Where:

C_p = Coefficient of performance (0.59 {Betz limit} is the maximum theoretically possible, 0.35 for ideal design)

η_g = Efficiency of the generator (50 percent for car alternator, 80 percent or more for a permanent magnet generator or grid-connected induction generator)

η_b = Efficiency of the gearbox/bearings (could be as high as 95 percent)

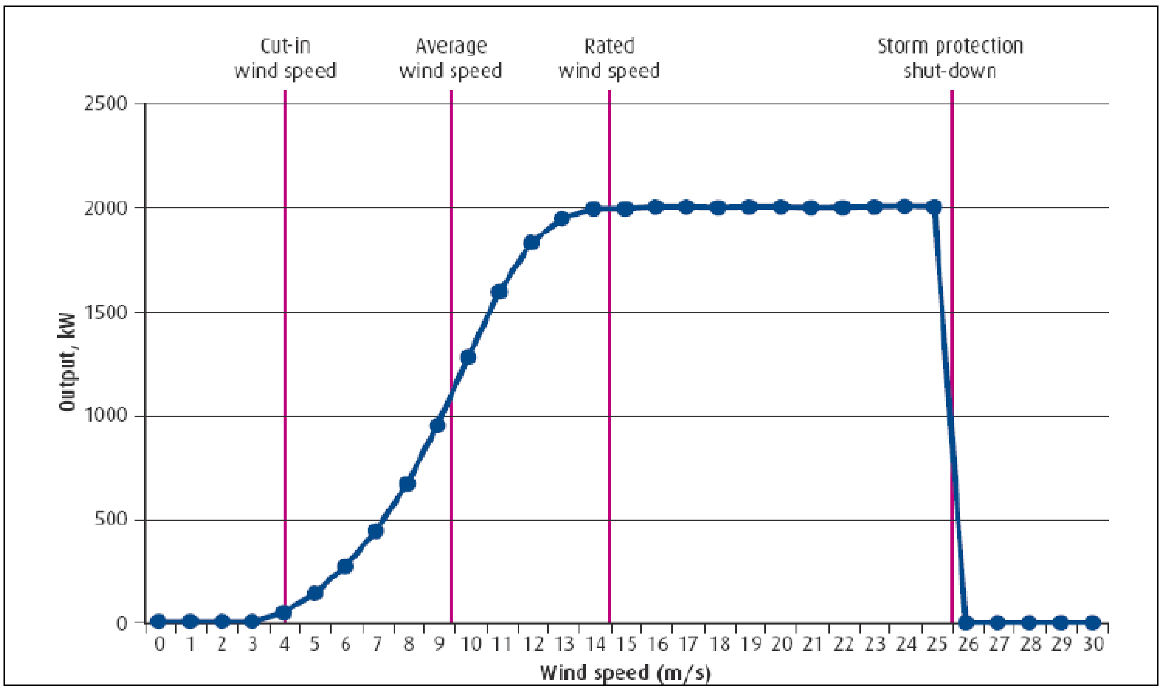


Figure 17 - Wind turbine power curve (Source: Phoon, 2006)

Ideally, the power generated by the wind turbine should increase as the wind speed increases. However, in reality, this is only true to a certain limit. Typically, wind turbine generators are designed such that no power is generated below a cut-in speed and to shut down to protect the machine when the wind speed exceeds the cut-out speed. The wind power output only increases with the wind speed between the cut-in speed and the rated wind speed. After reaching the rated speed, power output generated by the wind generators remains constant, producing the rated power. The wind turbine power curve is illustrated in Figure 17.

Availability

Generally, production of power from wind is dependent on two main things which are the availability and speed of the wind and also the characteristics of the wind generator. The later does not pose much problem as wind turbines have typical annual availability of 95 percent. Nevertheless, the intermittent and diffuse nature of the wind, can present substantial challenges to wind generation availability as no power can be generated when the wind does not blow. This 'fuel' shortage can be regarded as forced outage, resulting in effective availability of wind power generation units that is much lower than conventional generation when the intermittency of wind is taken into consideration.

Capacity Credit

Presently, many utitlities are reluctant to give capacity credit to wind generation (Chen, 2000). However, studies of the UK system has concluded that wind plants do have a positive capacity credit. This capacity credit is determined by the correlation of wind generation with the system load with higher correlation meriting higher capacity credit (Milligan and Porter, 2005).

3.7.2 Modelling Wind Generation

There are several ways of modelling the capacity credit of wind generation in order to evaluate its contribution to generation system reliability. This thesis, however, only highlights several frequently and widely known approaches.

A) Retrospective Analysis

In retrospective analysis, the wind generators are modelled as load modifiers. This is easily achieved by substracting the hourly wind generation capacity from the expected load demand. The reliability assessment study is then carried out using the net demand to form the load probability table. The advantage of this approach is that it takes the detailed chronological variation of wind output into consideration. Meanwhile, the drawback according to Milligan (1996) is that the variance of the wind power output is not captured and quanified into the LOLP calculations.

Capacity credit can be represnted in two ways using the retrospective approach: namely the Effective Load Carrying Capability (ELCC) method or Firm Capacity Method (FCM) and the Equivalent capacity Method (ECM).

B) Reliability Curves

This approach is similar to the retrospective analysis whereby the wind generating units are modelled as load modifiers. However, in the reliability curves method, the reliability indices such as LOLE are obtained by varying the annual peak demand. The process of conducting reliability curves analysis is as follows;

1. Firstly, LOLE values are plotted for two cases which are:
    - i. Without wind generation
    - ii. With wind generation

2. Determine the levelof reliabiltiy to be evaluated. The example shown in Figure 18 (Milligan and Parsons, 1997) has the reliability criterion set to 0.1 days per year.

3. Calculate the ELCC for the wind plant by taking the difference between the load values of the reliability level for the two curves.

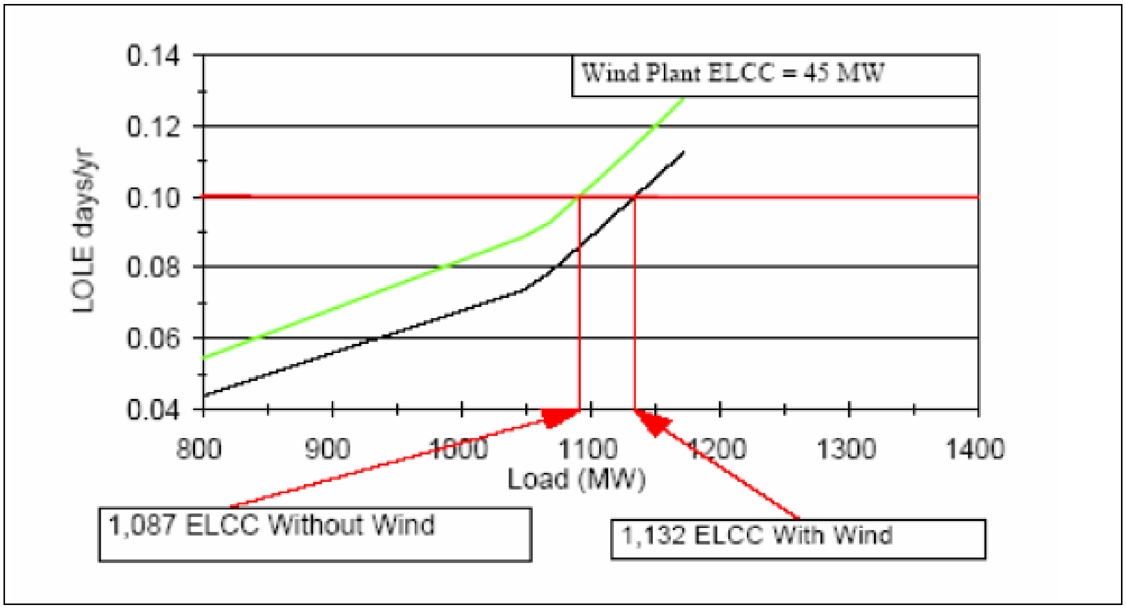


Figure 18 - Reliability curves for ELCC calculations of a wind plant (Source: Phoon, 2006)

C) Prospective Analysis

The prospective analysis approach models not only the mechanical availability but also the wind availability in a probabilistic manner. In order to capture the wind availability rate in the reliability models, forced outage rate is applied whenever there is lack of 'fuel' that is when the wind is not blowing. Milligan and Porter (2005) suggest that wind be modelled as a multi-block conventional generator. Several levels of wind output are then calculated and matched with the probability of obtaining that output. The values obtained are converted to relevant forms so that they appear as forced outage rates at different output levels in the reliability models.

D) Advanced Techniques

Unlike analytical methods, the chronological characteristics of wind speed and its corresponsing effects on wind power output is captured through the advanced techniques. The two main advanced techniques currently in use are the Sequential Monte Carlo Technique and also the Sliding Window Technique.

Sequential Monte Carlo (SMC)

A probabilistic model of the wind power data is developed in SMC using autoregressive integrated moving average (Billinton et.al, 1996), Markov modelling (Milligan and Graham, 1997) and several other techniques. Hourly availability of the wind is then determined from the probability distribution generated. This way, the 'outages' of wind are better represented and the expected wind-induced variation in reliability could be estimated. Nevertheless, this method requires extensive computation time.

Sliding Window Technique (SWT)

SWT is an extension to the convolution procedure that is used in conventional generation reliability modelling (Milligan, 2001). In SWT, the hourly variation of wind power is used to calculate an effective forced-outage rate for wind power plant. The key task in the analysis is to come up with the effective FOR for the wind plant, which varies with time. The effective FOR is however not the actual representation of the mechanical availability of the wind plants, but a statistical expectation of plant outage over a specific period of time.

This approach retains the diurnal and seasonal characteristics of the wind generation. Another advantage of SWT is that it explicitly convolves alternative wind power output levels and probabilities into the LOLP calculations.

E) Approximation Methods

Approximation methods are used when there are limitations in data availability which hinders ELCC from being calculated. The three main approximation methods are capacity factor, and time-period based methods.

Capacity factor

Milligan (2001) defines capacity factor as the ratio of statistically expected output over annual energy output. Meanwhile, Sinden (2005) interprets capacity factor as the amount of electricity produced by an electric generator, in this case the wind generators, as a percentage of the maximum theoretical production from the generator. Sometimes, capacity factor is also known as the load factor of the generator.

The value of capacity factor will always be less than 100 percent as there are many operational reasons as to why the generators may operate less than its maximum rating. Firstly, shutdowns for maintenance for both planned and unplanned outages (including lack of wind). Another reason is when there is lack of demand or electricity and the generation does not run (Sinden, 2005).

Capacity factor of a wind plant can easily be calculated from the hourly wind generation data. Nevertheless, this factor only gives the estimation of the potential wind energy production capability at the particular site. It does not relate to the system capacity composition, the chronological load and wind profiles, and the accepted system risk level.

Time-Period-Based Methods

Time-period-based approximation is, in a way, better compared to the capacity factor approach in the sense that it attempts to capture risk indirectly. This method assumes a high correlation between hourly demand and LOLP. Hourly load data and wind data are collected for at least a period of one year and ELCC is approximated from this. Nevertheless, this method still does not capture the full risk potentials involved.

3.7.3 Wind Power in the UK and GB

Recent years has seen tremendous growth of wind generation development in GB specifically as a result of the UK commitment to the Kyoto Protocol 1997. Figure 19 shows the large scale wind farm capacities in GB as of December 2005.

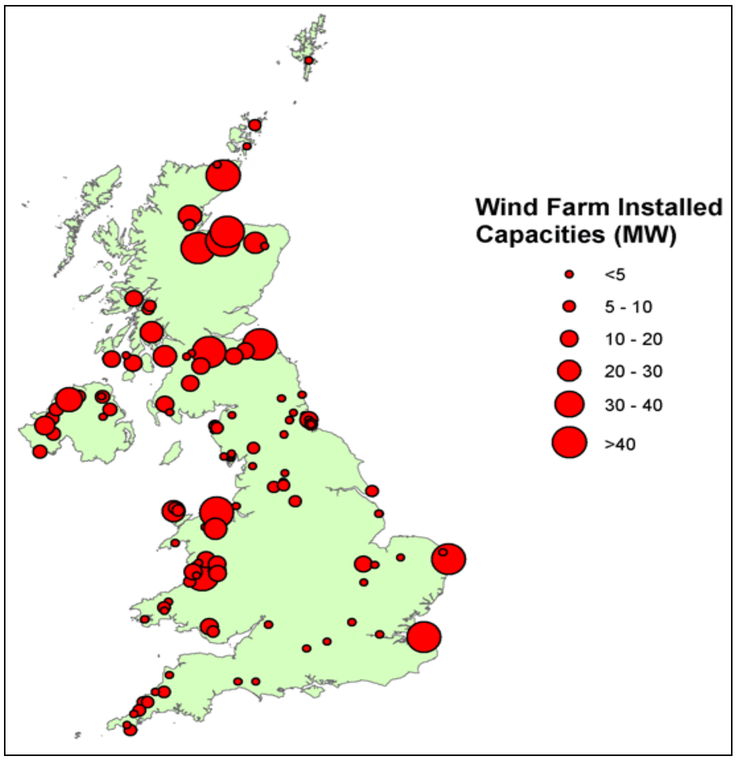


Figure 19 - GB large scale wind farms (Source: RESTATS, 2005)

Wind speed in the UK is higher in winter months (December, January and February) compared to the summer months (June, July and August). The wind resource also shows a clear pattern of high wind power output during daylight hours in comparison to night time (Sinden, 2005). This diurnal and seasonal variability is reflected in the capacity factor of the wind plants. Figures 20 and 21 demonstrate the variability of wind power in the UK monthly and hourly respectively in terms of capacity factor using average wind speeds for the period 1970-2003.

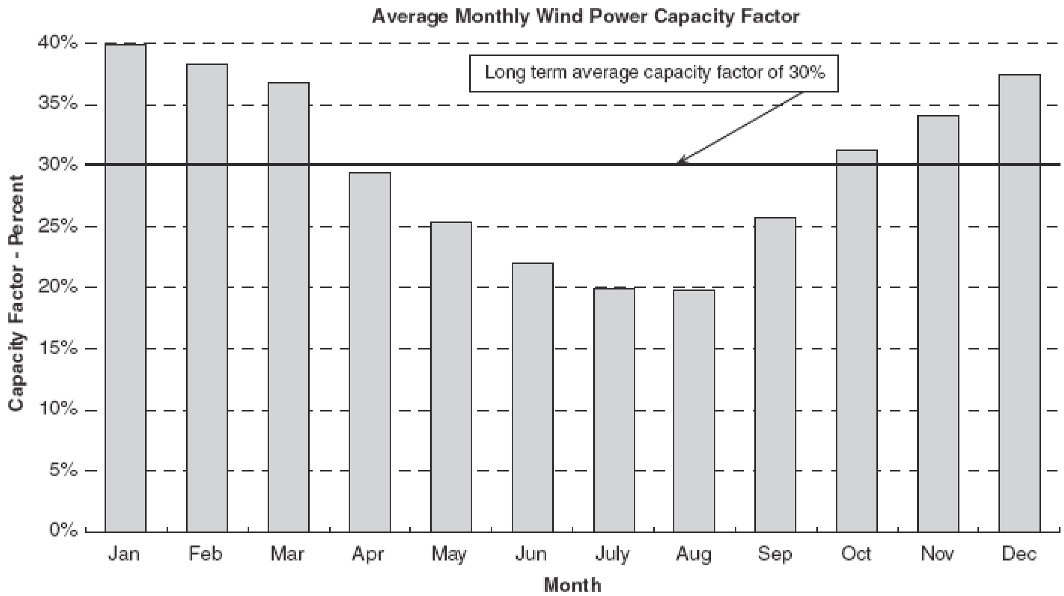


Figure 20 - Monthly wind power availability for UK (Source: Sinden, 2005)

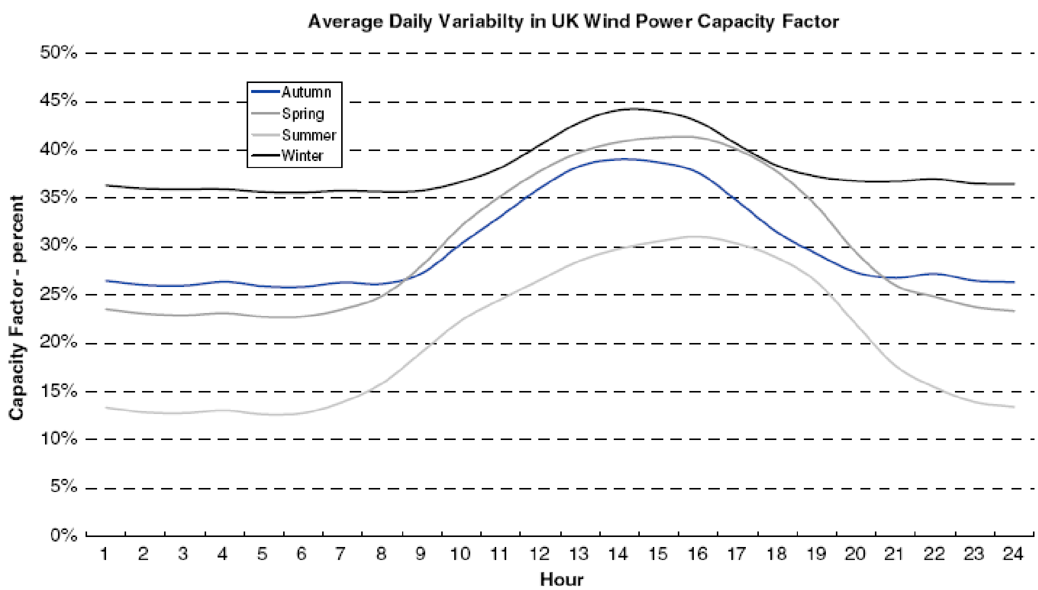


Figure 21 - Average hourly power availability by season (Source: Sinden, 2005)

As discussed earlier in the thesis, the ability of wind power to reliably contribute to the power system is dependent on the characteristics of the wind. A study of 34 years on 66 onshore weather recording sites in the UK demonstrated that wind power output in the UK has a weak, positive correlation to current electricity demand patterns (Sinden, 2005).

UK wind climate is subjected to extreme lows or highs in terms of wind speed. Nevertheless, a diversified wind power system would be less affected as it is rare that these extreme events affect large areas of the country simultaneously. This is proven by the study carried out by Sinden (2005), whereby the report found that low wind speed conditions affecting 90 percent or more of the UK would occur for one hour in every five years during winter. In addition, the chances of wind turbines shutting down due to high wind speed condition are very rare. According to the same author, high wind speed affecting 40 percent or more of UK would only occur in around one hour for every ten years.

Meanwhile; during peak demand periods, the capacity factor of wind power in the UK is around 30 percent higher than the annual average capacity factor (Sinden, 2005). The reported annual capacity factor of wind power in the UK is varies from 24 percent to 31 percent. The capacity factor is expected to increase in the future with more development of wind farms in Scotland and offshore where the wind speed is generally higher.

As of 2006, there are 133 onshore operational wind farms in GB with a total capacity of about 1.9 GW. In addition to that there are another 5 offshore wind farms with total capacity of about 304MW. 35 more onshore and offshore wind farms are under construction with the bulk of these being onshore wind farms in Scotland (BWEA, 2006).

3.7.4 Other Intermittent Generations

Apart from wind generation, other renewable generation that is being considered seriously are wave and tidal stream generation and also solar generation.

Wave and Tidal Generation

Wave and tidal generation is expected to contribute significantly to the UK generation in the next few decades as the technology matures. Presently, technologies for wave and tidal stream generation are still at the research and trial phase. Wave and tidal stream generation has huge potential in GB as the UK has some of the largest wave and tidal power in the world (Butler, 2001). Furthermore, GB and UK has an extensive coastline. Figure 22 shows the annual mean wave height of the UK coast. The wave and tidal power has the advantage over wind power as it is not only reliable but also more predictable. Although waves are random in nature, they still follow frequent seasonal and diurnal trends.

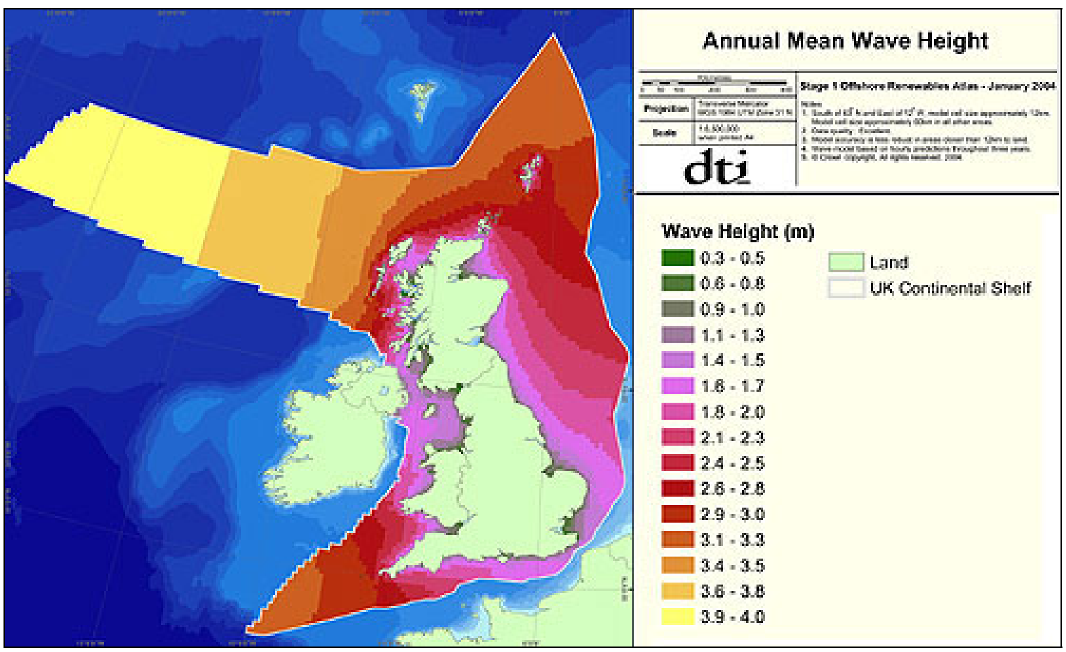


Figure 22 - Annual mean wave height off the UK coast (Source: BWEA, 2004)

Waves are a result of the effects of wind on the surface of the oceans and seas. They transmit large volumes of energy from windy conditions far out from sea to the shore. In some places, the energy contained within waves can reach 70MW/km (ESRU). This energy, if harnessed, can be used to produce electricity and presently many technologies are being developed to achieve this.

According to DTI cited by ESRU, at present, there are three types of wave energy collector. They are;

- Buoyant Moored Device
- Hinged Contour Device
- Oscillating Water Column

Nevertheless, waves are not as consistent or predictable as the tide and therefore problem arises when matching demand and supply. The factors causing intermittency of wave generation are the sea state, location and typical period. The inconsistency has hindered development of this technology in a way. So far, wave generation is restricted to small scale schemes and no large scale commercial plant is in operation yet (ESRU).

In estimating the amound of power to be genrated from wave energy, the linear wave theory assumes that the motion of the water past a point is sinusoidal. The period (T) for one wave to pass this point is given by the mathematical formula given as Equation 3.23

$$T = \sqrt{\frac{2\pi.\lambda}{g}} \qquad \text{Where, } \lambda = \text{wavelength (m)} \tag{3.23}$$

Meanwhile, the power, *P,* contained in the wave can be expressed in terms of the length of the wave (kW/m) and is given by Equation 3.24

$$P = \frac{\rho.g^2.a^2.T}{8\pi} \tag{3.24}$$

Where: g = gravity = 9.81 (m/s^2)
a = wave amplitude (m)

As for tidal generation technologies, they can be categorised into two main types which are tidal barrage generation and tidal stream generation. The former is operated like conventional hydro dam with a tidal barrage built in an estuary whereas the later has turbines placed underwater in the tidal stream allowing power to be produced from both in and out flows. Nevertheless, both are related to the lunar cycle rather than solar cycle. Tidal currents flow according to a predictable diurnal pattern. They vary by day and month whereby one tide with a period of about 12.4 hours represents the diurnal ebb and flow cycle and the other is the 28 day spring-neap period. In UK waters, the maximum spring current velocity is approximately twice the minimum mean neap tide velocity (Phoon, 2006). Figure 23 shows the average annual tidal power off the UK coastline.

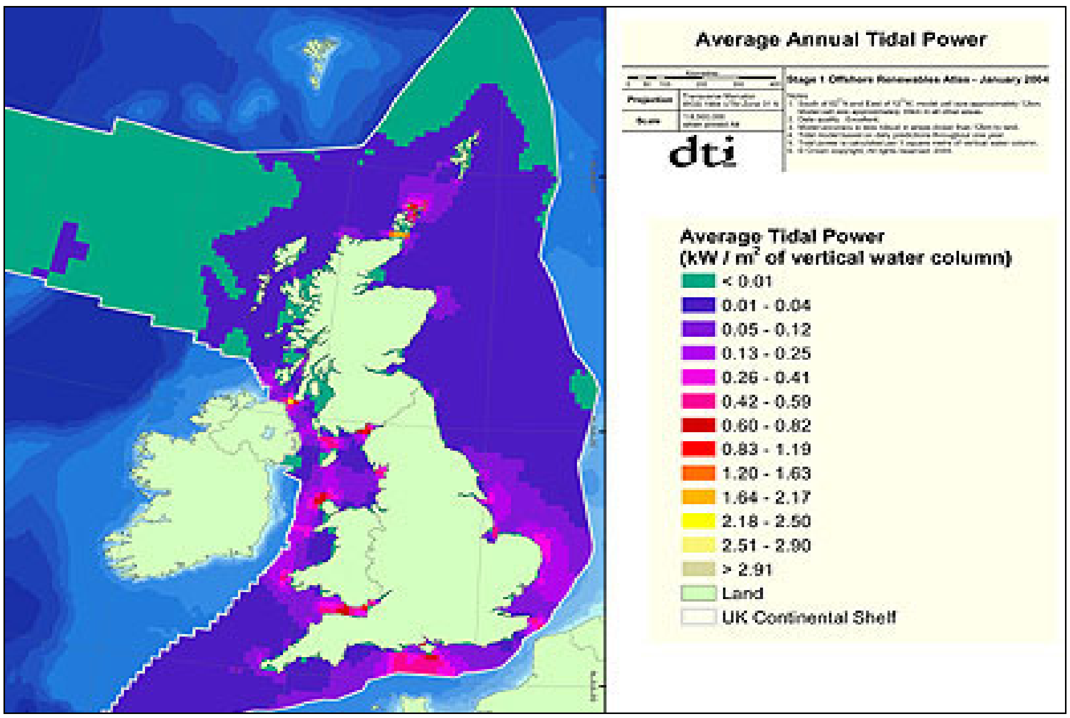


Figure 23 - Average annual tidal power off UK coastline (Source: BWEA, 2004)

Unfortunately, despite the high predictability of availability, the peak power generated through tidal power often does not coincide with the system peak load. Hence, although the wave and tidal generation cannot be relied on for supplying power during peak periods, they can become a good backup capacity whenever they are available.

Solar Power

The most common solar power generation in GB comes from the solar photovoltaic (PV) technology. Solar PV is sometimes referred to as solar cells. They are devices or banks of devices that use the photovoltaic effect of semiconductors to generate electricity directly from sunlight. However, they only need daylight and not direct sunlight to generate electricity and so can generate some power even on cloudy days.

The underlying theory behind solar PV operation is that the PV cell consists of one or two layers of semi-conducting material, normally silicon. When the light shines on the cell, it creates an electric field across the layers causing electricity to flow. This flow of electricity increases with greater intensity of light. The current produced is however in the form of direct current and has to be converted to alternating current before being used domestically or exported to the grid.

Like other renewable sources, solar generation is also subjected to intermittency. The intermittent nature of the solar generation is attributed to the factors below;

i. solar insolation / intensity
ii. time of the day and day of the year
iii. water content in the air
iv. cloud coverage
v. location of solar PV

Presently, solar PV is mostly used in domestic sectors, attached to the rooftop to generate electricity. Solar panels produce more power during summer months as they receive more sunlight during this period. In a way, having a large scale solar generation would complement the wind generation as the solar generation peaks during the summer months and troughs in winter months whereas wind generation does just the opposite.

Chapter 4 Reliability Evaluation Methodology

In this chapter, the methodology or method of approach taken in conducting generation reliability evaluation of the GB system for this thesis is explained. It is hoped that the steps outlined in this chapter will be beneficial to those who would like to take similar approach in conducting other generation reliability study. The chapter starts by describing the main steps used in the methodology before going into input data required and sources for that data.

4.1 Methodology

On the macro level, there are four main steps used in conducting this generation reliability evaluation. They are as follows;

1. Input data gathering
2. Model building
3. Simulation
4. Result analysis.

Firstly, the input data required to build the reliability models and the sources for these data are identified. Most of the time, the data found are in raw form, which means that they are not in the form that is ready to be used directly in the reliability model. Hence, the relevant data have to be extracted and prepared or converted to suit the reliability model.

Gathering the input data is the most important stage in the whole methodology as the quality of the input data will at the end of the day determine the quality of the reliability indices produced by the reliability models. Therefore, in any project, sufficient time must be allocated to data gathering. Scheduling of data collection must take into account the amount of detail and confidentiality of the data required. The input data used in this study is discussed specifically in section 3.2

Once the input data is ready, the next step in the reliability evaluation is to build suitable and relevant models. For this study, three models were identified to form the Great Britain System Reliability Evaluation Programme (GBSREP). They are the wind model, load model and the conventional plant model. More information of GBSREP can be found in Section 3.3. The models built should first be validated before customising it to carry out case studies. One way to do this is by using the IEEE 1996 RTS data. In this case, GBSREP is an extension to the SREP, which was validated using the RTS data.

Upon validation, the model is ready to be used to carry out analysis of the chosen system, which is the GB generation system. The next step is therefore carrying out simulations. For simulations, Load Probability Table (LPT) is tabulated followed by Capacity Outage Probability Table (COPT) and finally, System Margin State Table (SMST). The reference case set for comparison is known as the Base Case. In order to investigate the effects of various parameters on the system reliability, several case studies were created by changing the relevant data in the model. The case studies are extended in this study in an attempt to evaluate the reliability of GB system in the presence of intermittent renewables in the future, namely in 2013 and in 2020. The case studies used in this study are elaborated further in Chapter 6.

The end products of the reliability assessment are the reliability indices. The reliability indices chosen to quantify the reliability of the GB system for this study are the Loss of Load Expectation (LOLE), Loss of Load Probability (LOLP) and Expected Energy Not Served (EENS). The final step is to analyse these results are then analysed to form the conclusion on the reliability of the GB generation system.

The three key steps elaborated in the methodology to evaluate the reliability of a generation system can be summarised by Figure 24.

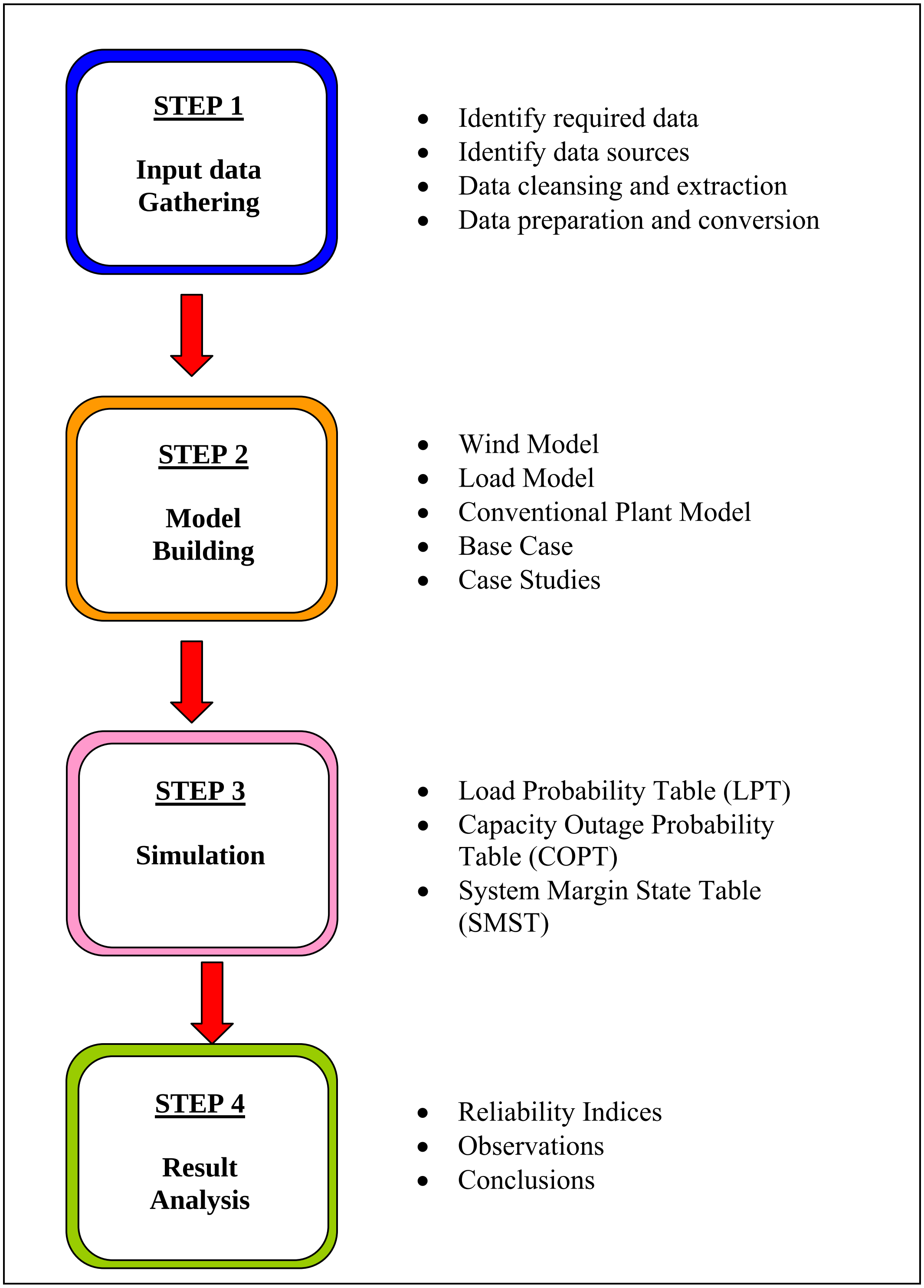


Figure 24 - Generation system reliability evaluation methodology

4.2 Input data

The data required in order to build the GBSREP can be categorised into three types. They are load data, generating plant data and wind data.

4.2.1 Load Data

There is an option to use daily peak demand, hourly peak demand and half-hourly peak demand. For this study, the hourly peak demand is chosen mainly because it offers a high degree of representation of the GB load demand profile and at the same time will not require much computation time in generating the reliability indices. Furthermore, the hourly peak demand offers a degree of flexibility as the daily peak demand can be extracted from the hourly peak demand and be used to calculate the reliability indices as comparison to those generated from the hourly demand. Hence, there are 8760 load data points for the hourly peak demand and 365 data for the daily peak.

A period of one year is used for this programme and it is chosen based on the financial year used by the National Grid for the sake of consistency in the system model. This financial year starts on 1 April and ends on 31 March every year. The load data used for the base case is from the 2006/07 financial year as this is the latest completed annual data. The historical data is obtained from the National Grid website. As the system operator, National Grid is required to publish the Initial Demand Outturn (INDO) biannually. This load data excludes export to external systems and also the station demands. INDO data can be found through the source link below:

Source : Operational Data, National Grid Website
Source Link : http://www.nationalgrid.com/uk/Electricity/Data/Demand+Data/

Meanwhile, for the future GB system, the load data required is the forecasted annual peak demand. The hourly peak demand for the year of interest can then be derived using the hourly profile from the base year or any other year deemed suitable. This forecasted annual demand can be found in the Seven Year Statement (SYS) published annually by the National Grid. The SYS in use as reference for this study is the SYS 2007. The data can be found through the source link below:

Source **:** Table 2.1- ACS Peak Demand Forecasts (GW), SYS2007

Source Link :

http://www.nationalgrid.com/uk/sys_07/default.asp?action=dddownload&Node=SYS&sNode=16&Exp=Y

The chronological load data used can be sourced directly from the system operator as is the case in this study. Alternatively, the load data can be generated using the primary load data such as in the IEEE RTS 1996. In order to do this, three sets of data will be required and they are as follows;

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 in a day)

4.2.2 Plant Data

The data required to establish the plant model and COPT or generating units are listed as follows;

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. availability or operational factor of generator units

Usually, the data can be sourced directly from the individual generating plants or from the system operator. In this case, the full list of all conventional and wind generating units for GB system is available from the Seven Year Statement made available online at the National Grid website. Both lists of existing and future plant in operation and expected to operate in the GB system can be found through the data download section of the SYS. The link to the SYS 2007 is given by the source link below.

Source : Table 3.6- Generating Unit Data (SYS 2007)

Source Link : http://www.nationalgrid.com/uk/sys_07/default.asp?action=dddownload

Next, effective capacity and annual availability or forced outage rates of each plant in operation is needed to carry out reliability evaluation of the GB generation system. Ideally, the availability for each of the generating units for the period of study would be obtained from the respective plant operators. Although this is possible, it is extremely time consuming and most of the time this data would not be released to the public as the data is confidential - especially in the competitive electricity market system. However, there is the option of looking at published availability data according to plant type and size. The various availability rates found through this study and their source link are shown as Figure 25, 26 and 27.

Source 1 : Performance of Generating Plants 2001 by World Energy Council

Source Link :

http://www.worldenergy.org/wec-geis/publications/reports/pgp/foreword/foreword.asp

Plant Type	Sizes (MW)	Availability Factor (%) 1994-1996
Gas Turbine	30 - 75	77.90
	76 - 150	86.18
	All Sizes	81.89
CCGT	101 - 200	85.93
	201 - 300	86.56
	301 & Up	88.26
	All Sizes	86.80

Figure 25 - Availability factor for gas turbine and CCGT according to sizes (WEC)

Source 2 : NERC Generating Availability Report 2005

Source Link : http://www.nerc.com/~filez/gar.html

Plant Type	Sizes (MW)	Availability Factor (%)	
		2005	2001-2005
Coal	001-099	88.61	88.03
	100-199	88.35	88.52
	200-299	89.73	88.54
	300-399	88.94	87.27
	400-599	86.09	86.17
	600-799	88.17	87.01
	800-999	88.74	87.63
	1000+	86.68	83.61
Oil	001-099	86.94	90.07
	100-199	85.63	84.76
	200-299	86.43	84.64
	300-399	84.25	82.53
	400-599	88.75	86.86
	600-799	70.79	81.73
	800-999	88.67	89.35
Gas	001-099	94.01	93.21
	100-199	87.71	86.84
	200-299	85.69	85.75
	300-399	89.58	84.57
	400-599	88.01	85.85
	600-799	86.85	80.88
	800-999	86.65	86.89
Nuclear PWR	400-799	84.57	90.24
	800-999	92.41	88.57
	1000+	90.48	90.66
Nuclear BWR	400-799	92.28	92.52
	800-999	91.77	92.58
	1000+	93.22	88.23
Gas Turbine	001-019	90.07	92.26
	020-049	93.90	94.95
	50+	93.41	93.14
Hydro	001-029	88.26	88.93
	30+	88.16	88.81
Pumped Storage	All Sizes	88.72	89.85

Figure 26 - Operational factor for generating unit according to plant types and sizes (NERC)

Source 3 : PRIS - IAEA

Source Link : http://www.iaea.org/programmes/a2/

Plant Name	Set No	BM Unit	Plant Type	UEC (MW)	Operational Factor (%) 2005	Operational Factor (%) 2001-2005
Dungeness B	21	T_DNGB21	Nuclear AGR	541	68.94	67.74
Dungeness B	22	T_DNGB22	Nuclear AGR	541	64.06	72.00
Hartlepool	1	T_HRTL-1	Nuclear AGR	604	55.13	71.50
Hartlepool	2	T_HRTL-2	Nuclear AGR	604	73.38	80.26
Heysham 1	1	T_HEYM11	Nuclear AGR	607	85.14	77.75
Heysham 1	2	T_HEYM12	Nuclear AGR	596	44.17	65.63
Heysham 2	7	T_HEYM27	Nuclear AGR	601	83.53	89.10
Heysham 2	8	T_HEYM28	Nuclear AGR	603	97.76	89.64
Hinkley Point B	7	T_HINB-7	Nuclear AGR	644	94.26	91.15
Hinkley Point B	8	T_HINB-8	Nuclear AGR	617	74.7	86.36
Hunterston	7	HUNB-7	Nuclear AGR	605	93.69	92.77
Hunterston	8	HUNB-8	Nuclear AGR	605	80.1	85.35
Torness	1	TORN-1	Nuclear AGR	600	95.57	86.81
Torness	2	TORN-2	Nuclear AGR	600	97.83	80.66
Dungeness A	1	T_DUNG-1	Nuclear Magnox	110	89.86	79.13
Dungeness A	2	T_DUNG-1	Nuclear Magnox	110	89.86	79.13
Dungeness A	3	T_DUNG-1	Nuclear Magnox	110	75.22	83.51
Dungeness A	4	T_DUNG-1	Nuclear Magnox	110	75.22	83.51
Oldbury	1	T_OLDS1	Nuclear Magnox	228	45.63	70.20
Oldbury	2	T_OLDS2	Nuclear Magnox	242	42.73	83.46
Sizewell A	1	T_SIZEA1	Nuclear Magnox	234	100	78.14
Sizewell A	2	T_SIZEA2	Nuclear Magnox	224	85.18	84.25
Wylfa	1	WYLF-1	Nuclear Magnox	245	82.19	78.40
Wylfa	2	WYLF-2	Nuclear Magnox	245	82.19	78.40
Wylfa	3	WYLF-3	Nuclear Magnox	245	98.69	77.78
Wylfa	4	WYLF-4	Nuclear Magnox	245	98.69	77.78
Sizewell B	3	T_SIZB-1	Nuclear PWR	595	85.34	89.95
Sizewell B	4	T_SIZB-2	Nuclear PWR	595	85.34	89.95

Figure 27 - Operational factor for nuclear units in GB

4.2.3 Wind Data

Relative to the load and plant data, the wind generation profile for wind plants in GB is quite difficult to find. This is because the information is confidential to each of the wind farm operators. The best way to get hold of the data is by contacting the individual plants themselves. Acquisition of wind data proved to be the most time consuming activity in this study and hence, future similar studies must allocate enough time to obtain the wind data.

For this study, four hourly wind generation output profiles were obtained from four different regions and geographical locations in GB for a period of one year. They are North Scotland, East Scotland, West Scotland and South Scotland and England. Ideally, the wind profile to be used in the model should be for the same period as the one used in the load data and plant data. Unfortunately, the wind generation profiles obtained are from different years but start and ends on the same day. A summary of the wind data is given by Figure 28. The individual and average capacity factor for these region falls between 24 percent and 30 percent, consistent with the findings of the study by Sinden (2005).

Region Number	Region Name	Profile Year
1	North Scotland	2005/06
2	East Scotland	2002
3	West Scotland	2002
4	South Scotland and England	2002

Figure 28 - Wind region and corresponding year from which the profile was taken

Nevertheless, it is assumed that the wind generation profiles remain the same every year for each of the regions so that these separate data sources can be used directly in the model. The wind data obtained is in the form of hourly fractions of the annual maximum capacity. Hence, those data are treated as primary data and wind generation data for 2006/07 is derived from them simply by multiplying the maximum wind capacity in the region by each of the hourly fraction in the relevant region.

Chapter 5 Reliability Evaluation Modelling

This chapter describes how the modelling process starts with the GB hourly load data and from this develops the LPT, similarly the generating unit data is used to develop the COPT and the convolution of the two tables produces the SMST. Basically, the topics covered in this chapter are Step 2, Step 3 and Step 4 of the methodology, which are Model Building, Simulation and Result Analysis.

It is to be noted that the modelling adopted for this study is the customisation and upgrade of SREP model developed by Phoon in his thesis entitled ‘Generation System Reliability Evaluations with Intermittent Renewables’.

5.1 Model Building

The modelling of the GB generation system is undertaken using MS Excel together with the built-in Visual Basic Editor. The developed programme is called Great Britain System Reliability Evaluation Programme or in short GBSREP.

5.1.1 Load Model

The load model is built using actual GB hourly chronological load data for 2006/2007 to represent the existing GB load demand. This model consists of 8760 data points, which represent the system hourly peak. The maximum demand for this system for this study period is 57,489 GW. Figure 29 shows the snapshot of the load model in GBSREP.

However, it must be noted that if the modelling of the load curve is undertaken using the primary load data, the total number if hours in a year would only be 52 weeks x 7 days x

24 hours, which equals to 8736 hours only instead of 8760. Hence some modification to the programme must be carried out accordingly.

GB LOAD DATA

GB Demand Profile Used: 2006/07
FY Start Date: 01-Apr-06
FY End Date: 31-Mar-07

Maximum load in system: 57489 MW
Minimum load in system: 22271 MW
Average load in system: 38668 MW
Calculated Load Factor: 67.1%

Hourly Peak Load

	Hour	1	2	3	4	5	6	7	8	9	10
Week No.	Day										
1	01-Apr-06	31811	33264	33214	32597	31207	30468	32028	35187	37648	39421
1	02-Apr-06	30798	32051	31733	31132	30051	29211	29256	30792	32682	35506
1	03-Apr-06	30189	32445	32433	31876	31388	32510	37920	44098	45286	46045
1	04-Apr-06	32852	34929	35139	34633	33912	34880	39752	45643	46694	46971
1	05-Apr-06	33661	35977	36230	35754	35065	35879	40669	46377	47238	47583
1	06-Apr-06	33093	35091	35215	34856	34073	34828	39696	45488	46533	46800
1	07-Apr-06	33064	35272	35324	34774	34000	34540	39133	44929	46109	46751
2	08-Apr-06	32825	34364	34468	33954	32772	31951	33308	36382	38773	40388
2	09-Apr-06	32129	33332	33410	32965	31861	30765	30516	32347	34293	36862
2	10-Apr-06	32149	34402	34707	34475	33919	34640	39151	44785	46988	47849
2	11-Apr-06	33354	35249	35497	35160	34168	34742	38937	44419	46649	48020
2	12-Apr-06	33467	35542	35836	35558	34643	35048	39102	44152	45602	46247
2	13-Apr-06	32561	34371	34550	33835	32839	33430	37402	42604	44478	45429
2	14-Apr-06	31847	33311	33326	32649	31353	30757	31929	34621	36684	38538
3	15-Apr-06	30495	31619	31441	30734	29330	28697	29571	32298	34883	36978

LoadData PlantData WindModel COPT Wind1 Wind2 Wind3 Wind4

Figure 29 - Snapshot of load model in GBSREP

5.1.2 Conventional Plant Model

For the conventional plant model, the generating units are grouped according to the plants and wherever possible, identical generators within the plant are grouped together. They are then arranged in ascending order according to their effective capacity. The total generation capacity for 2006/07 modelled for GB is about 77.3 GW. However, the SREP model developed by Phoon (2006) is designed for a system of generation capacity of 3.4 GW. It is recommended by the same author that the step increment for the capacity outage table be 1MW. Due to the limitation of MS Excel and shorter computation time, the plant model in GBSREP has to reduce the effective capacity of the generating units by a factor of 10 – so 10MW steps are used in the COPT.

The plant model consists of 148 groups of generating unit made up of 256 generators. It is important to note that hydro plants are included in the plant model and the combined cycle units are modelled as a generating block (of however many gas and steam turbines exist in each generation station) rather than individual generating units. Figure 30 shows a snapshot of the conventional plant in GBSREP.

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GB PLANT DATA

Total number of groups: 148
Total System Capacity: 7751.0 x10^7 W

Unit Group	Unit Type	No. of	Unit Size, (x10^7W)	Outage Rate,	Availability, A	Actual Unit (MW)	Group (x10^7W)	Actual Group Cap (MW)
Hinkley Point B	Nuclear AGR	1	62.000	0.253	0.747	617	62	617
Hinkley Point B	Nuclear AGR	1	64.000	0.0574	0.9426	644	64	644
Drax	Large Coal	6	65.000	0.1183	0.8817	649	390	3894
Grain	Oil	1	65.000	0.2921	0.7079	650	65	650
Peterhead	Dual Fuel Oil/Ga	1	66.000	0.1183	0.8817	660	66	660
Little Barford	CCGT	1	67.000	0.1344	0.8656	665	67	665
Killingholme 2	CCGT	1	67.000	0.1407	0.8593	665	67	665
Medway	CCGT	1	68.000	0.1344	0.8656	680.1	68	680.1
Littlebrook D	Oil	2	69.000	0.2921	0.7079	685	138	1370
Coryton	CCGT	1	72.000	0.1344	0.8656	720	72	720
Immingham CHP stage 1	CCGT	1	74.000	0.1344	0.8656	740	74	740
Keadby	CCGT	1	74.000	0.1344	0.8656	735	74	735
Didcot B	CCGT	1	75.000	0.1344	0.8656	750	75	750
Rocksavage	CCGT	1	75.000	0.1344	0.8656	748	75	748
Didcot B	CCGT	1	75.000	0.13440	0.8656	750	75	750
South Humber Bank	CCGT	1	77.000	0.1407	0.8593	769	77	769
Sutton Bridge	CCGT	1	80.000	0.1344	0.8656	800	80	800
Damhead Creek	CCGT	1	81.000	0.1344	0.8656	805	81	805
Seabank	CCGT	1	82.000	0.1344	0.8656	819.9	82	819.9
Rye House	CCGT	1	83.000	0.1407	0.8593	829	83	829
Spalding	CCGT	1	87.000	0.1344	0.8656	870	87	870
Teesside	CCGT	2	94.000	0.1407	0.8593	937.5	188	1875
Peterhead	CCGT	1	146.000	0.1174	0.8826	1458	146	1458
		265					7751.0	77283.9

Figure 30 - Snapshot of Plant Model in GBSREP for Base Case

The generator parameters modelled in GBSREP are as follows;

1. availability of generating units
2. outage rate of generating units
3. number of identical generator units in the system
4. effective capacity of generating units

5.1.3 Wind Model

The final part of the model building step is to model the intermittent wind profile and generation and integrate this into the existing model consisting of the load and conventional plant models. This way, the effect of intermittent generation on system reliability can be captured and studied. It is in the initial project objectives to include wave, tidal and solar generation models also. However, due to the time constraint, data limitation and low penetration level of these intermittent generations in the GB generation system presently, they have not been included in this study.

Wind plant hourly capacity profile model

Total number of wind region(s) to evaluate: 4
Maximum wind capacity from all regions: 941 MW

Calculate wind

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Total wind generation capacity to be evaluated for the year

Assumption: Wind capacity taken as average for the whole hour

Index	Day min	Day max	Day	Week	Date	1 (MW)	2 (MW)	3 (MW)	4 (MW)	5 (MW)	6 (MW)	7 (MW)	8 (MW)
1	59.2	595.9	Monday	1	01-Apr	538.1	483.5	442.0	546.6	595.9	546.7	273.6	300.2
2	60.5	660.1	Tuesday	1	02-Apr	60.5	84.6	201.0	91.7	119.9	136.8	188.5	183.7
3	19.4	522.2	Wednesday	1	03-Apr	473.4	442.4	342.3	522.2	345.8	368.4	338.4	318.6
4	47.4	468.0	Thursday	1	04-Apr	47.5	56.0	86.0	67.2	63.4	81.5	94.8	132.5
5	335.9	650.4	Friday	1	05-Apr	522.2	484.4	568.7	416.5	335.9	511.0	489.0	373.0
6	137.3	609.9	Saturday	1	06-Apr	471.2	425.4	393.5	460.7	553.1	358.0	382.5	609.9
7	29.8	250.8	Sunday	1	07-Apr	139.8	135.6	57.1	139.0	163.5	167.1	163.5	126.1
8	0.1	212.0	Monday	2	08-Apr	120.5	120.7	115.1	117.8	130.2	124.4	147.2	140.1
9	7.8	253.4	Tuesday	2	09-Apr	7.8	219.0	221.3	220.5	218.4	215.2	220.6	220.4
10	69.3	159.5	Wednesday	2	10-Apr	136.3	140.0	147.3	153.0	81.9	100.7	69.3	71.9
11	56.7	341.1	Thursday	2	11-Apr	111.5	111.8	111.5	115.8	115.8	101.8	86.2	56.7
12	147.3	315.5	Friday	2	12-Apr	293.2	315.5	282.6	276.7	264.6	267.2	264.0	231.1
13	13.4	194.1	Saturday	2	13-Apr	194.1	122.4	147.3	123.5	149.6	153.3	146.2	121.4
14	2.8	400.7	Sunday	2	14-Apr	10.4	14.9	19.8	2.8	9.0	21.8	23.4	78.7
15	75.3	269.6	Monday	3	15-Apr	75.3	195.5	209.8	167.3	163.4	145.3	169.1	182.9
16	206.5	618.8	Tuesday	3	16-Apr	206.5	259.3	250.4	252.4	303.3	279.3	308.2	386.9
17	315.1	644.5	Wednesday	3	17-Apr	490.2	337.7	478.7	387.0	443.6	434.0	465.1	530.9
18	169.0	392.2	Thursday	3	18-Apr	313.7	284.1	300.0	295.4	292.6	297.9	318.2	376.2
19	0.0	278.8	Friday	3	19-Apr	278.4	277.7	278.0	278.8	274.8	229.0	175.4	122.0
20	215.9	546.3	Saturday	3	20-Apr	215.9	263.2	289.4	367.9	378.9	352.9	379.1	365.1

Figure 31 - A snapshot of Wind Model in GBSREP from the Base Case

The wind model developed for this study adopts the load-modifying method as described in Chapter 3 of this thesis. It is an hourly model to suit the load data and model used for this study. In order to minimise the extreme highs and extreme lows of wind speed in GB, four wind models were created representing four different geographical locations in GB. As the wind profiles are in percentages of effective capacity, the capacity of each of these regions must be multiplied by the hourly fraction of the respective regions first to form the hourly chronological wind generation for that particular region.

Once created, the wind generation for all our regions are summed together to form the total wind generation for GB. This is then deducted from the load data for the corresponding hour. The resultant data is called the net load data. This modified load profile will then be used to produce the load probability table. Together with the existing conventional generating unit, the net load data will be used to determine the reliability of the GB system with intermittent wind effect incorporated into the load model.

A snapshot of the wind model, made of the hourly total of wind generation in GB is shown as Figure 31.

5.1.4 Case Studies

All the models are first built to represent the existing GB system. For this purpose, data from financial year 2006/07 is used to form the base case otherwise known as case study 1. This particular year is chosen as it is the latest complete annual data available to the public at the time of study and is therefore assumed to be the most representative of the present GB system.

In total, six case studies were analysed for this project. Four of them were carried out on the existing GB system and the other two focuses on the future GB system. The case studies conducted on the present system aim to investigate the effect of different factors on the system reliability. Meanwhile, the future case studies are analysed to evaluate the GB system reliability in the longer term. Many assumptions are made for each of the case studies and they are elaborated further in Chapter 6. The lists of case studies undertaken are as follows:

Case Study 1: Base Case 2006/07

Case Study 2: Interconnections with External Systems

Case Study 3: Diversified Wind Generation Capacity and Location

Case Study 4: Plant Availability

Case Study 5: GB Electric System 2013/14

Case Study 6: GB Electric System 2020/21

5.2 Simulation

The GBSREP is used to model and simulate conventional generation system in the presence of intermittent renewable (wind power in this study) with load and generating plants. The analytical method is adopted for this analysis. The model is also used to calculate the reliability indices namely Loss of Load Probability (LOLP) and Loss of Load Expectation (LOLE). Expected Energy Not Served (EENS) is then calculated from these indices to further quantify the indices more meaningfully.

There are three main parts to simulation using GBSREP. Firstly, LPT is generated. Once this is done, The COPT is tabulated. Finally, the SMST simulation is carried out by convolving LPT and COPT, to obtain the reliability indices. The simulation process is summarised in Figure 32.

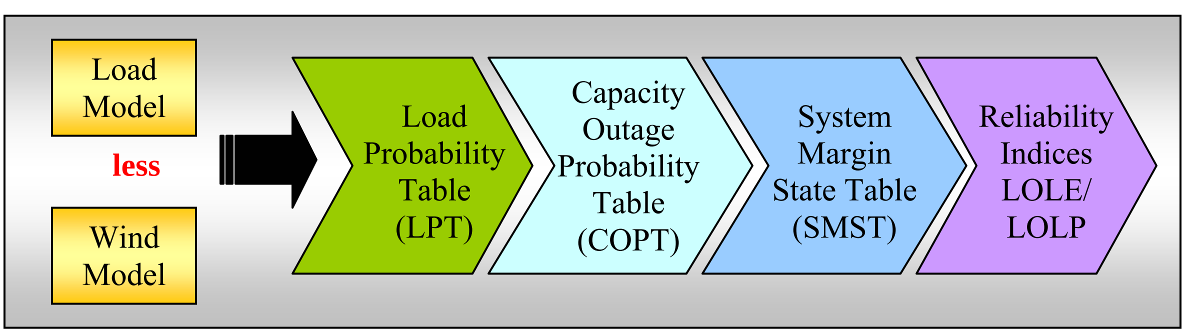


Figure 32 - Simulation process in GB generation reliability Assessment

5.2.1 Load Probability Table (LPT)

The LPT is tabulated using the net load data. The net load data is obtained by deducting the hourly wind generation from the load demand for the corresponding hour. The data is then converted to hourly percentage of peak load before being used to create the LPT. A snapshot of the net load model in percentage of annual peak load is shown as Figure 33. The probability of a load increase from every load level can be calculated using equation 5.1.

$$P(L_j) = \sum_j \frac{t_{ij}}{T} \tag{5.1}$$

Where:

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

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

Hourly Peak Load in Percentage of Maximum Demand

Week No.	Hour / Day	1	2	3	4	5	6	7	8	9	10	11
1	Saturday	0.54	0.57	0.57	0.56	0.53	0.52	0.55	0.61	0.65	0.68	0.69
1	Sunday	0.54	0.56	0.55	0.54	0.52	0.51	0.51	0.53	0.57	0.61	0.64
1	Monday	0.52	0.56	0.56	0.55	0.54	0.56	0.65	0.76	0.78	0.80	0.80
1	Tuesday	0.57	0.61	0.61	0.60	0.59	0.61	0.69	0.79	0.81	0.81	0.81
1	Wednesday	0.58	0.62	0.62	0.62	0.60	0.62	0.70	0.80	0.81	0.82	0.82
1	Thursday	0.57	0.60	0.61	0.60	0.58	0.60	0.68	0.78	0.80	0.81	0.81
1	Friday	0.57	0.61	0.61	0.60	0.59	0.60	0.68	0.78	0.80	0.81	0.81
2	Saturday	0.57	0.60	0.60	0.59	0.57	0.55	0.58	0.63	0.67	0.70	0.71
2	Sunday	0.56	0.58	0.58	0.57	0.55	0.53	0.53	0.56	0.59	0.64	0.67
2	Monday	0.56	0.60	0.60	0.60	0.59	0.60	0.68	0.78	0.82	0.83	0.83
2	Tuesday	0.58	0.61	0.62	0.61	0.59	0.60	0.68	0.77	0.81	0.83	0.84
2	Wednesday	0.58	0.61	0.62	0.61	0.60	0.61	0.68	0.76	0.79	0.80	0.80
2	Thursday	0.56	0.60	0.60	0.59	0.57	0.58	0.65	0.74	0.77	0.79	0.79
2	Friday	0.55	0.58	0.58	0.57	0.55	0.54	0.56	0.60	0.64	0.67	0.68
3	Saturday	0.53	0.55	0.54	0.53	0.51	0.50	0.51	0.56	0.60	0.64	0.65
3	Sunday	0.51	0.53	0.52	0.51	0.49	0.47	0.47	0.50	0.53	0.57	0.59
3	Monday	0.49	0.51	0.51	0.50	0.48	0.47	0.49	0.52	0.56	0.59	0.61
3	Tuesday	0.50	0.52	0.52	0.52	0.50	0.52	0.59	0.69	0.72	0.74	0.75
3	Wednesday	0.53	0.55	0.55	0.54	0.53	0.54	0.62	0.73	0.76	0.77	0.78
3	Thursday	0.55	0.57	0.57	0.55	0.53	0.55	0.62	0.73	0.75	0.77	0.77
3	Friday	0.55	0.57	0.57	0.55	0.54	0.55	0.62	0.73	0.75	0.77	0.77
4	Saturday	0.53	0.54	0.54	0.52	0.50	0.49	0.51	0.57	0.63	0.66	0.67
4	Sunday	0.51	0.52	0.50	0.49	0.47	0.46	0.47	0.51	0.54	0.60	0.64
4	Monday	0.50	0.53	0.53	0.51	0.51	0.52	0.62	0.75	0.77	0.78	0.78
4	Tuesday	0.53	0.55	0.54	0.53	0.52	0.54	0.63	0.75	0.76	0.78	0.78

Figure 33 - A snapshot of net 'load model' in hourly percentage of peak demand

This calculation can be done manually or using the built-in function in MS Excel called "*frequency*". This function calculates the number of times a value occurs within a range of values. The output is returned as a vertical array of numbers. The load level is arranged in a descending order from the peak load which is 100 percent to 0 percent. As the function returns the calculated frequency in the form of an array, the formula must also be entered as an array in MS Excel. This way, the number of occurrences for every value can be calculated. The value obtained from the calculation can then be converted to the exact probability of the corresponding load level. These exact probabilities can then be use to calculate the cumulative probability for every load level using Equation 5.2.

$$P(l \geq L_i) = \sum_{k \geq i} p(L_k) \qquad \textbf{(5.2)}$$

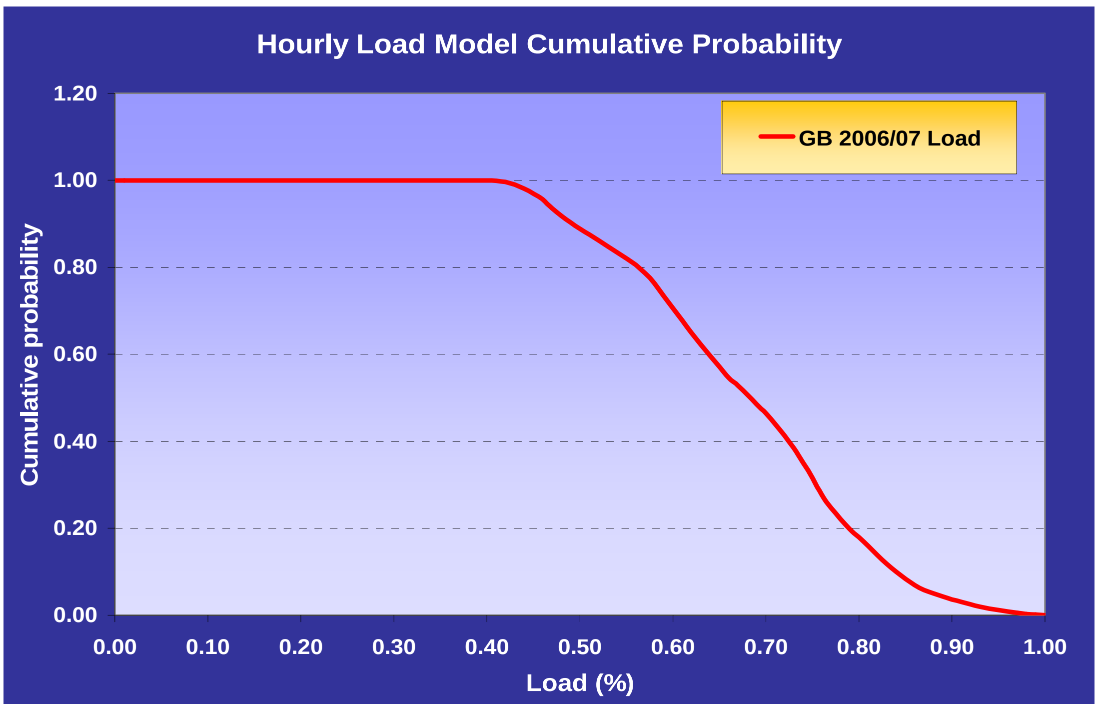


Figure 34 - Load cumulative probability curve for Base Case

The cumulative probability distribution function tabulated for the Base Case is shown by Figure 34. Meanwhile, a snapshot of the LPT generated for the base case is given by Figure 35. Similar approach can be taken to generate the load cumulative probability using daily peak load. LPT is generated automatically in worksheet "Load Data" in GBSREP.

Load Outage Table With Hourly Maximum Load

Load States	Peak Load (%)	Peak Load (/100)	Frequency	Probability	Cumulative Probability	Peak Load (MW)
0	100	1.00	2	0.000228	0.000228	57489.00
1	99	0.99	8	0.000913	0.001142	56914.11
2	98	0.98	15	0.001712	0.002854	56339.22
3	97	0.97	21	0.002397	0.005251	55764.33
4	96	0.96	27	0.003082	0.008333	55189.44
5	95	0.95	31	0.003539	0.011872	54614.55
6	94	0.94	31	0.003539	0.015411	54039.66
7	93	0.93	35	0.003995	0.019406	53464.77
8	92	0.92	50	0.005708	0.025114	52889.88
9	91	0.91	47	0.005365	0.030479	52314.99
10	90	0.90	52	0.005936	0.036416	51740.10
11	89	0.89	63	0.007192	0.043607	51165.21
12	88	0.88	57	0.006507	0.050114	50590.32
13	87	0.87	68	0.007763	0.057877	50015.43
14	86	0.86	96	0.010959	0.068836	49440.54
15	85	0.85	126	0.014384	0.083219	48865.65
16	84	0.84	143	0.016324	0.099543	48290.76
17	83	0.83	161	0.018379	0.117922	47715.87
18	82	0.82	177	0.020205	0.138128	47140.98
19	81	0.81	179	0.020434	0.158562	46566.09
20	80	0.80	185	0.021119	0.179680	45991.20
21	79	0.79	161	0.018379	0.198059	45416.31
22	78	0.78	206	0.023516	0.221575	44841.42
23	77	0.77	223	0.025457	0.247032	44266.53
24	76	0.76	264	0.030137	0.277169	43691.64
25	75	0.75	327	0.037329	0.314498	43116.75
26	74	0.74	317	0.036187	0.350685	42541.86
27	73	0.73	300	0.034247	0.384932	41966.97
28	72	0.72	248	0.028311	0.413242	41392.08

Figure 35 - Hourly Load Probability Table for Base Case

5.2.2 Capacity Outage Probability Table

GB electric system is made up of hundreds of generating unit of different types, effective capacity, and reliability operating in parallel. Assuming each of these units has two operation states, the GB system which has 256 generating units will have 2^{256} capacity states. This is equivalent to about 1.16 $\times 10^{77}$ states, which is obviously too much for any manual calculations and analysis to be carried out. Presently, to handle the large number of states, the recurrent algorithm based on discrete distribution is used by all utilities (McDonald and Wang, 1994).The recurrent algorithm starts of by creating a capacity table for a single generating unit such as shown in Table 9.

Available Capacity MW	Outage Capacity MW	Exact Probability P_i	Cumulative Probability P
c	0	1-q	1
0	c	q	q

Table 9 - Probability model for a single generating unit

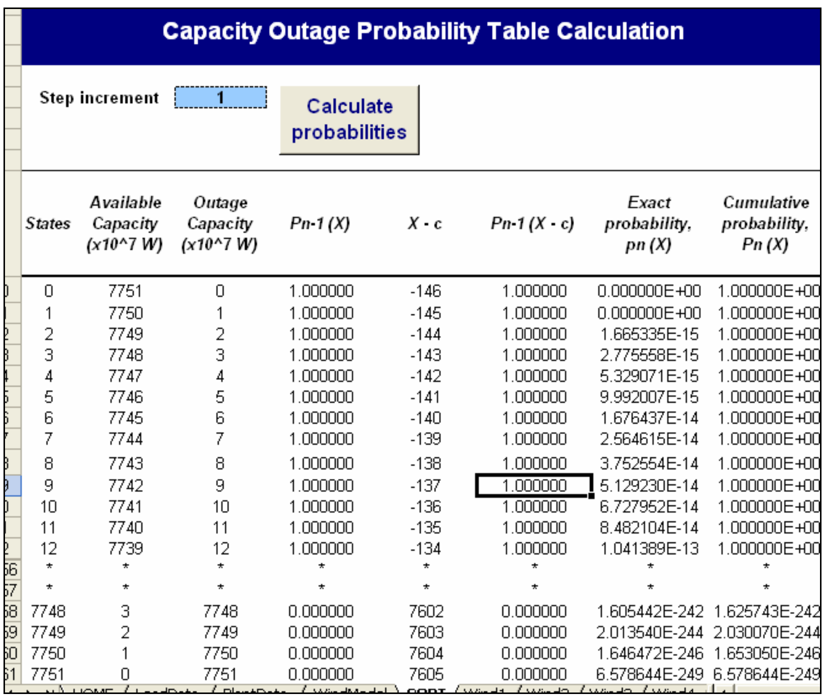
Where

c is the effective capacity of the generating unit

q is the forced outage rate (FOR)

The table is revised as units are added one after another. The capacity outage probability will be completed once the last generating unit, *n*, is added. Assuming X is a random variable with a discrete distribution, this recurrent procedure can be undertaken using a computer algorithm with the recurrence formula given by Equation 5.3. This equation is used to create the COPT for this study.

$$p_n(X) = p_{n-1}(X).(1-q) + p_{n-1}(X - Cn).q_n \qquad \textbf{(5.3)}$$



Capacity Outage Probability Table Calculation

Step increment: 1

Calculate probabilities

States	Available Capacity (x10^7 W)	Outage Capacity (x10^7 W)	Pn-1 (X)	X - c	Pn-1 (X - c)	Exact probability, pn (X)	Cumulative probability, Pn (X)
0	7751	0	1.000000	-146	1.000000	0.000000E+00	1.000000E+00
1	7750	1	1.000000	-145	1.000000	0.000000E+00	1.000000E+00
2	7749	2	1.000000	-144	1.000000	1.665335E-15	1.000000E+00
3	7748	3	1.000000	-143	1.000000	2.775558E-15	1.000000E+00
4	7747	4	1.000000	-142	1.000000	5.329071E-15	1.000000E+00
5	7746	5	1.000000	-141	1.000000	9.992007E-15	1.000000E+00
6	7745	6	1.000000	-140	1.000000	1.676437E-14	1.000000E+00
7	7744	7	1.000000	-139	1.000000	2.564615E-14	1.000000E+00
8	7743	8	1.000000	-138	1.000000	3.752554E-14	1.000000E+00
9	7742	9	1.000000	-137	1.000000	5.129230E-14	1.000000E+00
10	7741	10	1.000000	-136	1.000000	6.727952E-14	1.000000E+00
11	7740	11	1.000000	-135	1.000000	8.482104E-14	1.000000E+00
12	7739	12	1.000000	-134	1.000000	1.041389E-13	1.000000E+00
*	*	*	*	*	*	*	*
*	*	*	*	*	*	*	*
7748	3	7748	0.000000	7602	0.000000	1.605442E-242	1.625743E-242
7749	2	7749	0.000000	7603	0.000000	2.013540E-244	2.030070E-244
7750	1	7750	0.000000	7604	0.000000	1.646472E-246	1.653050E-246
7751	0	7751	0.000000	7605	0.000000	6.578644E-249	6.578644E-249

Figure 36 - A snapshot of COPT with 1 MW step increment from Base Case

The generation system reliability and modelling is conducted in the “COPT” worksheet in GBSREP. The snapshot of COPT build in GBSREP is shown as Figure 36.

5.2.3 System Margin State Table (SMST)

The SMST is formed from the load and generation model. Combining these two models can be undertaken easily without affecting the probabilities in any of the models on the basis that the events occurring in the two models are independent of each other (Endrenyi, 1978). Hence, by combining a discrete level of system load and a discrete level of available capacity, a discrete level of system margins, m_k is created.

A system margin is defined as the difference between system demand and the available effective capacity. Meanwhile, a cumulative margin state contains all the specified margin or less. Billinton and Allan (1996) states that the transition from one margin state to the other can be achieved by changing either the load or the capacity, but not when both are changed simultaneously. For a load state of L_i and capacity state C_n, the margin state the individual probability of the margin state is given by Equation 5.4 and 5.5 respectively.

$$M_k = C_n - L_i \quad \textbf{(5.4)}$$

$$p(M_k) = p(C_n).p(L_i) \quad \textbf{(5.5)}$$

It is important to note that different combinations of load demand and capacity states can produce identical margin states. However, these margin states are independent of one another and can be combined by summing up all the individual exact probabilities. The cumulative probability of state margins can be calculated using two methods. They are;

1. Formula method
2. Convolution Method

Formula Method

For the formula method, the cumulative probability of state margins is calculated using the mathematical formula given by Equation 5.6.

$$P(M) = \sum_{j=1}^{N} p(L_j).P(X_j) \qquad \textbf{(5.6)}$$

Convolution Method

Alternatively, the cumulative probability of state margins can be calculated by convoluting the LPT and COPT using the parallel calculation formula. This formula is shown as Equation 5.7.

$$P_c(X_c) = \sum_{j=0}^{N_b} P_a(X_k - X_j).[P_b(X_k).-P_b(X_{j+1})] \qquad \textbf{(5.7)}$$

Where:

$P_a(X_i)$ = cumulative probability of generating unit (for i = 0,1,2,…N_a)

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

$P_c(X_k)$ = system margin cumulative probability

X_k = Margin state (MW)

X_k can be a positive or a negative value. The most important single index is the cumulative probability of the first negative margin. A computer algorithm was written using the built-in Visual Basic in MS Excel to calculate the cumulative probability state margin based on the parallel formula. The computer program is attached Appendix A.

Figure 37 shows the snapshot of SMST from the GBSREP. For all the case studies, the step increment used for SMST is 1. Meanwhile, the maximum and minimum margin states are fixed to 410 and -60 respectively.

Margin States Table Calculation

Step increment	1	Capacity (x10^7W)	7751
Last Load State	100	Peak Load (x10^7W)	5749
Max. Margin States	410		
Min. Margin States	-60		

Calculate Margin and Reliability

States	Margin state (x10^7W)	Cumulative Margin Probability for hourly load	Cumulative Margin Probability for daily peak load	Margin in % of Peak Load	Mk * pk (for Mk < 0) Hourly	Mk * pk (for Mk < 0) Daily
0	410	4.078124E-05	5.451315E-04	7.1%		
1	409	4.031769E-05	5.391008E-04	7.1%		
2	408	3.985898E-05	5.331310E-04	7.1%		
3	407	3.940507E-05	5.272215E-04	7.1%		
4	406	3.895592E-05	5.213718E-04	7.1%		
5	405	3.851147E-05	5.155813E-04	7.0%		
6	404	3.807169E-05	5.098494E-04	7.0%		
7	403	3.763653E-05	5.041757E-04	7.0%		
8	402	3.720595E-05	4.985597E-04	7.0%		
9	401	3.677990E-05	4.930007E-04	7.0%		
10	400	3.635834E-05	4.874984E-04	7.0%		
11	399	3.594122E-05	4.820521E-04	6.9%		
12	398	3.552852E-05	4.766615E-04	6.9%		
13	397	3.512018E-05	4.713259E-04	6.9%		
14	396	3.471616E-05	4.660449E-04	6.9%		
15	395	3.431643E-05	4.608180E-04	6.9%		
16	394	3.392093E-05	4.556447E-04	6.9%		
17	393	3.352964E-05	4.505245E-04	6.8%		

Figure 37 - Snapshot of SMST with 1 MW step increment for Base Case

5.2.4 Reliability Indices

The reliability indices used in this study are LOLP, LOLE and EENS. From the SMST, the LOLP of the respective load model can be determined just by observing the probability of the first negative margin state. The corresponding LOLE can then be calculated simply by multiplying the LOLP value with the total number of days or hours in a year as follows;

LOLE (in hours/year) = cumulative probability of the first negative margin x 8760

LOLE (in days/year) = cumulative probability of the first negative margin x 365

EENS can then be calculated from LOLE as discussed in Chapter 3. For every case study, the reliability indices are calculated using both the reliability formula method and also the convolution method. These indices are also calculated using both daily and hourly peak load for comparison of results.

5.3 Result Analysis

Finally, the reliability indices obtained are analysed to form a conclusion on the generation reliability state of the GB generation system. To assist in the analysis, the values of LOLE are converted into seconds per year in the result discussion. Meanwhile, the LOLP are expressed in terms of percentages for result presentation. **However, all calculations of EENS were undertaken using their actual units which are hours per year for LOLE for hourly peaks and days per year for LOLE for daily peak load**. Discussions of reliability indices however will be focused on the LOLP, LOLE and EENS calculated using SMST, which is formed by the hourly peak load.

Chapter 6 Case Studies

A reliable generation system is vital in meeting the load requirements continuously. Any disruption in the supply will result in monetary loss to both generators and customers or even worse, lives if hospitals for example are affected. Several case studies are carried out to investigate the GB generation system reliability under different system conditions and scenarios.

Chapter 6 is a collection of the case studies whereby the description of the different case studies together with the assumptions is elaborated. Results and findings of the sensitivity analysis and different scenarios are also presented in this chapter. Basically, the case studies were conducted on two different systems. The first set contains studies based on the existing GB electric system. Meanwhile the second group of case studies involves future GB Electric System with various generation mix scenarios.

6.1 Existing GB Electric System

This group of case studies aims to understand the effect of different components of the system on the system reliability in the presence of intermittent generation, which is wind generation. The sensitivity factors are interconnections with an external system, the level of plant availability and wind diversity. Findings of this study are extremely useful in making decisions in the daily operation of the system. Firstly, a base case is set up as a reference case and any comparison will be made against this case.

Case Study 1: Base Case

For the base case, the model is set up to replicate the GB electric system in 2006/07. This particular year is chosen as the base year as it the most recent and therefore assumed to be the best indication to the existing GB system. Financial year analysis is carried out instead of calendar year 2006 to provide consistency with the National Grid study period which starts on 1 April one year and ends on 31 March the following year.

Load Data

The load data used for this case is from published BMRA Initial Demand Outturn (INDO) based on National Grid operational Generation metering. This load profile excludes station loads, pump storage pumping and interconnection exports. Therefore INDO is net GB demand, which is pure customer demand. The key information regarding the hourly load data in 2006/07 is as listed below:

Maximum Peak Demand	: 57,489 GW
Minimum Peak Demand	: 22,207 GW
Average Peak Demand	: 38,258 GW
Load Factor	: 66.6 percent

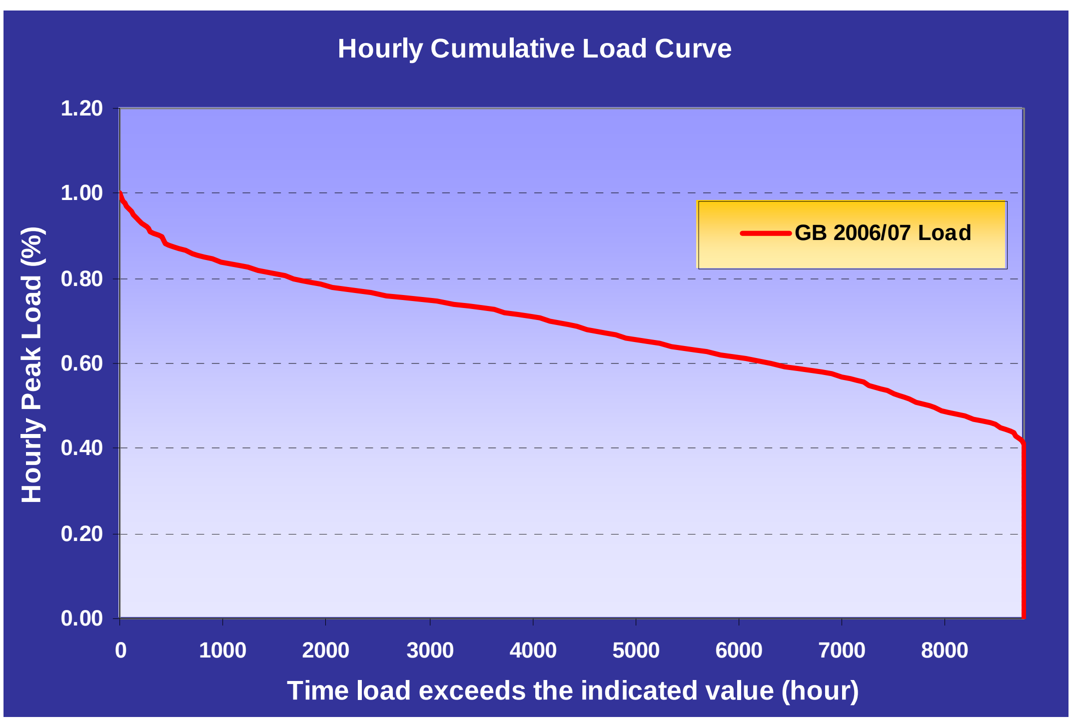


Figure 38 - GB hourly peak demand variation curve

Meanwhile, the hourly peak variation curve produced by the 200/07 profile is shown by Figure 38.

Plant Data

Several sources were found for the plant availability data as detailed in Section 4.2.2 of this thesis. A combination of plant availability from the various sources is used in building the plant data for the base case with actual data taking precedence followed by the most recent data. A compilation of the plant availability data sources used for each generating technology is given by Table 10.

Generating Technology	Data Source
CCGT	World Energy Council
Coal	NERC
OCGT	NERC
Oil	NERC
CHP	Assumed
Nuclear	IAEA
Biomass	Assumed
Hydro	NERC
Pumped Storage	NERC
Interconnector	National Grid

Table 10 - Plant availability sources used in Base Case

Biomass is believed to have an annual plant availability of 0.85. Meanwhile, availability for CHP is assumed to be the same as CCGT due to the similar level of complexity associated with the two technologies. As for the interconnectors, the French Link is reported to have maintained more than 97 percent availability every year (National Grid, 2007) and the Moyle is expected to demonstrate similar availability performance.

Wind Data

Wind resources vary between locations and countries as they are diffuse in nature. Hence, it is impossible to generalize the wind variation into one profile only. For this reason, the wind farms in GB are divided into four main regions depending on their geographical location. The study zones illustrated by Figure 39 adopted in SYS2007 are used as the basis in classifying the wind farms into the respective profile regions. Table 11 summarises the wind different regions and the source for the wind profile used by each region.

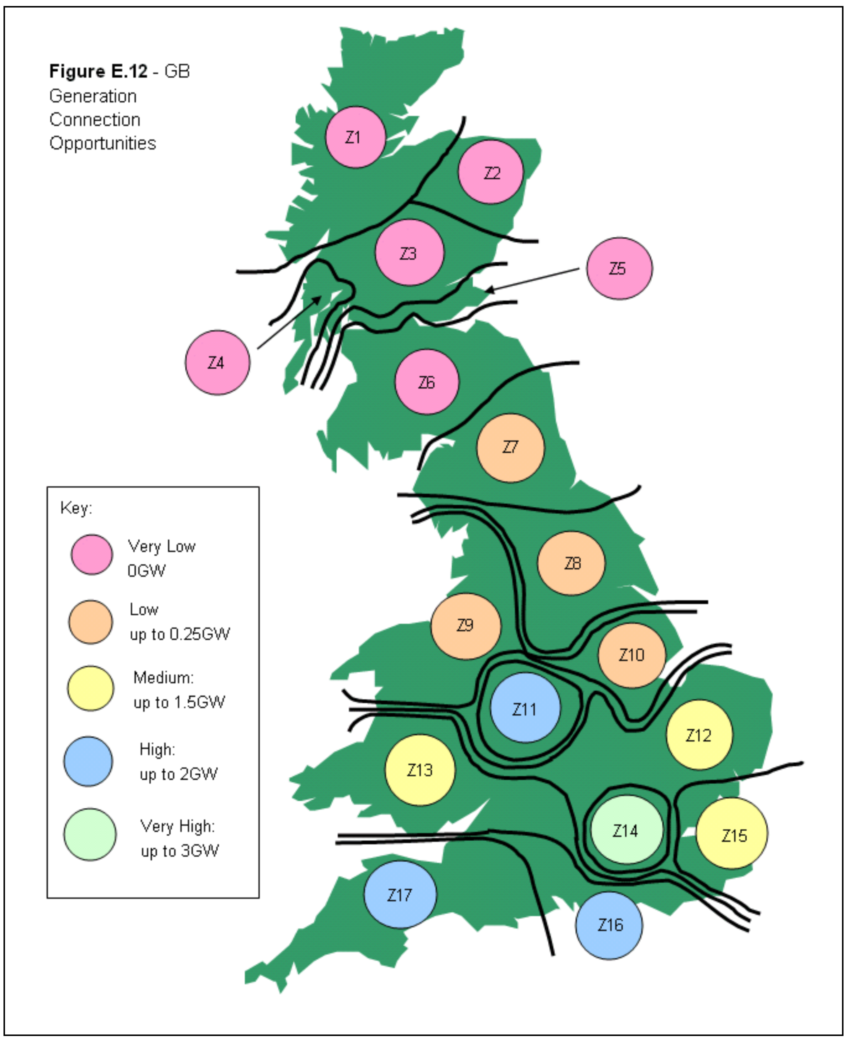


Figure 39 - System Study Zones adopted in SYS2007 (Source: National Grid, 2007)

Wind Profile Region	System Study Zones	Wind Profile Name	Wind Profile Data Source
1	1	Orkney	North Scotland
2	2	WF-3	East Scotland
3	3 to 6	WF-1	West Scotland
4	7 to 17	WF-2	South Scotland

Table 11- Summary of wind data used for Base Case

After sorting out the wind farms into respective regions, the total capacity per region is presented in Table 12. The total effective capacity generated by wind turbine generators in 2006/07 is 1066 MW.

Wind Profile Region	Wind Profile Name	Wind Generation Capacity (MW)	Wind Generation Capacity (%)
1	Orkney	363	34.05
2	WF-3	57	5.35
3	WF-1	506	47.47
4	WF-2	140	13.13
Total		1066	100.00

Table 12 - GB wind generation capacity according to wind profile regions

Results

Findings from the simulation of the base case using daily and hourly peak demand are tabulated in Table 13 below.

Method of evaluation	Daily Peak			Hourly Peak		
	LOLP (%)	LOLE (days/year)	EENS (MWh/year)	LOLP (%)	LOLE (hours/year)	EENS (MWh/year)
Reliability Formula	0.000229	0.00083	-	0.0000154	0.00135	-
Using SMST	0.000224	0.00082	8.246	0.0000151	0.00132	13.256

Table 13 - Results for Case 1 (Base Case)

If reliability criterion of LOLE of 1 day per year is used, GB system is highly adequate as the calculated using both methods are much less that the required figure. This is also true for both daily and hourly peak. The daily peak is the highest demand recorded for the day whereas the hourly peak is the peak demand for each hour of the day. The calculations using reliability formula and daily peak loads generate a slightly higher LOLE (0.00083) compared to that calculated using SMST (0.00082 days/year).

Meanwhile comparing the generated LOLP for using both methods and also both type of load models, the daily peak loads produces higher LOLP than the hourly peak loads. This observation is consistent for calculations using both reliability formula and convolution method. The highest LOLP calculated is only 0.000229 percent. Even at that figure, the LOLP for GB system in 2006/07 is extremely low. However, the high degree of reliability is expected as the reserve margin for the base case is about 35 percent, which is very high for such a large power system. Furthermore, the average plant availability rates are also high at 87.7 percent. Expected energy not served for this year is 8.246 MWh when calculated using the daily peaks and 13.256 MWh using the hourly peak load model.

Case Study 2: Interconnection with External Systems

In 2006/07, the GB system enjoyed an additional 2068 MW import capacity from its interconnection with external systems. This is equivalent to approximately 2.7 percent of the total generation capacity for that year. 1988 MW is contributed by the French Link and the remaining from Northern Ireland through the Moyle Interconnector.

This case study will investigate how much the system reliability will be affected in the absence of one or both of the interconnections. Three scenarios were created for Case Study 2 and they are summarised by Table 14.

Scenario Name	French Link (MW)	Moyle Interconnector (MW)
Base Case	1988	80
Scenario 2a	1988	0
Scenario 2b	0	80
Scenario 2c	0	0

Table 14 - Assumptions adopted for interconnections related scenarios

Results

Results obtained from GBSREP for the scenarios described above are tabulated in Tables 15 and 16. Results from the base case are also included for ease of comparison.

Scenario Name	Reliability Formula		Using SMST		
	LOLP (%)	LOLE (days/year)	LOLP (%)	LOLE (days/year)	EENS (MWh/year)
Base Case (BC)	0.000229	0.00083	0.000224	0.00082	8.246
Scenario 2a	0.000258	0.00094	0.000253	0.00092	9.331
Scenario 2b	0.003726	0.01360	0.003657	0.01335	144.857
Scenario 2c	0.004137	0.01510	0.004061	0.01482	161.358

Table 15 – Results obtained using daily peak load for Case Study 2.

Scenario Name	Reliability Formula		Using SMST		
	LOLP (%)	LOLE (hours/year)	LOLP (%)	LOLE (hours/year)	EENS (MWh/year)
Base Case (BC)	0.0000154	0.00135	0.0000151	0.00132	13.256
Scenario 2a	0.0000174	0.00153	0.0000171	0.00150	15.023
Scenario 2b	0.0002624	0.02298	0.0002574	0.02255	242.638
Scenario 2c	0.0002919	0.02557	0.0002864	0.02509	270.775

Table 16 – Results obtained using hourly peak load for Case Study 2

In the base case when all the interconnections are in, the LOLE calculated using hourly peak and SMST table is only 0.00132 hours per year, which is about 4.8 seconds per year. This is equivalent to 13.256 MWh of EENS in a year. If Moyle interconnection, which has import capability of 80 MW, does not exist, the LOLE for GB system increases very slightly by around 0.6 seconds per year to 0.00150 hours per year. Meanwhile if there are no interconnections with France, the effect on GB system reliability is more severe as this link has import capability of 1988 MW. If this is the case, the LOLE calculated using SMST table for hourly peak accumulates to 0.023 hours per year or 9.18 seconds.

Interestingly, it is observed that if the French link does not exist, having the 80MW Moyle interconnection will make a difference of 0.0025 hours or 9 seconds per year to the system LOLE. This is because, in a smaller system, the 80 MW has a greater contribution towards system reliability compared to that in a larger system. Results obtained for Case Study 2 are consistent with findings in Base Case in the sense that LOLE calculated using the daily peak is higher than that of hourly peak. Meanwhile, the calculation done using Reliability Formula generates higher LOLE compared to using SMST. Figure 40 shows the effect on LOLE in the absence of interconnection(s) for hourly peak using SMST.

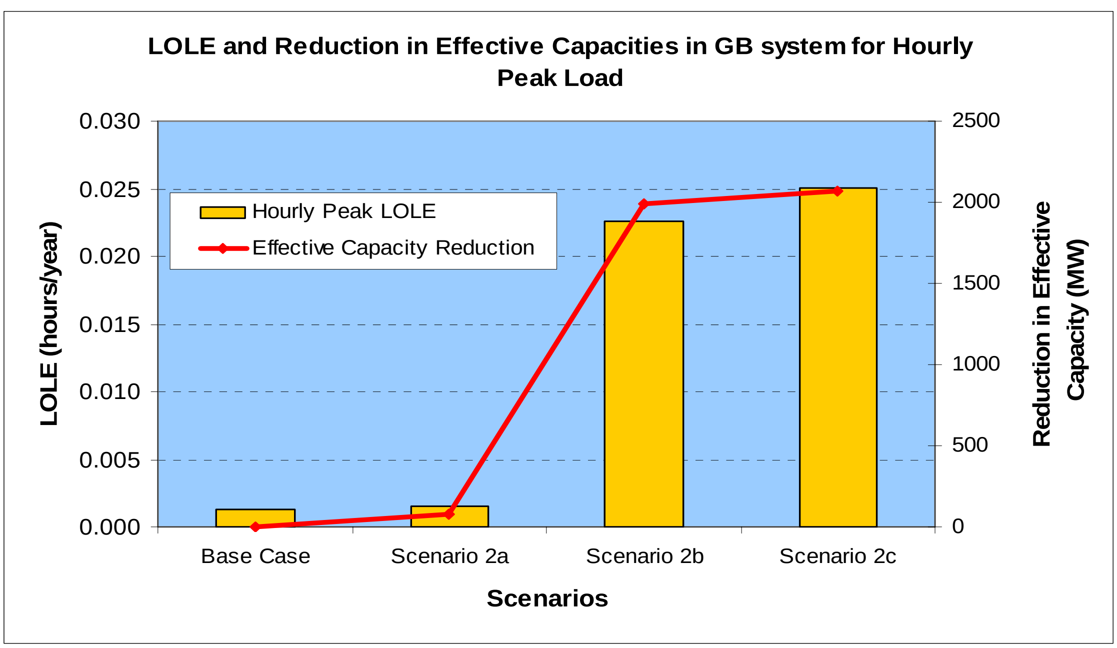


Figure 40 – Effect of reduction in interconnection capabilities on GB hourly peak load LOLE

Case Study 3: Diversity in Wind Generation Capacity and Location

Different parts of GB have different wind profiles. Although some of these locations have high potential in wind generation, which means high capacity factor, they are not necessarily the optimum region to build more wind capacity. This is the case if the wind profile does not match the demand profile whereby the peak generation does not coincide with peak demand.

Case Study 3 attempts to explore this by varying the percentage contribution of wind generation from each region while maintaining the total wind capacity. The chosen percentage shares are 50, 30, 15, and 5 percent as they are similar to the base case percentage shares, which are 47, 34, 13 and 5 percent (refer to Table 12 for more details). The corresponding wind capacity share in MW is shown in Table 17

Percentage Share (%)	**50%**	**30%**	**15%**	**5%**	**100%**
Wind Capacity Share (MW)	533	319.8	159.9	53.3	1066.0

Table 17 – Wind generation capacity shares (MW)

A few permutations of the above percentage shares are applied to the base case producing several scenarios for this particular case study. The changes made to the wind generation share for every region is compiled in Table 18.

Scenario Name	**Regional Percentage Contribution to Total Wind Capacity (%)**			
	Region 1 (Orkney)	**Region 2 (WF-3)**	**Region 3 (WF-1)**	**Region 4 (WF-2)**
Base Case	34.05	5.35	47.47	13.13
Scenario 3a	50	30	15	5
Scenario 3b	5	50	30	15
Scenario 3c	15	5	50	30
Scenario 3d	30	15	5	50

Table 18 - Regional percentage contribution to total wind capacity (%)

Results

The corresponding maximum wind power generated in each region for each percentage share as a result of the changes made is reflected in Table 19. Meanwhile the maximum wind capacity generated by all regions for each scenario is recorded in Table 20.

Region Name	Maximum Wind Capacity Generated (MW) at Different Percentage Shares			
	50%	30%	15%	5%
Region 1	486.8	292.0	146.0	49.0
Region 2	510.0	305.9	153.0	51.0
Region 3	526.0	315.7	157.9	53.0
Region 4	487.0	292.0	146.2	48.7

Table 19 - Regional Maximum Wind Generation based on Percentage Share

Scenario Name	Maximum Wind Generated (MW)
Base Case	940.5
Scenario 3a	900.0
Scenario 3b	987.3
Scenario 3c	976.5
Scenario 3d	922.5

Table 20 - Regional Maximum Wind Generation based on Percentage Share

Reliability indices calculated from GBSREP for Case Study 3 scenarios and also the base case can be found in Tables 21 and 22 below.

Scenario Name	Reliability Formula		Using SMST		
	LOLP (%)	LOLE (days/year)	LOLP (%)	LOLE (days/year)	EENS (MWh/year)
Base Case (BC)	0.000229	0.00083	0.000224	0.00082	8.246
Scenario 3a	0.000197	0.00072	0.000193	0.00070	7.057
Scenario 3b	0.000251	0.00092	0.000246	0.00090	9.101
Scenario 3c	0.000228	0.00083	0.000223	0.00082	8.235
Scenario 3d	0.000204	0.00074	0.000200	0.00073	7.344

Table 21 - Results obtained using daily peak load for Case Study 3

Scenario Name	Reliability Formula		Using SMST		
	LOLP (%)	LOLE (hours/year)	LOLP (%)	LOLE (hours/year)	EENS (MWh/year)
Base Case (BC)	0.0000154	0.00135	0.0000151	0.00132	13.256
Scenario 3a	0.0000138	0.00121	0.0000136	0.00119	11.824
Scenario 3b	0.0000179	0.00157	0.0000176	0.00154	15.480
Scenario 3c	0.0000157	0.00137	0.0000153	0.00134	13.456
Scenario 3d	0.0000143	0.00125	0.0000140	0.00122	12.252

Table 22 - Results obtained using hourly peak load for Case Study 3

From the results, scenario 3b generates the maximum wind generation with 987.3 MW out of the 1066 total installed capacity. However, in terms of LOLE calculation, scenario 3b has the worst LOLE of all the scenarios. Instead, the best LOLE is calculated for Scenario 3a whereby the expected load loss is 0.00119 hour or 4.27 seconds per year when calculated using the hourly peak demand and SMST. This is equivalent to about 11.8 MWh per year of energy not served. Looking at the LOLE values, all the scenarios have better LOLE values than the base case with the exception of scenario 3b.

This shows that the wind generation capacity share for 2006/07 as in the base case is not optimum in terms of reliability as it does not generate the best LOLE. It is also noted that ability to generate the most wind generation in an hour does not guarantee the lowest LOLE. Wind is diffuse in nature and unpredictable. Hence, the time of high wind generation does not necessarily coincide with the peak demands. The observations made through this case study confirm that the more wind generation in one particular region does not mean a better reliability. Instead, the system reliability depends on the correlation between the wind generation and the demand profile. The higher correlation between the two will result in better reliability.

Case Study 4: Plant Availability

Plant availability is a very important parameter in conducting generation reliability studies. A change to the average outage rate of the plants will have an impact to the GB system reliability. To understand this effect, some sensitivity analysis is performed by varying the plant availability. For this study, changes were made to the availability of the coal plants. Coal plants are chosen as they have the biggest share in the total generation capacity in GB for 2006/07 with approximately 37 percent. The average availability of all coal plants modelled in GBSREP was previously 86.8 percent.

Assumptions made for the sensitivity test are as follows:

Scenario 4a - All coal plants have availability factor of **0.75**

Scenario 4b - All coal plants have availability factor of **0.80**

Scenario 4c - All coal plants have availability factor of **0.90**

Results

Reliability indices calculated from GBSREP for the changes made to coal plant availabilities in Case Study 4 and also the base case are tabulated in Tables 23 and 24.

Scenario Name	Reliability Formula		Using SMST		
	LOLP (%)	LOLE (days/year)	LOLP (%)	LOLE (days/year)	EENS (MWh/year)
Base Case (BC)	0.000229	0.00083	0.000224	0.00082	8.246
Scenario 4a	0.034100	0.12447	0.033570	0.12253	1463.080
Scenario 4b	0.005496	0.02006	0.005400	0.01971	220.417
Scenario 4c	0.000034	0.00013	0.000034	0.00012	1.165

Table 23 - Results obtained using daily peak load for Case Study 3

Scenario Name	Reliability Formula		Using SMST		
	LOLP (%)	LOLE (hours/year)	LOLP (%)	LOLE (hours/year)	EENS (MWh/year)
Base Case (BC)	0.0000154	0.00135	0.0000151	0.00132	13.256
Scenario 4a	0.0025670	0.22487	0.0025266	0.22133	2615.333
Scenario 4b	0.0003947	0.03457	0.0003877	0.03396	376.462
Scenario 4c	0.0000023	0.00020	0.0000022	0.00019	1.816

Table 24 - Results obtained using hourly peak load for Case Study 3

As expected, the higher plant availability produces better LOLE values. The best system reliability is obtained when the coal plant availability is highest. Ideally, the availability should be 100 percent. Nevertheless this is practically impossible as the plants have to be taken out of service for scheduled maintenance and sometimes shut or partially closed for forced outages such as breakdown.

In this case study, Scenario 4c has the best LOLE value with only $2.2x10^{-6}$ hours or 0.7 seconds per year of loss load with expected energy not served is only about 1.8 MWh per year. Nevertheless, even at 0.86 availability rate for the coal plants as in the base case, the LOLE value for GB system is way ahead of reliability criteria if a requirement for 1 day LOLE per year is used.

When plotting the LOLE for hourly peak calculated using SMST (Figure 41), it is observed that the LOLE value obtained changes exponentially with the coal unit availability. The effect on system reliability is therefore higher at lower availability rates.

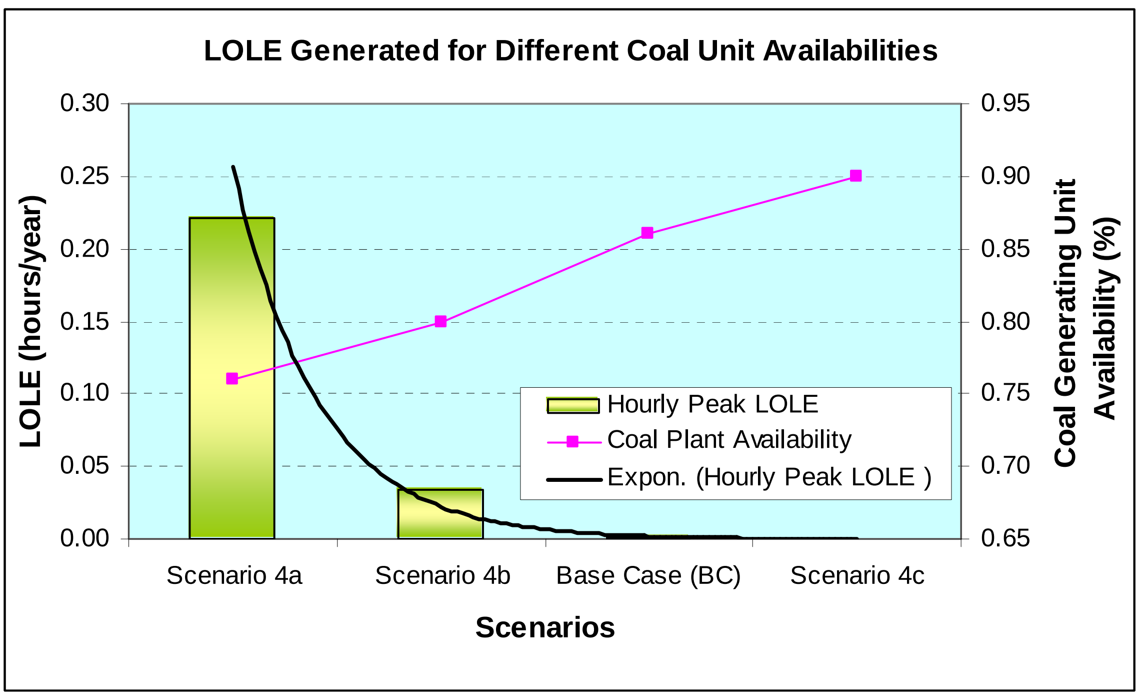


Figure 41- Effect of generating unit availability on GB hourly peak LOLE

6.2 Future GB Electric System

Generation system reliability assessment study is an integral part of future capacity expansion planning. Results obtained from these studies are used as input by the system planners in designing the future system with the best reliability that is economically viable. Most of the time, decisions on investments regarding future plant up is highly influenced by the outcome of the generation system reliability study although the situation for generation planning in a competitive wholesale electricity market is slightly different.

This collection of case studies investigates the reliability of future GB systems that are likely to materialise based on current contracted position and present state of the electricity supply industry in GB. Two study periods are chosen for this study. They are 2013/14 and 2020/21. 2013/14 is chosen as it is the last year forecasted in the SYS2007. Meanwhile, 2020/21 is selected to examine the reliability of GB system in a longer term.

Case Study 5: GB Electric System 2013/14

Under the British Electricity Trading and Transmission Arrangements (BETTA), which were introduced on 1 April 2005, National Grid, which assumes the role as GBSO is required to produce a seven year outlook of GB system annually. The outlook is presented as a report called the Seven Year Statement (SYS). The latest SYS is produced in 2007, covering forecasts of demand, generation and the transmission system up to 2013/14. This forecast is used to form Case Study 5.

In this report, the GB ACS peak demand forecasted for 2013/14 is GW 66.5 GW. This demand includes station load but excludes exports to external systems. Meanwhile, the total generation capacity inclusive of interconnections is 102GW. Figure 42 shows the generation mix based on plant type for 2013/14.

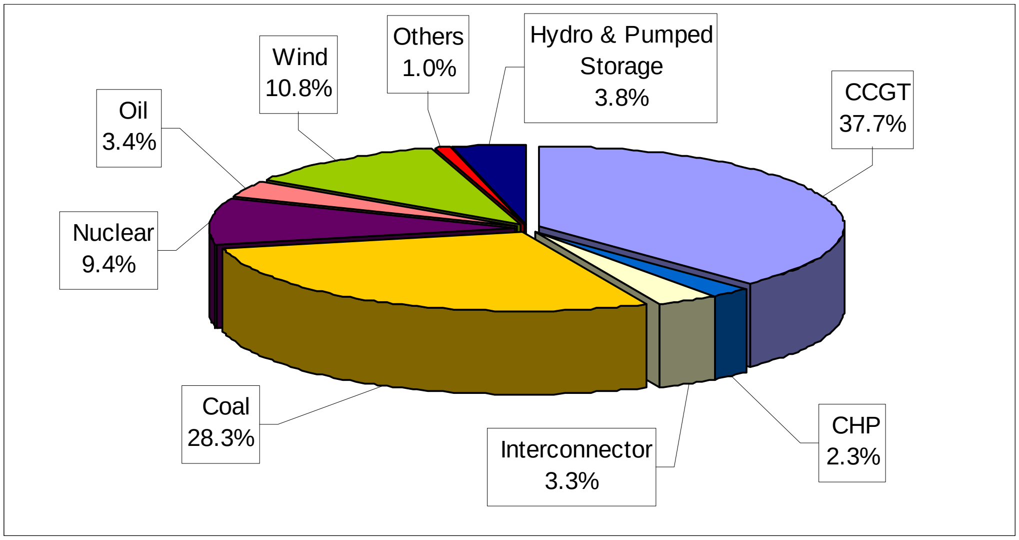


Figure 42 - GB Generation Mix According to Plant Type for 2013/14

Assumptions made:

1. The GB hourly load profile and wind profile remains the same as in 2006/07.
2. The plant availability for every plant type follows the availability rate of Case Study 1: Base Case, which includes the interconnectors.

Wind Data

Based on the geographical location of the wind farms, they are grouped and matched with relevant wind profiles as depicted by Table 25 below.

Profile Region	Study Zones	Profile	Capacity	Percentage (%)
1	1	Orkney	2632	27.89
2	2	WF-3	362	3.84
3	3 to 6	WF-1	5054	53.56
4	7 to 17	WF-2	1389	14.72
Total			**9437**	**100.00**

Table 25 - GB Wind Generation Capacity based on Region for 2013/14

Results

From the simulations, the outcome is as tabulated in Table 26

Method of evaluation	Daily Peak			Hourly Peak		
	LOLP (%)	LOLE (days/year)	EENS (MWh/year)	LOLP (%)	LOLE (hours/year)	EENS (MWh/year)
Reliability Formula	0.000305	0.00111	-	0.0000187	0.00164	-
Using SMST	0.000299	0.00109	11.976	0.0000184	0.00161	17.477

Table 26 - LOLP, LOLE and EENS for GB System 2013/14

The GB generation system reliability for 2013/14 appears to be in a good shape with the expectation of load loss is only around 0.00161 hours or 5.8 seconds a year. This is equivalent to about 17.5 MWh of unserved energy in a year. Both figures quoted are calculated using the SMST method with the load model based on the hourly peak load. If the reliability criterion of LOLE of 1 day per year is used, GB system in 2013/14 is extremely adequate as the calculated LOLE using both methods are much less that the required figure.

The highest LOLE generated by GBSREP is for the calculation using reliability formula using the hourly peak, which is 0.00164 hours per year. Meanwhile, the LOLE calculated using the convolution method and hourly load model to form SMST is again higher than that of daily peak but only by about 0.00002 hours per year. The expected energy not served calculated by reliability formula is around 11.98 MWh. The high degree of reliability is expected as the reserve margin for the 2013/14 system is still large, which is about 30 percent and there is no change in the average unit annual availability, which is about 86.6%.

Case Study 6: GB Electric System 2020/21

It is extremely difficult to predict the GB generation system in 2020 as it will be influenced greatly by many factors such the political and regulatory condition, the strength of the economy and also the level to which environmentally-driven restrictions and opportunities influence policy and investment decisions. Nevertheless, this medium range outlook and evaluation is important and useful in gauging the level of GB generation system reliability under certain composition as it can provide a good indication to future capacity expansion needs and investments.

There are many possibilities and scenarios that can be created for the system in 2020. Previous work by authors (Ault et. al, 2006) has come up with four different scenarios for GB generation system in 2020 in their study. The scenarios and their key parameters are as shown in Table 27.

2020 Scenario	Economic Growth	Environmental Focus	Technological Growth	Regulatory Structure
Economic Concern	Reduced	Reducing	Weak	Liberalised
Continuing Prosperity	Increased	Slightly Stronger	Strong	Liberalised
Environmental Awakening	Current Level	Stronger	Strong with environmental focus	Large liberalised with some environmental intervention
Supportive Regulation	Current Level	As at present	Moderate with central support	Mildly interventionist

Table 27 - Summary of 2020 GB Electricity Industry Scenarios (Source: Ault et. al, 2006)

For this study, the 2020 GB System is modelled base on the “Continuing Prosperity” scenario as it is the most challenging in terms of reliability as there will be an increase in intermittent generation and at the same time an increase in load demand. Under this scenario, the demand for electricity continues to grow year-on-year at a rate, which reduces slightly from that of present day due to an increase in demand-side management. The annual demand is thus forecasted to be at 415TWh in 2020 with a peak demand of

66GW. However, the expected peak demand seems to be on the low side as it is lower than the 2013/14 ACS forecasted peak demand, which is 66.5 GW.

Meanwhile in terms of generation, there will be continued interest in renewable energy with wind generation continuing to dominate. By 2020, wind generation is expected to contribute 13.8 percent to the total generation capacity, with a total installed capacity of 12 GW. Meanwhile, biomass is expected to produce 10 percent of GB electricity with installed capacity of 7 GW. It is also predicted that by 2020, 2 GW of marine technologies, which are wave and tidal stream generation will be incorporated to the system.

Generation Technology	Installed Capacity (GW)
Wind	12
Marine	2
Biomass	7
Hydro	2
Nuclear	8
Coal	9
Large gas-fired units	44
Microgeneration	3
Total	87

Table 28 - Generation technologies in the Continuing Prosperity Scenario (Source: Ault et. al, 2006)

As for the conventional plants, generation will be dominated by gas-fired units mainly in the form of CCGT. Other generating plants are CHP, coal, hydro and nuclear. Table 28 summarises the generation mix for this scenario as outlined by Ault et. al (2006).

Assumptions made:

To model the above scenarios, a number of assumptions were made and they are as follows:

1. The GB hourly load profile and wind profile remains the same as in 2006/07
2. The 12 GW wind generation is distributed according to the percentage share outlined in the base case between the four wind regions.
3. No marine generation model is included in GBSREP. Therefore, the marine generation capacity will be treated as additional hydro generation with availability of 0.88, which is the average availability of hydro plants in the base case.
4. Availability of biomass is assumed to be 0.85 as in base case.
5. All nuclear, coal, gas turbines (GT) and CCGT unit, which are older than 35 years, are assumed to be decommissioned and replaced by new units with capacity of 1000MW, 700MW, 240 MW and 750 MW each for nuclear, coal, GT and CCGT respectively. The availability for each of these plants is assumed to be 0.9.
6. The interconnections with external systems are as in 2013/14. This brings the total generating capacity for GB in 2020 to around 90 GW.
7. No more oil and diesel plants are in operation in 2020.

Wind Data

The wind generation for every wind profile region is summarised as Table 29.

Profile Region	Study Zones	Profile	Capacity (MW)	Percentage (%)
1	1	Orkney	3346.8	27.89
2	2	WF-3	460.8	3.84
3	3 to 6	WF-1	6427.2	53.56
4	7 to 17	WF-2	1766.4	14.72
Total			**12000**	**100.00**

Table 29 - GB Wind Generation Capacity based on Region for 2020/21.

Plant Data

Plant data is built based on the projected capacity mix as envisioned in the "Continuing Prosperity" scenario. However, there is some discrepancy between the targeted capacity, which is 75 GW and the modelled capacity, 74.8 GW. Nevertheless, the difference is considered negligible in such a large system, as it is less than 1 percent. Table 30 summarises the existing, targeted and added capacity to the 2013/14 GB system.

Plant Type	Existing Capacity (MW)	Expected Capacity (MW)	Model Target Capacity (MW)	Addition Capacity (MW)	Modelled Capacity (MW)	Size of New Unit (MW)	No of Unit Added
Biomass	392	7000	7000	6600	6992	300	22
CCGT	32439	44000	42240	9750	42189	750	13
CHP	148	-	3000	2880	3028	120	24
Hydro	1171	4000	1200	30	1201	10	3
Coal	1661	9000	9000	7000	8661	700	10
Nuclear	7087	8000	8000	1000	8087	1000	1
OCGT	298	-	1760	1440	1738	240	6
Pumped Storage	2744	-	2800	110	2854	110	1
Microgeneration		3000	-	-	-	-	
Total	45940	75000	75000	28810	74750	-	80

Table 30 - Existing, Targeted and Required Capacity Addition for 2020/21 system

Capacity Mix

Meanwhile, the revised capacity mix for the Continuing Prosperity Scenario for 2020/21 is shown by Figure 43.

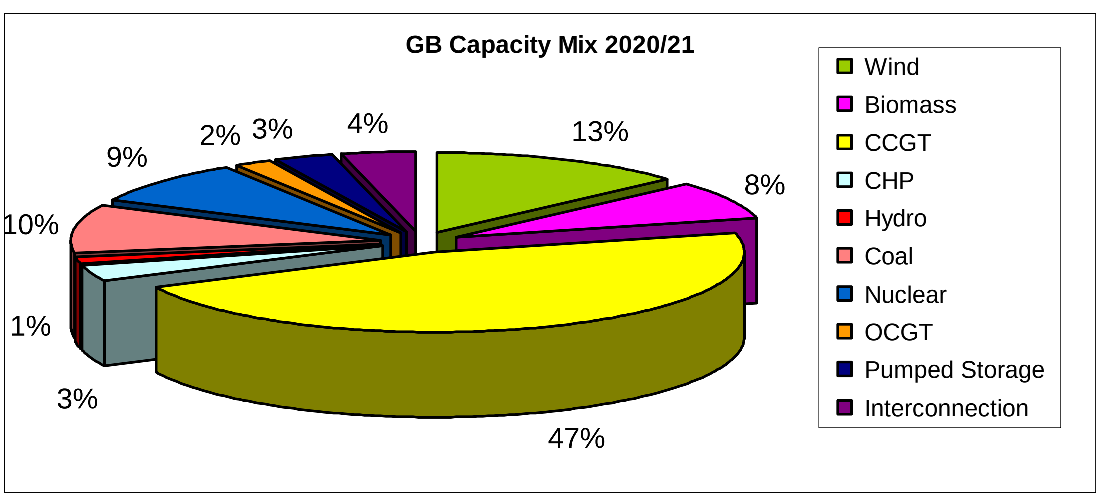


Figure 43 - GB Generation Capacity Mix for 2020/21

Results

Method of evaluation	Daily Peak			Hourly Peak		
	LOLP (%)	LOLE (days/year)	EENS (MWh/year)	LOLP (%)	LOLE (hours/year)	EENS (MWh/year)
Reliability Formula	0.0822	0.3002	-	0.00585	0.5127	-
Using SMST	0.0815	0.2974	3787.372	0.00580	0.5078	6382.809

Table 31 - LOLP, LOLE and EENS for GB System 2020/21

In 2020, the LOLE generated for GB generation system using SMST method, which is based on the hourly peak load is approximately 0.5078 hours per year as shown in Table 31. In terms of EENS, the LOLE corresponds to about 6.38 GWh per year. If the reliability criterion of LOLE of 1 day per year is used, GB system in 2020/21 can be considered adequate as the calculated using both methods are much less that the required figure.

The largest LOLP generated by GBSREP is for the calculation using reliability formula using the daily peak, which is about 0.0822 percent. This value is only about 0.0007 percent higher than using the convolution method with the daily peak load to form the SMST. The reserve margin for 2020 is about 18 percent. This is below the commonly used rule of thumb for reserve margin, which is 20 percent.

Chapter 7 Discussion, Interpretation & Contribution

This chapter aims to address three main subjects which are discussion of the strengths and weaknesses of the model, interpretation and discussion of the results obtained from the case studies modelled using the GBSREP and possible contributions of the findings and model developed through this study.

7.1 GBSREP Models

The GBSREP is developed from the System Reliability Evaluation Programme (SREP) and is customised to model and represent the GB system. As a starting point, the GBSREP is built based on the 2006/07 GB power system. Year 2006/07 is chosen as it has the most recent system characteristics and hence is the most representative of the existing GB system. The completed model is known as Case Study 1 and treated as a base case. This base case is intended to be the point of reference when making comparisons for results obtained from variations of system component in each case study.

A few parameters of the GBSREP model are fixed to specific values as recommended for the SREP models. In modelling the conventional system reliability, the reliability indices from SMST is simulated using 1 MW increment for best result accuracy (Phoon, 2006). Meanwhile, the maximum and minimum margin states are set to 410 MW and -60 MW for every case study and scenario in order to reduce the simulation time as the only value of interest in the SMST is the first negative margin state, which is -1 MW.

In GBSREP, the only intermittent generation modelled is wind. The focus on wind is intended as it is the most significant intermittent generation present in the GB 2006/07 system. Furthermore, this technology has a huge potential for expansion in the future systems. Looking at the generation capacity mix for GB in 2006/07, 1066 MW, which is about 10 percent of it, is contributed by wind generation alone. It is intended for the GBSREP model to incorporate representations of other intermittent renewables but due to time constraints and data limitations this has not been achieved. Hence, for future systems such as the 2020/21 system where there are capacity contribution from marine technologies, they are modelled as hydro plants.

Due to the size of GB system and also the limitation of MS Excel, the generation capacities had to be modelled in a factor of 10. As a result, some of the units are over-modelled where as the others are under-modelled in terms of capacity. Nevertheless, the total difference is small, less than 0.5% and is assumed to be negligible. The difference between the actual capacity and modelled capacity is as shown by Figure 44.

Parameters	2006/07	2013/14	2020/21
Total Effective Capacity (MW)	77,284	86,044	78,138
Modelled Capacity (MW)	77,510	86,300	78,240
Difference (MW)	226	256	102
Difference (%)	0.29	0.30	0.13
Actual Reserve Margin	34.4%	29.4%	18.4%
Modelled Reserve Margin	34.8%	29.8%	18.5%

Figure 44 - Difference between actual and modelled system parameters

The wind generation in GBSREP is modelled as a load-modifier, is very simple, straightforward and easily understood, using sets of wind data from four different regions in GB. They are North Scotland, East Scotland, West Scotland and South Scotland and England. The region demarcation are centralised in Scotland as this area has the highest density of wind capacity. These data are the actual hourly power output from wind farms in GB. Hence, they are net of planned and forced outages of the individual generators, the effect of array efficiency and other technical and operation efficiencies. Three of the wind profiles used are from 2002 and the forth is from 2005/06.

Modelling of wind generation is carried out based on one year of hourly chronological data only. The assumption used in modelling the wind generation is that the wind profile remains the same for every simulation. This is not very accurate as wind is diffuse in nature and unpredictable. Furthermore, the inter-annual variation of wind characteristics will not be captured by the model. Another drawback is that this method does not take into account the probability of the occurrence of wind. Instead, wind is assumed to be available at the particular hour. Nevertheless the effect of time (diurnal and seasonal) pattern variation of wind across the regions, such as more wind generation in winter is captured in GBSREP. Therefore, the wind power availability is matched to the occurrence of peak demand to a certain extent.

The reliability indices chosen for the evaluations are LOLE, LOLP and EENS. These values are calculated using two methods: the SMST method and calculations using reliability formula. LOLE and LOLP are chosen as they are the most commonly used measures of reliability. Meanwhile, EENS is useful for calculations to determine the value of loss load. Unfortunately, comparison of the generated indices and actual GB reliability criterion could not be carried out as the criterion interruption not to exceed 1 winter in 10 is too vague. Hence, for the sake of discussion comparison of the results is made against LOLE 1 day per year, assuming this is the criteria adopted in UK as in many other countries in the world.

It should be noted that the frequency of loss of load in the reliability evaluations is not calculated. This is because of errors occurring in the algorithm while establishing the COPT. Nevertheless, the results of the system reliability evaluated are not affected but another good reliability measure when evaluating the wind generation system reliability can be generated if it is available (Phoon, 2006).

Another weakness of GBSREP is that the generation model is limited to two states only. Hence, no derated states and segregation of peaking and base load unit model was considered when modelling the conventional generation system. Had there been more than two states modelled, prospective approach can be used to model the wind output power and the results compared with the current methods. However, the advantage of the two state assumptions is that the computation time is reduced greatly when calculating the reliability indices (Phoon, 2006).

Basically, GBSREP is able to evaluate the generation system reliability for GB. But, one of the inadequacies of this model is that is does not give any indications on the duration and also frequency of occurrence of capacity deficiency in the system in meeting the load demand. On top of that, the impact of the capacity shortages cannot be determined simply by using GBSREP.

7.2 Case Studies

In total, six case studies were created to evaluate the GB generation system reliability in the presence of intermittent renewable generation. Some system characteristics of the existing GB system are varied to investigate and understand their effect on the system reliability. The first case study is carried out on GB 2006/07 system. The reliability indices found from this case study is used as reference for other case studies.

In Case Study 2, the reliance of GB on interconnection with external systems in terms of reliability is investigated. In 2006, the total effective interconnection capabilities from the Moyle Interconnection and the French Link amount to 2.068 GW. It is observed that effect of non-existence of the French Link has a greater impact on GB system reliability. This is because around 96 percent of interconnection capabilities come from the French Link. Hence, the effect on system reliability increases with the size of the interconnection. It is also noted that the effect of not having the Moyle interconnection, which is 80 MW, on the GB generation system reliability is greater when the French Link does not exist. The reason behind this is that the same amount of generation has greater percentage share of the total effective generation in a smaller system.

Case Study 3 looks at the diffuse nature of the wind and the effect of diversifying the wind generation and capacity. Different percentage share is assigned to the four wind profiles used to investigate the effect on wind generation in each region. As different locations are subjected to different wind speeds at any one time, the total wind generation varies when the percentage share of total wind generation for every region is changed. It is found that the combination of percentage share with the most wind generation does not produce the best value of reliability indices. This clearly shows that there is lower correlation between the wind generation and the occurrence of peak loads. The generation system reliability increases with correlation between the wind power output and the occurrence of the peak demand.

Meanwhile, in Case Study 4, the availability of the generating units are varied to study the effect it has on the system reliability. Generating unit availability is one of the most important data inputs in modelling generation reliability. The availability of coal plants is chosen to test for sensitivity to this parameter as coal plants hold the largest percentage share in GB total effective generation capacity for 2006/07. This case study confirms that the system reliability increases with plant availability. It is noted that the increase is exponential.

Parameters	2006/07	2013/14	2020/21
Wind Penetration	1%	11%	13%
Modelled Reserve Margin	34.8%	29.8%	18.5%
LOLE (hours/year)	0.0013	0.0013	0.5078

Figure 45 - Difference between actual and modelled system parameters

The last two case studies, namely Case Study 5 and 6 are on the future GB system. In Case Study 5, the reliability of GB system in 2013/14 is evaluated whereas in 2020/21, the reliability of GB system in 2020/21 is estimated. There is an increase in terms of intermittent generation from the base year to 2020/21 with the highest penetration level in the latter year. On the other hand, the reserve margin and LOLE drops from 2006 to 2020. The results indicated that the system reliability decreases with reserve margin. Figure 45 summarises the observations from the three case studies. The LOLE values shown are calculated using the SMST method and also hourly peak load to form the load model.

7.3 Contributions

Several significant findings were generated as a result of this study. Some of them may have been mentioned and concluded in other literature. However, these results can be use as another reference for comparison purposes with other GB reliability modelling and evaluations. Alternatively, the results generated through this study can be used as supporting information for system planners to make decisions regarding GB system reliability especially for the future systems as the case studies conducted for this study are specific to GB system.

Meanwhile the methodology adopted and source of data introduced in this study is quite general and can be used by other planners when conducting reliability evaluations in the presence of intermittent renewable generations. This study is thought to have contributed to the research of generation system reliability in the presence of intermittent renewables for GB.

Chapter 8 Conclusions

There are two main parts to this chapter. The first part summarises and concludes the work done in evaluating the GB system reliability. This is followed by a review of the project aims and objectives in addition to the recommendation on further work to be carried out using this study as the foundation and starting point.

8.1 Summary

As the electric supply industry grows larger and more complex in any country (inclusive of GB) the role played by reliability evaluation increases in importance as well. In the short term, generation system reliability assessment is important in the decision making of the daily operation in terms of scheduling plant outages and dispatch list. Meanwhile, in the long term, outcome of reliability assessment would be extremely useful in making decisions on determining the amount of investment and capacity mix for future generation expansion planning.

Over the years, many reliability evaluation methodologies and models were developed to determine the level of system reliability. These models, which are built for the conventional generating units, are now matured and it used widely in many utilities. The output of the models, which are the reliability indices, has proven to be successful as most utilities if not all have managed to operate the system reliably using this measures. Reliability indices such as LOLE and LOLP are a good means of quantifying reliability of a system.

However, recent years has seen increased interest for intermittent renewable generation as a result of greater environmental concern and the security of supply of the fossil fuels. The four emerging technologies are wind, wave, tidal stream and solar. In GB, wind generation has been successfully incorporated into the system and is now contributing to the reserve margin whereas the other technologies are still in the pilot study or research and development stage. Nevertheless, the penetration level of wind generation is still low in the present system. Hence, the impact of intermittency of wind power on system reliability is still small. However, with more wind generation and intermittent generation scheduled for commission due to the UK commitments, there are concerns of the impact of the higher penetration level of intermittent generation on the system reliability.

Therefore, GBSREP was developed using MS Excel and the built-in Visual Basics to model the existing GB system, which consists of both models for conventional units and also model of intermittent generation. But, only wind generation is modelled and incorporated into this programme due to time restrictions and limitation of data. The calculations for the conventional generating unit model are based on the analysis approach. Meanwhile, the wind model is built as a load modifier using wind generation profiles for regions in GB. This tool was used to evaluate the GB generation system reliability in the presence of intermittent renewables.

Several conclusions were drawn from the case studies regarding the system reliability in GB. Looking at the base case, the existing GB system is more than adequate to meet the system demand if reliability criterion of LOLE of 1 day per year is used. However, the level of adequacy decreases with reduction in reserve margin and increase of wind penetration in the GB system from 2006 to 2020. In case study 2, it is noted that the GB system has greater reliance on the French Link as oppose to the Moyle interconnection due to the larger import capabilities. In addition, non-existence of interconnection and generating units, regardless of its size will have greater impact on the system reliability in smaller systems rather than big ones. This is because that capacity will then have a larger percentage share of total effective capacity.

It is also concluded that the time of occurrence of the peak load is crucial when intermittent generation is used to meet the peak load especially if the wind output power is modelled as a load modifier. This is because higher correlation between the load and the intermittent generation will result in greater system reliability. As wind is diffuse in nature and subjected to extreme highs and lows, diversification of wind generation capacity and location is important to increase the overall wind generation load or capacity factor.

Finally, the availability of individual generating units plays a very significant role to the system reliability. The higher the availability factor is, the higher the system reliability that results. The effect is greater if the unit has a large percentage share of the total effective capacity.

In conclusion, the GBSREP is a working model to evaluate the GB generation system adequacy. The main finding using this model is that the GB system is very adequate in meeting the system demand presently and in the future. This study and GBSREP provide rough estimates of GB system reliability, which can be a good reference for comparison and starting point to other similar evaluation studies. However, it must be noted that the model does not include the frequency and duration of the interruptions. It also does not address the security of the system or the transmission and distribution part of the system where most of the outages and resulting loss of customer supply occur.

8.2 Further Work

The aim of this study is to provide a means to quantify and evaluate the GB generation system in the presence of intermittent renewable under various scenarios. Initially, models of the four emerging renewable generation namely, wind, wave, tidal stream and solar generation were to be developed and incorporated to the conventional unit model. However, due to the time constraint, limitation of data and the amount of modelling work for credible results, this intention was not materialised. Only the wind generation model is completed, incorporated to GBSREP and analysed for the present and future GB system. Despite the shortcoming of the project aims, this study has produced a foundation and source of reference for future studies on GB system.

The tool, GBSREP however is not flawless and there are still many rooms for improvement. The following are the suggested further work for this study;

1. To improve the wind model and build wind more models using other methods such as advanced techniques so as the capacity credit evaluation for the wind generation in the GB system for present and future GB system can be carried out and compared.
2. To develop reliability models for the other three intermittent generations, which are wave, tidal stream and solar and integrate them into GBSREP.
3. To conduct reliability studies using GBSREP with the other three intermittent generation models for the future electricity industry scenarios in GB and determine the suitable level of reserve margin required to maintain the same level of system reliability.
4. To conduct economic evaluation on the additional reserves needed with the higher penetration of intermittent generation and also value of loss load in the case of supply interruptions.
5. To produce a comprehensive user manual for the GBSREP and database in GBSREP for GB data which includes historical demand and plant data for future studies.

It is hoped that the methodology, tools and findings from this study would be a useful addition to the resources regarding GB electricity system reliability specifically and the betterment of reliability evaluation methodology and models in general.

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APPENDIX A

GREAT BRITAIN RELIABILITY SYSTEM EVALUATION PROGRAMME (GBSREP)

Appendix A-1:

Calculation Algorithm for Capacity Outage Probability Table (COPT)

```
Sub COPT()

Sheets("COPT").Select
Range("A10:H50000").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 As Double
Dim C As Double
Dim U As Double

Groups = Sheets("PlantData").Cells(6, 4) 'Total number of groups
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) 'Number of generating units
    C = Sheets("PlantData").Cells(i, 5) 'Generating unit capacity
    U = Sheets("PlantData").Cells(i, 6) '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:D50000"), 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
Sheets("COPT").Cells(5, 3).Select

End Sub
```

Appendix A-2:
Calculation Algorithm for System Margin State Table (SMST)

```
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
Dim pLj, Lj, Ljd, pLjd, Ljm, Ljmd, PXj, PXjd As Double
Cells(21, 23) = 0
Cells(24, 23) = 0
Range("J10:P50000").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(756 + j, 4) * Sheets("COPT").Cells(6, 15)
    Ljd = Sheets("LoadData").Cells(756 + j, 12) * Sheets("COPT").Cells(6, 15)
    pLj = Sheets("LoadData").Cells(756 + j, 6)
    pLjd = Sheets("LoadData").Cells(756 + j, 14)
    Ljm = CInt(Sheets("COPT").Cells(k + 9, 11) + Lj)
    Ljmd = CInt(Sheets("COPT").Cells(k + 9, 11) + Ljd)
    If Ljm >= 0 Then
      PXj = Application.WorksheetFunction.VLookup(Ljm, Range("B10:H50000"), 7, False)
    Else
      PXj = 0
    End If

    If Ljmd >= 0 Then
      PXjd = Application.WorksheetFunction.VLookup(Ljmd, Range("B10:H50000"), 7, False)
    Else
      PXjd = 0
    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
  If Cells(k + 9, 11) < 0 Then                        ' For the sixth column, to calculate EENS
    Cells(k + 9, 15) = -Cells(k + 9, 11) * (Cells(k + 9, 12) - Cells(k + 10, 12))
    Cells(k + 9, 16) = -Cells(k + 9, 11) * (Cells(k + 9, 13) - Cells(k + 10, 13))
  End If
```

```
Cells(21, 23) = Cells(21, 23) + Cells(k + 9, 16) * 365
   Cells(24, 23) = Cells(24, 23) + Cells(k + 9, 15) * 8760

Next k
   ' For LOLP in days per year
   Cells(20, 23) = Application.WorksheetFunction.VLookup(-Step, Range("K10:M50000"), 3, False)
   ' For LOLP in hours per year
   Cells(23, 23) = Application.WorksheetFunction.VLookup(-Step, Range("K10:L50000"), 2, False)
   Call LOLE
   Sheets("COPT").Cells(5, 12).Select
   MsgBox ("" & k - 1 & " margin states calculated")

End Sub
```

Appendix A-3:

Calculation Algorithm for LOLE using formula

```
Sub LOLE()

Sheets("COPT").Select
Dim LOLE, P, CjLj, LOLEh, Ph, CjLjh
LOLE = 0
LOLEh = 0
For i = 0 To 100

' LOLE in days per year
   CjLj = Sheets("COPT").Cells(10, 2) - Sheets("LoadData").Cells(756 + i, 12) * Sheets("COPT").Cells(6,  15)
   ' Search 50000 lines below
   P = Application.WorksheetFunction.VLookup(CjLj, Range("C10:H50000"), 6)
   LOLE = LOLE + Sheets("LoadData").Cells(756 + i, 13) * P

'LOLE in hours per year
   CjLjh = Sheets("COPT").Cells(10, 2) - Sheets("LoadData").Cells(756 + i, 4) * Sheets("COPT").Cells(6, 15)
   Ph = Application.WorksheetFunction.VLookup(CjLjh, Range("C10:H50000"), 6)
   LOLEh = LOLEh + Sheets("LoadData").Cells(756 + i, 5) * Ph
Next i

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

End Sub
```

Appendix A-4:

Calculation Algorithm for Wind Model

```
Sub Wind()

Sheets("WindModel").Select
Range("G12:AD376").ClearContents
Dim regions As Single
regions = Sheets("WindModel").Cells(5, 7)

For i = 1 To 24
   For j = 1 To 365
      Cells(j + 11, i + 6) = 0
      For k = 1 To regions
      Cells(j + 11, i + 6) = Cells(j + 11, i + 6) + Sheets("Wind" & k & "").Cells(j + 12, i + 6) *
Sheets("Wind" & k & "").Cells(7, 7) / 100
      Next k
   Next j
Next i
Sheets("WindModel").Cells(5, 7).Select

End Sub
```