Provision of Power System Frequency Response in the Context of High Wind Penetration

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Abstract

Models have been developed to assess the extent that wind plant can contribute to power system frequency control and stability. These are important in the context of increasing wind penetration level into power systems and because variable speed wind turbines that are now the dominant technology do not directly contribute to system inertia, but displace conventional generation plant, thus reducing the total system inertia. It is now considered likely that wind generation will have to participate in power system frequency regulation but prior to this work, little was known about the aggregate impact of extensive wind capacity in this regard, although there has been extensive prior research on the modification of individual turbine controllers to deliver inertial response in the event of rapidly falling system frequency, and droop response so as to contribute to continuous frequency service.

A novel probabilistic approach has been developed to assess how the aggregate synthetic inertial response from wind plant at a given time depends on the available wind. The calculation of collective synthetic inertial response is based on an approach to modelling wind turbulence where wind variations over a short period of time (10 seconds in this modelling) are assumed to be adequately described by a Gaussian probability distribution with a set mean wind speed and variance determined by the site turbulence intensity. This approach is then further expanded to assess the aggregate inertial response available from wind generation across the GB power system and by using a simplified lumped representation of the rest of the power system, allows the interaction between the wind plant, through its controllers, and the power system to be represented. The complete model provides a way to evaluate synthetic inertial response from wind generation under time varying wind speeds on an hourly basis and across the regions, and also as a result of turbulence and short term wind speed variation across wind farms.

This research has also shown that the power output of wind turbines can also be actively controlled to provide droop response and to participate in primary frequency response. Different approaches to delivering droop response from wind plant have

been investigated. The combination of droop and inertial response has been assessed for a significant frequency event and the results show that the combined approach can provide an improved performance than either droop or inertial response alone.

Acronyms, Abbreviations & Symbols

Symbol	Unit	Definition
A	m^2	Swept area by the rotor blades
AC	-	Alternating Current
$B_{\mathrm{i,j}}$	-	Block for wind ramp probability calculations
C_P	-	Power coefficient of a turbine rotor
C_{Popt}	-	Optimal power coefficient
D	-	Droop
DC	-	Direct Current
DFIG	-	Doubly fed induction generator
E		Kinetic energy
EDF	-	Electricite de France
ESB	-	Electricity Supply Board
$E[X]$	-	Expectation
FRC	-	Fully rated converter
f	Hz	Power system frequency
$f_{norminal}$	Hz	Nominal frequency
f_{sys}	Hz	System frequency
df/dt	Hz/s	Rate of change of frequency
GB	-	Great Britain
H	s	Inertial constant
HQT	-	Hydro Quebec TransEnergie

HVDC	-	High voltage direct current
J	kgm^2	Inertia of rotating components
K_{opt}	-	Turbine torque controller constant
$k_{\mathrm{i,j}}$	-	Weighting factor
L_s	Meter	Integral length scale
NG	-	National Grid
PMG	-	Permanent magnet generator
P	MW, kW	Power
P_{rated}	MW, kW	Rated power
P_{avail}	MW, kW	Power available
p_i	-	Probability
Pr	-	Joint probability
$p(x, y)$	-	Joint probability
$\mathrm{Q}_{\mathrm{i,j}}^{(\mathrm{m})}$	-	Probability
R	meter	Rotor radius
S	MW	Rated power
$Spec(n)$	-	Kaimal spectrum
T_{rated}	Nm	Rated torque
T_{ref}	Nm	Reference torque
T_{aero}	Nm	Aerodynamic torque
T_d	Nm	Demanded torque
$T_{inertia}$	Nm	Added inertial torque
TSO	-	Transmission System Operator

U	m/s	Wind speed
UCD	-	University College Dublin
VAR	-	Vector auto regressive
X	-	Random variable
x	-	Derating factor
Z	Meter	Height above ground
ρ	kg/m^3	Air density
Ω	rad/s	Rotational speed
ω	rad/s	Rotational speed
ω_0	rad/s	Rated rotor speed
λ	-	Tip speed ratio
λ_{opt}	-	Optimal tip speed ratio
λ_{Pmax}	-	Tip speed ratio corresponding to maximum C_P
λ_{mod}	-	Modified tip speed ratio
θ	degree	Pitch angle
θ_{opt}	degree	Optimal pitch angle
$\frac{\partial P}{\partial \theta}$	MW/degree	Blade pitch sensitivity
σ	-	Turbulence intensity of the wind
r	-	Autocorrelation of the wind
τ	s	Lag

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Chapter One Introduction

1.1 Background

Rising concerns over energy security, climate change and eventual fossil fuel depletion have led to a rapid expansion of renewable energy in recent years. Among all available forms of renewable energy, wind power has seen the most steady and robust growth over recent years thanks to good wind resource in many countries and well developed technology.

The UK government is legally committed to achieving 15 per cent of its energy consumption from renewables by 2020 as dictated by the 2009 Renewable Energy Directive [1]. To achieve this ambitious target, a coordinated approach across the electricity, transport and heating sectors is required. There is an increasing consensus that the electricity sector will have a crucial role to play in delivering the renewable energy objectives. As the most commercially viable renewable technology available in the UK, wind energy has the potential to supply the bulk of electricity demand. It is estimated that by the year of 2020, 20% of the UK's electricity will come from wind power. Figure 1-1 shows the growth in wind capacity in the UK.

High wind penetration will pose challenges to the operation and control of power systems. The technical, operational and economic implications have been identified that result from the intermittency and limited predictability of wind generation [2]. With the evolving technologies and increasing size of wind turbines, variable speed wind turbines have become the dominant technology in the market. The main drivers behind the switch to this particular technology are better compliance with Grid Codes worldwide and a reduction in mechanical loads on the turbines due to variable speed operation [3-5]. With increasing wind penetration level into power systems, frequency stability has become a concern for transmission system operators (TSOs) around the world. This is because the inertia of variable speed wind turbines is decoupled by power electronic converters and cannot automatically contribute to power system inertia, whilst at the same time wind turbines displace conventional generation together with their inertia. Traditionally, wind generation is operated at optimal power below rated wind speed and has not been required to provide power reserve or contribute to frequency support.

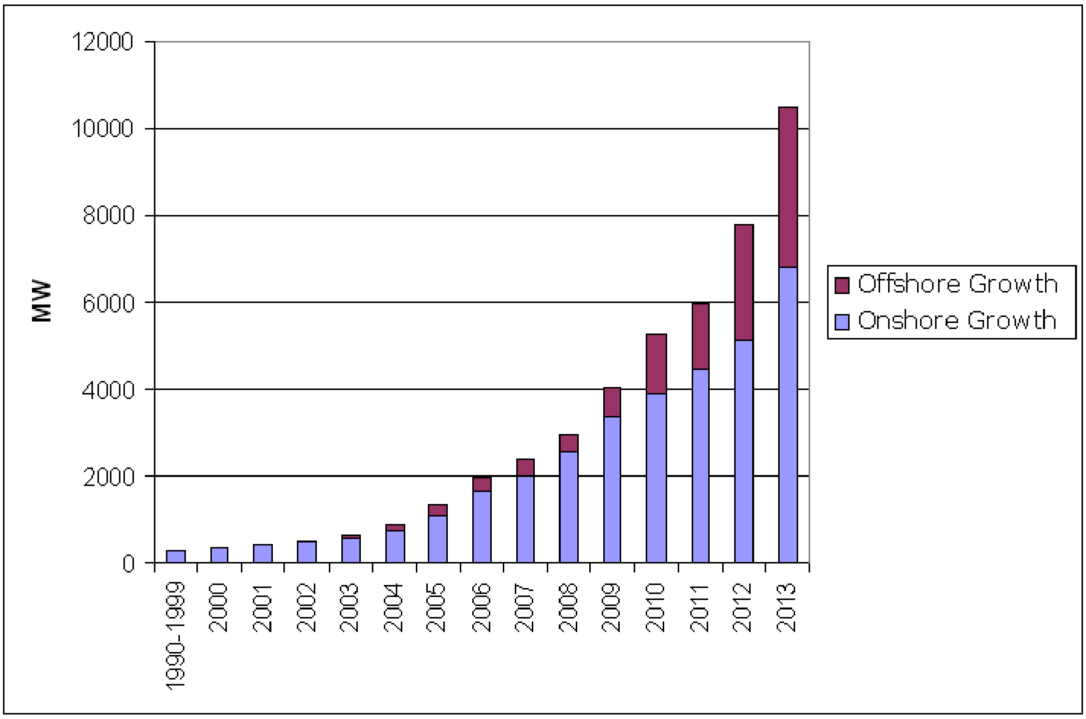


Figure 1-1 Wind power capacity in the UK, data taken from DECC [6]

This thesis aims to assess the potential for frequency support capability from wind generation in the context of high wind penetration. The final aim of the research is an assessment of collective synthetic inertial contributions from wind plant in the power system of Great Britain (GB) and the impact on its frequency stability. The combined inertial and continuous frequency support from wind plant is also investigated, given that conventional capacity may be insufficient to provide frequency response services when wind power supplies a significant amount of the total energy load.

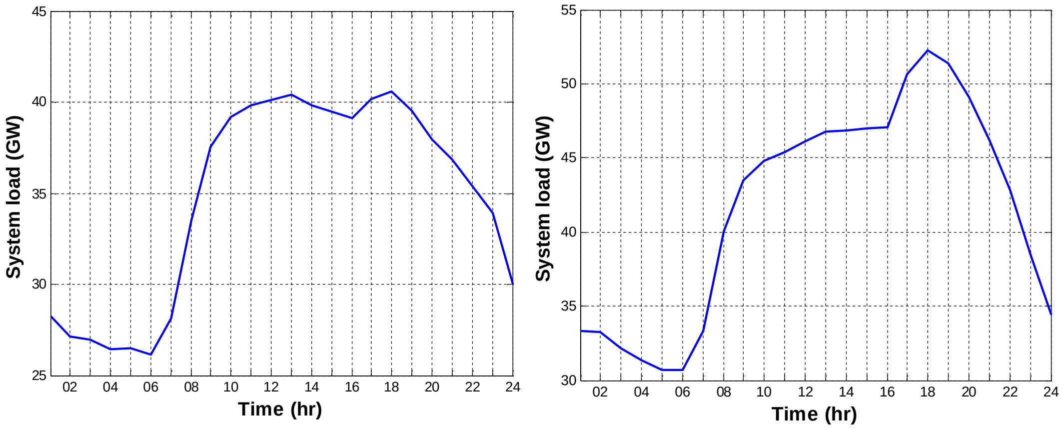
It should be noted that there are various different definitions of wind penetration. For instance, wind energy penetration level represents the proportion of total electricity supplied by wind power, either at a particular instant in time (sometimes called instantaneous penetration), or over a stated period of time. Alternatively, wind capacity penetration level can be defined as the ratio of installed wind capacity in total installed generation capacity. The definition of wind penetration used in this work will be the proportion of annual electricity supplied by wind.

1.2 **Motivation of the research**

1.2.1 Power balancing

The essential function of an electrical power system is to meet the electricity demand of consumers. To maintain the secure and reliable operation of power systems, the active power of generation and demand should match at any moment. However, a power system is never in equilibrium because the electricity demand varies continuously as consumers switch on or off their loads. However, the smoothing benefit arising from aggregation of individual consumers (both domestic and industrial) provides electricity utilities with certain degree of certainty [7]. Figure 1-2 illustrates the aggregate demand on typical summer and winter days in the GB power system [8]. It can be seen from the figure that electricity demand on the whole system exhibits a pattern throughout the day that is consistent with human behaviour, e.g. the demand starts increasing from around 6 am and reaches peak around 6 pm. As a consequence it is not so difficult for TSOs to predict with reasonable accuracy the generation required to supply the aggregate load and thus to schedule and dispatch the generating units on the system.

Pumped storage hydropower developments are widely used as energy storage systems in power systems around the world. Water is pumped from a lower reservoir to a higher one using inexpensive (otherwise surplus energy) produced during periods of low demand by power plant which cannot be easily shut down. The water in the higher reservoir is then released through hydraulic turbines to produce more valuable power during periods of peak demand. Although there is a net energy loss in the system because more energy is consumed in pumping than can be produced by the turbines, pumped storage has been identified as the most commercially viable means to balance power system demand and supply on a large scale. Typical round trip efficiency exceeds 70%.



(a) summer (b) winter

Figure 1-2 Illustration of system load in the GB power system

Aside from large scale energy storage, certain amount of active power is also required to be kept in reserve to ensure the balance between generation and demand while the loads constantly vary and to cover events of sudden generation losses. Reserve can be defined as the amount of generation capacity that can provide active power when required but has not yet committed to producing energy. In practice, different types of reserve services are required in response to different types of system events over different timescales. In other words, the reserve is required to follow the demand's fast variability from second to second and also to account for any errors in load forecasting. At the same time, it is also required to provide support for the sudden mismatches between generation and demand due to sudden loss of generation or increase in load. Slow variability is dealt with by scheduling and unit commitment.

National Grid requires access to sources of extra power in the form of either generation or demand reduction aiming to deal with unforeseen demand increase and/or generation unavailability. These additional power sources available to National Grid are referred to as Reserve and comprise synchronised and non-synchronised sources. Different sources require different timescales in order to be ready to deliver the services.

On a shorter time scale, wind power variability will affect the power balancing, particularly in the system with a significantly high amount of wind power. With the present relatively modest wind power capacity in most countries, power systems can be kept within the agreed limits without special measures being taken. However, with the increasing penetration of wind farms in power systems, there is a concern on how it will influence the future requirements for regulating power [9].

There are various ways of allowing wind generation to participate in power balancing in power systems with high wind penetration:

- Regulate wind plant's power fluctuations resulting from wind variations, for example by applying ramp rate limits
- Provide continuous frequency response from wind plant to counter minor frequency changes within the operational limits
- Provide synthetic inertial response from wind plant to support sudden frequency excursions due to large power imbalances

The first approach aims to reduce the impact of power fluctuations on the system while the other two approaches attempt to directly contribute to power system frequency stability. Studies have shown that the impact of fluctuating wind power can be reduced using various control strategies to smooth the power output from variable speed wind turbines [10, 11]. In this research the provision of synthetic inertial response and continuous frequency response from wind plant will be examined.

1.2.2 Frequency limits

Power system frequency is continuously changing. For secure operation of a power system, the frequency should remain nearly constant. In an electrical power network, a significant drop in frequency could result in high magnetising currents in induction motors and transformers [12] and activation of power system protection.

It is the role of TSOs to ensure that power system frequency is maintained as close to nominal (50 or 60 Hz) as possible whilst taking into account the operational and statutory limits. Following a sudden loss of demand or generation, caused either by a network fault or plant failure, there will be a difference between instantaneous generation and demand that will result in a frequency deviation from nominal. The GB power system operator, National Grid operates the system in such a way that:

- The maximum deviation of frequency in normal operation is no greater than 0.2 Hz. This is referred to as operational limit.
- The maximum deviation of frequency after a normal infeed loss is no greater than 0.5 Hz. This is referred to as statutory limits.
- The maximum deviation of frequency after an infrequent infeed loss is no greater than 0.8 Hz.
- Any deviation outside 49.5 Hz and 50.5 Hz must not exceed 60 seconds.

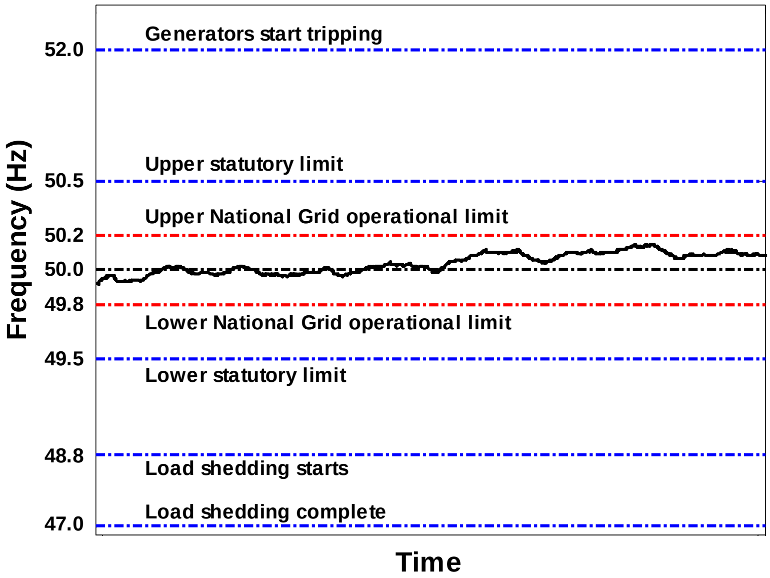


Figure 1-3 Operational and statutory frequency limits in the GB power system (Source: National Grid UK)

Figure 1-3 summarises the operational and statutory limits of system frequency for the GB power network. It can be seen that National Grid's usual operational limits are stricter than the legal requirements. Under unusual circumstances (e.g. substantial loss of load), the frequency may rise and generating units equipped with over-frequency protection will trip to decrease the generation when the frequency reaches 52 Hz. Under extreme circumstances when system frequency falls below 48.8 Hz, the electricity demand is interrupted for large noncritical loads with which National

Grid usually have reached an agreement so that such loads can be switched off , and if this is insufficient, sections of load are disconnected by under-frequency trips.

1.2.3 Types of frequency response

As generation and demand fluctuate so does power system frequency. If demand on the system is greater than generation, system frequency falls whilst if generation is greater than demand, system frequency rises. To effectively regulate the frequency, TSOs primarily rely on frequency response.

The regulation of power system frequency involves continuously varying generation to match demand over several timescales ranging from seconds to hours. The variations in generation are required not only to follow the demand's fast variability from second to second and also its slow variability over the day through appropriate scheduling of plant, but also sudden substantial mismatches between generation and demand, known as disturbances or contingency, for instance a large generation trip, loss of a transmission line.

Figure 1-4 illustrates a typical system frequency trajectory plotted on a nonlinear timescale. It can be seen that during the initial several seconds the frequency exhibits the usual noise associated with minor mismatch between the continuously varying demand and generation on the system. When a frequency event occurs on the system, a substantial frequency excursion will follow. The trace describes a typical time history of the frequency and the measures taken to contain the frequency within the statutory and operational limits.

A continuous frequency response is provided by conventional synchronous generators equipped with governor-control systems that adjust their power output to follow relatively modest changes in demand and so counteract the frequency fluctuations. Some generators in the power system are assigned by the TSO to operate in frequency-sensitive mode (i.e. under active governor control) to provide this service [7].

An occasional frequency response is provided to constrain significant frequency excursions resulting from sudden mismatch between generation and demand (e.g.

loss of generation). This normally involves response from large de-loaded synchronised generators and also perhaps from rapid response generation such as open cycle gas turbines.

According to National Grid, two types of frequency response are being used in the GB power system [13]:

- Dynamic frequency response is a continuously provided service used to manage the normal second by second changes on the system.
- Non-dynamic frequency response is usually a discrete service triggered at a defined frequency deviation.

National Grid achieves the non-dynamic frequency response by using the response services as defined below [14]:

- Primary response is an automatic change in active power generation (or demand) within 10 seconds after a major frequency event and can be sustained for a further 20 seconds.
- Secondary response is the provision of additional active power (or reduction in demand) within 30 seconds[1] after a frequency event and can be sustained for a further 30 minutes.
- High frequency response is the reduction in active power generation within 10 seconds after a frequency event and can be sustained indefinitely.

National Grid's definitions of frequency response are generally consistent with those of [7]. However, it should be noted that significant differences exist between the definitions in different power systems. National Grid owns and maintains the high-voltage electricity transmission system in England and Wales, together with operation of the power system across Great Britain (GB). It is responsible for the balancing of supply and demand at any moment through the balancing mechanism (BM) and bilateral contracts. Its definitions and customs are consistently used throughout this research.

[1] These figures are for the GB power system, and values will vary from country to country.

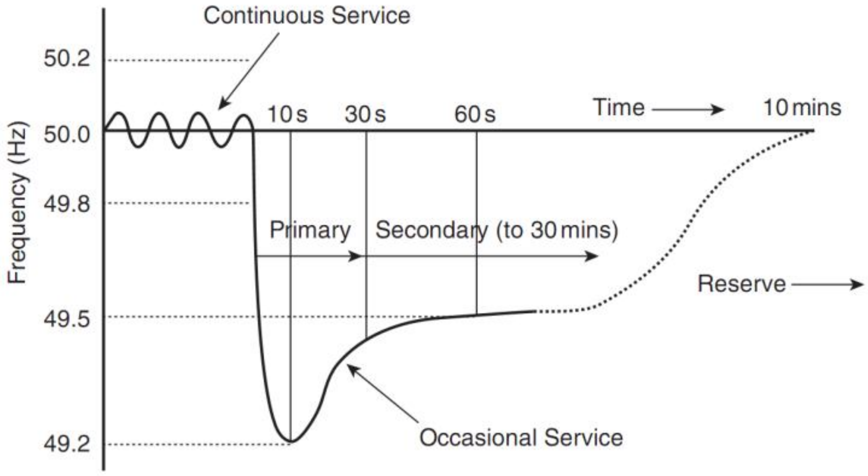


Figure 1-4 Frequency response in the GB power system, taken from [7]

1.2.4 Inertial response from synchronous machines

As described above, providing frequency response through primary or secondary response requires that some generators are required to be deloaded and so create headroom in order to increase output. The margin can be defined as the difference between the actual and full loaded generation. Aside from hydro and pumped storage plant, coal plants primarily provide this balancing service.

Inertia is the term that can be defined as the total amount of kinetic energy stored in all rotating generators and motors that are synchronously connected to the network (or near synchronously connected in the case of induction generators and motors). As a result of a transient frequency drop, each synchronously connected turbo-generator set together with all other synchronised machines will automatically decelerate thereby releasing kinetic energy to oppose the change in frequency. This natural characteristic can greatly assist in limiting the rate of change of frequency and the minimum frequency (nadir).

The kinetic energy stored in the rotating rotor and any coupled rotating components (such as the turbo-machinery) of a synchronous machine can be defined as:

$$E = \frac{1}{2} J\omega^2 \qquad (1\text{-}1)$$

where E is the kinetic energy, J is the effective inertia of the rotating components and ω is the rotational speed.

The inertial power contribution available from a synchronous machine can be determined by taking the time derivative of kinetic energy stored. The standard derivation of the simple mathematical relation can be shown as:

$$P = \frac{dE}{dt} = \frac{d(\frac{1}{2}J\omega^2)}{dt} \tag{1-2}$$

$$P = J \times \omega \times \frac{d\omega}{dt} \tag{1-3}$$

It can be seen from (1-3) that the inertial power contribution from a synchronous machine is determined by the rate of change of frequency (ROCOF) and the full power increase will be reached immediately after the initiation of ROCOF (maximum value). The red line in Figure 1-5 represents the inertial response of a synchronous generator of which the rotational speed is locked with the network frequency. In the event of a frequency drop, the remaining synchronous machines on the system will supply an injection of active power into the power network. This is referred to as inertial response. Figure 1-5 also shows that after the provision of inertial response, the power of the synchronous machine will temporarily decrease below the normal output level and so allow the rotor to accelerate back to synchronous speed. The area below normal power output represents the energy recovery after the restoration of system frequency.

It is worth adding that an electrical power system consists of many generating units and many loads while its total power demand varies continuously throughout the day in a more or less anticipated manner. The large and slow changes in demand are followed centrally by committing at regular intervals different generating units, known as unit commitment. It may be carried out once a day to provide the daily operating schedule whilst at shorter intervals, typically every 30 minutes, it is the role of economic dispatch that determines the actual power output supplied by each of these committed generators.

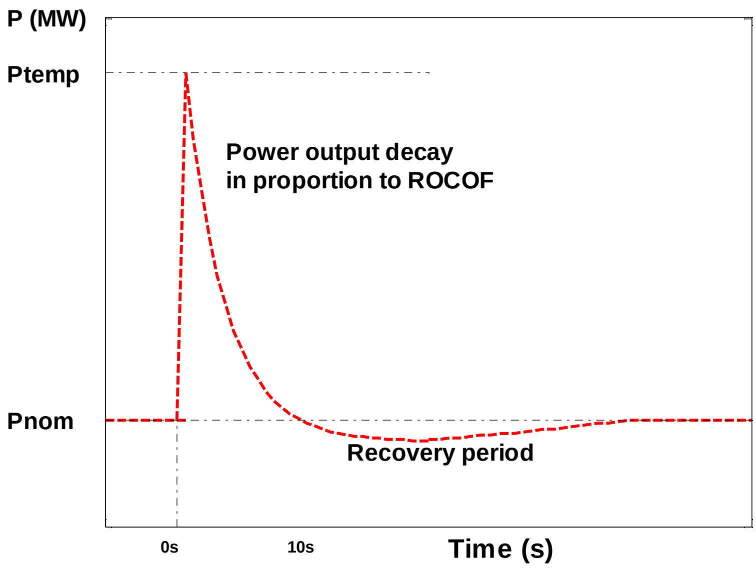


Figure 1-5 Inertial response from a synchronous machine

The response of a power system to a power imbalance is a complex, dynamic process as explained in power system stability and control textbooks, for instance [12] by Kundur *et al.* and [15] by Bumby *et al.*. It shows that this response can be divided into four stages depending on the duration of the dynamics involved [15]:

- Stage I Rotor swings in the generators (first few seconds)
- Stage II Frequency drop (a few seconds to several seconds)
- Stage III Primary control by the turbine governing systems (several seconds)
- Stage IV Secondary control by the central regulators (several seconds to a minute)

The dynamics associated with rotor swings in Stage I following a large disturbance on the system are highly nonlinear. Under steady state conditions, equilibrium is established between the input mechanical power and the output electrical power on each synchronous machine and its rotor speed remains constant at synchronous speed. The sudden disconnection of a generator on the system will produce rotor swings in the remaining generating units. At the instant of generation loss, the rotor angle of the remaining generators cannot change immediately and the electrical power exceeds the mechanical power delivered by its prime mover. The rotor is then decelerated and tends towards a new equilibrium point. It is known, for example [15], that at this stage the power contribution from each remaining generator will be determined by its electrical distance from the disturbance. The power imbalance will be shared among these connected generators each experiencing a different share and deceleration (or acceleration) until they settle to a new steady state condition. This stage lasts only for a few seconds until all the generators on the system reach a new steady state operation that differs from that prior to the disturbance.

This research is focused on the collective behaviour of all the generators in the system, e.g. Stage II, and the dynamics during the first rotor swings are ignored. During Stage II of the dynamics, the power contribution of each remaining generator in meeting the power imbalance is determined by its inertia and not by its electrical distance from the disturbance [15].

1.2.5 Frequency response services from wind generation

It is shown in Figures 1-6 to 1-7 that variable speed wind turbines demonstrate a different characteristic compared to conventional synchronous machines. Figure 1-6 illustrates the frequency dynamics when a large generation loss occurs on the power system with and without large amount of wind generation on the system. It can be seen in Figure 1-6 that for the same generation loss, it is not possible to maintain the system frequency within the frequency limit (49.2 Hz) when a large amount of wind generation is connected to the system and unable to contribute to system inertia.

Figure 1-7 shows the response from synchronous generators and wind generation after a frequency fall on the system. Unfortunately, variable speed wind turbines as explained above are decoupled from the system frequency and thereby cannot behave in the same way as synchronous machines. The power output of such wind turbines will remain unchanged (blue line in Figure 1-7) when a frequency fall occurs assuming there is no variations in wind speed at the time in question.

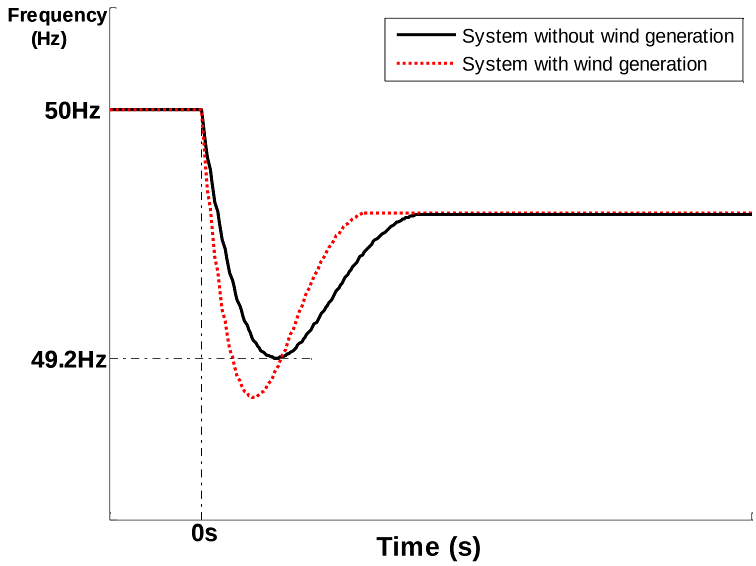


Figure 1-6 System frequency with reduced inertia after 1.8 GW generation loss

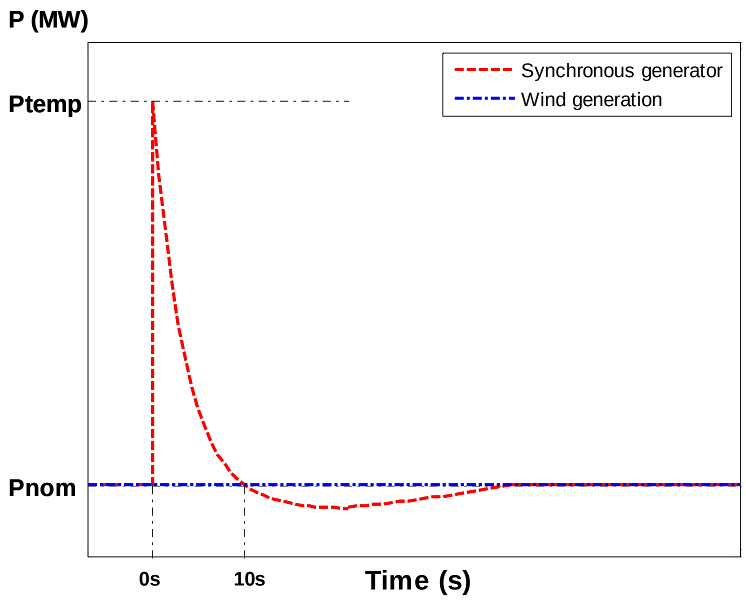


Figure 1-7 Response following a sudden generation loss (Source: National Grid UK)

With high wind penetration into the system there will be occasions when the capacity of conventional generators is limited so that an adequate level of response and reserve may be difficult to maintain, for instance, at times of low demand, depending on the instantaneous wind penetration level on the system.

1.3 Literature review

It was shown some years ago that variable speed wind turbine controllers can be modified to provide synthetic inertia support in response to changes in network frequency. GE in the USA filed a patent for this in the late 1990s and various papers were published soon after this, for instance [16-18]. A research group led by Professor Mark O'Malley at University College Dublin proposed to synthesise the inertial response from a DFIG by adding a supplementary torque term to the reference torque T_{ref} (in normal turbine operation) as shown in Figure 1-8. Under normal operation, the controller will keep the turbine at its optimal speed in order to produce maximum power. In the event of a frequency drop, the modified turbine controller will deliver a similar response to the inertial response of the conventional generator. The additional torque term will adapt the torque set point as a function of ROCOF.

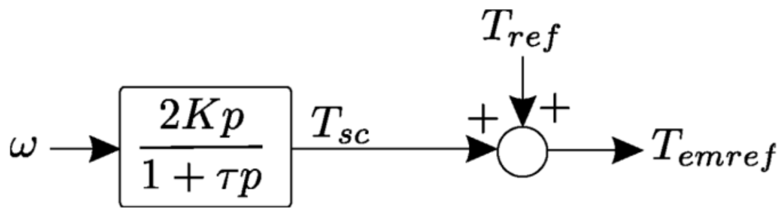


Figure 1-8 Supplementary control loop for DFIG controller, taken from [16]

It is also shown in [17] that the DFIG controller can be modified by adding a supplementary control loop which is independent of normal wind turbine operation and responds to system frequency changes using the derivative of system frequency, df/dt. It shows that the system frequency gradually falls from nominal value of 50 Hz to 49.75 Hz within around 20 seconds and the output power increases from pre-fault value of 0.68 pu to over 0.82 pu immediately after the frequency drop. However, the inertial power support lasts only a few seconds and the output power then rapidly decreases to below 0.68 pu before it returns to the pre-fault value, which suggests that the proposed inertial response is a 'one shot' scheme that responds to the rate of change of frequency (ROCOF), [17]. The same inertial control strategy was presented in [18].

It has been shown by engineers in Vestas [19], [20], that a variable speed wind turbine can provide an active power surge of 0.2 pu for at least 10 seconds. The power surge can be held constant despite the rotor speed falling over the transient. However, this consequently results in a longer recovery period and prolongs the power deficit resulting from operating the wind turbine below maximum energy capture efficiency. Figure 1-9 shows the wind turbine power against the rotor speed, where the blue line is the produced power under normal operation for a whole range of wind speeds. The black line represents the mechanical power captured by the turbine rotor at a given wind speed with Point 1 being the initial moment for the additional electrical power generation. When the over-production of electrical power is required by the amount of ΔP_{OP}, the turbine increase its power output and jumps from Point 1 to Point 2. As a result, the turbine rotor slows down to release the kinetic energy stored and so the electric output follows the trajectory from Point 2 towards Point 3, while the electrical output remains constant. When the rotor speed reaches the predefined lower limit of 0.7 pu, the provision of inertial response is terminated and the electrical output is reduced to below the mechanical power captured allowing the rotor to accelerate back to normal operation.

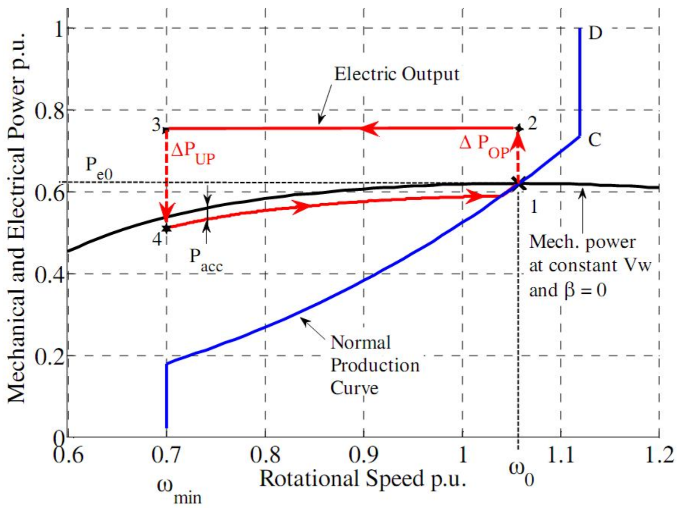


Figure 1-9 Wind turbine power vs the rotational speed, taken from [19]

In summary, for various speed wind turbines, e.g. DFIGs and FRCs, intrinsic inertial response cannot be seen by the electrical network owing to the decoupling between grid frequency and generator speed. However, synthetic response can be created with a supplementary inertial control loop which proportionally responds to grid frequency deviation [21-23].

In the last few years, research efforts on inertial response from wind turbines have attracted significant attention [16, 18, 21, 24-28]. Until recently wind turbines have not been required to provide such inertial response in practice, although some grid codes already include provisions for such services, for example Eirgrid [29, 30] and Hydro Quebec TransEnergie (HQT) [31]. National Grid in the UK has been working closely with industrial partners to assess frequency management challenges with the reduced system inertia due to the increasing non-synchronous wind capacity and the potential loss of up to 1800 MW in capacity [32, 33]. In France, EDF have supported PhD research at the University of Lille on virtual inertia from energy storage [34, 35].

There are various measures of system frequency change, most notably the derivative of system frequency and frequency deviation from nominal system frequency. Various responses are possible, such as a constant power increase in response to a system frequency change beyond a preset threshold, or alternatively a constant additional torque [36].

Morren *et al.* have examined the impact of using the two most common measures of system frequency change, namely the derivative of system frequency and the deviation of system frequency from the nominal value, to act as a trigger to initiate inertial control of a wind turbine, [37]. They conclude that use of the deviation of system frequency from the nominal value can provide better performance than use of the derivative of system frequency in case of a grid frequency event.

Knuppel *et al.* have pointed out that use of the derivative of system frequency for initiating inertial response may be practically difficult due to measurement noise and controller tuning, [38].

It has been shown in [39] that wind turbines can provide active power reserve using various de-loading strategies for different wind regimes: low load, partial load and full load operation. It shows that control of pitch angle can be effectively applied to full load operation (above rated) and de-loading can be achieved through increase in rotor speed (thus reduction in power coefficient) for low and partial load operations (below rated).

Research has also shown that frequency support from wind can be implemented not only at single turbine level but also at wind plant level and wind generation as a whole [40, 41].

An automatic generation control system has been implemented and validated on a wind plant in Spain [40]. It shows that improved performance in terms of plant output can be achieved using a supervisory plant control system providing power settings to individual wind turbines. A centralised wind farm control scheme is presented in [41] that comprises control systems on both plant and individual machine levels. It shows that the power production level required by the system operator can be allocated to each turbine within the wind farm. It is assumed that wind speed remains constant throughout the wind farm whereas in reality it is rarely the case. Research has also been taken further to system level investigating a coordinated control system of frequency support from wind in an island power system in Denmark [42]. It shows that better dynamic performance can be achieved through the combination of frequency support from wind generation in the system as a whole and conventional power plant.

1.4 Contributions of the thesis

The main original contributions of this PhD project are listed below:

- Development of a probabilistic approach to assessing collective synthetic inertial response from a wind farm taking into account turbulent wind variations and the differing response of the individual turbines.
- Extending the probabilistic approach to cover all wind plant across the GB power system.

- Linking the wind plant representation with a simplified dynamic model of the GB power system to be able to assess the aggregate impact of wind providing inertial support to the power system.
- Analysis of different approaches to delivering droop response from wind plant.
- Assessment of combined droop and inertial response from wind plant.
- Providing an approach that could be used by System Operators to schedule frequency support services together with weather forecast systems and local wind capacity.

1.5 **Structure of the thesis**

This thesis is set out as follows:

Chapter 1 describes the background, motivation and contribution of the research. In this chapter, power balancing issues and frequency requirements in power systems are introduced. Different types of frequency response from conventional and wind plant are presented. Early studies on frequency support from wind plant are also reviewed.

Chapter 2 describes variable speed wind turbine technologies, e.g. DIFG and FRC, etc., and latest development, especially offshore. The modelling of a variable speed wind turbine used throughout the research is also explained.

Chapter 3 explains the control strategy used in this research to provide synthetic inertial response from wind plant. A probabilistic approach to assessing the aggregate inertial response from wind plant is introduced in this chapter. Wind turbulence during the provision of synthetic inertia response is described by a Gaussian probability distribution.

Chapter 4 proposes a probabilistic approach to modelling the collective inertial contributions from wind generation in the GB power system taking account of the regional mean wind speeds and the wind capacity in each region. The impact of power contributions from the operational wind capacity on frequency stability is examined.

Chapter 5 examines the provision of continuous frequency response (droop control) from wind plant participating in continuous modest frequency changes. Delivering combined droop and inertial response from wind plant is also investigated in this chapter.

Chapter 6 presents the conclusions and limitations of this research. Future work is also included in this chapter.

1.6 **Publications**

Journal Papers

[1] **Wu L** and Infield DG, 'Towards an Assessment of Power System Frequency Support from Wind Plant – Modelling Aggregate Inertial Response'. Volume: 28, Issue: 3, *IEEE Transactions on Power Systems, 2013.*

[2] **Wu L** and Infield DG, 'Power System Frequency Management Challenges – A New Approach to Assessing the Potential of Wind Capacity to Aid System Frequency Stability'. Accepted by *IET Renewable Power Generation, Jul. 2014.*

Conference Presentations

[3] **Wu L** and Infield DG, 'Stabilizing Power System Frequency by Exploiting Wind Turbine Inertia'. Oral presentation at the UK-China Workshop on SUPERGEN, in Hangzhou, China, 12th -17th Sept. 2010

[4] **Wu L** and Infield DG, 'Modelling the Provision of Inertial Response from Variable Speed Wind Turbines'. Oral presentation at the international IET Conference on Renewable Power Generation, in Edinburgh, UK, 6th -8th Sept. 2011.

[5] **Wu L** and Infield DG, 'Wind Plant Contributions to Power System Frequency Response'. Scientific Proceedings at European Wind Energy

Association Annual Conference (EWEA 2012), in Copenhagen, Denmark, 16th -19th April, 2012.

[6] **Wu L** and Infield DG, 'Investigation on the Interaction between Inertial Response and Droop Control from Variable Speed Wind Turbines under Changing Wind Conditions'. *The 47th International Universities' Power Engineering Conference (UPEC 2012),* in London, UK, 4th -7th Sept., 2012.

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[8] **Wu L** and Infield DG, 'Delivering Combined Droop and Inertial Response from Wind Plant to the GB Power System'. *The 11th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants*, in Lisbon, Portugal, 13th -15th Nov., 2012.

[9] **Wu L** and Infield DG, 'Assessing Emulated Inertial Response from Wind Generation in the GB Power System'. Scientific Proceedings at European Wind Energy Association Annual Conference (EWEA 2013), in Vienna, Austria 6th -8th Feb., 2013.

[10] **Wu L** and Infield DG, 'Power System Frequency Management Challenges – A Probabilistic Approach to Assessing Wind Farm Potential for Aiding System Frequency Stability'. Oral presentation at the international IET Conference on Renewable Power Generation, in Beijing, China, 6th -8th Sept. 2013.

[11] **Wu L** and Infield DG, 'Assessing Frequency Stability in the GB Power System with High Wind Penetration'. Accepted by International Council on Large Electric Systems (CIGRE) Conference, in Paris, France, 24th -30th Aug. 2014.

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Chapter Two Variable speed wind turbine technology and modelling

2.1 Background

The power, P, captured by a wind turbine is given by the well-known expression:

$$P = \frac{1}{2}\rho A U^3 C_P(\lambda, \theta) \tag{2-1}$$

where P is the aerodynamic power captured by the turbine rotor, ρ is the air density in $\mathrm{kg/m^3}$, A is the area swept by the rotor blades in m^2, U is the wind speed in m/s, and C_P is the power coefficient which is a measure of the aerodynamic efficiency of the rotor and is defined as a function of tip speed ratio λ and pitch angle θ.

The density of air is rather low. Dry air has a density of 1.2041$\mathrm{kg/m^3}$ at 20 ℃ and 101.325 kPa. This leads directly to the large size of a wind turbine rotor in order to capture as much energy from the wind as possible. For instance, Vestas's recently developed V164-8.0 MW offshore prototype features a 164-metre rotor diameter.

The power coefficient C_P describes the fraction of the power in the wind that may be captured by the turbine rotor. It has a theoretical maximum value of 0.593, known as Betz limit, but lower peak values are generally achieved in practice. The power coefficient of a turbine rotor varies with the tip speed ratio λ and only achieves the maximum for a unique value of λ known as $\lambda_{opt.}$ A typical wind turbine C_P-λ curve with pitch angle being zero is shown in Figure 2-1.

The tip speed ratio λ is given by:

$$\lambda = \frac{R\Omega}{U} \tag{2-2}$$

where R is the radius of the rotor in metres, Ω is the rotational speed of the rotor in rad/s, U is the wind speed in m/s. By varying the rotor speed in proportion to the

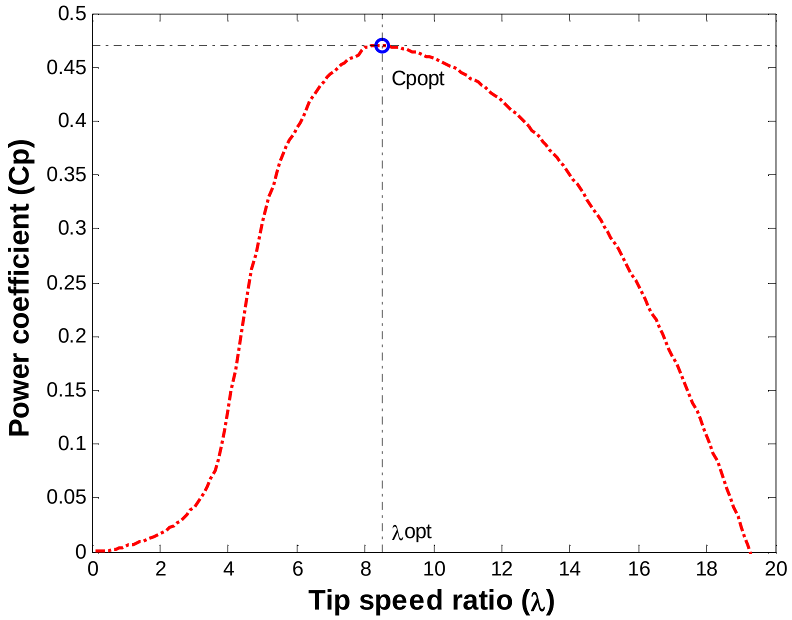

Figure 2-1 A typical wind turbine C_P-λ curve

wind speed, the tip speed ratio λ can be maintained at the optimal value λ_{opt} and so achieve the corresponding maximum C_{Popt} as shown in Figure 2-1.

There have been incremental improvements in the power coefficient C_P through optimised design of the rotor. It is currently possible to maintain the maximum (or near maximum) power coefficient over a wide range of wind speeds by operating the rotor at variable speed. However, these methods will give only a modest increase in turbine power output compared to fixed speed designs. Major increases in the output power can only be achieved by increasing the swept area of the rotor or by placing the turbines in areas with strong wind speeds. It is therefore natural that the rotor diameter has been continuously increasing over the past decades from around 30 meters to more than 170 meters today.

It can be seen from Equation (2-1) that a doubling of the rotor diameter will result in a four-times increase in power output. The influence of the wind speed is even greater and a doubling of wind speed will lead to an eight-fold increase in power due to the cube law. Thus there have been considerable efforts to ensure that wind farms are located in areas with strong wind and the individual turbines are sited optimally within the wind farm.

As a consequence of the increasing penetration levels of wind energy into power systems, and the new types of wind generators introduced to the generation mix, enormous efforts have been made towards properly representing steady and dynamic characteristics of wind turbines in large-scale power system stability analysis. Four basic wind turbine generator (WTG) configurations are often studied:

- Type 1 - Fixed speed wind turbine with a squirrel-cage induction generator
- Type 2 - Fixed speed wind turbine with a wound-rotor induction generator and adjustable rotor resistance
- Type 3 - Doubly fed induction generator (DFIG) based wind turbine
- Type 4 - Fully rated converter (FRC) based wind turbine

The basic principle of induction machines is electromagnetic induction. The voltage applied to a multiple-phase AC stator winding results in currents which in turn produce a rotating magnetic field. This field induces voltages (and therefore currents) in the rotor circuit. The interaction between the stator produced field and the rotor induced currents produces torque. When the induction machine is driven by a prime mover at a speed greater than its synchronous speed, it acts as a generator.

Wind turbine type 1 is one of the oldest technologies used in wind developments. It normally consists of an induction generator operating in a low slip range between 0 – 1% [1]. Many such turbines employ dual-speed induction generators which use two sets of windings within the stator frame. One set is designed to operate at a low rotational speed and the other is designed to operate at a high rotational speed. In this way, an improvement in energy capture can be achieved by operating the turbine at one of two fixed speeds so that the tip speed ratio is closer to the optimum than with a single fixed speed. Due to the high start-up current, it is common to employ a soft-starter to limit start-up currents. This type of wind turbines often requires high reactive power compensation using switched capacitors in parallel with each phase of the windings.

Wind turbine type 2 employs a wound rotor induction generator with variable external resistors. The external resistors can be varied to adjust the physical characteristics of the induction generator and thus to improve power extraction and prevent from exceeding the ratings. Type 2 turbines augment type 1 by allowing for a wider operating speed range.

Over the years, variable speed wind turbines have become the dominant technology. This is largely because variable speed operation can provide wind turbines with the ability to better comply with grid connection requirements and to achieve reduced mechanical loads as the turbine size continues to grow [1]. Variable speed wind turbines are designed to achieve maximum aerodynamic efficiency over a wide range of wind speeds. Below rated wind speed, the tip speed ratio λ can be maintained at the optimal value that corresponds to the maximum power efficiency by varying the rotational speed of the turbine rotor in proportion to the wind speed. At this tip speed ratio, λ_{opt}, the power coefficient C_P reaches maximum and so the aerodynamic power captured by the rotor is maximised. This is often used to justify that a variable speed wind turbine can capture more energy than a fixed speed wind turbine of the same size. However, practically this may not be as easy to achieve as this simple argument suggests because of the limitation of control regimes [2].

The configuration of a variable speed wind turbine is often more complex than that of a fixed speed wind turbine. Modern variable speed wind turbines typically employ an induction generator or synchronous generator that is connected to the network through power electronic converters and thus such turbines are decoupled from the power system frequency.

Different technologies of variable speed wind turbines are discussed and compared in this chapter. To establish a large wind turbine model that is representative of typical utility-scale multi-megawatt turbines, a 3 MW wind turbine conceptual model has been developed for use in this research. This 3 MW wind turbine is taken to be a three-blade, upwind, variable-speed, variable blade-pitch-to-feather wind turbine. The design of the turbine is based on a commercial machine [3] and has been chosen and modified specifically to assess the aggregate frequency support from wind plant.

This chapter is set out as follows: Section 2.2 describes DFIG wind turbines. Section 2.3 introduces FRC wind turbines. Section 2.4 compares various wind turbine technologies and latest developments, especially offshore prototypes. Section 2.5

describes the modelling of variable speed wind turbine developed in this research, and finally conclusions are presented in section 2.6.

2.2 The DFIG wind turbine

A simplified schematic of a DFIG wind turbine is shown in Figure 2-2. It consists of a wound-rotor induction generator with slip-rings to transfer current between the generator rotor windings and the converter. A DFIG wind turbine can deliver power to the network through both the generator stator and rotor. Power will be delivered to the network from the rotor when the generator is operating above synchronous speed while the rotor will absorb power from the network when the generator is operating below synchronous speed.

Together, the two power electronic converters are capable of four-quadrant operation which allows the active and reactive power to be transferred in either direction. The rotor-side voltage source IGBT converter is linked to a network-side IGBT converter through a direct current (DC) link[2]. The rotor-side converter will regulate the turbine rotating speed by feeding a controllable voltage into the rotor at the desired slip frequency and so enable variable speed operations [1]. The generator is normally controlled on the basis of vector control which decouples the active and reactive power control functions and provides great flexibility. It can also provide superior transient response which enables the induction generation to rapidly respond to changes in torque command. This enhances its capability of energy extraction from gusts and relieves drive-train stresses.

The function of the network-side converter is to transfer the required active power from the DC link to the grid or vice versa. This is carried out through a voltage control loop which ensures that the DC link voltage is maintained within specified limits (ie nominally constant). For instance, when more energy is required to deliver to the DC link from the turbine in response to increase in wind speed, the DC link capacitor will be overcharged and its voltage will increase. This will prompt the network-connected converter to transfer power from the DC link to the network.

[2] Sometimes this combination is referred to as a single converter.

Both converters are controlled through PWM techniques which ensure minimum harmonic injection into the network. Together, these converters decouple the network electrical frequency from the rotor mechanical frequency.

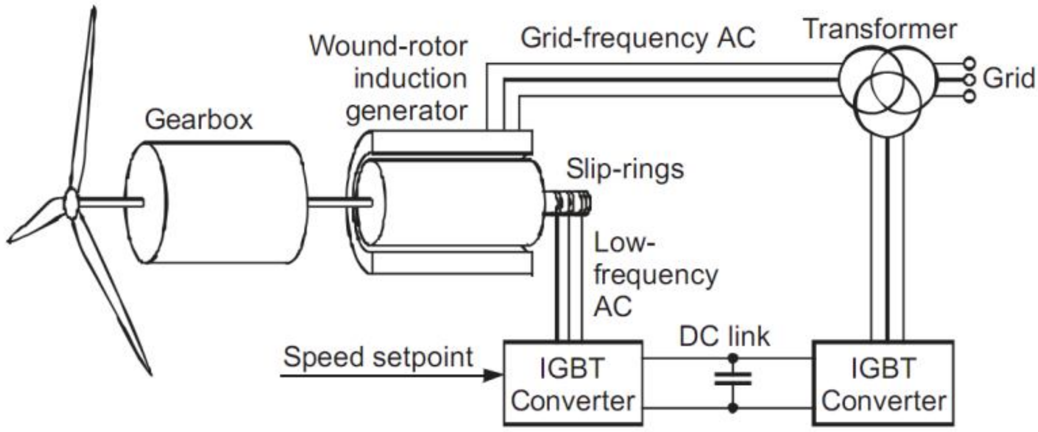

Figure 2-2 A typical DFIG wind turbine, taken from [4]

2.3 The FRC wind turbine

Fully rated converter (FRC) wind turbines are gradually gaining ground as the turbine size continues to grow. Fully, in this context, means that all the power going through the converters in contrast with DFIGs having typically around a third of the total power go through the converters. A wide range of electrical generators can be employed such as induction generators, conventional or permanent magnet synchronous generators. For a FRC wind turbine, the dynamics of the electrical generator is effectively isolated from the power network because all the power produced will be delivered to the grid through the power electronic converter. The electrical frequency of the converter on the network side is identical to the network frequency while the frequency on the generator side varies with the changing wind speed.

2.3.1 FRC wind turbines with induction generators

A fully rated converter wind turbine with an induction generator is shown in Figure 2-3. Either wound rotor or squirrel-cage induction generator can be employed in such schemes. The converters of a FRC turbine allow the standard squirrel-cage induction generator to operate at variable frequency, and thus allow anything from 0 to 100%

variable speed operation. The active power from the induction generator is rectified by the generator-side converter and then fed to the DC link. The network-side converter acts as an inverter, transferring power to the network from the DC link.

Vector control of the induction generator is also employed, similar to that of a DFIG. The reactive power demand of the induction generator is provided by the generator-side converter, whilst the network-side converter is used to transfer the generated active power to the network and also inject or absorb reactive power to/from the network respectively. The main drawback of this scheme is that two IGBT converters rated at full power are needed and such converters are expensive. The advantage is that the generator is a robust squirrel-cage machine and the DC link is more system friendly during AC network faults and disturbances.

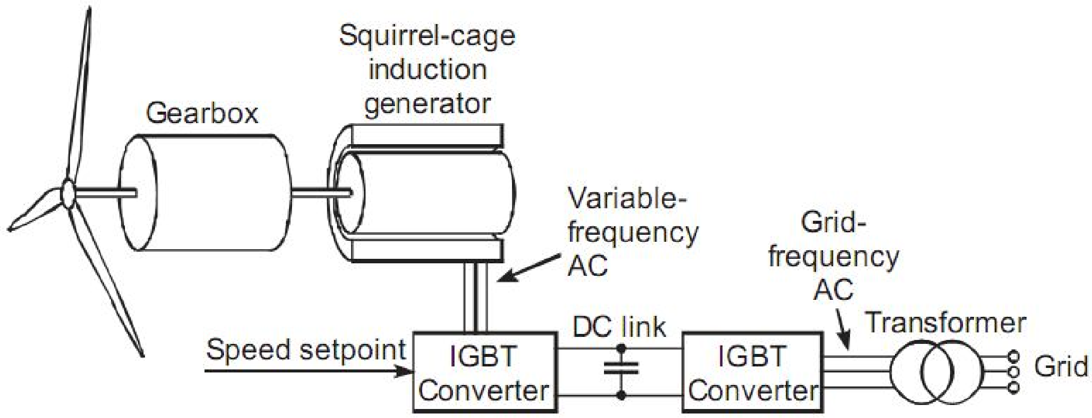

Figure 2-3 A FRC wind turbine with an induction generator, taken from [4]

2.3.2 FRC wind turbines with synchronous generators

A synchronous generator can be used in place of the induction machine of section 2.3.1. Unlike an induction generator it does not need to be supplied with reactive power and therefore the output power can be delivered to a DC link through a simple bridge rectifier or controlled rectifier. It can be manufactured with a very large diameter and large number of poles. Such a machine can operate at low speed and high torque, and so can be directly coupled to the turbine rotor, eliminating the need for a gearbox.

A synchronous generator can be built either with a wound rotor supplied with a suitably controlled DC field excitation current, or with a permanent magnet rotor. Both approaches have been demonstrated in large scale wind turbines. A wound rotor has the advantage of controllability of the generated voltage through field current control. This reduces the DC link duties compared to a rotor with permanent magnets in which the generator terminal voltage is proportional to the speed. However, with permanent magnets the generator is more efficient due to the absence of external excitation which appears as a loss in overall efficiency. As the AC output is rectified, it is not required to generate a frequency as high as 50 Hz at the highest rotational speed.

As shown in Figure 2-4 the generator-side converter could be a simple diode rectifier, which is typical in small wind turbines. In larger wind turbines, a controlled rectifier is often used. Depending on the choices above, the DC bus may or may not keep a constant voltage as the speed varies. The network-side converter is likely to be an IGBT based inverter that is required to transfer active power unidirectionally but is capable of injecting or absorbing reactive power to/from the grid.

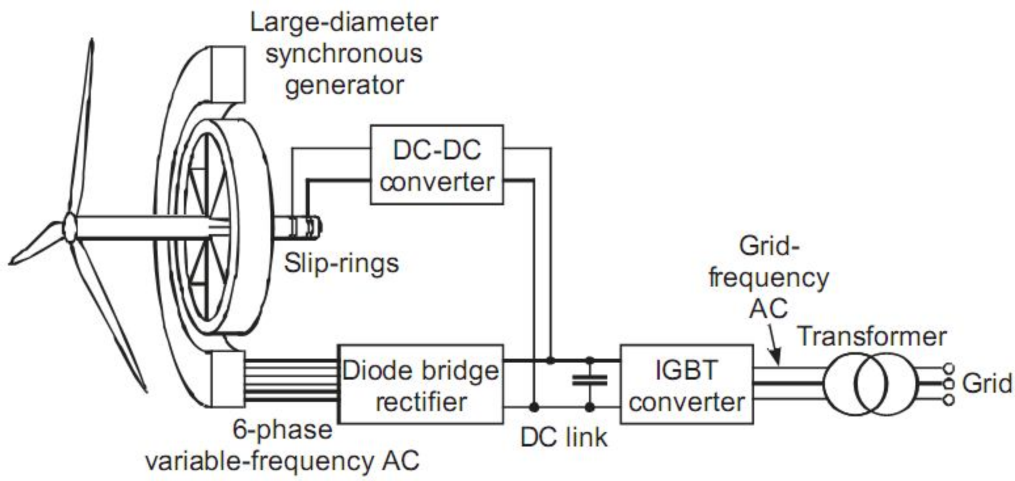

Figure 2-4 FRC wind turbine with a synchronous generator, taken from [4]

2.4 Wind turbine technology and development

Until the late 1990s, fixed speed wind turbines using a multistage gearbox and standard squirrel-cage induction generator had been the dominant technology. Since the late 1990s, variable speed wind turbines have been increasingly installed around the world because of the requirements associated with the larger turbine size and tougher grid codes (including fault ride through). There have been numerous generator systems proposed for variable speed wind turbines, most of which can generally be categorized into DFIG and FRC as described above.

Five different generator systems for conventional variable speed wind turbines have been compared in [5], namely the doubly fed induction generator with three-stage gearbox (DFIG3G), the doubly fed induction generator with single-stage gearbox (DFIG1G), the direct-drive synchronous generator with electrical excitation (DDSG), the permanent magnet generator with no gearbox (DDPMG) and the permanent magnet generator with single-stage gearbox (PMG1G). A generic 3 MW wind turbine was used to compare the five generator systems. Note the comparisons in [5] are not based on latest technologies however the impact of new turbine technologies has been updated below.

The results show that the DFIG3G is the lowest cost solution using standard components which can explain why this technology has been the most commercially successful so far. However, DFIG3G has a low energy yield due to the relatively high losses in the gearbox. Moreover the gearbox has been the largest contributor to turbine downtime because of the complexity involved in repair and replacement. The paper concludes that because DFIG3G is largely constructed from standard components, major improvements in performance or cost reduction may be difficult to achieve. The DFIG1G is an interesting option in terms of energy yield per unit cost. However, this system has not been attractive to turbine manufacturers so far. The DDSG appears to be the heaviest and most expensive scheme.

The DDPMG generator system seems much more attractive to turbine manufacturers, offshore applications in particular. This is because it eliminates the need for a gearbox and the overall weight of the generator for the same air-gap diameter is nearly halved. It seems that there is a trend in time towards larger turbines and also a convergence towards the use of permanent magnet generators in offshore wind development. The PMG1G has not been widely considered as a viable option. However, it also has the potential for other applications, for instance, ship propulsion.

It should be noted that these comparisons are primarily based on onshore data owing to the fact that offshore data are either limited or unavailable in the public domain.

Different drivetrain configurations for offshore wind applications have been compared in [6]. In their work, a probabilistic-statistical approach presented in [7, 8] has been used to estimate delays due to sea conditions and the travel and positioning times of vessels for offshore wind. The offshore turbine availability for different drivetrain configurations is then examined taking into account offshore failure rates and delays resulting from sea conditions and access difficulties. It shows that permanent magnet synchronous generators consistently outperform the wound rotor synchronous generator for various gearbox types. This may in part explain why offshore turbines are increasingly employing permanent magnet generators. It also concludes that single stage gearboxes outperform three and two stage ones across all generator and converter types. It should be noted that assumptions about component reliability are critical to results such as these, and there is limited data on the reliability of very large direct drive generator designs.

The choice of wind turbine technologies has a profound impact on availability and, ultimately, cost of energy for wind [9]. It is shown in [6] that DDPMG with a fully rated converter exhibits the best availability for offshore applications whilst the normal wound rotor DFIG outperforms all the other turbines with three stage gearboxes.

Wind turbine technology has developed rapidly over the last two decades. The rated capacity of onshore turbines has increased from 100kW to around 3MW during this period. However, due to site constraints and difficulties in transport, onshore turbine sizes are unlikely to continue growing.

The economics of offshore wind as explained in [10] are currently driving the scaling-up of wind turbine technology which is anticipated to considerably exceed the size of the largest onshore machines today. This scaling-up to around 8 MW today together with the anticipated increase in turbine rating to perhaps 15 MW over the next decade is driving changes in turbine design. For instance, larger offshore turbines tend to adopt fully rated converters, whereas an onshore wind turbine typically uses a doubly fed induction generator and includes a gearbox to step up the rotational speed. Current designs also include the arrangement of direct drive permanent magnet synchronous generators with no gearbox, the arrangement of conventional drive trains with either induction generators or wound rotor synchronous generators, or hybrids of the two with a permanent magnet generator and low ratio gearbox.

Table 2-1 summarises the characteristics of a number of large turbines under development around the world, specifically for offshore application. Note that the date of prototype testing may change and that zero gearbox stages mean direct drive.

These designs would not be economically viable for onshore application where different economies of scale apply. For offshore applications where the cost of wind turbines will account for a smaller portion, it is preferred to employ large wind turbines to reduce the levelised cost of energy. It can be seen clearly that there is a trend towards larger turbines and also a convergence towards the use of permanent magnet generators, although limited operation experience with such electrical machines and the associated bearing arrangements means that their reliability is in practice unknown.

Table 2-1 Selected planned offshore prototypes (taken and updated from [10])

Manufacturer	Model	Date of prototype test	Rated power (MW)	Generator type	Gearbox stages
Areva	M5000	2004	5.0	PM	2
Repower	5M	2004	5.0	DFIG	3
Bard	Bard 5.0	2008	5.0	DFIG	3
Repower	6M	2009	6.2	DFIG	3
Bard	Bard 6.5	2011	6.5	PM	3
Sinovel	SL 6000	2011	6.0	DFIG	3
GE Energy	4.1-133	2011	4.1	PM	0
Guodian UP	UP-6000	2012	6.0	DFIG	3
Goldwind	PMDD6000	2013	6.0	PM	0
Siemens	SWT 6-154	2013	6.0	PM	0
Alstom	Haliade150	2013	6.0	PM	0
Gamesa	G11X-5.0	2013	5.0	PM	2
Nordex	N150/6000	2013	6.0	PM	0
Samsung	S7.0-171	2013	7.0	PM	3
Enercon	E-126	2013	7.5	PM	0
Vestas	V164/8.0	2014	8.0	PM	2
Gamesa	G14X	2014	7.0	PM	2
Sway	Sway	2015	10.0	PM	0
AMSC	Sea Titan	2015	10.0	PM	0

2.5 Wind turbine modelling

A conventional variable-speed pitch-regulated wind turbine, rated at 3 MW, has been studied in this research that is typical of modern large machines. The general properties of this turbine are taken from a commercial machine [3], as shown in Table 2-2. In such wind turbines, the conventional approach for controlling power production operations comprises two basic control systems: a turbine torque controller and a collective blade pitch controller. These two control systems are designed to work separately: below rated wind speed/power the turbine torque controller functions to maximise energy capture, and above rated wind speed/power, the blade pitch controller acts to regulate the rotor speed and to maintain the power within ratings.

Table 2-2 Characteristics of the 3 MW wind turbine model

Rating	3 MW
Rotor orientation, configuration	Upwind, 3 blades
Control	Variable speed, collective pitch
Drive train, ratio	High speed, multiple stage gearbox, 1:100
Rotor diameter	100 m
Hub height	81 m
Cut in, rated, cut out wind speed	3 m/s, 11.2 m/s, 25 m/s
Cut in, rated rotor speed	0.5095 rad/s, 1.8983 rad/s

The wind turbine model developed in this research is described below, including a simple rotor aerodynamic model, lumped drive train model, and turbine controller. In modern turbine technologies, the electrical sub-system has a much smaller time constant than the mechanical sub-system. It is thus reasonable to assume the electrical sub-system performs instantaneously as required by the turbine supervisory controller. This is an acceptable simplification for the purpose of investigating the performance of frequency response from individual wind turbines and a wind farm collectively, even under time varying wind speeds.

2.5.1 Rotor aerodynamics

A general rotor aerodynamic model that represents the captured energy from the wind is given by Equation (2-1). As mentioned, the turbine modelled in this research is typical of large modern machines and is taken from a commercial design [11]. The assumed turbine operating regime is shown in Table 2-3.

Table 2-3 Wind turbine operational regime

Wind speed (m/s)	Electrical power (MW)	Aerodynamic power (MW)	Rotor speed (rad/s)	Pitch angle (degree)
3	0.0580	0.0611	0.5095	0
4	0.1375	0.1447	0.6793	0
5	0.2673	0.2827	0.8492	0
6	0.4640	0.4885	1.0190	0
7	0.7369	0.7756	1.1888	0
8	1.0999	1.1578	1.3587	0
9	1.5661	1.6485	1.5285	0
10	2.1483	2.2614	1.6983	0
11	2.8594	3.0099	1.8682	0
11.2 (rated)	3	3.1579	1.8983	0.34
11.5	3	3.1579	1.8983	2.53
12	3	3.1579	1.8983	4.31
13	3	3.1579	1.8983	6.66

14	3	3.1579	1.8983	8.48
15	3	3.1579	1.8983	10
16	3	3.1579	1.8983	11.43
17	3	3.1579	1.8983	12.72
18	3	3.1579	1.8983	13.93
19	3	3.1579	1.8983	15.07
20	3	3.1579	1.8983	16.18
21	3	3.1579	1.8983	17.26
22	3	3.1579	1.8983	18.31
23	3	3.1579	1.8983	19.32
24	3	3.1579	1.8983	20.31
25	3	3.1579	1.8983	21.28

Figure 2-5 shows a plot of the aerodynamic power against rotor speed for a series of wind speeds at optimal pitch angle $\theta_{opt} = 0^0$. It should be noted that at the rated wind speed of 11.2 m/s, the captured aerodynamic power reaches a maximum which is slightly higher than the rating (3 MW) of the turbine. This is because a 5% loss at the drive train and generators is assumed throughout this modelling study. The red line in Figure 2-5 represents the optimal operational conditions for each wind speed (below rated). The rotor speed will be kept nominally constant for above rated wind speed as will the demanded torque. This is achieved by varying the blade pitch angle with the changing wind speed as will be explained in detail below.

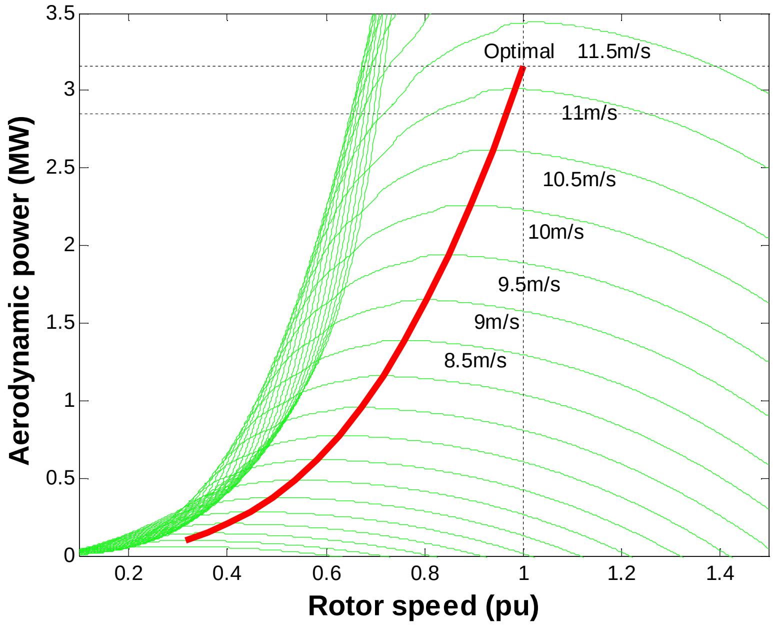

Figure 2-5 Aerodynamic power versus rotor speed

2.5.2 Drive train model

The lumped inertia drive train model used in this research is given by:

$$J\frac{d\omega}{dt} = T_{aero} - T_d \qquad (2\text{-}3)$$

where J is the total (lumped) inertia of the drive train system including rotor, gearbox, shafts couplings etc, and the generator (note that the generator inertia has been referred to low speed shaft), ω is the mechanical rotational speed of the rotor, T_{aero} and T_d are the aerodynamic torque supplied to the system and the torque extracted from the system at the generator (sometimes called the air gap torque). When the wind speed changes, the imbalance between aerodynamic torque and demanded torque will cause the rotor to accelerate or decelerate. The turbine controller will then act to bring the turbine back to balance in order to ensure that the rotor can capture maximum energy from the wind within the rating of the turbine.

2.5.3 Turbine controller

An advantage of variable speed wind turbines is that below rated wind speed, the rotor speed can be adjusted in proportion to the wind speed so that the optimum tip speed ratio and thus the maximum power coefficient, C_{Pmax}, is maintained. The power coefficient, C_P, will reach its maximum value at the optimum tip speed ratio, $\lambda = \lambda_{opt}$ which means that the aerodynamic power captured by the rotor is maximized.

Two basic control systems are necessary to regulate variable speed wind turbines. At low wind speed, the rotational speed of the rotor is regulated by varying the demanded torque at the generator in response to the measured rotor speed itself. As the wind speed increases, the energy available for capture will rise at the rate of the cube of wind speed. However, high wind speed is not encountered frequently enough to justify a drive train design that is able to extract the total energy available. So aerodynamic power limiting is required. At a pre-determined wind speed (rated wind speed), the limit on turbine power output is reached and the excess power in the wind must be discarded [12]. For simplicity, the variable speed wind turbine modelled in this research has adopted a control strategy assuming that the turbine torque controller is regulated from cut-in through to rated wind speed to track optimal power curve whereas for a sophisticated commercial wind turbine a constant rotational speed region at cut-in and also near rated wind speed is commonly used.

i. Below rated wind speed

Below rated wind speed, the rotor speed, ω, is proportional to wind speed, U, the power increases with U^3 and ω^3, and the torque with U^2 and ω^2. The aerodynamic torque is given by:

$$T_{aero} = \frac{1}{2}\rho\pi R^3 \frac{C_P}{\lambda} U^2 \qquad (2\text{-}4)$$

Since $U = \frac{R\omega}{\lambda}$, (2.4) can be written as:

$$T_{aero} = \frac{1}{2}\rho\pi R^5 \frac{C_P}{\lambda^3} \omega^2 \qquad (2\text{-}5)$$

In the steady state therefore, the optimum tip speed ratio can be maintained by setting the demanded torque at the generator to balance the aerodynamic torque. The demanded torque can then be regulated by (2.6) such that this torque changes to match the aerodynamic torque. It is generally unnecessary for this mode of operation to pitch the blades and therefore the pitch angle is set to its optimal value for below rated operation ($\theta_{opt} = 0^0$ in this case). Below rated torque control uses the standard relation

$$T_d = K_{opt}\omega^2 \qquad (2\text{-}6)$$

where K_{opt} is the constant (controller gain) for the tracking of the maximum power coefficient curve (under steady state conditions) and can be obtained by:

$$K_{opt} = \frac{1}{2}\rho\pi R^5 \frac{C_P}{\lambda^3} \qquad (2\text{-}7)$$

The parameters for the modelled turbine controller have been listed in Table 2-4.

Table 2-4 Wind turbine control parameters

C_{Pmax}	K_{opt}	λ_{max}	J ($kg \cdot m^2$)	ρ ($kg \cdot m^3$)	A (m^2)
0.47	4.67×10^5	8.46	12×10^6	1.225	7854

ii. Above rated wind speed

Above rated wind speed, blade pitch control system provides the way to regulate the aerodynamic power and limit the rotor speed, thus ensuring that rated power is not exceeded. Once the rated torque is reached, no further increase in demanded torque can be allowed, so the turbine will start to speed up. Pitch control is then used to regulate the rotor speed, with the demanded torque held constant. Figure 2-6 shows the corresponding blade pitch angle for a series of wind speeds above rated.

A linearization analysis of the rotor aerodynamics for a number of wind speeds above rated is shown in Table 2-5. Here $\frac{\partial P}{\partial \theta}$ is the blade pitch sensitivity that depends on the wind speed, rotor speed and blade pitch angle.

Note that the rotor speed has been maintained at constant (1.8983 rad/s) and the rated aerodynamic power is 3.16 MW. The linearization process involves perturbing the blade pitch angle at each operating point and calculating the resultant variations in aerodynamic power and can be obtained by:

$$\frac{\partial P}{\partial \theta} = \frac{1}{2}\rho A U^3 \frac{\partial C_P(\lambda,\theta)}{\partial \theta} \tag{2-8}$$

and

$$\frac{\partial P}{\partial \theta} = \frac{P_{aero-rated}}{C_P}\frac{\partial C_P(\lambda,\theta)}{\partial \theta} \tag{2-9}$$

The pitch sensitivity varies nearly linearly with blade pitch angle as shown in Figure 2-7. The red line in this figure represents the best fit line of the original data.

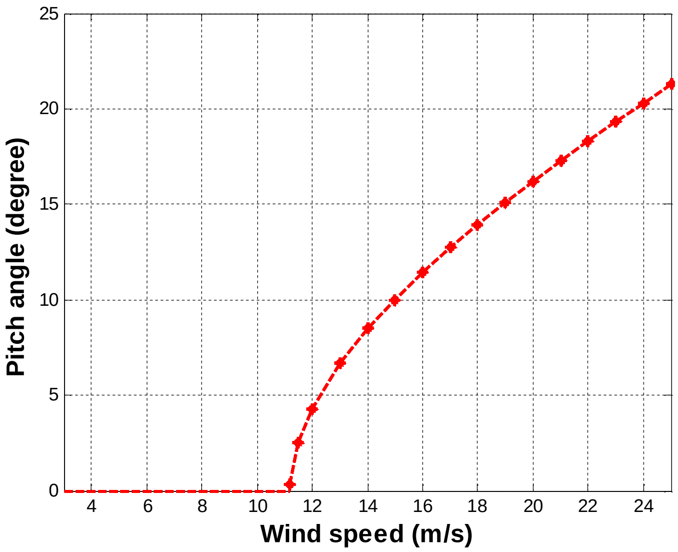

Figure 2-6 Blade pitch angle versus wind speed

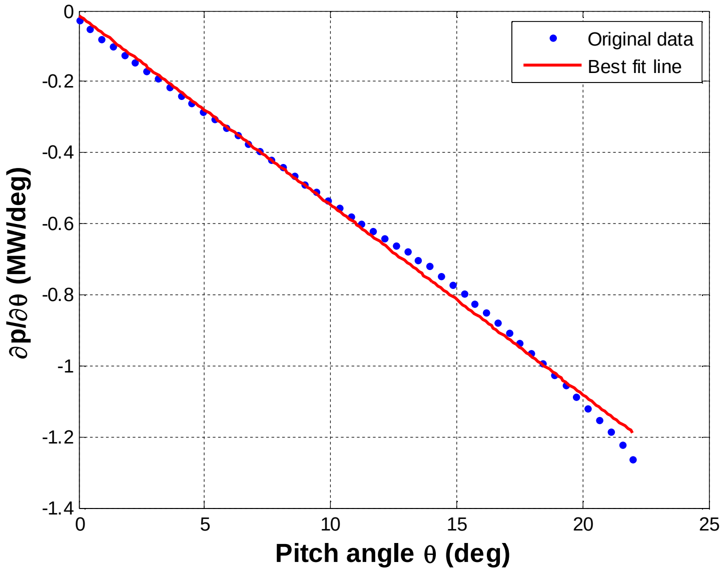

Figure 2-7 Sensitivity function $\partial \mathbf{P}/\partial \boldsymbol{\theta}$ versus pitch angle θ

Figure 2-8 summarises the power output, rotor speed and pitch angle plotted against a wide range of wind speeds. It highlights the controller operating points for various wind speeds. Below rated wind speed, the rotor speed linearly increases with the wind speed and so maintains a constant tip speed ratio to achieve maximum C_P. The power captured by the turbine rotor increases at the rate of the cube of wind speed. Above rated wind speed, the rotor speed and power will remain constant at rated value. This is achieved by controlling the pitch angle with the rising wind speed. It should be noted that the control system for regulating variable speed wind turbines must be appropriately designed in terms of both control strategy and its implementation [13-17]. Leithead *et al* show that the following general goals for a wind turbine control system [18]

- Alleviating the transient loads throughout the wind turbine;
- Regulating and smoothing the power generated;
- Ensuring that the power-train has the appropriate dynamics, particularly damping of the power-train;
- Maximising the energy capture.

Table 2-5 Sensitivity of aerodynamic power to blade pitch angle

Wind speed (m/s)	**Pitch angle (degree)**	**$\partial P/\partial \theta$ (MW/deg)**
11.2 - Rated	0.34	-0.0458
11.5	2.53	-0.1615
12	4.31	-0.252
13	6.66	-0.3693
14	8.48	-0.4619
15	10	-0.5403
16	11.43	-0.6083
17	12.72	-0.6648
18	13.93	-0.7207
19	15.07	-0.7856
20	16.18	-0.8519
21	17.26	-0.9192
22	18.31	-0.9871
23	19.32	-1.0549
24	20.31	-1.1258
25	21.28	-1.2009

To effectively achieve these design goals, the control strategies are required to operate across the full operational envelope of wind speeds by carefully combining the below rated wind speed strategies with the above rated wind speed strategies. The switching between these strategies must be realised in a smooth manner and avoid the introduction of large transients. Various switching procedures have been introduced in the literature [19, 20]. For instance, Burton *et al* propose to introduce a torque-speed ramp between different control regions [2]. The speed set point for the blade pitch controller is set a little higher to prevent the torque and pitch controllers from interfering with each other. In this research, a simple switching logic is implemented to ensure that only one of the control loops is active at any point. Below rated the torque controller is active and the pitch angle is kept at minimal value whilst above rated the pitch controller is active and the torque demand is fixed at rated value.

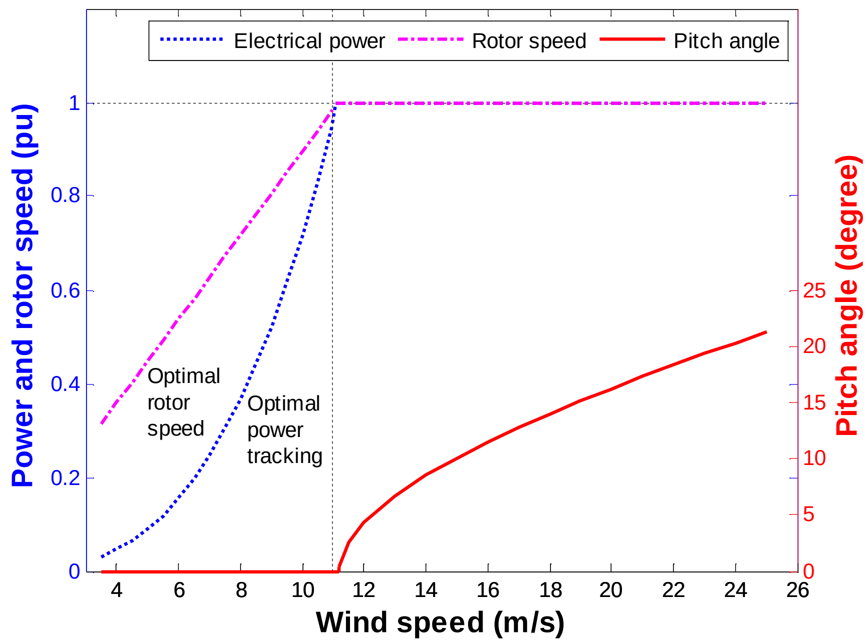

Figure 2-8 Power, rotor speed and pitch angle in normal operations

2.5.4 Simulations results

To evaluate the performance of the developed model, a series of simulations are performed using deterministic wind speeds (constant, without turbulence) and also turbulent wind.

The power response and rotor speed for low, medium and high constant wind speeds have been shown in Figures 2-9 to 2-11. Below rated wind speed (e.g. 6 and 10 m/s) the pitch angle is kept constant to the optimal value (i.e. $\theta_{opt} = 0^0$). In the meantime, the turbine torque controller regulates the power output with the increasing wind speed. The turbine rotor speed is thus controlled to be in proportion to the wind speed under steady state conditions, thereby ensuring that maximum power is extracted from wind. Above rated wind speed the electrical power output will be limited at rated power (3 MW electrical) and so is the rotor speed (Figure 2-11).

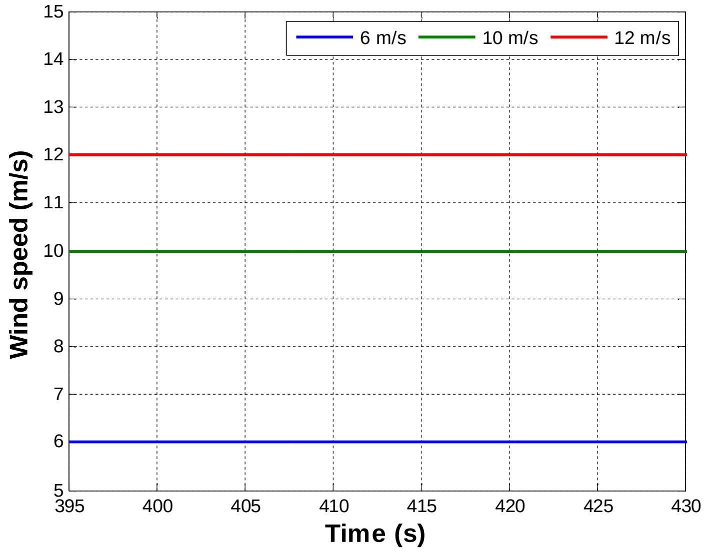

Figure 2-9 A series of example constant wind speeds

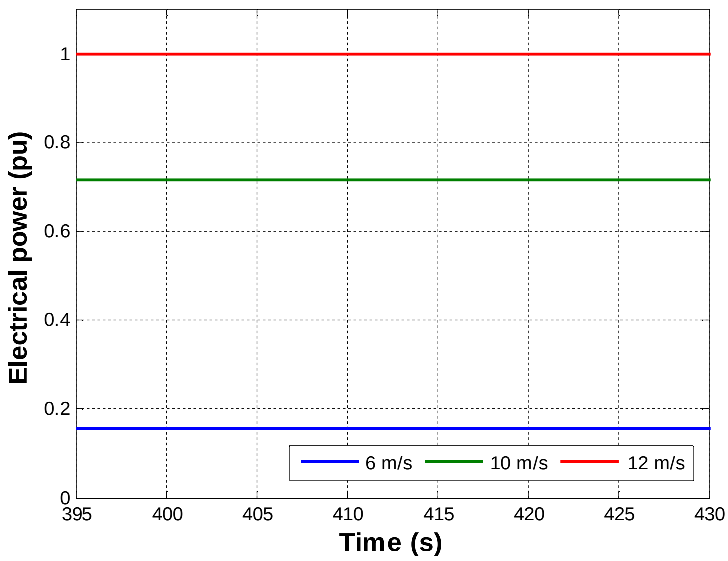

Figure 2-10 Electrical power for a series of constant wind speeds

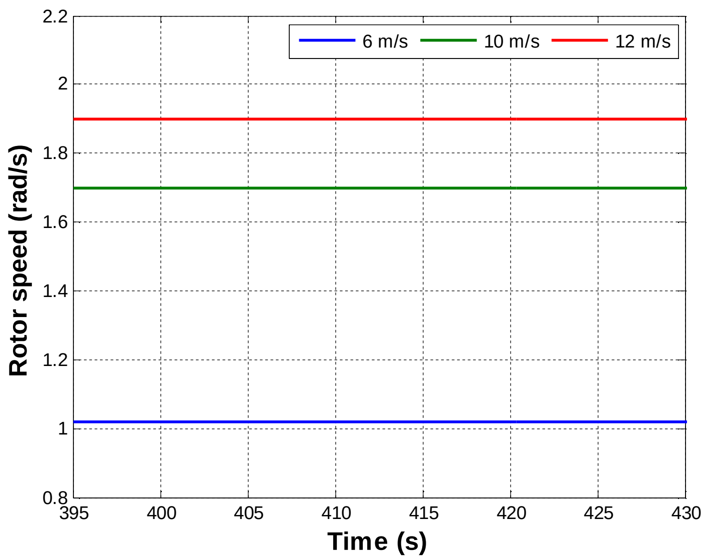

Figure 2-11 Rotor speed for a series of constant wind speeds

Figure 2-12 illustrates the simulation results for turbulent wind where the mean value is 12 m/s with 10% turbulence intensity. It can be seen from Figure 2-12 (a) that the wind speed is continuously varying around the mean value. In response to variations in wind speed, the turbine rotor speed (Figure 2-12 (c)) and blade pitch angle (2-12 (d)) are adjusted by turbine torque and blade pitch controllers. Figure 2-12 (b) shows that the power output reflects the variations in wind speed and will temporarily drop to below rated when the instantaneous wind is below rated (11.2 m/s) and as a result the pitch angle will reduce to the optimal value (zero in this model).

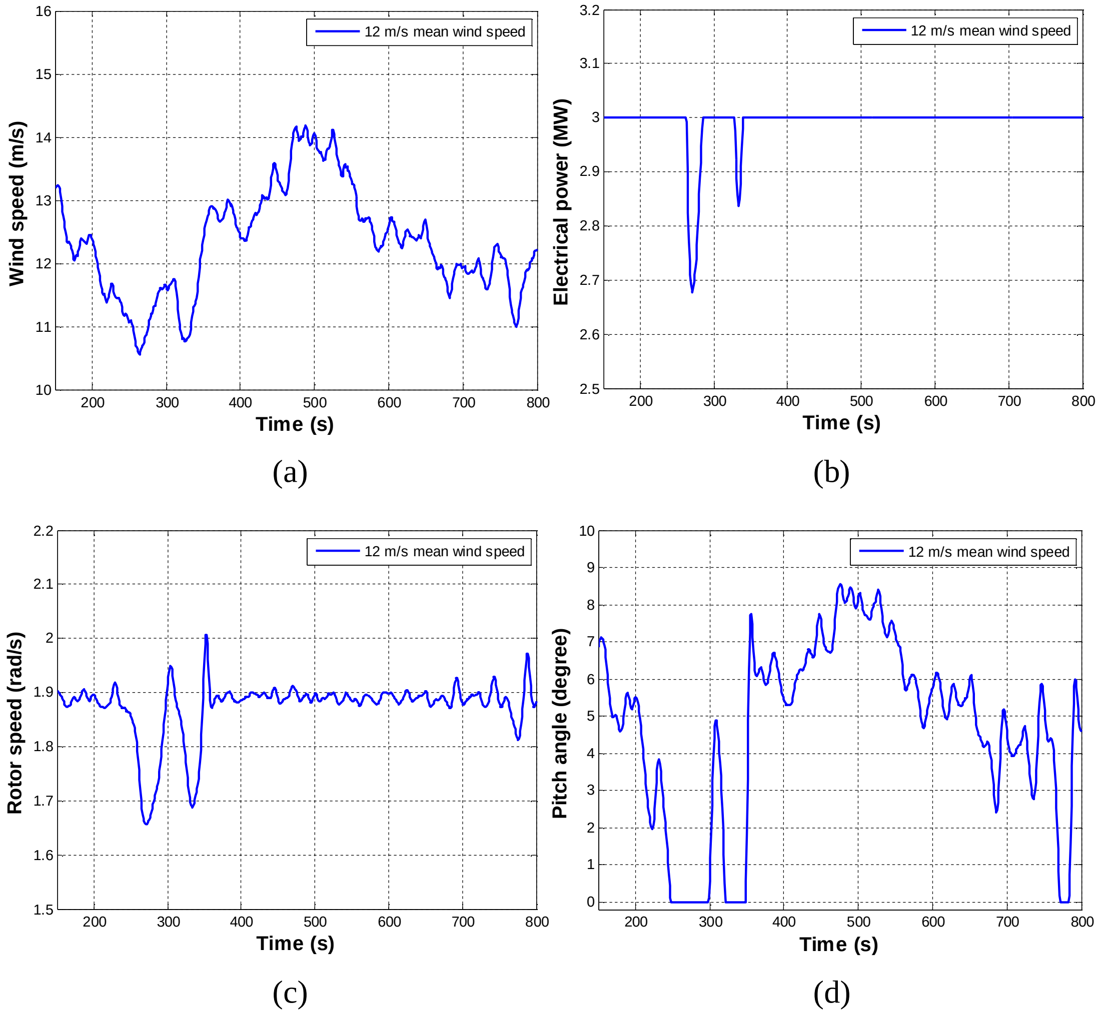

Figure 2-12 Response for 12 m/s mean wind speed with 10% turbulence intensity

Figure 2-13 illustrates the simulation results for turbulent wind with 10 m/s mean value and 10% turbulence intensity. It can be seen that the pitch angle (Figure 2-13 (d)) is kept constant at optimal value when the wind speed does not exceed the rated. Turbine rotor speed will vary along with the wind speed to follow the maximum power tracking as shown by the red line in Figure 2-5.

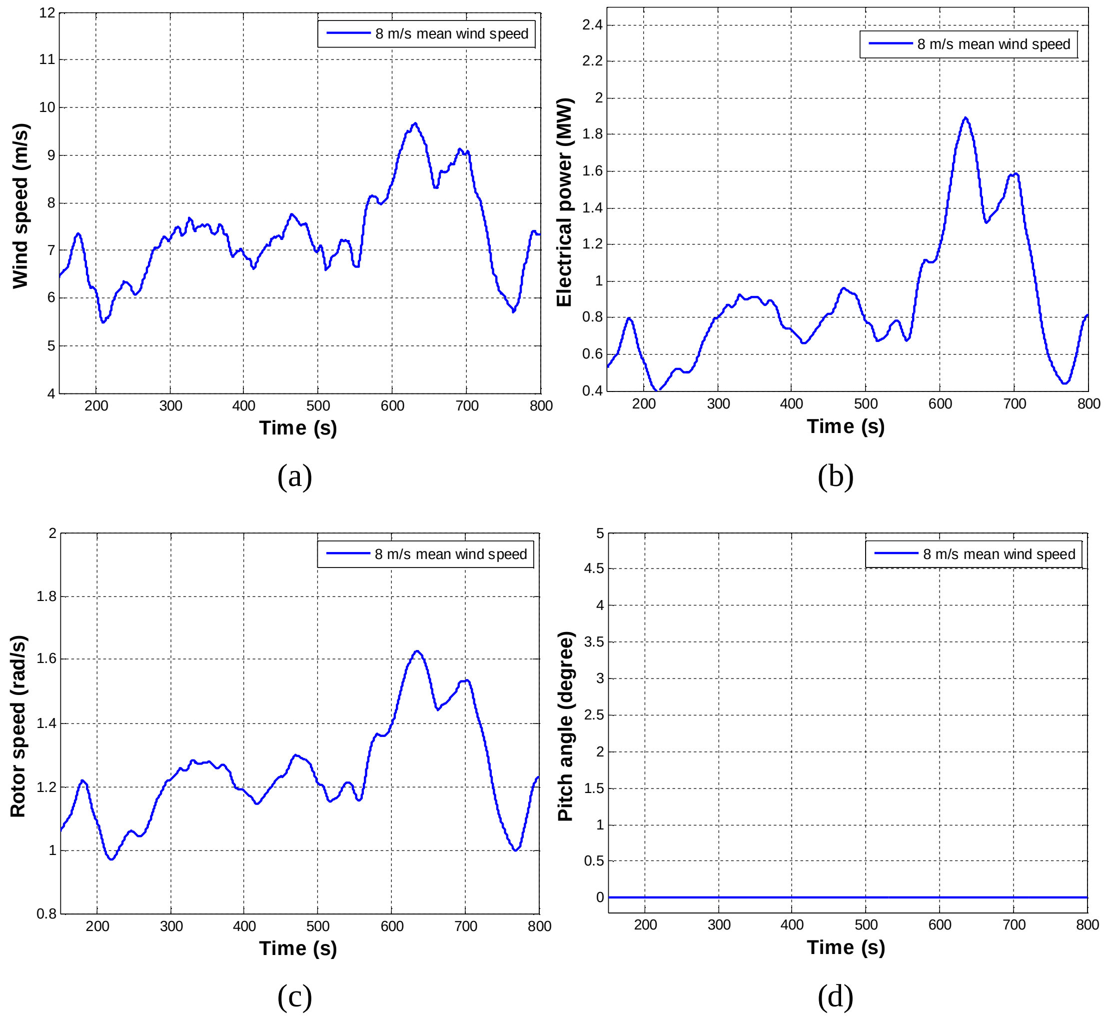

Figure 2-13 Response for 8 m/s mean wind speed with 10% turbulence intensity

2.6 Conclusions

Modern variable speed wind turbine technologies and their development have been introduced in this chapter. To assess frequency support from wind plant and its impact on power system frequency stability, a simplified, generic variable speed wind turbine model has been developed for this purpose. The general turbine properties are taken from a commercial machine that can effectively represent large machines of today.

Since accurate measurement of the wind speed experienced by a wind turbine for turbine control purposes proves to be not practical, it is common to use control strategies that are developed in the torque/rotor speed plane rather than the rotor/wind speed plane due to the advantage of being independent of wind speed. In our developed turbine model, rotor speed has been chosen as an important control variable both below and above rated wind speed. Below rated, the torque controller regulates the torque demand based on the rotor speed to achieve maximum power tracking. Above rated, the pitch controller regulated the aerodynamic power captured by the rotor based on the speed error between actual rotor speed and its reference value.

The generator of a variable speed wind turbine is connected indirectly to the grid, e.g. via power electronic converters, thereby decoupling the rotational speed of the rotor from the grid frequency whilst the generator of a fixed speed wind turbine is connected directly to the grid, thereby locking the rotational speed of the rotor to the grid frequency. In comparison with fixed speed wind turbines, variable speed wind turbines have several advantages which outweigh the cost of power electronics required to provide variable speed operation. Aside from the increase in energy capture below rated wind speed, better load alleviation above rated wind speed and grid compliance can also be achieved through variable speed operation. A number of variable speed wind turbine technologies have been introduced and compared in this chapter. A full converter has been assumed (ie a type 4 turbine) in this research as this allows unrestricted speed variation; however in practice speed variation is limited to 30% to avoid aerodynamic stall of the rotor so that a similar inertial response would be delivered by a turbine using a DFIG arrangement (type 3 turbine).

To develop a generic model, no specific generator or power electronics have been included in our model. A rather generic turbine with one-mass drive train is hoped to represent the wide range of wind turbines currently installed worldwide. It should be noted that above rated wind speed, it requires the controller to briefly overload the power electronic converters to provide synthetic inertial response from wind turbines. Barnes *et al.* have suggested that a short period (typically tens of seconds) of overloading will not lead to damage to electrical components of wind turbines [21].

This chapter has concentrated on the modelling of the normal operation for a variable speed wind turbine. The thesis will now turn to introducing how to modify the turbine controller and so deliver frequency support from wind plant, both inertial response and droop control, and also to assessing aggregate inertial response from wind plant under time varying wind conditions.

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Chapter Three Assessing aggregate inertial response from wind plant

3.1 Background

As already outlined in the previous chapters, with increasing wind penetration into power systems, it is likely that wind power plant will be expected to provide frequency response in support of the system frequency regulation and control, in particular some form of synthetic inertial response. It is then of great importance for the TSOs that frequency support from the aggregate wind plant connected to the power system is predictable and verifiable. The first step toward this goal is to assess the net response from a wind farm to an event requiring a contribution to frequency support through individual wind turbines providing some kind of inertial response, also known as synthetic inertia.

Early studies on inertial response from wind plant assume constant wind conditions [1-7]. However, in reality this is never the case. It is inadequate as the wind is rarely, if ever, constant due to wind turbulence. Moreover, the response of a wind plant/farm will be the aggregate of the different individual turbine responses, each dependent on the local wind fluctuations.

Estimating the inertial response available poses a challenge to wind farm operators and TSOs because of the wide range of potential variability of the wind resource, both locally, and nationally. The inertial response of a wind turbine must be determined for a range of wind conditions including, importantly, wind speed changes during the transient event itself to which the wind turbine is responding. In order to do so properly, a methodology must be developed to assess how the aggregate inertial response from a wind farm at a given time depends on the available wind. In this chapter a model of the collective contributions of wind plant to power system frequency response is developed taking account of the variation of wind speed. This can then be used by power system analysts together with knowledge of wind generation available at a given time on the system to evaluate the potential for frequency support.

A probabilistic approach has been developed based on the dynamic wind turbine model presented in Chapter 2, and the non-standard inertial controller proposed below.

The calculation of aggregate inertial response is based on a simplified approach to wind turbulence modelling where wind variations over a short period of time (10 seconds in this modelling) are assumed to be adequately described by a Gaussian probability distribution with a set mean wind speed and variance determined by the site turbulence intensity [8].

A simple but effective approach to calculating the joint probability of successive wind speed values representing the wind ramps is described in this Chapter. A detailed description of the general probabilistic approach is to be found in [9], although applied there to a rather different problem. This approach is then used to calculate the joint probabilities of the start and end wind speed values of the wind ramps. In this research wind speed variations between zero and 50 m/s are allowed, although of course the probabilities of winds reaching 50 m/s are very low. A range of wind speed levels are examined: low, medium and high. In order to reduce the potentially infinite number of wind ramps modelled, a rough block method has been developed to divide wind variations into 36 scenarios which cover all conceivable wind speeds and variations. The power response including inertial power contribution and normal wind turbine operation is then obtained for the 36 scenarios. Using the proposed probabilistic approach the expected aggregate inertial response from wind plant/farm can be determined for mean constant wind speeds.

This chapter is set out in the following way: Section 3.2 discusses the theory describing how to provide synthetic inertial response from variable speed wind turbines. Section 3.3 compares two control approaches to providing synthetic inertial response in terms of wind turbine performance; Section 3.4 introduces the probabilistic concepts used in this aggregation modelling; Section 3.5 describes the calculation of the joint probabilities for wind ramps; a methodology to evaluate the aggregate inertial response from a wind plant/farm is then introduced in Section 3.6; and finally, conclusions are presented in Section 3.7.

3.2 **Inertial response from wind turbines**

The kinetic energy stored in the rotating rotor and any coupled rotating components (such as the turbo-machinery) of a synchronous machine can be defined as:

$$E = \frac{1}{2} J \omega^2 \qquad (3\text{-}1)$$

where E is the kinetic energy, J is the effective inertia of the rotating components (taking account of gear ratios where they might exist), and ω is the rotating speed.

The inertial power contribution available from a synchronous machine can be determined by taking the time derivative of kinetic energy stored. The standard derivation of the simple mathematical relation can be shown as:

$$P = \frac{dE}{dt} = \frac{d(\frac{1}{2} J \omega^2)}{dt} \qquad (3\text{-}2)$$

$$P = J \times \omega \times \frac{d\omega}{dt} \qquad (3\text{-}3)$$

The inertia constant H is defined as the ratio of kinetic energy stored in the rotor system at nominal speed to the nominal power of the electrical machine. It has dimensions of time and represents the time duration over which the stored kinetic energy can be released when continuously providing nominal power, and is given by, [10]:

$$H = \frac{1}{2} \frac{J {\omega_0}^2}{S} \qquad (3\text{-}4)$$

where ω_0 is the rated rotor speed, and S is the rated power of the electrical machine. From (3-3) and (3-4):

$$\frac{P}{S} = 2H \times \frac{\omega}{\omega_0} \times \frac{d[\frac{\omega}{\omega_0}]}{dt} \qquad (3\text{-}5)$$

Letting $\overline{P}$ and $\overline{\omega}$ denote the power and rotor speed in per unit, power and torque are given by:

$$\overline{P} = 2H \times \overline{\omega} \times \frac{d\overline{\omega}}{dt} \qquad (3\text{-}6)$$

$$\overline{T} = 2H \times \frac{d\overline{\omega}}{dt} \qquad (3\text{-}7)$$

Apart from transient conditions where the load angle is varying, the speed of a synchronous machine is locked to the network frequency. Consequently (3-6) and (3-7) can be written in terms of f and df/dt in per unit rather than $\overline{\omega}$ and $d\overline{\omega}/dt$:

$$\overline{P} = 2H \times \overline{\omega} \times \frac{df}{dt} \qquad (3\text{-}8)$$

$$\overline{T} = 2H \times \frac{df}{dt} \qquad (3\text{-}9)$$

If, for simplicity, a fixed rate of change of frequency is assumed to occur in response to some event, a synchronously connected generator will decelerate (or accelerate) at a constant rate and thus appear mechanically as a constant torque on the generator. Power will not however be constant as the speed of the machine will fall or rise at a constant rate over the duration of this simplified constant df/dt event. Note that droop control is assumed not to contribute to the frequency recovery as this would of course change the value of df/dt. So far this discussion has focused on synchronously connected generators. Now attention is turned to the delivery of "inertial response" from variable speed wind turbines.

The provision of inertial response from an individual variable speed wind turbine can be obtained by controlling the power output in response to frequency changes thereby making variable speed wind turbines appear more like conventional generators with synchronously connected inertia. The principle of inertial control is well known and involves modification of the demanded torque in response to a change in system frequency by adding an extra torque term. The modified demanded torque is then given by:

$$T_{mod} = T_{ref} + T_{inertia} \qquad (3\text{-}10)$$

where T_{mod} is the modified demanded torque, T_{ref} is the demanded torque in normal operation and $T_{inertia}$ represents the added torque.

$$T_{ref} = K_{opt}\omega^2 \tag{3-11}$$

$$T_{inertia} = K_i \frac{df}{dt} \tag{3-12}$$

From (3-11) and (3-12), (3-10) can be given as:

$$T_{mod} = K_{opt}\omega^2 + K_i \frac{df}{dt} \tag{3-13}$$

where K_i is the inertia control constant and can be given by

$$K_i = 2 \times H_e(\omega) \times T_{rated} \tag{3-14}$$

$H_e(\omega)$ is the effective inertia constant of a variable speed wind turbine and can be defined as:

$$H_e(\omega) = \frac{1}{2}\frac{J\omega^2}{P} \tag{3-15}$$

where ω is the rotor speed, and P is the corresponding power output of the turbine.

It should be noted that this H value is calculated in terms of the rated or maximum rotor speed in (3-4). At lower rotor speeds, such will occur at below rated wind speed, the energy stored in the rotor will of course be lower, as will the power output. The inertia constant H of the wind turbine modelled is 6.61 s at rated power and was taken from a commercial design.

From equations (2-3) and (2-4) taken from Chapter 2 on wind turbine modelling:

$$T_{ref} = 0.5\rho\pi R^5 \frac{C_{Popt}}{\lambda_{opt}^3}\omega^2 \tag{3-16}$$

The power output of the turbine for a given wind speed below rated rotor/wind speed is then given by:

$$P = 0.5\rho\pi R^5 \frac{C_{Popt}}{\lambda_{opt}^3}\omega^3 \tag{3-17}$$

Consequently (3-15) can be written as:

$$H_e(\omega) = \frac{J\lambda_{opt}^3}{\rho\pi R^5 C_{Popt}} \frac{1}{\omega} \quad (3\text{-}18)$$

As C_P and λ, for maximum power extraction, will normally be constant below rated rotor/wind speed, the effective inertia constant H_e is inversely proportional to rotor/wind speed and reaches its minimum at rated rotor/wind speed as shown in Table 3-1.

Table 3-1 Effective inertia constant of the wind turbine

Wind speed (m/s)	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**11.5**	**12**
$\boldsymbol{H_e}$ **(MWs/MVA)**	25.33	18.99	15.20	12.66	10.85	9.50	8.44	7.60	6.91	6.61	6.33

Extracted power from the wind turbine can therefore be given as

$$P_{mod} = K_{opt}\omega^3 + K_i\omega\frac{df}{dt} \quad (3\text{-}19)$$

$$P_{mod} = K_{opt}\omega^3 + \frac{2J\lambda_{opt}^3}{\rho\pi R^5 C_{Popt}}\frac{df}{dt}T_{rated} \quad (3\text{-}20)$$

It can be seen from (3-20) that the extra power (overproduction) due to the provision of inertial response (second term on the right hand side of the equation) will be proportional to the rate of change of frequency (df/dt), which means the extra power from the wind turbines will be the same for the instant immediately following a fixed df/dt regardless of the prevailing wind speed level. However, the overall power extracted from wind turbines will, of course, vary with the wind speed level because the rotor speed ω will be proportional to the wind speed. And also, the rate of fall of rotor speed over the transient will reduce along with the increase in wind speed.

3.3 Two different inertial control approaches

In this research, two different approaches to enabling inertial response from wind turbines are compared. To better explain and demonstrate the different effects these two controllers have on the performance of the turbine, a fixed rate of change of frequency event is used to examine the provision of inertial response. In a real power system other plant would ensure a rapid recovery of frequency and there will be an interaction between the wind plant response and the remainder of the power system. This more complex situation will be examined in Chapter 4. The purpose for now is to develop a representation of the aggregate inertial response for wind plant, in particular a wind farm, which can be used in power system studies. For simplicity at this stage it will be assumed that the system frequency is initially fixed at 50 Hz .

In the case of a wind turbine, the added torque term $T_{inertia}$ of (3-10) will reduce in value as the system frequency falls, in this case at a fixed rate because, for simplicity, df/dt is fixed at a constant value. If this were the only term in the wind turbine controller (irrespective of whether df/dt was fixed or not), then the torque and power resulting from any system frequency change, would be exactly as for a synchronous generator. In other words, the turbine can deliver a perfect inertial response for as long as the real inertia, the turbine rotor speed and the wind allows the turbine to continue generating. However, the change in wind turbine rotor speed is not at a constant rate even under a fixed rate of change of system frequency because the wind turbine rotor is not synchronously linked to the network and rotational kinetic energy is being extracted. There are also other inherent characteristics of wind turbines that differ from those of synchronous generators and conventional prime movers. In particular their aerodynamic performance can be dramatically affected by the rotor speed in relation to the wind speed (formally the dimensionless ratio of the rotor tip velocity divided by the wind speed, known as the tip speed ratio and usually denoted by λ). If the rotor speed is reduced too rapidly the rotor may stall resulting in an abrupt fall in aerodynamic power available for generation. This suggests that attempting to emulate the response of a synchronous generator is probably not the best way for a wind turbine to deliver network support. An approach that can provide inertial response better tailored to wind turbine characteristics is introduced in this chapter and the comparative performance of the two different controllers is presented.

In the first approach, referred to as ideal inertial response, the controller exactly mimics the characteristic of a synchronous generator during the provision of inertial response. An ideal inertial response under the simplified conditions of constant

df/dt provides a constant additional torque, as shown by the dotted torque response in Figure 3-1. Despite the change in wind turbine rotor speed not being at a constant rate, the wind turbine generator is controlled through the power electronic variable speed drive to provide a constant air-gap torque, exactly as a synchronous generator would under such conditions.

In the second approach, referred to as non-standard inertial response, we allow the usual wind turbine power tracking control term $K_{opt}\omega^2$ in equation (3-11) to adjust the wind turbine torque as in normal turbine operation. This term is present in almost all variable speed wind turbine controllers and ensures that during normal operation below rated wind speed the optimal tip speed ratio, λ, and thus performance is maintained under steady state conditions. However since the provision of inertial response results in a reduction of rotor speed, the $K_{opt}\omega^2$ term reduces in magnitude resulting in a tapering off of the inertial response. This actually has the advantage of reducing the net energy loss over the transient and shortening the recovery period. It should be noted that both options deliver the same additional power immediately following the change of frequency, and so can, at least initially when it is most valuable, deliver the full inertial response. It should also be noted that in the simplified modelling approach used here, no allowance has been made for time delay associated with the measurement of frequency, *f*, and thus *df/dt.*

The two different approaches to providing inertial response are compared for constant wind speed of 9 m/s in Figures 3-1 to 3-4. Figure 3-1 shows the demanded torque for the two approaches when the inertial controller is activated at 400*s* and for a duration of $10s$. It can be seen that ideal inertial response provides a constant torque for a fixed rate of system frequency fall, while the demanded torque for non-standard inertial response is itself falling over the time period of inertial response. The constant torque demanded by ideal inertial response will reduce the rotor speed more rapidly than in the case of the proposed inertial response as shown in Figure 3-2. This is important since it results in significant loss of aerodynamic power input (Figure 3-3) and thus an increased net energy loss over the transient that has then to be compensated for by the remainder of the power system, in practice making additional demands on system secondary response.

Electrical power is obtained simply by multiplying torque and rotor speed. Comparison of the electrical power from ideal inertial response with that from the proposed non-standard inertial response (Figure 3-4) shows that the latter has a more desirable characteristic in terms of the energy payback when, following the inertial response, the wind turbine rotor must be accelerated back so as to be able to deliver useful power again. It is also clear that recovery occurs more quickly with the modified inertial controller; this will assist TSOs in managing such loss of plant events that in the main cause the unwanted frequency transients, and so facilitate improved frequency recovery. It is important to note that, as already alluded to, there is a net energy price to be paid for the provision of inertial response. This is because stored kinetic energy in the wind turbine is extracted by slowing down the rotor, which moves the wind turbine away from the optimum operating point and thus reduces its aerodynamic efficiency.

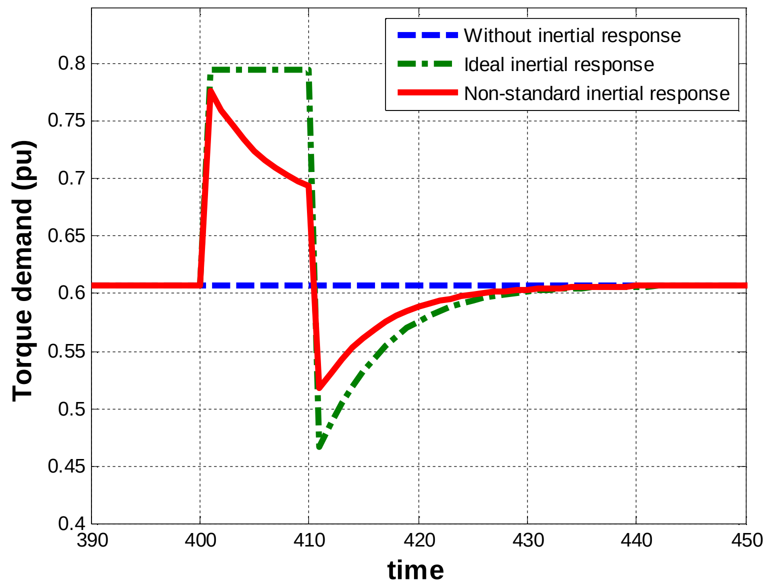

Figure 3-1 Torque demand at constant wind speed of 9 m/s

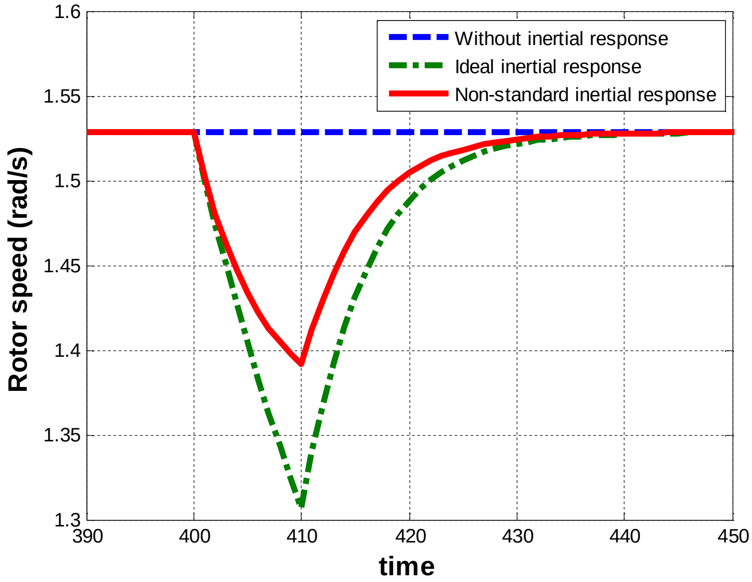

Figure 3-2 Rotor speed at constant wind speed of 9 m/s

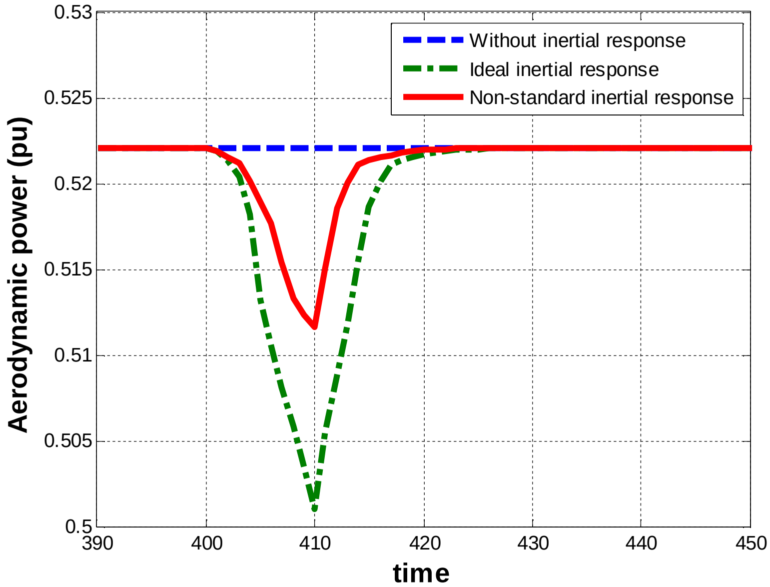

Figure 3-3 Aerodynamic power at constant wind speed of 9 m/s

Over the complete transient period (covering both the provision of inertial response and the following recovery period), rotor speed is below the optimum value and this directly results in energy loss.[3] The additional energy that must be supplied during the recovery period covers the energy to accelerate the wind turbine rotor back to its initial speed (ignoring losses in the electrical conversion, this is equal to the energy

[3] Strictly this conclusion only applies when the wind turbine is operating initially below rated wind speed.

provided during the inertial response) together with the loss of energy caused by below optimal turbine operation over the complete transient period. Exactly how much energy is lost depends on the duration and magnitude (controlled by the value of K_i) of the required inertial response, and the precise design of the controller (for example whether it is the ideal or as proposed here, or indeed another “inertial response”) [11]. Whatever, the approach, this net loss is real and has to be made up by other plant in the power system.

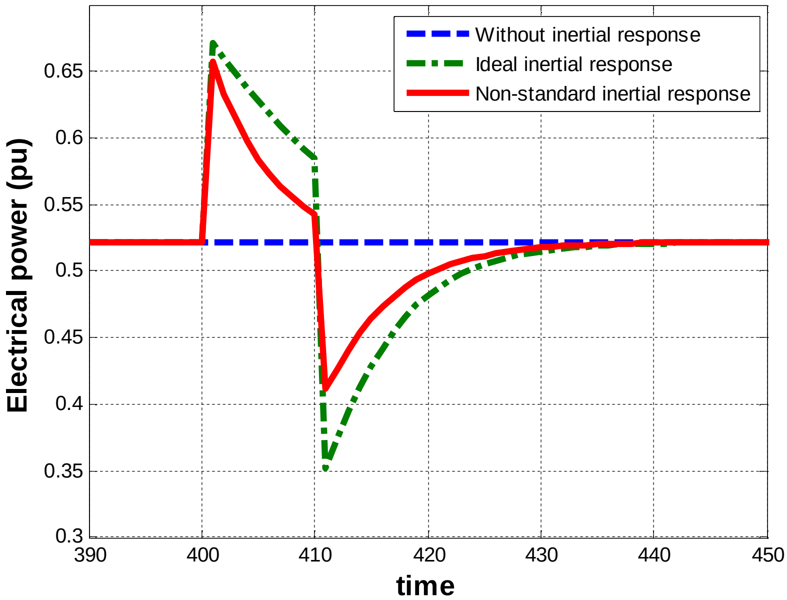

Figure 3-4 Electrical power at constant wind speed of 9 m/s

To summarize, the proposed non-standard inertial response results in a smoother power transient, a shorter recovery period and a reduced net energy loss compared to the ideal inertial response. The proposed approach is likely to be favoured by wind farm operators. It could also relieve the demands on secondary response that could result from the delivery of inertial response from the wind turbines. The impact of any inertial control approach on the frequency stability of power systems needs to be examined for a range of different scenarios since the frequency response of the power system is highly dependent on the size and nature of the power system, the instantaneous plant mix, the load, and the wind power available. Such a study will be introduced in Chapter 4, and care should be taken not to over-interpret the results presented here.

3.4 Probabilistic concepts used in the aggregation modelling

An elementary concept, which will be used to explain how to assess aggregate inertial response from wind plant, is that of expectation, denoted by **E**. **E**[x] represents the expected value of the random variable x. sometimes referred to as the mean value of x, it can be defined as:

$$E(x) = \int_{-\infty}^{\infty} xp(x)dx \qquad (3\text{-}17)$$

for a continuous random variable x, and as:

$$E(x) = \sum_{1}^{n} x_i p(x = x_i) \qquad (3\text{-}18)$$

for a discrete random variable x_i, where p represents the probability .

A well known expectation is the expected value of squared deviations from the mean. This is the variance, and is defined for the discrete case as:

$$\sigma^2 = E[(x - \bar{x})^2] \qquad (3\text{-}19)$$

Its square root is known as the standard deviation (or root mean square).

An especially useful expectation is known as the auto-covariance. It gives information about the nature of a time series; basically its correlation with itself in time. A normalised version, autocorrelation is commonly used. It has the value of unity for zero lag k. for a discrete random variable and for a particular time lag, it is defined as:

$$r_k = \frac{E[(x_t - \bar{x})(x_{t+k} - \bar{x})]}{\sigma^2} \qquad (3\text{-}20)$$

It should be apparent that if we regard the time lag as an independent variable (continuous or discrete) we have an autocorrelation function. As already stated it will take the value of 1 at zero, i.e. r(0)=1, or in discrete terms, $r_0 = 1$. The shape of the function tells us all about the nature of the time series.

The probability density function $p(x)$, describes the probabilities associated with different values of a random variable. Normal or Gaussian probability distribution is widely used and can be defined as:

$$p(x) = \frac{1}{\sigma\sqrt{2\pi}} e^{-x^2/_{2\sigma^2}} \tag{3-21}$$

Joint Normal probability distribution describes the combined probability of two random variables x and y, both independently normally distributed, but where there is a fixed correlation or autocorrelation function relating them. It can be defined as:

$$p(x, y) = \frac{1}{2\pi\sigma^2\sqrt{1-r^2}} e^{-\left\{\frac{(x-U)^2+(y-U)^2-2r(x-U)(y-U)}{2\sigma^2(1-r^2)}\right\}} \tag{3-22}$$

As mentioned above, for simplicity the wind variations in this research are assumed to be Gaussian distributed and stationary with a fixed mean and standard deviation, σ, which is determined by the turbulence intensity.

The probability of two successive wind speed values U_1 and U_2 is given by the joint Gaussian probability distribution:

$$P(U_1, U_2) = \frac{1}{2\pi\sigma^2\sqrt{1-r^2}} e^{-\left\{\frac{(U_1-U)^2+(U_2-U)^2-2r(U_1-U)(U_2-U)}{2\sigma^2(1-r^2)}\right\}} \tag{3-23}$$

where r is the autocorrelation of the wind at lag τ. Here, τ is a given value of 10 seconds, corresponding in this case to the duration of the ramp being considered. This autocorrelation is critical and can be estimated from an appropriate wind turbulence spectrum, in this research taken to be Kaimal [12]. As in [13], the autocorrelation at lag τ can be calculated from the spectrum as follows:

$$r = \int_0^\infty Spec(n) \cdot \cos(2\pi n \cdot \tau)\, dn \tag{3-24}$$

The Kaimal spectrum, $Spec(n)$, for wind turbulence is given by [12]:

$$Spec(n) = \frac{0.164 \times \frac{f(n)}{f_0}}{n\left[1+0.164 \times \left(\frac{f(n)}{f_0}\right)^{\frac{5}{3}}\right]} \tag{3-25}$$

where

$f(n) = n \times \frac{Z}{U}$;

$f_0 = 0.041 \times \frac{Z}{L_s}$

and Z is height above ground in this example set as 80 meters, L_s is the integral length scale (here taken to be 120 metres) which relates to the site topography, I is turbulence intensity chosen as 0.2 throughout the research, and U is mean wind speed. Using these assumed values,

$f_0 = 0.027$;

$\sigma = UI$.

A simple approach to calculating the joint probability of successive wind speed values representing the wind variations is introduced here. Using this approach the expected value of aggregated inertial response from wind plant can be obtained combining the inertial power response from all possible wind variations, weighted by the corresponding joint probabilities.

3.5 Calculation of the joint probabilities

The concept of joint probability has been introduced above. It is rather difficult to determine the impact of all the possible wind variations as, theoretically, for a given constant mean wind speed wind ramps can start and end at any wind speed. In order to reduce the potentially infinite number of various wind ramps to a suitable finite number, a rough block approach is used to represent start and end wind speed ranges and thus reduce the required computations to a sensible number.

As illustrated in Figures 3-6 to 3-8, the starting wind speed is divided into 6 blocks or ranges: 0-3.5; 3.5-6.5; 6.5-9.5; 9.5-12.5; 12.5-15.5; and 15.5-50 m/s. The end of transient wind is also divided into 6 blocks with exactly the same wind speed ranges. It should be noted that only the wind speed range of 0-50 m/s has been considered in this research because wind speeds under normal operations rarely exceed 50 m/s and wind turbines are unlikely to be required to participate in frequency regulation and control in extreme weather conditions.

Joint probabilities (vertical scale in these figures) are calculated for each combination of start and finish wind speed range. For instance, for a wind ramp starting in the range 6.5-9.5 m/s, probabilities of ending the transient at the different blocks/ranges can be calculated through suitable integration of (3-23). In this manner, the infinite number of potential wind ramps is reduced to just 6 squared, ie 36, scenarios that can represent effectively all the possible wind ramps for a given mean wind speed. The probability of a wind ramp starting in the range s1 to s2 m/s and ending in the range e1 to e2 m/s is given by the integral:

$$Pr = \int_{s1}^{s2} \int_{e1}^{e2} P(U_1, U_2) d\, U_1 dU_2 \qquad (3\text{-}26)$$

where of course P depends on the mean wind speed, standard deviation and autocorrelation at the appropriate time lag.

For a specific example, the probability that the wind ramps from within the range 9.5-12.5 m/s to the range 6.5-9.5 m/s is given by:

$$Pr = \int_{9.5}^{12.5} \int_{6.5}^{9.5} P(U_1, U_2) d\, U_1 dU_2 \qquad (3\text{-}27)$$

Table 3-2 and Figure 3-6 show the probabilities of wind ramps at a mean wind speed of 6 m/s and assuming a turbulence intensity of 20%. As can be seen in Figure 3-6, the probability of wind ramps is mainly concentrated on the blocks where starting wind speed is near to the mean wind speed value. For instance, for a wind ramp starting in the range of 3.5-6.5 m/s, the probability of ending the transient in the range of 3.5-6.5 m/s is the highest (0.479). It shows that the probability of wind variations that start with wind speeds in the range 3.5 to 9.5 m/s is 0.98 (ie close to unity). Note that this is simply the sum of blocks for the ranges 3.5-6.5 and 6.5-9.5 m/s.

Table 3-2 Joint probabilities at mean wind speed of 6 m/s

Start wind / End wind	0-3.5	3.5-6.5	6.5-9.5	9.5-12.5	12.5-15.5	> 15.5
0-3.5	0.003	0.015	0.001	0	0	0
3.5-6.5	0.015	0.479	0.149	0	0	0
6.5-9.5	0.001	0.149	0.185	0.001	0	0
9.5-12.5	0	0	0.002	0	0	0
12.5-15.5	0	0	0	0	0	0
> 15.5	0	0	0	0	0	0
Subtotal	0.019	0.643	0.337	0.001	0	0
Total			1			

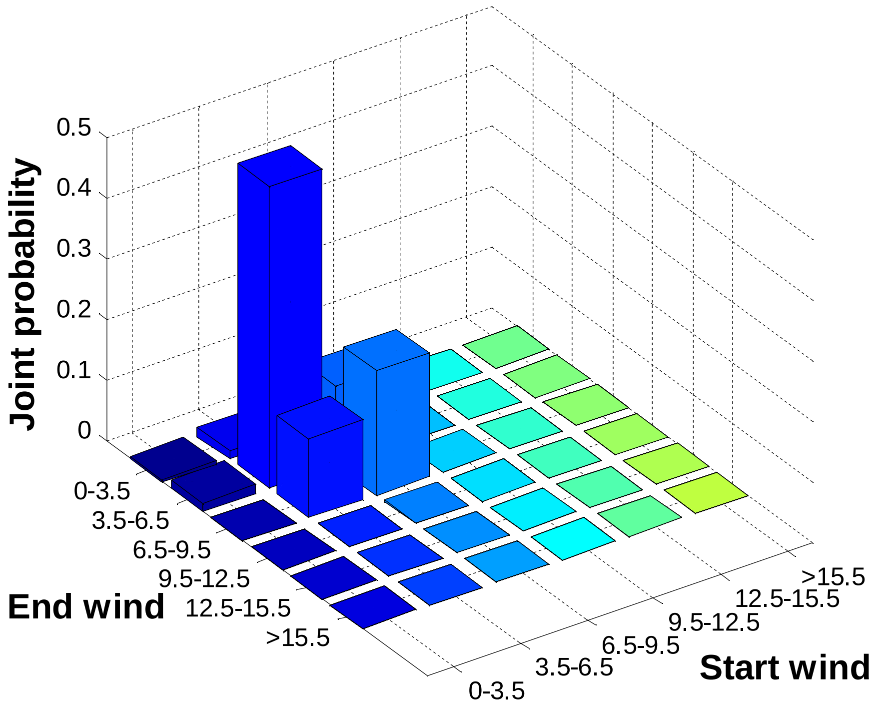

Figure 3-6 Joint probabilities for mean constant wind speed of 6 m/s

Table 3-3 shows the probabilities of wind ramps at a mean wind speed of 10 m/s with a turbulence intensity of 20%. As can be seen in Figure 3-7, the probability of wind ramps is mainly concentrated on the blocks where starting wind speed is near to the mean wind speed value of 10 m/s. The probability of wind variations that start with wind speeds in the range 6.5 to 12.5 m/s is 0.855.

Table 3-4 shows the probabilities of wind ramps at a mean wind speed of 12 m/s with a turbulence intensity of 20%. As can be seen in Figure 3-8, the probability of wind ramps is mainly concentrated on the blocks where starting wind speed is near to the mean wind speed value of 12 m/s. The probability of wind variations that start with wind speeds in the range 9.5 to 15.5 m/s is 0.78.

Table 3-3 Joint probabilities at mean wind speed of 10 m/s

Start wind / End wind	0-3.5	3.5-6.5	6.5-9.5	9.5-12.5	12.5-15.5	> 15.5
0-3.5	0	0	0	0	0	0
3.5-6.5	0	0.006	0.022	0.011	0	0
6.5-9.5	0	0.022	0.167	0.154	0.017	0
9.5-12.5	0	0.011	0.154	0.268	0.060	0.002
12.5-15.5	0	0	0.018	0.059	0.025	0.001
> 15.5	0	0	0	0.002	0.001	0
Subtotal		0.039	0.361	0.494	0.103	0.003
Total				1		

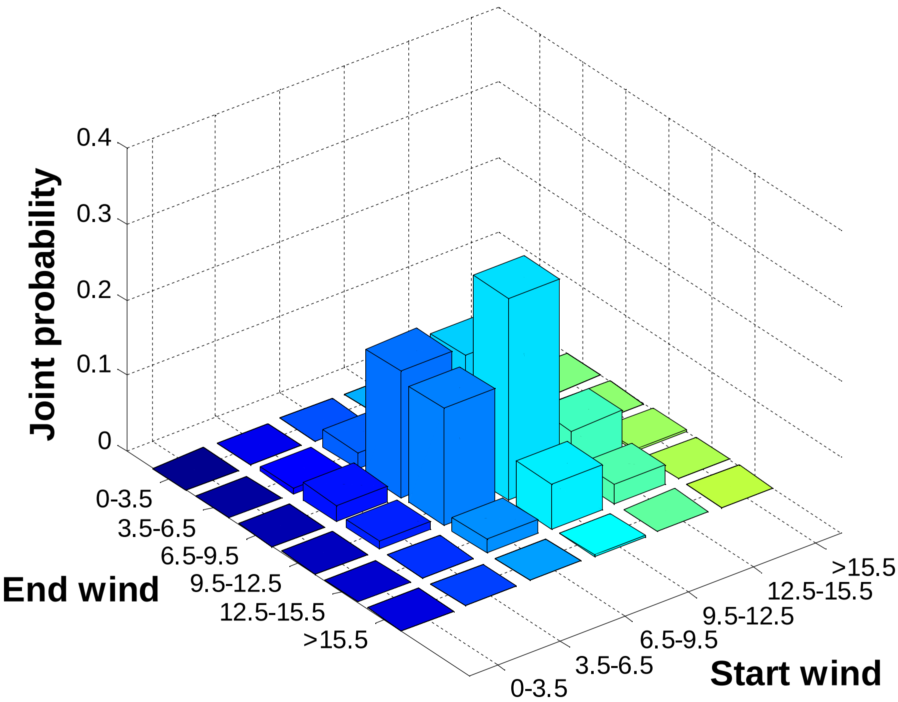

Figure 3-7 Joint probabilities for mean constant wind speed of 10 m/s

Table 3-4 Joint probabilities at mean wind speed of 12 m/s

Start wind / End wind	0-3.5	3.5-6.5	6.5-9.5	9.5-12.5	12.5-15.5	> 15.5
0-3.5	0	0	0	0	0.001	0
3.5-6.5	0	0	0.004	0.005	0.001	0
6.5-9.5	0	0.004	0.034	0.067	0.030	0.003
9.5-12.5	0	0.005	0.067	0.203	0.138	0.021
12.5-15.5	0	0.001	0.030	0.138	0.142	0.034
> 15.5	0	0	0.003	0.021	0.034	0.014
Subtotal	0	0.010	0.138	0.434	0.346	0.072
Total			1			

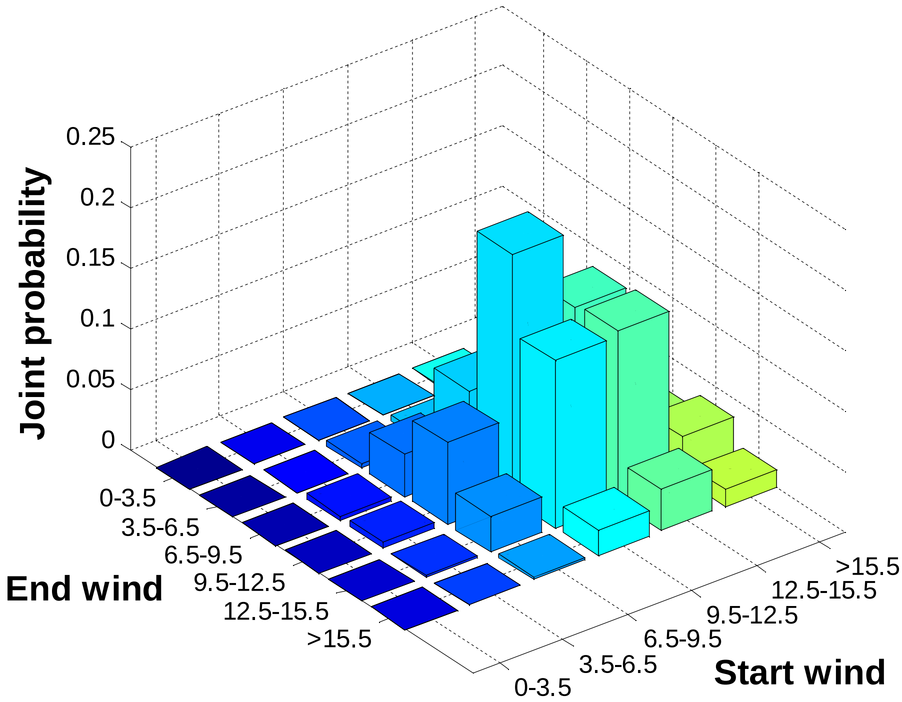

Figure 3-8 Joint probabilities for mean constant wind speed of 12 m/s

It can be seen from these figures that the probabilities at which wind ramps are more likely to concentrate will shift with the mean constant wind speed. It suggests that although theoretically there exists an infinite number of wind ramps, the probability distribution for wind variations will be dominated by those with start and end wind speeds close in value to the mean wind speed.

3.6 Expected aggregate inertial response from wind plant/farm

As mentioned above, wind variations for a given mean wind speed at a given time can be divided into 36 scenarios. However, in practice many of the blocks have probabilities that are effectively zero, and this further reduces the computational burden of later calculations. For each wind variation considered, the inertial response available from the wind turbine can be calculated using the proposed inertial control approach (non-standard inertial response), although this aggregation technique can be applied to any inertial control algorithm.

The inertial response is calculated by assuming the wind speed starts from mid point and ends at mid point for each scenario. Since the differences in wind speeds for the blocks are small the response will be approximately linear over this range and so the midpoint will give an acceptable approximation to the mean response. For example, the inertial response for the scenario in which wind variation starts in the range 3.5-6.5 m/s and ends between 6.5-9.5 m/s can be obtained by assuming the wind speed linearly increases from 5 to 8 m/s. In this way, the power response for the 36 wind ramp scenarios can be obtained.

It should be noted that the power response for each of the 36 scenarios is independent of mean wind speed. For instance, the power response for the wind ramp for which the wind speed starts in the range 3.5-6.5 m/s and ends in the range 6.5-9.5 m/s will remain the same no matter what the site mean wind speed is. Therefore, for a given mean wind speed, the overall aggregate inertial response will be determined by the combination of these power responses weighted by the corresponding probabilities.

For simplicity, it has been assumed that prior to the transient the wind speed is steady. In reality, time varying wind speeds prior to the transient will have some impact on the response at below rated wind speeds since in general the wind turbine rotor speed will not have reached the optimal steady state value. Because wind speeds prior to the transient are as likely to be higher than the mean than lower (due to the assumption of Gaussian turbulence), these effects should cancel. This has been verified by running the turbine model with wind ramps from above and below just prior to the transient. For the particular case of operation at 10 m/s wind ramps from

11 and 9 m/s were inserted in the 10 seconds prior to the inertial response. These were found to have negligible impact on the magnitude of the response.

As explained in Section 3.4, the expected value of a random variable (continuous or discrete) is the sum of all possible values of the variable weighted by the associated probabilities. Suppose random variable X can take value x_1 with probability p_1, value x_2 with probability p_2, and so on, up to value x_k with probability p_k. Then, as explained above, the expected value of this random variable, denoted $E[X]$ is defined as:

$$E[X] = x_1p_1 + x_2p_2 + \cdots + x_kp_k \tag{3-28}$$

Since all probabilities p_i must sum to unity, i.e.

$$p_1 + p_2 + \cdots + p_k=1 \tag{3-29}$$

the expected value can be viewed simply as a weighted sum, with p_i being the weights.

This approach is applied to calculate the expected aggregate inertial response from a wind plant/farm. If the whole wind farm is viewed as a single wind turbine (ie by ignoring any systematic wind variations across the wind farm and any wake effects so that each wind turbine within the wind farm can be assumed identical), then the expected aggregate inertial response from such a wind farm equivalent wind turbine can be estimated by summing up the multiple individual representative inertial time responses corresponding to the 36 possible wind ramp cases, weighted by the appropriate probabilities calculated using (3-28). The aggregate curve is calculated point by point in time using the appropriate probability weightings. The expected aggregate inertial response that results from this process, for a range of wind speeds, has been plotted over the time period as shown in Figures 3-9 to 3-11.

It can be seen in Figure 3-9 that the aggregate inertial response available at low wind speeds of 6 to 9 m/s can be significantly greater in terms of absolute power contribution throughout the transient than that for a constant wind with the same mean value, and the recovery is quicker. These differences reflect the non-linearity of the turbine response as a function of nominal operational wind speed.

Figure 3-10 shows that at the mid range mean wind speed of around 10 m/s, the aggregate inertial response available in the wind plant as a whole is very close to that for a steady wind speed of this central value. Figure 3-11 shows that the aggregate power response at high wind speed, at and above rated wind speed, is significantly lower than the power response for steady wind. This is because the aggregate response includes operation above rated wind speed where the power is regulated. Since ten minute mean wind speeds are commonly available from wind site data it is proposed that application of the method developed here could be based on selection of the wind speed: either low, medium, or high, that is closest to the measured wind speed at the time in question. The contribution to inertial response calculated in this way can thus be updated every ten minutes. For greater accuracy an interpolation approach could be used.

The difference between aggregate power response for a given mean wind speed, assuming a 20% turbulence intensity, and the respective power response under steady wind speed for a range of wind speeds is summarized in Figure 3-12.

Various tendencies can be identified. First, as already indicated in Figures 3-9 to 3-11, the difference between the response at a steady mean wind speed and the aggregate response for a group of turbines exposed to that same mean wind speed, depends on the mean wind speed itself. It can be seen that this difference is largest at the lowest wind speed of 6 m/s and decreases with increasing wind speed up until 10 m/s. At 10 m/s the aggregate power response is very close to the power response under steady wind; this is a little below rated wind speed (11.2 m/s). Above 10 m/s, the difference initially increases, becoming significantly larger, only to fall again above rated wind speed. This pattern of change reflects the non-linear response of the rotor aerodynamics and the controller as can be seen comparing the steady wind responses in Figure 3-12, and in particular the fact that the rotor speed no longer controlled to increase with wind speed above rated wind speed. Moreover, the aggregate response depends on the weighted response across a range of wind speeds for which as just said, the turbine response is strongly non-linear.

The shape of the response is also of interest. For the 14 m/s steady wind cases, the aerodynamic power from the turbine actually increases during the period when inertial response is operative. This is because above rated the blades start off pitched to limit the aerodynamic power and as the transient progresses they pitch back increasing aerodynamic power and thus maintaining rotor speed nearer to optimal than in the lower wind speed cases where the turbine significantly loses torque as it slows down to deliver the inertial response. Moreover, for this case no recovery is required since the power is already at 1 per unit at the end of the inertial response. The aggregate response at 14 m/s is somewhat different but still reflects the impact of above rated operation.

Below rated, there is a clear tendency for the rate of power fall off during the transient, and also the rate of recovery, to decrease with falling wind speed. This is consistent with the reduction of H_e already discussed. The aggregate response at 12 m/s is perhaps the most problematic with a limited fractional increase in power and a slow recovery period in part due to the reduced value of H_e. It can be concluded that the capacity to provide aggregate inertial response from the wind farm is more complex than hitherto recognized and that the common perception that such capacity should increase with increasing wind speed is not accurate.

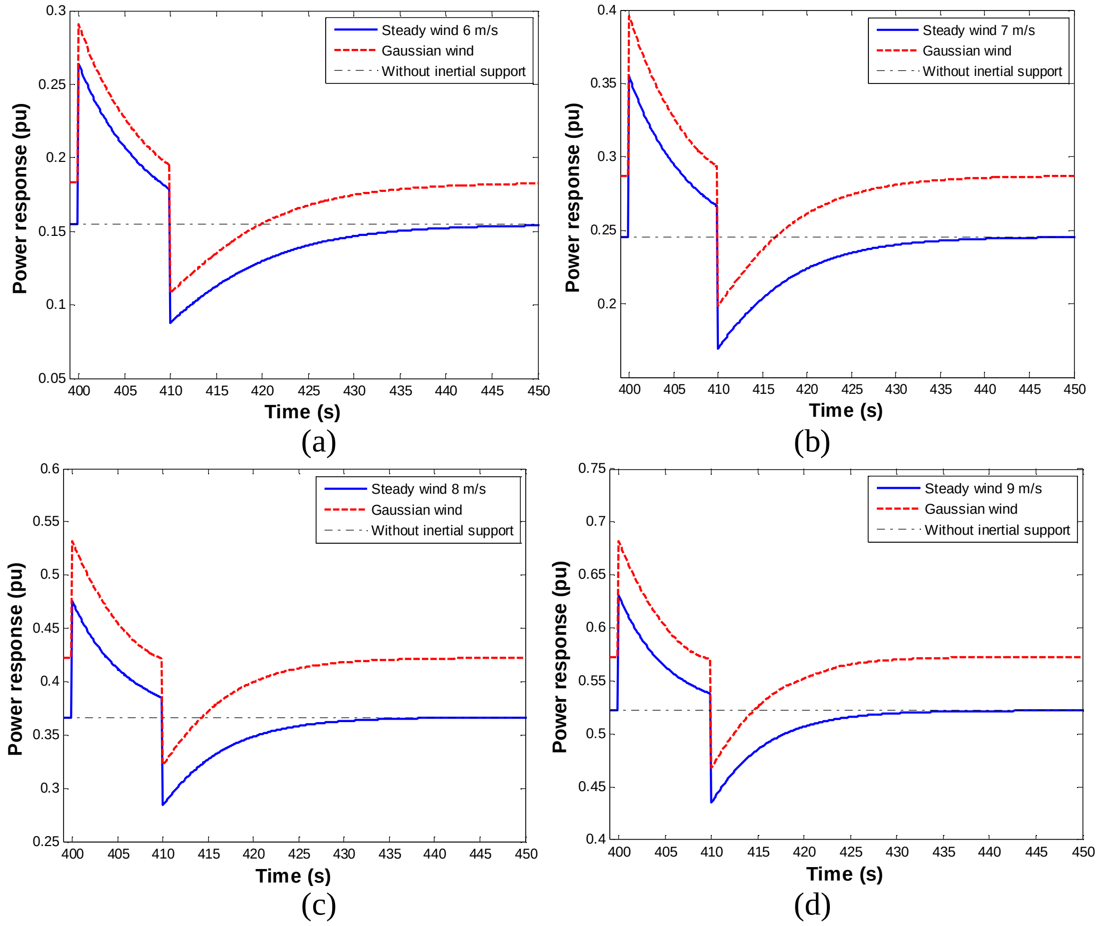

Figure 3-9 Power response at low wind speed

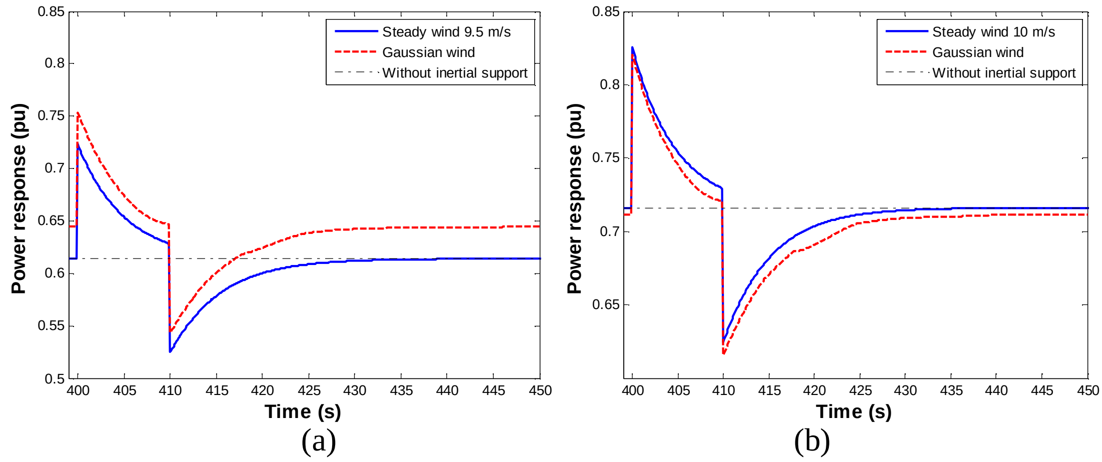

Figure 3-10 Power response at medium wind speed

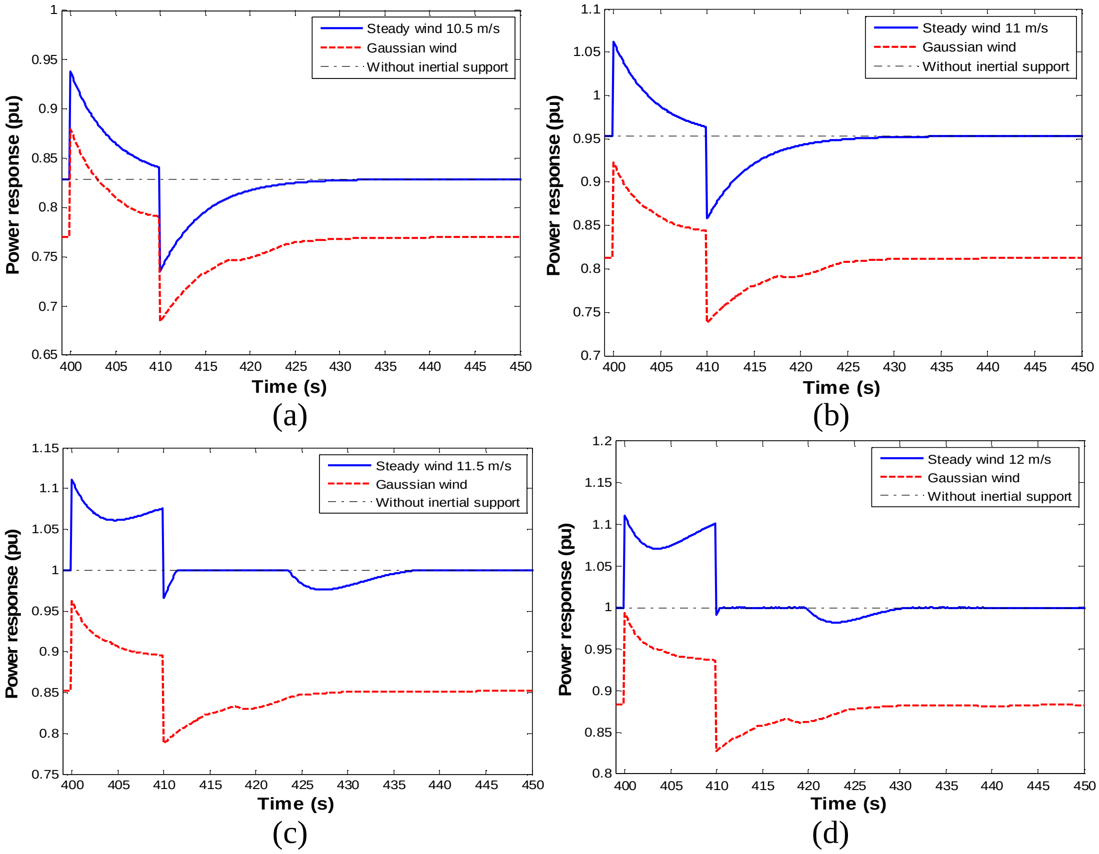

Figure 3-11 Power response at high wind speed

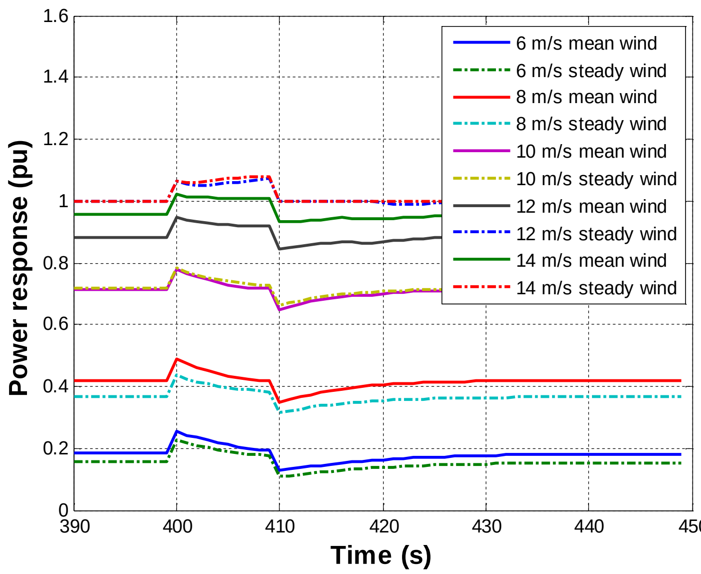

Figure 3-12 Power response for a range of wind speed levels

The aggregate response of a wind farm of arbitrary size[4] in terms of inertial response can be calculated using this probabilistic approach. The results are shown in Figures 3-9 to 3-12 for a wide range of site mean wind speed.

Wind variations have been effectively represented by 36 scenarios as explained above, where the starting and ending wind speeds are divided into 6 blocks respectively. The number of blocks used is a compromise between accuracy and computational effort, but it is important to assess the impact of different block numbers. This been done by considering two further block resolutions, namely 3 and 12 blocks.

For 12-block modelling, the starting wind speed is divided into 12 blocks: 0-3; 3-4; 4-5; 5-6; 6-7; 7-8; 8-9; 9-10; 10-11; 11-12; 12-13; and 13-50 m/s, with the final wind speed is also divided into 12 blocks with the same wind speed ranges. Wind variations are thus represented by 144 scenarios using 12 blocks to model the wind ranges. This modelling requires significantly longer computational time due to the large number of turbine responses that must be calculated, one for each wind ramp (144 in total).

For 3-block modelling method, the starting wind speed is divided into 3 blocks: 0-5; 5-12; and 12-50 m/s. The ending wind speed is divided into 3 blocks with the same wind speed ranges. Wind variations can be represented by 9 scenarios in this way. However, this modelling could prove to be too crude to represent the wind variations realistically.

All three block sizes can now be compared in their representation of the expected aggregate inertial response from wind plant using the probabilistic approach. The power response resulting from these calculations, for low, medium and high wind speeds, are plotted as shown in Figure 3-13 to 3-15.

[4] In fact the aggregation model does not take account of the number of turbines in the wind farm. It is tacitly assumed that there are sufficient turbines for the results to be statistically accurate.

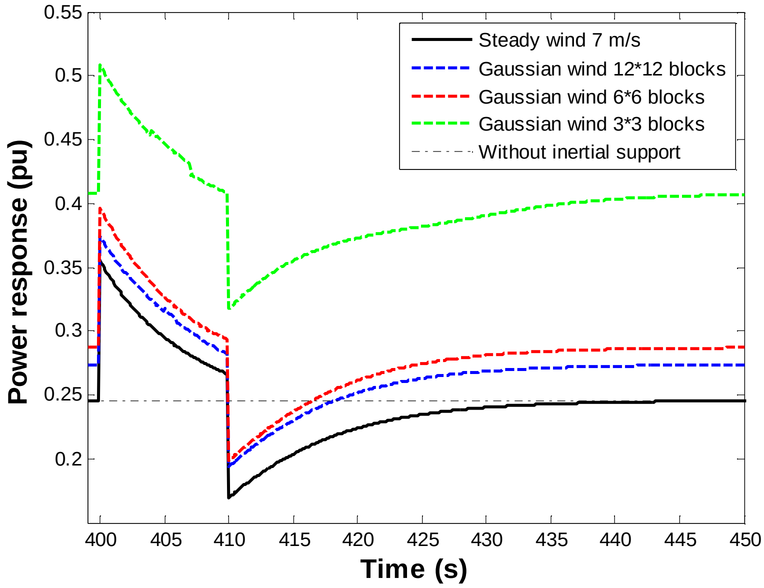

Figure 3-13 Power response for various block modelling methods at 7 m/s

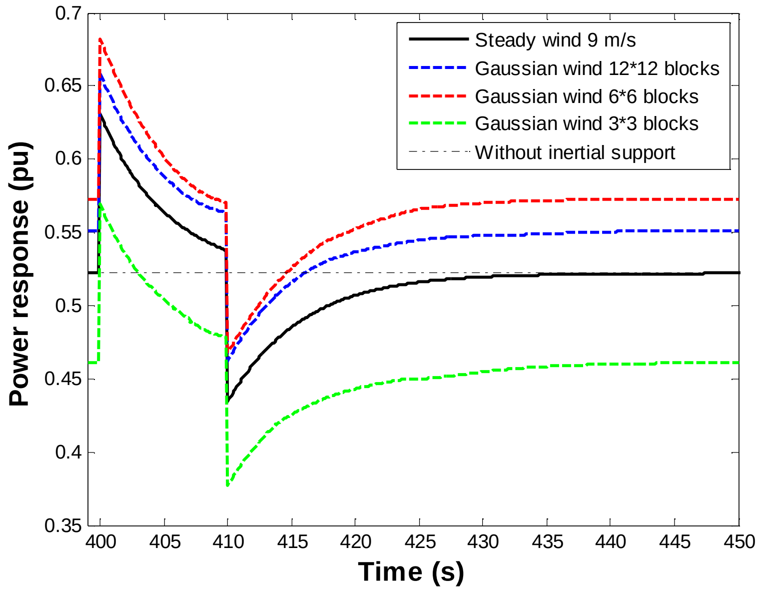

Figure 3-14 Power response for various block modelling methods at 9 m/s

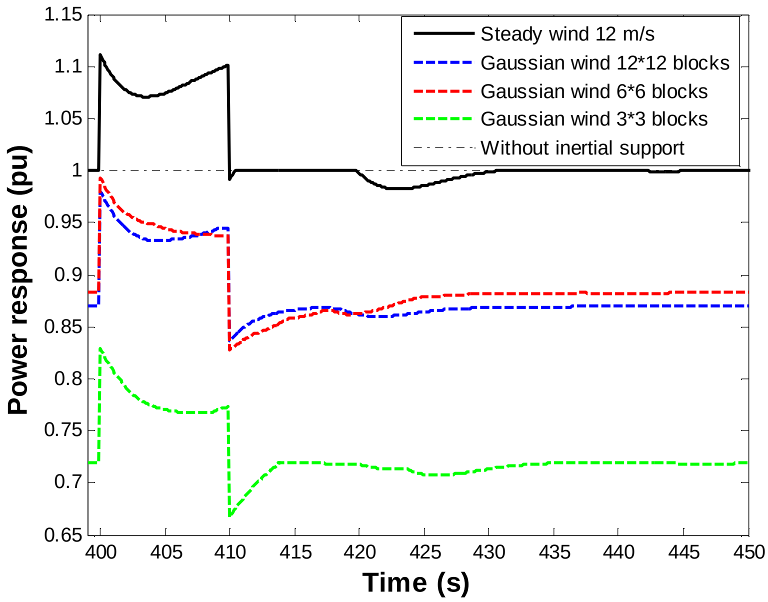

Figure 3-15 Power response for various block modelling methods at 12 m/s

It can be seen from Figures 3-13 to 3-15 that using 6 blocks and 12 blocks exhibit a relatively good agreement whereas the use of only 3 blocks results in considerable differences in the response. It can be concluded that 3 blocks is too few to provide a reliable estimate. Both 6 and 12 blocks would appear to be adequate and clearly 6 is much more attractive from a computational point of view.

It can be seen from Figures 3-11 (c) and (d) and 3-15 that from around 420 seconds there is an unexpected variation in the response for these high above rated wind speed cases. This is due to imperfect pitch control as shown in Figures 3-16 and 3-17. There is a clear pitch overshoot between 415 and 425 seconds (Figure 3-17), this results in a lower than rated rotor speed between 420 and 430 seconds (Figure 3-16). Consequently, the turbine torque controller reduces the torque demand in an attempt to track maximum power.

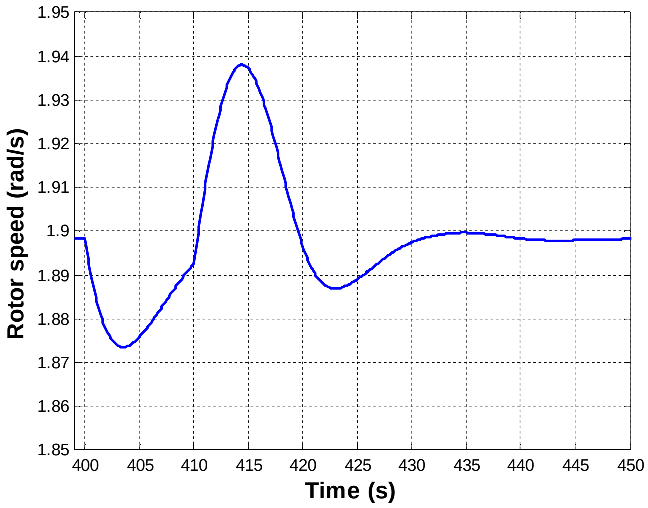

Figure 3-16 Rotor speed response at 12 m/s during and after the transient

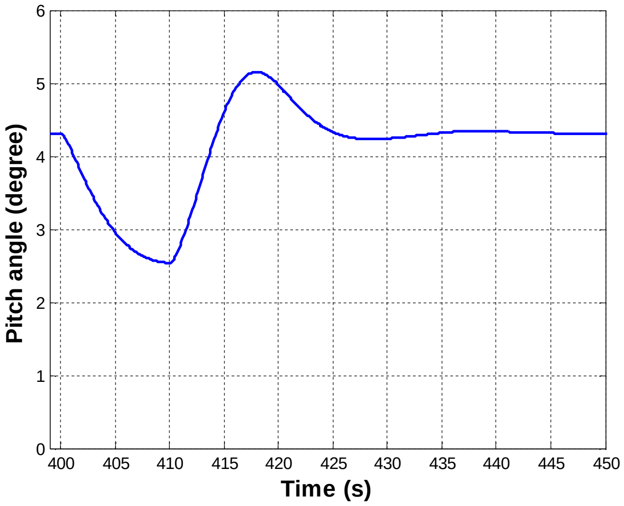

Figure 3-17 Pitch angle response at 12 m/s during and after the transient

3.7 Conclusions

A novel approach to calculating the aggregate inertial response from a wind farm has been explained in this chapter. The novelty lies in the approach to estimating the inertial response from a collection of turbines at a site available under varying wind conditions. This is achieved by using a Gaussian probability distribution to represent the wind variations over the time period of the required inertial response, thus significantly reducing the computing complexity. To date it has not been possible to validate the approach due to lack of data. It is hoped that this can be remedied in the near future.

The analysis has clearly shown that the capacity for providing inertial frequency support does not increase with rising wind speeds as a result of the changes in turbine aerodynamic control associated with above rated power operation.

Wind generation will make up only a small proportion of the instantaneous total power generation when wind speeds across the power system are generally low. In these circumstances, conventional generators, such as those powered by gas, coal or nuclear, will meet the bulk of demand on the network. At such times the actual synchronous inertia on the system would be high and no problems are foreseen in dealing with any sudden loss in generation or rapid and unexpected increase in demand. Normal TSO practice to plan for such contingencies would remain adequate. It is the times of high instantaneous wind penetration and the concomitant reduction in conventional plant on the bus bars that will pose greatest operation challenges and have the most to gain from frequency support from wind. As will be seen from the analysis in Chapter 4, high wind generation level in the power system will have the downside in terms of reduction in system inertia, but then the wind capacity can certainly make useful contributions to power system frequency stability provided the wind capacity is equipped with some kind of synthetic inertial capability.

This chapter has outlined an approach for calculating the expected inertial response from wind farms. How much synthetic inertial response wind capacity can contribute to network frequency support depends on the wind speed and its variations, generation mix at that time, and wind penetration level. Further research is needed to examine in detail how far and fast this aggregate inertial response can be delivered and what impact it will have on arresting grid frequency drops, and if delivery of inertial response will result in an increased demand for primary and secondary response from the conventional plant on the power system. These factors will be examined in Chapter 4. Additional work will also explore droop response service provision from wind plant and its interactions with inertial response under changing wind conditions as will be explained in Chapter 5.

The stochastic process of wind variation poses significant further challenges to assessing the capability of aggregate wind plant across an entire power system to provide inertial response. This is because the geographically distributed nature of the wind plant means that individual wind farms will be exposed to very different wind speeds. These variations cannot, in contrast to the present approach, be regarded as random. There are significant correlations in spatially distributed wind speeds and these depend, not surprisingly, on the distances between the sites in question [14]. The approach proposed here can also be used to describe the response of offshore wind farms for which the wind turbulence levels would generally be lower than onshore.

Reference

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Chapter Four Assessing inertial response from wind capacity in the GB power system

4.1 Background

As made clear in Chapter 1, frequency stability is of growing concern to the transmission system operators (TSOs), especially of smaller power systems like those of Great Britain and the Republic of Ireland [1, 2]. This is because wind penetration in these systems is expected to be greater than, for example, the much more extensive synchronised regions of the European power network.

Power system frequency is a continuously changing variable that is determined and controlled by the second-by-second (real time) balance between system demand and generation. If demand is greater than generation, the frequency falls. If generation is greater than demand, the frequency rises.

Following a sudden loss of demand or generation, caused either by a network fault or plant failure, there will be a difference between instantaneous generation and demand that will result in a frequency deviation from nominal. The GB power system operator, National Grid runs the system in such a way that:

- The maximum deviation of frequency after a normal infeed loss is no greater than 0.5 Hz.
- The maximum deviation of frequency after an infrequent infeed loss is no greater than 0.8 Hz.
- Any deviation outside 49.5 Hz and 50.5 Hz does not exceed 60 seconds.

There are two types of frequency response: dynamic and non-dynamic. Dynamic frequency response is a continuously provided service used to manage the normal second by second changes on the system whilst non-dynamic frequency response is usually a discrete service triggered at a defined frequency deviation.

National Grid achieves this by using the response services, which are defined below [3]:

- Primary and secondary response is an automatic increase in generation (or reduction in demand) when the frequency falls below 50 Hz. Primary response is required to be delivered within 10 seconds, while secondary response is normally within 30 seconds[5].
- Tertiary response is sourced from unsynchronised standby generators that can provide instructed level of output within 20 minutes. This service can typically be supplied by open cycle gas turbines and reciprocating inertial combustion engines.
- High frequency response is an automatic reduction in generation (or increase in demand) when frequency is above 50 Hz. High frequency response, like primary response, is required to be delivered within 10 seconds.

Unlike synchronous generators, modern variable speed wind turbines (using doubly fed induction generators or fully rated converters) cannot intrinsically contribute to power system inertia. It has been shown however in Chapter 3 and elsewhere, for example [4-9], that such turbines can be modified to deliver inertial power contribution similar to that of synchronous generators in response to system frequency drops. As already mentioned, most studies are based on constant wind speed and do not investigate the impact of wind speed transients on the provision of inertial response from wind turbines (see for example [4, 5]); this is a problem since the wind speed is never constant. The wind turbulence over the complete transient period (covering both the provision of inertial response and the following recovery period) should be taken into account.

In this Chapter, as in Chapter 3, variations in wind speed have been modelled using a Gaussian probability distribution to assess the probabilistic inertial power contribution from a wind farm. However, the methodology presented in Chapter 3 was developed to apply to only a one single wind farm, with a given hourly, or ten minute, mean wind speed. We know that wind speed will vary across any power system of significant spatial extent and so the inertial response available from the installed and operational wind capacity with the power system needs to be assessed in a manner that reflects this. It will be found convenient to treat identified

[5] These figures are for the GB power system, and values will vary from country to country.

geographical regions within the power system (in this case covering England, Wales and Scotland) as having a different representative ten minute or hourly mean wind speeds and associated with these, specific regionally installed capacities..

Previous research also shows that the impact of wind generation on power system frequency stability can be significant. The behaviour of the combined Ireland and Northern Ireland power system following a frequency event has been examined for various wind penetration scenarios by a joint research team from University College Dublin and utilities in Ireland, [7]. In their study, one of the few to take variations in wind into account, the inertial contributions of wind generation are estimated from a function established from historical wind farm operational data. Due to the difficulties in determining the number of wind turbines connected to the grid at any moment, significant uncertainties exist in terms of the stored kinetic energy associated with this wind capacity. This study concludes that the kinetic energy available from wind generation can be approximated as a function of the aggregate power output from wind generation using empirical data from geographically distinct wind plant across the country. In this way, a linear programming based dispatch model incorporating the wind power output along with the inertial contributions from fixed speed wind turbines (using squirrel cage induction generator), conventional power output and the associated reserve, system load and wind time series is developed to assess the frequency response on an hourly basis.

An interesting and useful follow up study that considers variable speed wind turbines in the context of the combined Ireland and Northern Ireland power system is [8]. In this study, the impact of frequency responsive wind plant on the projected combined Ireland and Northern Ireland power system in 2020 has been investigated. It shows that the inertial power contributions of a variable speed wind turbine equipped with the emulated inertial response capability can be aggregated from the averaged response of many trials on an individual turbine for different wind speeds and turbulence conditions. A series of field tests were performed on an operational wind plant based on GE WindINERTIA control strategy and the averaged results are shown in Figure 4.1.

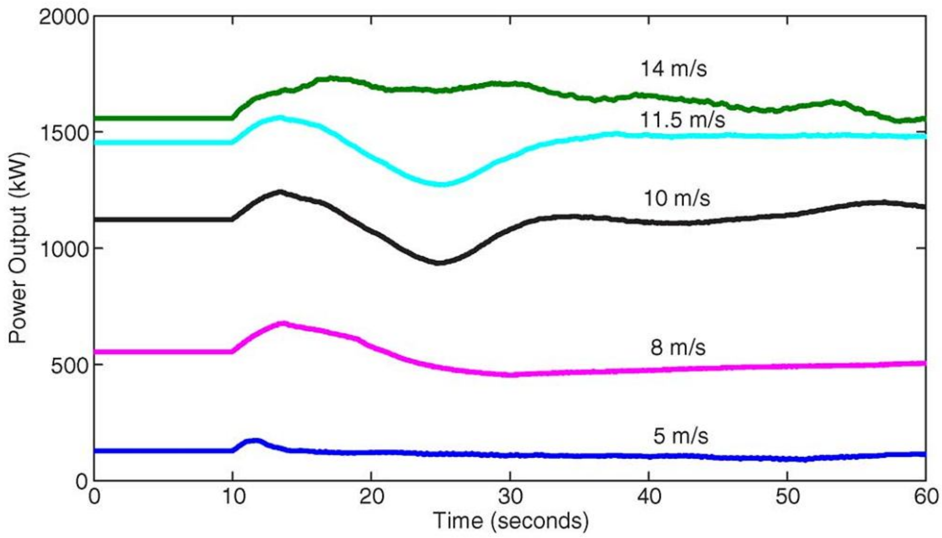

Figure 4.1 WindINERTIA field test results, taken from [8]

This study also concludes that the proportion of the operational variable speed wind turbines on the system, and thus the inertial power contributions available can be estimated as a function of the wind power output into the system. In comparison with the relationship between stored kinetic energy and power output from wind capacity established in [7], this study exhibits a similar characteristic. However, significant uncertainty exists at midrange wind generation level in terms of the potential number of operational wind turbines, which highlights the difficulties in determining the inertial response available from wind generation in this manner. For instance, at a wind generation level of 0.2 pu averaged across the whole power system, the number of operational wind turbines may vary from 0.25 pu to 0.9 pu, which means that the power generated could come from a small number of turbines operating at high power output or a large number of turbines operating at low power output. This is consistent with the results presented in Chapter 3 and shows that the capacity to provide aggregate inertial response from wind is more complex than hitherto recognised and that the common perception that such capacity should increase with increasing wind speed is not accurate.

It is rather difficult to determine the inertia constant H for the projected GB power system in 2020 and clearly this parameter will depend on the level of load on the power system and the corresponding plant mix scheduled to meet this net demand, and this in turn will depend on the anticipated level of wind power generation.

As reviewed above, the research team from University College Dublin examined power system frequency stability in the context of the provision of frequency support from variable speed wind turbines connected to the combined Ireland and Northern Ireland Power System in 2020 [8]. A one bus model was developed in Simulink to represent the combined Ireland and Northern Ireland Power System in 2020. It incorporates all conventional generation on the system, including steam, OCGT, and CCGT generators, two HVDC interconnectors to Great Britain, also fixed and variable speed wind turbines [10, 11]. Their model shows that with increasing wind penetration levels, system inertia will decrease considerably for the projected year of 2020 compared with 2009 level (Figure 4-2).

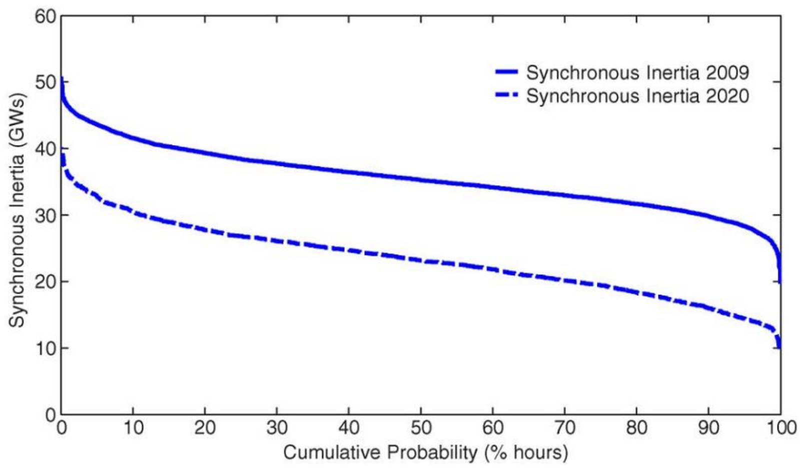

Figure 4-2 Synchrous inertia duration curves for the combined power system, taken from [8]

The effect of low system inertia has been assessed by National Grid’s Grid Code Frequency Response Working Group [2]. Previous research has shown how the power system characteristics can be estimated using measured data. A series of planned tests have been performed on the power system within the Republic of Ireland to develop a dynamic load model using the frequency characteristics recorded [12]. A procedure for the estimation of power system inertia constant using frequency transients measured on a Japanese power system is presented in [13]. A polynomial approximation is used in their study to estimate the system parameters, such as inertia constant and online spinning reserve capacity. An interesting approach for the estimation of power system parameters using cumulative operational data from the Dinorwig pumped-storage hydro power station is presented in [14]. Values of the natural frequency, damping factor and stiffness are derived for the System Frequency Response model described by Anderson and Mirheydar [15].

With the rising wind penetration levels, it is likely that TSOs will have to rely on wind farms to deal with transient events on the system through the delivery of so called synthetic inertia from the wind capacity together with frequency support from conventional plant commitment in order to ensure secure and reliable system performance.

The challenges are twofold; first, the inertial response available from wind generation can be difficult to predict due to the wind turbine availability and the wide range of potential variability of the wind resource, both locally, and nationally. Second, the power system dynamic characteristics (such as total available inertia) will change constantly due to changes in plant mix resulting from the time varying nature of the load and also the time variable wind power generation.

The contribution of this chapter is to address these challenges and to propose a probabilistic approach to modelling the collective inertial contributions from wind generation in the GB power system taking account of the variation of the regional mean wind speeds and the variation from region to region. Although the GB power system is used as the case study, this approach can be easily extended to apply in other power systems.

This chapter is set out as follows: Section 4.2 describe the modelling of the GB power system. Section 4.3 explains the synthesised wind speed data used for the assessment of aggregate inertial response from wind generation. Section 4.4 describes the estimation of installed wind capacity in the GB power system. Section 4.5 explains how the aggregate inertial response from wind generation under varying wind conditions is assessed. Section 4.6 examines the impact of power contributions from the operational wind capacity on frequency stability and quantifies the response to a sudden loss of generation in terms of frequency minimum (nadir) and ROCOF; and finally conclusions are presented in section 4.7.

4.2 GB power system modelling

A well established System Frequency Response (SFR) model, [15], is used in this research to estimate the frequency response of a large power system. The modelling is explained in this section.

An SFR model assumes that only the largest time constants of the generating units are relevant and that generation on the system is dominated by reheat steam turbine generators (covering coal and nuclear plant, the steam cycle component of CCGTs) as shown in Figure 4-3. An equivalent single machine is used to represent the dynamics of the conventional generators by ignoring the synchronising oscillations that may occur between generators in a large power system. SFR models have since been applied to develop under-frequency load shedding schemes and power system frequency dynamics analysis in various studies [16-18].

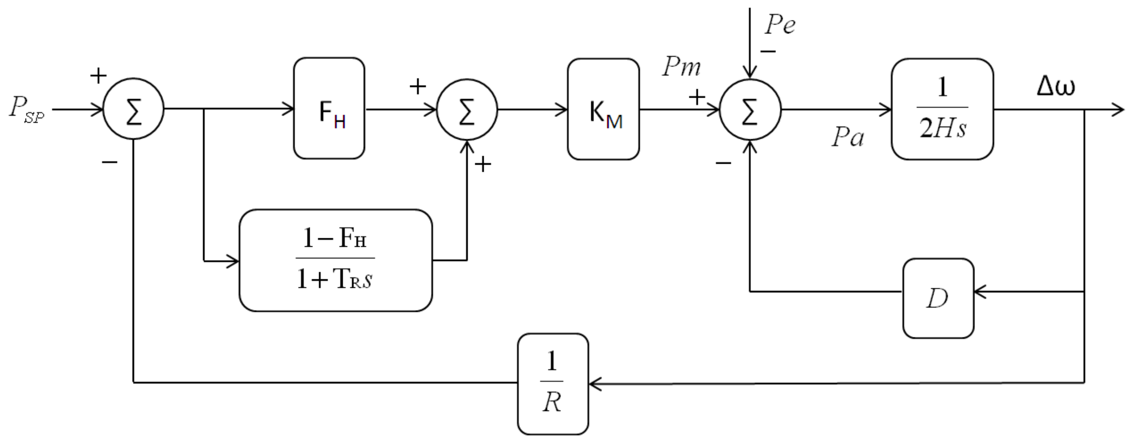

Figure 4.3 System frequency response (SFR) model

P_{SP} = Incremental power set point, per unit

P_m = Turbine mechanical power, per unit

P_e = Generator electrical load power, per unit

$P_a = P_m - P_e$ = Accelerating power, per unit

$\Delta\omega$ = Incremental speed, per unit

F_H = Fraction of total power generated by the HP turbine

T_R = Reheat time constant, seconds

H = Inertia constant, seconds

D = Damping factor

K_m = Mechanical power gain factor

R = Droop

For this research, the SFR model is modified to include wind generation and thus capture the key aspects of the frequency behaviours of the GB power system projected to 2020. As shown in Figure 4-4, the wind generation is able to deliver inertial power contributions in response to system frequency fall. This modified SFR model is considered adequate for the purposes of investigating system wide frequency dynamics. Local and distributed effects however should be examined more carefully using more detailed models. Note that over frequency events will not be examined in this work as wind capacity can be easily curtailed and so decrease the overall system generation when required.

Table 4-1 lists the system parameters (but not including the inertia which varies with wind penetration) used in the modelling.

Table 4-1 SFR model parameters for 6 am on mid-summer and mid-winter days

F_H	T_R	K_M	R	D
0.15	15.0	0.82	0.04	1.0

H: Inertia constant, s.
F_H :Fraction of total power generated by high pressure turbine;
T_R: Reheat time constant, seconds;
K_M: Mechanical power gain factor;
R: Governor droop;
D: Damping factor

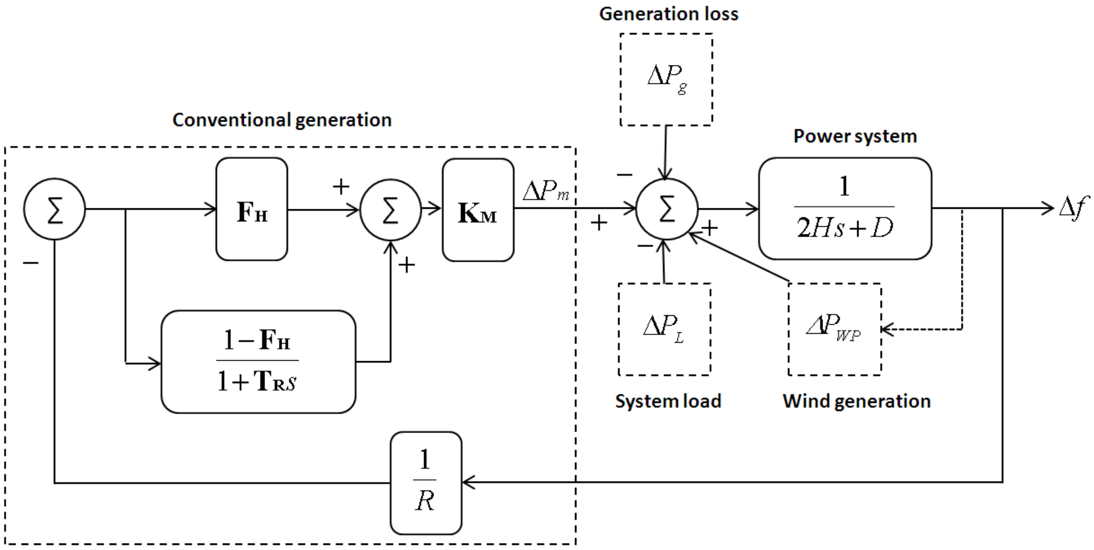

Figure 4.4 GB power system model

Given the difficulty in determining the instantaneous system inertia and lack of data, the aggregate inertia constant of the modified SFR model used in this research will be varied as outlined below to reflect the changes in plant mix for different wind time series and to properly capture the frequency dynamics following an assumed generation loss of 1.8 GW. It is assumed that the generation loss of 1.8 GW will occur at 6:00 in the morning when supply a minimum system load of 25 GW in the summer and 30 GW in the winter. These daily minima have been selected as these hours will have least conventional plant on the system and thus suffer the largest falls in system frequency.

For each demand level, simulations are conducted to examine the frequency support from frequency responsive wind plant to the frequency behaviours following an infeed loss of 1.8 GW. The wind time series (hourly mean wind speeds) on typical mid-summer and mid-winter days are applied to reflect the amount of wind generation into the system. The system inertia will, therefore, vary with the wind penetration into the system. The conventional generation parameters will remain unchanged to investigate how the simulated frequency trace can be contained with and without the support from wind plant. Of course, the power system inertia will reduce along with the wind power injection into the system reflecting the fact that the conventional generation with its inherent inertial response have been replaced by variable speed wind capacity with no intrinsic inertia. It can be anticipated that the remaining conventional generation will not be able to provide the frequency response required to contain the system frequency within statuary limits. However, it is important to investigate how much reliance can be placed on wind capacity for dealing with frequency stability in a large power system.

The reduced system inertia constant will be calculated taking into account wind time series and resultant operational wind capacity as follows [19]

$$H_{reduced} = \frac{\sum H_i S_i}{\sum S_i} \tag{4-1}$$

Table 4-2 shows the example power system configuration on a typical mid-winter day.

Table 4-2 Example power system configuration on a typical mid-winter day

	Wind	**Nuclear**	**Pumped Storage**	**Others**	**System Load**	**Generation Loss**	**Inertia Constant**	**Instantaneous Wind Penetration**
	9.64	6.9	1.8	11.66	30	0.06	4.1	32%
H	0	6.5	4.5	6	-	-	-	-
Capacity: GW;	Inertia constant H: s;		Generation loss: pu.					

4.3 Synthesised wind speed data for the assessment of aggregate inertial response from wind capacity in the GB power system

It has been shown in previous literature and also in Chapter 3 that individual wind turbines can be controlled to provide frequency support in response to a change in system frequency. In reality, wind speed is constantly changing, and the combined response from wind generation will comprise contributions from each wind farm, each operating under different local wind conditions. It is of importance for the TSOs that frequency support from wind generation is predictable and verifiable. An approach to assessing the aggregate inertial response from wind capacity operating within the GB power system is presented in this Chapter. This approach is based on a validated spatial wind model [20] and the probabilistic method for the aggregation of the inertial response of geographically dispersed wind generation presented in Chapter 3. Although the approach is applied here to the case of the GB power system, it can be easily adapted and applied to other power systems and other wind regimes.

A Vector Auto Regressive (VAR) model, as detailed in [20] is applied to synthesise wind speed data for these power system impact studies. This VAR modelling approach takes account of the diurnal and seasonal variations in wind speed through detrending, and captures accurately the correlation of wind speeds across the geographical areas in the GB power system. Fourteen meteorological office stations in the UK were chosen to characterise the wind speed data in 14 of the SYS study regions as shown in Figure 4-5. It should be noted that three study regions (Regions 4, 14 and 16) have been left out due to lack of reliable wind data from local meteorological stations. However, these three regions have limited wind capacity and this simplification should have no significant impact on the overall results. The VAR model has been used in this research to synthesise the hourly mean wind speeds that will be used for wind farm dynamic response modelling in each study region. The VAR process is driven by white (Gaussian distributed) noise, and by using different random number seeds independent realisations of the wind speed time series can be generated.

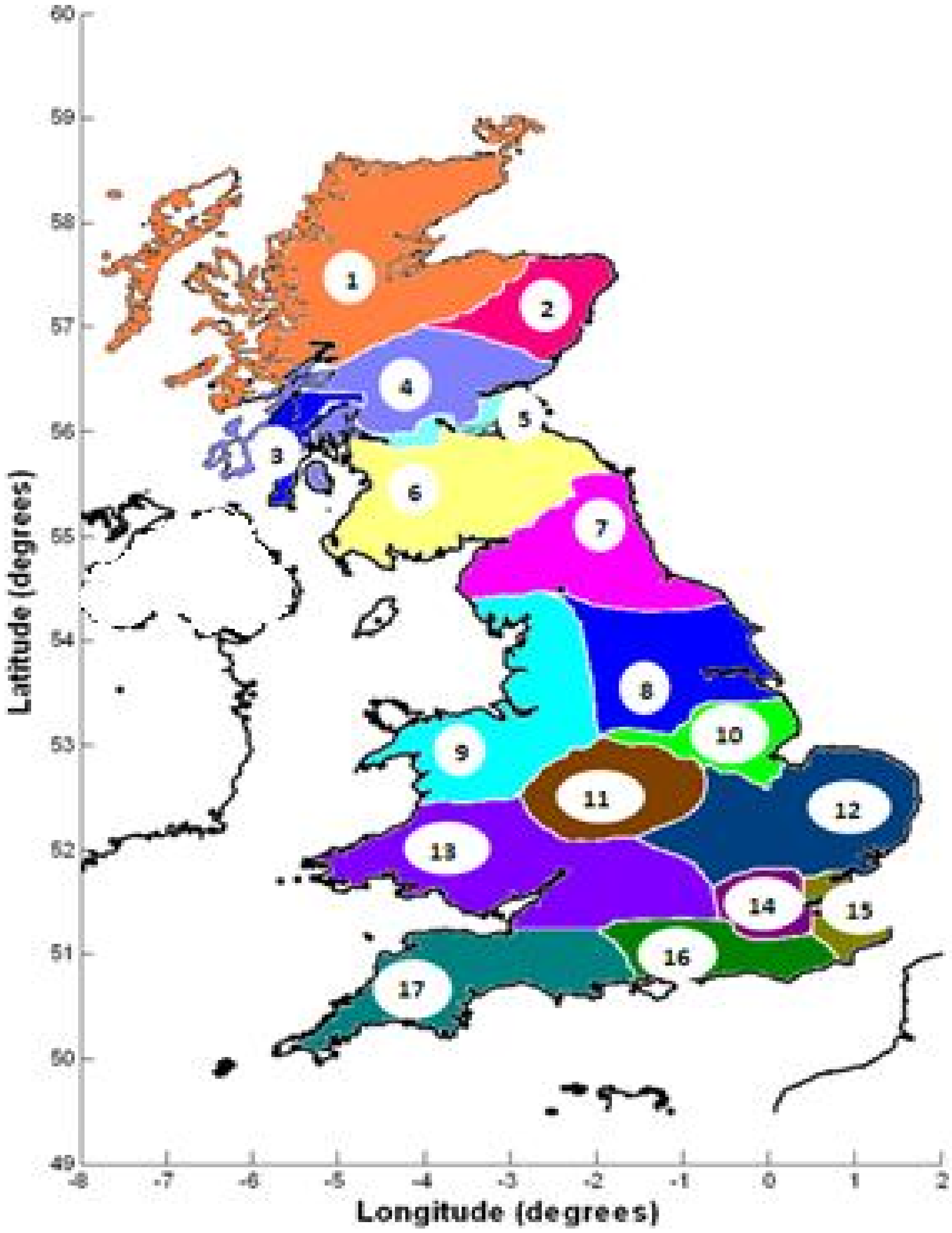

Figure 4.5 Study regions in the GB power system

4.4 Estimation of wind capacity in the GB power system in 2020

National Grid (NG) has developed a ‘Gone Green Scenario’ that describes an energy future designed to meet the emissions related challenges of climate change.

While this is still work in progress in that future scenarios must be adapted as time progresses, this NG view of a potential energy mix for 2020 will meet the UK government’s climate change target as presently formulated. This scenario assumes that the correct economic incentives are in place to meet the climate change targets. Table 4-3 lists the projected generation mix in 2020.

Table 4-3 Gone Green Generation Mix 2020 [2]

	Wind	**Other Renewables**	**Nuclear**	**Pumped Storage**	**Oil**	**Coal**	**Gas**	**Interconnector**	**Total**
Capacity (GW)	29.5	3.3	6.9	2.7	0.8	19.8	34.2	2	99.2
Percentage	30%	3%	7%	3%	1%	20%	34%	2%	100%

For modelling purposes, the GB power system is divided into 17 study regions, consistent with the 17 SYS boundaries identified by National Grid [3]. The installed wind capacity in each region for the year of 2020 is estimated on the basis of wind farms already operational, under construction, and consented as listed in RenewableUK’s UK Wind Energy Database, [21]. Tables 4-4 and 4-5 list the estimated wind capacity in each region.

The installed wind capacity estimated in this manner totals 27.4 GW by 2020 and includes offshore wind. This is broadly consistent with National Grid’s ‘Gone Green’ scenario with a total of 29.5 GW. Wind speeds however are not available offshore using the spatial wind model and thus offshore capacity has been allocated to the nearest onshore region. The resultant errors in modelling are unlikely to be significant, although future work is planned to extend the spatio-temporal wind field models when suitable offshore data becomes available.

Table 4-4 Estimated wind capacity in 2020 (by region)

Region	Capacity (MW)	Name	TSO
1	2047	North West (SHETL)	SHETL
2	247	North (SHETL)	SHETL
3	369	Sloy (SHETL)	SHETL
4	439	South (SHETL)	SHETL
5	1296	North (SPT)	SPT
6	4245	South (SPT)	SPT
7	4127	North & NE England	NGET
8	2246	Yorkshire	NGET
9	3498	NW England & N Wales	NGET
10	2284	Trent	NGET
11	163	Midlands	NGET
12	3044	Anglia & Bucks	NGET
13	876	S Wales & Central England	NGET
14	6	London	NGET
15	1825	Thames Estuary	NGET
16	187	Central S Coast	NGET
17	493	South West England	NGET

Table 4-5 Estimated wind capacity in 2020

Region	Onshore (MW)			Offshore (MW)				Total
	Operational	Under construction	Consented	Operational	Under construction	Consented	In planning	
01	785	284	393	10	0	0	575	2047
02	132	29	61	0	0	0	25	247
03	137	54	5	0	0	0	173	369
04	389	32	18	0	0	0	0	439
05	2	25	58	0	0	6	1205	1296
06	2152	740	903	0	0	0	450	4245
07	262	188	206	184	62	0	3225	4127
08	131	175	400	0	0	540	1000	2246
09	310	25	59	847	576	389	1292	3498
10	123	9	62	194	270	1200	426	2284
11	31	29	103	0	0	0	0	163
12	141	61	161	60	821	0	1800	3044
13	206	83	212	0	0	0	375	876
14	6	0	0	0	0	0	0	6
15	60	31	146	563	1000	12	13	1825
16	1	0	20	0	0	0	166	187
17	128	29	36	0	0	0	300	493
Total	4996	1794	2843	1858	2729	2147	11025	27392

4.5 Probabilistic modelling of aggregate inertial response from wind capacity

A probabilistic methodology to assess the combined response from a wind farm under time varying wind speed has been presented in Chapter 3. In this approach wind variations over a short period of time, 10 seconds, comparable to the inertial response transient, are described by a Gaussian probability distribution.

A block approach is used to limit the number of calculations undertaken, with the blocks defined in terms of the start and end values of the wind speed for the transient period of 10 seconds. The start wind speed is divided into 6 blocks and the end wind speed is also divided into 6 blocks. In this way, the potential infinite number of wind ramps over the transient is reduced to 36 scenarios that can effectively represent all the possible wind ramps for a given mean wind speed. The blocks can be represented as:

$$B_{i,j} \; (i=1,\ldots,6; \; j=1,\ldots,6) \qquad (4\text{-}2)$$

Although the expected inertial response should be calculated using the full range of wind ramps and their probabilities, only wind variations between zero and 50 m/s are used in this research as wind speeds beyond this range rarely occur. As mentioned in Chapter 3, the probability distribution for the wind ramps is dominated by those that start and end wind speeds close to the mean. The wind ramps that start or end within the ranges further away from the mean have considerably lower probabilities.

This approach, designed for the aggregation of inertial response from a wind farm is extended as outlined below, to estimate the aggregate expected inertial response available from the operational wind generation capacity across the entire geographical area of the GB power system.

Common practice in previous studies is for the inertial response to be triggered by a fixed frequency deviation (Δf) or ROCOF (df/dt), or both, and for the added torque to remain constant over a pre-set period (around 10 seconds in duration) and so deliver inertial response independent of the response of the rest of the power system. In reality, the inertial power contribution from wind generation is part of closed system and is dependent on the wind conditions (through its impact on the value of H prevailing at the time in question) and the ROCOF that depends also on the dynamic response of the conventional plant and in particular, its inertia. The maximum ROCOF is achieved at the instant immediately following the sudden loss of generation or increase in load and is dependent only on the system inertia and the mismatch between instantaneous generation and load. With the increasing power injection into the system from conventional generation and wind generation in response to the falling frequency, the ROCOF will decrease till the generation and demand on the system is balanced. Therefore the aggregate expected inertial response from wind generation has to be assessed reflecting this dynamic interaction. Simply calculating how the power system would respond to a preset power injection from wind generation is not sufficient. A description of the developed aggregation methodology is given below.

The wind capacity in each study region is represented by one single effective wind turbine (for simplicity all wind turbines are assumed to be identical). The GB power system can be represented by 17 regions with hourly average wind speeds $\overline{\mathrm{U_m}}$ (m=1,…,17) and wind power installed capacity $\mathrm{P_m}$ (m=1,…,17) in each region. For any given event (assumed to last for 10 seconds) across the power system, the wind capacity, $\mathrm{P_m}$, in each region will experience different transient wind speeds and thus operate in 36 blocks described in Chapter 3, with appropriate probabilities, $\mathrm{Q_{i,j}^{(m)}}$ (m=1,…,17; i=1,…,6; j=1,…,6).

When the 17 regions are combined, the wind capacity operating in a range corresponding to a particular block can be calculated using weightings defined as follows. Weighting $k_{\mathrm{i,j}}$, can be calculated from:

$$k_{\mathrm{i,j}} = \sum_{\mathrm{m=1}}^{17} \mathrm{P_m Q_{i,j}^{(m)}} \qquad (4\text{-}3)$$

For each of the blocks, the corresponding weighting $k_{\mathrm{i,j}}$ is the sum of the wind capacity in each region multiplied by the probability associated with the specified wind ramp range. The weightings for a set of wind speeds across the GB power system are shown in Table 4-6. The weightings (vertical axis in this figure) for 36 blocks are illustrated in Figure 4-6.

The expected aggregate inertial response from wind generation as a whole can then be calculated combining the inertial power response from the 36 blocks each one represented by a power response (equivalent to a turbine controller plus wind ramp input), weighted by the appropriate weightings calculated using (4-3).

This is a key additional step towards accurate estimation of the frequency support potentially available from wind capacity.

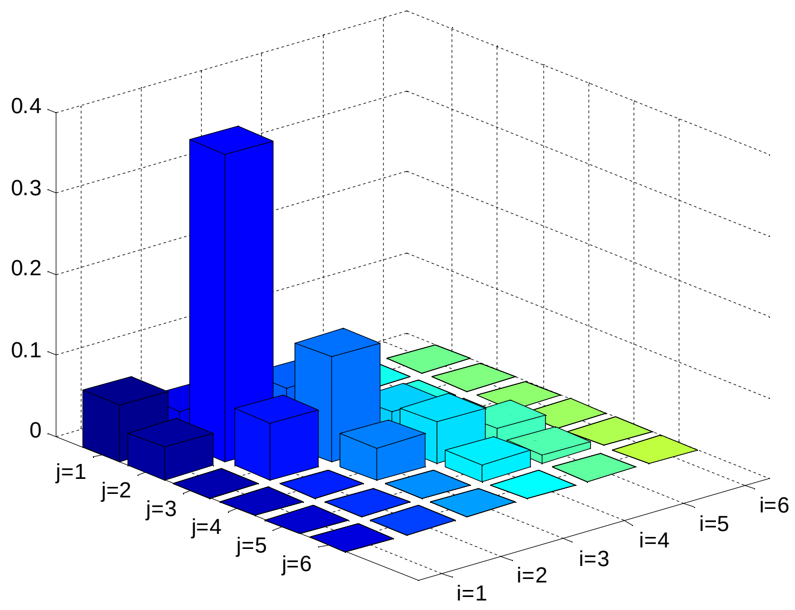

Figure 4.6 Weightings for a set of wind speeds

Table 4-6 Weightings for a set of wind speeds

Start wind / End wind	i=1	i=2	i=3	i=4	i=5	i=6
j=1	0.07	0.04	0	0	0	0
j=2	0.04	0.38	0.07	0	0	0
j=3	0	0.07	0.13	0.04	0	0
j=4	0	0	0.04	0.05	0.02	0
j=5	0	0	0	0.02	0.01	0
j=6	0	0	0	0	0	0
Total				1		

4.6 Case studies

The proposed probabilistic approach to calculating the aggregate inertial response from wind generation is used to estimate the contributions to maintaining frequency stability in the GB power system. It is estimated that the installed wind capacity will be 27.4 GW by 2020 as explained above. The generating wind capacity can then be calculated on an hourly basis, given an average availability of 95% (reflecting the combination of onshore and offshore installed wind capacity). It is assumed that 6.9 GW of nuclear power plant will supply the base load on the system in 2020. Conventional generation (coal and gas powered plant) will make up the rest of the generation mix.

The wind speeds across the GB power system for a series of 30 different representative summer and winter days are obtained using the VAR wind model as outlined above. The system load is anticipated to remain flat over the period from 2010 till 2020 due to a combination of significant load reduction from energy efficiency measures and increase from electric vehicle charging and heating using heat pumps. The power system inertia constant values are calculated for the hours in question as explained in Section 4.2. The impact of the aggregate inertial response from wind capacity on frequency stability is examined assuming a sudden loss of 1.8 GW of generation occurs. Since the response from the wind will depend on the mean wind speed levels prevailing at the time in question, it is important to investigate how these vary across the 30 wind speed values for the 17 regions.

Case study 1 – a typical winter day

The system load on a typical British winter day in 2020 is assumed to remain flat for modelling purposes over the period from 2010 ie a minimum system load of 30 GW at 6 am in the winter. Figure 4-7 shows the example wind speeds in three regions for a series of 30 different representative winter days. It is assumed that there is no curtailment of wind power and so the number of operational wind turbines will be determined merely by the wind speeds alone.

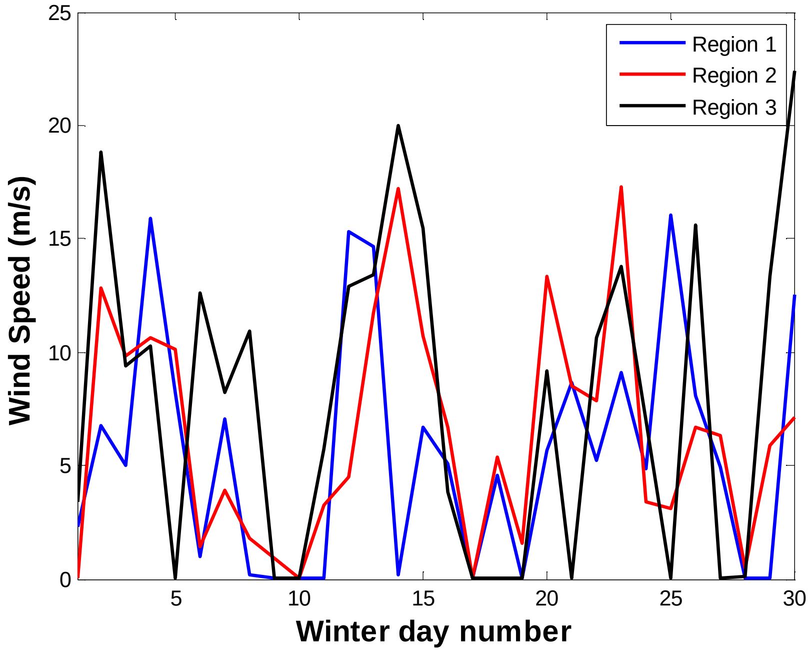

Figure 4-7 Example winter wind speeds (Regions 1, 2, and 3) for the 30 sample days

The impact of the aggregate inertial response from wind capacity on frequency stability is investigated assuming a sudden loss of 1.8 GW[6] of generation occurs at the simulated events. Since the response of the wind will depend on the mean wind speed levels prevailing at the time in question, it is important to probabilistically analyse how the stochastic inertial contributions from wind affect power system frequency stability. 30 simulation runs have thus been carried out to examine the maximum frequency deviation and ROCOFs with and without frequency support from wind capacity.

Figure 4-8 shows the probability density function (pdf) for the aggregate generated wind power (in per unit where the reference value is the total installed rated capacity of 27.4 GW) at 06:00 in the morning for winter days. This has been estimated by calculating the mean output for each region for each of the 30 wind speed values, and then binning the corresponding probabilities according to wind speed. Figures 4-9 to 4-10 show the frequency minimum (nadir) and rate of change of frequency (ROCOF) following the event[7] with and without inertial frequency support from the wind capacity plotted against aggregate wind output for each of sample hours. It can be

[6] This is anticipated to be the capacity of the largest single generating unit on the GB system in 2020.

[7] ROCOF here is measured 0.1 seconds after the loss of 1.8 GW to allow time for the inertial response to occur.

seen that the additional power contribution from the operational GB wind plant can significantly reduce the extent to which the frequency falls and thus improves the frequency minimum (nadir) following the event. It also shows that with higher wind penetration, lower frequency minima and higher ROCOFs will occur. Better system frequency control can be expected from high wind penetration, although this does depend on the amount of conventional plant displaced and the consequent loss of system inertia. Carefully coordinated control of wind capacity and conventional plant is essential to secure system operation.

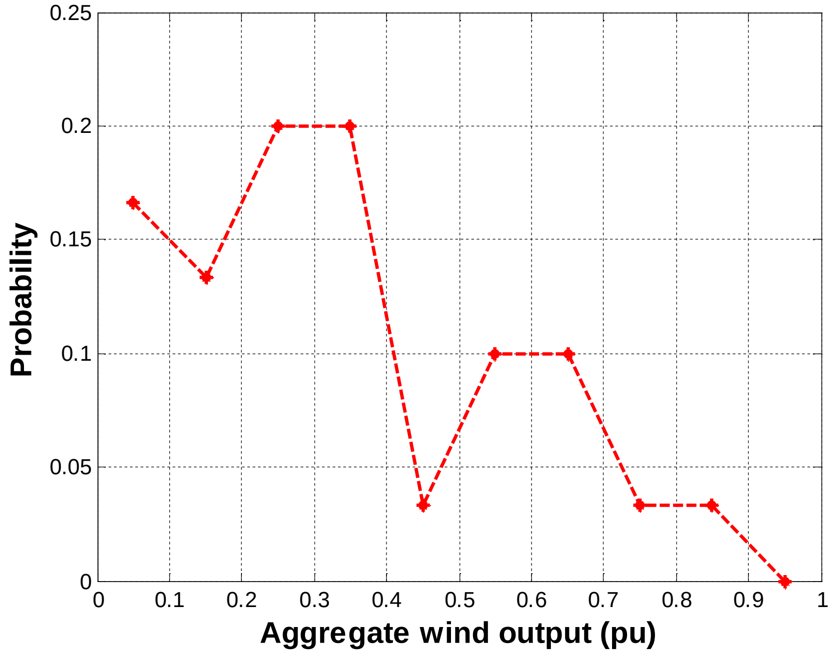

Figure 4-8 Probability of aggregate wind output for 30 sample winter days

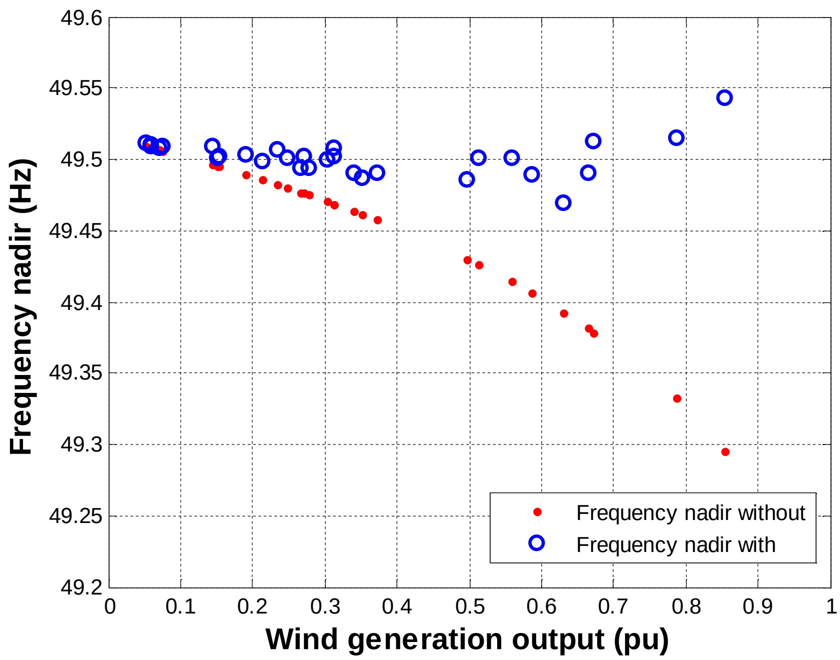

Figure 4-9 Frequency minimum (nadir) following transient

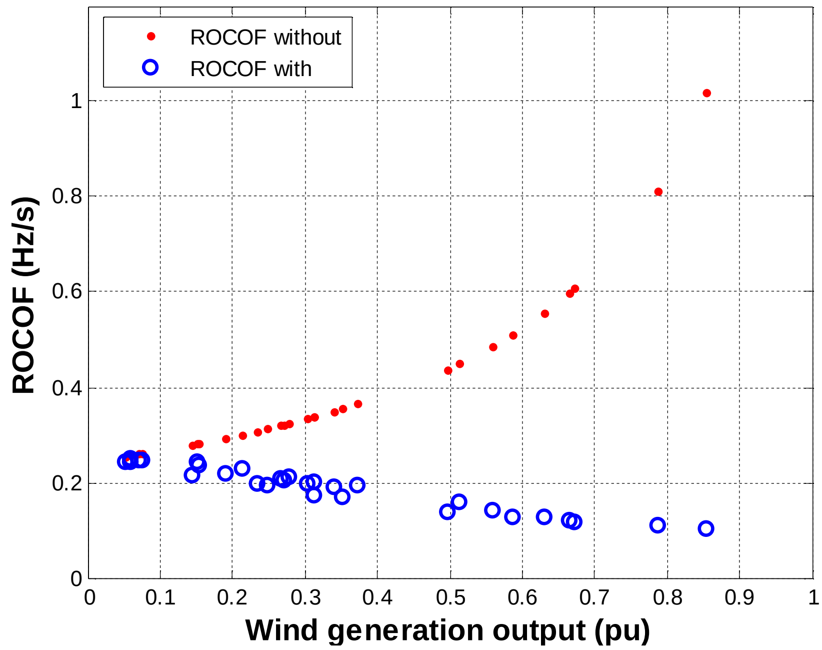

Figure 4-10 Rate of change of frequency (ROCOF) following transient

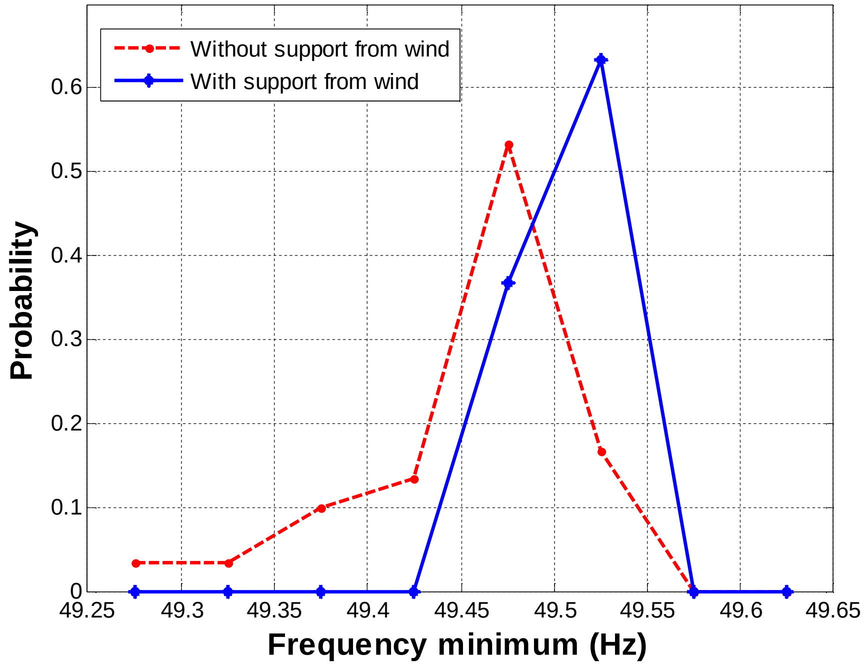

Figure 4-11 Probability density function of nadir

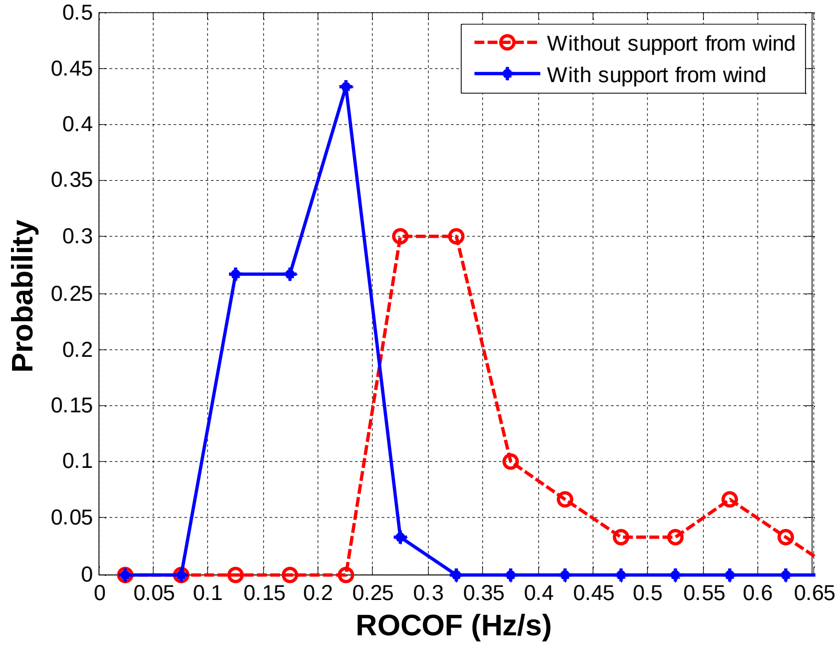

Figure 4-12 Probability density function of ROCOF 0.1 s after event

Figure 4-11 shows the pdf for frequency minimum for the 30 samples winter hours with and without frequency support from wind, whilst Figure 4-12 shows that the pdf for the ROCOF (measured 0.1 seconds following the transient in order to allow for delay in frequency sensing) can be reduced by the wind plant. Frequency sensing delay has been represented by a simple filter in this work following [22, 23]. Future work will investigate how the power ramp rate limitations and sensing delays will affect the system dynamics. It is clear from these figures that the pdfs have been shifted significantly in the desired direction; ie to larger nadirs and lower ROCOFs, and that uncertainty, represented by the spread, has been reduced.

The estimation of inertial power contribution available from wind is based on the assessment of wind power under varying wind conditions in various regions using the VAR model. It is assumed that TSOs will gather weather data and wind power forecasts and production data from wind farm operators in near real-time. Due to the non-linearity of wind power output, it is difficult to estimate the available responsive wind capacity from the overall wind power output on the system as shown in [7, 8]. The approach presented here does not depend on this since the model assumes that hourly wind speed values are known in all 17 regions and that inertial power contributions based on these can be relied on. In practice there will still be some uncertainty, albeit relatively small, but further research is required to test this assumption.

Case study 2 – a typical summer day

Simulation runs have also been undertaken for a series of 30 different representative summer days. Figure 4-13 shows for example wind speeds in regions 1, 2 and 3 for the 30 different sample summer days. It should be noted that no considerable difference in wind speed can be observed between the selected winter and summer days for these three regions. This is because these regions are located in areas with abundant wind resources, and because of the limited sample size. However, on average, wind speeds and resulting wind output on summer days are significantly lower than that on winter days: the mean wind speed for the selected 30 winter days across all 17 regions is 6.32 m/s, whereas for summer the value is 4.94 m/s.

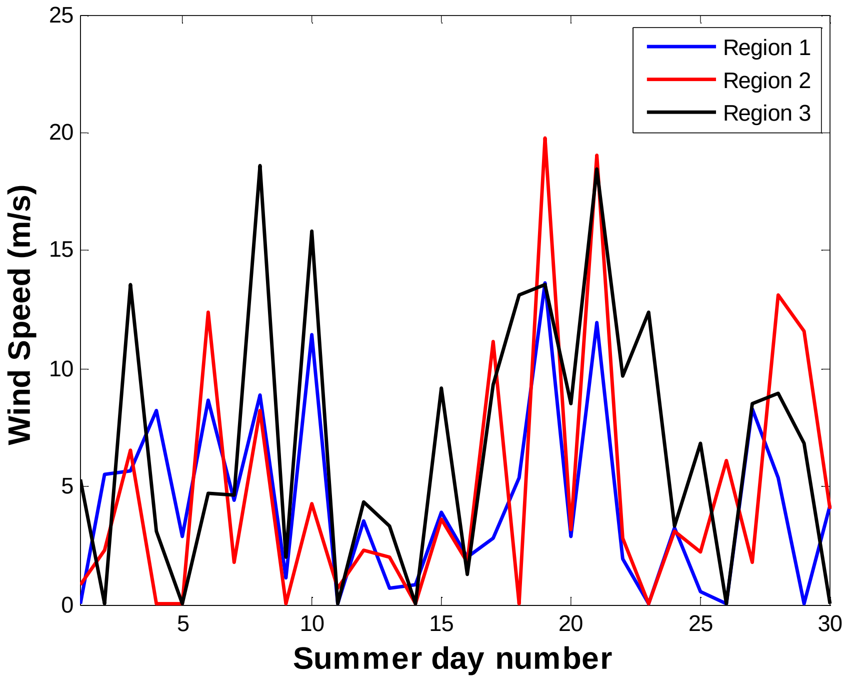

Figure 4-13 Three example regions' summer wind speeds for the 30 sample days

Figure 4-14 shows the probability density function (pdf) for the aggregate generated wind power (in per unit where the reference value is defined in the same way as before) at 06:00 in the morning for summer days. It can be seen that in most of these sample days aggregate wind output will be lower than 50 % of the installed wind capacity whilst the aggregate wind output in winter days exhibits a wider range and higher value (Figure 4-8). It suggests that although the system is subject to lower minimum load on summer days, less wind power is likely to be fed into the system.

Figures 4-15 and 4-16 show the frequency minimum and ROCOF following the event with and without inertial frequency support from the wind capacity.

Similar conclusions result from the summer day analysis, Figures 4-17 and 4-18, although the improvement in nadir pdf is more limited: the result of less wind plant available to respond due to the much lower winds prevailing at this time of year, and the reduced conventional plant operation relative to the loss of plant (assumed still to be 1.8 GW). The pdf for ROCOF, however, is reasonably improved.

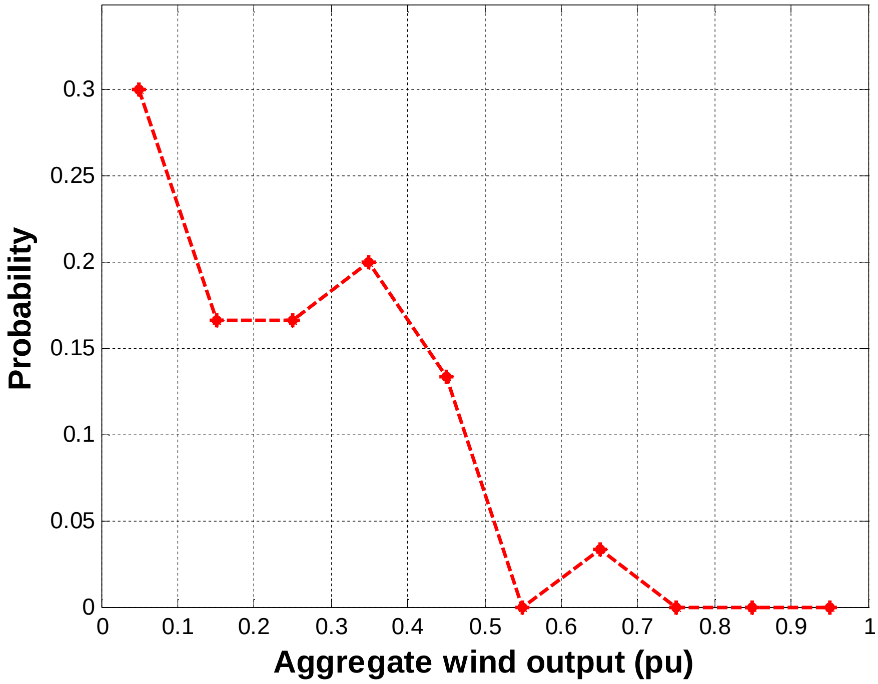

Figure 4-14 Probability of aggregate wind output for 30 sample summer days

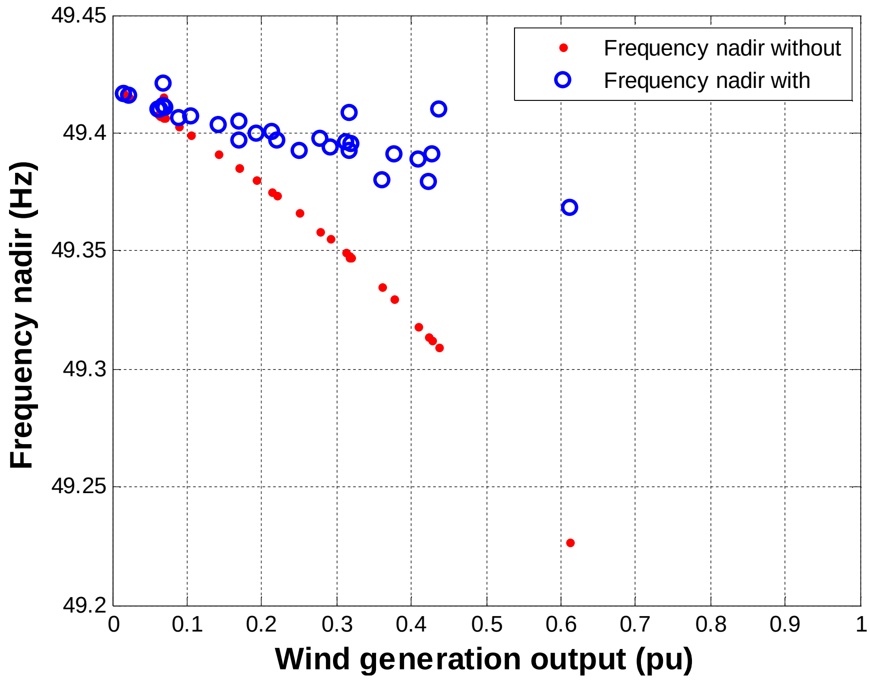

Figure 4-15 Frequency minimum (nadir) following transient

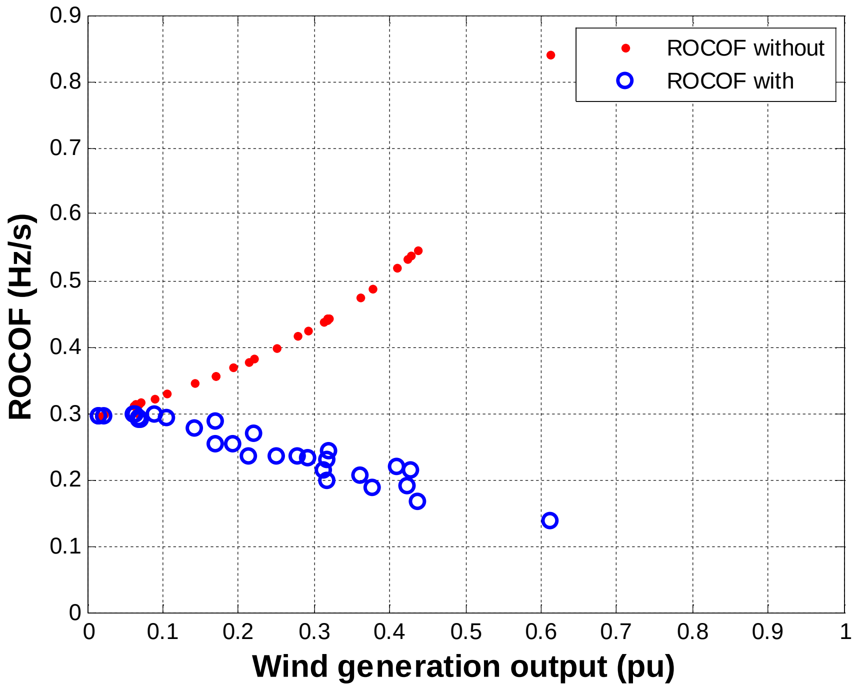

Figure 4-16 Rate of change of frequency (ROCOF) following transient

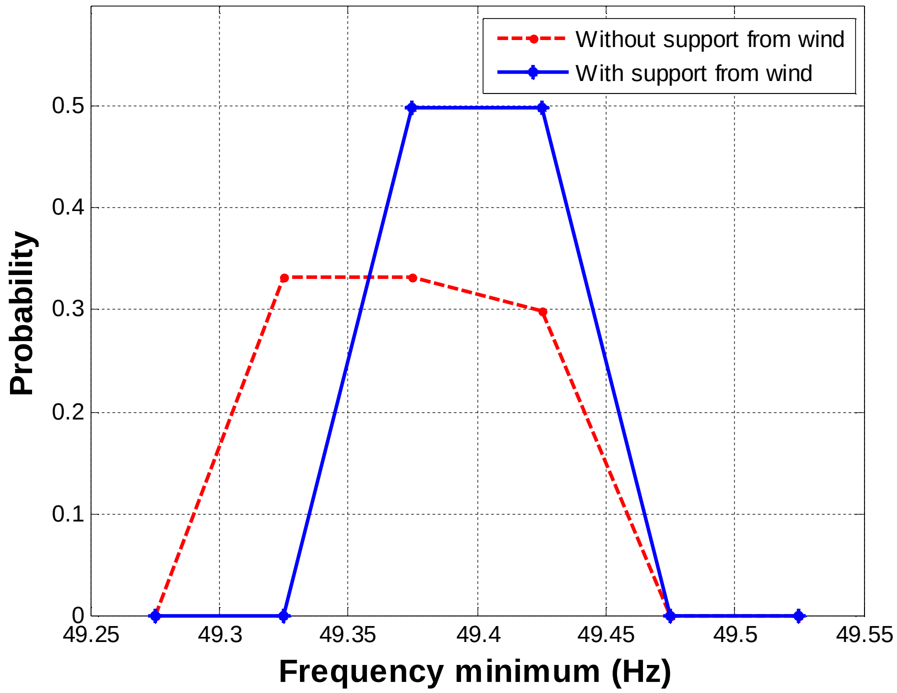

Figure 4-17 Probability density function of nadir

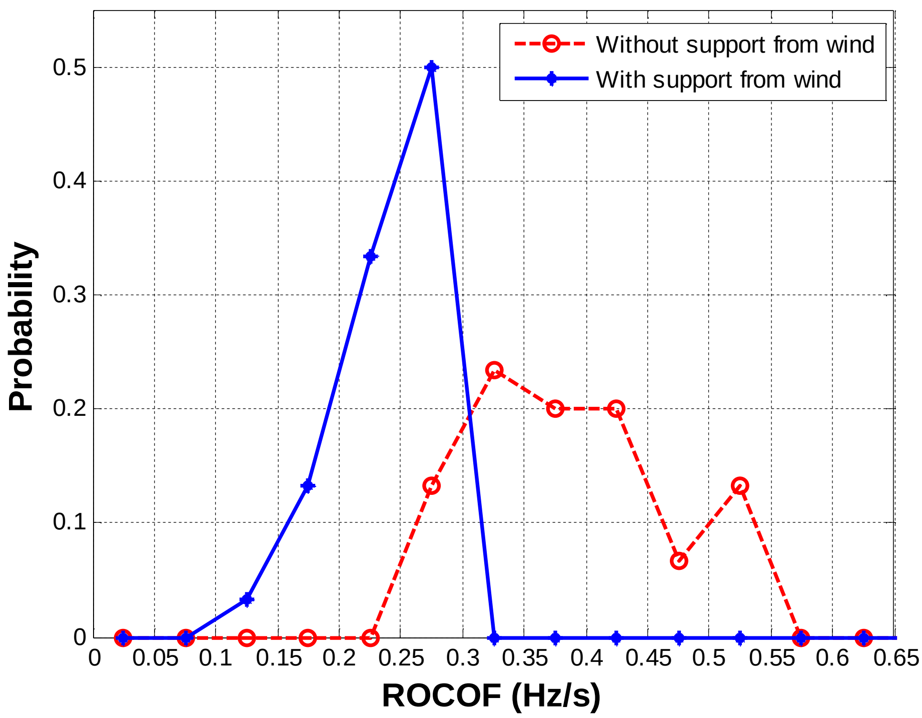

Figure 4-18 Probability density function of ROCOF 0.1 s after event

4.7 Inertial response activated by frequency deviation Δf

Previous sections have used ROCOF (df/dt) to activate the inertial response from wind plant and for the added torque to respond. In this section, a fixed frequency deviation (Δf) threshold has been introduced and compared with df/dt and no threshold.

Figure 4-19 shows system frequency response with a Δf threshold and with df/dt and no threshold. It can be seen that frequency drops at a higher rate (blue line) with no additional power contribution from wind before it reaches the threshold (49.8 Hz). Note it is assumed that frequency deviation below this threshold will activate the inertial support from wind. It shows that fast response inertial support from wind can reduce the initial ROCOF and thus assist system frequency regulations. This will also contribute to power system protection by limiting the fast drop in frequency.

However, Figure 4-19 also shows that the resulting frequency minimum using Δf is higher than using df/dt alone. This is because using the Δf method results in a lower system frequency initially than that using df/dt alone and therefore the output from conventional plant will be greater as shown in Figure 4-21. This explains the higher nadir when using Δf.

It can be seen that a fast frequency response (using df/dt) is crucial to containing the initial ROCOF. Wind plant has the potential to provide frequency support in a faster rate than other conventional generation. This is an important merit for wind plant that may well have a role to play in the context of high wind penetration.

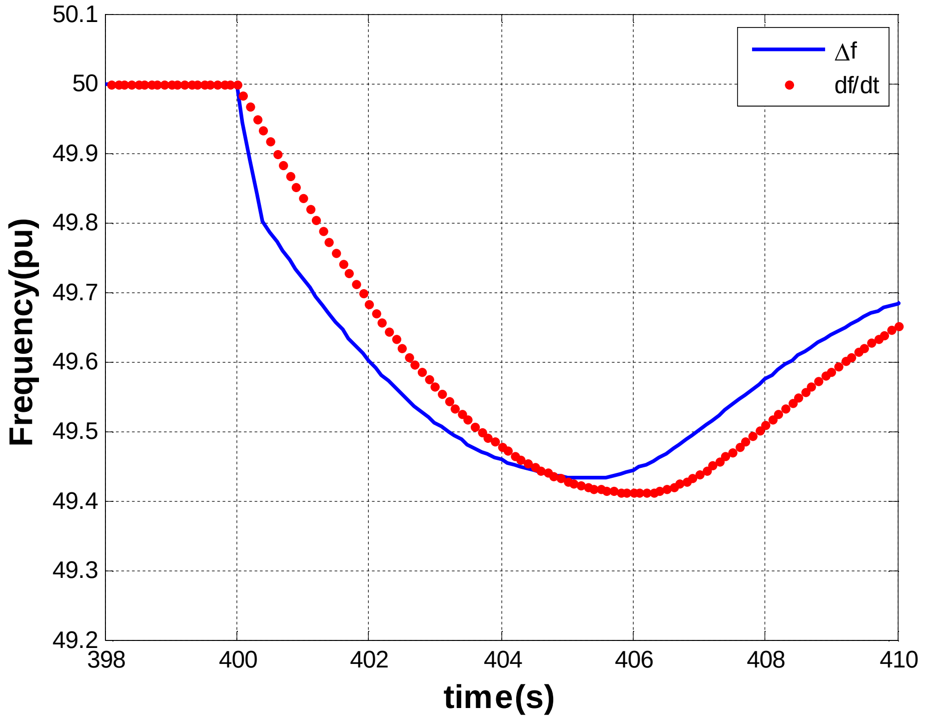

Figure 4-19 System frequency response

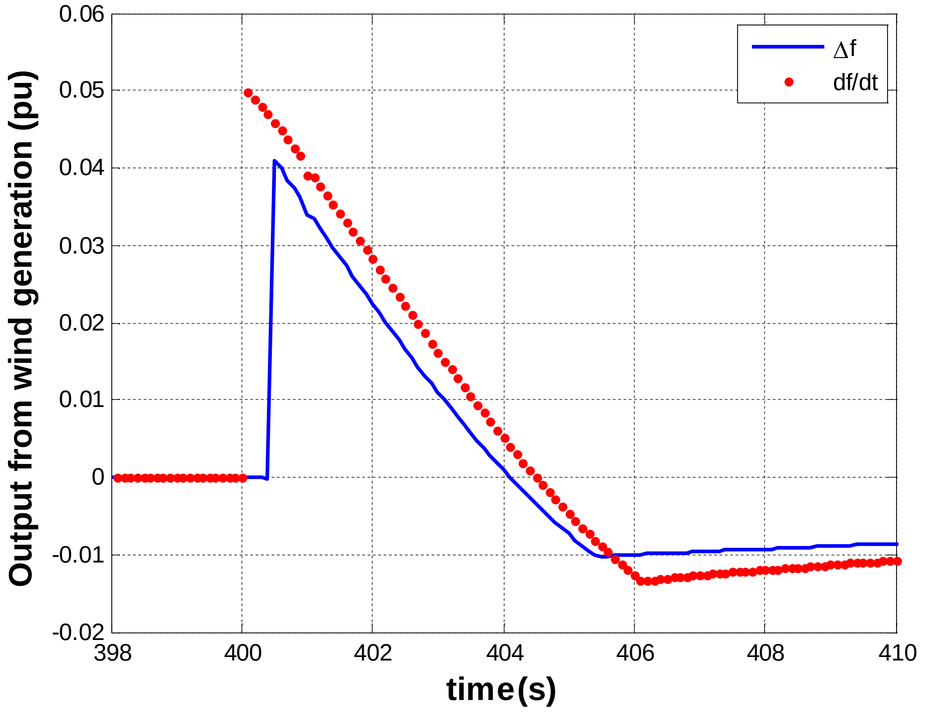

Figure 4-20 Wind generation output

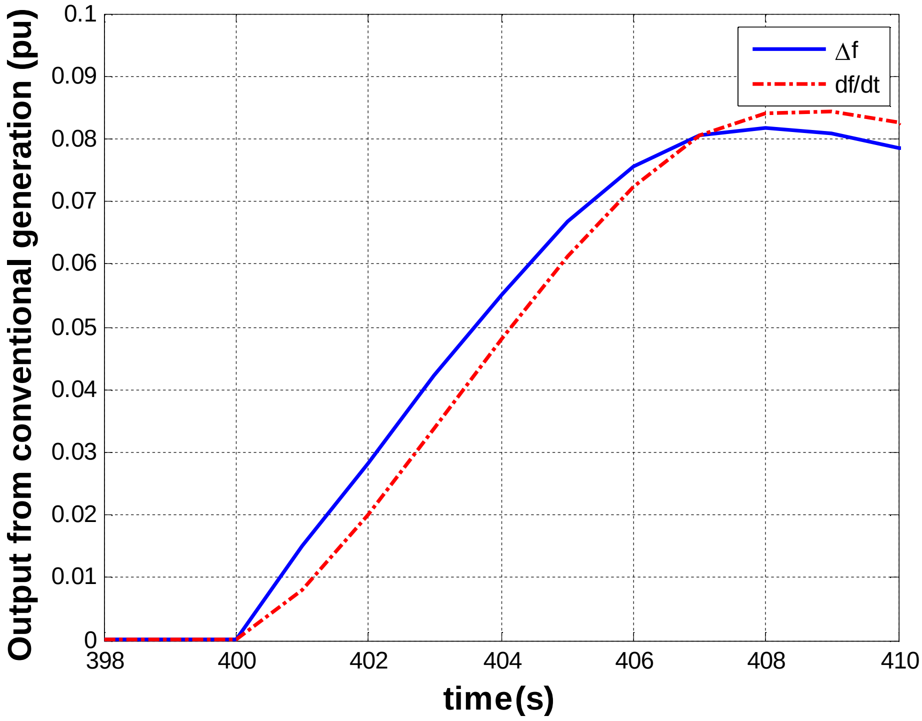

Figure 4-21 Conventional generation output

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4.8 Conclusions

A probabilistic approach to assessing the aggregate inertial response available from wind generation in the GB power system has been presented in this chapter. Its novelty lies in the assessment of aggregate inertial response from wind turbines under time varying wind speeds on an hourly basis and across the regions, and also as a result of turbulence and short term wind speed variation across wind farms. The wind variability during the provision of inertial response from wind turbines has been described by a Gaussian probability distribution. The GB power system was represented by 17 study regions with distinct but correlated hourly mean wind speeds and local installed wind capacity reflecting NG's Gone Green scenario. It is assumed that there is no curtailment on wind power and so the number of operational wind turbines will be stochastically determined by the wind model explained above, although with higher wind penetrations in the future, this is an assumption that would have to be relaxed.

The collective inertial power contribution from wind generation is examined using predetermined wind speeds across the UK for test days (mid-winter and mid-summer), calculated with a sophisticated VAR based stochastic resource model. These wind speed time series manifest the correct temporal and spatial characteristics and in fact can be re-sampled by the model to give equally likely days with different wind histories. The dynamic characteristics of the power system reflect the time of year and in particular the plant mix on line and the resulting system inertia level. As explained above, the parameters of the system, such as the inertia constant, power plant mix and system reserve will vary in time and reflect the amount of wind generation into the power system.

The modelling approach differs from that adopted by the research team at University College Dublin (UCD) in that a comprehensive UK wide wind field model is used that removes the uncertainty regarding numbers of turbines available to contribute to inertial response. Only example summer and winter days are presented here but the methodology could be re-run to show the expected degree of variation in this connected wind capacity from day to day. Nevertheless, this work has demonstrated that installed wind capacity, if suitably controlled, can deliver a consistent improvement in power system response in the event of a large sudden loss in generation, even if that response depends on the conditions prevailing and the amount of wind and conventional plant on the bus bars at any given time.

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Chapter Five Delivering combined droop and inertial response from wind plant

The provision of inertial response from wind plant has been presented in previous chapters. Studies have shown that the power output of wind turbines can also be actively controlled to participate in primary frequency response[8] by being made to follow a droop response much as for conventional plant. This generally involves varying the turbine's nominal active power output based on an adjusted power reference instead of tracking the optimal power curve. There are two main ways of producing the new power reference: first by specifying a fraction of the power available that should be captured under steady state conditions (i.e. 90% P_{avail}) thus leaving 10% P_{avail} in hand as reserve to deliver the droop characteristic; and second by specifying a constant power reserve (i.e. 10% P_{rated}). The second approach will be difficult or impossible to implement at low wind turbine power output and for this reason the first approach is used here.

Various approaches to providing droop response from wind turbines are investigated in this chapter. The delivering of combined droop and inertial response from wind plant is examined for a frequency event.

This chapter is set out as follows: Section 5.1 describes continuous frequency response from conventional synchronous machines. Section 5.2 introduces various approaches to providing droop response from wind plant. Section 5.3 describes the combined droop and inertial response from wind plant. A power system frequency event is passed open-loop to the control system for verification of the response. And finally, conclusions and future work are presented in section 5.4.

5.1 Continuous frequency response from synchronous machines

Primary or continuous frequency response, as explained in Chapter 1, is a continuously provided power balancing service used to manage the normal second by second changes in system frequency. It is often also referred to as droop response. It is used to describe the linear (falling) relationship between generator synchronous

[8] Sometimes called continuous frequency response.

speed/frequency and power output from the plant as shown in Figure 5-1. Generating plant from small diesel engines to large steam turbine generators generally have droop characteristics and these have the advantage of allowing straightforward adjustment of load sharing between plant [1, 2].

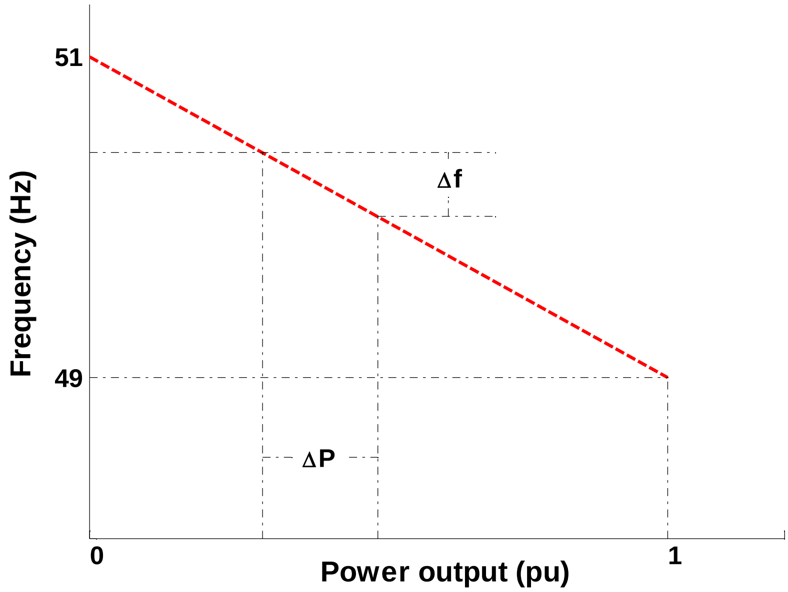

Figure 5-1 Droop control schematic

The value of droop D determines the steady-state speed versus load characteristic of the synchronous generator. The ratio of speed or frequency deviation to change in power output is given by:

$$Percent\ D = \frac{percent\ frequency\ change}{percent\ power\ output\ change} \times 100 \qquad (5\text{-}1)$$

The parameter D is referred to as speed regulation or droop [1]. For instance, a 4% droop means that a 4% frequency deviation results in 100% in power output.

The speed deviation between the measured rotor speed and the reference speed is amplified and integrated to produce a control signal which regulates the main steam supply valves in the case of a steam turbine, or gates in the case of a hydraulic turbine [1]. An isochronous governor normally works to supply an isolated load or when the particular generator in a multi-generator system is not required to respond to changes in system frequency. For load sharing between generators on the system, droop response is required.

5.2 **Delivering droop response from wind plant**

For variable speed wind turbines, the provision of droop requires that the turbine output becomes a linear function of power system frequency, and this must be independent of wind speed. It also requires that at the nominal grid frequency, the turbine must operate with head room, i.e. derated, to allow upward power regulation to compensate for falling frequency. Thus turbines will be operated away from the optimum power curve, to create this power margin/reserve capability. At any time, the actual power margin will be affected by the prevailing wind conditions. This approach mimics governor-droop control of conventional synchronous generators as described above.

It is conventional for power system plant to operate with 4% droop [2]. Here, the proposed droop for the wind turbine has been set at D = 8%, where the droop, D is defined to be the ratio of system frequency deviation to the change in power out of the wind turbine, and thus, selection of this droop ensures that a 8% frequency deviation on the power system will result in 100% change in power output from the wind turbine. In practice, in the UK, normal frequency variations will be restricted within National Grid's operational limits of 49.8 to 50.2 Hz (Figure 1-3) so that turbine power response would be restricted to 90% of rated power at 50.2 Hz. During severe events, frequency can fall below the operation limit, but since the turbine will already be operating at or near C_{Pmax} (Figure 2-1), it cannot generate any further sustained increase in output.

When the power system is operating at the nominal (UK) frequency of 50 Hz, the wind turbine will operate derated at 95% of the maximum power that could be available to the grid at the wind speed at the time in question. As the power system frequency falls to 49.8 Hz the wind turbine will, as a function of system frequency, increase its output to 100% as shown in Figure 5-2. The relationship between frequency deviation on the system and wind plant power output is given by:

$$\Delta P = 1/D\ (f_{sys} - f_{norminal}) \qquad (5\text{-}2)$$

where the parameter D is defined as above, f is frequency in Hz.

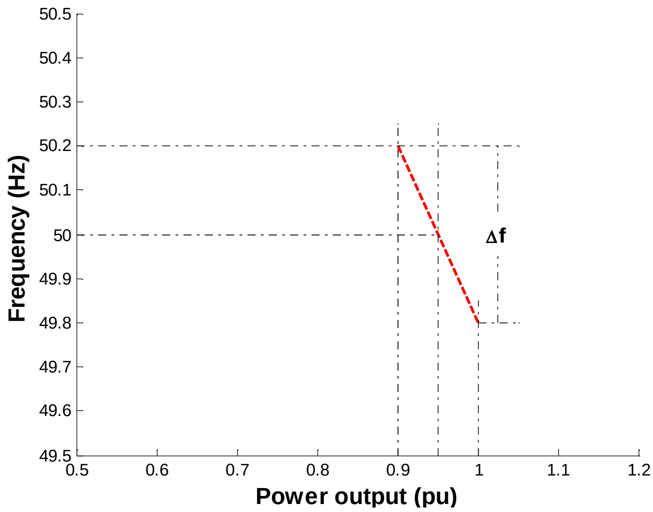

Figure 5-2 Droop characteristic of wind plant

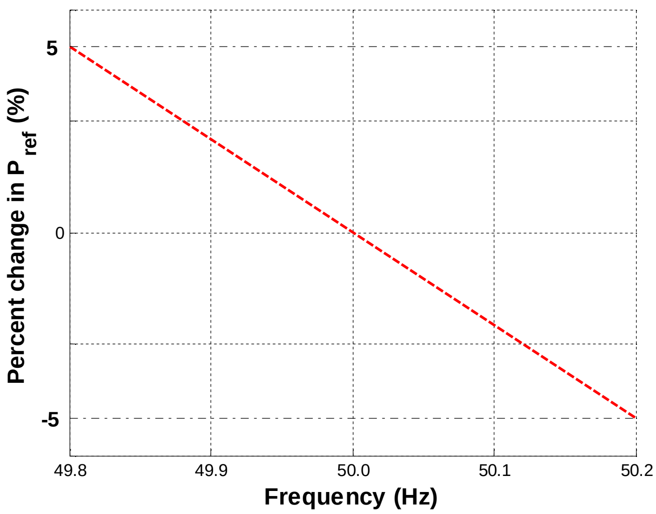

Figure 5-3 Power reference as a function of system frequency

To implement the droop characteristic the measured system frequency is transformed into a power reference as shown in Figure 5-3. In this work the droop characteristic is fixed; however dynamic droop has been proposed in [3].

A primary frequency control strategy has been developed that enables DFIGs to provide a proportional frequency response by regulating the pitch angle according to frequency variations [4]. The control scheme was tested for a series of constant wind speeds. The results show a good response for above rated wind speed whereas the dynamic performance has been compromised for below rated wind speed owing to the non-linearity of the response.

An integrated control strategy of a wind farm has been presented in [5] that can provide automatic generator control according to network operator's instructions. Two control levels are involved: a supervisory wind farm controller providing set points to individual turbines; and a turbine level controller implementing these set points using active and reactive power control loops. The active power control at turbine level generally involves optimal power tracking below rated wind/power and power limiting using pitch regulation above rated wind/power. However, a certain level of active power control flexibility can be achieved by modifying the pitch angle when operating below rated wind speed and so providing power reserve.

A control approach to providing primary frequency response (droop control) from DFIGs has been proposed in [6, 7]. In the proposed control strategy, wind turbine generators will operate away from the optimum power extraction curve and thus create power reserve to regulate the power output in response to system frequency changes. The injected active power is initiated through the rotor-side power electronic converter, followed by pitch control in order to regulate the mechanical power. It suggests that power electronic converters have the advantage of providing fast response while the slower pitch angle regulation can then allow the mechanical power to vary and match demanded electrical power. In this way, a new equilibrium will be established rapidly and better dynamic performance can be anticipated.

Frequency response capability of fully rated converter wind turbines has been examined in response to a sudden imbalance in generation and demand on the system [8]. The active power output of the turbine is adjusted in response to changes in power system frequency, emulating the characteristics of a synchronous machine.

Control schemes that combine inertial response and droop control from wind turbines to participate in grid frequency regulation have been examined in [9]. The authors conclude that the combination of inertial control and rotor speed control can provide a useful response to grid frequency falls, and it is possible to respond at a faster rate than either inertial control or pitch angle control, or their combination. This is because pitch angle control is constrained by the maximum pitching rate and so cannot respond instantaneously. Excessive use of pitch control will result in wear and tear of the pitch mechanism, which has been found to be among the most vulnerable parts of a wind turbine, and failure of which usually leads to long downtime of the wind turbine [10].

It is evident that there is more than one way of providing droop control from variable speed wind turbines, including operation at higher than normal/optimal rotor speeds and thus at a lower power coefficient, known as rotor speed control approach, or using pitch control to reduce the aerodynamic power to below optimal/nominal, known as pitch angle control approach. The two approaches are explained and compared in the following section.

5.2.1 Pitch angle control approach

As explained in Chapter 2, two basic control systems are used to regulate variable speed wind turbines. Below rated wind speed, the turbine torque controller functions to maximise energy capture with blade pitch being set at a minimum value ($\theta_{opt} = 0^0$ in this case) and rotor speed increasing in proportion to wind speed. The maximising of energy capture is achieved by maintaining the optimum tip speed ratio and thus optimal C_P (Figure 2-1). As shown in Equation 2-6, the demanded torque is regulated in proportion to ω^2 and so the optimal λ and C_P can be achieved.

To achieve derating, Equation 2-6 for the demanded torque can be written as

$$T_{dder} = x \times K_{opt}\omega^2 \qquad (5\text{-}3)$$

where x is the value of derating factor which is determined by the droop D. For instance x = 0.9, representing 10% power derating, corresponds to D = 8% when grid frequency is 50.2 Hz.

According to Equation 2-3, the aerodynamic torque and modified demanded torque can be balanced when the aerodynamic torque is modified accordingly as follows:

$$T_{ader} = x \times \frac{1}{2}\rho\pi R^5 \frac{C_{Pmax}}{\lambda_{max}^3}\omega^2 \qquad (5\text{-}4)$$

This shows that the turbine will operate at a sub-optimal C_P, i.e. $x \times C_P$ below rated. To achieve this, wind turbines are required to operate at higher than minimal pitch angle below rated wind speed (θ_{opt} = 3.27^0 for 10% derating in this case). Figure 5-3 shows the required pitch angle for 10% power derating.

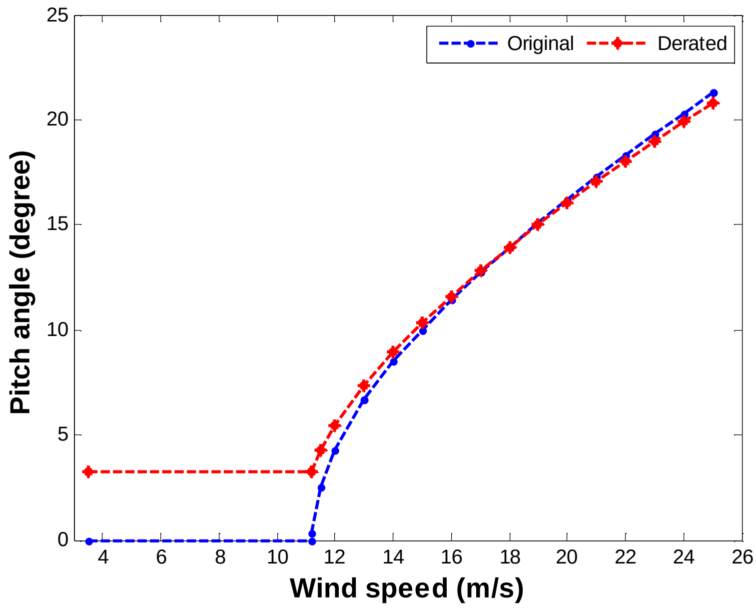

Figure 5-3 Blade pitch angle versus wind speed

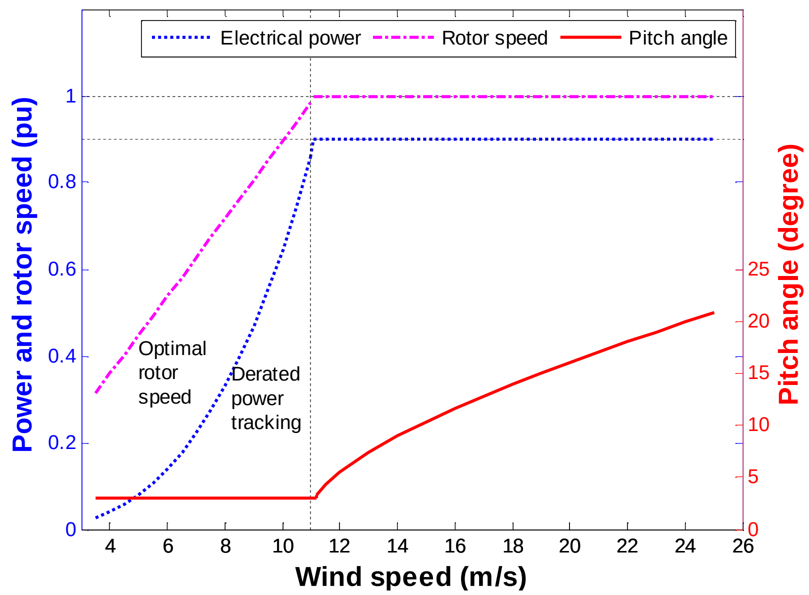

Figure 5-4 Power, rotor speed and pitch angle in 10% derated operations

Figure 5-4 summarises power, rotor speed and pitch angle in 10% derated operations corresponding to 50.2 Hz. Please note that derated wind turbines still operate at same rotor speed as in normal operations (dash-dot line in this figure), so does tip speed ratio λ. However, as pitch angle is no longer operating at optimal below rated, such turbines will track the derated power curve instead of optimal. Above rated wind speed, wind turbines in derated operations will reach rated rotor speed (same as in normal operations) and the demanded torque is regulated by the derating factor x. Pitch angle controller will act to maintain the rotor speed at rated. At this stage, the values of pitch angle will remain unchanged as in pre-derated operations due to the fact that pitch angle controller regulates the error between actual and reference rotor speed.

The performance of pitch angle control approach is tested for continuous frequency variations which represent the normal second by second mismatch in generation and demand as shown in Figure 5-5 for data taken from actual GB power system operations. Figure 5-6 shows the power response for the blade pitch angle control approach where the maximum blade pitching rate is set to 2 degree/s. In response to the frequency variations, the turbine continuously varies its power output within the range of 0 to 10 % derating. Pitch angle changes to provide continuous frequency response as shown in Figure 5-7.

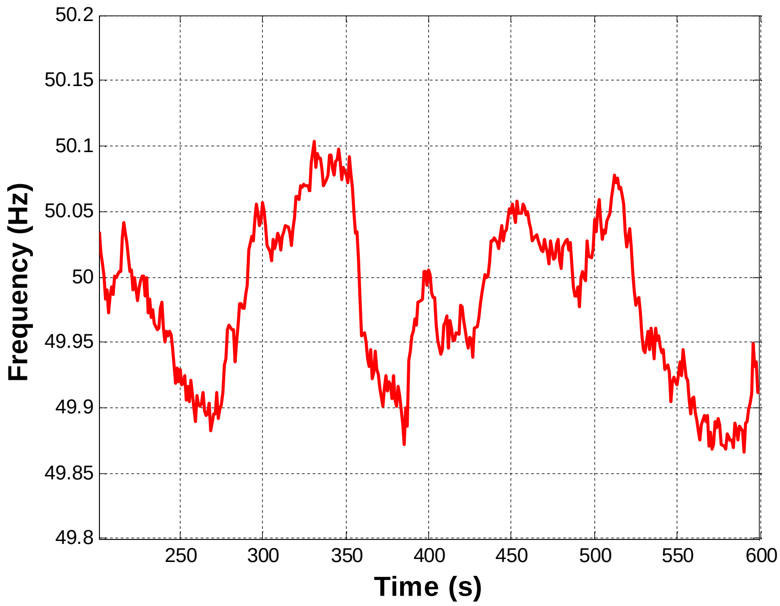

Figure 5-5 A frequency time series

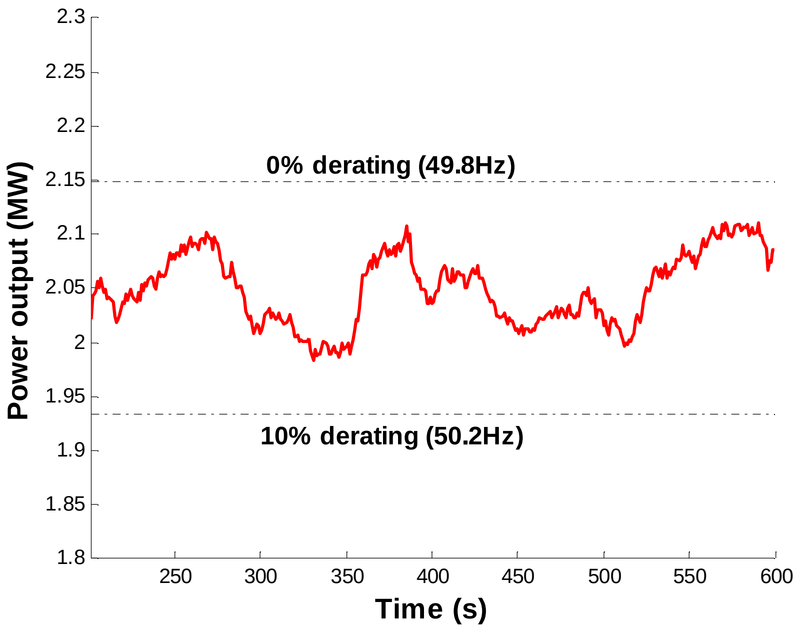

Figure 5-6 Power response for constant wind speed of 10 m/s and blade pitch control

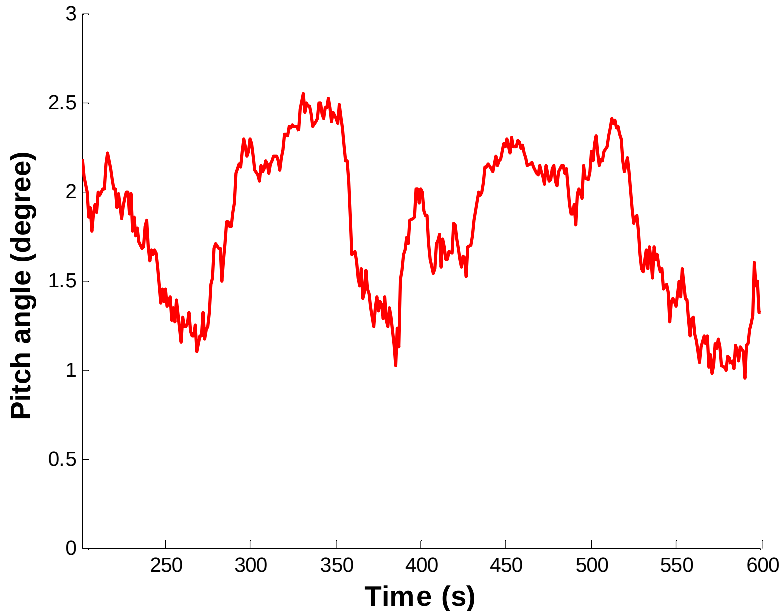

Figure 5-7 Pitch angle for constant wind speed of 10 m/s

Figures 5-8 and 5-9 show the power response and pitch angle for the same frequency variations but for above rated wind speed of 12 m/s.

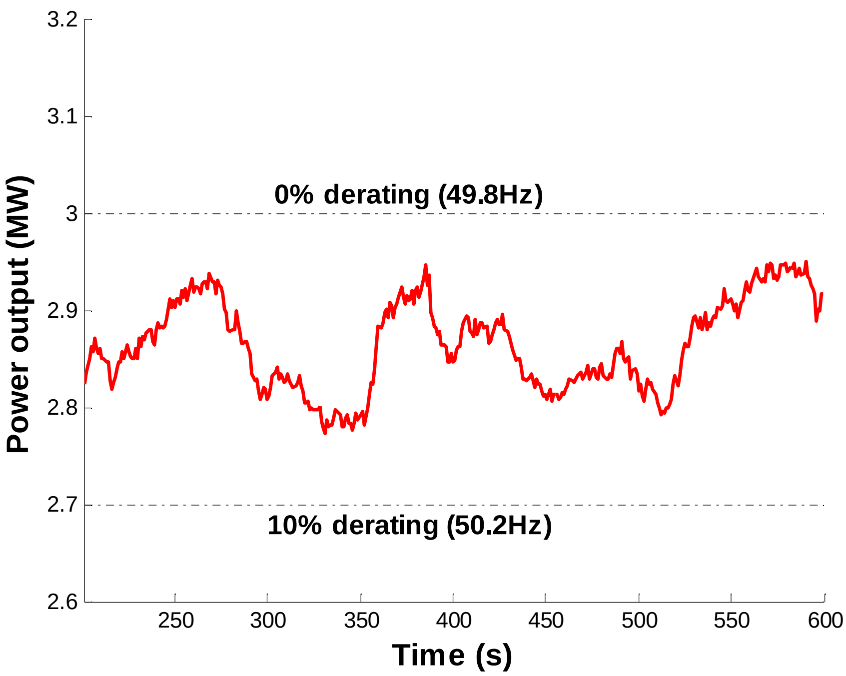

Figure 5-8 Power for constant wind speed of 12 m/s

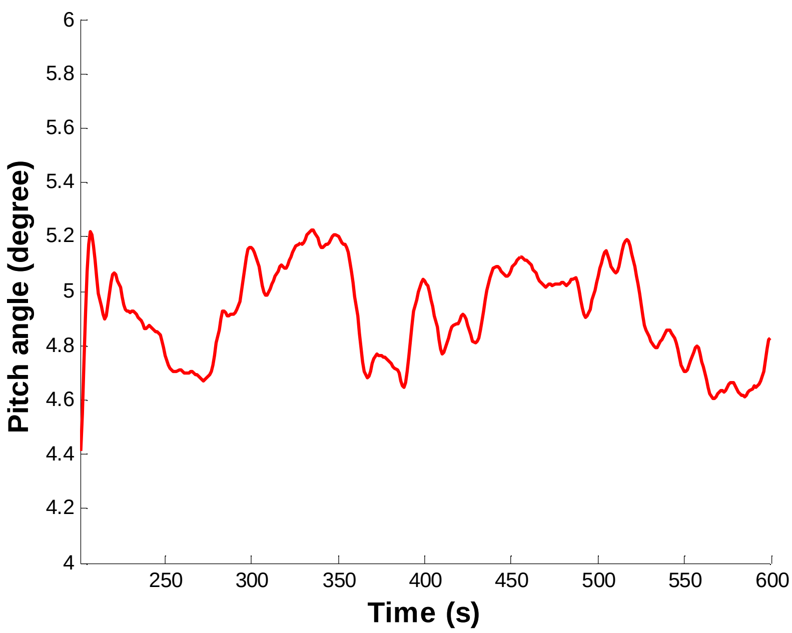

Figure 5-9 Pitch angle for constant wind speed of 12 m/s

The performance of pitch angle control approach is also tested for a turbulent wind speed of 10 m/s with 20% turbulence intensity as shown in Figure 5-10. Figure 5-11 shows the normal and derated operations.

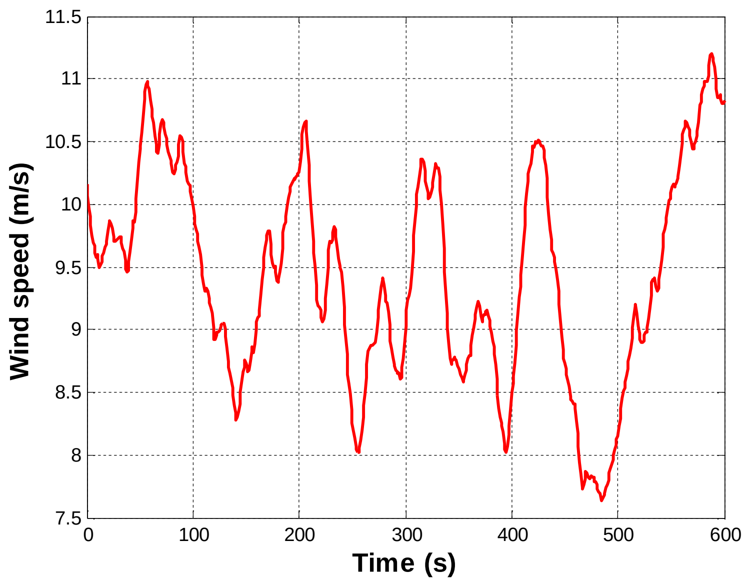

Figure 5-10 Wind speed 10 m/s with 20% turbulence intensity

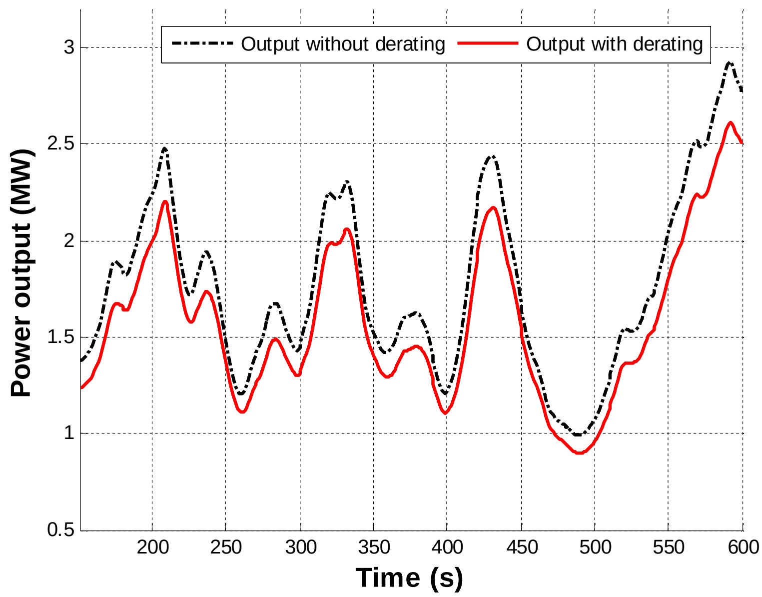

Figure 5-11 Power for turbulent wind speed

5.2.2 Rotor speed control approach

Rotor speed control can also be used to provide droop control from wind turbines. This strategy requires the rotor to rotate at a faster speed than in normal operation and thus achieve a lower power coefficient C_P, so providing the required reserve power and the potential to participate in frequency regulation. Figure 5-12 shows the optimal and derated power curves for a range of wind speeds. It can be seen that below rated wind speed rotor speed is required to be at 140% of that in normal operations to achieve 10% power reserve in the modelled wind turbine. The control strategy involves derating the wind turbine for below rated operation by varying the generator/rotor torque to obtain a sub-optimal tip speed ratio. In this region of operation, the blade pitch angle stays at the minimum. Above rated wind speed, blade pitch controller is used to regulate the power output within the ratings. Note that the rated rotor speed needs to be increased accordingly so that pitch angel controller will not intervene when the wind turbine is operating below rated wind speed. The control strategy is summarised as follows:

- Find C_{Pmax} and corresponding λ_{Pmax} for the minimum pitch angle.
- Calculate initial K_{opt} from $K_{opt} = 0.5\rho\pi R^5 \frac{C_{Pmax}}{\lambda_{Pmax}{}^3}$
- Form a sub-matrix of λ to C_P for the minimum pitch angle. Note that transformation for $\lambda > \lambda_{Pmax}$ is required. This is because operating points on the left hand side of $C_P - \lambda$ curve (Figure 2-1) are unstable as this is the stall region.
- Interpolate: according to the value of derating factor, x , find the λ_{mod} corresponding to $C_{Pmax} \times x$ from the sub-matrix mentioned above. The value of x is essential to linking the frequency variations with droop control and its calculation is introduced above.
- Calculate the modified control constant from:

  $$K_{mod} = x\left(\frac{\lambda_{pmax}}{\lambda_{mod}}\right)^3 \times K_{opt}$$

- Calculate modified reference rotor speed from:

$$Speed\_ref_{mod} = Speed\_ref \times \frac{\lambda_{mod}}{\lambda_{Pmax}}$$

To determine the power reference linked with frequency variations, the supplementary control systems must have an estimate of the power available on the turbine. The power available, P_{avail}, is referred to as the power that the turbine could theoretically capture from the wind when operating at maximum C_P and can be obtained using a wind speed estimator [11, 12]. For simplicity, no wind speed estimator has been developed in this research and the incoming effective wind speed is used.

The same continuous frequency time series is used to test rotor speed control approach. The power output in response to the frequency variation for constant wind speed of 10 m/s is shown in Figure 5-14. The normal and derated (10%) operations for turbulent wind (Figure 5-10) are shown in Figure 5-15.

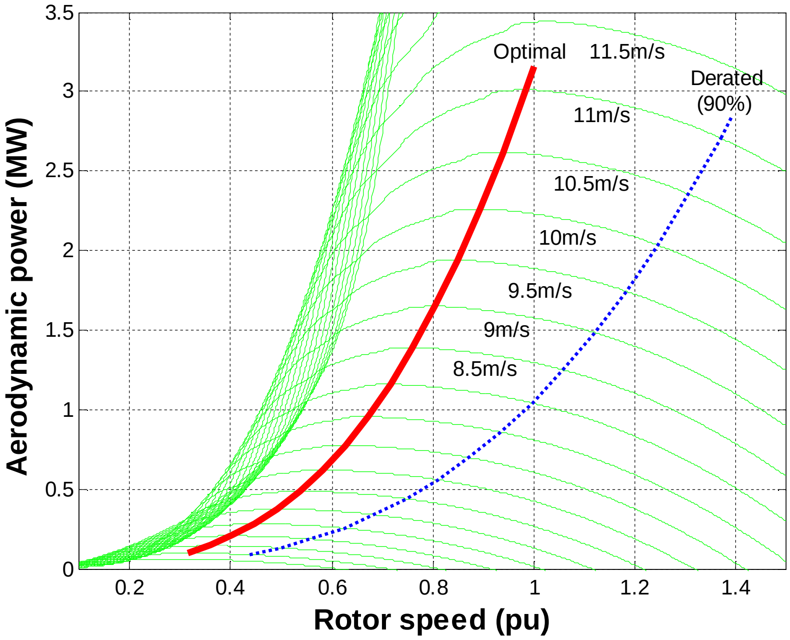

Figure 5-12 Optimal and derated power curves

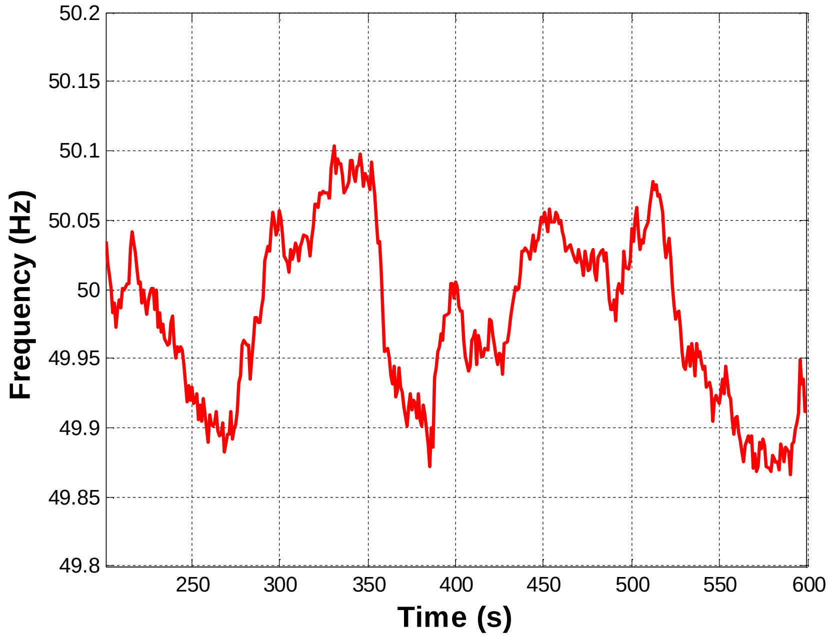

Figure 5-13 Frequency time series

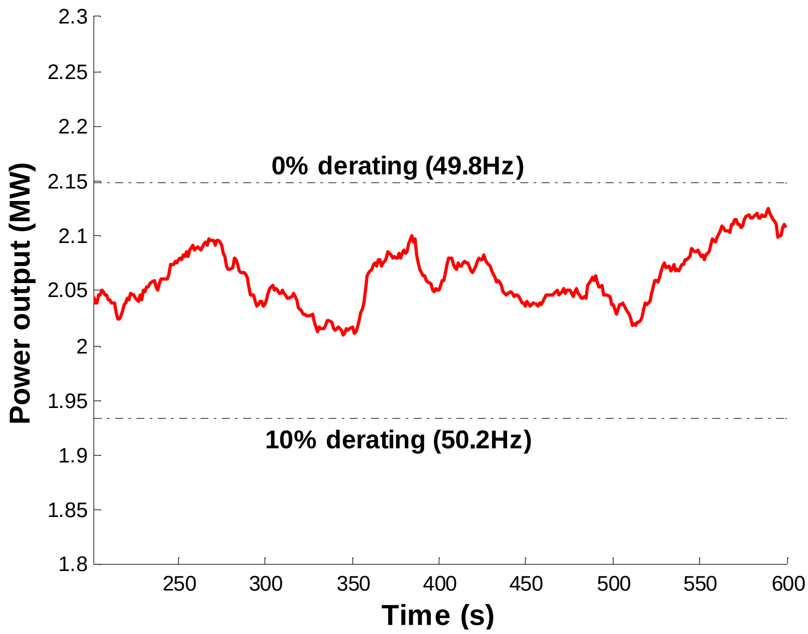

Figure 5-14 Power response at constant wind speed of 10 m/s

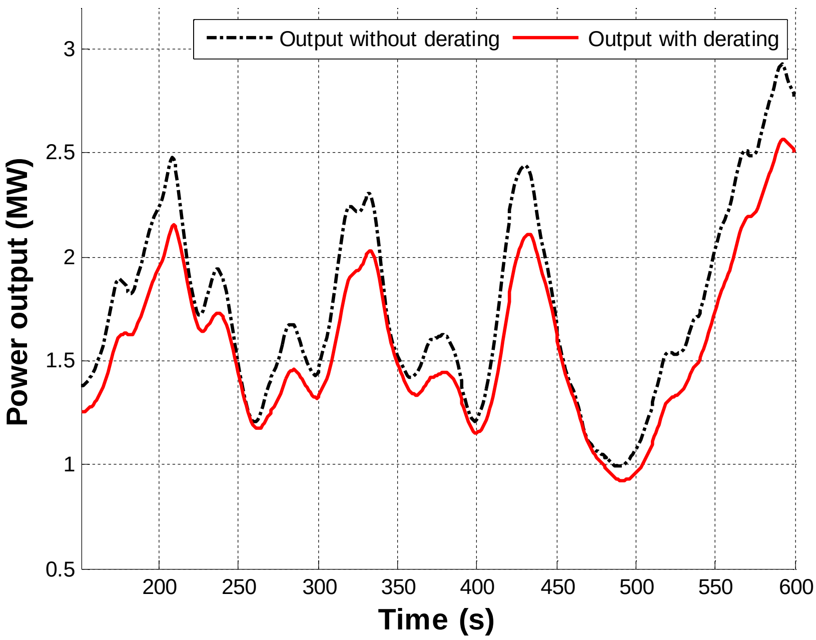

Figure 5-15 Power response for turbulent wind speed

One advantage of using the over-speed approach to derating is that greater than nominal inertial energy is available to contribute to frequency events. As shown in Figure 5-12, the rotor speed for operating derated is significantly higher than in normal operation, which may have the advantage of allowing the wind turbine to provide noticeably more frequency support for a short period.

Current wind turbine technology allows the rotor speed of DFIGs to vary between 0.67 – 1.33 pu [13]. The rotor speed control approach to frequency service requires the turbine rotor to vary within a wide range as shown in Figure 5-12. This may exclude DFIGs for such application depending on the shape of the $C_P - \lambda$ curve. An alternative is to allow the pitch regulation to limit the maximum rotor speed. This will have the effect that for higher but still below rated wind speeds the degree of derating will be reduced as will contributions to continuous frequency service. Full converter designs will allow higher rotor speeds but even here, turbine designers may be concerned about the higher loads.

5.3 Combined droop and inertial response from wind plant

Simulations were performed to show the functionality of various control approaches and to assess controller performance. For demonstration purposes, both pitch angle control and rotor speed control were tested for the same frequency event at a constant wind speed of 10 m/s. The frequency time series used is shown in Figure 5-16 and was taken from a recorded GB power system frequency event. The reference signals were passed open-loop to the control system of the wind turbine in order to assess its response, but ignoring any impact on the wider power system. System frequency is assumed to be 50 Hz prior to a sudden generation loss and starts to drop sharply at 214 s falling below the lower operational limit of 49.8 Hz after about 3 seconds.

For both approaches, the wind turbine set to have an 8% droop and thus is initially derated to 95% capacity. As explained above, the turbine will reach 100% capacity at lower limit of 49.8 Hz and produce only 90% of power available at upper limit of 50.2 Hz under steady state conditions. Here the dynamic response is assessed but for an open-loop assumption. A detailed study of closed-loop frequency response performance will be carried out in future work to include a grid model and conventional generation.

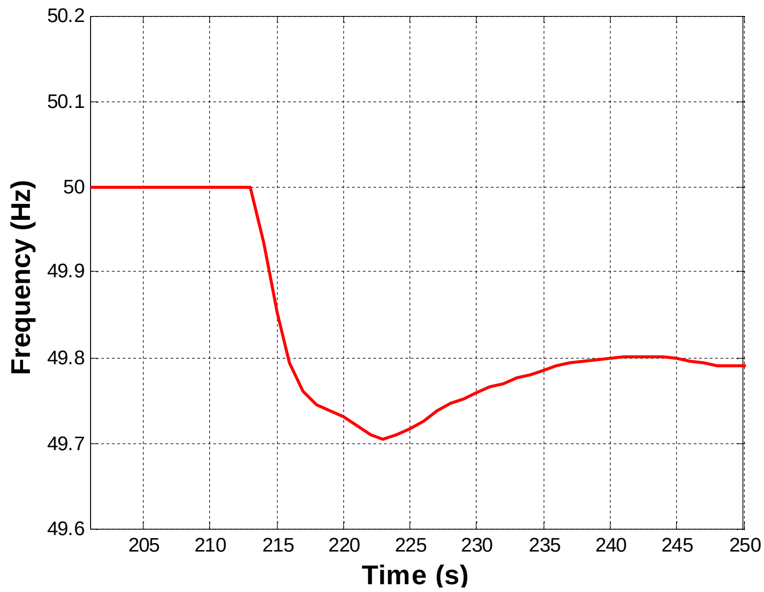

Figure 5-16 A frequency event on GB power system

Figure 5-17 shows the power response for inertial response, droop response (pitch angle control approach) and combined droop and inertial response. Following the frequency drop at 214 s, the inertial controller response is activated by the large rate of change of frequency (ROCOF) and reaches maximum output within 1 second. After a duration of approximately 5 seconds, the power falls to below the initial power to allow the rotor to accelerate back to normal speed (as discussed in more detail in Chapter 3). With inertial response only the pitch angle is kept at its initial value and the inertial power contribution comes from the slowing down of the rotor and thus the release of kinetic energy stored. With droop control alone, following the frequency deviation at 214 s, the droop controller is activated and starts to reduce the pitch angle (as in Figure 5-18) and so increase its power output along with the frequency fall. During the course of the response, rotor speed is kept at near the initial value as represented by the dark dashed line in Figure 5-19. When the frequency drops to 49.8 s at 216 s, the power output reaches maximum. Note that there is 1 second delay due to the relatively slow response of pitch mechanism.

The combined droop and inertial response demonstrate an interesting performance which provides improved power contribution than available from either droop or inertial response alone. This is because droop controller is activated by the frequency deviation and implemented by pitching the blades whilst the inertial controller is activated by ROCOF and implemented by slowing down the rotor and extracting kinetic energy from the rotor. The combined droop and inertial response will increase the aerodynamic power captured by the rotor by moving it towards optimal pitch thus increasing C_P, while at the same time extracting stored kinetic energy from the rotor, and consequently the combined power contribution increases.

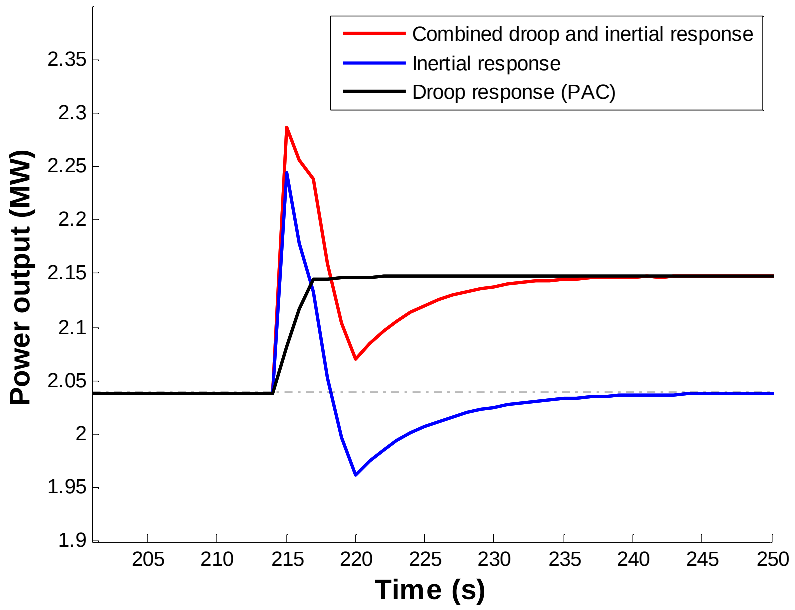

Figure 5-17 Power response (pitch angle control) at constant wind speed of 10 m/s

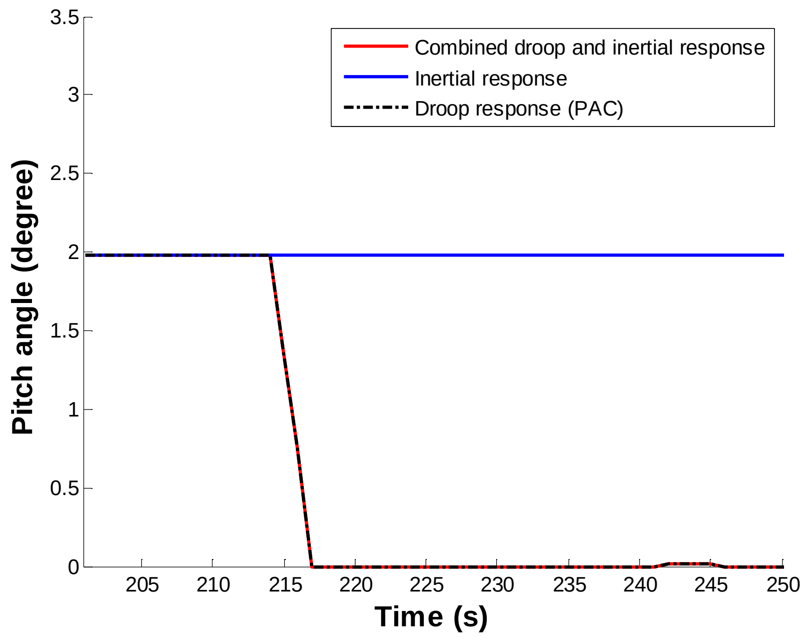

Figure 5-18 Pitch angle for pitch angle control approach

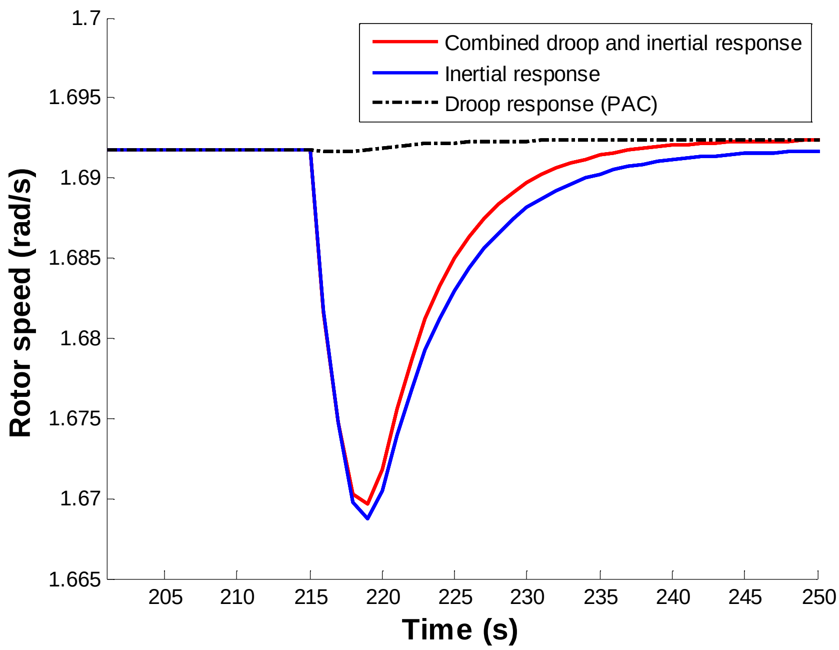

Figure 5-19 Rotor speed for pitch angle control approach

One advantage of using the rotor speed control approach to derating is that greater than nominal inertial energy is available to contribute to simultaneous loss of generation events. As shown in Figure 5-12, the rotor speed operating derated is significantly higher than in normal operation, which allows the wind turbine to provide noticeably higher frequency support for a short period.

Figure 5-20 shows the power responses for different control regimes at a constant wind speed of 10 m/s, when the inertial and droop response is activated automatically, following the same frequency event on the network (Figure 5-16). Before the transient event, the wind turbine is operating derated to 95% capacity. In response to the large frequency fall, the turbine releases kinetic energy for a duration of about 5 seconds. The droop controller initially delivers 95% of power available (black dashed line in Figure 5-20). Following the frequency deviation at 214 s, the droop controller is activated and the wind turbine reaches its 100% power available when the frequency drops to below 49.8 Hz. The derating factor, x, increases from 95% to 100% over the transient period to provide the required droop response. There are no delays associated with adjusting the torque as there were with blade pitching. Electrical power consequently increases to reflect the drop in frequency.

It is worth pointing out that the power response from combined droop (rotor speed control) and inertial control demonstrates improved performance than that with pitch angle control. In response to the frequency fall, the initial power contribution from the turbine reaches above 2.3 MW and is larger than that with pitch angle control. This is because the over-speeding approach allows the turbine to operate initially at a high rotor speed. In response to the same ROCOF and frequency deviation, the added additional torque stays the same. The higher rotor speed resulting from rotor speed control approach therefore can deliver greater power contribution. It can be seen that the combined approach will also require a recovery period to allow turbine output to recover after the provision of inertial response. However, the combined droop and inertial response can provide an improved power contribution immediately after the severe frequency event when it is critical for containing frequency excursions.

A downside to rotor speed approach is that wind turbines operate at higher rotational speed than normal to achieve derating. The large turbine rotor inertia prevents it from changing speed fast enough to follow the wind or system frequency variations. Instead of reaching the desired steady state operating point, under dynamic conditions it will tend to be on one side or the other of the set position. This problem could in part be solved by manipulating the rotor/generator torque to cause the rotor speed to change more quickly. This is not done in practice because the large resulting variations in torque will lead to increasing fatigue damage on the drivetrain.

The rotor speed control approach shows the advantages of improved performance in terms of power contributions. But it also brings the difficulties of controller design and increased fatigue damage.

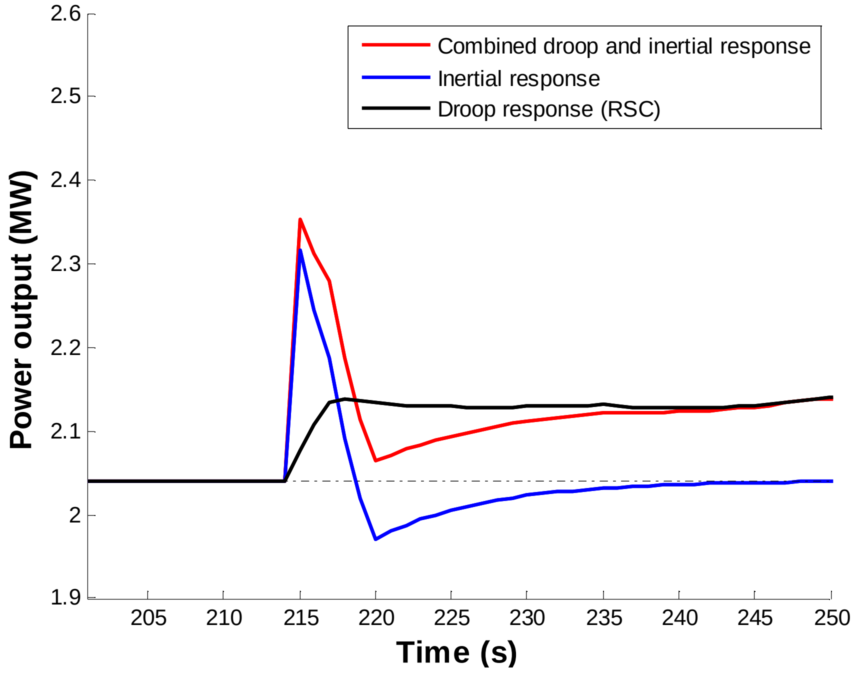

Figure 5-20 Power response (rotor speed control) at constant wind speed of 10 m/s

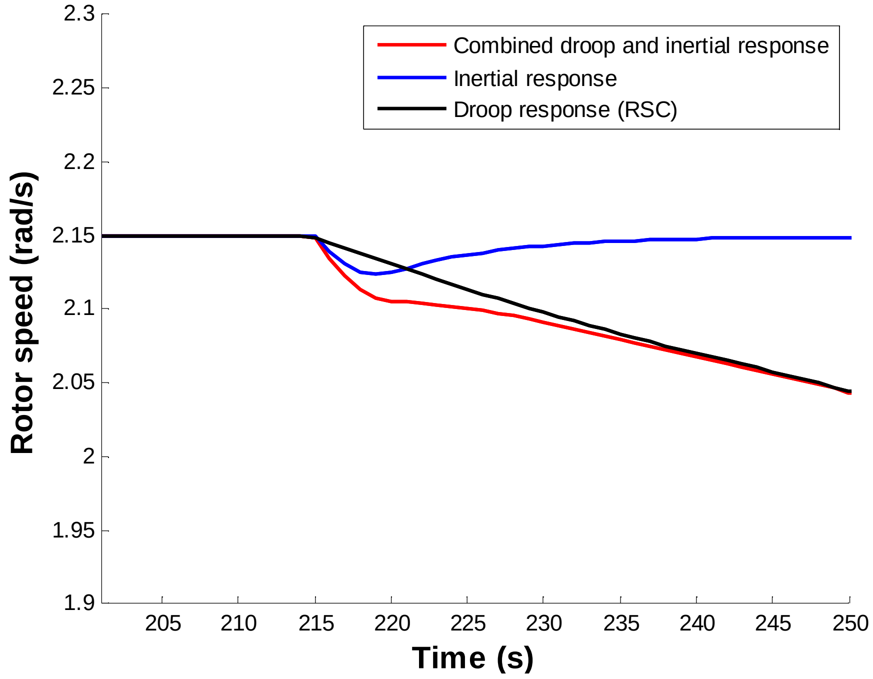

Figure 5-21 Rotor speed for rotor speed control approach

5.4 Conclusions and future work

The conventional goal of wind plant is to maximise the energy capture and therefore the power output will below rated vary with fluctuating wind. Synchronously connected thermal plant have mechanical governors that regulate the turbine input valves as the generator speed varies. In response to a sudden mismatch in generation and demand, referred to as a frequency event, a synchronous generator can provide continuous primary frequency response as required.

Historically, wind plant has not provided frequency response, because there have been no requirements or incentives. However, studies have shown that wind plant is capable of providing this service. In this chapter, various approaches to delivering droop response from wind plant have been presented and compared for normal frequency variations at constant and turbulent wind speeds. The combination of droop and inertial response has been assessed for a frequency event. It shows that the combined approach can provide an improved performance than either droop or inertial response alone.

Both pitch angle control (PAC) and rotor speed control (RSC) approaches have been presented and compared. Although the pitch mechanism has a relatively slow response, the PAC approach exhibits a satisfactory performance owing to the fact that small changes in pitch angle can greatly influence the aerodynamic power captured by the turbine rotor. The RSC approach requires the turbine to over-speed to reduce C_P, and the result is that more kinetic energy is stored in the rotor. This is an advantage when delivering inertial response. The disadvantage is that the high rotor inertia prevents the rotor speed from changing quickly to arrive at the new steady state operational point, and so variations in torque demand may have to change sharply in order to follow the required power reference. Previous studies have focused on delivering a constant derating power command using a rotor speed-power reference curve. In practice, turbine speed limitations, interactions between the turbine torque controller and blade pitch controller and the structural loads induced by the control strategies make operation non-ideal, and further investigation of these issues should be undertaken.

As discussed above, there are different ways of producing a power reference and so providing power reserve. Both blade pitch and rotor speed can be manipulated to provide this power reserve. How to produce a power reference better tailored to participate in frequency regulation and, in the meantime, mitigate the fatigue damage induced by the supplementary control systems merits further research.

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Chapter Six Conclusions and future work

6.1 Conclusions

Variable speed wind turbines have become the dominant technology during recent years. This is largely because variable speed operation can provide wind turbines with the ability to better comply with grid connection requirements and to achieve reduced structural loads as turbine size continues to grow. The configuration of a variable speed wind turbine is often more complex than that of a fixed speed wind turbine. Modern variable speed wind turbines typically employ an induction generator or synchronous generator that is connected to the power network through power electronic converters and thus such turbines are decoupled from the power system frequency.

In the context of high wind penetration, combined with the fact that wind generation progressively displaces conventional generation, there is a strong likelihood that wind generation plant will have to participate in power system frequency regulation. Historically this has not been the case due to a lack of formal requirements and economic incentives. Variable speed wind turbines are presently designed to achieve maximum aerodynamic efficiency over a wide range of wind speeds, making use of fast torque control and with blade pitch control used to limit the rotor speed above rated operation. The controller used for variable speed wind turbines can be modified to emulate the characteristics of a conventional synchronous generator and so provide inertial and droop frequency support. Previous studies have shown that individual variable speed wind turbines are capable of delivering such services.

However it remains unclear as to how reliable such services can be provided from wind plant, comprising many wind turbines in different locations under changing wind conditions. There is much research to be done before wind farm operators and TSOs can be confident about how much reliance can and should be placed on wind plant for dealing with transient events on the power system, and the research needs to be backed up by experiment. To date very little has been done other than simple calculation, almost always for a single turbine operating with constant wind. Estimating frequency response available from wind generation poses a challenge to wind farm operators and TSOs because of the wide range of potential variability of the wind resource, both locally, and nationally. The capability of wind plant providing such support must be determined for a range of wind conditions including, importantly, wind speed changes during the transient event itself to which the wind turbine is responding. This thesis directly tackles these challenges.

In this research, a novel probabilistic approach has been developed to assess how the aggregate synthetic inertial response from wind plant at a given time depends on the available wind. A model of the collective inertial contributions of wind plant to power system frequency response is developed taking account of the variation of wind speed in time and location.

The calculation of collective synthetic inertial response presented is based on an approach to modelling wind turbulence where wind variations over a short period of time (10 seconds in this modelling) are assumed to be adequately described by a Gaussian probability distribution with a set mean wind speed and variance determined by the site turbulence intensity. This methodology allows the aggregate response from a large number of wind turbines to be estimated without having to model directly the individual turbine responses, which would be computationally prohibitive.

The stochastic process of wind variations poses significant further challenges when it comes to assessing the capability of wind generation as a whole across an entire power system to provide inertial response. This is because the geographically distributed nature of the wind plant means that individual wind farms will be exposed to very different mean wind speeds and turbulent variations. These variations cannot be regarded as completely random since there are significant correlations in spatially distributed wind speeds and these depend on the distances between the sites in question and the nature of the local climate. A new approach to assessing the aggregate inertial response available from wind generation in the GB power system has been developed to deal with this by extending the wind farm aggregation approach. It provides a way to evaluate the synthetic inertial response from wind generation under time varying wind speeds on an hourly basis and across the regions, and also as a result of turbulence and short term wind speed variation across wind farms. In this work, the GB power system is represented by 17 study regions with distinct but correlated hourly mean wind speeds and local installed wind capacity. The collective inertial power contribution from wind generation is then examined using predetermined wind speeds across the GB power system for test days (mid-winter and mid-summer), calculated with a sophisticated VAR based stochastic resource model. A simplified lumped model of the power system is used to allow the wind turbines (through their controllers) to interact with the power system and impact on the system frequency response. Results from this modelling have demonstrated that installed wind capacity, if suitably controlled, can deliver a consistent improvement in power system response in the event of a large sudden loss in generation, even if that response depends on the conditions prevailing and the amount of wind and conventional plant on the bus bars at any given time.

Droop response is used to describe the linear (falling) relationship between generator synchronous speed/frequency and power output from the conventional plant. The wind plant models, in particular the wind turbine controllers, have been extended to include droop and thus participate in primary frequency response. Both blade pitch and rotor speed can be manipulated to provide the power reserve for upward power adjustment in case of a frequency fall on the system.

Different approaches to delivering droop response from wind plant have been implemented and compared. The combination of droop and inertial response has also been assessed for a significant system frequency event. The results show that the combined approach can provide an improved performance than either droop or inertial response alone.

The statistical approach to modelling whole power systems with turbines contributing to frequency response can provide System Operators with a valuable tool for planning and dispatch purposes. The synthesised wind profiles across the power system used in this thesis could in the future be replaced by wind power forecasts, and the results used to ensure that the system as a whole has sufficient frequency service available to ensure system frequency stability at all times.

6.2 **Future work**

The approach to estimating the synthetic inertial response from wind plant under varying wind conditions is based on using a Gaussian probability distribution to represent the wind variations over the duration of the transient event. However it has not been possible so far to validate the approach. This could be done in two ways. First, existing power system models can incorporate wind plant and the modelled controllers could be modified to deliver inertial and/or droop response. These models could be set up with the same wind speeds across the different regions, and the results compared with the statistical modelling. The power system models will not model the individual turbines, but nevertheless such an exercise would be useful. Second, attempts could be made at experimental validation, for individual turbines, and also for wind farms. The latter would require significant resources, and is only likely to be undertaken if concern grows regarding power system frequency stability.

The VAR based stochastic wind resource model used in this research did not include offshore data. An improved VAR wind synthesis model has been made available to include offshore wind data around the UK coasts. This improved wind model should be used to test and compare the approach to assessing the collective inertial frequency support from wind capacity, both onshore and offshore.

Two approaches have been introduced in this research to provide droop response from wind plant: pitch angle control (PAC) and rotor speed control (RSC). Both approaches have shown pros and cons in terms of interactions between the turbine torque controller and blade pitch controller and the structural loads induced by the control strategies. The impact of different control strategies on the turbine life cycle certainly requires better understanding.

Both approaches have demonstrated an improve performance in terms of power contributions when the combination of inertial and droop response is used. How to produce a power reference better tailored to participate in frequency regulation and, at the same time, mitigate the fatigue damage induced by the supplementary control systems merits further research.