Evaluating and Planning Flexibility in a Sustainable Power System with Large Wind Penetration

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Juan Ma

School of Electrical and Electronic Engineering

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ABBREVIATIONS

EU	European Union
SO	System Operator
UC	Unit Commitment
UCC	Unit Construction and Commitment
NFI	Normalised Flexibility Index
LOWE	Loss of Wind Estimation
UK	United Kingdom
IEEE RTS	IEEE Reliability Test System
SCADA	Supervisory Control and Data Acquisition
EDF	Électricité de France
WPF	Wind Power Forecast
NWP	Numerical Weather Prediction
WC	Wind Capacity
ND	Net Demand
CCGT	Combined Cycle Gas Turbine
MLL	Minimum Load Level
LFT	Low Flexible Technology
MFT	Medium Flexible Technology
HFT	High Flexible Technology
MSG	Minimum Stable Generation
OPEX	Operational expenditure
CAPEX	Capital expenditure
APL	Annual Peak Load
TG	Thermal Generation Output
MDT	Minimum Down Time

LOC	Lost Opportunity Cost
NPF	Normalised Profit of Flexibility
LOLP	Loss of Load Probability

LIST OF SYMBOLS

$\sigma_{nd}(t)$	Standard deviation of net demand forecast error at time *t*
$\sigma_{d}(t)$	Standard deviation of gross demand forecast error at time *t*
$\sigma_{w}(t)$	Standard deviation of wind forecast error at time *t*
$r_{UP}(t)$	Aggregated upward reserve requirement at time *t*
$r_{DOWN}(t)$	Aggregated downward reserve requirement at time *t*
$\varepsilon(t)$	Wind forecast error at time *t*
$W_f(t)$	Forecasted wind power at time *t*
$W_r(t)$	Realised wind power at time *t*
$D_f(t)$	Forecasted demand at time *t*
$u(i,t)$	Binary variable for the status of unit *i* at time *t* (on/off)
$p(i,t)$	Decision variable for the output of unit *i* at time *t*
$w_c(t)$	Decision variable for wind curtailment at time *t*
$\mathrm{INC}(i)$	Incremental cost of unit *i*
$\mathrm{STC}(i)$	Start up cost of unit *i*
I	The number of generating units in the considered set
T	The number of hours in the considered time horizon
$P_{\min}(i)$	Minimum stable generation of generator *i*
$P_{\max}(i)$	Maximum capacity of generator *i*
$T_{up}(i)$	Minimum up time of generator *i*
$T_{down}(i)$	Minimum down time of generator *i*
$t_{on}(i,t-1)$	The amount of time that unit *i* has been online before time *t*

$t_{off}\left(i,t-1\right)$ The amount of time that unit *i* has been offline before time *t*

$Ramp_{up}\left(i\right)$ Maximum ramp up rate of unit *i*

$Ramp_{down}\left(i\right)$ Maximum ramp down rate of unit *i*

$r_{up}\left(i,t\right)$ The upward reserve that can be provided by generator *i* at hour *t*

$r_{down}\left(i,t\right)$ The downward reserve that can be provided by generator *i* at hour *t*

Δt The time for the units to ramp up/down their output

$OC(i,t)$ Operational cost of the existing unit *i* at time *t*

$AOC(j,t)$ Operating cost of the additional unit *j* at time *t*

$AIC(j)$ Investment cost of unit *j* amortised over the optimisation horizon

e_j Binary decision variable which indicates whether the additional flexible unit *j* should be built

$C_{MW}(j)$ The cost per MW of building unit *j*

$L(j)$ The expected lifetime of unit *j*

$w\left(k,t\right)$ Modified wind generation at hour *t* in week *k*

$w_{original}\left(k,t\right)$ Original wind generation at hour *t* in week *k*

$CF_{week}(k)$ Wind capacity factor in week *k*

CF_{season} Wind capacity factor of the whole season

$wg(t)$ The potential wind generation output at time *t*

$wc(t)$ Wind curtailment at time *t*

$K_c\%$ The maximum proportion of the total wind generation that is allowed to be curtailed over a year

$\pi_E\left(t\right)$ Market-clearing price for energy at hour *t*

$P\left(i,t\right)$ The scheduled output of generating unit *i* at hour *t*

$S_{DA\_E}(i)$ The revenue of unit *i* obtained from providing energy in the day-ahead market

$Re(i,t)$ The reserve provided by unit *i* at hour *t*

$C_{OPP}(i,t)$ Opportunity cost of unit *i* at hour *t*

$S_{DA\_R}(i)$ The revenue of unit *i* obtained from providing reserve in the day-ahead market

$C_{DA}(i)$ The total cost of unit *i* in the day-ahead market

$\Omega_{\mathrm{DA}}(i)$ The profit of unit *i* in the day-ahead market

$W_{\mathrm{DA}}(t)$ The utilised wind power in the day-ahead market

$Deviation(t)$ The deviation between the volumes traded in the day-ahead market and delivered in the real-time balancing market

$B_{up}(i)$ The bid of generator *i* for up-regulation in the real-time balancing market

$B_{down}(i)$ The bid of generator *i* for down-regulation in the real-time balancing market

$\pi_{up}(t)$ The clearing price of up-regulation at hour *t* in the real-time balancing market

$R_{up}(i,t)$ The up-regulation provided by generator *i* at hour *t*

$S_{RT\_up}(i)$ The revenue of generator *i* obtained from providing up-regulation

$C_{RT\_up}(i)$ The cost of generator *i* for providing up-regulation

$\Omega_{RT\_up}(i)$ The profit of generator *i* obtained from providing up-regulation

$S_{RT\_down}(i)$ The revenue of generator *i* from providing down-regulation

$R_{down}(i,t)$ The down-regulation provided by generator *i* at hour *t*

$\pi_{down}(t)$ The clearing price of down-regulation at hour *t* in the real-time balancing market

$C_{RT\_down}(i)$ The cost of generator *i* for providing down-regulation

$\Omega_{RT\_down}(i)$ The profit of generator *i* obtained from providing down-regulation

$\Omega_{RT}(i)$ The profit that generator *i* obtains in the real-time balancing market, from providing upward and downward regulation

Ω_{DA} The overall profits for all the conventional generators in the day-ahead market

Ω_{RT} The overall profits for all the conventional generators in the real-time balancing market

$\overline{\Omega}$ The normalised profit of the thermal system, which is the 'average profit' per MWh obtained from selling energy and reserve

$\sum P$ The total energy traded in the day-ahead market

$\sum Re_{up}$ The total up-regulation deployed in the real-time balancing market

$\sum Re_{down}$ The total down-regulation deployed in the real-time balancing market

$\overline{\Omega}_{flex}$ The normalised profit of flexibility for balancing purpose

$flex(i)$ Normalised flexibility index of generator *i*

$FLEX_A$ Normalised flexibility index of the whole system *A*

P(NoWC) The probability of no wind curtailment in system

$\mathrm{P}(\mathrm{V\_MLL})$ The probability of the violation of minimum load level

$\mathrm{P}(\mathrm{V\_Ramp\_up})$ The probability of the violation of ramping up capability

$\mathrm{P}(\mathrm{V\_Ramp\_dn})$ The probability of the violation of ramping down capability

ABSTRACT

The University of Manchester

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Flexibility describes the system ability to cope with events that may cause imbalance between electricity supply and demand while maintaining the system reliability in a cost-effective manner. Flexibility has always been present in the power system to cater for unplanned generator outages and demand uncertainty and variability. The arrival of wind generation with its variable and hard to predict nature increases the overall needs for system flexibility.

This thesis provides a systematic approach for investigating the role of flexibility in different power system activities including generation scheduling, generation planning and market operation, and furthermore proposes two 'offline' indices for flexibility evaluation.

Using the tools and metrics presented in this thesis, it is possible to perform the following tasks:

- Conduct generation scheduling simulation to evaluate the impacts of wind on the flexibility requirement of power systems;
- Use the unit construction and commitment algorithm to 1) estimate the maximum allowable wind capacity for an existing system; 2) find the optimal investment of new flexible units for accommodating more wind generation; and 3) decide an optimal generation mix for integrating a given wind penetration;
- Use the market model to reveal the value and profitability of flexibility and evaluate the corresponding effects of alternative market design;
- Use the two proposed flexibility indices to quantitatively assess the flexibility of individual generators and power systems without undertaking complex and time consuming simulations.

DECLARATION

No portion of the work referred to in this thesis has been submitted in support of an application for another degree or qualification of this or any other university or other institute of learning.

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DEDICATION

To my beloved Mum and Dad

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ABOUT THE AUTHOR

Juan Ma received her B.S. degree and M.E. degree in Electrical Engineering from Tsinghua University, China, in 2006 and 2008. In September 2008 she joined the University of Manchester to pursue her Ph.D degree in Power System Engineering.

LIST OF PUBLICATIONS

The following list contains the journal and conference publications resulting from this PhD research project and corresponding collaborations.

1. J. Ma, V. Silva, D.S. Kirschen, R. Belhomme, L. Ochoa. "Evaluating and Planning Flexibility in Sustainable Power Systems," *Special Wind Energy Issue of the IEEE Transactions on Sustainable Energy*, submitted for second round of reviews.

2. J. Ma, V. Silva, L. Ochoa, D. S. Kirschen, R. Belhomme. "Evaluating the Profitability of Flexibility," *The 2012 IEEE PES General Meeting,* San Diego Manchester Hyatt San Diego, CA, USA, Jul 22-27, 2012. Accepted.

3. J. Ma, D.S. Kirschen, R. Belhomme, V. Silva. "Optimizing the Flexibility of a Portfolio of Generating Plants," *in Proc. The 17th Power System Computation Conferece (PSCC)*, Stockholm, Sweden, Aug 22-26, 2011.

4. D.S. Kirschen, J. Ma, R. Belhomme, V. Silva. "Optimizing the Flexibility of a Portfolio of Generating Plants to Deal with Wind Generation," *in Proc. IEEE PES General Meeting*, Detroit, Michigan, USA, July 24-29, 2011. Invited paper.

5. D.S. Kirschen, A. Rosso, J. Ma, L. F. Ochoa. "Flexibility from the demand side," *The 2012 IEEE PES General Meeting,* San Diego Manchester Hyatt San Diego, CA, USA, Jul 22-27, 2012. Accepted. Invited paper.

CHAPTER 1

INTRODUCTION

1.1 Sustainable Requirement for Renewable Energies towards a Low-Carbon Future

Lighting a house, cooking a dinner, heating a building, running a train, operating a factory – all these require energy. Energy is hailed as the ‘blood’ of people’s social life, economic growth and national security. In turn, the world’s population and economic growth continuously drive the demand for energy to a higher level.

The energy sectors in most countries have heavily relied on fossil fuels. In the most recent decades, the world has been suffering from the lack of fossil-fuel supply and the environmental problems caused by fossil-fuel based power supply, such as air pollutions and climate change. To support the sustainable development, developing renewable and clean energy resources has been put on the top list of most governments around the world. For instance, in 2008, the European Communities announced a plan to increase the proportion of renewable energies to 20% of the total energy consumption in the EU by 2020 [1] and all 27 EU countries have been allocated their internal binding targets. The UK government has set a goal of having 15% of its energy consumption from renewable energies by 2020.

Renewable energy replaces conventional fuels mainly in three sectors: electrical power generation, heating/cooling and transportation. In many EU countries, electricity generation is currently the biggest source of CO_2 emissions [2]. To reach the target of 20% of energy supplied by renewable sources, it is estimated that 34% of Europe’s electricity needs to be sourced from renewable energy and wind power is expected to take a prominent part in the renewable portfolio [3].

1.2 Wind Power Generation in Electric Power Systems

1.2.1 Development of Wind Power Generation

Compared to conventional resources, wind power has numerous advantages, such as

- Wind resources are plentiful both onshore and offshore, and they are widely distributed [4].

- Wind generation has lower operational costs than conventional generation (e.g. coal-fired and gas-fired generation).

- Wind generation is clean. Greenhouse emissions and air pollution produced during the construction of wind plants are tiny and declining, and there is no emission or pollution produced by their operation.

- Wind farms are available in a wide range of sizes, and they normally occupy less land space per kWh of electricity generated than conventional power stations. Furthermore, wind turbines are quite tall (20-80m) which does not affect the use of the land below for other purposes, like agriculture.

Therefore, wind power is regarded as one of the most promising renewable energy technologies, and many policy instruments are specialised for wind power [5, 6] which led to a rapid development of wind power in recent years.

Since 1990, Europe has experienced remarkable growth in wind power generation. Denmark, Germany and Spain adopted relatively high regulation prices for wind generation, which pushed a rapid growth in wind capacity installation in these countries.

Figure 1.1 shows the installed wind power capacity worldwide [7] and in EU Member States [8] between 1998 and 2009.

With significant improvement in wind generation technology, the European Wind Energy Association has increased its 2020 target from 180GW to 230GW, and its 2030 target from 300GW to 400GW [3].

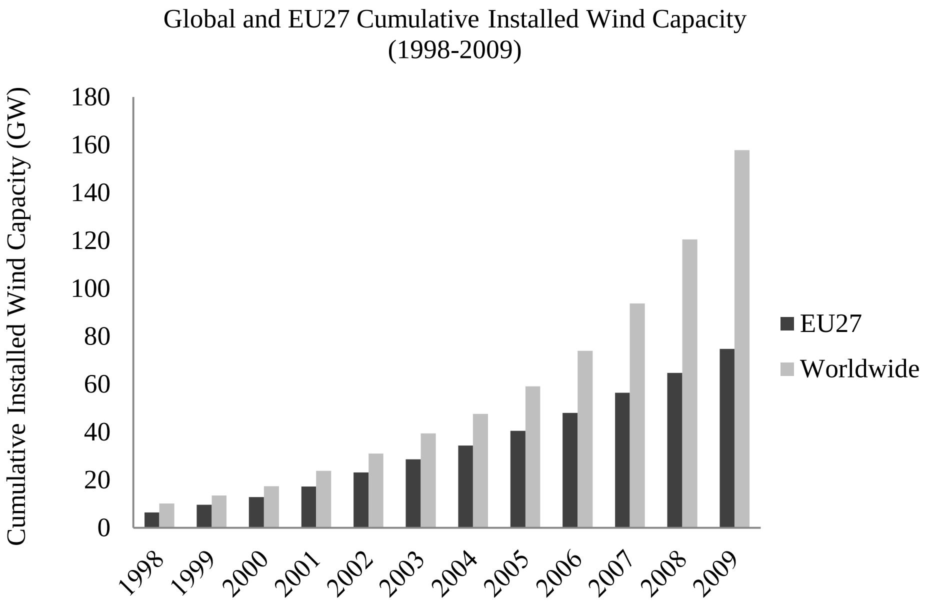


Figure 1.1: Cumulative Installed Wind Capacity in Worldwide and EU27 [7, 8]

1.2.2 Challenges of Balancing Issues with High Wind Penetration

Although the deployment of large volumes of wind capacity can be driven by appropriate policy instruments, its adequate integration into a power system is challenging due to the variable and unpredictable nature of the wind resource.

Various meteorological factors influence the wind power, such as wind speed, wind direction, temperature, and humidity. These random factors contribute to the two main characteristics of wind power that challenge its integration in power system operation:

- Uncertainties: Wind blows randomly. The output of a wind turbine could vary from zero to the maximum in a relatively short period. Scheduling a power system with wind generation relies on the forecast for future scenarios. While remarkable advances have been made in the accuracy of the forecasting of wind power generation in recent years [9, 10], significant uncertainties are still inevitable. For security reasons, power system should always have sufficient backup to handle these uncertainties.

- Variability: Wind power generation varies frequently on different time scales (seconds, hours, days, seasons and years). A dramatic change from zero to the maximum could happen in a single day, which significantly increases the difficulties in the operation of the system. The situation aggravates when the variations in the wind generation and the load happen in opposite directions, which increases the variability of the net demand[1] that needs to be served by conventional generation.

In conclusion, wind generation increases the levels of uncertainty that need to be catered by the system and the magnitude of the variations in the demand that will need to be followed by adjusting the output of the remaining generation plants. The responsibility of maintaining the balance between the load and the generation lies with the system operator (SO). To this end, the SO should procure sufficient reserves to protect the system against uncertainty, ensure that sufficient generation is scheduled to meet demand and that the scheduled generation is capable of adjusting its output from one period to the next to follow the fluctuations of the net demand. Achieving this goal requires that sufficient flexibility is present in the system either from the generation or the demand side (if available) so that the load-generation balance is maintained at all times. In this context, it is important to examine how the needs for flexibility evolve with wind penetration and explore cost-effective options to provide the additional flexibility for accommodating wind power.

[1] In this thesis, net demand is designated as the gross demand minus wind generation. It is the part that has to be met by non-wind generation (thermal generation in this thesis) in the system.

1.3 Flexibility Needs for Integrating Large-Scale Wind Power

In this work, the flexibility is defined as the ability of a system to cope with uncertainties and variations in the generation and demand, while maintaining the system reliability at minimum cost.

Traditionally, power systems were designed to provide, in a cost-effective and reliable manner, enough flexibility to cope with the variability and the forecast error of demand and with unplanned generation outages. The large-scale wind power integration challenges this traditionally well-adapted system by increasing the level of uncertainty and variability in the system.

Therefore, in order to integrate the large penetrations of wind generation without compromising the system security, more flexibility services are required to cope with the forecasted and un-forecasted changes in net demand. For example, fast ramping capability and frequent start-ups are needed to handle the frequent and sharp fluctuations of wind power, and more operational reserve is required to cope with the uncertainty of wind power.

Generally speaking, the more flexible a system is, the more economic and environmental benefits it can make use of from a high penetration of wind power. A non-flexible system is likely to lead to significant waste of wind resource because wind power will have to be curtailed due to the flexibility limitations. In theory, there would be no limit to the level of wind that can be accommodated in the generation mix if it were possible to have fully flexible generation in the mix (e.g., a fully hydro system with lots of storage might be able to accommodate 100% of wind generation). However, in most realistic scenarios, even a flexible system has a limit for adopting wind generation, beyond which the wind power will be wasted. Therefore, it is necessary to understand the flexibility level of a system and its capability of adequately accommodating wind generation so that to determine whether increasing the system flexibility or avoiding further investment in wind capacity.

The fast deployment of wind farms keeps driving the need for higher flexibility in power systems. Around this topic, numerous studies have attempted to answer two key questions:

1) How does wind generation affect the balanced state of a power system?

2) What measures can increase the flexibility of the power system to respond to a larger share of wind generation?

The effects of wind generation on power systems have been explored in many studies [11-16]. These studies have illustrated the effects of high penetration of wind generation capacity from different angles, including the short- and long-term effects, local and system-wide effects, technical and economic effects. All these effects trigger the need for enhancing the system flexibility on different time scales, in different locations, with appropriate technologies and reasonable costs.

Significant work has been done on exploring the potential of flexibility sources in integrating large amounts of wind power. According to the literature, the main resources of flexibility include:

- Scheduling of flexible generating units [17-19]

- Participation of demand side response [20-22]

- Application of energy storage [23-25]

- Benefit of interconnections [26-28]

1.4 Research Objectives and Proposed Methodologies

1.4.1 Research Objectives

Although a remarkable amount of work has been done on topics related to the requirement and the resources of flexibility, an overarching study about 'flexibility' that addresses its role in the operation of systems with wind generation, the need for taking into account flexibility adequacy in expansion planning and evaluation of the remuneration of flexibility is still unavailable.

Furthermore, in the literature, the concept of 'flexibility' lacks quantitative metrics that could be used 'offline'. Most studies about flexibility are based on multi-temporal simulation of power system operation [29-31]. Being clear that a detailed analysis of flexibility requires such simulation it is also important to have metrics capable of providing estimations of 'how flexible a system is' and as a result, comparing the flexibility levels of two systems is possible. This is of interest for the system operator to assess the individual suppliers' contribution to the flexibility of the system and the ability of the system to accommodate renewable generations.

This thesis aims to provide an overall picture of flexibility in the following aspects of power system activities: generation scheduling, expansion planning and electricity market. The focus is on the flexibility provided by conventional generation, i.e., fast-ramp plants (e.g. gas- or coal-fired generators). Proper indices are expected to be established to provide 'offline' flexibility evaluation.

In this context, the objectives of this thesis are:

1) Provide a better understanding of additional flexibility requirement in the wind-integrated system. It is expected to answer two questions: why accommodating wind generation requires more flexibility and what are the main technical characteristics for conventional generation to provide the flexibility. The answers to these questions will form the basis for

further studies on the evaluation of flexibility in different aspects of system activities.

2) Address the role of flexibility in the operation of systems with wind generation. Non-wind generators should be scheduled in a more flexible manner to cope with the increased uncertainties and variations. The new operation pattern may involve changes in generation pattern, reserve provision, carbon emissions, operational costs and wind utilisation factor[2]. Thus, a proper model is needed to explore how these relevant parameters change with different penetrations of wind generation. Furthermore, it would be also interesting to draw comparisons between various systems to evaluate the role of flexibility in accommodating wind generation.

3) Enhance the flexibility of an existing power system to enable it to accommodate more wind generation. Traditional generation planning models usually consider generation adequacy targets but do not explicitly look at the operability of the future system [32, 33]. Since the hourly, daily and seasonal variations of wind generation significantly change the pattern of residual demand, the requirement of operational flexibility has to be taken into account. The new planning model is expected to decide an adapted generation portfolio that ensures the system operates reliably and economically with large-scale wind generation.

4) Find out whether the electricity market provides sufficient revenue to make the provision of flexibility profitable. It is interesting to investigate the profitability of flexibility for balancing wind in the market environment. In addition, how these profits are affected by increasing wind penetrations, by different parameters and alternative market design are also worthy to be discussed.

[2] Wind utilisation factor is defined in this thesis as the proportion of the utilised wind generation in the total potential wind generation. It is equal to 1 minus the percentage of wind curtailment (% of total potential wind generation).

5) Develop indices to evaluate the flexibility of individual generators and the overall system. Such indices are expected to evaluate the system flexibility level through an 'offline' calculation without performing complex time consuming simulations. The development of these indices should allow us to compare the flexibility levels between different systems and estimate their capability to accommodate wind generation.

1.4.2 Proposed Methodologies

The understanding of the additional flexibility requirements in a wind-integrated system should be firstly based on an analysis of the characteristics of wind generation and their impacts on net demand. Such analysis aims at disclosing the relation between gross load and wind generation and identifying the flexibility requirement under the corresponding net demand.

To evaluate the flexibility of conventional generation in power system operation, a technique based on unit commitment (UC) approach will be used. Unit commitment schedules the generating units to meet the system's demand with minimum cost, whilst subjected to the dynamic constraints relevant to flexibility requirement (ramping rate, tertiary reserve, and minimum up/down time). The outputs of UC allow us to assess the role of flexibility in terms of changes in generation pattern, reserve requirement, operational cost, CO_2 emissions and wind utilisation for different wind penetration levels.

To determine the optimal generation mix to accommodate high wind penetration, it requires a technique that bridges the gap between the long-term investment decisions on the plants to be built and the short-term operational decisions on how these plants are scheduled. The proposed method in this work is based on an enhanced unit-commitment algorithm, designated as unit construction and commitment (UCC), which takes account into not only whether a generating unit should be committed at a given time but also whether building this unit would reduce the sum of the operational and investment costs. The method considers the flexibility requirement in hourly, daily and seasonal time scales. A heuristic 'priority ordering' constraint is proposed to reduce the computation time without misleading the decisions on flexible investments.

To evaluate the profitability of flexibility in a market environment, a market model based on a centrally operated system with perfect competition is developed. The model takes into account day-ahead and real-time balancing markets and enables the assessment of profit obtained from the provision of flexibility. Furthermore, the rolling clearing of electricity markets is proposed to analyse the impacts of market design on the profit of flexibility. In addition, the effects of different parameters on the profitability of flexibility are discussed.

Finally, to estimate the flexibility level of a power system without the need of computationally demanding simulations, two indices are proposed. The first index, designated as the normalised flexibility index (NFI), is obtained by analysing the 'adjustable space' of individual generators and the whole system. This index can be used to identify the flexibility level of a single generator (or a generation mix) and indicate its contribution to the whole system's flexibility. The second index, called the Loss of Wind Estimation (LOWE), is proposed to evaluate the flexibility level of a system by its ability to accommodate wind. The LOWE is established based on the statistical analysis of net demand. It is defined as a joint probability of several features that relevant to flexibility requirement and describes the possibility that wind curtailment occurs in a power system during a year.

1.5 Contributions of this Work

The research carried out in this work provides a systematic approach for exploring the role of flexibility in different power system activities (generation scheduling, generation expansion and market operation) and proposes two indices for offline flexibility evaluation.

The main contributions of this work are summarised as follows:

1. *Evaluation of the role of flexibility in generation scheduling.*

Any power system is inherently flexible to some extent and is capable of handling certain amount of variations and uncertainties from both demand and generation side. One of the main contributions of this work is to explore the performance of this existing flexibility in generation scheduling. This is achieved by analysing the effects of flexibility from technical, economic and environmental aspects. These analyses are critical for better understanding of the technical requirements for providing flexibility. They also form the basis to study the role of flexibility in generation expansion planning and market operation.

2. *Planning model to determine the optimal generation mix to accommodate wind generation.*

Certain level of wind penetration is allowed in an existing power system because of the system's inherent flexibility. However, this penetration has an upper limit and once the threshold is reached no more wind generation can be properly scheduled. In order to 'upgrade' the level of flexibility of a system, additional flexible units should be invested. The second main contribution of this work is proposing a methodology to determine the optimal investment on these additional flexible units. The main features of this methodology are:

- Bridging the gap between the long-term investment decisions on the plants to be built and the short-term operational decisions on how these plants are scheduled. This planning model can not only consider the generation adequacy but also take into account the operational flexibility adequacy at the planning stage.

- Assessing the needs for flexibility, taking into account critical aspects as hourly, daily and seasonal variations in both load and wind profiles.

- Avoiding running the proposed planning optimisation algorithm over a whole year with the hourly resolution that would require an excessive amount of computing time. This is achieved by using a procedure to organise representative load profiles and wind profiles. It considers four representative weeks, selected from each season. The use of representative profiles helps to find a balance between simulation time and capturing the necessary information to access flexibility requirements. The problem of initialisation of these representative weeks is also considered since directly connecting the four representative weeks may affect the optimal solution through the start-up costs, the minimum up-down time constraints and the ramping rate constraints. Initialisation methods are proposed to avoid awkward changes between consecutive weeks.

- A heuristic constraint, named 'priority ordering constraint', aiming at reducing the computation time is also developed. Sets of relatively small generating units with similar technical and cost characteristics are prime candidates for providing flexibility. The optimisation algorithm can spend a considerable amount of time comparing solutions involving one or the other of these units, but end up with no significant gain because their characteristics are almost identical. The priority ordering constraint sets an artificial priority order among these units and the units are then committed in this order. It is validated that this constraint is able to improve the computational efficiency without distorting the optimisation results.

3. *Assessment of the value of flexibility in a market environment*

Since flexibility plays a significant role in systems with large-scale variable generation integration, its value should be reflected by the market profit. Failing to do so will hinder the investment in flexibility for accommodating the expected penetrations of wind generation. Previous studies mainly focused on the discussion of wind integration cost[3] [15, 34], which is in essence the cost for

[3] Wind integration cost: The costs incurred to incorporate wind generation into a real-time electricity supply, ensuring system security.

providing flexibility to accommodate wind generation. In a market environment, system flexibility influences the clearing price of the system as well as the quantity of energy and reserve traded by the generators and ultimately alters their profits. This work provides a method to evaluate the profit that the system can obtain from providing flexibility in a typical market model involving both day-ahead and real-time balancing markets. The effects of different parameters on the profit of flexibility are also discussed.

The rolling planning of the day-ahead market is also proposed to evaluate the effects of market design on the profitability of flexibility. It proves that the efficient market design can make better use of forecasting information and thus reduce the physical flexibility requirement of the system. Therefore, flexible market designs can be regarded as a 'virtual' flexibility resource.

4. Two innovative indices to provide offline flexibility evaluation.

The term 'flexibility', although frequently quoted in the context of coping with the imbalances between load and generation in the power system, lacks an explicit index to evaluate its level. In the literature, flexible units are usually referred to those units with high ramping rates, quick start-up capability, and expensive operational cost. However, it is difficult to tell exactly how flexible a system is or to compare the flexibility of different systems without performing simulations of system operation over long periods. The proposed indices in this work provide innovative ways of quantifying flexibility. With these indices, one can intuitively compare the flexibility levels of different power system or different generating units. Moreover, their applications in determining the wind expansion targets and the conventional generation planning are also desirable.

The two indices presented in this work provide a convenient and efficient offline methodology to evaluate the flexibility without carrying out cumbersome calculations.

1.6 Thesis Structure

According to the objectives presented above, the thesis is organised as seven Chapters and their correlation is illustrated in Figure 1.2.

Chapter 1 introduces the background of this thesis, presents the main objectives expected to be achieved, briefly describes the methodologies that applied, and summarises the main contributions of this work.

Chapter 2 reviews the main findings from the state of the art of wind integration study, and categorise the corresponding flexibility services used to mitigate the impacts of wind penetration. It then gives explicit definition for flexibility and specify the scope of flexibility study in this work. Within this scope, the analysis on the hourly characteristics of wind generation and their impacts on the flexibility requirement of the thermal generation system are performed.

Chapter 3 explores how generation scheduling copes with large amounts of wind power. The evaluation is conducted by a whole-system approach and is developed based on a unit commitment (UC) model. The value of conventional generation flexibility is assessed in terms of the changes in generation pattern, reserve provision, operational cost, CO_2 emissions and wind utilisation. Vertical comparisons are drawn to evaluate the behaviour of flexibility under different wind penetration levels. Horizontal comparisons are undertaken between systems with different levels of flexibility to explain the contribution of flexibility in accommodating wind generation.

Chapter 4 proposes a technique named unit construction and commitment (UCC) to determine the optimal generation mix to cope with the additional flexibility requirement caused by wind integration. Test results based on the IEEE RTS system are presented and demonstrate how different wind penetration levels affect the need for flexibility investment.

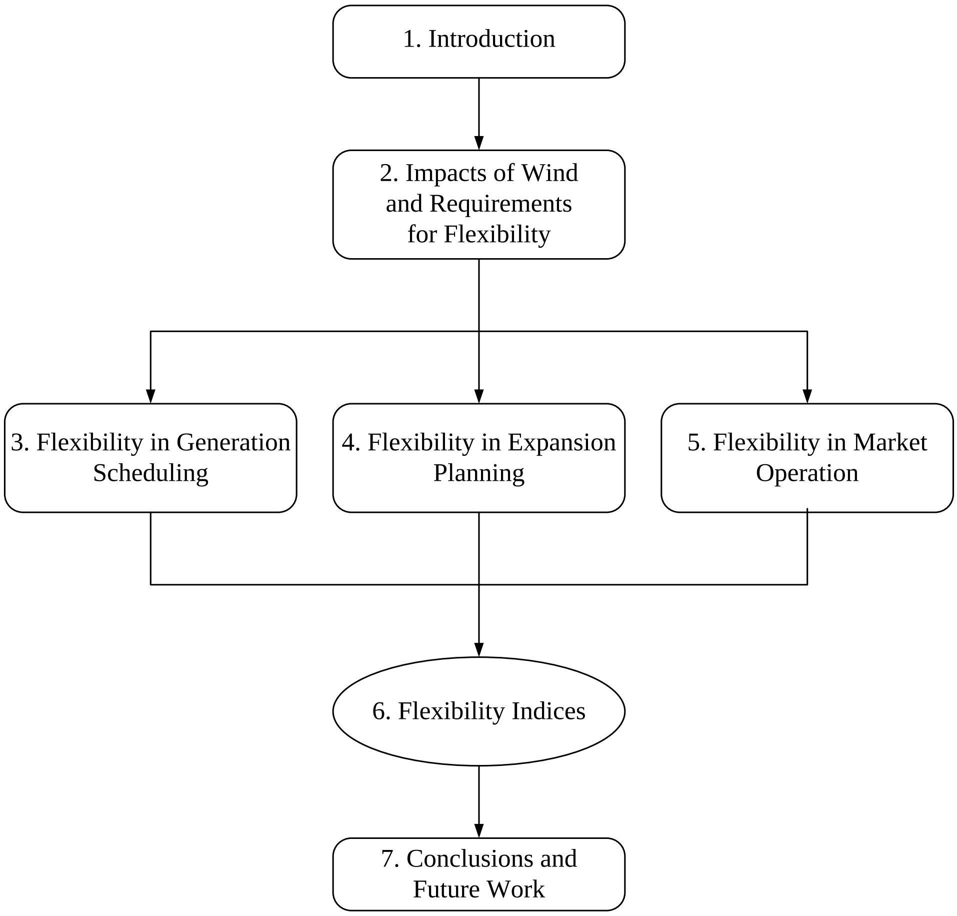


Figure 1.2: Thesis Structure

Chapter 5 explores the profit of flexibility in a market environment for balancing purpose. It describes a method to quantify this profit based on an electricity market model that takes into account both day-ahead and real-time balancing market. It discusses how this profit varies with different wind penetration levels. It also analyses the effects of different factors on the profit of flexibility. Finally, rolling planning of the day-ahead market is introduced to evaluate the impacts of market design on the flexibility requirement and the flexibility profit.

Chapter 6 proposes two innovative indices to evaluate the flexibility level of a power system. The validity of these indices is verified using test cases on the IEEE RTS system and the ‘scaled-down’ UK system.

Chapter 7 concludes this work and proposes directions for future work.

CHAPTER 2

FLEXIBILITY TO COPE WITH LARGE-SCALE WIND PENETRATION

2.1 Introduction

The integration of large-scale wind generation has impacts on various aspects of a power system over a wide range of time frames. In order to mitigate these impacts, flexibility services are needed on different time scales. Therefore, the evaluation of flexibility should be established on the knowledge of when, where and which flexibility service is needed.

In this Chapter, we will first review the main findings from the state of the art of wind integration studies, and categorise how the impacts of wind can be associated with flexibility requirements on different time frames.

Flexibility is a complex concept that comprises different sources of flexibility, different drivers for its need, and different actions for its deployment. Given the vastness of the scope of this subject, in this work we will only focus on some aspects defined in this Chapter.

Within the scope of this thesis, we focus on the flexibility required on the hourly time scale. As a consequence, it is essential to understand the impacts of hourly wind characteristics on net demand to form the basis of further analysis of flexibility.

The wind time series given in [35] represents typical wind output profiles with hourly resolution, and they are obtained from the aggregated wind generation data over thirty regions in UK. These representative time series will be used here to analyse the characteristics of wind generation, as well as their possible impacts on the system net demand and ultimately on the requirement of flexibility. The analysis is processed by the following step: First, by statistical analysis of the representative wind data, the hourly, daily and seasonal patterns of wind power output is summarised, furthermore, the variable and unpredictable nature of the wind power output is discussed. The system load and wind power are then aggregated, and statistical analyses are performed again to show how wind penetration affects the net demand. Finally, the flexibility services required to cope with these wind impacts are discussed.

2.2 Review of Impacts of Wind Integration

2.2.1 Impacts of Wind Integration over Different Time Frames

As discussed in the previous Chapter, it is expected that uncertainty and variability of wind generation will drive the need for more flexibility in the power system. How these characteristics affect the power system is the main concern of wind integration studies. There is a significant body of research that has emerged in the past few years from the academic community, international and national governmental institutions, technology developers and utilities. This alone shows the importance of this topic. These researches have illustrated the effects of wind integration from different perspectives, including the short- and long-term effects, local and system-wide effects, as well as technical and economic impacts.

Important aspects that pose challenges to the integration of large-scale wind generation include: the accuracy of wind forecast, the geographical distribution of wind resources, its correlation with load, and the existing flexibility of generation portfolios.

Wind integration studies in Europe

In [15, 36-43] Holttinen *et al*. performed simulations using realistic wind data of the Nordic power system. They made extensive analyses of the short- and long-term impacts of high penetration of wind generation on the power system operation and electricity market operation. A series of representative conclusions tailored for the European power systems were drawn. Given their relevance to this thesis, some of their findings are highlighted here.

These studies start with a thorough analysis of wind generation data, including their stochastic behaviour, variability, temporal correlation, and spatial correlation. The main conclusions are summarised as follows:

- The second and minute variations are much less prominent than the hourly variations. Very fast variations are smoothed out due to the inertia of the large rotating blades of variable speed wind turbine. When considering a large area with geographically dispersed wind farms, the second and minute variations will be further mitigated by the smoothing effect. This indicates that the hourly wind data covers the most important information that describes the variability of wind generation in a large system with geographically dispersed wind farms.

- The hourly wind power productions from different wind farms are correlated to some extent. The correlation[4] of the hourly wind generation is strong (over 0.7) for distances less than 100km and becomes weaker (below 0.5) for distances above 200-500km. The smoothing effect should be taken into account when the up-scaling wind power production data to represent large volume of wind production data.

- The smoothing effect of an area has an upper limit, where an increase in the number of turbines will not decrease the variations by the total wind power production of the area. When enough turbines from a large enough area are combined, the smoothing effect reaches saturation and the time series can be up-scaled with representative hourly variations.

[4] Correlation is a statistical measurement that describes the degree of relationship between two variables. It measures the extent to which two variables tend to vary together. It ranges in value from -1 to +1.

- There is often a distinct yearly (seasonal) and daily (diurnal) pattern in wind power production. This is mainly driven by weather patterns, like wind, sun, temperature, or local phenomena. An example of the latter is found in California, where there are morning and evening peaks, and are caused by the wind blowing from the desert to the sea and in the opposite direction, respectively.

- The prediction error increases with increasing forecast horizon. In western Denmark, when forecasting 6 hours ahead, the error for the installed capacity of about 1900MW wind power was between ±100MW for 61% of the time, and large errors (more than 500MW) occurred nearly 1% of the time. When forecasted 36 hours ahead, small errors happened 37% of the time while large errors occurred during 7% of the time. Geographical dispersion of wind farms can also, in some cases, reduce the forecasting errors.

Based on the understanding and analysis of wind generation patterns and characteristics, the authors evaluate the impacts of the integration of large volumes of wind generation on the power system. These include the impacts on reserve requirement, conventional generation patterns, power exchanges, CO_2 emissions, operational cost, wind utilisation, generation adequacy and market prices.

- ***Impacts on reserve requirement:***

  Wind integration has little impacts on primary reserve (seconds-minutes) because the local inertia of wind plants and the smoothing effect of geographical dispersion of wind farms smooth out the variations within tiny time scales.

  The increased reserve requirement is mainly seen on a 15 minutes to 1 hour time scale. In the Nordic countries, wind power would increase the reserve requirements by 1, 2 and 4% of wind power capacity at 5, 10 and 20% wind energy penetration[5] [15] of gross demand, respectively.

- ***Impacts on conventional generation patterns and CO_2 emissions:***

  The variability of wind power will cause the rise of start-ups of thermal power plants. Wind power will replace coal or gas-condense power and thus reduce the fuel costs and CO_2 emissions. In the Nordic countries, the reduction of CO_2 emissions is high (700gCO_2/kWh) at low penetration of wind, but this effect reduces (620gCO_2/kWh) at higher penetration level (more than 10% wind energy penetration).

- ***Spilled wind energy:***

  Wind energy curtailment becomes significant with large potential wind generation. Experiences in West Denmark show that when wind power produces more than 20% of the gross demand, the spilled wind can reach as much as 10% of the total potential wind energy.

- ***Impacts on generation adequacy:***

  In the Nordic countries, the analyses of three years of hourly wind generation data together with the earlier studies show that the capacity credit of wind power is close to the average power produced. Wind power can contribute to power system adequacy.

Wind integration studies in USA

High penetration of wind in the system may need: (a) frequent switching of generators (b) allocation of more ramping capability to account for wind variability, and (c) more regulation capacity. All of these services are associated with additional costs. Therefore, cost-of-service studies are the concern of most

[5] Wind energy penetration is the share of produced wind power in the power system, presented here as % of annual gross demand.

utilities with significant wind potential and strong determination to promote wind generation. In the literature, many studies assess the impacts of wind in terms of the increased cost of managing the system with significant wind generation [34, 44-48].

In [44], Brian Parsons and Michael Milligan conclude studies held by some utilities in U.S. [14, 45-48]. The main concern of these studies is the impacts of wind on power system operation and the associated integration cost. The main approach of these researches is by starting with the physical behaviour of the system without wind, and then discussing how that physical behaviour is affected by wind power. In these studies, the impacts of wind on conventional generation are usually analysed over three key time frames that correspond to system operation. The first is the regulation time frame (seconds to minutes), which is the concern of regulation capability provided by automatic generation control. The second is the load following time frame (10 minutes to few hours), which is mostly relevant to ramping capability of power system. The third is the scheduling (unit commitment) time frame which can range from several hours to a few days. This period is for planning the required quantity of generation and load following capability. Wind integration studies are performed on these time frames with wind capacity penetration of 3.5%-20%. At these wind penetration levels, the impact on regulation and load following appear to be modest (no more than 0.2$/MWh wind integration cost), and the unit commitment time scale appears to be more prominent (up to 6.57$/MWh wind integration cost). The paper also indicates that better forecasting and larger balancing areas would be helpful to mitigate wind integration costs.

While this paper focused on the impacts of wind power integration on the system operation and the associated integration cost, J.Charles Smith and Michael Milligan identified in [13] the impacts of wind integration on other aspects of the power grid. In this paper, more comprehensive studies have been conducted to look at the impacts of wind power from four aspects: wind plant interconnection issues, wind impacts on system operation, transmission planning and market operation issues. Accordingly, they indicated the possible measures that can improve the ability of integrating increasing amounts of wind capacity in power systems. We summarise the main conclusions of these four aspects as follows:

- ***Wind plant interconnection issues:***

  Special concern about this aspect is to design and protect the interface between the wind plant and the utility system to minimise any interference with the operation of the power system as a result of any problems with the wind plant. This area is usually relevant to dynamic stability studies with super-short time scale (milliseconds to seconds). Improving the capabilities of wind plant, like low-voltage ride-through, reactive power control, SCADA information, voltage control, output control, ramp rate control, power electronic control (governor response and inertial response) is crucial to mitigate the impact of wind plant interconnection on the power grid.

- ***Wind impacts on power system:***

  This issue includes the impacts on regulation, load following, and scheduling. Most wind integration studies concentrate on this aspect. It is increasingly recognised that the variability and uncertainty of wind can only be properly dealt with in combination with demand, because the net demand is the true part that has to be met by the rest of the system. The authors point out that the impact of wind on regulation has been found to be modest [46, 47]. In this respect, the authors also discuss the capacity credit of wind. They conclude that the capacity value of wind usually ranges from approximately 10% to 40% of the wind plant rated capacity.

- ***Transmission Planning:***

  Greater use of existing transmission system capacity and new transmission investment are needed to harvest large amounts of remote wind energy to the market. Considering the uncertainty and variability of wind generation, a more flexible transmission product is required. For example, a transmission system tariff, which deals with penalties due to imbalances, would provide incentive for wind operators to improve wind forecasts and update them in a timely fashion.

- ***Market operation:***

  Well-functioning day-ahead and real-time markets provide the best means to deal with wind variability. The aggregation of wind plants over large geographical areas provides an effective mechanism to reduce wind plant variability. Many studies in U.S. recognise that large balancing areas can help manage wind plant variability more easily than small balancing areas.

In particular, J.Charles Smith and Michael Milligan mention that there may be times that a balancing authority is unable to take wind energy into the system. This could happen during low-load periods if wind generation is near its maximum output, and it is also possible that large wind penetrations in a system could contribute to system ramp events that are difficult to follow.

Timescales of flexibility-related events and actions

In [49], a report from EDF and the University of Manchester, F. Bouffard, et al. carried out a thorough inventory and qualitative analysis of the issues related to flexibility in power systems, including the actors and the events which may give rise to some needs and outlets for flexibility, as well as the associated actions to provide such flexibility. These flexibility-related events and actions are deemed to be tightly coupled to the timeframe within which they may happen and ultimately used. Table 2.1 summarise the time scales over which flexibility-related actions and events have an effect [49]. It is concluded that the expression of flexibility can arise over a single timescale or may even carry on several timescales for which may overlap.

Table 2.1 Timescales of Flexibility-Related Actions and Events

Actions and Events	Duration	
	Min	Max
Deviation up & down	Seconds	Days
Ramping up & down	Seconds	Minutes
Outage	Seconds	Days/Years
Primary reserve	Seconds	Hours
Secondary reserve	Seconds	Hours
Tertiary reserve	Seconds	Hours
Unit shutdown	Seconds	Minutes
Unit Start-up	Minutes	Hours
Unit maintenance	Days	Months
Unit construction	Years	Years
Unit retirement	Years	Years

Conclusions of Wind Integration Studies and Flexibility Studies

Although different wind integration studies categorise the impacts of wind from different aspects, there is considerable consistency between their results and insights. These wind impacts and the related flexibility services can be classified according to the time scales in which they are involved.

Main impacts of wind integration and the corresponding flexibility requirements can be summarised in Table 2.2.

Table 2.2 Impacts of Wind Integration on Power Systems

	Time scale	**Domain**	**Elements affected**	**Flexibility requirement**
SUPER SHORT-TERM	Milliseconds to seconds	Wind plant interconnection	Dynamic stability	Better design of wind plant
SHORT-TERM	Seconds to minutes	Regulation	Primary regulation	Improve AGC; Participation of wind farms
	Minutes to hours	Load following	Ramping rate	Increase ramping capability
	Hours to days	Generation scheduling; Day-ahead market	Generation pattern of conventional generation; Transmission and distribution efficiency; Wind utilisation	Increase spinning and standing reserve; Improve forecasting; Efficient market design; Possibility of curtailing wind
LONG-TERM	Years	Expansion planning	Generation adequacy; Flexibility adequacy; Transmission adequacy	Optimise generation mix; Increase transmission investment

In general, minute to minute and hourly variations and uncertainties of wind generation and the associated short-term impacts on power system operation are the main concerns of wind integration studies. Unit commitment (UC) is crucial for the reliability of short-term system operation. Therefore, one of the major challenges of high wind penetration is the way that it affects the UC problem. Accordingly, short-term flexibility that is needed to cope with the wind impacts on the UC problem, like ramping capability and operational reserve, is of the most concern in the operation of a sustainable power system [29, 50-59]. This is also the main object of study in this thesis.

From the system planning point of view, traditional generation planning focused on meeting generation adequacy but usually did not explicitly consider the short-term flexibility (especially ramping capability) in the future system [60-63]. New adapted system planning should take into account the requirement for short-term flexibility to ensure that the future system can accommodate certain targets of wind integration, in a reliable and economic way [31].

Electricity market based on a centrally operated system usually relies on a UC [9, 64, 65]. In the market clearing problem, production costs (like start-up costs, fuel costs) used in the traditional UC problem are replaced by the bids of different market participants. In a wind-power-rich market, in order to cope with additional flexibility requirements, flexible units may need to be committed more frequently and thus changes in the generation usage pattern will be observed. This will directly impact the market clearing price [66-68], the total cost of electricity, and the profit of the conventional generators.

Therefore, the UC problem tailored to cater for wind generation forms the basis to evaluate the performance of short-term flexibility in the generation scheduling, generation planning and market operation. A large and growing body of literature has investigated the adapted UC for wind-power-rich system. The two main streams of work will be introduced in the next Section.

2.2.2 Impacts of Wind Generation on Optimal Scheduling

Different approaches have been proposed to adapt the conventional UC problem to the wind power-rich system. The main issue is how to incorporate the uncertainty and variability of wind power generation in the UC formulation.

These approaches are mainly divided into two groups: deterministic and stochastic. The main criterion that differentiates the two is the way they address the uncertainty and the variability of wind generation, especially the way that they procure reserve.

In the deterministic approach, uncertainties of wind power are incorporated in the UC by explicitly allocating additional hourly reserve in the reserve constraint. The additional reserve requirement is determined offline and treated as input for the deterministic UC. Typical ways of specifying the additional reserve requirement in the deterministic UC include:

- Percentage of hourly wind power forecast [51, 69, 70]
- Probabilistic representation of wind power forecast error [30, 71-73]
- Calculation of system reliability with consideration of wind power [74, 75]

The deterministic UC is based on the predictions of wind power output in the next days. The pre-specified reserve requirement aims to make sure that the system can cope with all the possible deviations (or at least most of them) between forecasted and realised situations. Since the reserve requirement is calculated offline and treated as input in the reserve constraint, consideration of uncertainty of wind forecast will not cause significant computational burden on the deterministic UC. The deterministic UC is easier to implement, especially for realistic systems, and it is widely used in the industry.

An alternative approach to accommodate the wind power uncertainty is to apply stochastic programming [56, 76-80]. In the stochastic approach, uncertainty of wind is considered by simulating the possible wind power realisations with respect to the probabilities of their occurrence. The objective of the stochastic UC is to minimise the expected cost of supplying the demand over representative scenarios. There is no need for a priori specification of minimum reserve requirement for the system. Instead, the reserve is scheduled in an implicit manner. In other words, the reserve is the output of the UC problem rather than the input of the UC obtained from the offline calculation. Considering possible scenarios of wind realisations, the decision of the stochastic UC should be able to respond to any of the realisations considered when the real time comes. The stochastic UC can generally schedule the system with a more robust manner with less conservative cost than a deterministic one. However, considerations of a large number of scenarios inevitably impose significant computational challenge. Particularly for scheduling with a large number of units over a long period with temporal connections between consecutive hours, the size of the stochastic UC problem will become intractable (at least with commercial solvers).

Although the deterministic UC is usually considered being conservative and may cause excess of reserve, it prepares the system in a more rigid and applicable way. Since our problem needs to take into account all the constraints relevant to flexibility requirement, it involves a large number of decision variables. Therefore, the deterministic UC is more preferable to solve this problem within acceptable computational time.

Probabilistic representation of the wind forecast error, which is typical in determining the additional reserve in most wind integration studies, is applied in this work. Details of offline calculation of total reserve requirement, including the reserve for forced outage, demand forecast error and wind forecast error, will be provided in the next Chapter.

2.3 Definition of Flexibility and Scope of this Work

In the broader engineering field, flexibility is defined as the ability of a system to respond to potential internal or external changes, in a timely and cost-effective manner [81]. This definition of flexibility differs according to the variations and uncertainties that systems need to face, and the resources available to provide it.

In the context of electric power systems, flexibility describes the system ability to cope with uncertainty and variability in both generation and demand side while maintaining the system reliability in a cost-effective manner.

As introduced in the previous Sections, high penetration of wind power has impacts on the power system over different time scales, from milliseconds to hours to years. Depending on these impacts, there are corresponding measures to mitigate them and maintain the system in a balanced state. In general, the ability that the system has for deploying all these measures constitutes its flexibility.

In this work, we focus on the flexibility requirement associated with the generation scheduling domain, which is mostly relevant to the hourly variation and uncertainty of wind power output. Specifically, in this context, wind power generation changes the original power balance and asks for additional flexibility mainly for three reasons:

Firstly, large integration of wind penetration will replace some of the conventional generation without an increase of system demand. In order to maintain the demand-generation balance, conventional generators will be required to reduce their power output according to wind generation at each hour (we assume that wind generation will be always used before any other form of generation due to its lowest operational cost). This reduction will be constrained by their minimum stable generation, and it can be expected that, for certain levels of net-demand, wind curtailment may be the sole source of flexibility.

Secondly, wind power generation is difficult to predict. The forecast error of wind may result in significant deviations between the scheduled value and the actually delivered value. In order to guarantee the demand-generation balance at the real delivery time, additional reserve has to be provided to back up over- or under-estimation of wind generation. This will further stress the need for flexibility from conventional generation or otherwise the need for curtailing the wind generation.

Thirdly, wind power generation output is variable and conventional generators have to change their output in the same variable way. This requires higher ramping capabilities in the conventional generation portfolio and potentially more frequent unit start/stop.

In conclusion, large volumes of wind generation bring extra generation, uncertainty and variability to the original power system scheduling process. In order to handle these changes and accommodate wind generation effectively, the conventional generation has to reduce their output, and provide sufficient reserve and ramping capability. All these three aspects are involved in the domain of flexibility for accommodating wind generation.

As mentioned in Chapter 1, flexibility can be provided from various resources, from flexible generation, demand side management, storage, interconnections to flexible market designs. In this work, flexible thermal generators are used as examples to illustrate the validity of the approach and the metric proposed. The same methodology can be extended to include alternative sources of flexibility. We will explore the performance of thermal generation flexibility in the generation scheduling, generation expansion planning and market operation. Based on detailed evaluation and analysis of thermal generation flexibility, we aim at providing a better and broad understanding of the role of flexibility and evaluating the flexibility through quantitative studies.

Since the object of this study is the flexibility required on the hourly time scale, it is essential to understand the hourly characteristics of wind generation and their impacts on the flexibility requirements. These will be analysed using historical wind generation data.

2.4 Characteristics of Wind Power

2.4.1 Magnitude of Wind Generation Output

The output of wind plant relies on the availability of wind energy, which depends on the wind speed at a certain location and certain time. The wind turbines firstly convert the wind into rotating kinetic energy and then to electricity. Although wind power output is largely dependent on the strength of wind resources, the relationship between the wind speed and wind power output is not simply linear. Figure 2.1 shows an example of a typical wind turbine power output curve [82]. Although these curves have similar shapes, they are mostly wind-turbine-specific.

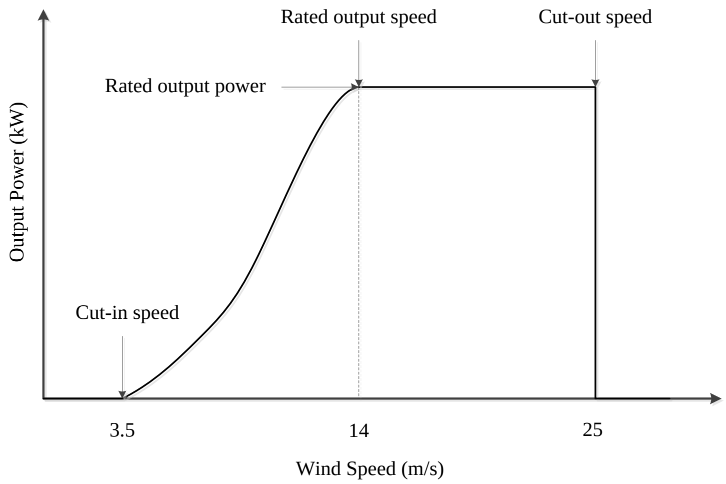


Figure 2.1: Example of a Typical Wind Turbine Power Output Curve [82]

- ***Cut-in speed:***

  When wind speed is low, the blades of wind turbine would not rotate due to the friction and large inertia, and no electricity is generated. Only when wind speed is fast enough and the blades have enough torque to overcome the resistance, the wind plant will start to generate electricity. The speed at which the turbine begins to rotate and generate power is referred as cut-in speed and this speed is typically between 3 to 4 m/s.

- ***Rated speed:***

  From Figure 2.1, it can be seen that beyond the cut-in speed, wind power output raises simultaneously with the increase of wind speed. The increment stops when wind speed reaches a certain level, where the wind plant reaches its maximum nameplate capacity. This wind speed is called 'rated speed' and it typically falls between 12 to 17m/s. The corresponding wind power output is called rated power. When the wind speed is higher than the rated speed, the output of the wind turbine maintains at the rated power.

- ***Cut-out speed:***

  If the wind speed keeps going up to a certain level that may damage the rotor, the self-protection system of the turbine will stop the rotor. This wind speed, to which point that the braking system is activated, is called cut-out speed.

Therefore, the output of a wind generator can vary from zero to its maximum rated capacity, and when the wind speed is between the cut-in speed and the rated speed, the output of a wind plant is proportional to the cube of the wind speed [82].

Normalised wind generation is often used to represent the ratio of aggregated wind power (from different wind turbines or wind farms) in total wind capacity. It reflects the strength of wind resources at the corresponding time.

In this work, normalised historical wind data for one year is used to represent the typical variation of the wind resources. The normalised wind generation retains the information of realistic capacity factor and hourly variations of wind generation. Different representative scenarios of wind penetration in a power system can then be prepared by multiplying the normalised wind generation with various wind installed capacity. As a result, the absolute value of hourly wind generation and the absolute value of variations between consecutive hours will be changed accordingly. This provides a concise way to prepare the simulated wind data with different penetration levels. For the sake of simplicity, here we do not consider the impact of geographical dispersion on the aggregated wind generation.

The normalised value of wind generation is calculated based on the aggregated wind generation data in the year 2005 in the UK [35]. As an example, Figure 2.2 shows the normalised pattern of wind power generation in two weeks selected from January and July.

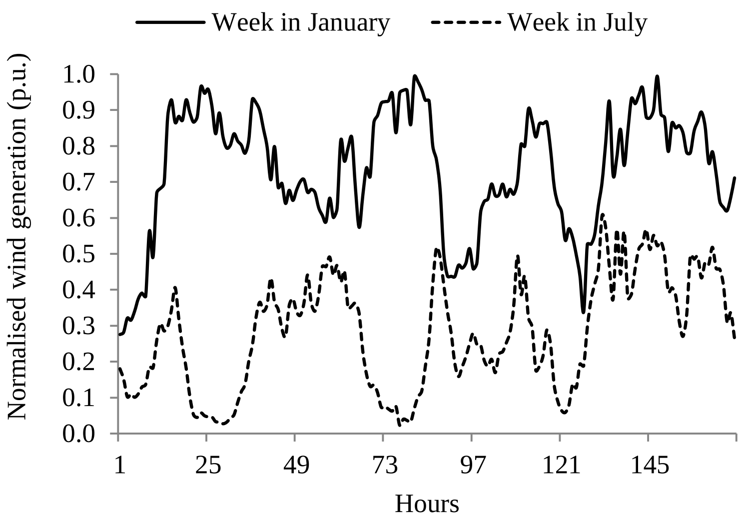


Figure 2.2: Normalised Wind Generation of Two Weeks in January and July in the UK in 2005 [35]

It is seen from Figure 2.2 that wind power fluctuates frequently, and even within one day, the wind power output can vary over 70% of the total capacity. It is seen from this time series that there is more wind resource in winter than in summer, but this needs to be further proved by statistical analysis since the two randomly selected wind profiles indicate a trend but are not sufficient to draw conclusions.

2.4.2 Statistical Analysis of Wind Generation Output

Seasonal patterns

In a short period, wind power output fluctuates intensively due to random variations in wind resources. However, in the long-term statistical analysis, e.g. during a year, wind power output follows a certain degree of regularity because of the seasonal characteristics of the meteorology.

The following statistical analysis is based on the aggregated wind power data in the UK in 2005 [35]. Normalised monthly average wind profile is illustrated in Figure 2.3. It is seen that there are more wind energy in autumn (September, October and November) and winter (December, January, and February) than in spring (March, April and May) and summer (June, July and August).

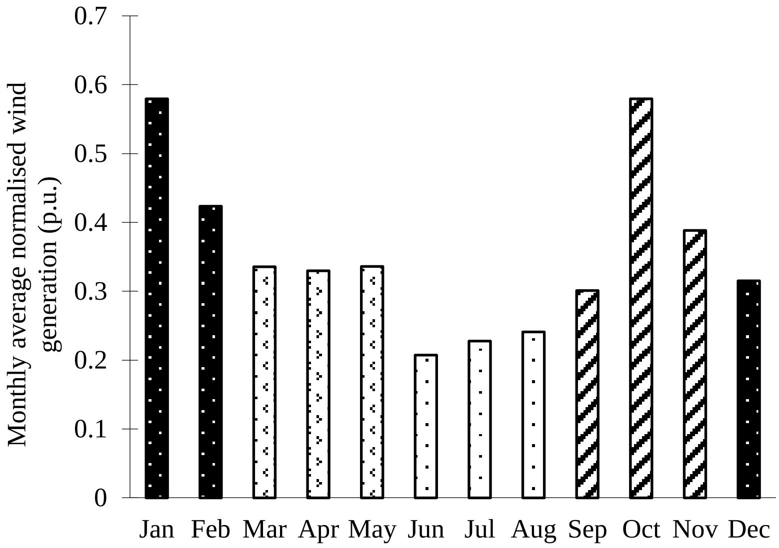


Figure 2.3: Monthly Average Normalised Wind Generation in the UK in 2005 [35]

Figure 2.4 illustrates the histograms of wind power output in four seasons. In winter, when the wind is usually strong and widely spread, there is more chance for the wind power output to be higher than 50% of the total capacity. However, in summer, when the wind is mild and rare, the wind power output is lower than 50% of the total capacity most of the time. Wind in spring is milder than in winter, and the wind in autumn is relatively stronger than in summer. These facts are based on the UK data so our discussion of the results are not generalised.

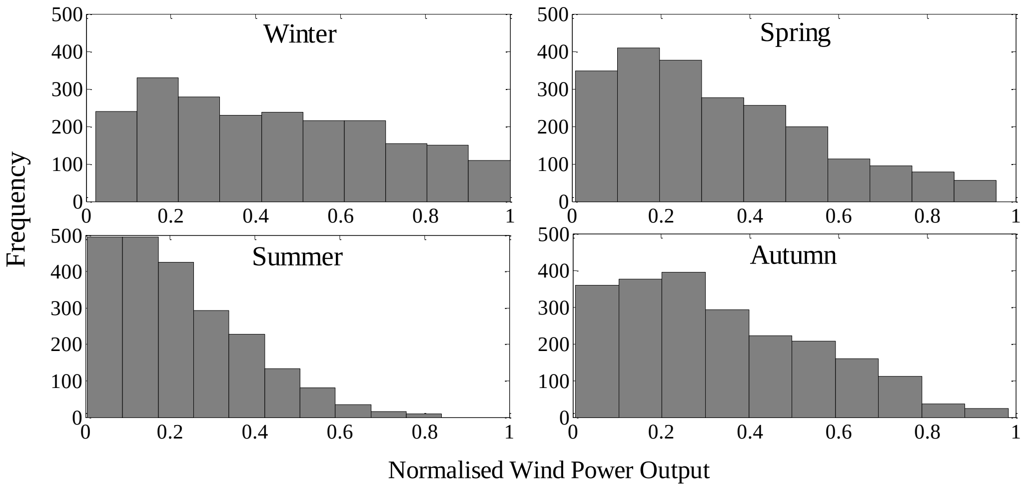


Figure 2.4: Histograms of Normalised Wind Power Output in Four Seasons

Seasonal variations of wind power generation have critical effects on generation planning and operation. For example, in winter when there are plenty of wind resources, more flexible units should be scheduled to accommodate the accordingly large-scale variations and uncertainties. While in summer when there is modest wind generation, conventional generators will take most of the responsibility for serving the gross load.

Capacity factor

The theoretical maximum wind energy production in a year is calculated by multiplying the total wind capacities with total hours in a year. From the above statistical analysis, during one year, there is rarely a period when the wind power output reaches its maximum capacity. Therefore, the actual wind energy production in a year is always lower than this theoretical maximum value. The capacity factor is used to measure the ratio of annually real production to the annually theoretical maximum, and typical capacity factors for wind generators are between 20% and 40%. Offshore wind farms usually have higher capacity factor than onshore wind farms, because there is usually stronger wind on the sea than on the land. In 2005, the capacity factor of offshore wind farms in the UK is around 36% while this number is only 27% for onshore wind farms. Capacity factor of overall wind farms, including offshore and onshore, are approximately 33.2%.

Wind Penetration

There are two key concepts relating to the contribution of wind power in the power system:

- Wind capacity penetration: refers to the ratio of the installed wind capacity to the total generation capacity. For instance, in 2010, the UK has 90.208GW of total generation capacity, of which 5.38GW belongs to wind farms [83]. The capacity penetration of wind power is calculated as $5.38/90.208 = 5.9\%$.

- Wind energy penetration: represents the fraction of the total annual demand supplied by wind energy. Using the above example, assumed an average 30% wind capacity factor, the annual wind energy generation is approximately $5.38 \times 8760 \times 30\% = 14.14\ \text{TWh}$. Given the annual electrical energy used in this year is around 383TWh [83], the wind energy penetration is $14.14 / 383 = 3.69\%$.

In particular, wind energy penetration is a key parameter to evaluate the wind contribution in total electrical energy consumption. However, the maximum allowable wind energy penetration is limited by the flexibility of the rest of the generation portfolio. In the cases where wind is curtailed, the actually scheduled wind energy is lower than the total wind energy that can be produced by the aggregated wind generators.

2.4.3 Variability of Wind Power Output

The variability of wind power output is due to meteorological fluctuations. At modest penetration levels, the variability of wind is smoothed by the variations of demand [15]. With large wind penetration, however, the effects of wind power variations on the net demand become significant.

As mentioned in the previous Sections, hourly variations are the main concern in generation scheduling, system planning and market operation [15], and also the focus of this work.

Figure 2.5 shows the duration curve of relative hourly wind power variations (p.u.) in the UK in 2005 [35]. It is observed that over 90% of time during this year, the hourly change is within 10% of the total installed capacity.

Upward variations occurred in 4398 hours, accounting for 50.2% of time. Therefore, upward and downward variations of wind power are almost symmetrical in the time of occurrence.

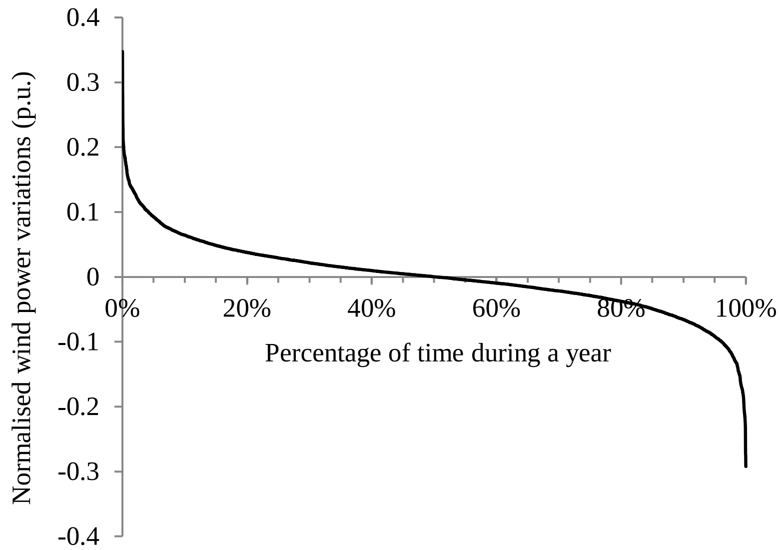


Figure 2.5: Duration Curve of Normalised Wind Power Variations in the UK in 2005 [35]

Duration curves of aggregated wind power variations (in GW) with different wind capacities, as 5GW, 10GW, 15GW are shown in Figure 2.6. More installed wind capacity in the system leads to larger aggregated wind power variations.

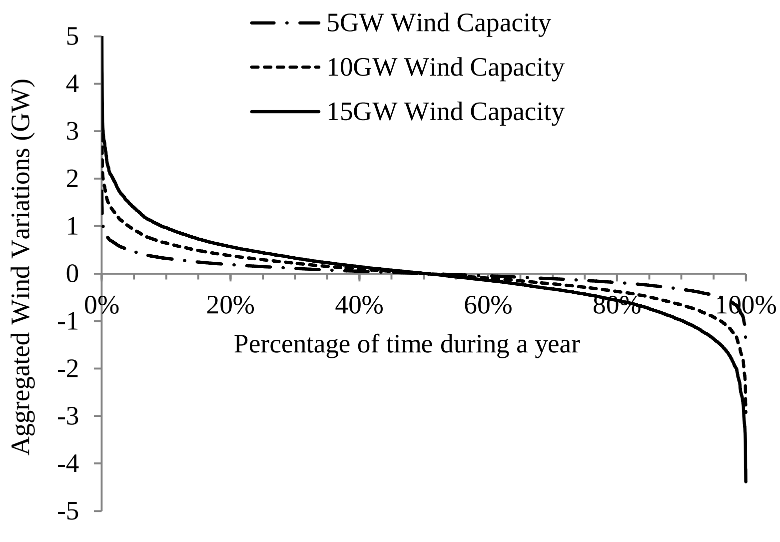


Figure 2.6: Duration Curves of Aggregated Wind Variations under 5GW, 10GW, and 15GW of Wind Installed Capacity

Cumulative distribution functions of aggregated wind power variations under different wind capacities are illustrated in Figure 2.7.

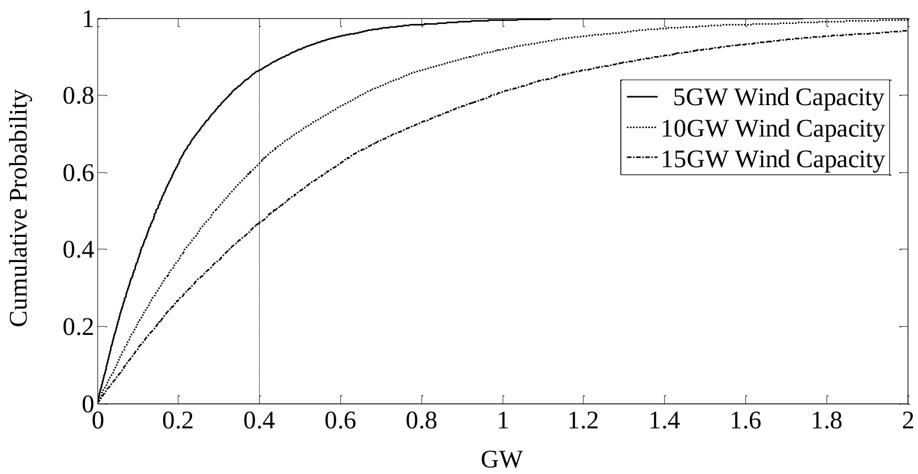


Figure 2.7: Cumulative Distribution Functions of Wind Power Variations under Different Wind Capacities

The cumulative density function is the probability of a random variable being less than or equal to a certain number. In this case, for example, it is easy to read the probability of wind power variations being less than or equal to 0.4GW out of the graph. When there is 5GW of total wind capacity, wind power variations is less than 0.4GW in 87% of time during the year. If the total wind capacity is doubled to 10GW, this probability will be reduced to 62%, which conversely indicates an increasing opportunity for the variations to be higher than 0.4GW. With more capacity installed, like 15GW, this probability will further drop to 45%, which means over half of the time during the year, the variations are larger than 0.4GW. These analyses are useful for proposing the flexibility index in Chapter 6.

2.4.4 Uncertainty of Wind Power Forecast

The wind power forecast for the next 24-72 hours is crucial for day-ahead power system operation and energy trading. These forecasts are used as input data in the unit commitment and the economic dispatch and are also crucial for trading in the day-ahead market, e.g. in Nordic market [43], USA markets [9].

At present, there is a variety of methods for wind power forecast (WPF) and typical wind forecast methods are classified as below [9]:

$$\text{WPF}\begin{cases}\text{Persistence Model}\\ \text{WPF with NWP}\begin{cases}\text{Physical Approach}\\ \text{Statistical Approach}\end{cases}\end{cases}$$

The persistence method is known as the simplest way for forecasting the wind. It assumes that the future wind generation at $t+t0$ will be the same as it was at time t. This method, as it is easy to implement, is usually used as a benchmark for evaluating the performance of advanced forecasting tools. The accuracy of this method is rapidly reduced with increasing prediction time. However, in the short term time scale (several minutes to few hours), it was found this simplified method performs even better than Numerical Weather Prediction tools [84].

Advanced wind power forecasting methods are mainly based on the numerical weather prediction (NWP). There are two main approaches: physical and statistical approach. They differ in their way of converting the forecasts of meteorological variables to the predictions of wind power output.

The physical approach collects sufficient information of meteorological parameters and down-scales the wind speed and direction to the turbine hub's height. It then analyses the information with complex computation, and use the power curve to get an estimation of the wind power output. The requirement of acquisition of a huge amount of meteorological information and the complex computation both limit the feasibility of physical approach in the short-term forecast (several minutes to hours). In practice, the performance of physical approach is often satisfactory for longer periods (more than 6 hours ahead).

The statistical approach directly translates the input meteorological variables into wind generation without considering the physical transformation procedures. It is done with a statistical block whose parameters are estimated by capturing the relation between historical meteorological predictions and power output. This statistical block combines the inputs such as numerical weather prediction of the speed, direction, temperature, together with online measurement such as wind power, speed, and direction. It then gives out a direct estimation of regional wind power from the input parameters.

The accuracy of wind power forecast is critical for properly injecting wind generation into the power system. Regardless of the forecasting tools, forecast errors are inevitable because of the randomness of any meteorological events. While substantial advances have been made in the accuracy of the forecasting of wind power generation, a significant residual uncertainty remains. Consequently, the uncertainties drive the need for flexibility in terms of increasing the requirement for reserve.

Statistically, uncertainty can be expressed by the standard deviation of wind forecast error. Larger standard deviation indicates poorer accuracy of wind forecast. An example of performance of forecast errors' dependency on forecast lead time is demonstrated in Figure 2.8 [16]. Here, the standard deviation of wind forecast error is normalised by the total wind capacity. It is shown that the accuracy of the wind power forecast deteriorates by almost 50% from 0-2h to 36h ahead. This feature is the basis for designing a flexible market which will be discussed in Chapter 5.

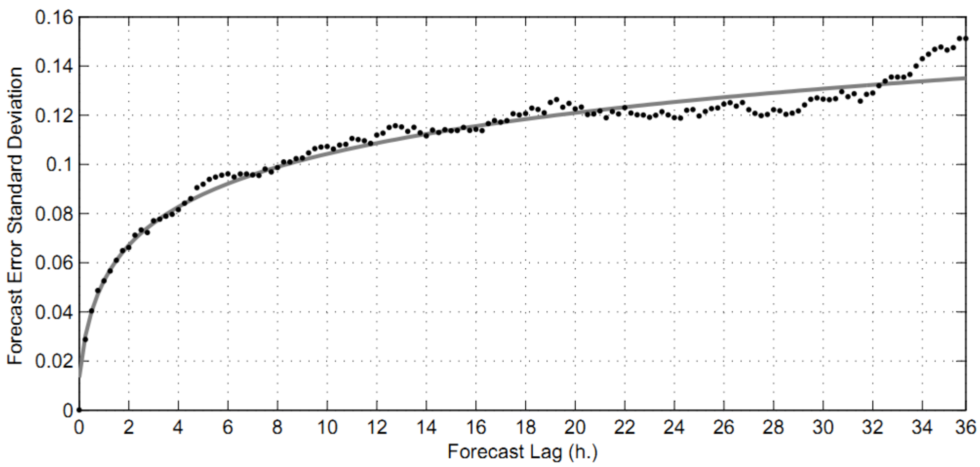


Figure 2.8: Normalised Standard Deviation of Wind Power Forecast Error [16]

2.5 System Net Demand

2.5.1 Net Demand

When the conventional generators and wind generators are both serving the load and assuming that wind generation has the priority in the generation scheduling because of its lower cost, it can be treated as a negative demand in the scheduling process. The net demand, which is calculated by subtracting gross demand with wind generation, corresponds to demand that needs to be served by conventional generators. Therefore, the impact of wind generation on system operation is firstly reflected on its impacts on the net demand.

Historical demand data in the UK in 2005 [35] is used (with annual peak load at 65GW). Given wind capacities at 10GW, 20GW, 30GW and 40GW, load duration curves of the gross load and the net load under each wind integration scenario are illustrated in Figure 2.9. The area below the duration curves represents the amount of energy that must be served by the conventional generation, and it decreases as the installed wind capacity increases. Therefore, the overall capacity factor of conventional generators decreases as the installed wind capacity increases.

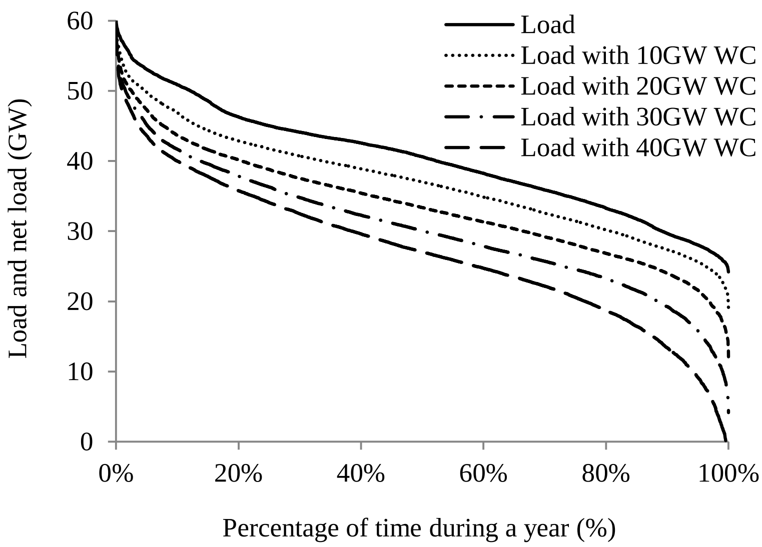


Figure 2.9: Load and Net Load Duration Curves for 0-40GW Installed Wind Capacity

For security reasons, some conventional generators need to be scheduled all the time to provide sufficient reserve to cope with the unexpected imbalances between load and generation. Depending on their minimum generation levels a share of the net load is always served by conventional generation. For high wind penetrations, there might be some instances when the net demand drops to an extremely low level, e.g. 5GW, 0GW or even negative. Once the net demand drops lower than the minimum load level of the synchronised plants, wind curtailment becomes the sole means of flexibility to maintain the load-generation balance.

System demand follows the energy consumers' behaviour and it thus shows a typical diurnal pattern being higher in the daytime and lower in the night. However, wind power depends on random meteorological parameters and results in a stochastic performance independent from the electricity demand. For daily system operation, wind power generation have different possible impacts on the difference between the peak and valley demand, and thus change the generation pattern of conventional generators. Here, the difference between the peak and valley demand refers to the difference between highest and lowest demand during a day.

These possible impacts can be grouped into three scenarios:

Wind generation increases the difference between the peak and valley demand.

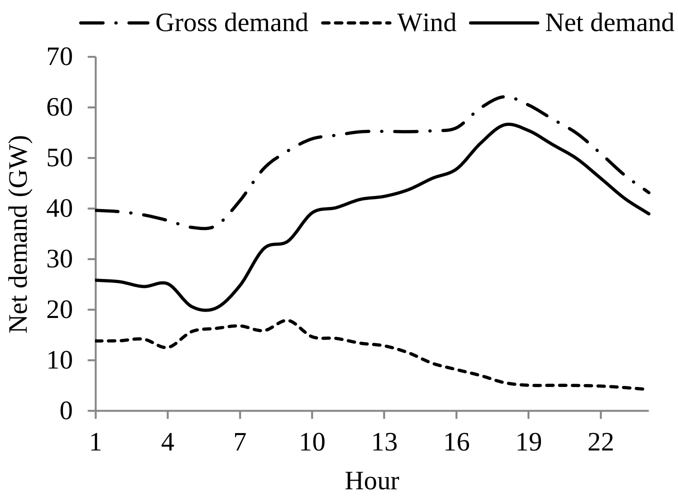
As shown in Figure 2.10 (a), if the gross demand and wind power profiles have contrary trends, the difference between the peak and valley net demand is increased compared with original gross demand pattern. In this case, gross demand goes up from night-time to daytime, while wind power reduces during the same time. The original peak-valley difference is 25GW, and this number is increased to 36GW after wind power is involved.

Wind generation does not affect the difference between the peak and valley demand.

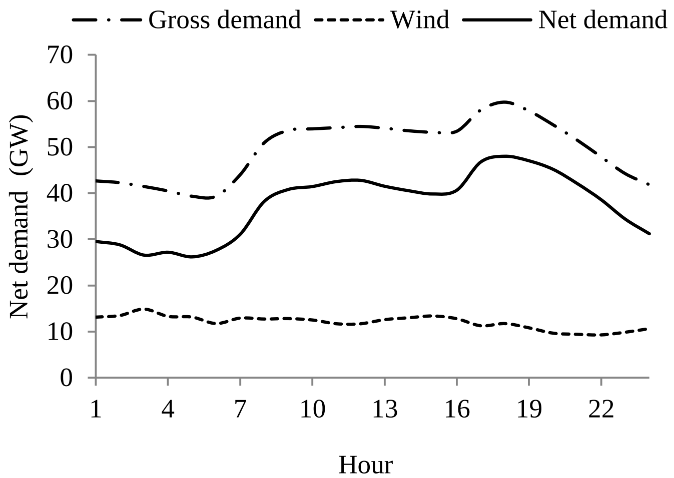
Sometimes in a year when the wind resource is relatively stable, fluctuations in wind power are accordingly small, as shown in Figure 2.10 (b). In this situation, there would be no obvious changes in peak-valley difference. The net demand follows the same pattern as original situation of the gross demand.

Wind generation reduces the difference between the peak and valley demand.

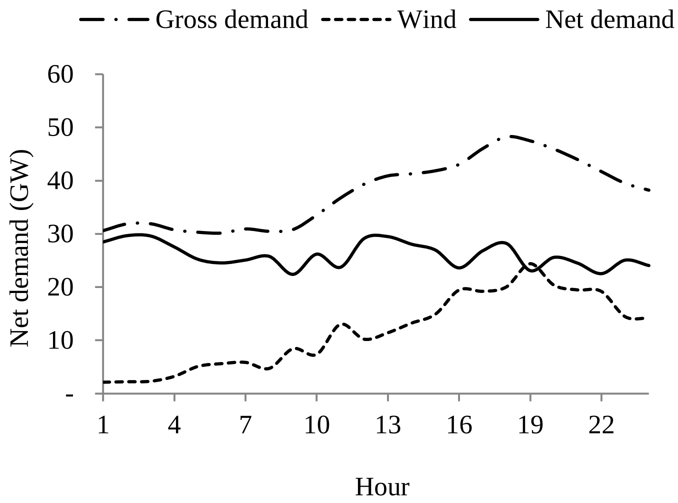
Figure 2.10 (c) illustrates the most ideal situation when wind power is integrated. In this case, peak-valley difference in net demand is reduced due to the wind power participation, which ultimately reduces the pressures on conventional generators to adjust their positions in daily operation.



(a)



(b)



(c)

Figure 2.10: Impacts of Different Wind Patterns on Daily Demand

2.5.2 Net Demand Variability

In Section 2.4.3, we have discussed the wind power variations. In power system operation, wind power variations can only be properly assessed in combination with demand variations, because the aggregated variations are the true factors that affect the dispatch patterns of conventional generators. The same data as for plotting Figure 2.9 are used to create the data set for the analysis of net demand aggregated variations. The aggregated variation is the difference between two consecutive hours in the net demand ($P_{t+1} - P_t$). For clarity, hourly upward and downward variations are separately processed in the duration curves, and only three situations are plotted in Figure 2.11: demand without wind, net demand (ND) with 20GW wind capacity (WC) and ND with 40GW WC.

It is shown that the magnitude of aggregated variations in the net demand increases with installed wind capacities. The maximum upward variation in the situation without wind is 7.809GW. However, this number is as high as 13.196GW in the situation with 40GW installed wind power, which is almost doubled as when the wind was not involved. Data analysis shows that the situation is even worse for the downward variations. Compare the downward variations between the scenarios with no wind and 40GW wind capacity, the maximum downward variation is -5.234GW for the former one while it is -17.403GW for the latter ones. These indicate a steeply increasing pressure on the remaining generation to cope with the aggregated variations.

At the same time, it is found that when there is no wind power, downward variations occur more frequently than upward variations, which is 57% versus 43% of time during the year. These numbers for up/down variations change to 54% versus 46% with 20G installed wind power in the system, while they become more symmetrical as 53% versus 47% in the situation with 40G wind capacity. The likelihood that upward and downward variations occur becomes closer. This illustrates that under large-scale wind penetrations, the symmetry of wind power variations has an overwhelming balancing effect on the asymmetry of gross demand variations.

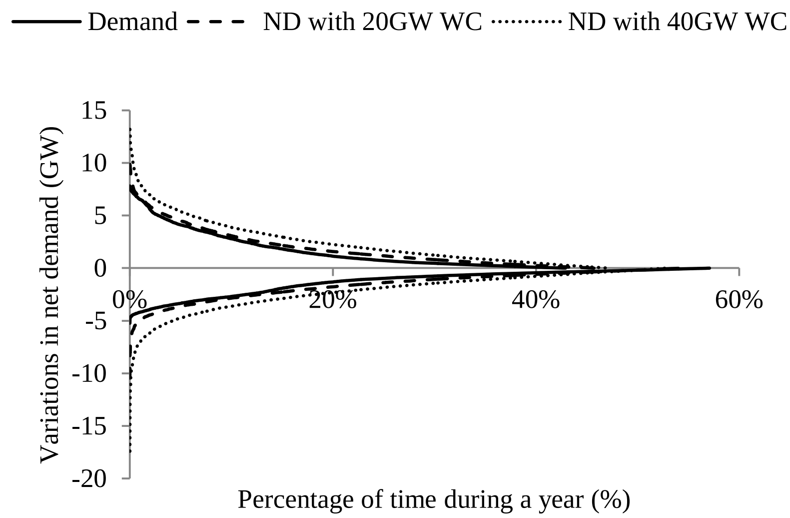


Figure 2.11: Variations in Net Demand under 0GW, 20GW and 40GW Wind Installed Capacities

2.5.3 Net Demand Uncertainties

Since the net difference between demand and wind generation is the part to be balanced by conventional generation, the uncertainty of this net difference is the most concern in setting proper reserve to ensure the security of supply. The traditional power systems without renewable generation have been operated in a highly secured manner because the uncertainty in the demand forecasting is well understood and handled. Demand forecast errors are relatively small because demand usually follows the energy consumers' living and working pattern, and demand forecasting is a mature technology with long historical experiences. Demand forecast errors are usually represented by a normally distributed random variable with zero mean and standard deviation of typically 1-6% of current demand [30, 76, 85, 86].

Now given that the wind generation is taken into account in the net demand, the additional uncertainty of wind forecasting has to be accounted for in setting reserve requirements. In Section 2.4.4, it has mentioned that it is common to measure the accuracy of wind power forecast statistically by the standard deviation of wind forecast error. In this work it is assumed that the wind forecast error is a normally distributed random variable with zero mean and standard deviation σ_w. Strictly speaking, for a single wind generator, it is impossible to assume that the forecast error fits normal distribution. However, according to the central limit theorem, the large number and the wide geographical dispersion of wind turbines justify the normality assumption of wind forecast error in a widely distributed situation [76, 87]. The normality assumption of wind power forecast error is quite common in literature [74, 78, 88, 89].

As demand forecast and wind generation forecast errors are usually assumed to be uncorrelated, the net demand error also fits for a zero-mean normal distribution whose standard deviation $\sigma_{nd}(t)$ is obtained by considering both the standard deviation of demand forecast error $\sigma_d(t)$ and the standard deviation of wind forecast error $\sigma_w(t)$:

$$\sigma_{nd}(t) = \sqrt{\sigma_d(t)^2 + \sigma_w(t)^2} \qquad \forall t \in T \tag{2.1}$$

Although uncertainty of net demand increases with installed wind capacity, the large geographical spreading of installed wind power is conversely helpful in reducing the variability and increasing the predictability of the aggregate wind power production. Furthermore, developments in forecasting methodologies also improve the accuracy of wind forecast error. At present, the National Grid in the UK assumes that the standard deviation of wind forecast error is around 50% of the forecast wind output four hours ahead of real time, and this number is expected to be reduced to 30% in 2020 [18].

2.6 Flexibility Requirements for Accommodating Wind Power

As discussed before, wind generation alters the pattern of net demand by changing the magnitude of net demand, and increasing its variability and uncertainties. These changes all have impacts on the operation of thermal plants.

2.6.1 Minimum Load Level

The difference between the demand and the wind generation is the profile that has to be met by the thermal plants. With wind generation integrated in the system, the generation required from thermal plants is reduced. For security reason, there should always be a certain amount of thermal generators synchronised to meet the technical requirements of operating reserve and these generators need to produce a minimum amount of energy (constrained by their minimum stable generation), which determines the minimum load level of thermal generators. When the minimum load level of thermal generators plus wind generation exceeds the gross demand, wind generation needs to be curtailed. In other words, technical constraints relevant to minimum generation requirement, such as must-run plants, minimum stable generation, and minimum up times, may prevent a fully integration of potential wind generation during low demand periods. Therefore, a flexible system should have sufficiently low minimum load level to accommodate high wind integration.

2.6.2 Ramping Capability Requirement

As statistical analysis in Section 2.5.2, the aggregated variations in net demand are increased with the larger wind penetration. The thermal generation thus has to be flexible enough to follow these changes. The change of output position of the thermal plants is limited by their ramping capability. For example, CCGT is usually able to maintain 100% response for tertiary reserve [90], while the ramping capability of old nuclear power plant is relatively small since changing the reactor's power output requires inserting and removing fuel or control rods [91]. Typically, the ramping capability of thermal generators is ordered like this: CCGT>Oil>Coal>Nuclear. At the same time, many countries are contributing to find ways to improve the ramping flexibility of traditionally inflexible technologies.

2.6.3 Tertiary Reserve Requirement

Any uncertainty that may cause imbalances between the generation and the load will put the security of system at risk. Therefore, a system must always have sufficient reserve in order to keep the uncertainties in control. In this work, we consider reserve services in the tertiary regulation interval.

In a traditional power system, the amount of reserve maintained at any time is firstly sufficient to cover the loss of the largest generator in order to deal with sudden outage of committed generating units. This is usually described as meeting the N-1 security criterion.

Secondly, the extra reserve can cover the demand forecast error that may cause the unexpected deviation at the delivered time. As mentioned before, demand forecast error can be modelled by a normally distributed random variable. The confidence interval of a normal distribution follows the '68-95-99.7 rule', as shown in Figure 2.12. That is about 68.27% of the values lie within 1 standard deviation of the mean; about 95.45% of the values are within 2 standard deviation of the mean; and about 99.73% of the values are within 3 standard deviation of the mean, which almost cover all the values in the distribution. Therefore, analytical method to determine the reserve requirement for demand forecast error is usually based on 3 standard deviation of demand forecast error.

In realistic operation, system operators usually determine the reserve for demand forecast error based on their experiences. For example, according to the China Southern Power Grid operating reserve regulations, total reserve for demand forecast error should be no less than 2% of maximum load of the whole network system.

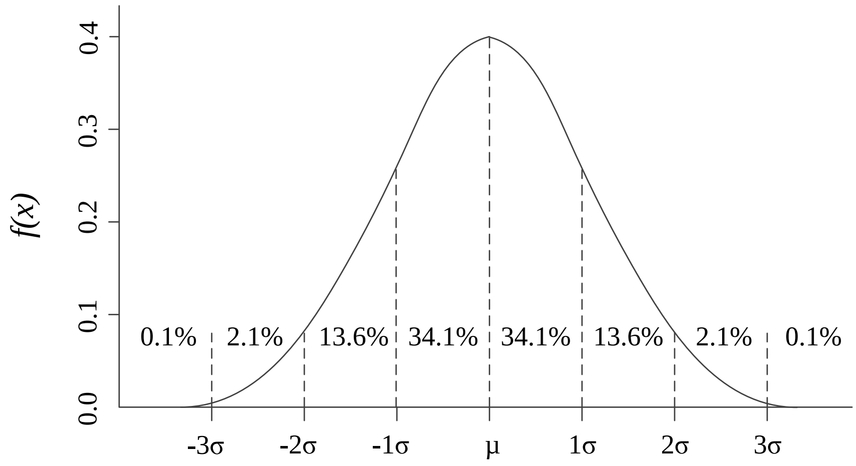


Figure 2.12: Confidence Intervals for a Normal Distribution [87]

With large wind generation integrated in the system, the uncertainty of net demand has considerably increased, as discussed in Section 2.5.3. Likewise, the new reserve is expected to cope with this new uncertainty by covering 3 standard deviation of the net demand forecast error. With the similar analytical method to determine the demand forecast error as above, the upgraded reserve can be mathematically represented as (2.2).

$$r_{nd}(t) = 3\times\sigma_{nd}(t) = 3\times\sqrt{\sigma_d(t)^2+\sigma_w(t)^2} = \sqrt{\left(3\sigma_d(t)\right)^2+\left(3\sigma_w(t)\right)^2} \quad \forall t\in T \quad (2.2)$$

Although $3\sigma_w(t)$ is enough to cover most of the uncertainties in wind forecasting, it is too conservative when a low amount of wind is scheduled. Notice here that the scheduled wind may be less than forecasted wind if wind curtailment occurs due to technical constraints, so it is calculated by the difference between forecasted wind and curtailed wind. The largest wind generation lost is no more than the scheduled wind, so if the scheduled wind is smaller than $3\sigma_w(t)$, there is no need to keep $3\sigma_w(t)$ at this moment. Taken this situation into account, the reserve for net demand forecast error should be modified as (2.3):

$$\begin{aligned} r_{nd}(t) &= 3\times\sigma_{nd}(t) = 3\times\sqrt{\sigma_d(t)^2+\sigma_w(t)^2} \\ &= \sqrt{\left(3\sigma_d(t)\right)^2+\min\left(3\sigma_w(t),\left(w_f-w_c\right)\right)^2} \qquad \forall t\in T \end{aligned} \tag{2.3}$$

And the total upward reserve considering largest in-feed generator and net demand forecast error should be:

$$r_{up}(t) >= \max\left(u(i,t)P_{\max}(i)\right)+3\sigma_{nd}(t) \qquad \forall t\in T \tag{2.4}$$

Only the demand and wind forecast error need to be taken into account into the downward regulation:

$$r_{dn}(t) >= 3\sigma_{nd}(t) \qquad \forall t\in T \tag{2.5}$$

From the statistical point of view, this method is typically used to consider the stochastic behaviours of wind and demand forecast in the deterministic optimisation problem. This is common in research studies, as shown in [30, 71, 72].

In realistic operation, the additional reserve for wind generation is usually deployed using more applicable ways. For instance, National Grid separated the reserve service by different functions, namely:

- Basic reserve: reserve for demand forecast error and conventional generation loss
- Reserve for wind: additional reserve required to manage variability of wind output

Apparently, due to the complicated operation in reality, system operator tends to choose more concise and feasible way to set the additional reserve service for wind integrations. National Grid currently assumes that there is a need to carry operating reserve equivalent to 50% of the forecasted wind output four hours ahead of real time. With the development of wind forecasting tools, this number is expected to be reduced to 30% [18]. Similar methods for setting additional reserve in proportion to the wind power point forecast can also be found in literatures [51, 70].

2.7 Chapter Conclusions

This Chapter analyses the flexibility requirement in power systems with high penetration of wind power. This is done by reviewing previous wind integration studies across Europe and America and analysing the characteristics of wind and their impacts on flexibility requirement.

The previous studies provide an extensive analysis of the impacts of wind generation on the power systems. They usually start with the thorough analysis of wind characteristics. Then they evaluate the corresponding impacts on power system from different perspectives, including the short- and long-term impacts, local and system-wide impacts, technical and economic impacts. The main findings in these studies are summarised, and the wind impacts and the corresponding flexibility requirements are categorised according to the time scales in which they are involved. By doing so, we get an overall picture of where, when and which flexibility services are needed to cope with high penetration of wind power.

Among all types of flexibility, the main interest of this work is the short-term (hourly time scale) flexibility requirement in the optimal scheduling (unit commitment), generation expansion planning and market operation.

Two main approaches used in literature for addressing the uncertainty and variability of wind in unit commitment (UC) algorithm are identified and compared. The first is based on deterministic scheduling of power systems and incorporate the uncertainty of wind generation in UC by increasing the system reserve requirement. Although this approach is deemed to be conservative, it has significant advantages in terms of the capability of handling large systems in reasonable computation time. The alternative method to adapt the UC for wind power-rich systems is stochastic programming. This approach incorporates wind uncertainty by considering representative scenarios of wind power output and their probability of occurrence, and incorporates these scenarios in the objective function and constraints of the UC problem. Considerations of these scenarios inevitably result in large amounts of decision variables that will pose significant computational challenges. However, it is widely accepted that stochastic programming leads to more robust results than deterministic approaches.

Considering that we will evaluate the flexibility performance in a relatively large system with a huge number of variables, the deterministic UC is more appropriate for this work.

Base on these literature reviews, the scope of flexibility issues to be studied in this work is presented. We will focus on the flexibility performance of thermal generations in the aspects of generation scheduling, generation planning and market operation. We aim to evaluate the role of flexibility in these aspects, and establish proper index to assess the flexibility level of power system, in an effective and intuitive way.

Apart from the knowledge from the literature review, in this Chapter we also present the analysis on the realistic wind data to get a better understanding of their impacts on the net demand and the flexibility requirement. Based on these analyses, the main drivers for flexibility are concluded:

1) Integration of wind generation reduces the generation from thermal generation. However, sufficient thermal capacity has to be synchronised to meet the technical requirement of operating reserve. These synchronised generators form the minimum load level of power system which may prevent the fully integration of potential wind generation. In order to accommodate wind generation sufficiently, more flexible units

with lower minimum stable generation should be used to provide the operational reserve.

2) Variability of wind generation has considerably increased the aggregated variations in net demand, especially in the situation with large-integration of wind penetration. This requires more flexible units with higher ramping capability to cope with the fluctuations.
3) Uncertainty of wind forecast poses significant challenges on reserve requirement. Original reserve prepared for thermal generator outage and demand forecast error is not sufficient to cover the new situation. Additional reserve is needed and furthermore, this reserve has to be provided in a more flexible way because the requirement is more variable.

CHAPTER 3

VALUE OF FLEXIBILITY IN GENERATION SCHEDULING

3.1 Introduction

In Chapter 2, we have studied the characteristics of wind generation and their impacts on net demand. Because of the significant difference between wind generation and gross demand, the net demand profile will be significantly distorted when the wind generation is considered as negative demand. In a conventional system with a fossil fuel based generation portfolio, thermal generators must provide sufficient flexibility to follow the variations and manage the uncertainties in net demand. Such flexibility can be provided by frequent changing the output of the flexible units with high ramping capability and also by quick switching the flexible units with short minimum up/down time.

All power systems have some level of inherent flexibility. However, this flexibility is not unlimited and once exhausted, the system will have no further capability for accommodating wind generation. In such cases, wind curtailment is the sole source of flexibility, and it has to be used to maintain the supply/demand balance and the security levels. Wind curtailment usually happens when the minimum load level[6] (MLL) or ramping capability are violated.

In this Chapter, a methodology for evaluating the performance of the flexibility of generators is introduced. This methodology takes a whole-system approach

[6] Minimum load level: For security reasons, certain number of thermal units have to be kept synchronised all the time to provide the spinning reserve. The generation output of these synchronised units forms the minimum load level (MLL) in the system.

and is based on a unit commitment (UC) algorithm that minimises the operational cost whilst satisfying flexibility requirements. With this model, the performance of flexibility is analysed in terms of generation output, operational cost, CO_2 emissions, start-ups and wind utilisation.

In this Chapter, flexibility is studied through:

- A vertical comparison conducted to reveal how thermal plants are operated in a more flexible manner in order to accommodate different levels of wind.

- A horizontal comparison among different systems in order to show their different capability of accommodating wind generation.

3.2 Approach for Evaluating Generation Flexibility

In order to represent the operational flexibility of a power system and evaluate its contribution to the integration of wind power, an approach based on unit commitment (UC) is considered appropriate for the following reasons:

- UC is a mature method widely recognised and used to make the operation plan for generating units (on/off status and output in each period). It is easy to monitor changes in generation output, ramping and start-ups using a UC algorithm.

- UC takes into account ‘dynamic’ constraints related to the supply of flexibility, such as minimum stable generation, minimum up/down time, ramping capability and reserve requirement.

- UC minimises the operational costs while enforcing the flexibility related constraints so that the flexibility can be delivered in an economic way. It allows us to study the effect of flexibility on the cost of running the system.

The UC program is implemented using mixed integer linear programming (MILP) and is solved by FICO™ Xpress optimisation solver [92]. The structure of the approach is shown in Figure 3.1.

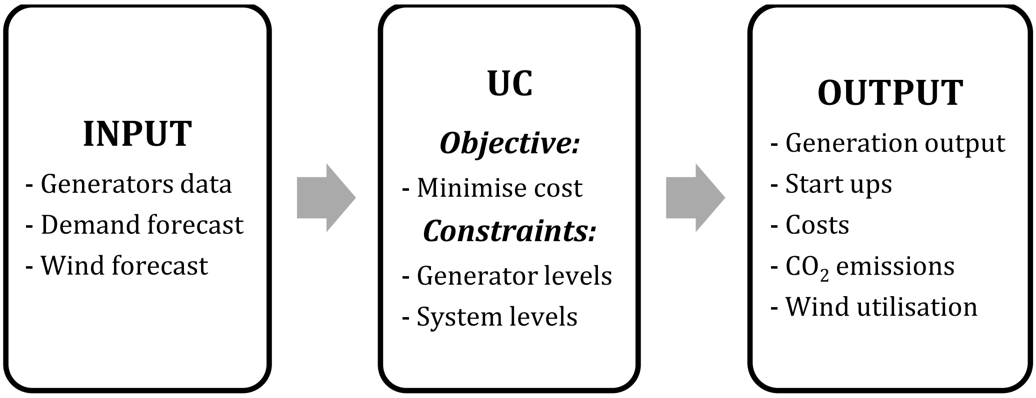


Figure 3.1: Structure of the Methodology for Flexibility Evaluation

Input Data

The input data for UC is comprised of parameters of generators, as well as demand and wind forecast time series. Detailed representations of these data take into account the following aspects:

- Technical parameters that define the flexibility of different types of units: minimum stable generation, capacity, ramping up/down rate, minimum up/down time, initial status and CO_2 emission rate.
- CO_2 emissions associated with different types of fuel are modelled according to the parameters provided by [93].
- The costs of generators are represented by the combination of incremental cost[7] and start-up cost.
- The net demand to be balanced by thermal generators is calculated from the demand and wind forecast time series. There are two methods to obtain the forecasted data:

[7] Incremental cost: The increase or decrease in costs as a result of one more or one less unit of production. It is also referred to as 'differential cost' or 'marginal cost'.

    - Using forecasting tools, and as mentioned before, the most common and convenient method is the persistence model;
    - Adding the simulated forecast error on the realistic data.

  In this work, we choose the second one due to its advantages in monitoring and controlling the forecast error. This method will be introduced in detail in Section 3.3.

- Historical wind and demand data are normalised to capture the variability of the time series. These are then up-scaled for different levels of wind capacity and annual peak demand to prepare the input data of different case scenarios.

Optimisation Algorithm

The main body of the approach is the UC algorithm. It is used to make the decisions of turning on or shutting down the individual generating units and changing their output to meet the load with minimum cost. This cost minimisation takes into account the constraints required to keep the system's reliability and the generator's feasibility over the whole optimisation period. Details of the UC algorithm will be introduced in Section 3.4.

Output

Finally, the evaluation of flexibility is based on the outputs of the UC program, which include:

- Generation output to show the changes in the operational patterns of the thermal generating units when facing the different levels of wind penetration. It is helpful to understand how to deploy the flexibility services in order to cope with high penetration of wind power, and how different types of units behave according to their intrinsic flexibility capabilities.

- Number of start-ups to see how the generation usage patterns change with the variability of net demand.
- Costs for different scenarios to understand whether the system can offer flexibility services (reserve, fast ramping and frequent start-ups, etc.) in a cost-effective way.
- CO_2 emissions to reveal the contribution of flexibility in realising the low-carbon transition and the impacts of CO_2 prices on the usage pattern of plants and the overall system emissions.
- Wind utilisation to assess the flexibility of systems by their ability of accommodating wind.

3.3 Simulation of Wind Forecast Error

In this Section, we will introduce the method used to prepare the wind forecast data set.

The development of a wind forecasting tools is out of the scope of this work. Instead, we assume that a forecasting tool is available and provides an hourly sequence of wind power forecasts. The historical data will be treated as the wind power realisation and by adding the simulated wind forecast error, the simulated wind power forecast will be obtained.

To simulate the wind forecast error properly, both the stochastic behaviour and the temporal correlation of wind have to be taken into account and a detailed explanation of how this is done is presented in the following Sections.

3.3.1 Stochastic Behaviour of Wind Power Forecast Error

In this work, it is assumed that the accuracy of the wind power forecasts is known. As an example, using a forecasting tool developed by Bart Ummels [16], the standard deviation of the forecast error for 12GW wind power capacity is shown in Figure 3.2.

Although different forecasting tools result in different forecasting errors, these errors show similar patterns, i.e., a sharp increment within the first few hours followed by a slower but gradual increment [94-96].

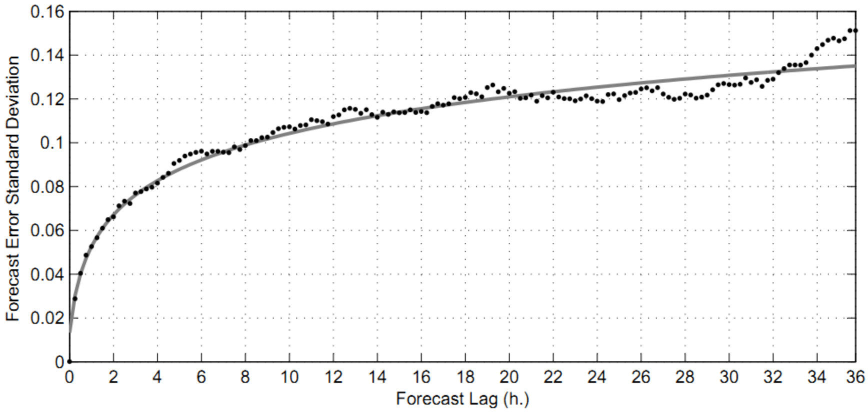


Figure 3.2: Normalised Standard Deviation of the Forecast Error [16]

In this work, the wind forecast errors $\varepsilon(t)$ are modelled as zero-mean normally distributed random variables. For each time point, the wind forecast error is fit to a normal distribution with standard deviation $\sigma(t)$. This standard deviation increases with the length of the forecasting horizon, as shown in Figure 3.3. The wind power forecast error is mathematically written as:

$$\varepsilon(t) = w_f(t) - w_r(t) \sim N\left(0, \sigma(t)\right) \quad \forall t \in T \tag{3.1}$$

where $w_f(t)$ and $w_r(t)$ represent the forecasted wind power and the realised wind power at time point t, respectively.

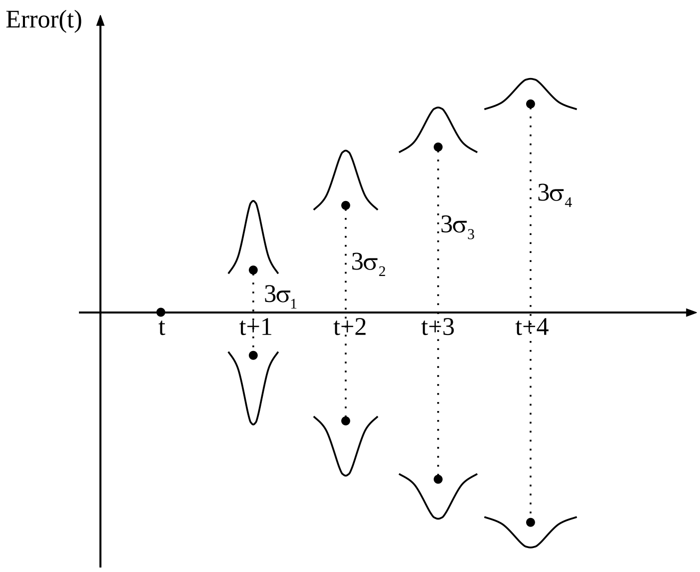


Figure 3.3: Wind Forecast Error with Different Lead Time

In reality, statistical models for wind speeds at specific locations do not fit normal distributions [76, 97]. Furthermore, the non-linear wind speed to power output relationship may further distort the statistical distribution. However, in this work, wind generation is aggregated from a large number of wind turbines widely dispersed in a country or region which allows the use of the central limit theory to justify the normality assumption of the forecast error [76, 87]. This normality assumption of wind power forecast error is quite common in literature [74, 78, 88, 89]. It has to be clarified that this assumption only fits for the situation where the widely dispersed wind farms have little correlation with each other. If it is about the wind farms strongly correlated to each other, the assumption does not work any more and more specific assumptions for the distribution of the wind generation is needed.

3.3.2 Temporal Correlation of the Wind Power Forecast Error

Besides the stochastic nature of the wind forecast error, its simulation has to consider the coherence between the forecasting periods over the horizon. Models that do not take into account temporal correlation usually bias the simulation of realistic cases and this is emphasised in [98].

The autocorrelation of the wind forecast error describes the correlation between the values of time series at different points of time. Assuming k is the time lag between the wind forecast error time series, the autocorrelation of the wind forecast error can be expressed as a function of the time lag k [99]:

$$\psi_k = corr\left(\varepsilon_t, \varepsilon_{t+k}\right) = \frac{1}{n} \frac{\sum_{t=1}^{n}\left(\varepsilon_t - \bar{\varepsilon}\right)\left(\varepsilon_{t+k} - \bar{\varepsilon}\right)}{\sigma^2} \qquad k = 1, 2, 3, \ldots \qquad (3.2)$$

In which $\bar{\varepsilon}$ is the mean value of the series $\{\varepsilon_1, \varepsilon_2, \varepsilon_3, \ldots\}$, and σ^2 is the variance of the series.

The autocorrelation of the wind forecast error can be approximated by an exponential decrease function with increasing time lags [97, 100, 101]. This means that wind forecast errors with shorter time lags have a stronger correlation, while the wind forecast errors with longer time lags have a smaller relevance to each other. Mathematically, the autocorrelation function is modelled as:

$$\psi_k = e^{-\theta k} \qquad \theta > 0, k = 1, 2, 3 \ldots \qquad (3.3)$$

3.3.3 Stochastic Differential Equation with Given Distribution and Autocorrelation

As discussed in the preceding Sections, the simulation of wind forecast error has to consider both stochastic distribution and temporal correlation of the time series. One way to achieve this is to model wind forecast error with a diffusion process[8], which is a solution to a stochastic differential equation [97, 100, 101]. We will use this method to construct a stochastic differential equation that can fit for the normal distribution and the autocorrelation of the time series of wind forecast error.

[8] Diffusion process: In probability theory, a diffusion process is a solution to a stochastic differential equation. It is a continuous-time Markov process with continuous sample paths.

According to the theorem in [101], assuming there is a probability density function $f(x)$ which is continuous, bounded, and strictly positive on (l,u), zero outside (l,u) and has finite variance.

Consider the stochastic differential equation:

$$dX_t = \theta(\mu - X_t)dt + \sqrt{v(X_t)}dW_t, \quad t \ge 0 \tag{3.4}$$

where $\theta > 0$, μ is the mathematical expectation of $f(x)$ and W_t denotes a standard Brownian motion[9]. v is a non-negative function defined in the set (l,u). If

$$v(x) = \frac{2\theta}{f(x)} \int_l^x (\mu - y) f(y) dy, \ \ x \in (l,u) \tag{3.5}$$

then the following conclusions hold:

- The solution X_t is mean-reverting[10] and ergodic[11] [87] with invariant density $f(x)$.
- If the process X_t is stationary then the autocorrelation function is $e^{-\theta k}$.

Therefore, in order to obtain a stationary process X_t that fits for normal distribution and has an autocorrelation function with an exponential decay of parameter θ, we need to construct the corresponding stochastic differential equation first.

For a normal distribution, state space (l,u) is $(-\infty,\ \infty)$. By substituting $f(x)$ in (3.5) with the following equation:

---

[9] Standard Brownian motion is a continuous-time stochastic process.
[10] Mean-reverting: Over time, if a process tends to drift towards its long-term mean, it is called mean-reverting.
[11] Ergodic: In mathematics, if a dynamical system has the same behaviour averaged over time as averaged over space, it is called ergodic.

$$f(x)=\frac{1}{\sqrt{2\pi\sigma^2}}e^{-\frac{(x-\mu)^2}{2\sigma^2}} \tag{3.6}$$

and in this case $u=0$, then after rearrangement $v(x)$ can be written as:

$$\begin{aligned} v(x) &= -\frac{2\theta}{f(x)}\int_{-\infty}^{\infty} yf(y)dy \\ &= -\frac{2\theta}{\frac{1}{\sqrt{2\pi\sigma^2}}e^{-\frac{x^2}{2\sigma^2}}}\int_{-\infty}^{\infty} y\frac{1}{\sqrt{2\pi\sigma^2}}e^{-\frac{y^2}{2\sigma^2}}dy \\ &= -2\sigma^2\theta e^{\frac{x^2}{2\sigma^2}}\int_{-\infty}^{\infty} e^{-\frac{y^2}{2\sigma^2}}d\frac{y^2}{2\sigma^2} \\ &= 2\sigma^2\theta \end{aligned} \tag{3.7}$$

By substituting $v(x)$ in (3.4) with the expressions in (3.7), the corresponding stochastic differential function is expressed by:

$$dX_t = -\theta X_t dt + \sigma_t\sqrt{2\theta}dW_t,\quad t\geq 0 \tag{3.8}$$

As a result, the solution of this stochastic differential function X_t fits for normal distribution and has an autocorrelation function with an exponential decay of parameter θ.

The time series of wind forecast error can then be obtained by the iteration process:

$$X_t = X_{t-1} + dX_t \tag{3.9}$$

Finally, the simulated wind forecast is calculated by the sum of the actual wind generation and the wind forecast error. Similarly, simulated demand forecast can be obtained in the same way.

Figure 3.4 illustrates the actual wind power output (normalised by the nominal capacity) and the simulated wind forecast (obtained by adding the simulated errors to the actual wind). It is seen that as the forecast horizon increases, it is more likely to have larger wind forecast errors. At the same time, the temporal correlation in wind forecast error between consecutive hours is well reflected.

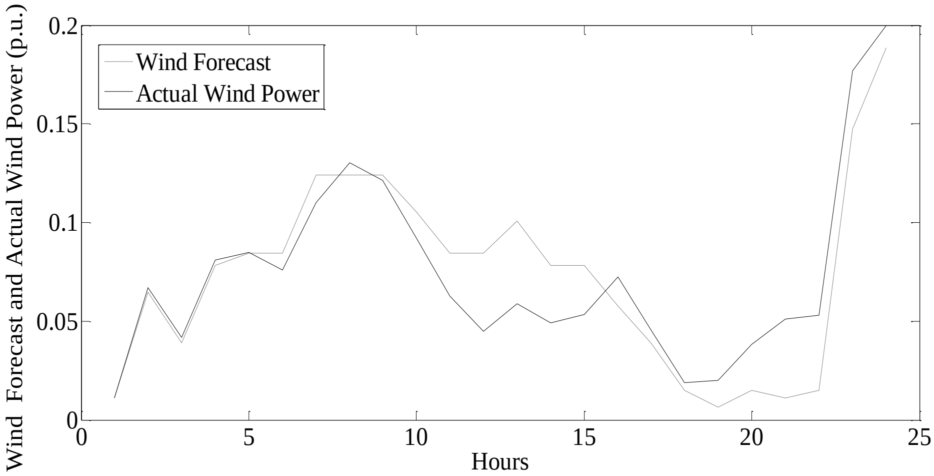


Figure 3.4: Simulated Wind Forecast and Actual Wind Power (p.u.)

3.4 The Unit Commitment (UC) Model

The objective of a conventional UC problem is to minimise the total system operating cost subject to system- and generator-level constraints. Here, system-level constraints are the whole system requirements, i.e., balance between generation and demand, and reserve requirements, while generator-level constraints are associated with individual generating units, such as minimum stable generation, maximum capacity, ramp rates, and minimum up/down time.

In general, the planning horizon is for the next 24 hours, and the two main decision variables, namely binary variables $u(i,t) \in \{0,1\}$ for the unit status (off/on) and the generation output $p(i,t)$ for each unit, are both based on hourly resolution. When considering wind penetration in the UC problem, wind curtailment at each period $w_c(t)$ is introduced as a new decision variable.

3.4.1 Objective Function

The objective of the conventional UC program is to minimise the system cost of supplying the net demand, which is the sum of the fuel cost and start-up costs of all the committed generating units during the total planning horizon. The objective function of UC problem is formulated as follows:

$$\min \sum_{t=1}^{\mathrm{T}} \sum_{i=1}^{\mathrm{I}} u(i,t)\big(\mathrm{INC}(i) \times p(i,t)\big) + \sum_{t=1}^{\mathrm{T}} \sum_{i=1}^{\mathrm{I}} u(i,t)\big(1-u(i,t-1)\big)\mathrm{STC}(i) \quad (3.10)$$

where $u(i,t)$ indicates the on/off status of unit *i* at hour *t*. A value of '1' indicates the unit *i* is synchronised at hour *t*, while a value of '0' means the unit is not synchronised at the moment. $p(i,t)$ is the active power generated by unit *i* at hour *t*. $\mathrm{INC}(i)$ and $\mathrm{STC}(i)$ respectively indicate the incremental cost and start up cost of unit *i*. I is the number of generating units in the considered set, and T is the number of hours in the time horizon.

The simplest way to consider start-up cost is that once the unit is synchronised with the system, it generates a fixed cost STC.

The objective function will be subjected to a set of constraints described in the following Section.

3.4.2 Constraints

As mentioned before, constraints can be grouped into 'system-level constraints' and 'generator-level constraints'. They represent system security requirements and unit operational limitations, respectively.

(1) System-level constraints

- System hourly power balance:

Total power generation must equal the demand in all time intervals.

$$\sum_{i=1}^{N} p(i,t)u(i,t) + \left[W_f(t) - w_c(t)\right] = D_f(t) \quad \forall t = 1,...,T \qquad (3.11)$$

where $W_f(t)$ is the forecasted wind power generation at hour *t*. $w_c(t)$ is the decision variable representing the curtailed wind generation at hour *t*. $D_f(t)$ is the forecasted demand at hour *t*.

- Reserve requirements:

In order to operate the power system in a secure and reliable manner, it is necessary to have some spare capacity in the synchronised units in order to deal with un-forecasted imbalances between load and generation. Both upward and downward reserves are required. The amount of upward reserve maintained at any time should be sufficient to cover the loss of the largest generator, demand under forecasts, and wind generation over forecasts. Downward reserve should be enough to handle demand over forecasts and wind generation under forecasts. The amount of reserve needed to handle the aggregated forecast error of wind and demand is set by the '3σ' risk criteria, which has been introduced in Chapter 2.

The upward tertiary reserve requirements, $r_{UP}(t)$, is set by:

$$r_{UP}(t) >= \max\left(u(i,t)P_{\max}(i)\right) + 3\sigma_{nd}(t) \qquad \forall i \in I, t \in T \qquad (3.12)$$

The downward tertiary reserve, $r_{DOWN}(t)$, is set by:

$$r_{DOWN}(t) >= 3\sigma_{nd}(t) \qquad \forall t \in T \qquad (3.13)$$

where $\sigma_{nd}(t)$ represents the standard deviation of net demand at hour *t*, which has been discussed in Section 2.5.3.

(2) Generator-level constraints

- Generation limits

Generating units must be operated within their minimum stable generation and maximum capacity.

$$P_{\max}(i) \le p(i,t) \le P_{\min}(i) \qquad (3.14)$$

- Minimum up time and minimum down time

Once the unit is running, it can not be turned off immediately. So minimum up time is the minimum time that a unit must be 'on' before it can be shut down. Conversely, once the unit is de-committed, there is a minimum time before it can be re-committed. Mathematically, the minimum up/down time constraints for unit *i* can be expressed as:

$$\left[T_{up}(i) - t_{on}(i,t-1)\right]\left[u(i,t) - u(i,t-1)\right] \ge 0 \qquad (3.15)$$

$$\left[T_{down}(i) - t_{off}(i,t-1)\right]\left[u(i,t-1) - u(i,t)\right] \ge 0 \qquad (3.16)$$

where $T_{up}(i)$ and $T_{down}(i)$ are the minimum up and down time of the generating unit *i*. $t_{on}(i,t-1)$ and $t_{off}(i,t-1)$ represent the amount of time that unit *i* has been online and offline before hour *t*.

- Maximum ramp-up and ramp-down constraints

To avoid damaging the turbine, the electrical output of a unit cannot change beyond a certain amount over a certain period Δt:

Maximum ramp up rate constraint:

$$p(i,t+\Delta t) - p(i,t) \le \mathrm{Ramp}_{\mathrm{up}}(i)\Delta t \qquad (3.17)$$

Maximum ramp down rate constraint:

$$p(i,t)-p(i,t+\Delta t)\le \mathrm{Ramp}_{\mathrm{down}}(i)\Delta t \tag{3.18}$$

- Constraints for units to provide up/down reserve:

All generation units may contribute to up/down tertiary reserve according to their scheduled position and physical characteristics. For each synchronised generator, its ability to provide up reserve is limited by its spare capacity and ramping up rate. Likewise, their position relative to minimum stable generation and ramp down rate describe their maximum allowable capacity available for down reserve. Mathematically, their ability to provide up/down tertiary reserve can be described as:

$$\begin{aligned} r_{up}(i,t) &\le u(i,t)\min\left\{P_{\max}(i)-p(i,t),\ Ramp_{up}(i)\Delta t\right\} \\ r_{down}(i,t) &\le u(i,t)\min\left\{p(i,t)-P_{\min}(i), Ramp_{down}(i)\Delta t\right\} \\ &\qquad \forall i\in \mathrm{A}, t\in \mathrm{T} \end{aligned} \tag{3.19}$$

where $r_{up}(i,t)$ and $r_{down}(i,t)$ represent the upward and downward reserve that can be provided by conventional generator *i* at hour *t*, respectively. $P_{\max}(i)$ and $P_{\min}(i)$ are the maximum capacity and the minimum stable generation of conventional generator *i*. $Ramp_{up}(i)$ and $Ramp_{down}(i)$ indicate the ramping up and down rate of generator *i*, respectively. Δt is the time for the units to ramp up/down their output.

3.5 Scenarios for Simulation

The simulations are based on both vertical and horizontal comparisons between different scenarios. By analysing the case study results, we are trying to understand the effects of wind generation on the power system and how the non-wind part of system responds to the new challenges by operating their intrinsic flexibility. Good understanding on these features forms the basis for this work. It is also critical for establishing indices to provide a quantitative evaluation of flexibility, which will be introduced in Chapter 6.

Scenarios Used for Vertical Comparisons:

Vertical comparisons are undertaken by simulating the operation of power system with different scenarios of installed wind capacities. It aims to find out how different types of units in the system contribute to the flexibility required to accommodate wind.

To achieve this, a generation mix is designed with three technologies that represent low, medium and high flexible units. The characteristics of these different technologies are presented as follows:

- Low flexible technology (LFT):
  Low flexible units have limited intrinsic flexibility due to their high minimum stable generation (close to their maximum capacity), low ramping rates, and long minimum up and down times. In addition, such units usually have low operational cost. Once started, their low costs enable them to be scheduled in the merit order, and their technical constraints make them difficult to change their on/off status or output during operation. Although their output usually remains quite flat, in some extreme circumstances, there are also chances for them to contribute to flexibility by tripping off or slightly changing their output to lower down the total balancing cost of the system. In a realistic system, a good example of low flexible units is the existing nuclear plants in the UK. These units have no greenhouse gas emissions, so their high capacity factor will have no negative impact on CO_2 emissions in the system.

- Medium flexible technology (MFT):
  Compared to low flexible units, the intrinsic flexibility in medium flexible units is relatively higher. Smaller minimum up/down times make them easier to be started or shut down when necessary. Although it is

technically possible for them to do so, their high start-up costs still reduce the chances of this happening frequently. Lower minimum stable generation and higher ramping capability provide them with a wider adjustable range in generation output. To cope with the variable changes in net demand, medium flexible units alter their output quite often. They have higher marginal cost than low flexible units, so their dispatch priority is lower, and ultimately their capacity factor is also usually lower. A representative of medium flexible units in the UK is coal power plant. The biggest drawback of coal power plants is their high CO_2 emissions. Considering their large penetration in the present UK power system, they are the main sources of CO_2 emissions in the electricity sector.

- High flexible technology (HFT):
  High flexible units are regarded as the main provider of flexibility due to their low minimum stable generation, high ramping rate, small minimum up and down time and low start-up costs. However, these units usually have high marginal costs that push them to the last merit order in the dispatch. The situation can change when the equivalent marginal cost is altered taking into account the effect of CO_2 penalty price. Rather than providing base loads, high flexible units are mostly used in catching up with the variable peak of the net demand. In the UK, the examples of high flexible thermal units are the combined circle gas turbine (CCGT). In the past ten years, the capacity of CCGT has experienced a high increase giving the UK power system more tools to cope with large volumes of wind generation. Indeed, the advantages of low-carbon emissions and flexibility in accommodating renewable energies 'stabilize' their position in future generation portfolios.

The simulated system for vertical comparisons is composed of these three technologies, and the proportion of each technology is similar to the existing generation mix of the UK system in 2009 [83]. The capacity for each technology is listed in Table 3.1. Technical parameters and costs of each technology are presented in Appendix A.

Table 3.1 Capacity of Different Technologies in the Simulated System for Vertical Comparisons

Name of Technology	Installed Capacity (GW)	Share in Total Capacity
LFT (Nuclear)	2.5	17%
MFT (Coal)	6.5	43%
HFT (CCGT)	6	40%

Typical demand profiles are obtained from [35], and the aggregated load factor during a year is around 66% of annual peak load. The annual peak load is assumed to be 12GW, and therefore the annual energy consumption is around 69TWh.

Wind generation profiles with hourly resolution are also obtained from [35], and they represent typical wind output profiles in the UK. The overall capacity factor involving both onshore and offshore wind plants are around 33%.

The simulated system mimics a ‘scaled-down’ UK system for qualitative analysis of flexibility behaviours in typical wind-integrated system.

Scenarios Used for Horizontal Comparisons:

While vertical comparisons explore the effects of different wind penetrations on the flexibility requirement of a fixed generation mix, horizontal comparisons aim to find out how different systems with different flexibility behave under the same wind penetration level.

Based on the ‘scaled-down’ UK system introduced in the previous Section, the portfolio share of different technologies in the mix are adjusted to form two different systems with lower and higher flexibility. In the low flexible (LF) system, all high flexible technologies (CCGT) are replaced by low flexible technologies (nuclear power plants), while in the high flexible (HF) system, all low flexible technologies (nuclear power plants) are replaced by high flexible technologies (CCGT). Here, the ‘scaled-down’ UK system represents the medium flexible (MF) system. The installed capacities of each technology in these three systems are presented in Table 3.2.

Table 3.2 Three Simulated Systems with Different Flexibility Levels for Horizontal Comparisons

Name of System	Installed Capacity of Technology (GW)		
	LFT (Nuclear)	MFT (Coal)	HFT (CCGT)
LF System	8.5	6.5	0
MF System	2.5	6.5	6
HF System	0	6.5	8.5

3.6 Simulation Results

Simulation studies are performed using the scenarios introduced above with FICO™ Xpress software. Both vertical and horizontal comparisons will be given in the following Sections.

3.6.1 Vertical Comparison

Vertical comparisons are made with the 'scaled-down' UK 2009 thermal system under different levels of ***potential wind energy*** relative to energy consumption: 0, 10, 20, and 30% of total energy demand. The potential wind energy may be larger than the real wind energy integration (percentage of total annual demand served by wind) if wind curtailment occurs.

Through vertical comparisons, the response of the power system to wind penetration will be discussed via generation patterns, capacity factors, reserve, number of start-ups, operation costs, CO_2 emissions and wind energy curtailment. Particularly, the effects of carbon prices on the operation of wind-integrated systems are also analysed.

Generation Patterns of Conventional Technologies (without Wind Penetration):

In order to analyse the generation patterns of conventional plants under different wind penetrations, it is necessary to understand the base case when there is no wind generation. The UC program runs over the whole year with hourly resolution. Figure 3.5 shows the hourly generation output of the three technologies. For clarity, only the snapshot of January is shown. The hourly generation outputs of high flexible technology (HFT), medium flexible technology (MFT) and low flexible technology (LFT) are presented by different colours of areas. These areas are stacked up together without overlapping, so the contour of the aggregated area shows the total conventional generation output from all the three technologies.

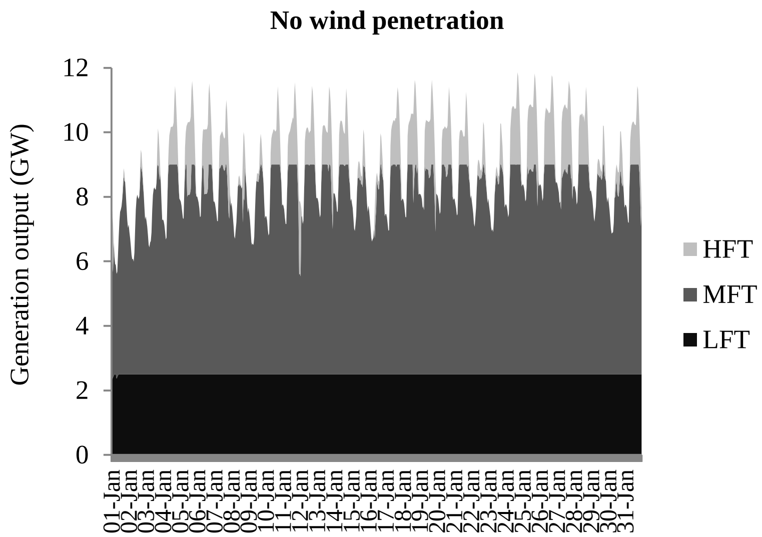


Figure 3.5: Hourly Generation Output of Conventional Technologies in January 2005 (without Wind Penetration)

The demand for electricity usually follows the typical daily and weekly patterns due to the regular working and living patterns of human beings. The regularity in demand makes it easy for conventional generation to follow the variations of demand. Consequently, the generation outputs of conventional units usually follow some typical rules:

- LFT (nuclear) runs at their maximum output during the whole time horizon. They have the first merit order in the thermal system because of their lowest operational costs. Once dispatched, it is difficult to alter either their on/off status due to their large minimum on time, or their output due to their small deployable space between minimum stable generation (MSG) and maximum output. In a traditional system without wind generation, the base load is relatively high, and the LFT is responsible for supplying part of the base load by keeping their generation at maximum output. As seen from Figure 3.5, LFT provides steady generation output at 2.5GW.

- MFT (coal power plants) contribute in both serving the base load and following the net demand variability. During all the hours in January, the overall generation from MFT is maintained above 3GW. The stable area indicates the contribution of MFT to the base load supply. Above 3GW, the overall generation varies from 3 to 6.5GW. Besides LFT (nuclear), MFT is the second cheapest technology in the system, and therefore they take part of the responsibility to serve the base load. At the same time, they are also able to follow the peaking variations because they are more flexible than LFT. Their higher ramping capability and lower minimum stable generation (around 50% of capacity) allow them to adjust their output easily when synchronised. The small minimum up/down times enable them to be switched on/off frequently. However, from the economic perspective, frequent changes in status are not wise considering their high start-up costs.

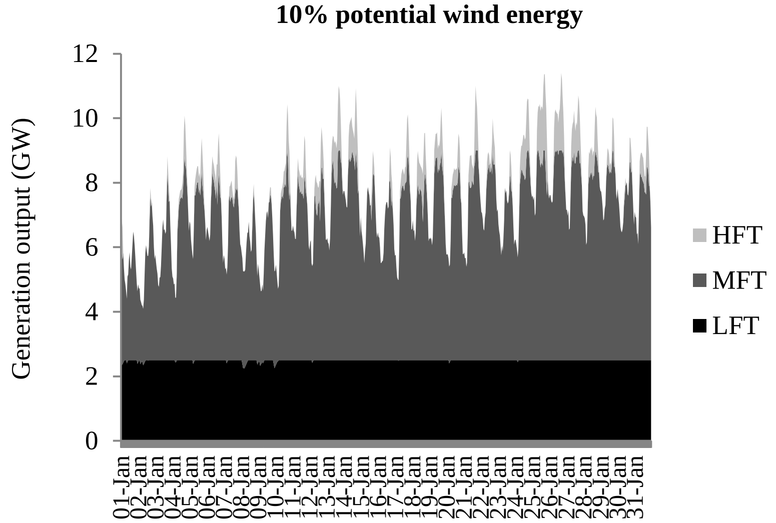
- HFT (CCGT) plays a vital role as marginal plants to follow variable net demand. They are frequently turned on and off and ramped to follow sharp changes of net demand in consecutive hours. These are because of their high ramping capability, low minimum up/down time and low start-up cost.

Generation Patterns of Conventional Technologies (with Wind Penetrations) potential wind energy

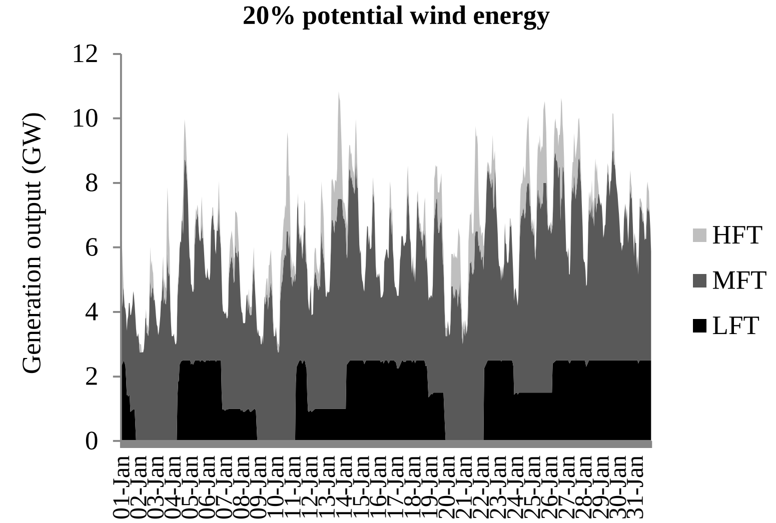
Figure 3.6 (a), (b), (c) show the generating patterns of the three technologies when 10, 20 and 30% potential wind energy is considered. The potential wind energy may be larger than the real wind energy integration (percentage of total annual demand served by wind) if wind curtailment occurs.

Compared with the base case (no wind) shown in Figure 3.5, the output of the three conventional technologies gradually becomes lower but more variable as the potential wind energy increases. Integration of wind generation squeezes out the conventional generation while at the same time poses more challenges on conventional units to follow its uncertain and variable output. It can be seen that all the three technologies change their generation patterns to meet the new net demand.

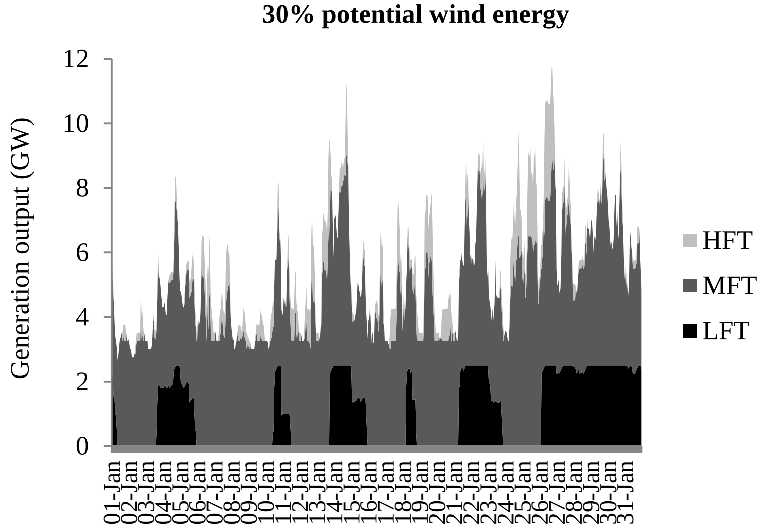
For LFT (Nuclear), although they are the least flexible plants in the system, their outputs are no longer constant. As shown in Figure 3.6, gaps appear in the darkest area (LFT) when wind energy penetration goes up to 20 and 30%. This is mainly because in some periods when there is high wind, the equivalent base load to be served by LFT is reduced largely. Therefore, some LFT plants can provide their flexibility by means of shutting down for a long time and turning on again until the net demand goes up. This flexibility service differs from the hourly flexibility that HFT (CCGT) or MFT (Coal) can provide. It is a longer term flexibility that helps to fit for the changes between high-wind and low-wind periods, which can last for several hours to several days or weeks. However, these observations are dependant on the assumptions of the characteristics of nuclear power plants. If start-up costs of nuclear power plants are very high or their minimum start up and shut down time are very long, the nuclear power plants are usually operated at their maximum output without any switches during a long term.



(a) Generation output under 10% potential wind energy (% of annual demand)



(b) Generation output under 20% potential wind energy



(c) Generation output under 30% potential wind energy

Figure 3.6: Hourly Generation Output of Conventional Technologies in January 2005 (with 10, 20, and 30% potential wind energy)

Reduction in net demand also depresses the generation from MFT (coal) but at the same time drives the generation output to a more variable pattern. Similarly, to match the pattern of net demand, HFT (CCGT) must behave in a more flexible manner. As in the base case where no wind is considered, the hourly flexibility requirement is still fulfilled by MFT (coal) and HFT (CCGT), except that the requirement is much higher and it is realised by more frequent start-ups and steeper changes in their generation output.

Number of start-ups:

In general, the number of start-ups during a year increases with larger volumes of wind power. As seen from Figure 3.7, the number of total start-ups of all conventional technologies increases from 1384 with no wind to 2266 with 30% winds. In addition, no matter in which level of wind energy penetration, HFT (CCGT) always maintains the highest number in start-ups which proofs its highest flexibility among these generation technologies.

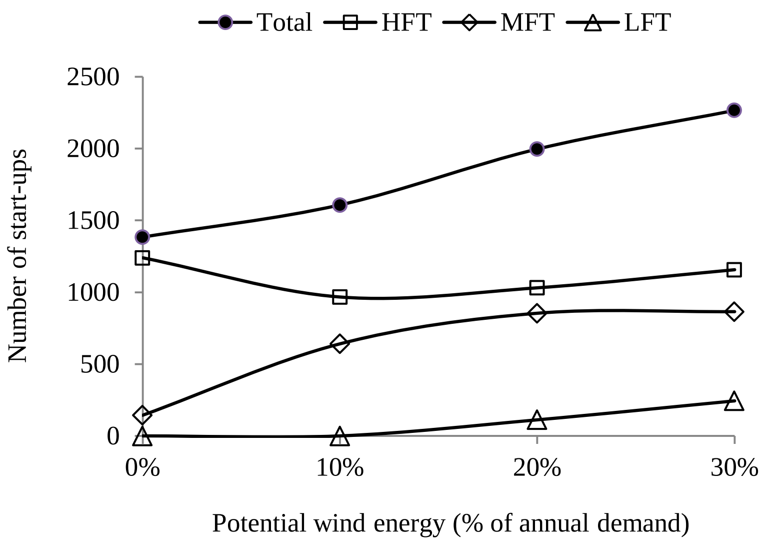


Figure 3.7: Number of Start-Ups of Conventional Technologies under Different Wind Energy Penetrations

In particular, LFT (nuclear) experiences an increase in number of start-ups from 0 (no wind) to 244 (with 30% wind penetration). As discussed before, this provides a longer term flexibility to cope with shifts between low/high wind periods. The start-up number of LFT (nuclear) is small compared with HFT (CCGT) or MFT (coal) due to its long minimum up/down times.

For MFT (coal), numbers of start-ups are 144, 641, 854, and 865 corresponding to 0, 10, 20, and 30% of wind energy penetrations, respectively. The number of start-ups shows a sharp rise when the wind penetration increases from 0 to 10%. However, during the same transition, the number of start-ups in HFT (CCGT) drops. This is because the objective function considers both start-up costs and fuel costs, and the optimisation results are the trade-off between the two. When wind power is integrated, HFT (CCGT) units are the first to be replaced because of their high fuel cost. Some HFT units thus have to be shut down and part of their duty of handling the variations in net demand fall upon MFT (coal), which causing more start-ups in MFT (coal) plants.

Since a certain number of MFT (coal) has to take the responsibility to serve the base load, the MFT (coal) that can be freely switched on/off to provide flexibility are limited. Once the variations in net demand are beyond the capability of MFT (coal), HFT (CCGT) units are deployed again. As observed from Figure 3.7, the number of start-ups in HFT (CCGT) increases again as the wind energy penetration goes up to 20 and 30%.

Variations of generation output*[12]*:

Very similar trends are observed in the variations of generation output as in the number of start-ups, as shown in Figure 3.8. The total annual variations of all three technologies increase steadily as wind penetration goes up. The variations of generation of HFT (CCGT) experience a drop from no wind to 10% wind penetration, and as wind penetration increases, they increase again. The variations of generation from MFT (coal) and LFT (nuclear) both raise with higher levels of wind penetration.

It is noticed that the absolute variations of HFT (CCGT) generation output are lower than those of MFT (nuclear) units. This is mainly because the low capacity factor of HFT (CCGT) due to their high operational cost.

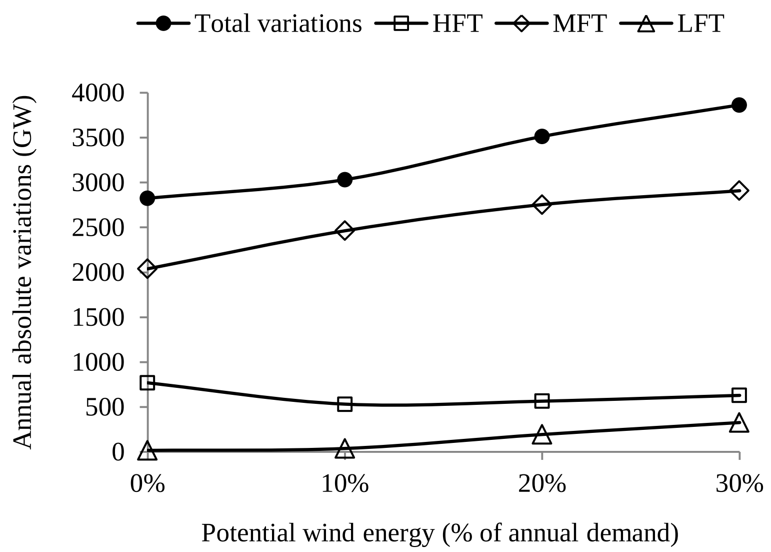


Figure 3.8: Annual Absolute Variations of Conventional Technologies under Different Wind Energy Penetrations

[12] Variations of generation output are calculated by the sum of all the absolute changes (both increases and decreases are considered to be positive) in generation output between consecutive hours.

Impacts of wind generation on tertiary reserve requirements:

Day-ahead dispatch of conventional generation considering wind integration relies on the forecast of wind generation. Since wind generation largely depends on weather patterns, its value is hard to predict. The magnitude of wind forecast error (in real terms) becomes more significant with larger volumes of wind capacity. Therefore, more operational reserve is required to cover the deviations between the forecasted and the delivered wind generation. The average hourly reserve[13] requirement is shown in Figure 3.9. For clarity, only the upward reserve is illustrated. The average hourly reserve during a year rises steadily from 500MW without wind to 1600MW with 30% potential wind energy.

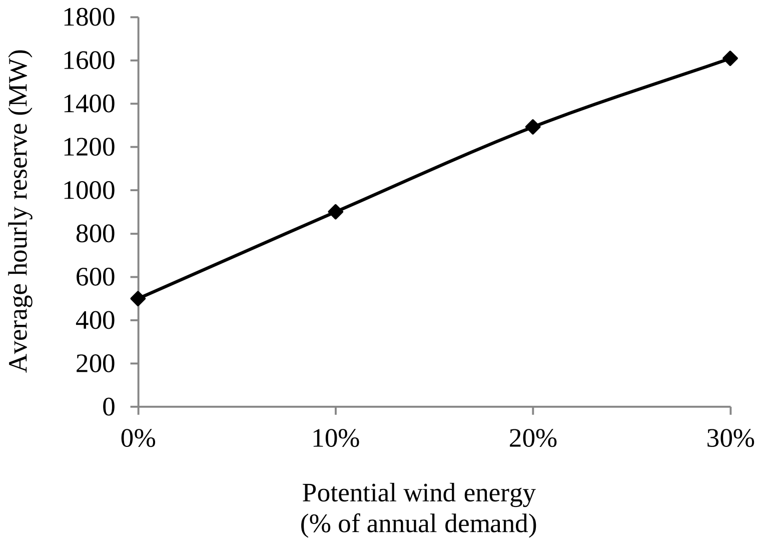


Figure 3.9: Average Tertiary Reserve Requirement under Different Wind Penetrations

System operation costs

The preceding Sections looked at the changes in system operation from a technical point of view. This Section assesses the impacts of wind from an economic perspective.

[13] Average hourly reserve is calculated by dividing the total hourly reserve requirement during a year by the total hours in this year.

In theory, the integration of wind generation reduces the operational cost of the system by replacing expensive fossil fuels with 'free' wind generation. However, digesting this wind resource requires extra operational expenditure (OPEX) to cope with the variations and uncertainties, such as the extra cost of reserve and start-up costs.

Numerical results of system operation costs are presented in Figure 3.10. The line with cross marks shows the amount of annual conventional generation, and the line with square marks shows the total operational cost. Conventional generation drops almost linearly with the corresponding linear increase in wind penetration. However, the changes in total operational cost do not follow the same trend. From 0 to 10% wind penetration, the operational cost drops at almost the same rate as conventional generation drops. This is because the effects of flexibility requirement on balancing cost are not prominent with low wind penetration. With large wind penetrations, more than 10% in this case, the rate of reduction in total cost slows down with more wind generation due to the increasing balancing costs for providing flexibility. The balancing costs are increased for two reasons:

- Expensive CCGT is used more often thus increasing the fuel related cost.
- More start-ups of plants are required thus increasing the corresponding start-up cost.

Therefore, two main impacts of wind generation on system operational cost can be concluded from the numerical results (Figure 3.10):

- Reduction of total operational costs due to the replacement of expensive fossil fuels by cheap wind generation.
- Rate of reduction in operational costs slows down with higher wind penetration because the corresponding flexibility services charge for more balancing cost.

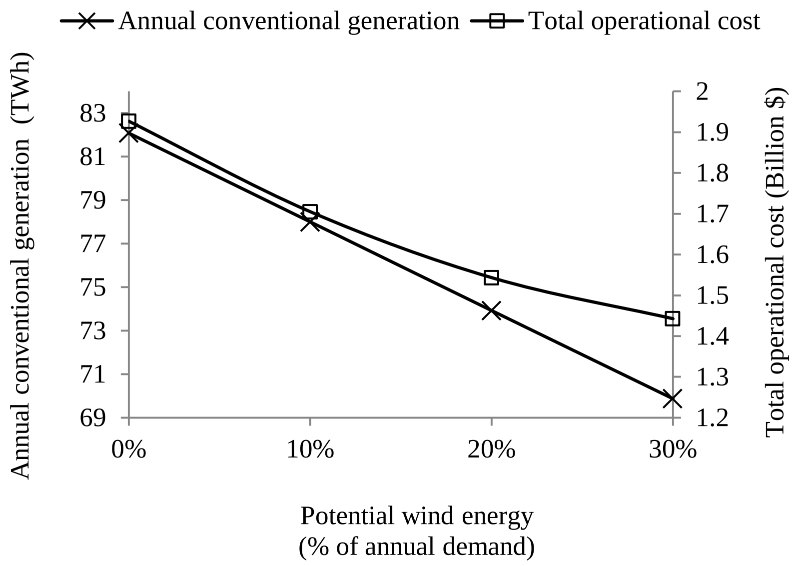
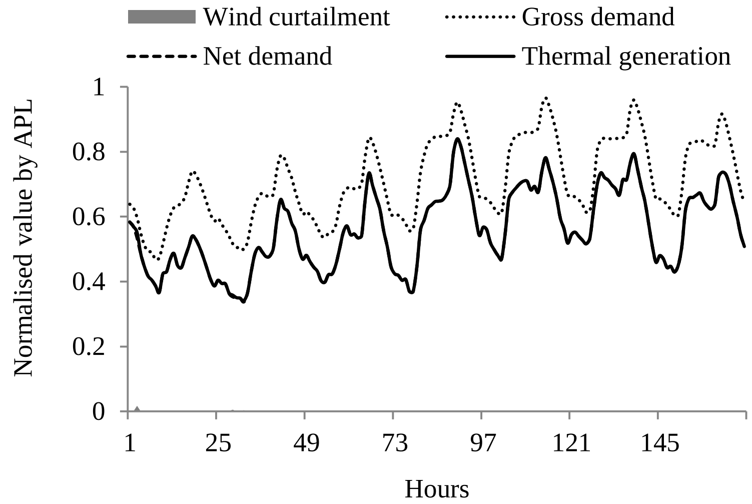


Figure 3.10: Annual Conventional Generation and Normalised Operational Cost under Different Wind Energy Penetrations

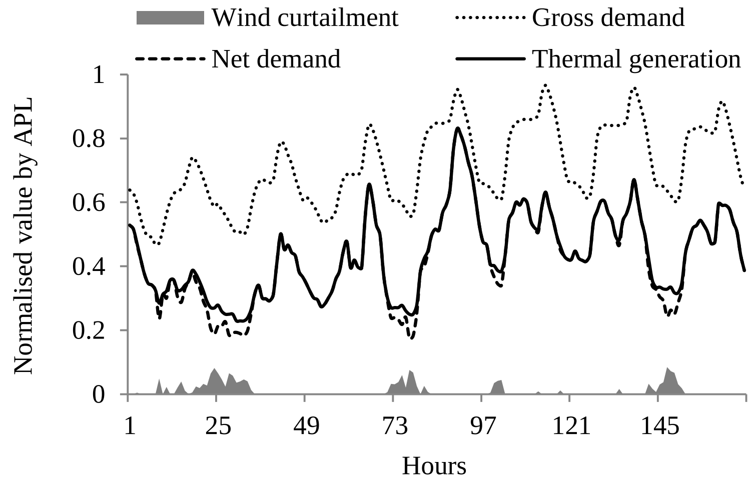
Wind generation utilisation

It was mentioned before that the flexibility of a system can be reflected by its ability of using potential wind generation. A flexible system is capable of accommodating large volumes of potential wind generation with minimum curtailment. To explain this, we first need to answer the questions of why and when wind curtailment happens.

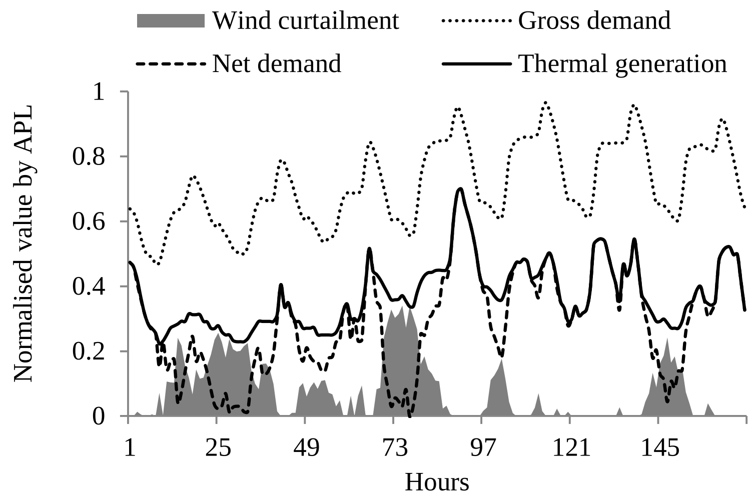
Figure 3.11 (a), (b), (c) illustrates the gross demand, the net demand, the thermal generation output, and the wind curtailment for 10, 20, and 30% potential wind energy, respectively. In each graph, areas in grey indicate the curtailed wind. Dotted lines show the gross demand profiles. Dashed lines represent the profiles of net demand (gross demand minus potential wind generation). Solid lines represent the dispatched thermal generation. For clarity, the snapshot of one week is shown. All the data in the graph are normalised by annual peak load (APL).



(a) Wind curtailment, net demand, and thermal generation for 10% wind penetration



(b) Wind curtailment, net demand, and thermal generation for 20% wind penetration



(c) Wind curtailment, net demand, and thermal generation for 30% wind penetration

Figure 3.11: Wind Curtailment, Net Demand, and Thermal Generation for Different Wind Energy Penetrations

At each hour, the relationship between wind curtailment (*WC*), net demand (*ND*) and thermal generation output (*TG*) can be mathematically represented by the following function:

$$TG(t) = ND(t) + WC(t) \qquad t \in T \tag{3.20}$$

As net demand is obtained by subtracting the gross demand by potential wind energy, once wind is curtailed, the demand that has to be met by thermal units will be increased.

As seen from the simulation results, when there is 10% potential wind energy in the system, almost all the wind is properly absorbed. The curves of thermal generation and net demand coincide with each other. For modest wind penetration levels, the reduction in net demand and the change of its shape (compared to no wind situation) are both small, as shown in Figure 3.11 (a). Thermal units have sufficient flexibility to digest the changes caused by this level of wind penetration.

As wind penetration goes up to 20%, more wind curtailment occurs. It is found that most wind curtailment appears at the time when there are sharp valleys in the net demand. This phenomenon can be more clearly observed in Figure 3.11 (c) with 30% wind energy penetration.

When comparing among Figure 3.11 (a), (b), (c), the profiles of net demand change significantly due to different wind penetrations. However, the profiles of thermal generation show something in common among different wind penetrations, which is that they never go down to the extremely small level as where net demand may achieve. This is because some thermal units have to be kept synchronised all the time to provide the spinning reserve for security reason. The generation output of these synchronised units forms the minimum load level (MLL) of the system. During high wind periods, net demand of the system may drop below the MLL, which indicates that generation is larger than demand at these moments. This is not allowed because it will break the balanced state of the system and cause a frequency rise. In such cases, wind generation has to be curtailed in order to bring the net demand level back above the MLL.

The MLL of the system is the key driver for applying wind curtailment. Another driver for wind curtailment is the lack of ramping capability of thermal units. In some cases when thermal units do not have sufficient ramping capability to follow up the sharp changes in wind generation, curtailment has to be triggered.

The proportion of annual wind curtailment relative to the total potential wind energy is shown in Figure 3.12. With 10% wind penetration, only a small amount of wind generation is curtailed. The curtailment goes up to 2% and 7% of potential wind generation, under 20% and 30% of wind penetration, respectively.

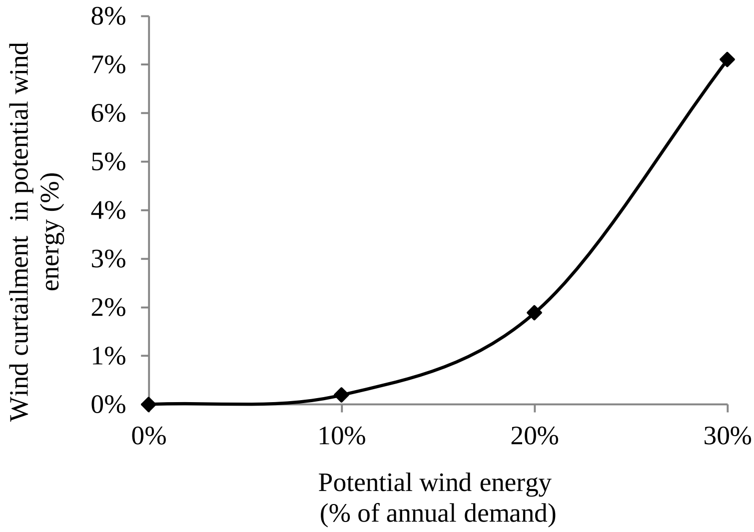


Figure 3.12: Proportion of Annual Wind Curtailment in Total Potential Wind Energies

CO_2 emissions and effects of CO_2 prices

The development of wind power generation plays a vital role in realising the low-carbon transition in the next decades. The extent that CO_2 emissions can be reduced by replacing fossil fuels with wind energy is analysed in this Section. In addition, the impacts of CO_2 price on further decarbonisation are also discussed.

In Figure 3.13, the line with cross mark shows the CO_2 emissions in the base case (without considering a CO_2 price). In the figure, annual CO_2 emissions are normalised by the total annual thermal generation and expressed by ton/MWh. The CO_2 emission rates for HFT (CCGT) and MFT (coal) are 0.394 and 0.942 ton/MWh, respectively. Therefore, replacing HFT (CCGT) and MFT (coal) generation with wind generation can achieve a reduction in CO_2 emission of 0.394ton/MWh or 0.942ton/MWh, respectively. It is seen from Figure 3.13 that the normalised CO_2 emission in the whole system is gradually reduced from 0.62ton/MWh with no wind to 0.48ton/MWh for 30% wind energy penetration.

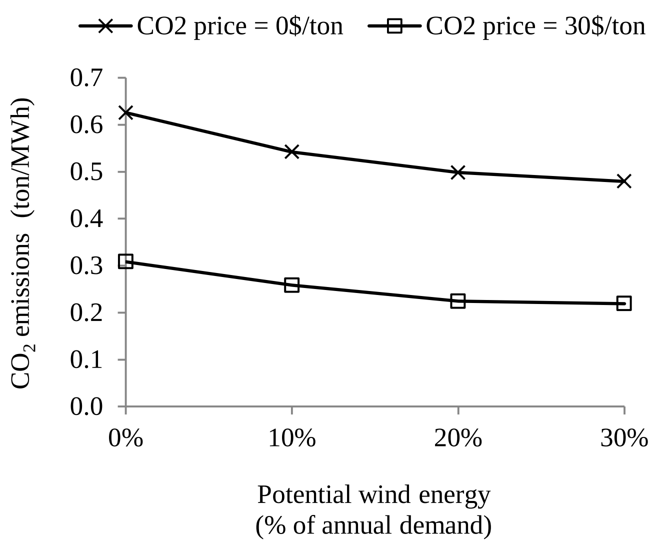


Figure 3.13: CO_2 Emissions in the Cases without CO_2 Price and with 30$/ton CO_2 Price

If a CO_2 penalty price is imposed, the generation cost of MFT (coal) and HFT (CCGT) changes and if this penalty is sufficiently high their merit order can be inverted. This can reduce the annual CO_2 emissions, as shown in Figure 3.13, where the normalised CO_2 emissions considering the CO_2 penalty prices are only around half of those in the case without CO_2 price.

The technologies with higher CO_2 emission rate (ton/MWh) are the most affected by this CO_2 penalty charge. The penalty fee applied to thermal generators for producing 1MWh of electricity is calculated by multiplying the emission rate (ton/MWh) with CO_2 penalty price ($/ton). For example, in this case, given a

CO_2 price of 30$/ton, the penalty fee for HFT (CCGT) is equal to $0.394 \times 30 = 11.82\$/\text{MWh}$, and for MFT (coal), it is equal to $0.942 \times 30 = 28.26\$/\text{MWh}$. Originally, MFT plants have lower incremental cost (30$/MWh) than HFT (CCGT) plants (40$/MWh), resulting in a higher merit order for the former (in terms of dispatch). However, when considering CO_2 penalty fees, the variable cost for HFT (CCGT) and MFT (coal) are raised to 51.82$/MWh and 58.26$/MWh, respectively, which means it is now more economic to produce electricity with HFT (CCGT) rather than MFT (coal). Therefore, a sufficiently high carbon price will lead to a shift in the 'merit order' of plants across a system. As a result, power from high carbon-dioxide generation will be reduced. It is clear that the CO_2 price can be used as an incentive to the development of low-carbon emission technologies.

3.6.2 Horizontal Comparison

In vertical comparisons, we have discussed how a thermal system adapts to different wind penetrations by deploying their intrinsic flexibility. The discussion was addressed from the aspects of changes in generation pattern, operational reserve, cost, CO_2 emission and wind utilisation.

In this Section, horizontal comparison aims at comparing the flexibility level of systems with different thermal generation mix. Since different systems comprise different generating plants characterised by distinct marginal and start-up costs, CO_2 emissions and dynamic ratings, it is hard to perform a comparison of flexibility performance using any of these parameters alone. Instead, we select wind curtailment as the parameter for comparison since it has been seen in Section 3.6.1 that the system flexibility can be reflected by the amount of wind curtailment.

Given the same thermal capacity, gross demand and wind penetration, the volume of wind curtailment in different systems (High Flexible, Medium Flexible, Low Flexible systems introduced in Section 3.5) is compared, as shown in Figure 3.14. The simulation result validates that more flexible system can make better use of the potential wind generation. It can be seen that the high flexible (HF) system presents an advantage for accommodating wind generation. Independent of the level of wind penetration, it always has the smallest wind curtailment. When the potential wind penetration is less than 20%, almost all the wind can be absorbed by the HF system. On the contrary, there is much higher wind curtailment in the low flexible (LF) system, e.g., with 30% potential wind penetration, almost 15% of the potential wind generation has to be curtailed.

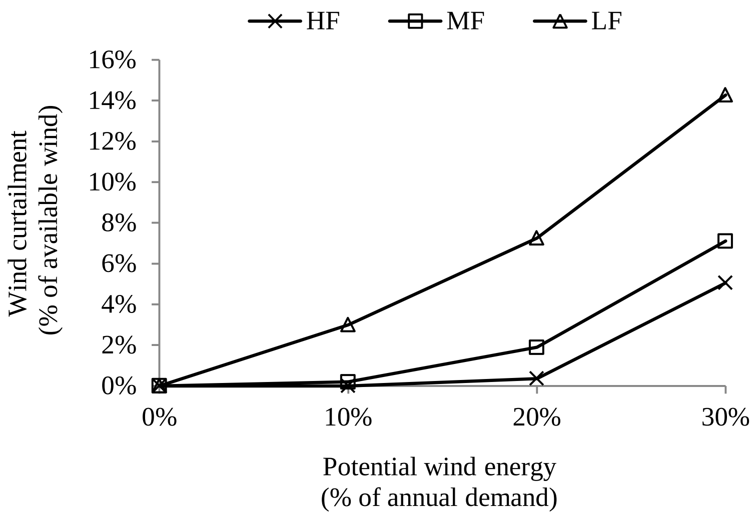


Figure 3.14: Comparisons of Wind Curtailments in High, Medium and Low Flexible Systems

3.7 Chapter Conclusions

In this Chapter, a system-level approach is proposed for the evaluation of thermal generation flexibility in wind power-rich systems. This approach is based on a unit commitment program that takes into account different aspects that are relevant to the study of flexibility: technical constraints, economic concerns, and environmental effects.

Simulations are performed based on a ‘scaled-down’ 2009 UK system to understand the flexibility requirements and how different wind penetration levels affect them. Main conclusions are addressed from the following aspects:

- Wind integration significantly drives the profiles of net demand to be more variable. Therefore, generation output from thermal units has to be more variable. This means that more ramping power is supplied from thermal generators and start up/down becomes more frequent.
- More operational reserve is required to cope with the increased uncertainty from larger wind penetration.
- Different technologies can provide different types of flexibility. Even the low flexible plants (like nuclear power plants) can provide long-term flexibility by shutting down and starting the units to cope with the 'shifts' between high and low wind periods. The selection of the providers of flexibility services depends very much on a trade-off between technical and cost characteristics of different technologies.
- Wind integration reduces the fuel cost of the system by displacing part of expensive fossil fuels. However, extra cost associated with the flexibility services is needed to accommodate large volumes of wind power properly. Additional cost for flexibility to some extent offsets the benefit from replacing conventional generation by wind generation. Therefore, the integration of large-scale wind generation is not only a technical but also an economic challenge for power systems.
- A major benefit of wind generation is the reduction of CO_2 emissions. However, when this additional flexibility required to cope with wind is provided by thermal units, the reduction rate of CO_2 emissions slows down as the flexibility requirement goes up.
- CO_2 penalty price on fossil fuel technologies significantly reduces CO_2 emission by changing the 'merit order' to give priority to low-emission technologies.
- Wind utilisation is the most direct parameter to evaluate the flexibility level of a power system. A high flexible system usually has a large deployable space that is able to accommodate wind in an efficient way. Therefore, wind utilisation in high flexible systems can be very high, i.e. minimum or no wind curtailment. On the contrary, a low flexible system

is limited by its high minimum load level and low ramping capability, and wind curtailment occurs more frequently.

CHAPTER 4

OPTIMAL GENERATION MIX TO ACCOMMODATE WIND POWER

4.1 Introduction

In Chapter 3, the flexibility requirements evolved with the increasing wind penetrations have been discussed. In order to cope with the additional uncertainties and variations from wind generation, thermal generation has to be operated in a more flexible manner. The flexibility services deployed to accommodate wind generation includes more frequent starting up/down, faster ramping up/down capability, and more reserve. However, each system has limited inherent flexibility constrained by start up/down times, ramping capabilities and minimum load level. Therefore, there is a technical-economic limit for each system to accommodate wind generation. Once wind integration exceeds this threshold, additional investments of flexible units are required to cope with further wind integration.

This Chapter presents a methodology to determine the optimal generation mix to provide the flexibility required for accommodating a given amount of wind generation. Such an optimisation must bridge the gap between the long-term investment decisions on the plants to be built and the short-term operational decisions on how these plants are scheduled. This is achieved in this work by introducing a new optimisation algorithm, designated as unit construction and commitment (UCC) algorithm. The algorithm is developed based on the unit commitment (UC) algorithm introduced in Chapter 3 which enforces the flexibility constraints, such as ramping rate, minimum stable generation and minimum up/down time. Therefore, the optimisation results are capable to answer the question of whether a plant is worthy to be built to provide additional flexibility with reasonable cost.

Section 4.2 introduces how to extend the conventional UC to the UCC that is capable of determining the optimal generation mix to accommodate wind. These enhancements will significantly increase the complexity of the optimisation problem. To cope with this problem Section 4.3 presents a technique that can be used to improve the computational efficiency. Section 4.4 demonstrates the effectiveness of the proposed approach using the IEEE RTS 26-unit system [102, 103].

4.2 Methodology for Determining the Optimal Investment in Flexible Units

Traditional generation planning models focused on the generation adequacy requirement but usually did not explicitly consider the short-term flexibility requirements in the system to be built [60-63]. On the other hand, while a traditional unit commitment considered the short-term flexibility requirements in detail (ramping capability, minimum up/down time, start-up costs), it lacked the capability of making a long-term decision on the generation investment [104].

Therefore, a new optimisation algorithm is needed, combining the advantages of the above two models that takes into account both the long-term investment decisions and the short-term flexibility requirements. Significant modifications are required to transform a traditional UC algorithm into such a new algorithm capable of balancing the long- and short-term costs of providing flexibility:

- The optimisation algorithm must be able to decide not only when a particular generating unit should be started and shut down, but also whether building that unit is optimal or not.
- The objective function must include not only the operating cost but also the amortised investment cost of each generating unit.
- The optimisation horizon must be sufficiently long in order to capture the intra-day, daily and seasonal variations in load and wind generation that drive the need for flexibility.

- It should explicitly specify the wind integration target. Therefore, the optimisation problem considers not only generation adequacy but also flexibility adequacy (flexibility level needed to attain a specific wind integration target)

The main extensions from the classic UC algorithm to the proposed UCC are summarised in Table 4.1. In the following Sections, we will describe how each of these extensions is implemented.

Table 4.1 Main Extensions from UC to UCC

	UC	**UCC**
Decision variables	On/off status of generators Output of generators	On/off status of generators Output of generators 'Existence' of generators
Objective function	Operational cost	Operational cost Investment cost
Optimisation horizon	24h-168h	One year
Constraints	System-level constraints Generator-level constraints	System-level constraints Generator-level constraints Wind utilisation constraint

4.2.1 Variable Set of Generating Units

A conventional UC problem usually includes two types of decisions variables:

- Binary decision variables representing the on/off status of the generator in each hour
- Continuous decision variables indicating the output of the generator in each hour.

In a conventional UC problem, all the generators are scheduled under the premise that they already exist in the system. In other words, the generation mix considered in a conventional UC problem is a fixed set of available generating units. Instead, the proposed UCC model should have the opportunity to add or remove generating units from the available set to model the existence or non-existence of generating units. To this end, a new binary decision variable that sets the existence or non-existence of the generating units is introduced. A value of '1' for this decision variable indicates that the corresponding generating unit exists and can be committed. Conversely, a value of '0' indicates that the corresponding unit does not exist and cannot be committed.

4.2.2 Objective Function

Since the optimisation considers both the existence and commitment status of each generating unit, the objective function must include not only the operating cost but also the investment cost of the candidate generating units, amortised over the optimisation horizon. Equation (4.1) shows the expression of this modified objective function:

$$\min\left(\sum_{i=1}^{N}\sum_{t=1}^{T}OC(i,t)+e_j\left(\sum_{j=1}^{A}\sum_{t=1}^{T}AOC(j,t)+\sum_{j=1}^{A}AIC(j)\right)\right) \tag{4.1}$$

Here $OC(i,t)$ is the operational cost of the existing unit *i* at time *t*; $AOC(j,t)$ is the operating cost of the additional unit *j* at time *t*; and $AIC(j)$ is the investment cost of unit *j* amortised over the optimisation horizon. e_j is the binary decision variable which indicates whether the additional flexible unit *j* should be built.

Equation (4.2) defines the amortised investment cost over one year:

$$AIC(j)=C_{MW}(j)P_{MAX}(j)\left(\sum_{n=1}^{L(j)}\frac{1}{(1+ROI)^n}\right)^{-1} \tag{4.2}$$

where $C_{MW}(j)$ is the cost per MW of building unit *j*. $P_{MAX}(j)$ is the capacity of unit *j*. $L(j)$ is the expected lifetime of unit *i*. *ROI* is return on investment. The larger the *ROI* is, the larger the amortised investment cost is, which implies a larger proportion of investment cost in the total cost (objective function). The investment cost of a generating unit is taken into consideration only if this unit has been built ($e_j = 1$) and is thus available for commitment.

As the same in the UC algorithm introduced in Chapter 3, the operational cost $OC(i,t)$ considers incremental cost and start-up cost, as shown in Equation (4.3).

$$OC(i,t) = u(i,t)\big(\mathrm{INC}(i) \times p(i,t)\big) + u(i,t)\big(1 - u(i,t-1)\big)\mathrm{SC}(i) \qquad (4.3)$$

where $u(i,t)$ is the decision variable indicating the on/off status of generator *i* at hour *t*. $p(i,t)$ is the decision variable showing the generation output of generator *i* at hour *t*. $\mathrm{INC}(i)$ and $\mathrm{SC}(i)$ represent the incremental cost and start-up cost of generator *i*, respectively.

This objective function can be used to determine the additional investment for an existing system. It contains two terms, one of which is the operating cost of the existing units and the other is the overall cost (i.e. investment cost plus operating cost) of the newly invested units. Two other applications can also be implemented by changing the objective function. First, it can be used to determine the optimal wind integration planning in an existing system by removing the second term (the overall cost of the new newly invested units) in the objective function. Second, it can be used to determine the optimal investment in a completely new system by removing the first term (the operating cost of the existing units) in the objective function, which assumes that the target system is empty at the beginning. All the above three applications will be demonstrated in Section 4.4.

4.2.3 Optimisation Horizon

The optimisation horizon of a conventional UC usually ranges from one day to a week. Such a horizon is not suitable for assessing investment decisions because one week is unlikely to include all the operating conditions that the system is likely to experience. In particular, when considering the needs for flexibility, one should take into account the variations in demand and wind generation that occur naturally over the course of a year. Running the proposed optimisation algorithm over a whole year with the hourly resolution would require an excessive amount of computing time [56]. Furthermore, with commercially available computer, the memory is hardly to cope with the exponential increase of decision variable in this year-long problem. For instance, the error 'out of memory' occurs when running this year-long problem with a commercially available computer.To overcome this problem, in this work, four representative weeks are used to represent an approximation of the demand and wind variations over the year. Each week is the representative of the typical demand and wind generation patterns of the season it belongs to. Load and wind profiles, due to their distinct characteristics, are modelled in different ways.

The load profile of the representative week for a season is modelled as the average of the load profiles of all the weeks in this season. Load profile usually follows the typical weekly and diurnal pattern. Therefore, using the average weekly values on one hand can represent the general variations in the demand in this season and on the other hand guarantees that the representative week keeps the same load factor as this season. Using load data from UK 2005 [35] and taking winter as an example, the load profiles of all the weeks in winter are plotted in Figure 4.1 by dash lines and the load profile of the representative winter week is shown in bold black line.

Usually, net demand is the part that is actually served by the conventional generation. Therefore, the relationship between wind and demand should be considered into the determination of the representative weeks. Considering that the hourly wind and demand is usually random, it is better to separate the representative wind and demand profiles to mimic the stochastic relationship between wind and demand.

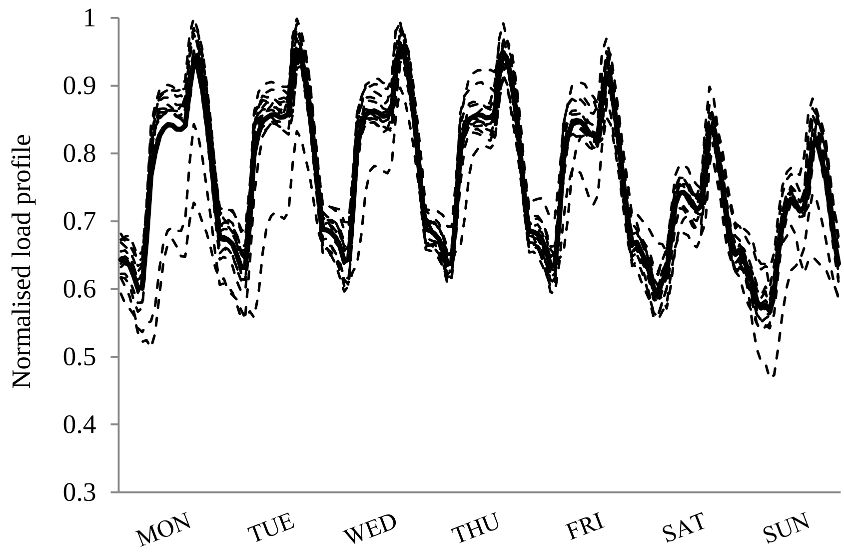


Figure 4.1: Representative Winter Week Load Profile and the Weekly Load Profiles in Winter

For the case of wind generation it is in general not possible to find such 'representative' weeks since there are no repetitive daily or weekly patterns. As a consequence, average values are not sufficient for modelling the wind profile. In order to capture the 'representative' wind variability, two criteria should be considered:

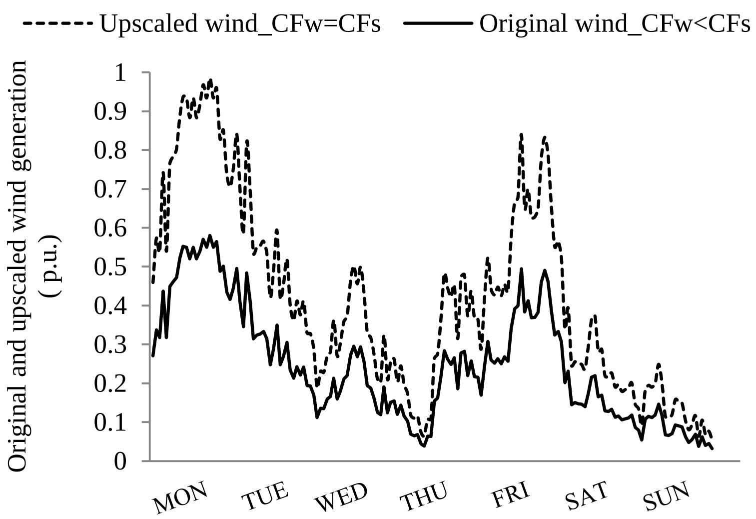
- The representative wind profile must keep the same wind capacity factor as the corresponding season. This is to guarantee that the original wind-energy penetration level is not altered.
- The variations of the representative wind profile must show the worst-case scenario in the corresponding season. In this way, the flexibility requirement due to the variability of wind generation is not underestimated.

For winter, as an example, the hourly wind generation output of each week *k* in winter (*W*) is firstly scaled up or down according to the average capacity factor for the whole season. A scale factor (SF) is obtained by dividing the wind capacity factor of winter by that of each winter week. Thus, for each winter week *k*, the hourly wind generation is modified as follows:

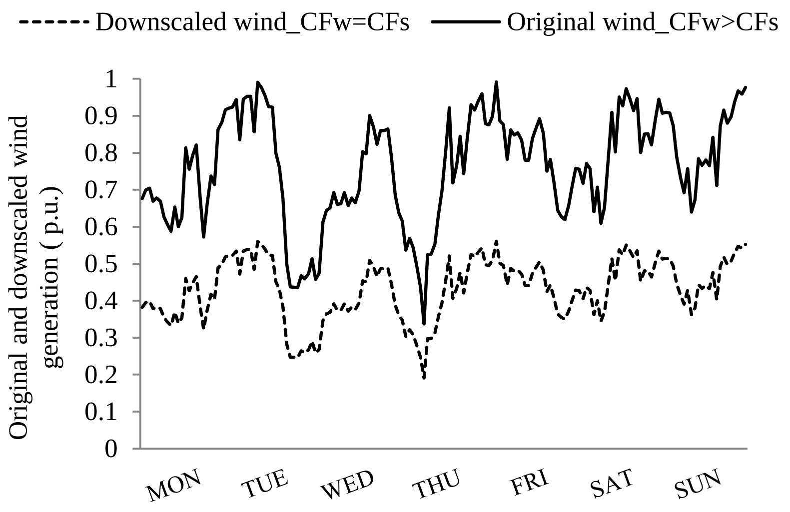
$$w(k,t) = w_{original}(k,t) \times \frac{CF_{season}}{CF_{week}(k)} \qquad \forall t \in T, k \in W \qquad (4.4)$$

where $CF_{week}(k)$ is the weekly wind capacity factor and CF_{season} is the wind capacity factor of the whole winter. $w_{original}(k,t)$ is the original wind generation output at hour t in week k, and $w(k,t)$ is the modified wind generation output at time t in week k.

If $CF_{week}(k)$ is smaller than CF_{season}, wind profile in the week k should be up-scaled, conversely, wind profile should be down-scaled if $CF_{week}(k)$ is larger than CF_{season}. Figure 4.2 (a) and (b) show examples of up-scaled wind generation (week 49) and down-scaled wind generation (week 1) based on the original wind generation data from UK 2005 [35]. In this way, all the weekly wind profiles in winter are rescaled to have the same capacity factor as the whole winter.



(a) Original and up-scaled wind generation in week 49 of 2005 UK (p.u.)



(b) Original and down-scaled wind generation in week 1 of 2005 UK (p.u.)

Figure 4.2: Original and Modified Wind Profiles

Secondly, the aggregated (sum of) hourly variations in each week are calculated. This is done by adding up the absolute values of hourly variations (independent of being upward or downward variations). Finally, the week with the largest aggregated variations is selected as the representative week for winter. The selected week maintains the same capacity factor as the winter season and at the same time represents the worst-case scenario of the variations of wind profile.

Representative wind profiles for the other three seasons, spring, summer and fall, are constructed using the same method.

Wind penetration at most of the time reduces the net demand that has to be met by conventional generators. However, one must consider the possibility that every few years there might be a week with extremely high demand and there happens to be no wind during that period. The optimal generation mix calculated on the basis of typically representative weeks might not be sufficient to handle effectively such a situation. To take such a possibility into account, the optimisation can be performed using a composite load profile consisting of the four representative weeks plus one or more weeks representing extreme conditions. Figure 4.3 illustrates such a load profile with an extreme week inserted between the representative winter week and the representative spring week.

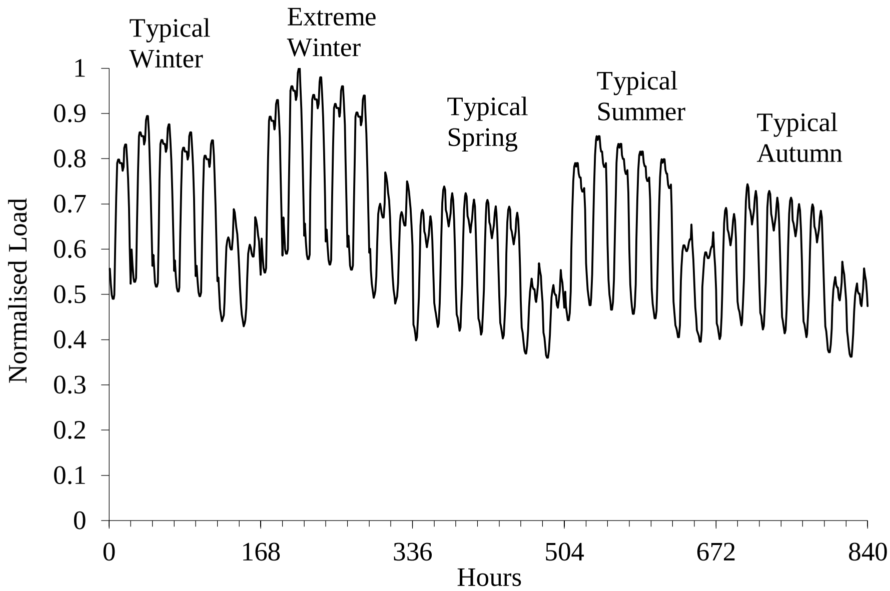


Figure 4.3: Load Profile with Four Seasonal Representative Weeks and One Extreme Winter Week

The relative weighting given in the objective function to these extreme weeks should reflect their rarity. Table 4.2 shows the weightings that should be applied to the weekly operating costs if we assume that an extreme winter week happens every four years.

Table 4.2 Weighting Factors for Representative Weeks

Week	Weighting Factors
Typical winter	12.75
Extreme winter	0.25
Typical spring	13
Typical summer	13
Typical autumn	13

4.2.4 Initialisation of Decision Variables

In the preceding Sections, both representative demand profiles and wind profiles have been selected for each season. The four representative weeks will be linked together to form the whole profiles of the year. Two aspects of this linkage must be emphasised:

- The existence decision variables should run through all weeks, otherwise a decision might be made to invest in a unit only for one season.
- The initialisation of the commitment variables at the beginning of each week must be done carefully.

The number of hours that each unit has been on or off, and their output during the period preceding the optimisation interval define the initial state of the system. This initial state affects the optimal solution through start-up costs, minimum up- and down-time constraints and ramp rate constraints. In a conventional UC, this initial state is part of the input data [105]. In UCC, however, this information is not available. Moreover, the final state of a week representing a season is usually not the initial state of the week representing the next season. An incorrect initialisation could therefore bias the calculation of the optimal amount of flexibility. The initial state of each week should be representative of the initial state of that season. Since each of these weeks represents an 'average' of all the weeks of a particular season, one can make the assumption that it is followed by a similar week. The final state of each representative week should thus be equal to its initial state, as illustrated in Figure 4.4. This approach is implemented by not assuming any initial status in the UC but enforcing the equality of the initial and final state of each week.

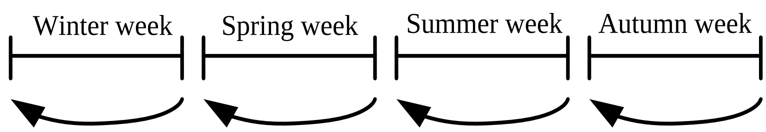


Figure 4.4: Initialisation of the Four Representative Weeks

4.2.5 Considering Allowable Wind Curtailment

While a conventional generation portfolio could be designed to accommodate any amount of wind generation it may not always be economically justified to do so. In some cases, the flexibility could be best provided by the wind generators themselves in the form of wind curtailment. The tolerable amount of wind curtailment over the optimisation horizon can be introduced into the UCC problem using an additional constraint:

$$\sum_{t=1}^{T} wc(t) <= K_c\% \times \sum_{t=1}^{T} wg(t) \tag{4.5}$$

where $wg(t)$ and $wc(t)$ represent the potential wind generation output and the wind curtailment in period *t*, respectively. $K_c\%$ is the maximum proportion of the total wind generation that is allowed to be curtailed over a year. This constraint ensures that sufficient additional flexibility is built to accommodate at least $(100 - K_c)\%$ times the potential wind generation over a whole year.

In all the test cases presented in the following Sections, $K_c\%$ is assumed to be 20%. In reality, this number can be set by the system operators according to their experience and expectations for wind utilisation.

4.3 Improving the Computational Efficiency

The extended optimisation horizon and the introduction of “existence” decision variables make the size of the UCC problem considerably larger than that of a conventional UC problem with a similar number of generating units. This could leads to an excessive amount of computing time for a commercially available computer.

In this work, we propose a heuristic constraint named ‘priority ordering constraint’ (POC) to reduce the computational time.

Sets of relatively small generating units with similar technical and cost characteristics are prime candidates for providing flexibility. The optimisation algorithm can spend a considerable amount of time comparing solutions involving one or another of these units for no significant gain because their characteristics are almost identical. Introducing an artificial priority order among these units can cut the search short and hence save a considerable amount of computing time. Units in a set are then committed in the order of priority unless one of them is subject to a minimum down time constraint. The constraints used to implement this heuristic process are described as below.

1. If unit *i* is synchronised at hour *t*-1, it should be committed at hour *t* before any other unit with a larger index in the set (*S*) of similar units:

$$\begin{aligned} &\text{if} \quad u(i,t-1)=1 \\ &\text{then} \quad u(i,t)\geq u(i+1,t) \quad \forall i\in S \end{aligned} \tag{4.6}$$

2. If unit *i* is off at hour *t*-1 and has been off for at least the minimum down time (MDT), then it should be committed at hour *t* before any other unit with a larger index in the set (*S*) of similar units.

$$\begin{aligned} &\text{if} \quad \sum_{t-MDT}^{t-1} u(i,t)=0 \\ &\text{then} \quad u(i,t)\geq u(i+1,t) \quad \forall i\in S \end{aligned} \tag{4.7}$$

3. If unit *i* is off at hour *t*-1, and has not yet been off for the minimum down time (MDT) it must remain off and no longer has priority over similar units:

$$\begin{aligned} &\text{if} \quad \sum_{t-MDT}^{t-1} u(i,t)\geq 0 \\ &\text{then} \quad \text{unit } i \text{ has no priority} \end{aligned} \tag{4.8}$$

The whole process can be summarised by a flowchart shown in Figure 4.5.

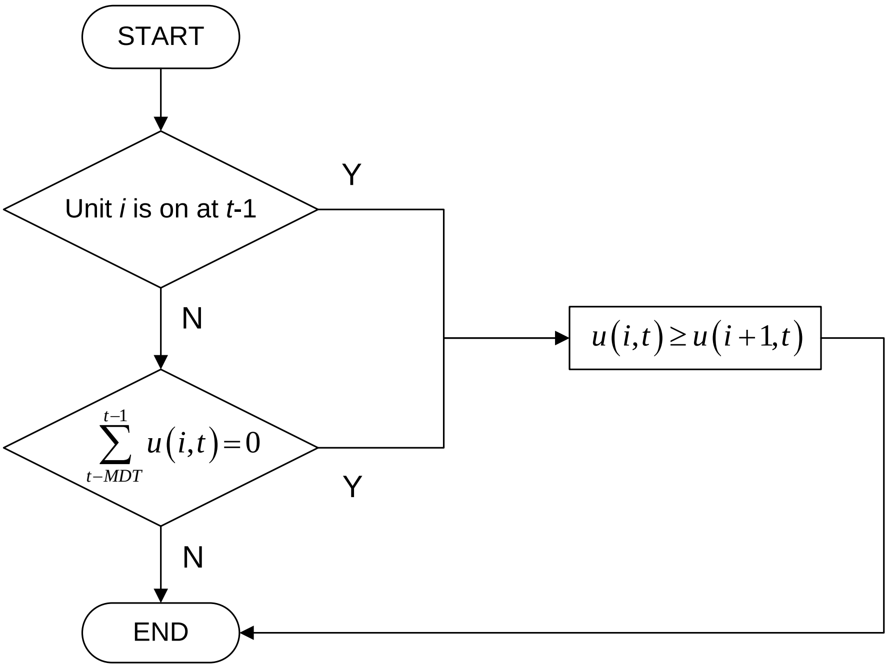


Figure 4.5: Flowchart for Priority Ordering Constraint

Since logical expressions with decision variables are not allowed in the constraints in the software used (FICO™ Xpress), we have to change these formulations into mathematical expressions. To simplify constraints (4.6), (4.7), and (4.8), the following substitutions are made:

$$\begin{aligned} x &= unitcom(i,t-1) \\ y &= \sum_{t-MDT}^{t-1} unitcom(i,t) \\ c &= unitcom(i,t) - unitcom(i+1,t) \end{aligned} \tag{4.9}$$

Then (4.6), (4.7), and (4.8) can be simplified as:

$$\begin{aligned} &x = 1, \qquad c \geq 0 \\ &x = 0, y = 0,\ c \geq 0 \\ &x = 0, y \geq 1,\ c \text{ is } flexible \end{aligned} \tag{4.10}$$

Constraint (4.10) can be further simplified as:

$$\begin{aligned} c \cdot x &\geq 0 \\ c + y &\geq 0 \end{aligned} \tag{4.11}$$

Equations (4.11) form the basic rule for "priority ordering" constraint, and can be implemented in FICO™ Xpress. This simplification is an example to show how to deal with non-analytic constraints in FICO™ Xpress solver.

4.4 Validation of the Effectiveness of the UCC

To validate the effectiveness of the UCC and to demonstrate potential uses of the UCC, a set of case studies are conducted using the IEEE RTS system [102], which consists of 26 units (omitting hydro generating units) and has an installed capacity of 3105 MW. This IEEE RTS system is chosen to test the UCC program because of its diversity in unit types, i.e., it contains a variety of base, intermediate and peaking generating units. The parameters of each unit can be found in Appendix B.

4.4.1 Estimation of Maximum Allowable Wind Capacity Installation

The UCC can be used to estimate the maximum wind generation that can be accommodated in an existing system. In this case, the existence of all the generating units is fixed by setting the value of 'existence variable' at 1 and this binary variable is thus removed from the consideration. The maximum wind generation is the decision variable in this problem and is determined by the output of the UCC.

Normalised wind and load profiles are the same as used in Chapter 3 [35] in order to show the realistic fluctuations in wind and load. The wind profile has a wind capacity factor of 0.33, and the load profile has a load factor of 0.67. Normalised wind and load profiles for the four representative weeks are selected using the methodology introduced in Section 4.2.3. The absolute wind data is then obtained by multiplying the normalised wind profiles by the wind capacity and the absolute demand data is equal to the product of the normalised demand profiles and the annual peak load (APL). It is assumed that the 26 thermal units originally serve such demand profile with APL of 2500MW.

While the wind profile, the load profile and the annual peak load are known, the question is how much wind capacity is able to be accommodated in such a system, without wasting more than K_c% (assumed 20% in the test case) of the annual potential wind generation. The algorithm described in the flowchart shown in Figure 4.6 is able to find this maximum wind capacity value (% of APL).

Let a and b be the lower and upper boundaries for wind capacity value. They will be initialised with 0% (a) and 200% (b) of APL, respectively. When the wind capacity is 200% of APL, the available annual wind power generation is nearly equal to the total annual demand. So 200% of APL is set as the upper limit for wind capacity. The first attempt of wind capacity is set as $W = \frac{a+b}{2}$. This value is used as an input parameter for the UCC. After running the UCC, depending on its outcome, there exist the two following steps. If the UCC is not feasible, the upper boundary is lowered to the current wind capacity as b=W. If the UCC is feasible, the lower boundary is lifted to the current wind capacity level as a=W. Then, the UCC is conducted again using the new lower or upper boundaries as $W = \frac{a+b}{2}$. The above procedure is repeated until the difference between the lower and upper boundaries is less than 1%. At that time, the maximum wind capacity level W that can make the UCC feasible is known.

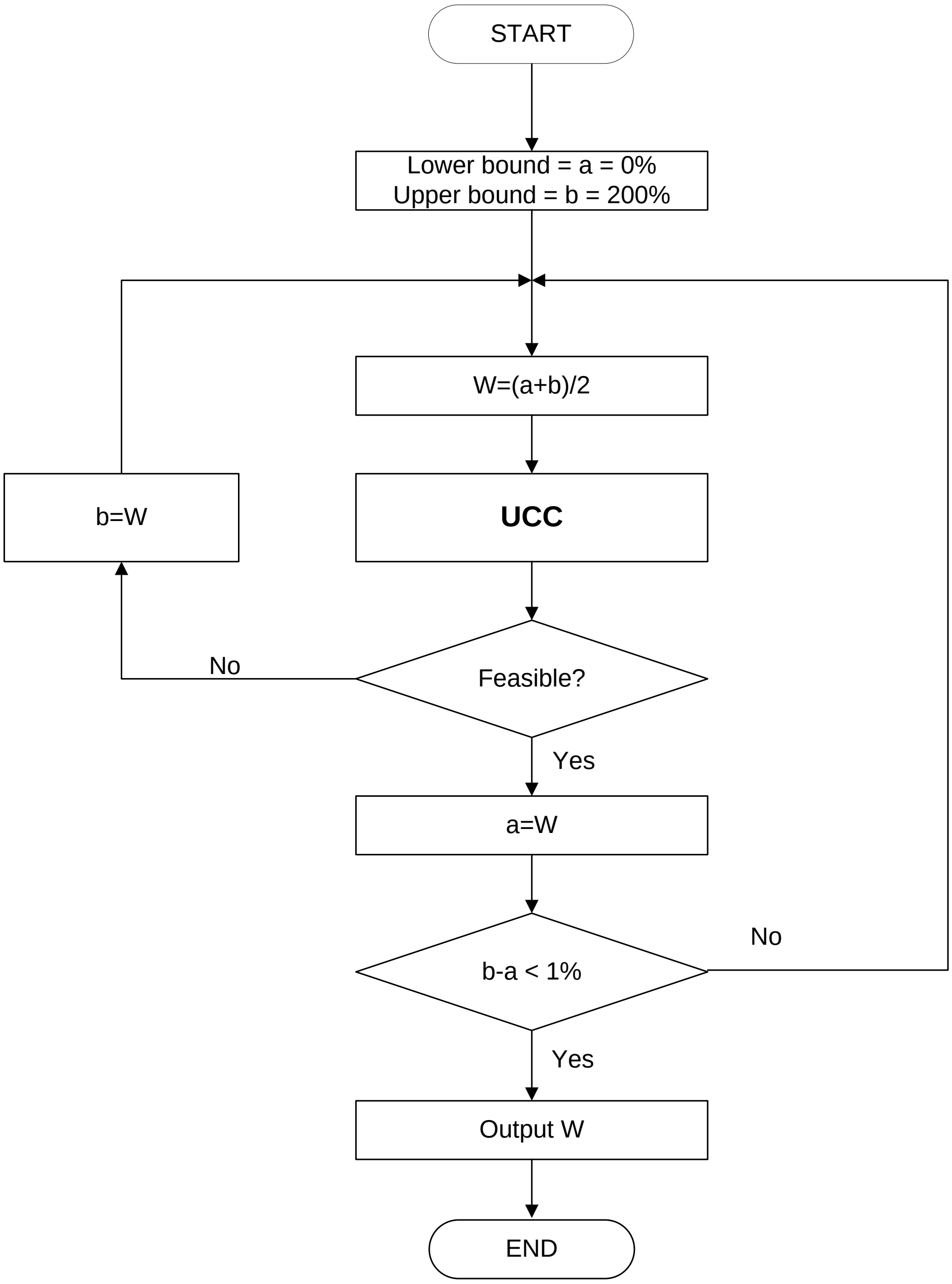


Figure 4.6: Flowchart for Estimating the Maximum Allowable Wind Capacity in an Existing System

Using the above algorithm, the maximum feasible installed wind capacity in the 26 thermal units system (without wasting more than 20% of potential wind generation) was found to be 47.2% of the APL and that corresponds to 1180MW. The proposed algorithm can be used for any expected $K_c\%$ of wind curtailment. In this case, if $K_c\%$ is assumed to be greater than 20%, it means that the constraint for wind utilisation is relaxed, and as a result, the maximum feasible installed wind capacity would be larger than 1180MW.

4.4.2 Optimal Investment in New Generating Unit

Once wind capacity reaches the maximum allowable level in the existing system, the flexibility of the system needs to be increased to accommodate further wind capacity installation. The UCC is able to help the system operator to determine the appropriate investments, to achieve the required flexibility level at minimum cost.

From the above test case, it was estimated that the 26 thermal-unit system is able to accommodate at maximum 1180MW of wind capacity without wasting more than 20% of wind power generation. Therefore, in order to further increase the wind installed capacity and ensure a high wind utilisation factor (at least 80%), new investments in flexibility are needed.

In order to analyse this investment in flexibility, it is assumed that three candidate generation units, of the same capacity and different flexibility levels and costs, are being considered as investment alternatives. However, only one of these will be selected to be built. Table 4.3 gives the parameters of the three units, and they are named as low flexible (LF), medium flexible (MF) and high flexible (HF) units, according to their flexibility, respectively. Large differences in fuel costs have been chosen to investigate whether a HF unit should be built to accommodate high wind penetration, even if its operating cost is extremely high (3700$/MWh). The extremely high cost is not realistic. It is only used in this case to demonstrate whether the methodology works appropriately.

Table 4.3 Parameters of the Units Being Considered

Candidate units	Pmin (MW)	Pmax (MW)	Ramp rate (MW/h)	Min up/down time (h)	Investment Cost (k$/MW)	Fuel Cost ($/MWh)
LF	100	200	70	8	2117	18
MF	50	200	100	4	536	250
HF	10	200	150	1	409	3700

Table 4.4 shows that when the total wind capacity is increased from 1180MW to 1250MW (Case 1), the optimisation chooses the LF unit which has the lowest cost. If the target wind capacity is increased to 1300MW (Case 2), the MF unit is selected because the LF unit cannot sufficiently enhance the system's flexibility. When the target goes up 1350MW (Case 3), even more flexibility is needed, therefore, the HF unit is selected even though it has an extremely high operating cost. The results obtained show that the UCC is able to select the best investment option, taking into account both the flexibility requirement and the annual operational costs.

Table 4.4 Investment Decision under Different Targets of Wind Capacity Installations

Base Case: Max wind 1180MW	New target for wind (MW)	Candidate Units	LF	MF	HF
Case 1	1250	Investment Decisions	Selected		
Case 2	1300			Selected	
Case 3	1350				Selected

4.4.3 Effects of Wind Integration on Flexibility Requirement

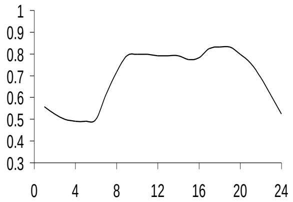
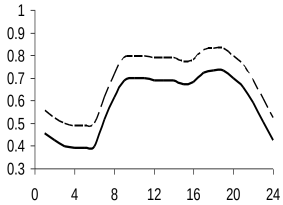
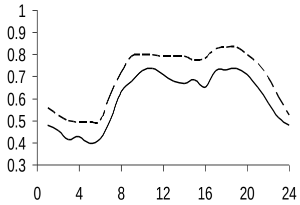
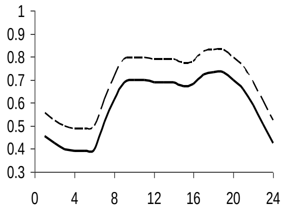
This test case is supposed to show whether the results of the UCC can properly reflect the effects of the integration of wind generation on flexibility requirements. In this case, it is considered a 'blank system' where all the 26 thermal units are candidate units to be invested (the investment cost for each unit is shown in Appendix B). In contrast to the previous study where we started from an existing system, here it is intended to find the optimal mix that minimises the total cost.

As described in the previous Chapters, high wind penetration in power systems has three main impacts on system operation:

1) it reduces the net demand to be supplied by conventional units;
2) reserve must be increased to cope with wind forecast errors, that are added to the original reserve required for sudden loss of the largest generating unit and demand forecast errors; and,
3) fast ramping and frequent start-ups are required to compensate the fluctuations in wind power.

Four cases, described in Table 4.5, illustrate how the model captures each of these impacts. The UCC runs over the four representative weeks. In order to demonstrate this clearly, here a snapshot of one day is taken to show the different wind profiles. Case 1 is the base case with no wind penetration. Annual peak load (APL) is set at 2200MW. In Case 2, wind generation penetration is 10% (potential wind generation in total annual demand). Wind generation is assumed to be constant over the optimisation horizon. In Case 3, wind penetration level is still 10%, but the wind generation fluctuates over the optimisation horizon. In Case 4, wind power generation is assumed to be flat and covers 10% of the annual gross demand. However, the uncertainty of the wind generation is assumed to be larger than in Case 2. This is modelled using the different standard deviations (STD) of the wind forecast error, which are 0.01 (normalised by the APL) in Case 2 and 0.03 in Case 4.

Table 4.5 Definition of the Four Cases Used to Study the Effect of Wind Generation on the Need of Flexibility (Dotted Lines: Base Case without Wind)

<table>
<tr><th></th><th>Net demand Profile</th><th>Wind forecast</th><th>STD of wind forecast error</th></tr>
<tr><td>1</td><td>
</td><td>No wind</td><td>No forecast error</td></tr>
<tr><td>2</td><td>
</td><td>10% wind penetration (without fluctuations)</td><td>$\sigma = 0.01$</td></tr>
<tr><td>3</td><td>
</td><td>10% wind penetration (with fluctuations)</td><td>$\sigma = 0.01$</td></tr>
<tr><td>4</td><td>
</td><td>10% wind penetration (without fluctuations)</td><td>$\sigma = 0.03$</td></tr>
</table>

According to the incremental costs and the flexibility level, the 26 candidate units are divided into three groups: units 1-5 are peaking units, 6-16 are intermediate units, 17-26 are base units. Peaking units are the most flexible and expensive ones, while base units are the least flexible and cheap ones. Intermediate units are the ones in between the above two.

The UCC determines which of the original 26 units are actually needed to provide the optimal amount of flexibility in the above four cases.

Table 4.6 shows the results of the UCC and illustrates the three impacts of wind penetration on the optimal generation mix when compared to that of the base case without wind.

Table 4.6 Test Results for 4 Cases with Different Wind Penetrations

Case	Investment Decisions	Total cost (k$)
1 (Base case)	Units 4,5,20 are not needed	280,017
2	Units 4, 5, 18, 19, 20 are not needed	246,084
3	Units 19, 20 are not needed	248,827
4	Units 5, 20 are not needed	254,922

In the base case, three generating units (4, 5, and 20) are excluded from the optimal mix. Comparing with the base case, Case 2 shows that wind generation displaces base generating units 18 and 19 (inflexible and less expensive) and reduces the total cost. However, in Case 3 a decision is made to build peaking units 4 and 5 (flexible and expensive), which shows that fluctuations in wind power increase the requirement for flexibility. A comparison of Cases 2 and 4 shows that, when the reserve requirement is increased to cope with a larger uncertainty of the wind forecast, more generating units (peaking unit 4 and base units 18 and 19) are needed to achieve the minimum total cost. Figure 4.7 summarises the percentage of the number of peaking and base units out of 26 (total number of units), for the above four cases.

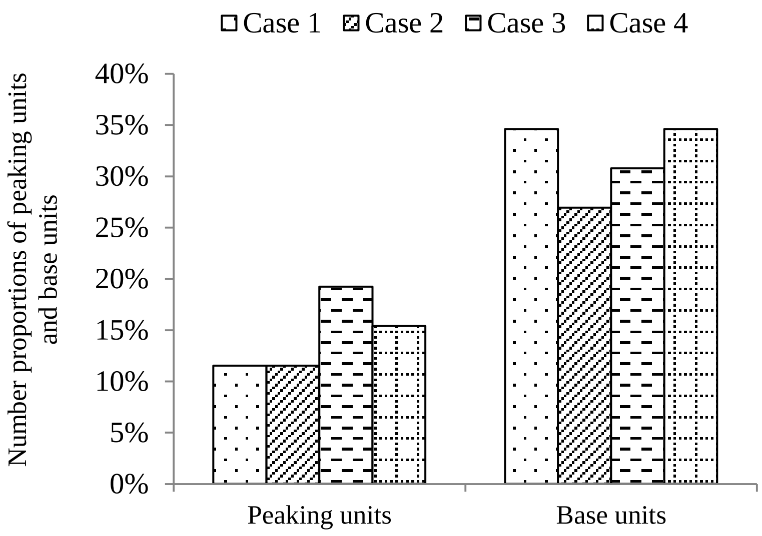


Figure 4.7: Percentage of the Number of Peaking Units and Base Units out of 26

It is seen from Figure 4.7 that constant wind generation reduces the need for base units as in Case 2. Peaking units are not affected since no more flexible units are required.

Fluctuations in the wind power require more peaking units to provide the additional flexibility requirement. That is why the proportion of flexible peaking units increases sharply in Case 3.

The larger uncertainty caused by wind forecast errors requires more units to provide reserve. Therefore, in Case 4, the proportion of peaking units and base units both increase compared with Case 2.

It is shown that the three main effects of wind integration on the power system can be well reflected by the results of the UCC problem.

4.4.4 Computing Efficiency

In Section 4.3, a technique named ‘priority ordering constraint’ was introduced, aiming at reducing the computational time. This Section will show the effect that such technique has on the computational speed and on the optimality of the solution.

Table 4.7 shows that the proposed priority ordering constraint (POC) significantly reduces the computing time required (reduced from 39.6h to 11.2h), while producing solutions whose costs are slightly different (only 0.12%) from the optimal solution obtained without POC.

Table 4.7 Effect of the Heuristic Constraint Used to Reduce the Computing Time

10% wind energy penetration	**APL=2200MW**	
Computer	Intel(R)Core(TM) I7 CPU, 1.60GHz, 4.00GM (RAM)	
Solver	FICO^{TM} Xpress 7.2	
POC	Without POC	With POC
Computing time (hours)	39.6	11.2
Investment decisions (units not built)	17, 20	19, 20
Total cost (k$)	248,528	248,827
Difference in total cost	0.12%	

4.5 Chapter Conclusions

In this Chapter, a technique to optimise the flexibility of the generation mix for different wind penetrations has been proposed. The technique is based on an enhanced UC program, designated as the ‘unit construction and commitment (UCC) algorithm’. The main enhancements include:

- Introducing an additional set of binary decision variables to indicate the existence of a particular generating unit.
- Taking into account seasonal variations in the demand and wind generation.
- Considering annualised investment cost in the objective function.
- Introducing a wind utilisation constraint.

A heuristic constraint called ‘priority ordering’ has also been implemented to achieve a reasonable computing time.

The proposed technique has been tested using the IEEE RTS 26-unit system with different wind penetrations. It is shown that the technique can be used to quantitatively assess the benefits and impacts of wind generation on power system operational flexibility as it is able to compute the changes in flexible and non-flexible units in the system.

In addition, it is shown that the proposed UCC program can also be used to estimate the maximum wind capacity that an existing system is able to accommodate without losing more than a predefined amount of wind generation. Around the world, many countries and regions have ambitious targets for wind power integration. However, the ability that a system can accommodate the wind is limited by the flexibility of the system. Therefore, in order to efficiently utilise the potential wind, it is important to have a good evaluation of the system flexibility, as well as a good estimation of the optimal wind capacity in such a system. The proposed UCC may help the system operators to decide the optimal wind capacity installation in an existing system.

Once the threshold of the wind capacity is achieved, the UCC can also help the system operator to determine the optimal new investments to enhance the flexibility of the system, and thus to cope with large-scale wind penetrations.

CHAPTER 5

PROFITABILITY OF FLEXIBILITY SERVICES IN ELECTRICITY MARKET

5.1 Introduction

In the preceding Chapters, it has been discussed the impacts of wind generation on the requirements of operational flexibility, and how to determine an optimal generation mix to accommodate a certain level of wind penetration. Both of them are addressed from a whole system perspective to support system operators or policy makers to set a framework for the development of the flexibility required to cope with wind. In a market-based system, it is interesting to evaluate the market value of flexibility for balancing wind and how this evolves with increasing wind penetrations.

However, unlike energy or ancillary services, flexibility cannot be easily quantified as an independent product. In essence, flexibility describes the comprehensive abilities of a generator to deliver energy or reserve, i.e., how fast and to what extent it can deliver energy or reserve. As a consequence, the profit of flexibility is embedded in the overall profit that a generator obtains from providing energy or reserve. To extrapolate the profit of flexibility an approach to separate it from overall profits is required.

This Chapter describes an approach to quantify the profitability of flexibility using a market model that takes into account day-ahead, rolling planning and real-time balancing markets. Normalised profit is applied to separate the profit of flexibility from overall profits. A set of studies are performed to access the impacts of wind penetrations and market design on the profit of flexibility and to evaluate the effects that the different aspects related to system flexibility (wind variability, wind uncertainty, minimum load level of the system) have on it.

5.2 Market Design

In this work, the evaluation of flexibility profit is undertaken based on a market model that takes into account both day-ahead and real-time balancing markets. To discuss the impacts of flexible market design on the profit of flexibility, this model will be compared with an alternative market design, which introduces ‘rolling planning’ of the day-ahead and real-time balancing markets.

5.2.1 Day-ahead Market

The day-ahead electricity market is modelled as a centralised market based on a unit commitment whose objective is to minimise the overall ‘cost’ of supplying energy while respecting the operating constraints.

The market is assumed to be perfectly competitive, so every generator bids for supplying energy according to their true operational cost (start-up cost, incremental cost). This assumption aims at exposing the actual profit of flexibility avoiding the effects of bidding strategies or market power manipulation. The impact of bidding strategies on the profit of flexibility is an important topic of research on its own and lies out of the scope of this thesis.

The system operator is assumed to be also the market operator. In the day-ahead market, the market operator collects the generators’ bids and the information of the forecasted wind and demand for the next day. It then runs a generation scheduling program to clear the market and send dispatch signals to each unit. The mathematical model of the generation scheduling is similar to the unit commitment (UC) introduced in Section 4.4 (refer to Equations (4.10) – (4.19)), in which operational costs are replaced by the bids of generators (in this case, the values of the two are equal since it is assumed that generators bid according to their true operational costs). The day-ahead energy market is cleared at the uniform market-clearing price, i.e. generators are paid by a uniform market-clearing price ($/MWh), in each specific time period, for each MWh of energy they provide. This price is determined by the incremental cost of the marginal unit. In addition to the payments based on the market clearing price, it is also assumed that there are side payments to ensure the recovery of start-up costs but no extra profit can be obtained from them.

In the day-ahead market, scheduled generators obtain revenue from two streams: energy and reserve. The revenue that generators receive for providing energy is equal to the market-clearing price for each period multiplied by the amount of energy scheduled during that period. The revenue that generators receive for providing reserve is based on their lost opportunity cost (LOC), i.e., the marginal profit that they lost because they are asked to provide reserve rather than energy [106, 107]. The LOC is generator-specific and time-specific. For each generator, the LOC is equal to the difference between its marginal cost and the market clearing price in a specific time period.

Not all the spare capacity in the system is remunerated by the LOC. Only the units used to satisfy the reserve constraint receive this payment.

In economics, payment for holding reserve is a type of 'option fee'[14][64]. The system operator pays this option fee to make sure that the equivalent amount of regulation power can be bought, if needed, in the real-time balancing market. Generators who get paid this 'option fee' in the day-ahead market commit to deliver this amount of regulation power in the real-time market if they are called. If they fail to do so, they have to buy an equivalent amount of regulation power at the spot market price in the real-time market to fulfil their commitment.

In the day-ahead market, the profits of generators obtained from providing energy and reserve are calculated as follows:

- **Revenue from energy for generator *i*:**

[14] In power system economics, an option fee is the money paid by a buyer to a seller for the option to exercise the real contract. It can be considered as a type of 'deposit' to guarantee that the option contract will be exercised with the agreed amount, agreed price and agreed time.

$$S_{DA\_E}(i) = \sum_{t=1}^{t=T} \pi_{\mathrm{E}}(t) P(i,t) \tag{5.1}$$

where $\pi_E(t)$ is the market-clearing price for energy at hour *t*. $P(i,t)$ is the scheduled output of generating unit *i* at hour *t*. $S_{DA\_E}(i)$ indicates the revenue of unit *i* obtained from providing energy in the day-ahead market.

- **Revenue from reserve for generator *i*:**

$$S_{DA\_R}(i) = \sum_{t=1}^{t=T} C_{opp}(i,t) Re(i,t) = \sum_{t=1}^{t=T} \left[\pi_E(t) - C_{INC}(i) \right] Re(i,t) \tag{5.2}$$

where $Re(i,t)$ represents the reserve provided by unit *i* at hour *t*. $C_{INC}(i)$ is the incremental cost of unit *i*. $C_{OPP}(i,t)$ indicates the opportunity cost of unit *i* at hour *t*. $S_{DA\_R}(i)$ represents the revenue of unit *i* obtained from providing reserve in the day-ahead market.

- **Cost for generator *i*:**

$$C_{DA}(i) = \sum_{t=1}^{t=T} C_{INC}(i) P(i,t) \tag{5.3}$$

where $C_{INC}(i)$ is the incremental cost of unit *i*. $C_{DA}(i)$ is the total cost of unit *i* in the day-ahead market.

- **Profit for generator *i* in the day-ahead market:**

$$\Omega_{DA}(i) = S_{DA\_E}(i) + S_{DA\_R}(i) - C_{DA}(i) \tag{5.4}$$

where $\Omega_{\mathrm{DA}}(i)$ represents the profit of unit *i* in the day-ahead market.

After the day-ahead market is cleared, the scheduled wind power is known. It is obtained by the forecasted wind generation minus the wind being curtailed. Mathematically, the scheduled wind power at hour *t* in the day-ahead market is expressed as follows:

$$W_{DA}(t) = W_f(t) - W_c(t) \qquad \forall t \in T \tag{5.5}$$

where $W_{DA}(t)$ represents the scheduled wind generation output at hour *t* in the day-ahead market. $W_f(t)$ and $W_C(t)$ indicate the forecasted wind generation output and the wind curtailment at hour *t* in the day-ahead market, respectively.

The scheduled wind power will be used to determine the imbalance to be compensated in the real-time balancing market.

5.2.2 Real-time Balancing Market

Real-time balancing market is usually operated by the system operator because it is critical for keeping the balance between load and generation and ensuring the reliability of the whole system. Here, it is assumed that the imbalances to be levelled out in the real-time balancing market are caused by the aggregated errors of wind and demand forecast, while the imbalances caused by conventional generation are not considered. The deviation between the volumes traded in the day-ahead market and delivered in the real-time balancing market is calculated by the following equation:

$$\begin{aligned} Deviation(t) &= \left[D_{RT}(t) - D_{DA}(t)\right] - \left[W_{RT}(t) - W_{DA}(t)\right] \\ &= \left[D_{RT}(t) - W_{RT}(t)\right] - \left[D_{DA}(t) - W_{DA}(t)\right] \end{aligned} \tag{5.6}$$

where $D_{RT}(t)$ and $W_{RT}(t)$ are the actual demand and wind power in the real-time balancing market. $D_{\mathrm{DA}}(t)$ represents the forecasted demand in the day-ahead market. The method used to obtain these data has been introduced in

Chapter 3. $W_{\mathrm{DA}}(t)$ is the scheduled wind power in the day-ahead market, which is calculated by (5.5). In essence, the imbalance to be compensated is the deviation between the forecasted net demand in the day-ahead market and the realised net demand in the real-time balancing market.

If $Deviation(t)$ is positive, the realised net demand is larger than the forecasted net demand in the day-ahead market. Upward regulation is activated to compensate the underestimate of the net demand. Instead, if $Deviation(t)$ is negative, downward regulation is activated to compensate the overestimate of the net demand. All generators that provide regulation services in the real-time balancing market need to offer their bids in a price/quantity format.

Price of bids: It is assumed that the real-time balancing market is perfectly competitive and thus the bidding prices for up- and down- regulation are also based on their real incremental costs. For example, if the incremental cost for generator *i* is 10\$/MWh, it will bid 10\$/MWh for up-regulation and -10\$/MWh for down-regulation. Here, the positive bid for up-regulation $B_{up}(i)$ means that generator *i* would like to increase its output for 10\$/MWh. And the negative bid for down-regulation $B_{down}(i)$ means that generator *i* would like to pay 10\$ for reducing 1MWh of its production.

Quantity of bids: The quantities of their bids are associated with their day-ahead agreement. For each generator *i*, the quantity of its bid for up-regulation $r_{up}(i,t)$ and down-regulation $r_{down}(i,t)$ are constrained by the following equations, respectively:

$$
\begin{aligned}
r_{up}(i,t) &\le R_{up}^{MAX}(i,t) = \min\left\{P_{\max}(i) - P(i,t),\ Ramp_{up}(i)\Delta t\right\} \\
r_{down}(i,t) &\le R_{down}^{MAX}(i,t) = \min\left\{P(i,t) - P_{\min}(i), Ramp_{down}(i)\Delta t\right\} \qquad (5.7) \\
&\forall i \in A, t \in T
\end{aligned}
$$

where $P(i,t)$ is the scheduled output of generator i at hour t in the day-ahead market. $R_{up}^{MAX}(i,t)$ and $R_{down}^{MAX}(i,t)$ show the upper limit of generator i to bid for up/down regulation at hour t in the real-time balancing market.

Once up-regulating power is needed ($Deviation(t)$ is positive), up bids $r_{up}(i,t)$ are stacked up in ascending order of the prices $B_{up}(i)$ until the up-regulation requirement is satisfied. Mathematically, this process can be realised by the objective function (5.8) and the regulation balance constraint (5.9):

$$\min \sum_{i=1}^{I} r_{up}(i,t) B_{up}(i) \tag{5.8}$$

$$\sum_{i=1}^{I} r_{up}(i,t) = Deviation(t) \tag{5.9}$$

While downward regulation is called ($Deviation(t)$ is negative), generators provide down regulation by reducing their scheduled generation output in the day-ahead market. Down bids $r_{down}(i,t)$ are stacked up in ascending order of the prices $B_{down}(i)$ until the down-regulation requirement is satisfied. Mathematically, this process can be realised by the objective function (6.10) and the regulation balance constraint (6.11):

$$\min \sum_{i=1}^{I} r_{down}(i,t) B_{down}(i) \tag{5.10}$$

$$\sum_{i=1}^{I} r_{down}(i,t) = \left| Deviation(t) \right| \tag{5.11}$$

The real-time balancing market is assumed to be cleared in an hourly basis. The clearing price is determined by the last accepted MWh of regulation. These rules are similar to the ones used in the Nordic balancing market [108].

In the real-time balancing market, generators can obtain profit by selling their spare generation capacity or by reducing their output to provide downward regulation. The profit is calculated by the following equations:

- **Revenue from up-regulation for generator *i*:**

$$S_{RT\_up}(i) = \sum_{t=1}^{t=T} \pi_{up}(t) R_{up}(i,t) \tag{5.12}$$

where $\pi_{up}(t)$ is the clearing price of up-regulation at hour *t* in the real-time balancing market. $R_{up}(i,t)$ indicates the up-regulation provided by generator *i* at hour *t*. $S_{RT\_up}(i)$ is the revenue of generator *i* obtained from providing up-regulation.

- **Cost for providing up-regulation for generator *i*:**

$$C_{RT\_up}(i) = \sum_{t=1}^{t=T} C_{INC}(i) R_{up}(i,t) \tag{5.13}$$

where $C_{INC}(i)$ is the incremental cost of generator *i*. $C_{RT\_up}(i)$ is the cost of generator *i* for providing up-regulation.

- **Profit from providing up-regulation for generator *i*:**

$$\Omega_{RT\_up}(i) = S_{RT\_up}(i) - C_{RT\_up}(i) \tag{5.14}$$

where $\Omega_{RT\_up}(i)$ represents the profit of generator *i* obtained from providing up-regulation.

- **Revenue from down-regulation for generator *i*:**

$$S_{RT\_down}\left(i\right)=\sum_{t=1}^{t=\mathrm{T}}C_{INC}\left(t\right)R_{down}\left(i,t\right) \tag{5.15}$$

where $S_{RT\_down}\left(i\right)$ is the revenue of generator *i* from providing down-regulation. $R_{down}\left(i,t\right)$ indicates the down-regulation provided by generator *i* at hour *t*. Generators reduce their output to provide down-regulation, so revenue can be obtained by saving the corresponding operational cost.

- **Cost for providing down-regulation for generator *i*:**

$$C_{RT\_down}\left(i\right)=\sum_{t=1}^{t=T}\pi_{down}\left(t\right)R_{down}\left(i,t\right) \tag{5.16}$$

where $\pi_{down}\left(t\right)$ is the clearing price of down-regulation at hour *t* in the real-time balancing market. $C_{RT\_down}\left(i\right)$ is the cost of generator *i* for providing down-regulation.

- **Profit from providing down-regulation for generator *i*:**

$$\Omega_{RT\_down}\left(i\right)=S_{RT\_down}\left(i\right)-C_{RT\_down}\left(i\right) \tag{5.17}$$

where $\Omega_{RT\_down}\left(i\right)$ represents the profit of generator *i* obtained from providing down-regulation.

- **Profit for generation *i* in real-time balancing market:**

$$\Omega_{RT}\left(i\right)=\Omega_{RT\_up}\left(i\right)+\Omega_{RT\_down}\left(i\right) \tag{5.18}$$

$\Omega_{RT}\left(i\right)$ is the profit that generator *i* obtains in the real-time balancing market, from providing upward and downward regulation.

5.2.3 Rolling-clearing of the Electricity Market

Until now, we have introduced the structure of the traditional market model (involving day-ahead market and real-time balancing market) and the settlement mechanism in each of the markets. In this Section, an alternative market design, named 'rolling clearing', is introduced to evaluate the effects of flexible market designs on the profitability of flexibility.

Given the fact that wind forecast is usually updated several times a day and the accuracy of wind forecast increases with shorter lead times, the use of frequently updated wind forecast can reduce the uncertainty that systems have to cope with, thus reducing the requirement for additional reserve. The 'rolling clearing' market design aims at using these features to facilitate the deployment of flexibility.

The use of rolling clearing in the systems with wind penetration has been originally proposed in [65], and has also been applied in [77, 109]. The underlying principle of rolling-clearing is that instead of carrying out the commitment once a day (for example day-ahead) the commitment is carried out more frequently. Take the example presented in Figure 5.1, where a 6-hour rolling commitment is shown. The first commitment is performed, then the system is 'rolled' forward 6 hours and the stochastic parameters such as wind and demand forecasts are updated. As the wind and demand forecast update emerges, the system operator re-schedules the thermal generation. Then the day-ahead and real-time balancing markets will be re-cleared with the latest information.

The advantages of this design include:

- Wind forecast is updated every 6 hours and the day-ahead market will be cleared 4 times per day. Therefore, the impact of wind forecast errors on the reserve requirement in the day-ahead market is reduced.

- The balancing market clears the differences between the latest forecasted and the realised net demand, and therefore the requirement for regulation power in the real-time balancing market is reduced.

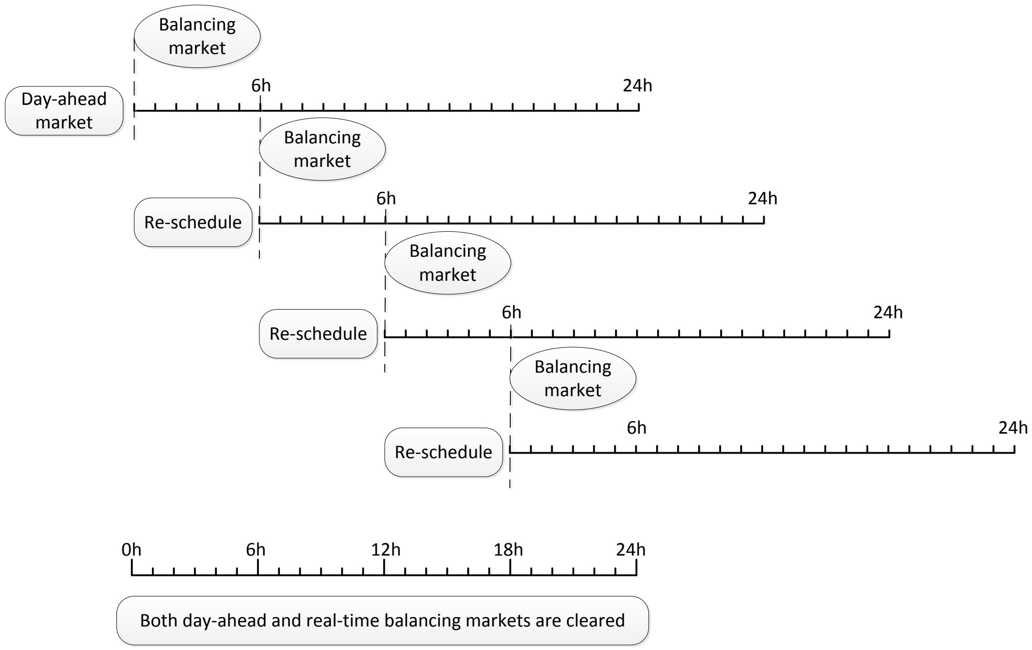


Figure 5.1: Rolling-clearing of Day-ahead and Balancing Markets with Updated Wind Forecast Every 6 Hours

Since a flexible market design reduces the requirement for technical flexibility, the profit that is made by providing flexibility will also be influenced. This will be discussed in Section 5.4.7 using a numerical test case.

5.3 Approach for Evaluating the Profitability of System Flexibility

In Section 5.2.1 and Section 5.2.2, it has been introduced the basic market model involving day-ahead and real-time balancing markets. Based on this market model, it will be now introduced how to evaluate the profit of system flexibility.

To the best of our knowledge, no mechanism has yet been proposed to calculate the additional profit that can be obtained from providing flexibility to accommodate wind generation. In this work, a method to evaluate the profit of system flexibility for balancing wind is proposed. Herein, for the sake of simplicity, the term '*profit of system flexibility for balancing wind*' is simplified as '*the profit of flexibility'*.

In the market environment, thermal generators get profit from providing energy and reserve, which includes the energy and reserve traded in the day-ahead market and the regulation traded in the real-time balancing market. Flexibility describes the ability of the thermal generators to provide energy and reserve in a more variable and swifter manner. In essence, the profit of flexibility can be regarded as an additional reward for the conventional generators that can provide energy and reserve more frequently and more quickly to cope with high wind penetration. Therefore, the profit of flexibility is implicitly included in the overall profit that thermal generators obtain from providing energy and reserve. Here, the overall profit includes the profit that all the thermal generators obtain from both day-ahead and real-time balancing markets. In Section 5.2.1 and Section 5.2.2, it has been introduced how to calculate the profit of generator i in the day-ahead market $\Omega_{DA}(i)$ and in the real-time balancing market $\Omega_{RT}(i)$. The overall profits for all the conventional generators in these two markets are calculated by the following formulations, respectively:

$$\Omega_{DA} = \sum_{i=1}^{I} \Omega_{DA}(i) \tag{5.19}$$

$$\Omega_{RT} = \sum_{i=1}^{I} \Omega_{RT}(i) \tag{5.20}$$

To properly evaluate the profit of flexibility, it is required to separate it from the overall profit. This is achieved by introducing the normalised profit (\$/MWh) over the total energy produced by conventional generators.

$\overline{\Omega}$ represents the ***normalised profit*** of the thermal system, which is the 'average profit' per MWh obtained from selling energy and reserve. It is calculated by dividing the overall profits from day-ahead and balancing markets by the algebraic sum of the energy it traded in these markets, as shown in the following equation:

$$\overline{\Omega} = \frac{\Omega_{DA} + \Omega_{RT}}{\sum P + \sum Re_{up} - \sum Re_{down}} \tag{5.21}$$

where $\sum P$ is the total energy traded in the day-ahead market. $\sum Re_{up}$ and $\sum Re_{down}$ are the total up- and down-regulation deployed in the real-time balancing market.

Comparing the normalised profits in the two situations (with and without wind), the difference between them shows the additional profit obtained from providing flexibility for balancing purpose. This difference is defined as the ***normalised profit of flexibility for balancing purpose***. Mathematically, it can be expressed by the following equation:

$$\overline{\Omega}_{flex} = \overline{\Omega}_{with\_wind} - \overline{\Omega}_{no\_wind} \tag{5.22}$$

For convenience, the term '***normalised profit of flexibility for balancing purpose***' that corresponds to $\overline{\Omega}_{flex}$, is herein simplified as '**NPF**'.

In the next Section, some test cases are performed to discuss how the NPF evolves with increasing levels of wind penetration and how it is affected by different factors and flexible market designs.

5.4 Test Cases

Test cases are conducted based on the IEEE RTS 26 thermal-unit system [102]. Wind and demand profiles are the same as used in Chapter 3, which are obtained from [35]. Average load factor is around 67%, and aggregated wind generator capacity factor is 33%. Annual peak load is 2500MW for the test cases.

First, the impact of flexibility requirement on the day-ahead (DA) market clearing price is analysed. This will be followed by the discussion of NPF under different wind penetrations. Effects of different factors on the profit of flexibility will be shown next. Finally, effects of a flexible market design will be explored.

5.4.1 Impacts of Flexibility Requirement on the Market Clearing Price

The simulations based on the market model are conducted at different levels of wind penetration (0, 10, 20, 30, 40, 50% of total annual demand) for the period of a year. The day-ahead market price duration curves under different wind penetration levels are depicted in Figure 5.2.

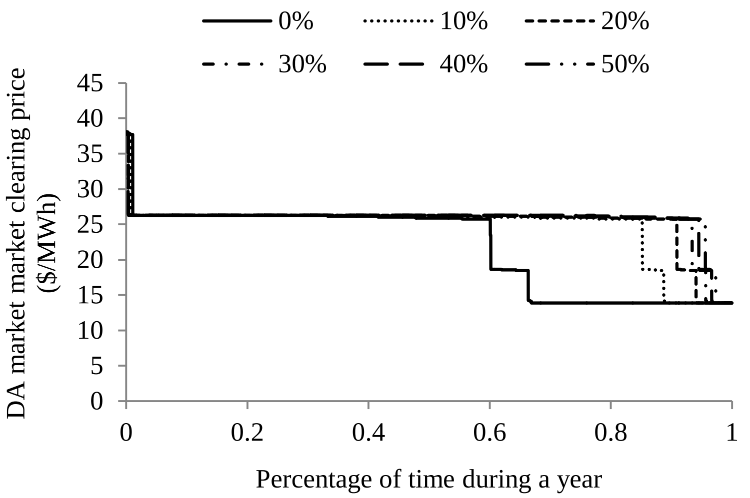


Figure 5.2: Price Duration Curve for Day-ahead Market Considering Different Levels of Wind Penetration

It is seen that the price duration curve shifts to the right as wind penetration increases, indicating that the occurrence of higher market clearing prices is increasing. Here it has to clarify the difference between this result and the result shown in Figure 3.7 (P93). In Figure 3.7, with 10% wind penetration, the number of start-ups in high flexible generators is reduced compared with no wind situation. However, in Figure 5.2, with 10% wind penetration, high flexible generator with high operational cost becomes marginal unit more frequently than in the situation without wind. This is because in the former case, the annual peak load (12GW) is relatively small compared with total conventional capacity (15GW), so the lower flexible unit can provide some amount of flexibility with their idle generation when the flexibility requirement is low (10% wind penetration). However, in the latter case, the annual peak load (2500MW) is relatively large compared with total conventional capacity (3105MW). So the low flexible units are mainly used to serve the base load and leave all the flexibility services to the high flexible units.

If wind is constant and perfectly predicable, it would simply depress the market-clearing price in most time periods since it would replace generation from thermal generation. However, the variability and uncertainty of wind generation modify the impact on market prices. There is no linear relation between the introduction of 'free' wind energy and the consequent drop in electricity and market prices. The additional flexibility required to accommodate wind generation comes at a cost and this is reflected in the market by increasing the market-clearing price. The drivers for this are:

- The variability of wind generation increases the need for fast ramping and swift switching units.
- More reserve is required, and it has to be deployed more quickly. As well, such reserve can only be provided by those flexible units with larger 'deployable capacity'.
- Since the generation output of conventional generators is reduced with wind integration, it is closer to the minimum stable generation (MSG) and therefore the deployable space to provide downward reserve is squeezed out. To satisfy the requirement of larger downward reserve, units with lower MSG have to be used.

To meet the requirements mentioned above, more flexible units (with fast ramping rate, low minimum up/down time and low MSG), which are typically more expensive, are dispatched more frequently, thus increasing the occurrence of higher market clearing prices.

It can be seen in Figure 5.2 that there are small fractions of the price duration curves exceeding 26$/MWh. These correspond to the periods when U20 (with the highest marginal price at 37.7$/MWh) becomes the marginal unit. Figure 5.3 amplifies this part to make it clearer.

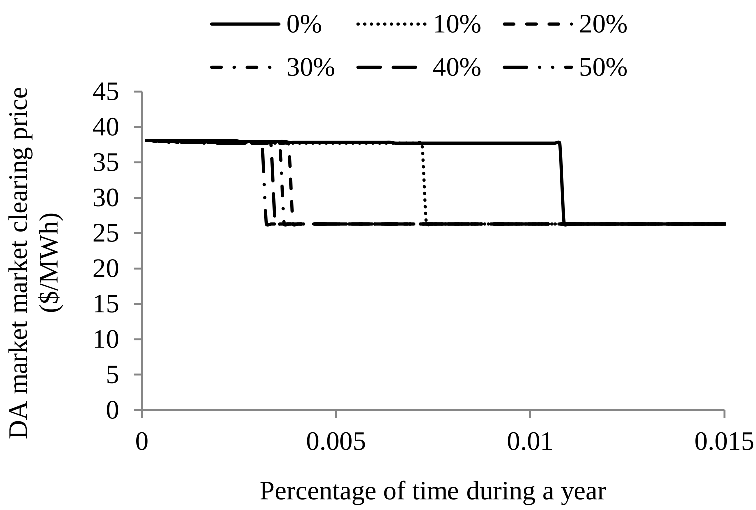


Figure 5.3: Zoom in of the Highest Price Area in the Duration Curve of Figure 5.2

It is seen that contrary to the general trend of the price duration curves, this small part of price duration curve shifts to the left as wind penetration increases, which means that the possibilities of U20 becoming marginal unit are reduced in this process. This is because U20 is quite special in this system. Although it is very inflexible (with high MSG), it is most expensive in the system. It is only dispatched when the net demand is extremely high. As the wind penetration increases, the net demand is reduced so U20 is less likely to be scheduled.

As a conclusion, wind penetration has brought two aspects of impacts on the day-ahead market:

- ***Expensive flexible generators*** have to be deployed more frequently to handle the variability and uncertainty of wind generation.
- Generation from ***expensive inflexible generators*** is reduced.

5.4.2 Aggregated NPF for the Whole System

Figure 5.4 shows the normalised profit for the IEEE 26 thermal-unit system [102]. The horizontal axis shows the potential wind energy in percentage of the annual energy demand. Potential wind energy refers to the gross generation output from the total installed wind capacity in the system. The normalised profit is shown on the left vertical axis. The right vertical axis indicates the wind generation that can be actually utilised to serve the load. Here it is called 'utilised wind generation' to distinguish from the potential wind generation.

The black columns show the normalised profit in the base case without wind generation (0%). The grey columns show the NPF for balancing wind compared to the case without wind generation. The black curve shows the proportion of gross demand that is served by wind generation (actual wind penetration).

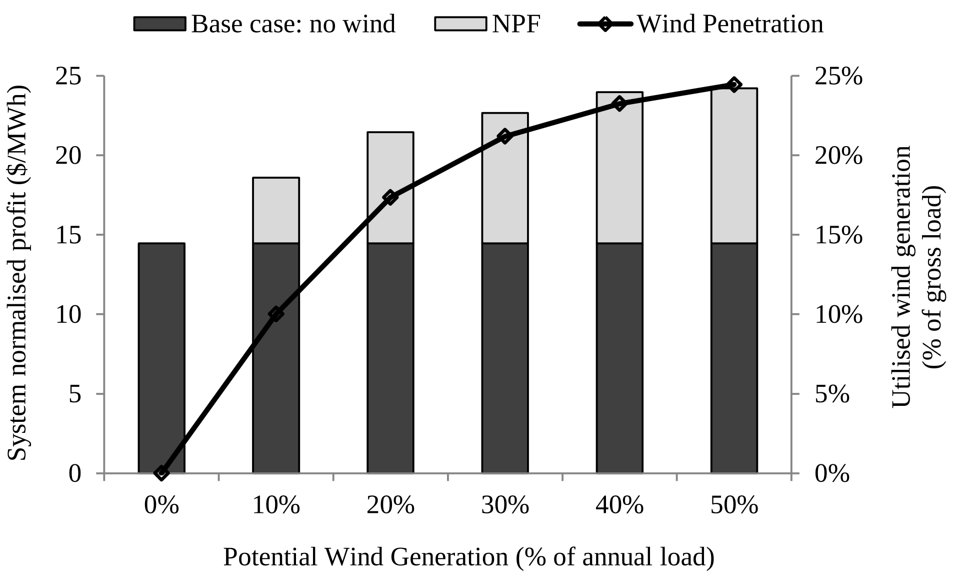


Figure 5.4: Normalised Profit of IEEE RTS 26-unit System and NPF ($\overline{\Omega}_{flex}$)

Two conclusions are drawn from the results shown in Figure 5.4:

- The NPF rises as the wind penetration increases. This shows that the payment based on uniform market clearing price is able to reflect the remuneration of the contribution of flexibility.

- The increase of the normalised profit slows down with larger penetration of wind until it finally stops as the wind capacity reaches a certain limit. This is because the system flexibility is exhausted and no more wind generation can be accommodated.

The difference between the potential wind generation and the utilised wind generation is the part that has to be curtailed because of the limitation of flexibility. The comparisons between the potential wind generation and the utilised wind generation are presented in Table 5.1, and the corresponding wind utilisation factors[15] are calculated.

Table 5.1 Comparison between Utilised Wind Generation and Potential wind Generation

Installed wind capacity (MW)	**Potential wind generation (% of gross annual demand)**	**Utilised wind generation (% of annual demand)**	**Wind utilisation factor (%)**
500	10%	10.0%	100%
1000	***20%***	***17.4%***	***87%***
1500	***30%***	***21.2%***	***71%***
2000	40%	23.3%	58%
2500	50%	24.4%	49%

For a low penetration of wind generation (10%), the potential wind generation can be fully accommodated in the system. By increasing the wind installed capacity, the potential wind generation is increased accordingly, but it is getting more difficult for the power system to accommodate this generation adequately. It is seen that since potential wind generation reaches 30%, a large increase of potential wind generation (from 30% to 50%) can only result in a small increase of utilised wind generation (from 21.2% to 24.4%).

[15] Wind utilisation factor is defined in this thesis as the proportion of the utilised wind generation in the total potential wind generation. It is equal to 1 minus the percentage of wind curtailment (% of total potential wind generation).

The wind utilisation factor drops from 100% to 49% when the installed wind capacity increases from 500 to 2500MW. It is seen that in order to guarantee a high wind utilisation factor at 80%, the maximum wind installed capacity should be in between 1000 and 1500 (as highlighted in bold italics). In Section 4.4.1, when using the planning model to estimate the maximum allowable wind installed capacity in the same system (IEEE RTS 26-unit system) with the same wind utilisation factor (80%), it was found that the maximum allowable capacity is 1180MW. The consistency between these two results confirms again the validity of the planning model.

In the context of this thesis, large volumes of wind capacity bring two impacts to the system:

- It reduces the generation output of conventional generators;
- It brings more variability and uncertainty.

Consequently, wind penetration increases the available flexibility of the conventional system by increasing the deployable space in the units. Simultaneously, wind increases the requirement for flexibility by introducing more variability and uncertainty. The balance between these two aspects will define the net change in terms of flexibility. The balance can, to some extent, be reflected by the NPF. If the increase of the flexibility requirement exceeds the increase of the available flexibility, the NPF becomes positive. Otherwise, it is negative.

The relationship between the increase of the available flexibility and the increase of the flexibility requirement is illustrated in Figure 5.5.

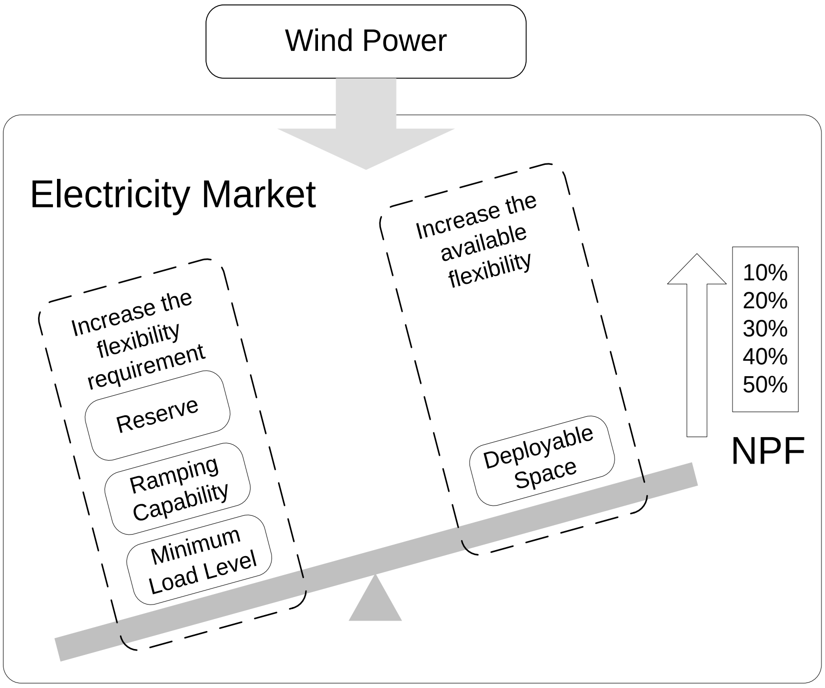


Figure 5.5: Relationship between the Increase of Available Flexibility and the Increase of Flexibility Requirement and the Associated NPF

For the case study performed (results presented in Figure 5.4) it is found that the flexibility for balancing wind always makes a positive profit (NPF>0) under different wind penetration levels (10, 20, 30, 40, 50%). This implies that for all the considered scenarios, the increase of the flexibility requirement is higher than the increment of the available flexibility. As shown in Figure 5.5, the left side of the balance is always heavier than the right side.

The increase of the NPF is maintained until the upper limit of the inherent flexibility of the conventional system is reached. This means that the capability for accommodating wind generation is saturated since all the available flexibility is exhausted, and more investment in flexible generating units is required to accommodate further wind capacity.

As discussed in Section 2.6, reserve capacity, ramping capability, and minimum load level (MLL) in a power system are the three main aspects that determine its inherent flexibility. In the following cases, we will analyse their respective impacts on the NPF of the system. By removing or reducing the flexibility requirement associated with each of them (eliminating the corresponding block on the left side of the balance in Figure 5.5), and comparing the results with the original case where all the three aspects are considered (Figure 5.4), their respective impacts on the NPF will be shown.

5.4.3 Effect of the Uncertainty of Wind Generation on the NPF

Wind forecast error is the key driver for the need of additional flexibility due to its impact on the reserve requirement. In order to analyse the impacts of forecast error on the NPF, wind is assumed to be perfectly predictable therefore no additional reserve is needed.

Simulations are broken down into different levels of wind penetration, from 10% to 50% of annual demand. The NPF is calculated for each scenario and the results obtained are shown in Figure 5.6. The NPF for the test case introduced in Section 5.4.2 is used here as the base case for comparison (as results shown in Figure 5.4), as shown in the black columns. The base case takes into account the additional reserve for wind forecast error, the variability of wind generation and the minimum load level of the conventional system. Grey columns represent the NPF under the scenario with perfect wind forecast.

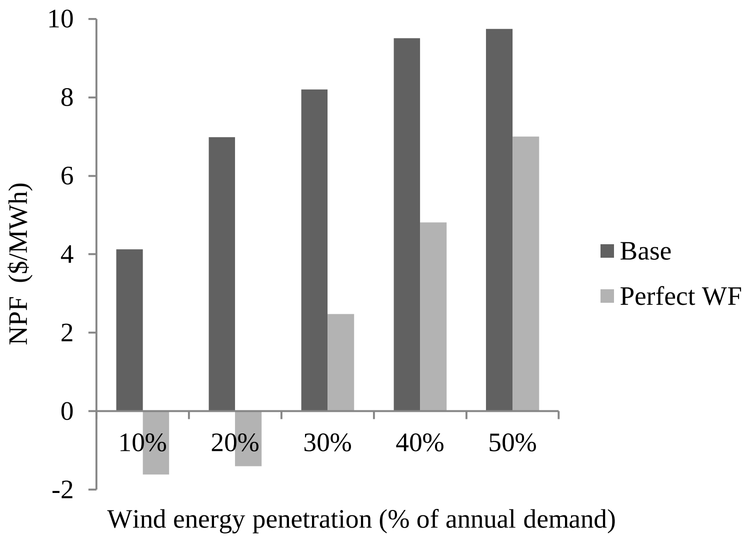


Figure 5.6: The NPF in the Base Case and in the Case with Perfect Wind Forecast

In the lower wind energy penetration levels, 10% and 20%, NPF under perfect wind forecast are found to be negative. It means that the increase in the available flexibility is larger than the increase in the flexibility requirement, as shown in Figure 5.7. Since perfect wind forecast is considered, there is no need to provide additional reserve for wind forecast error, and the block for 'reserve' is removed from the left side of the balance. Such movement results in the reduction of the weight on the left side, and the balance sways to the right hand side.

When the wind penetration level increases to 30%, 40% and 50%, the NPF is positive. This is because the flexibility requirement associated with ramping capability and MLL rises, and the balance sways back to the left hand side, as shown by the dotted line in Figure 5.7.

It is seen from Figure 5.6 that the NPF under perfect wind forecast is always much lower than in the base case where wind forecast error is considered. Therefore, the accuracy of wind forecast significantly influences the NPF. However, the extent to which it can affect the NPF is still determined by the net balance between the increase of the flexibility requirement and the increase of the available flexibility as wind generation is introduced.

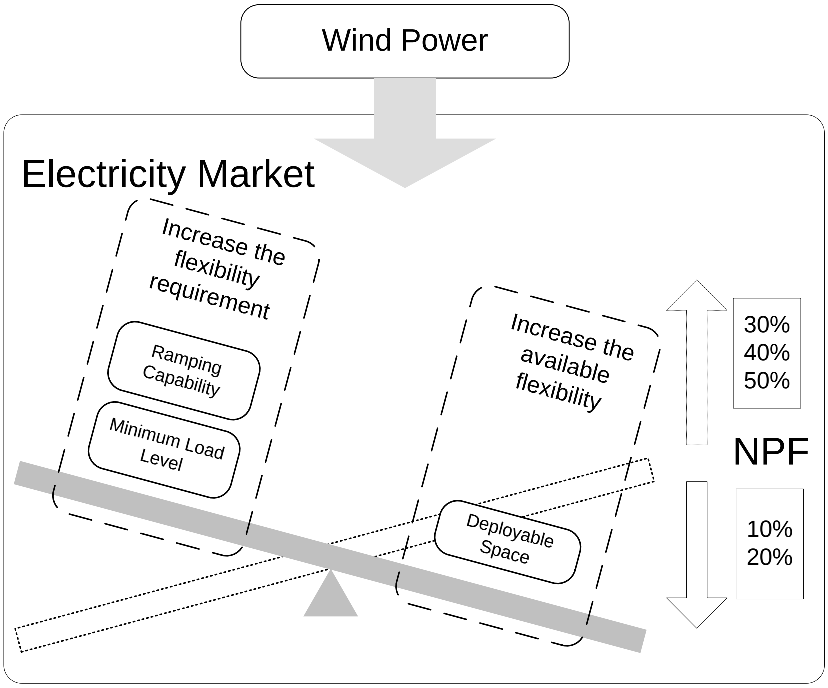


Figure 5.7: The Increase in the Flexibility Requirement and the Available Flexibility under Perfect Wind Forecast

5.4.4 Effect of the Variability of Wind Generation on the NPF

To evaluate the effect of the variability of wind generation, the ‘flat wind’, which corresponds to the same annual wind generation as the variable wind generation, is used to perform the simulation.

The results of the NPF for the base case and the case with ‘flat wind’ are shown in Figure 5.8.

Theoretically, a reduction in the variability would also reduce the NPF comparing with the base case. This is because the block for ‘ramping capability’ is removed from the left side of the balance. As expected, the results in the lower wind energy penetration levels (10% and 20%) show that the NPF is reduced compared with the base case.

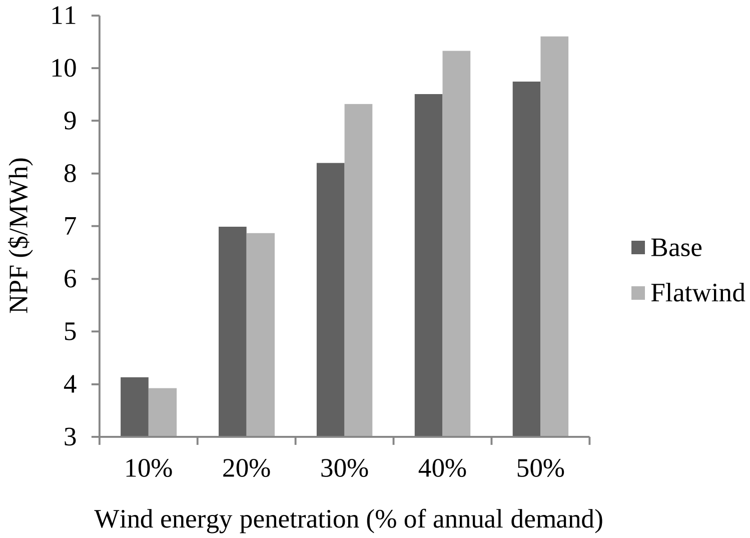


Figure 5.8: The NPF in the Base Case and in the Case with 'Flat Wind'

However, situation changes when the wind penetration is increased. This is attributed to the impacts of 'flat wind' on the minimum load level (MLL). In essence, the 'flat wind' shows the average value of the variable wind generation, so it is smaller than the actual wind generation in high wind periods while is larger than the actual wind generation in low wind periods. The 'boost' effect of the wind generation in low wind periods will result in a further reduction in net demand comparing with the same periods in the base case where the actual variable wind generation is considered. Since this reduction squeezes out the downward deployable space of conventional units, more flexible units with lower minimum stable generation (MSG) are required to start up to provide sufficient down reserve. As the wind penetration level increases, this effect becomes more severe and overwhelms the benefit that obtained from the reduction of the variability. Therefore, with large wind penetrations, 30%, 40%, and 50%, the NPF is larger than in the base case.

5.4.5 Effect of the Minimum Load Level (MLL) on the NPF

When wind integration squeezes the conventional generation, more flexible units with lower minimum stable generation (MSG) have to be operated in order to provide enough downward reserve. Therefore, not considering the downward reserve constraint essentially relaxes the requirement for minimum load level (MLL) of the system. Such movement does not mean that all the requirement for MLL is ignored. The MLL is still required to provide enough security or voltage support in the system. In Figure 5.9, the results for the case without considering downward reserve constraint are compared with the base case.

It is seen that without considering the downward reserve constraint, the NPF becomes smaller in all the wind integration levels due to the relaxation of the MLL requirement. This reduction is relatively small since the reduction in flexibility requirement associated with MLL is quite small.

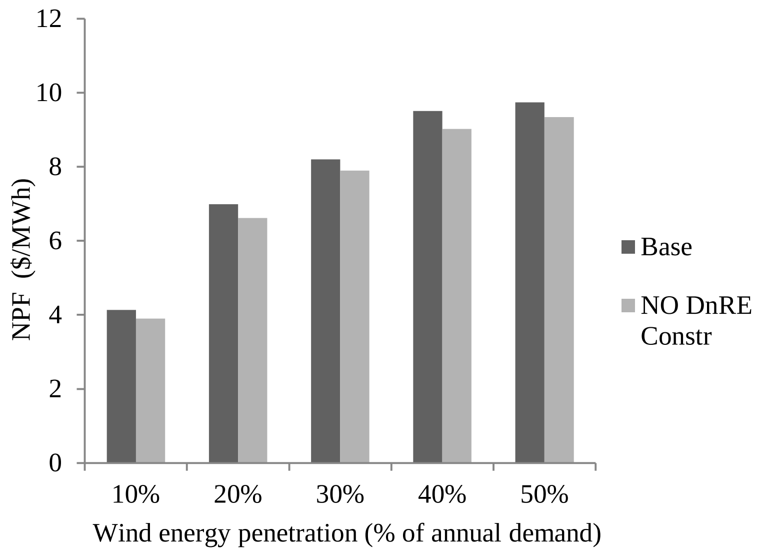


Figure 5.9: The NPF in the Base Case and in the Case without Considering the Downward Reserve Constraint

5.4.6 Joint Effect of Uncertainty and MLL on the NPF

The joint effects of uncertainty and MLL on the NPF are shown in the black columns in Figure 5.10. These are obtained by assuming a perfect wind forecast and removing the downward reserve constraint. Comparing them with the base case and the case with only perfect wind forecast, it shows that a further reduction in the flexibility requirement will cause a surplus in the available flexibility and ultimately result in a large drop in the NPF.

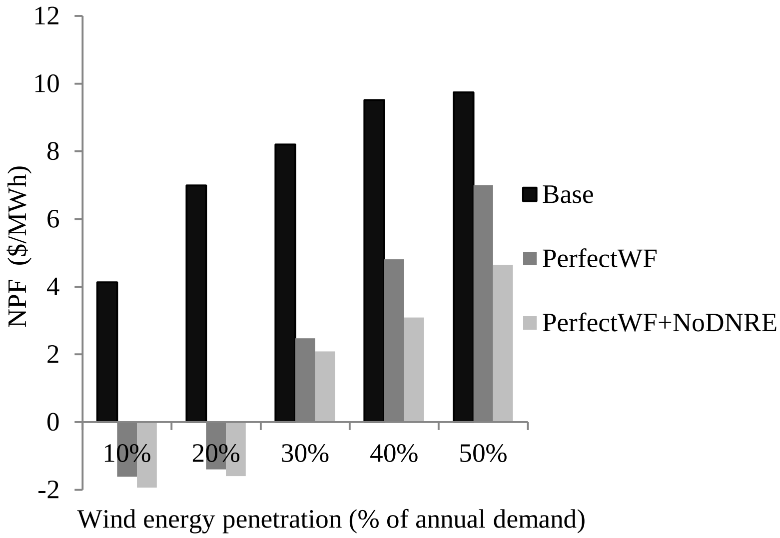


Figure 5.10: Joint Effect of Uncertainty and MLL on the NPF

5.4.7 Effect of the Rolling Clearing of Electricity Market on the NPF

For a market design where energy and reserve markets are cleared on a day-ahead basis, the system operator needs to procure reserve to cover for a 24h wind forecast uncertainty. An alternative to this is to use the rolling market clearing introduced in Section 5.2.3 so that the market is cleared more frequently and with more accurate wind forecasts. This affects the overall system cost and the profitability of flexibility. The difference between the two market designs is illustrated in Figure 5.11, in terms of the NPF achieved with a forecasting and scheduling horizon of 24 hours, and a rolling 6-hour market clearing. From the results it is possible to see that improving the market design, by using ‘rolling clearing’, reduces the overall profitability from flexibility. This result indicates that the value of the flexibility is driven not only by the physical flexibility of the generation mix but also by the design of the markets where this flexibility is traded. A more efficient market design is one that reduces the exposure to wind uncertainty, which in turn reduces the requirement for physical flexibility. Therefore, an efficient market design can be regarded as a non-technical source of flexibility.

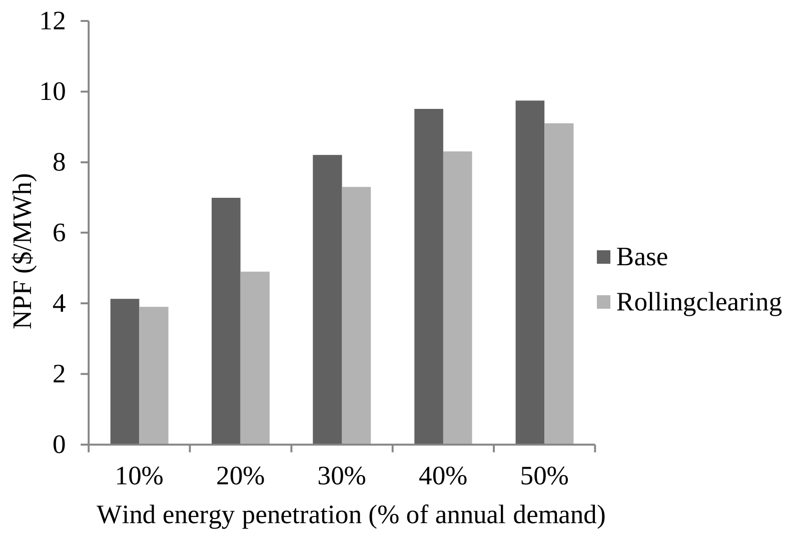


Figure 5.11: The Effects of Rolling Clearing on the NPF

5.5 Chapter Conclusions

In this Chapter, a market model that allows the study on the profit of flexibility is introduced. The market model takes into account the day-ahead market and the real-time balancing market, and additionally the rolling clearing of the market. It represents a typical market design with uniform clearing price payment scheme. The program established on the model can not only be used to analyse the profit of flexibility but may also facilitate the future work relevant to the performance of flexibility in the market environment.

Based on this market model, it is proposed an approach to evaluate the profitability of system flexibility. The normalised system profits are calculated under the two situations: with and without wind generation. The difference between the two defines the profit of flexibility and is designated as the NPF. It is found that this profit rises as the wind penetration increases until the wind integration is saturated due to the exhaustion of flexibility. Therefore, tracking the evolution of this profitability, as a function of the wind penetration, provides a means to determine when additional investment in flexibility would be desirable.

Furthermore, it analyses the effect of different factors on the profit of flexibility (NPF): wind forecast error, wind variability and minimum load level (MLL). Through these sensitivity analyses, it is concluded that the wind integration increases the available flexibility while at the same time increases the flexibility requirement. The profit of flexibility is used to reflect the trade-off between the two. If the increase of the flexibility requirement overwhelms the increase of the available flexibility, the NPF is positive, which means the system flexibility gains extra profit from balancing wind. Otherwise, the NPF is negative.

The effect of market design on the flexibility requirements is demonstrated by introducing the ‘rolling market clearing’. It is shown that such a market improves the use of existing technical flexibility and reduces the need for investments in additional flexibility resources. This has shown that the market design can be seen as a non-technical source of flexibility.

CHAPTER 6

FLEXIBILITY INDICES

6.1 Introduction

The quantification of flexibility is an emerging and important topic. Much effort has recently been dedicated to quantify the flexibility of power systems. Most techniques proposed are based on multi-temporal simulation of power system operation [29-31, 110]. Being clear that a detailed analysis of flexibility requires such a simulation, it is also interesting to explore 'offline' evaluation metrics capable of providing estimations of 'how flexible a system is' and as a result directly comparing the technical flexibility of different systems and generators. To this end, quantitative metrics, which can be used 'offline' to assess the level of system flexibility and the contribution of individual generator on the aggregated flexibility is highly desirable.

This thesis presents two alternative metrics/indices to evaluate the flexibility of individual generators and the aggregated system flexibility, without performing time consuming multi-temporal simulations.

The first metric/index is named 'normalised flexibility index' (NFI) and it is used to identify the flexibility level of individual generating unit and to give an estimation of its contribution to the whole system's flexibility. This index is developed based on the analysis of the deployable space of generating units, and the flexibility level of individual generators is expressed as a normalised positive number less than 1. The flexibility level of the whole system is calculated by the 'weighted sum' of the flexibility levels of individual generators in this system.

The second metric/index is called Loss of Wind Estimation (LOWE) and it represents the flexibility level of a system in terms of its ability to accommodate wind. A system with higher LOWE is less flexible than a system with lower

LOWE. The index is established based on the statistical analysis of net demand. It is defined as a joint probability of several features that are relevant to the flexibility requirement, and is expressed as percentage of time in a year.

A realistic generation system usually contains various types of units and even the units using the same fuels may have different technical parameters. The large number of units along with their specific characteristics makes it difficult to define their flexibility levels by the conventional method. The two indices presented in this work are able to assess the flexibility of individual units and the whole system via quick 'offline' calculations.

6.2 Normalised Flexibility Index (NFI)

The flexibility of a conventional generation mix describes its ability to follow the changes in net demand at different time scales. In this work, the changes in net demand are mostly defined by two aspects:

- variations in forecasted net demand between consecutive hours; and,
- difference between forecasted value and real delivered value

A flexible power system should have sufficient ramping capability to cope with the predicted variations in net demand and carry enough operating reserve to fulfil the gap between forecasted and actual net demand. These requirements are usually fulfilled by flexible generation, storage, and flexible demand (when available). In this work, given that our focus is on thermal generation flexibility, it is assumed that these requirements are met solely by thermal generation. Both part-loaded synchronized generators and quick start/shut down generators can be used to meet these requirements.

Part-loaded synchronized (PS) generators can provide upward load following and upward reserve, and their contribution is limited by their ramp-up rate and the spare capacity between their scheduled output and their maximum capacity. Likewise, their ramp-down rate and the difference between their scheduled output and their minimum stable generation (MSG) limit their ability to provide downward load following and downward reserve. Since the constraints for hourly load following and for upward reserve are similar, here we take the reserve constraints as an example. Mathematically, this can be summarised as follows:

$$\begin{aligned}
&r_{up}\left(i,t\right) \le \min\left\{P_{\max}\left(i\right) - p\left(i,t\right),\ Ramp_{up}\left(i\right)\cdot\Delta t\right\} \\
&r_{\mathrm{dn}}\left(i,t\right) \le \min\left\{p\left(i,t\right) - P_{\min}\left(i\right),\quad Ramp_{dn}\left(i\right)\cdot\Delta t\right\} \quad \forall i \in PS, \forall t \in T
\end{aligned} \tag{6.1}$$

Here, $r_{up}\left(i,t\right)$ and $r_{\mathrm{dn}}\left(i,t\right)$ are the up and down reserve that can be provided by conventional generator *i* at hour *t*. $P_{\max}\left(i\right)$ and $P_{\min}\left(i\right)$ are the maximum capacity and the minimum stable generation (MSG) of conventional generator *i*. $Ramp_{up}\left(i\right)$ and $Ramp_{dn}\left(i\right)$ indicate the ramping up and down rate of generator *i*, $p\left(i,t\right)$ describes the position of the output of generator *i* at hour *t*. Δt is the time available for generators to ramp up/down their output. To cope with the hourly variations in net demand, here Δt corresponds to 1 hour.

Generating units who can quick start/shut down (QS) within the required time scale, e.g. less than one hour, can also provide load following or up/down reserve. For example, their contribution to reserve is formulated as:

$$\begin{aligned}
&r_{up}\left(i,t\right) \le \min\left\{P_{\max}\left(i\right), Ramp_{up}\left(i\right)\cdot\Delta t\right\} \\
&r_{dn}\left(i,t\right) \le \min\left\{p(i,t),\quad Ramp_{dn}(i)\cdot\Delta t\right\} \quad \forall i \in QS, \forall t \in T
\end{aligned} \tag{6.2}$$

From (6.1) and (6.2) it is possible to see that the ramp rates and the difference between the MSG and the capacity of a plant are the parameters that define its capability of providing flexibility. Based on this, a flexibility index can be defined for each conventional generator *i*. To allow comparisons, this index needs to be normalised as follows to account for the variable sizes of the units:

$$flex(i) = \frac{\frac{1}{2}\left[P_{\max}(i) - P_{\min}(i)\right] + \frac{1}{2}\left[Ramp(i) \cdot \Delta t\right]}{P_{\max}(i)} \tag{6.3}$$

where $\frac{1}{2}\left[Ramp(i) \cdot \Delta t\right]$ is the average value of $Ramp_{up}(i) \cdot \Delta t$ and $Ramp_{dn}(i) \cdot \Delta t$, and thus indicates the speed at which a unit can adjust its output within $P_{\max}(i) - P_{\min}(i)$. Notice that for QS units, the $P_{\min}(i)$ is replaced by 0.

The flexibility index of a whole system A is then defined as the weighted sum of the flexibility indices $flex(i)$ of the individual generators. The weighting factors are taken as equal to the capacity contribution of each unit. The whole system flexibility is thus calculated by:

$$FLEX_A = \sum_{i \in A} \left[\frac{P_{\max}(i)}{\sum_{i \in A} P_{\max}(i)} \times flex(i) \right] \quad \forall i \in A \tag{6.4}$$

Although power system operation can be very complex and variable, this index is not affected by operational decisions. It thus provides a simple method to assess the technical ability of different power systems to provide flexibility.

6.3 Verification of the NFI

In this Section, the NFI is tested on IEEE RTS 26-unit system [102]. This system is chosen because of its diversity in unit types and available technical parameters. Using the method proposed in the previous Section, flexibility indices are calculated and the results are listed in Table 6.1. Letters in bold show the flexibility index for the whole system, and regular ones show flexibility index for each individual technology. With these indices, it is possible to compare the flexibility between different units and systems.

Table 6.1 Normalised Flexibility Index for the IEEE RTS 26-unit System

Name	NFI
26-unit system	**0.5352**
U12_Oil/Steam (1-5)	0.8000
U20_Oil/CT (6-9)	0.2100
U76_Coal/Steam (10-13)	0.7266
U100_Oil/Steam (14-16)	0.6875
U155_Coal/Steam (17-20)	0.5395
U197_Oil/Steam (21-23)	0.5204
U350_Coal/Steam (24)	0.4357
U400_Nuclear (25-26)	0.4691

The generation units in the power system can be categorised into two groups: flexible and non-flexible units. Whether a single generator is flexible or not is defined by comparing its individual NFI with the whole system's NFI. If the NFI of one specific unit is higher than the system's NFI, this unit is regarded as flexible in this system. Vice versa, non-flexible units are those with a flexibility index lower than the system level. For example, in this case, the 26-unit system has an index level of 0.5352. Thus, for this system, units U12, U76, U100, and U155 are flexible units, whereas U20, U197, U350 and U400 are non-flexible units. It is important to define the flexible and non-flexible units on a system-based criterion but not an isolated plant technical parameters criterion, because the contribution of the flexibility of a single unit changes from system to system. Take the example of CCGT, these are currently used to supply flexibility in a thermal based system like the UK system but not in a hydro dominated system like Norway.

Based on their flexibility index, these technologies are re-organised to form three new test systems: high flexible mix, medium flexible mix and low flexible mix. The high flexible mix consists of the most flexible types U12, U76, U100, and U155 with 9 units of each type. The medium flexible mix is made of mixed flexible types U12, U76, U350, and U20 with 7 units of each type. The low flexible mix contains the least flexible types U197, U400, U350 and U20 with 4 units of each type. These three groups of units are used to represent systems with different flexibility level. The number of units in each group is chosen so that these systems have comparable installed capacities.

The three generation mixes are compared using the same load (with annual peak load of 2200MW) and the same wind generation (with 880MW installed capacity). The wind generation utilisations in the three systems are used to verify whether the flexibility index can reflect the actual flexibility of the system in terms of its ability to accommodate the potential wind generation output.

The normalised annual load profile and wind profile are obtained from 2005 UK system to represent the realistic variations [35]. These two normalised profiles are respectively multiplied by the annual peak load of 2200MW and wind capacity of 880MW to create the input data. These data will be the input of a unit commitment model (introduced in Chapter 3) which is able to dispatch the thermal generation and wind generation with hourly resolution for the whole year. If the system is short of flexibility, some wind generation will be curtailed. The more wind generation can be integrated without being curtailed, the more flexible a system is, and therefore a higher flexibility index it should have. Therefore, by comparing the wind utilisation factors among different systems, it is possible to validate the flexibility index.

The test results are shown in Table 6.2.

Table 6.2 Wind Utilisation Results of Demonstration Systems with Different Flexibility Index

Generation Mix APL=2200MW Wind Capacity=880MW	**Total capacity (MW)**	**Flexibility Index**	**Wind Utilisation Factor**
High Flexible Mix 9*(U12+U76+U100+U155)	3087	0.6333	80.59%
Medium Flexible Mix 7*(U12+U76+U350+U20)	3206	0.4836	41.99%
Low Flexible Mix 4*(U197+U400+U350+U20)	3868	0.4621	10.67%
26units system (Mix of all type of units)	3105	0.5352	48.48%

As expected, the high flexible group with the highest index 0.6333 is able to utilise 80.59% of total potential wind generation and the medium flexible group with index 0.4836 is capable of absorbing 41.99% of total wind generation. The low flexible system with the lowest index 0.4621 is only able to handle 10.67% of wind generation which means most of the wind generation has to be curtailed.

Apart from the designated formed groups, from Table 6.2 it can be seen that the index is also valid in evaluating the flexible level of the 26-unit system. The system has an index of 0.5352 in between the highest and medium flexible mix. This is supported by its wind energy usage (48.48%) that is also in between those of the two groups (80.59% and 41.99%).

Besides the application in comparing flexibility levels of different systems, this flexibility index is capable of estimating the change of flexibility brought by a new investment in the original system. Investment of a new generator with higher flexibility index than the original system will enhance the flexibility level of the original system. On the other hand, a generator with lower flexibility index than the original system will depress the system flexibility level. The offline calculation of the flexibility index is very convenient to obtain an order of estimate of the contribution of new generators in flexibility without performing system operation simulations.

Although using the proposed NFI index is able to compare the flexibility levels of two different systems, it is not able to directly indicate the ability of a system to accommodate variable generation. This is because it only assesses the deployable space of conventional generation but does not capture the complexities of the power system in terms of characteristics of demand or variable generation. In this work, another index is also proposed, which captures the characteristics of the conventional generation, the demand and the wind, to directly evaluate the ability of a power system to accommodate wind generation.

6.4 Loss of Wind Estimation (LOWE)

Wind curtailment occurs whenever the system does not have sufficient flexibility to cope with the variability and uncertainty of wind generation and therefore it appears more frequent in a non-flexible system than in a flexible one. This provides another way of assessing the system flexibility, namely by the possibility of wind curtailment appearance.

In this Section an alternative index is proposed to provide an offline estimation of the system flexibility via the probability of having wind curtailment, and is named as Loss of Wind Estimation (LOWE). LOWE represents the estimated probability that wind curtailment occurs in a system during a year. It is a statistical measure of the likelihood of wind curtailment rather than a quantification of the amount of wind energy being curtailed. The LOWE intends to obtain an order of estimate of the capability of system in accommodating wind whilst avoiding system operation simulations.

Wind curtailment usually happens whenever the variation of net demand is beyond the flexibility capability of the system and this occurs most likely in the following situations[16]:

1) net demand is lower than the minimum load level (MLL) of the system;
2) net demand drops sharply and committed generators do not have sufficient ramp-down capability or cannot be shut down quickly enough; and
3) net demand increases sharply and committed generators do not have sufficient ramp-up capability and offline generators cannot be start up quickly enough.

It is assumed that the above three events are independent to each other, which means the occurrence of one event makes it neither more nor less probable that the other two occur. Considering that the probability of the occurrence of each event is $\mathrm{P}(\mathrm{V\_MLL})$, $\mathrm{P}(\mathrm{V\_Ramp\_up})$ and $\mathrm{P}(\mathrm{V\_Ramp\_dn})$, where the character 'V' means the corresponding constraint is violated, the probability that each

[16] In practice, wind curtailment occurs not only due to balancing issues but also due to network constraints (capacities of transmission corridors). Since network constraints are not considered in this work, here we only discuss the impacts of balancing issues on wind curtailment. However, the ideas proposed in this work can also be extended to other constraints that may affect the wind curtailment.

event does not happen is calculated by $1-\mathrm{P}(\mathrm{V\_MLL})$, $1-\mathrm{P}(\mathrm{V\_Ramp\_up})$, $1-\mathrm{P}(\mathrm{V\_Ramp\_dn})$, respectively. Therefore, the probability of the system in a situation where there is no wind curtailment is the ***joint probability***[17] [87] that none of these three events happens. Mathematically, it can be expressed as:

$$\mathrm{P}(\mathrm{NoWC}) = \left[1-\mathrm{P}(\mathrm{V\_MLL})\right] \times \left[1-\mathrm{P}(\mathrm{V\_Ramp\_up})\right] \times \left[1-\mathrm{P}(\mathrm{V\_Ramp\_dn})\right] \tag{6.5}$$

where $\mathrm{P(NoWC)}$ is the probability of no wind curtailment in system.

Accordingly, the Loss of Wind Estimation (LOWE) is calculated by:

$$\begin{aligned} \mathrm{LOWE} &= 1-\mathrm{P}(\mathrm{NoWC}) \\ &= 1-\left[1-\mathrm{P}(\mathrm{V\_MLL})\right] \times \left[1-\mathrm{P}(\mathrm{V\_Ramp\_up})\right] \times \left[1-\mathrm{P}(\mathrm{V\_Ramp\_dn})\right] \end{aligned} \tag{6.6}$$

$\mathrm{P(V\_MLL)}$ is the probability of net demand drops below minimum load level of the system and it is expressed by:

$$\mathrm{P}(\mathrm{V\_MLL}) = \mathrm{P}(\mathrm{Netdemand} \le \mathrm{MLL}) \tag{6.7}$$

The net demand varies with hours during a year and it is regarded as a random variable in this problem. In statistical analysis, probability of a random variable less than or equal to a fixed number A forms the cumulative distribution function (CDF) of this random variable [87]. Mathematically, for every real number A, the CDF of a real-valued random variable x is given by:

$$\mathrm{F}_x(\mathrm{A}) = \mathrm{P}(x \le \mathrm{A}) \tag{6.8}$$

[17] Joint probability: In statistics, joint probability is a measure where the likelihood of two events or more events occurring together and at the same point in time is calculated. For example, joint probability is the probability of event Y occurring at the same time event X occurs.

In this case, the random variable is the net demand and number A is replaced by MLL. So P(V_MLL) is the value of CDF of net demand evaluated at MLL, as shown in (6.9).

$$\mathrm{P}(\mathrm{V\_MLL}) = \mathrm{F}(\mathrm{MLL}) \tag{6.9}$$

As an example, the normalised demand and wind profiles of the UK in 2005 [35] are used here to represent the realistic variations. Demand profiles are multiplied by the 12GW annual peak load, and wind profiles are scaled up by different wind capacities to show the various penetration levels. CDFs of net demand under 0, 10, 20, and 30% wind energy penetration are shown in Figure 6.1. It is seen that with more wind penetration, CDF of net demand moves towards the left. This will result in larger possibilities of net demand to cross the vertical line representing the MLL, and thus larger P(V_MLL) is observed. The CDF indicates that there are more chances to have wind curtailment in the situations with larger wind integration.

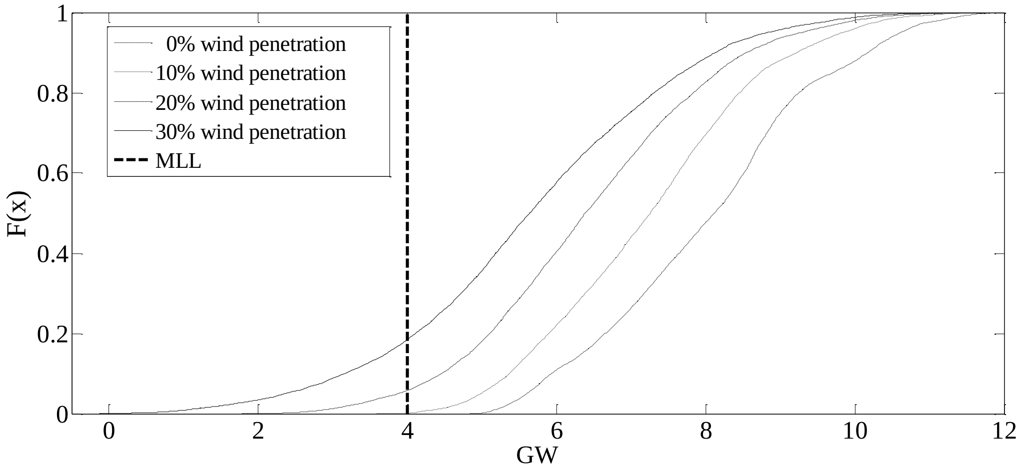


Figure 6.1: CDF of Net Demand with 0, 10, 20, and 30% Wind Energy Penetration

To get the value of P(V_Ramp_up) and P(V_Ramp_dn), similar methods are used. Now the random variables are upward variation and downward variation in net demand. The fixed boundary for P(V_Ramp_up) is the aggregated ramping up capability of the system, designated as $\sum \text{Ramp\_up}$, which can be expressed as:

$$\begin{aligned} P(\text{V\_Ramp\_up}) &= P\left(\text{Up\_Variation} \geq \sum \text{Ramp\_up}\right) \\ &= 1 - P\left(\text{Up\_Variation} \leq \sum \text{Ramp\_up}\right) = 1 - F\left(\sum \text{Ramp\_up}\right) \end{aligned} \tag{6.10}$$

The same procedure used for P(V_MLL) is repeated here to determine $P(\text{V\_Ramp\_up})$. Firstly, the CDF of upward variations in net demand is plotted and then the value of the CDF is evaluated at $\sum \text{Ramp\_up}$ to get $F\left(\sum \text{Ramp\_up}\right)$. Finally, $P(\text{V\_Ramp\_up})$ is obtained by $1 - F\left(\sum \text{Ramp\_up}\right)$.

The P(V_Ramp_dn) is determined in a similar way, by replacing the CDF for downward variations in net demand and the fixed boundary is the value of aggregated ramping down capability of the system.

$$\begin{aligned} P(\text{V\_Ramp\_dn}) &= P\left(\text{Dn\_Variation} \geq \sum \text{Ramp\_dn}\right) \\ &= 1 - P\left(\text{Dn\_Variation} \leq \sum \text{Ramp\_dn}\right) = 1 - F\left(\sum \text{Ramp\_dn}\right) \end{aligned} \tag{6.11}$$

The equations (6.8), (6.9), (6.10), and (6.11) can now be used to calculate the LOWE. By rearranging these four equations, the LOWE is expressed as:

$$\text{LOWE} = 1 - \left(1 - F(\text{MLL})\right) \times F\left(\sum \text{Ramp\_up}\right) \times F\left(\sum \text{Ramp\_dn}\right) \tag{6.12}$$

The LOWE describes the possibilities of wind curtailment in a system and it can be used in evaluating the system flexibility. Given the same wind penetration, the system with lower LOWE value is obviously more flexible.

In addition, the application of this index is not limited to flexibility comparisons. It may have another two interesting applications:

- Estimation of the maximum allowable wind capacity in an existing system;
- Evaluation of the extent to which the flexibility level is developed by the new investments.

If a tolerance standard of time with wind curtailment is given, i.e., Q% of time during a year, the LOWE can then be compared with Q% to assess the flexibility of the system. The LOWE is increased with the higher wind penetrations, and once it is found to be larger than Q%, the corresponding wind penetration W% is deemed as the maximum allowable wind penetration in this system. In other words, the system is flexible enough to accommodate W% of wind penetration without having wind curtailment more than Q% of the time. Further wind installations will result in a larger LOWE beyond the boundary of Q% because the available flexibility is not sufficient to cope with such wind penetration.

Furthermore, the effects of new invested generators on system flexibility can also be seen through the LOWE index. Whether the corresponding value will be reduced or increased and to what extent the value is changed are both indicating the contribution of the new investments on the system flexibility.

To get a better understanding on these functions, comparisons are drawn between LOWE and LOLE. LOLE is short for Loss of Load Expectation and its application in assessing Generation Adequacy is an internationally accepted practice [111]. Several aspects are compared between the two and the results are listed in Table 6.3.

The comparison shows that the proposed LOWE is a statistical index with similar characteristics with widely used LOLP.

Table 6.3 Comparisons between LOLP and LOWE

	LOLP	**LOWE**
Concept	For what percentage of time during a year, the available generation is likely to fall short of the demand during a year	For what percentage of time during a year, the potential wind energy is likely to be curtailed
Function	Measurement of generation adequacy	Measurement of system flexibility
Criterion	Whether system has sufficient capacity and auxiliary services to supply demand	Whether system has sufficient flexibility to follow the changes in wind generation
Consequence of exceeding the standard	LOLP larger than acceptable standard indicates that the inadequacy in generation will threaten the system security.	LOWE larger than acceptable standard indicates that wind penetration is beyond the affordability of the flexibility of system

6.5 Verification of LOWE

LOWE is calculated on the three testing systems set up in Chapter 3, which are high flexible (HF), medium flexible (MF) and low flexible (LF) systems. The determination of MLL, $\sum \text{Ramp\_up}$ and $\sum \text{Ramp\_dn}$ usually requires practical operational experience as reference. In a realistic system, the system operator defines a system-specific MLL taking into account the supply surplus, up/down reserve and the feedback from the stakeholders. To demonstrate the application of the LOWE index, in the simulation the MLL in each system is assumed to be 50% of the summation of all units' minimum stable generation within the same system. For $\sum \text{Ramp\_up}$ and $\sum \text{Ramp\_dn}$, they are assumed to be the summation of all units' ramping capabilities. These assumptions are used to create an equal basis for the comparison.

The technical parameters of the three test systems are listed in Table 6.4.

Table 6.4 MLL, $\sum$Ramp_up , $\sum$Ramp_dn for the Three Test Systems

Name of System	MLL (MW)	$\sum$Ramp-up (MW/h)	$\sum$Ramp-dn (MW/h)
HF system	3750	9400	11750
MF system	4250	7450	9375
LF system	5450	2770	3675

The LOWE of the three systems with different wind energy penetrations is calculated and the results are shown in Table 6.5.

Table 6.5 LOWE for Three Systems with Different Wind Penetrations

Name of System	10% wind	20% wind	30% wind
HF system	0.00%	4.36%	15.28%
MF system	0.78%	7.92%	21.90%
LF system	11.45%	27.57%	45.95%

To validate the LOWE index, a comparison is carried out with the results from a unit commitment [18] performed for a time horizon of one year with hourly resolution. The simulation results obtained by the unit commitment are shown in Table 6.6.

Table 6.6 Simulation Results for Probability of Wind Curtailment Using UC Model

Simulation Results	10% wind	20% wind	30% wind
HF system	0.00%	1.77%	12.48%
MF system	1.45%	9.59%	22.53%
LF system	15.44%	30.82%	49.25%

Comparisons between the LOWE and the simulation results of wind curtailment probability are plotted in Figure 6.2. As mentioned earlier in this Section, LOWE is not a calculation of the realistic quantity of wind curtailment, but rather to evaluate the flexibility level of system. It is found in Figure 6.2 that LOWE is well suitable for this purpose because it shows very good approximation to what may happen in the realistic process.

[18] The results of wind curtailment probability from a UC program are obtained by dividing the number of hours with wind curtailment by the total 8760 hours during a year. This is different from the actual wind curtailment discussed in the previous Chapters.

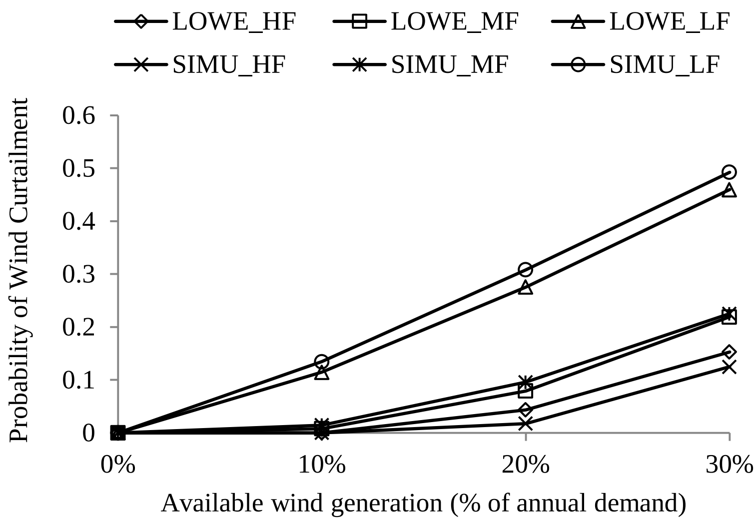


Figure 6.2: Comparisons between LOWE and Simulation Results by UC Models

The LOWE in this case is calculated based on rough assumptions on the MLL. The MLL is both system-specific and case-specific. In practice, the more accurate information can be used to determine MLL, the better estimation can be achieved from the LOWE index.

6.6 Chapter Conclusions

In this Chapter, two flexibility indices are proposed to evaluate the flexibility of power systems. The main purpose is to provide offline methodologies to estimate the flexibility level of a system without implementing complex time consuming operational models. In reality, comprehensive time consuming simulations are necessary for the system operator to get sufficient information of the flexibility level of the system. However, the indices proposed in this work provide a convenient way for them to get a quick overview of the flexibility of different regions or countries.

The normalised flexibility index, NFI, is proposed based on the analysis of the deployable space of individual generators and their contribution to the whole system. The index is expressed by a normalised number and can be used to evaluate and compare the flexibility level of individual generators as well as different power systems. The term ‘flexible unit’ is then redefined as a relative one and it must correlate to the power system it belongs to. Only those units with higher flexibility level than the system level are considered flexible units within the same system. Therefore, a flexible unit in one system does not ensure it is also flexible in other systems.

The second index, namely Loss of Wind Estimation (LOWE), assesses the flexibility level of system by their capability of accommodating wind. The index represents the estimated probability that wind curtailment occurs in a system. The index is obtained by statistical analysis of net demand on its probability to violate systems’ technical thresholds (MLL, Ramping capability) relevant to flexibility. Its applications are not only limited to compare different systems’ flexibility levels. Other possible applications include: assessment of the maximum allowable wind penetration in an existing system, and evaluation of the effects of new investment on the original system’s flexibility level.

CHAPTER 7

CONCLUSIONS AND FUTURE WORK

7.1 Conclusions

The EU has set out a 2020 target of supplying 20% of the total energy demand by renewable energy. Similar decisions have been made in many countries and regions around the world. Wind generation is one of the most technically mature and cost effective renewable technologies and is posed to play a key role in future generation portfolio.

However, wind power cannot be scheduled and dispatched in the same way as conventional generation due to its uncertain and variable nature. Integration of large volumes of wind power has impacts on the existing power system in different aspects over various time scales. Hence, the provision of flexibility is critical to mitigate these impacts and accommodate wind generation properly.

The need for flexibility has long been recognised by the electricity industry. In the literature, a number of studies that fell within the scope of flexibility have been carried out with different techniques. Given the vast number of tools, criteria and theories available, from a system operator's point of view, it is essential to have a systematic approach that covers the whole spectrum of the flexibility in power systems. Unfortunately, there is still a lack of work being done for this purpose. This thesis attempts to fill this gap by providing a broad view of the role of flexibility in different power system activities, from generation scheduling, generation planning, to market operation, and furthermore presenting two 'offline' indices for flexibility evaluation.

According to time scale, flexibility can be classified into super short-, short-, and long-term flexibility. In this work, we focused on the short-term flexibility that is crucial for reliable generation scheduling and market operation. The short-term flexibility also affects the operational flexibility of a future wind power-rich system and thus has impacts on the long-term generation planning.

Using the tools and metrics in this thesis, system operators and decision makers will be able to perform the following tasks:

- Conduct generation scheduling simulation to evaluate the impacts of wind on the flexibility requirement (flexible generation, additional reserve, start-ups, ramping requirement, wind utilisation…).
- Use the unit construction and commitment algorithm to 1) estimate the maximum allowable wind capacity for an existing system; 2) find the optimal investment of flexibility for accommodating more wind generation; and 3) decide an optimal generation mix for integrating a given wind penetration.
- Use the market model to reveal the value and profitability of flexibility and evaluate the corresponding impacts of alternative market design.
- Use the two proposed flexibility indices to quantitatively assess the flexibility of individual generators and power systems without undertaking complex and time consuming simulations.

The study of the thesis is mainly focused on a thermal-based generation portfolio and the main conclusions may be summarised as follows:

- To meet the technical requirement of operating reserve, sufficient thermal capacity has to be synchronised and these generators form the minimum load level of a power system. Full integration of wind generation requires the thermal system to be operated with a lower minimum load level. Flexibility is essential in wind power integration because of the resulting lower minimum load level and the increased variability and uncertainty of the net demand, which in turn requires generators with lower minimum stable generation and faster ramping rates as well as more flexible reserves.

- Integrating large-scale wind generation in a power system is not only a technical problem but also an economical challenge. The reduction in fuel cost by wind integration (as it displaces conventional generation) is partly offset by the cost of additional flexibility services involved at the same time.

- In the generation scheduling the medium flexible generators (like coal plants) are usually deployed prior to the high flexible units (like CCGT) because of their lower operating cost. The high flexible units are mostly used to cope with the peaking variations in the net demand. It is interesting to note that even the lowest flexible units, like old nuclear power plants, can provide certain longer term flexibility. However, imposing a higher CO_2 penalty charge could revert this merit order of deployment by significantly increase the operational cost of high-emission generators and thus encouraging the use of low-emission units.

- In order to keep a high wind utilisation factor, power systems usually have an upper limit for the 'optimal' wind installation capacity. Once this limit is violated, wind curtailment will occur more frequently (e.g., during minimum net demand periods or sudden spikes in wind power) because of the lack of flexibility. In this situation, more flexible units are required to be invested to cope with further wind capacity. Therefore, in wind power-rich systems, generation planning of conventional generators must consider the flexibility adequacy in order to fully integrate a given wind penetration.

- The proposed 'normalised profit of flexibility for balancing purposes' (NPF) can be used to separate the profit of flexibility from the overall profit of the system. It is shown that the NPF increases with wind penetration until this is saturated due to the exhaustion of flexibility. Therefore, tracking the evolution of this profitability, as a function of wind penetration, provides a method to determine when additional investment in flexibility would be desirable. Wind integration increases both the requirement and availability of flexibility services in the market. The sign (positive or negative) of the NPF allows assessing the balance between the increase of the flexibility requirement and the available flexibility services.

- The effect of market design on the flexibility requirement and on the profit of flexibility is demonstrated by introduction a rolling market clearing. Given the fact that wind forecast is usually updated several times a day and the accuracy of wind forecast increases with shorter lead times, the use of frequently updated wind forecast can reduce the uncertainty that systems have to cope with, thus reducing the requirement for additional reserve. The 'rolling clearing' market design use these features to facilitate the deployment of flexibility. It is therefore reduce the need for technical flexibility in the market and thus can be seen as a non-technical source of flexibility. However, from the perspective of flexible unit owners, this implies an unpleasant reduction of their profit from providing flexibility services.

- Although accurate calculation of system flexibility usually requires detailed simulation taking into account different specifications of the units in a power system, there are 'offline' methods capable of conveniently estimating this flexibility. Here, two indices were introduced: the normalised flexibility index (NFI) and the loss of wind estimation (LOWE). The former one can be used to evaluate and compare the flexibility level of single generators as well as the whole generation mix. It is also capable of evaluating the contribution of new investment on the flexibility of the existing system. The latter one assesses the flexibility level of system by their capability of accommodating wind. It can be used to estimate the probability that wind curtailment occurs in a system. Compared with multi-temporal simulations, these indices are far less complex and computational demanding while still provide reasonable estimation.

7.2 Future Work

In this work, thermal generators have been used as the main resource of flexibility. However, besides this type of conventional generators, there are other sources of flexibility which also need to be investigated. The main alternative sources of flexibility include demand side management, energy storage and interconnections. These flexibility resources can be integrated into the proposed mathematical framework by adding the corresponding constraints, relationships and parameters. Their effects on generation scheduling, generation planning and market operation can then be assessed. Initial steps toward this were taken in [112, 113].

As discussed in previous Chapters, there are two main methods that address wind variability and uncertainty in the generation scheduling problem: stochastic and deterministic. In this work, the deterministic approach was chosen mainly because of its advantage in terms of computational efficiency. However, recent wind integration studies have shown that robust solutions can be obtained by stochastic approaches. The most important challenge is how to tackle the intensive computational requirements, especially when applying the stochastic method in real power systems. This will rely on further improvement of stochastic programming and high performance computers.

The proposed UCC in this work aims at providing a method to determine the optimal investment taking into account the flexibility adequacy in the future portfolio. However, the UCC has not considered the uncertainties such as the changes in demand and price, or the scheduled maintenance and the unexpected outages. These factors all have influences on the decision of optimal investment. Therefore, in future work, the UCC can be extended to take into account these factors and become more powerful and realistic.

Another interesting topic that may be worth to be studied is the value of flexibility in an imperfect competitive market. As oppose to the perfectly competitive market used in this thesis, where the information transparency avoids the manipulation of the market by suppliers, in an imperfectly competitive market the supplier always tries to bid higher than its true operational cost to make more profit. Different bidding strategies will have different impacts on the results of market operation, thus changing the values of system flexibility. What bidding strategies can result in the most benefit for individual participants and how these biddings will affect other participants and the whole system are both valuable questions for future study.

Finally, the two flexibility indices proposed in this work are preliminary and may need to be refined to be used in real industry applications. For the NFI, more factors, like minimum up/down time, response time for providing different kind of reserve, etc. could be taken into account to get more accurate results. Furthermore, when considering other resources of flexibility, their specific characteristics must also be considered. Similar improvements can also be made for the second index, LOWE.

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APPENDIX A

PARAMETERS OF THE 'SCALED-DOWN' UK THERMAL SYSTEM

This appendix includes technical parameters and costs of each technology in the 'scaled-down' UK thermal system.

Technology Name	P_{min} MW	P_{max} MW	INC £/MWh	STC £	M_{up} h	M_{dn} h	R_{up} MW/h	R_{dn} MW/h	CO_2 t/MWh
HFT (CCGT)	250	500	40	1200	1	1	400	500	0.394
MFT (Coal)	250	500	30	3000	4	4	200	250	0.942
LFT (Nuclear)	450	500	20	0	8	54	10	25	0

APPENDIX B

PARAMETERS OF IEEE RTS 26

THERMAL UNITS

This appendix presents the technical and economical parameters of IEEE RTS 26 thermal units.

Units	INVEST $/kW	P_{min} MW	P_{max} MW	INC $/MWh	STC $	M_{up} h	M_{dn} h	R_{up} MW/h	R_{dn} MW/h
1-5	536	2.4	12	25.7	68	1	1	48	60
6-9	409	4	20	37.7	5	1	1	30.5	70
10-13	536	15.2	76	13.7	655.6	3	2	38.5	80
14-16	536	25	100	18.4	566	4	2	51	74
17-20	1154	54.24	155	11.3	1048.3	5	3	55	99
21-23	1154	68.95	197	23.4	775	5	4	70	120
24	1154	140	350	11.3	4468	8	5	50.5	100
25-26	2117	100	400	8.0	0	8	5	50.5	100