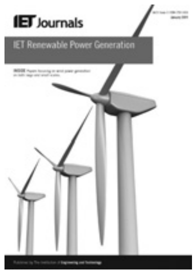
www.ietdl.org

Published in IET Renewable Power Generation
Received on 24th December 2013
Revised on 9th May 2014
Accepted on 11th July 2014
doi: 10.1049/iet-rpg.2013.0424

Special Issue: Selected Papers from The 2nd IET Renewable Power Generation Conference 2013



ISSN 1752-1416

Power system frequency management challenges – a new approach to assessing the potential of wind capacity to aid system frequency stability

Lei Wu, David Infield

Department of Electronic and Electrical Engineering, University of Strathclyde, 204 George Street, Glasgow G1 1XW, UK
E-mail: lei.wu@strath.ac.uk

Abstract: With the increasing wind penetration level in power systems, transmission system operators have become concerned about frequency stability. The inertia of a variable speed wind turbine is decoupled by power electronic converters from the power network and therefore does not intrinsically contribute to power system inertia. Moreover, as wind plant progressively displaces conventional generation and their inertia, a substantial reduction in power system inertia may occur. Variable speed wind turbines can be controlled to provide synthetic inertial response to compensate for their lack of direct contribution to power system inertia. A probabilistic approach to assessing the collective inertial contributions from wind generation across a power system is proposed and is applied to the Great Britain power system. The impact of the aggregate inertial response on arresting frequency fall is examined for the case of a sudden generation loss of 1.8 GW at the time of minimum load on both a mid-summer and a mid-winter day. The results show that synthetic inertial response from wind can reduce the rate of fall of frequency and the minimum system frequency (nadir) following the loss of generation event.

1 Introduction

As one of the most commercially viable renewable energy sources, wind power has the potential to supply a large proportion of electricity demand worldwide. It is anticipated that the installed wind capacity in the power system of Great Britain (GB) will grow significantly over the coming years. By 2020, 20% of the UK's total electricity consumption is expected to come from wind energy. This transformation will have profound impact on the nature and behaviour of the GB power system that the transmission system operator (TSO), National Grid (NG), is so concerned that they have to set up the Frequency Response Working Group to investigate the system stability in the years ahead as wind penetration increases [1]. Frequency stability with high wind power penetration is of growing concern to the TSOs worldwide, especially for smaller power systems like those of Great Britain and the Republic of Ireland [1, 2], because wind penetration in these systems is expected to be higher than for the more extensive synchronised regions such as covered by the European power network. To ensure reliable performance of the power system into the future, an improved understanding of the system's dynamic characteristics with high penetrations of wind is required.

Power system inertia 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. The initial rate of change of frequency (ROCOF) will be determined by the total inertia within the power system and extent of the power mismatch. With the potential increase in generator unit size and reduced power system inertia due to wind, a larger frequency minimum and greater initial ROCOF could occur following a sudden generation loss on the system. These combined effects could lead to system wide instability.

Modern variable speed wind turbines (using doubly-fed induction generators (DFIGs) or fully rated converters) cannot intrinsically contribute to power system inertia. It has been shown, however, that such turbines can be modified to deliver additional power similar to that released from synchronous generators in response to system frequency drops [3–8]. These early studies (e.g. [3, 4]) assume a constant wind speed whereas in reality the wind speed is never constant. Wind turbulence over the complete transient period (covering both the provision of inertial response and the following recovery period) and also the variations in mean wind speed across the entire power system should be taken into account.

The behaviour of the combined Ireland and Northern Ireland power system following a frequency event has been examined by a joint research team from University College Dublin and utilities in Ireland [6]. In their study, one of the few studies to take wind variations into account, the inertial contributions available from wind generation can be estimated through the relationship between the kinetic energy of the wind plant and the aggregate wind power output when the loss of generation event occurs. This work, however, highlights significant uncertainty in the determination of the number of wind turbines connected to the grid at any given time in relation to a given aggregate level of generated wind output. An interesting and useful follow-up study [7] considers variable speed wind turbines in the context of the same power system projected to 2020. The results show that the aggregate synthetic inertial power contributions from the installed variable speed wind turbines can be obtained from the averaged response identified through multiple trials made using an individual turbine but at different wind speeds. The study concludes that for wind speed above 15–20% of rated, a synthetic inertial power contribution can be securely delivered, and that this is relatively independent of wind speed. Consistent with the results of [6], it is shown that the available inertial power contributions can be defined as a function of the aggregated wind output at the time in question. The work also shows that for intermediate wind penetration levels, significant uncertainty exists as to the number wind turbines actually connected to the network, which highlights the difficulties in determining the inertial response available from wind generation.

The technical challenges in understanding the impact of inertial response from wind are twofold: first, the inertial response available from wind generation can be difficult to predict due to variable wind turbine availability and the variability of the wind resource, both locally, and nationally; and second, the power system dynamic characteristics (such as total available inertia) will vary with changes in the conventional plant mix resulting from the time-varying nature of the load and also of the wind power generation. This paper deals with both of these issues.

A probabilistic approach to modelling the collective inertial contributions from wind generation is used, which takes into account the temporal and spatial variation of wind speed. The short-term turbulent wind variability during the transient can be described by a Gaussian probability distribution, as presented in [9]. However, the methodology presented in [9] is only for a single wind farm with a known 10-min or hourly mean wind speed, and so the approach has been further developed to assess the collective inertial response from the total operational wind capacity within the power system.

The paper is set out as follows: Section 2 describes the modelling of the GB power system, a variable speed wind turbine and the provision of inertial response. Section 3 explains how the aggregate inertial response from wind generation under varying wind conditions is assessed. Section 4 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 and future work are presented in Section 5.

2 System modelling

2.1 GB power system modelling

A well-established system frequency response (SFR) model [10] is used to estimate the frequency response of a large power system. 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. An equivalent single machine is used to represent the dynamics of the conventional generators by filtering out the synchronising oscillations that may occur between generators in a large power system. SFR models have been used in a variety of applications [11–13].

Table 1 SFR model parameters on mid-summer and mid-winter days

F_H	T_R	K_M	R_G	D
0.15	6.0	0.8	0.08	1.0

F_H: Fraction of total power generated by high pressure turbine
T_R: Reheat time constant, seconds
K_M: Mechanical power gain factor
R_G: Governor droop
D: Damping factor

For this study, the SFR model is modified to include wind generation and thus capture the key aspects of the frequency response of the GB power system projected to 2020. The wind generation can be controlled to deliver inertial power contributions in response to system frequency fall. Note that over-frequency events will not be examined in this work since wind capacity can be easily curtailed and so decrease the overall system generation when required.

The aggregate inertia constant of the modified SFR model used in this study will vary in time, in order 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 when supplying a minimum system load of 25 GW at 6:00 am in summer and 30 GW at the same time in winter. These daily minimum loads have been selected since these hours will have least conventional plant on the system and thus are expected to suffer the largest and most rapid falls in frequency.

Table 1 lists the system parameters used in the modelling for the two load cases (but not including the inertia which varies with wind penetration).

2.2 Wind turbine modelling

The wind turbine is modelled by a simple rotor aerodynamic model, a lumped drive train model and turbine controller. A fully rated converter has been assumed (i.e. a type IV turbine) 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 III wind turbine).

The aerodynamic equation used to calculate the energy captured by the wind turbine rotor is given by

$$P_{\text{aero}} = 0.5\rho A U^3 C_P(\lambda,\ \theta) \tag{1}$$

where P_{aero} is the aerodynamic power, ρ is the air density in kg/m^3, $A = \pi R^2$ is the rotor swept area in m^2 (R being the rotor radius in m), U is the wind speed in m/s and C_P is the power coefficient defined in the conventional manner as function of λ, the tip speed ratio and θ, the pitch angle, and is a measure of the aerodynamic efficiency of the rotor.

The lumped inertia drive train model is given by

$$J\frac{\mathrm{d}\omega}{\mathrm{d}t} = T_{\text{aero}} - T_d \tag{2}$$

where J is the total (lumped) inertia of the drive train system,

IET Renew. Power Gener., 2014, Vol. 8, Iss. 7, pp. 733–739
doi: 10.1049/iet-rpg.2013.0424

including rotor, gearbox, shafts couplings and so on, and the generator (referred to low speed shaft) in kgm^2, ω is the rotational speed of the rotor, T_{aero} is the aerodynamic torque supplied to the system and T_d is 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 sets torque and blade pitch so as to operate the turbine in the most effective manner.

Below rated wind speed, the demanded torque is regulated according to (3) to achieve operation at the optimal value of C_P. In this control regime, the blade pitch is fixed.

$$T_d = K_{\mathrm{opt}}\omega^2 \tag{3}$$

where K_{opt} is the constant (controller gain) for tracking $C_{P\max}$ (under steady-state conditions) and can be obtained from

$$K_{\mathrm{opt}} = 0.5\rho\pi R^5 \frac{C_{P\max}}{\lambda_{\max}^3} \tag{4}$$

where $\lambda_{\max}$ is the optimal value of the tip speed ratio, equal to $R\omega/U$.

Above rated wind speed, pitch control regulates the aerodynamic power so as to limit the rotor speed. Table 2 lists the system parameters used in the wind turbine model. The turbine is assumed to generate rated power of 3 MW at 11.5 m/s. It should be noted that low induction wind turbine rotors with increased swept area for a given rated power output would have larger potential for inertial response, but these are not investigated here.

2.3 Provision of inertial response

The provision of inertial response from a variable speed wind turbine can be obtained by modifying the demanded torque in response to system frequency changes (ROCOF). An approach that can provide inertial response better tailored to wind turbine characteristics, referred to as non-standard inertial response, has been proposed in [9]. The modified demanded torque is simply the conventional power point tracking torque as in (3) plus an additional term, T_{inertia}, to deliver the inertial response.

$$T_{\mathrm{dmod}} = K_{\mathrm{opt}}\omega^2 + T_{\mathrm{inertia}} \tag{5}$$

Letting $\bar{T}$ denotes the torque in per unit, the added torque term, T_{inertia}, can be written as

$$\bar{T}_{\mathrm{inertia}} = 2H \times \frac{\mathrm{d}\bar{\omega}}{\mathrm{d}t} \tag{6}$$

As the speed of a synchronous generator, $\mathrm{d}\bar{\omega}/\mathrm{d}t$, is locked to the rate of change of grid frequency, $\bar{T}_{\mathrm{inertia}}$ can be written in terms of $\mathrm{d}f/\mathrm{d}t$ in per unit as

$$\bar{T}_{\mathrm{inertia}} = 2H_{\mathrm{e}} \times \frac{\mathrm{d}f}{\mathrm{d}t} \tag{7}$$

where H_{e} is the effective inertia constant of a variable speed wind turbine whose power output varies with the wind and rotor speed and can be defined as

$$H_e(\omega) = \frac{J\lambda_{\max}^3}{\rho\pi R^5 C_{P\max}}\frac{1}{\omega} \tag{8}$$

In this way, the inertial response can be delivered from wind turbines in relation to changes in power system frequency. It will be seen that the actual response depends on the wind speed and the characteristics of the wind turbine.

Table 2 Wind turbine model parameters

$C_{P\max}$	K_{opt}	$\lambda_{\max}$	J	ρ	A
0.47	4.67×10^5	8.46	12×10^6	1.225	7854

3 Assessing aggregate inertial response from wind

As wind speed is constantly changing and is different from turbine to turbine within a wind farm, the combined or aggregate response from wind generation across the power system will comprise contributions from all these individual wind turbines, each operating under different wind conditions. A novel approach to assessing the aggregate inertial response from wind capacity operating within the GB power system is presented here. This approach is based on a validated spatial wind model [14] and an extended version of the probabilistic method, first presented in [15], but explained in more detail below, for the aggregation of the inertial response of geographically dispersed wind generation. 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 wind regimes.

3.1 Estimated wind capacity in 2020

The GB power system is divided into 17 study regions in this work, consistent with the 17 SYS boundaries identified by National Grid [16]. 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 [17]. The installed wind capacity estimated in this manner totals 27.4 GW in 2020 and includes offshore wind as explained in [15]. This is broadly consistent with NG's 'Gone Green' scenario with a total of 30 GW installed. Wind speeds are not available offshore using the spatial wind model and thus such 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.

3.2 Synthesised wind speed data

A vector auto regressive (VAR) model is applied to synthesise wind speed data for power system impact studies [14]. This VAR modelling approach takes into account of the diurnal and seasonal variations in wind speed through detrending, and simulates 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 SYS study regions.

Note that three study regions (Regions 4, 14 and 16) have been omitted due to lack of reliable wind data from the 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 study 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 noise, and by using different random number seeds, independent realisations of the wind speed time series can be generated.

3.3 Probabilistic calculation of collective frequency support

Wind variations over a short period of time, 10 s, comparable to the inertial response transient, can be described by a Gaussian probability distribution [9]. The probability of two successive wind speed values U_1 and U_2 is then given by the joint Gaussian probability distribution:

$$P(U_1,U_2)=\frac{1}{2\pi\sigma^2\sqrt{1-r^2}} \times e^{-\left\{\left((U_1-U)^2+(U_2-U)^2-2r(U_1-U)(U_2-U)\right)/\left(2\sigma^2(1-r^2)\right)\right\}} \quad (9)$$

where r is the autocorrelation of the wind at lag τ, U is the mean wind speed, σ is the standard deviation determined by $\sigma = UI$. I, the turbulence intensity is chosen as 0.2. The autocorrelation, r, can be calculated from the power spectral density of wind speed turbulent variations as follows

$$r = \int_0^{\infty} \mathrm{Spec}(n) \cdot \cos(2\pi n \cdot \tau)\mathrm{d}n \quad (10)$$

The Kaimal spectrum, Spec(n), for wind turbulence is given by

$$\mathrm{Spec}(n) = \frac{0.164 \times (f(n)/f_0)}{n\left[1 + 0.164 \times (f(n)/f_0)^{5/3}\right]} \quad (11)$$

where $f(n) = n \times Z/U$; $f_0 = 0.041 \times Z/L_s$, and Z is height above ground in this example set as 80 m, L_s is the integral length scale (here taken to be 120 m) which relates to the site topography.

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 s. The start wind speed is divided into six blocks and the end wind speed is also divided into six 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

$$B_{i,j}(i = 1, \ldots, 6; j = 1, \ldots, 6) \quad (12)$$

The probabilities of various wind ramps for a mean wind speed of 10 m/s are shown in Fig. 1. It can be clearly recognised that the probability distribution for the wind ramps is dominated by those that start and end with wind speeds close to the mean. Fig. 1 shows that for a wind ramp starting in the range of 9.5–12.5 m/s, the probability of

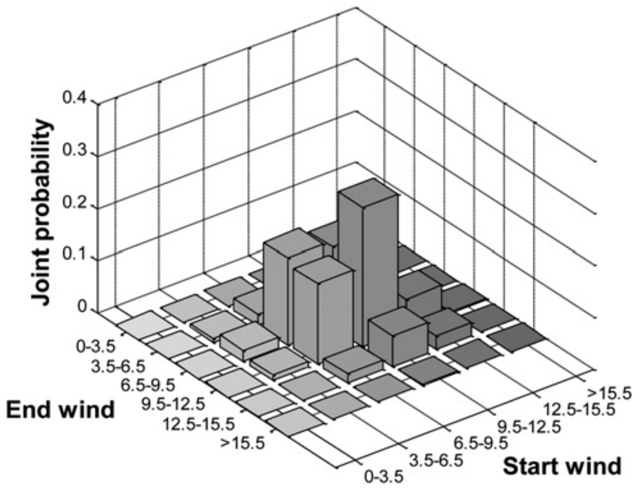


Fig. 1 *Joint probabilities for mean wind speed of 10 m/s*

ending the transient in the range of 9.5–12.5 m/s (block $B_{4,4}$) is the highest. The wind ramps that start or end within the ranges further away from the mean have considerably lower probabilities.

The approach designed for the aggregation of inertial response from a wind farm is extended, as presented in [9] and 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 to activate synthetic inertial response by a fixed frequency deviation (Δf) or ROCOF (df/dt), or both, and allow the added torque to remain constant over a pre-set period (around 10 s in duration) and so deliver inertial response independent of the response from 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 H value) and ROCOF that depends also on the dynamic response of the conventional plant. The maximum ROCOF is achieved at the instant immediately following the sudden loss of generation or increase in load. With the increasing power injection into the system from conventional generation and wind generation, 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). As mentioned already, the GB power system can be represented by 17 regions with hourly average wind speeds $\overline{U_m}$ ($m = 1,\ldots,17$) and installed wind capacity P_m ($m = 1,\ldots,17$) in each region. For any given event (assumed to last for 10 s) across the power system, the wind capacity, P_m, in each region will experience different transient wind as represented by the 36 blocks, introduced above, with their individual probabilities, $Q_{i,j}^{(m)}$($m = 1,\ldots,17$; $i = 1,\ldots,6$; $j = 1,\ldots,6$).

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

doi: 10.1049/iet-rpg.2013.0424

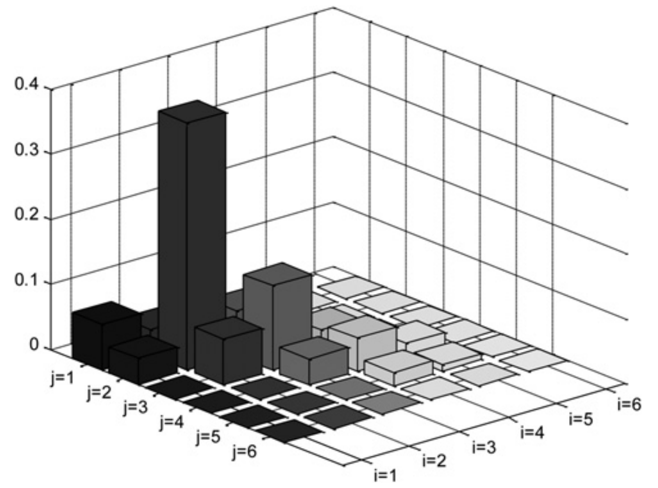


Fig. 2 *Example weightings for one of the 30 wind speed sets*

calculated from

$$k_{i,j} = \sum_{m=1}^{17} P_m Q_{i,j}^{(m)} \quad (13)$$

For each of the blocks, the corresponding weighting $k_{i,j}$ is the sum of the wind capacity in each region multiplied by the probability associated with the specified wind ramp range. Fig. 2 illustrates the probability weightings (vertical axis in this figure) for one of the 30 sets of wind speeds across the GB power system. The expected aggregate inertial response from wind generation as a whole can then be calculated combining the inertial power response from all 36 blocks, each one represented by a power response (equivalent to a turbine controller plus wind ramp input), weighted by the appropriate probabilities calculated using (13).

4 Case studies

The proposed probabilistic approach that calculates 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 wind power output can then be calculated on an hourly basis from the regional wind speeds, assuming an average turbine availability of 95% (reflecting the combination of onshore and offshore 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 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 [18]; and thus, together with the plant mix determined by the wind penetration, the SFR model described in Section 2.1 can be determined. The impact of the aggregate inertial response from wind capacity on frequency stability is examined using the SFR model, assuming a sudden loss of 1.8 GW of generation occurred. As wind power will vary from day to day in a random manner, a sample of 30 independent realisations is used for both a typical winter day (Case Study 1), and also a typical summer day (Case Study 2). The SFR model output is a time series of frequency covering the response to the loss of generation event. An example output is shown in Fig. 3, from which the ROCOF and frequency minimum can be determined.

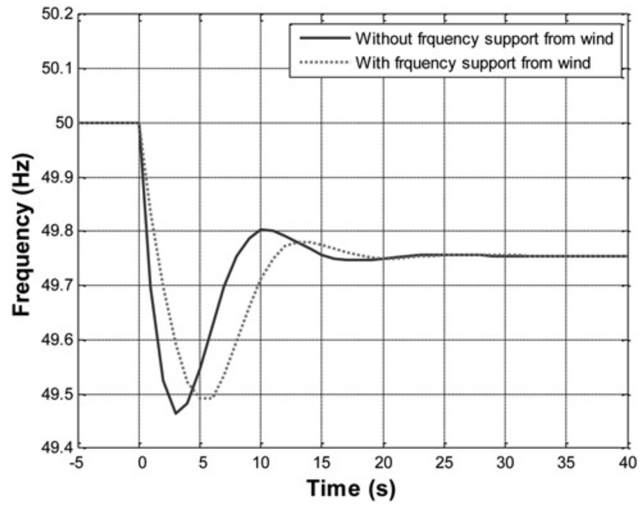


Fig. 3 *Sample output from SFR model for 1.8 GW generation loss*

4.1 Case study 1 – a typical British winter day

Fig. 4 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 6:00 in the morning for winter days. This has been estimated by calculating the mean output for each region for each of the 30 sample wind speed values, and then binning the corresponding probabilities according to wind speed. Fig. 5 shows the frequency minimum (nadir) and ROCOF following the event (ROCOF is measured 0.1 s after the loss of 1.8 GW to allow time for the inertial response to occur) as calculated using the SFR model with and without inertial frequency support from the wind

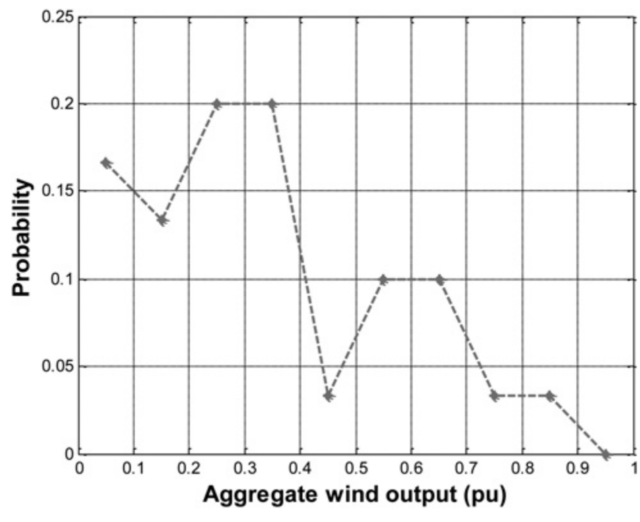


Fig. 4 *Probability of aggregate wind output for 30 sample days*

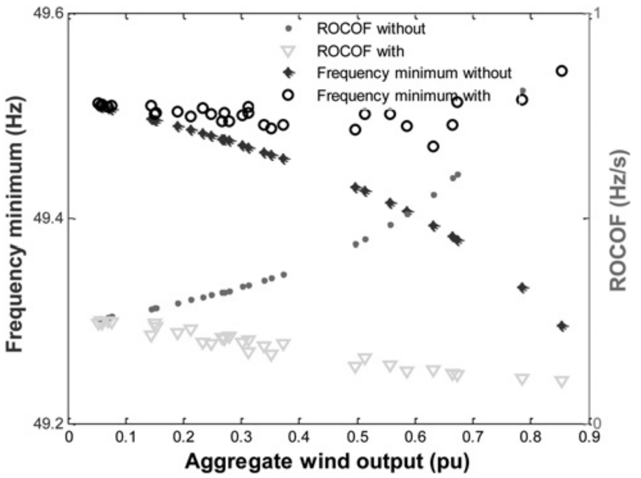


Fig. 5 *Frequency minimum (nadir) and ROCOF following transient*

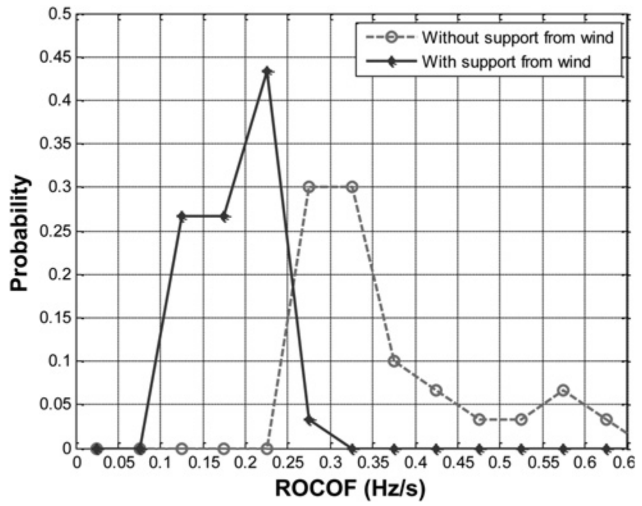


Fig. 7 *Probability density function of ROCOF 0.1 s after event*

capacity plotted against aggregate wind output for each of sample hours. It can be seen that the additional power contribution from the operational 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 and conventional plant is essential to secure system operation.

Fig. 6 shows the pdf for frequency minimum for the 30 sample winter hours with and without frequency support from wind, whereas Fig. 7 shows that the pdf for the ROCOF, measured 0.1 s following the transient in order to allow for the delay in frequency sensing, is shifted to lower ROCOF values by the wind plant. Frequency sensing delay has been represented by a simple filter in this work following [19, 20]. 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; that is, 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 the regions considered, as calculated using the VAR model. In practice, it is assumed that TSOs will gather weather data and wind power forecasts and production data from wind farm operators. Owing 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 [6, 7]. 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 since wind power forecasts are not perfect. Moreover, not all wind turbines will have the exact inertial response modelled in this work and this will add to the uncertainty; it is hoped that in the future agreed standards for inertial response will be developed to ensure a more uniform response from wind plant to major events of the sort investigated here. It is clear though that the approach proposed here removes much of the uncertainty reported in [6], although further research into this is recommended.

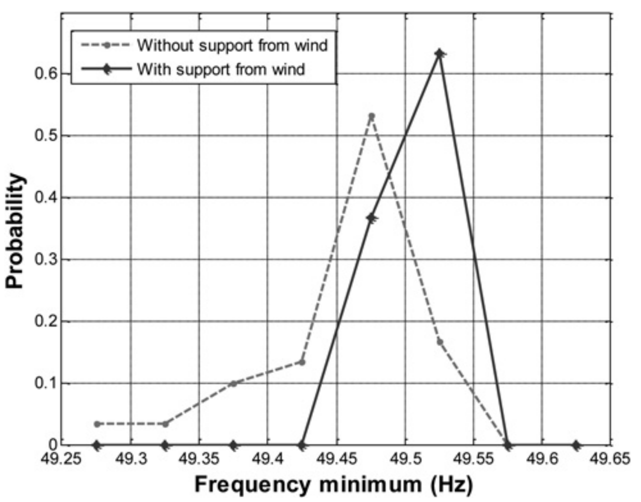


Fig. 6 *Probability density function of nadir*

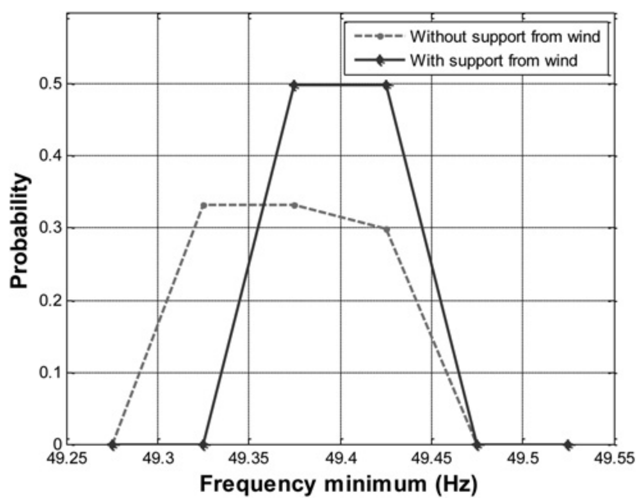


Fig. 8 *Probability density function of nadir*

doi: 10.1049/iet-rpg.2013.0424

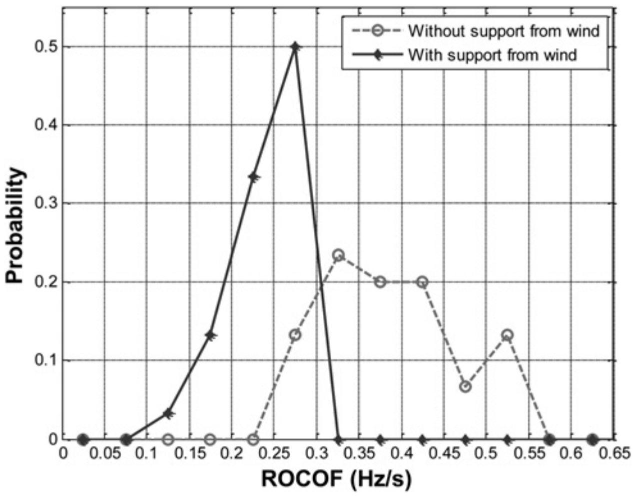


Fig. 9 *Probability density function of ROCOF 0.1 s after event*

4.2 Case study 2 – a typical British summer day

Similar conclusions result from the summer day analysis (Figs. 8 and 9), although the improvement in nadir pdf is more limited. The limited impact is the result of less wind plant being available to respond due to the much lower winds prevailing at this time of year, and also the reduced conventional plant in operation to meet the lower summer load relative to the loss of plant (assumed still to be 1.8 GW). The pdf for ROCOF, however, is reasonably improved.

5 Conclusions and future work

A probabilistic approach to assess the aggregate inertial response available from wind generation in the GB power system has been presented. 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 wind speed variation across wind farms. The impact of frequency support from wind plant on the power system as a whole can be quantified with some degree of confidence if the wind speeds in the 17 GB regions are known together with the wind turbine characteristics. A conceptual 3 MW wind turbine has been used in this work, although the aggregation method can be equally well applied to other wind turbines and different control approaches to delivering inertial response, as for example with those now commercially available from Siemens, Vestas and GE [21–24].

By sampling 30 representative daily hourly wind speed values, the variation in expected power system response can be assessed in terms of probability distributions for the minimum post-event frequency (nadir) and ROCOF. These show a wide range of possible responses reflecting the fact that wind speeds across the GB system on a given hour of a given day in the year can vary considerably. Nevertheless, this work has demonstrated that wind turbines, if suitably controlled, can deliver a consistent improvement in power system response, even if that response depends on the conditions prevailing and the amount of wind and conventional plant on the bus bars at the time in question.

6 References

1 National Grid: 'National Grid Workgroup Report GC022 Frequency Response', January 2013. http//www.nationalgrid.com/NR/rdonlyres/9A0A6194-170F-4A15-9F9D-A72711CC2B7B/58504/FrequencyResponseWorkgroupReportv11.pdf, accessed December 2013
2 Ruttledge, L., Flynn, D.: 'System-wide inertial response from fixed speed and variable speed wind turbines'. Power and Energy Society General Meeting, IEEE, 2011, pp. 1–7
3 Ekanayake, J., Jenkins, N.: 'Comparison of the response of doubly fed and fixed-speed induction generator wind turbines to changes in network frequency', *IEEE Trans. Energy Convers.*, 2004, **19**, pp. 800–802
4 Morren, J., Pierik, J., *et al.*: 'Inertial response of variable speed wind turbines', *Electr. Power Syst. Research*, 2006, **76**, pp. 980–7
5 de Almeida, R.G., Lopes, J.A.P.: 'Participation of doubly fed induction wind generators in system frequency regulation', *IEEE Trans. Power Syst.*, 2007, **22**, pp. 944–950
6 Doherty, R., Mullane, A., Nolan, G., *et al.*: 'An assessment of the impact of wind generation on system frequency control', *IEEE Trans. Power Syst.*, 2010, **25**, pp. 452–460
7 Ruttledge, L., Miller, N.W., O'Sullivan, J., *et al.*: 'frequency response of power systems with variable speed wind turbines', *IEEE Trans. Sustain. Energy*, 2012, **3**, pp. 683–691
8 Gautam, D., Goel, L., Ayyanar, R., *et al.*: 'Control strategy to mitigate the impact of reduced inertia due to doubly fed induction generators on large power systems', *IEEE Trans. Power Syst.*, 2011, **26**, pp. 214–224
9 Wu, L., Infield, D.: 'Towards an assessment of power system frequency support from wind plant - modeling aggregate inertial response', *IEEE Trans. Power Syst.*, 2013, **28**, pp. 2283–2291
10 Anderson, P.M., Mirheydar, M.: 'A low-order system frequency response model', *IEEE Trans. Power Syst.*, 1990, **5**, pp. 720–729
11 Anderson, P.M., Mirheydar, M.: 'An adaptive method for setting underfrequency load shedding relays', *IEEE Trans. Power Syst.*, 1992, **7**, pp. 647–655
12 Inoue, T., Taniguchi, H., Ikeguchi, Y., *et al.*: 'Estimation of power system inertia constant and capacity of spinning-reserve support generators using measured frequency transients', *IEEE Trans. Power Syst.*, 1997, **12**, pp. 136–143
13 O'Sullivan, J.W., O'Malley, M.J.: 'A new methodology for the provision of reserve in an isolated power system', *IEEE Trans. Power Syst.*, 1999, **14**, pp. 519–524
14 Hill, D.C., McMillan, D., Bell, K.R.W., *et al.*: 'Application of auto-regressive models to U.K. wind speed data for power system impact studies', *IEEE Trans. Sustain. Energy*, 2012, **3**, pp. 134–141
15 Wu, L., Infield, D.: 'Power system frequency management challenges – a probabilistic approach to assessing wind farm potential for aiding system frequency stability'. IET Conf. Renewable Power Generation, Beijing, China, 9–11 September 2013
16 National Grid: 'National Electricity Transmission System Seven Year Statement', May 2011. http://www.nationalgrid.com/NR/rdonlyres/4AB92B80-499A-4D3A-84E4-BBE884CBBA55/49900/NETSSYS2011.pdf, accessed December 2013
17 RenewableUK: 'UK Wind Energy Database', http://www.renewableuk.com/en/renewable-energy/wind-energy/uk-wind-energy-database/, accessed December 2013
18 Kundur, P., Balu, N.J., Lauby, M.G.: 'Power system stability and control' (McGraw-Hill, London, 1994)
19 Clark, K., Miller, N.W., Sanchez-Gasca, J.J.: 'Modeling of GE wind turbine-generators for grid studies', 2009
20 Ruttledge, L., Flynn, D.: 'UCD parameter tuning working paper – GE WindINERTIA demonstration project', 2013
21 Knuppel, T., Thuring, S., Kumar, S., *et al.*: 'Frequency activated fast power reserve for wind power plant delivered from stored kinetic energy in the wind turbine inertia'. 10th Int. Workshop on Large-Scale Integration of Wind Power into Power System as well as on Transmission Networks for Offshore Wind Farms, Aarhus, Denmark, October 2011
22 Tarnowski, G.C., Kjaer, P.C., Dalsgaard, S., *et al.*: 'Regulation and frequency response service capability of modern wind power plants'. IEEE Power and Energy Society General Meeting, 2010, pp. 1–8
23 Tarnowski, G.C., Kjar, P.C., Sorensen, P.E., *et al.*: 'Variable speed wind turbines capability for temporary over-production'. IEEE Power and Energy Society General Meeting, 2009, pp. 1–7
24 Miller, N.W., Clark, K., Shao, M.: 'Frequency responsive wind plant controls: impacts on grid performance'. IEEE Power and Energy Society General Meeting, 2011, pp. 1–8