Future stability challenges for the UK network with high wind penetration levels

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Abstract

Offshore wind plant such as variable speed wind turbines (DFIG) will play an increasingly important role in future decades if ever-stringent requirements of energy security and low carbon emissions are to be met. Although some analysis of the impact of DFIG on system stability has previously been reported, none of it is based on a large network representing a real system, or the large network is simply not publicly available. This paper describes one such suitable equivalent dynamic network for stability studies based on the whole UK transmission system. The methodology for appropriate control system design and adjustment of the parameters under different dispatch conditions is presented. The network model is subsequently updated according to various National Grid future energy scenarios where DFIG models are appropriately added and distributed. Two important aspects contributing to future system stability are studied in detail, namely maximum value of the rate of change of frequency and transient stability. A number of detailed cases studies under varying wind penetration levels are presented which quantify the impact of key influencing factors such as the size of the largest generating unit for n-1 contingency, amount of primary system response, frequency dependency of load, and others. The study concludes that none of the individual factors can provide a complete solution and that careful cost benefit analysis is needed to determine the proper mix of services and reinforcements needed in the future.

1. Introduction

Energy security, diversity of electricity supply and low carbon emissions have been major drivers in recent large scale wind energy developments around the world. Off shore wind plant in particular such as variable speed wind turbines (DFIG) will provide an increasing proportion of electricity in countries such as the UK. This replacement of conventional thermal plant with high inertia constants with low inertia wind turbines poses a number of stability challenges. One major challenge is the alleviation of network frequency disturbances. According to the UK grid code, all registered generators should provide frequency response capability to mitigate frequency disturbances [1]. However, due to the fact that these network supporting requirements are only applicable to transmission connected large synchronous generators, the smaller non-synchronous generators provide very limited contribution to system stability. This issue has been highlighted in the recently released System Operability Framework document by National Grid [2]. Since the mechanical dynamic performance of DFIG (and other inverter connected DG) is decoupled from the main grid, higher penetration levels of such generating plant in the system is likely to cause the system frequency performance to worsen [3].

Of the various techniques used for identifying potential loss of mains connection or islanding condition [4], most countries, including UK, Austria, Belgium and Italy, adopt rate of change of frequency (ROCOF) as their main strategy. However, high ROCOF values can also temporarily occur over the entire network in the event of loss of large infeed (generation or import) or demand (export) leading to relay tripping [5]. In these circumstances, a large number of electricity consumers can lose their electricity supply as happened once in the UK on 27th May 2008 when 546MW of demand had to be shed to preserve system stability. According to [5], two main actions can be taken to prevent spurious loss of generation due to ROCOF. The first possibility is to increase the recommended ROCOF setting (or disabling the relay altogether), and the second action entails limiting the rate of change of frequency by ensuring either sufficient primary frequency response through the use of additional synchronous generators or Synthetic Inertia response through new control technologies applied in the non-synchronous generators (DFIG or inverter connected power plants).

Among other previous work in the area, [6] analyses the dynamic contribution of DFIG-based wind farms to system frequency response in detail. In [7], the methodologies used to extract kinetic energy with their impact on the system dynamic frequency performance are introduced.

A second major challenge is system transient stability where large numbers of traditional coal plants at the centre of the network will be decommissioned and replaced by wind farms. Although the large offshore wind farms can provide local reactive power support through HVDC connection, this reactive power support is only available at the point of connection. Low MVAr capability of onshore DFIG also results in lack of reactive power control capability in the future. This lack of reactive power support leads to transient stability issues as assessed by system critical fault clearance time (CFCT). Dynamic oscillatory performance with different kinds of wind turbines integrated into the system is presented in [8]. The limitations of the voltage capability of wind turbines at different penetration levels are discussed in [9]. The work of [10] investigates the impact of large wind power generation on both the steady state and transient voltage stability. Electromechanical oscillation performance is discussed in [11]. Also, the steeper drop of frequency due to smaller wind turbine inertia is reported. In [12], the impact of increased penetration of DFIG is analysed by small signal and transient stability study. However, only a limited number of studies from these papers analyse the network frequency response with high penetration levels of wind. Furthermore, research studies based on large-scale real test systems involve complex proprietary network modelling not publically available.

In needs to be emphasised here that in order to have high level of confidence in the frequency performance investigation, it is crucial to employ a validated dynamic model of the system [2]. The model should be validated for both steady state and dynamic studies before any future scenarios can be considered and assessed. Hence, the main contributions of the present paper are threefold. Firstly, an equivalent dynamic model of the whole UK transmission system for stability studies is established and subsequently extended to represent future system scenarios with high penetration of wind farms. A systematic methodology is proposed and demonstrated using UK system data. Secondly, rate of change of frequency (ROCOF) in the case of high wind farm penetration is analysed, including the detailed evaluation of three influencing factors: amount of maximum generation loss in a single event, fast frequency response reserve, and frequency dependent demand. Thirdly, the issues related to system transient stability are explored in detail.

The paper is organized as follows. In Section II, the UK dynamic equivalent model is established based on the current National Grid statement and other publically available data. The methodology for changing the parameters under different dispatch conditions is introduced for the purpose of network validation and updating. Section III examines future system structures including transmission line reinforcements, power plant demand changes and wind farms development plans. One representative future UK transmission system is modelled. Section IV analyses system frequency performance under different demand and wind power distribution conditions. Section

V studies transient stability by way of assessing system critical fault clearance time. Conclusions are presented in Section VI.

2. Dynamic Equivalent UK System Model

For correct understanding of the future system frequency performance, a reliable reduced order dynamic model is needed. The proposed 21-bus equivalent transmission network model superimposed on the UK map is presented in Figure 1. The following sections describe the process of developing, validation and extension of the model to represent future generation scenarios.

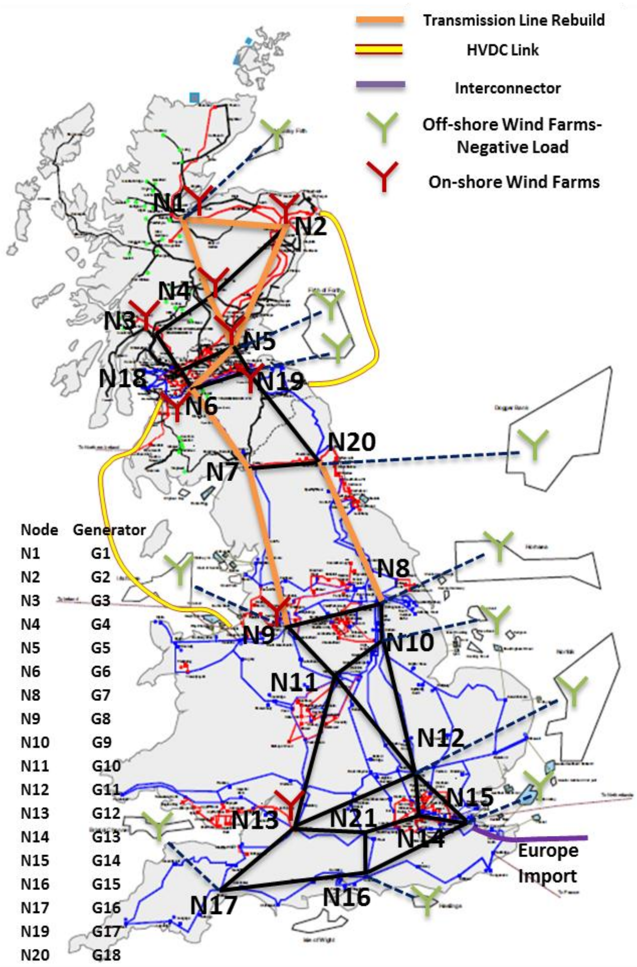

Figure 1. Equivalent 21-bus UK Transmission System Model

2.1 Power flow parameters

The equivalent UK model has been introduced in previous work [13]. The model contains 21 buses located in 17 study zones based on critical boundaries defined by the UK National Grid in their annual report (ETSY) where the generation and demand profiles for each study zone can be found. The calculation of the transmission line impedances is achieved by solving the line parameters R, X_L and X_C between two nodes from the known values of voltage magnitudes and angles at each end of the line (V_s, V_r and θ_s, θ_r) that accompany their sending end and receiving end power (P and Q) [13].

2.2 Method for adjusting system parameters to cater for different operating conditions

In order to test the system performance on both historical days and future predicted scenarios, a method is needed to efficiently adjust the system profile (originally based on Winter Peak Demand) so that the model can be used for studies under different operating conditions. The procedure can be described as follows:

1. The historical demand data with each half hour of the day is recorded on "New Electricity Trading Arrangements, Balancing Mechanism Reporting System (BMRS)" [14]. Thus, demand of the specific day and time (Historical Demand) is used to scale down all existing loads in the model with one common ratio: Historical Demand/Winter peak Demand.

2. In April 2010, Britain issued a new 'deterministic' standard which invited industrial consultation [15]. The standard proposes that cost-benefit analysis should be used in network investment and dispatching. According to this approach, large coal and CCGT plants are dispatched according to the Dark and Spark Spread as shown in Figure 2 (The 'Spark Spread' is the difference between the

cost for CCGT to generate 1MWh energy and the price for which that energy can be sold. The 'Dark Spread' is used for coal plant in the same way [16]).

3. The historical generation data, also provided in [14], is used to dispatch generators in each zone: when the Spark Spread is greater than Dark Spread, the CCGT plant in each zone will be dispatched before coal plant. The opposite is the case when Dark Spread is greater than Spark Spread. The nuclear power plants are dispatched at all times except when there are particular issues on that day.

4. The principles outlined in the above points 2 and 3 are used in the model to split the total amount of generation between coal, CCGT and nuclear technology in each study zone.

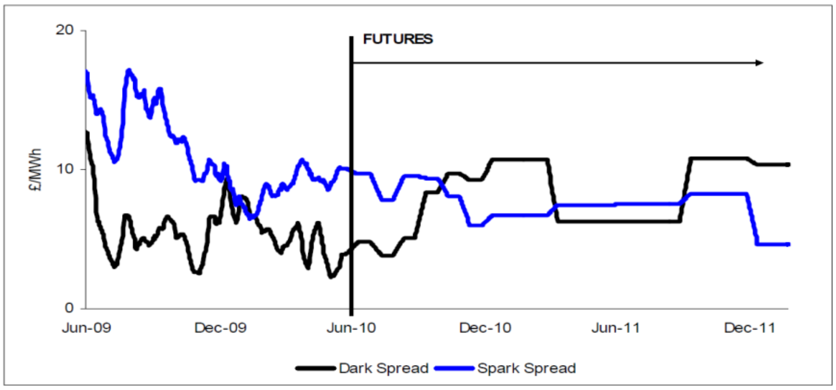

Figure 2. Spark and Dark spread [15]

2.3 *Dynamic data*

The dynamic model of the system is built using the load flow network model and library components provided by PSS/E software [17] in which all generators are of round-rotor type with typical parameters based on [18-19]. The data includes transient and sub-transient time constants, reactance, and aggregated inertia constants.

In UK, for a registered capacity of 100MW, the generator is to provide a primary response of 10% of its capacity in 10 seconds. To implement this principle in simulation studies, in each study zone the generators are separated into two groups.

The first group of generators (amounting to 90% of total capacity) is not equipped with any turbine governor (i.e. no turbine response following a disturbance), and the second group (amounting to 10% of total capacity) with the steam turbine model (TGOV1) based on the IEEE Standard [20].

The General Electric (GE) WT3 DFIG model is used. The current model version does not have the capability to provide inertia response during network disturbance. The reactive power capability varies from 0.9pf under-excited to 0.95pf over-excited. More detailed description of this model can be found in [21-22]. The detailed parameters are included in the Appendix.

2.4 Control system design

To have a similar dynamic performance of the established model compared to the actual system, control systems such as automatic voltage regulator (AVR) and power system stabilisers (PSS) must be tuned. It was assumed that AVRs are attached to all generators. However, it is also known that the AVR action may reduce the damping performance of the system [23]. Indeed, it is pointed out in the UK Ten Year Statement [3] that "several power system stabilisers should be installed between generators in England and Wales and Scotland for the purpose of oscillation stabilization." The small signal analysis reveals the presence of one unstable as well as two lightly damped interarea modes. Their corresponding eigenvectors and participation factors indicate that generators G_1, G_2, G_4, G_5, G_6, G_7, G_8, G_{12}, G_{17}, G_{18} (attached to corresponding nodes in Figure 1) have the dominant effects on the interarea modes.

Hence, the STAB1 model in PSS/E [17] was used to represent the PSS with an auxiliary signal fed to the voltage input of the AVR on the designated generator. The auxiliary signal can be the generator power, frequency or generator speed. The typical transfer function of the PSS is [24]:

$$PSS(s) = K_s \frac{T_W}{1+T_W s} \frac{1+T_1 s}{1+T_2 s} \frac{1+T_3 s}{1+T_4 s} \tag{1}$$

The step-by-step multimachine Nyquist-Bode PSS design methodology of [25] was applied. Finally, eight generators (G_1, G_2 and G_5 in Scotland; G_7, G_8, G_{12}, G_{17} and G_{18} in England & Wales) were chosen as the most effective locations to be equipped with PSS.

2.5 Validation of the model

The transient performance of the equivalent model was validated by comparing the frequency response with the real data recorded by PMUs during the known system events. The results (reported in [13]) indicate that there is good correspondence between the recorded and simulated response. This includes major interarea oscillations as well as system load flow conditions at pre-fault and post-fault period.

3. Modelling Future Scenarios in UK Power System

In order to investigate the future system frequency performance, the reduced model needs to be updated to reflect the probable future generation scenarios and penetration levels.

Although information relating to future operating framework can be accessed from the National Grid documents, these plans can change when new policies are considered or new circumstances develop. Therefore, the model and the associated systematic methodology presented here aim to provide the required flexibility in changing the operating conditions based on different future frameworks. In this paper, the system's parameters are adjusted according to the most recently released document Electricity Ten Year Statement (ETYS) and Offshore Development Information [26].

3.1 Future energy scenarios of onshore and offshore wind plant

The existing 17 zones are still retained. Each represented by one or two nodes depending on the major power transfers to adjacent zones and network density in each zone.

One useful source of information in the context of future system performance study is the Future Scenarios Consultation which outlines a few alternative directions of system development based on the comments received from industrial participants [26]. These scenarios have been termed as: Slow Progression (SG), Gone Green (GG) and Accelerated Growth (AG). The scenarios are significantly different from one another starting from 25GW of installed offshore capacity in SG to 57GW in AG by 2030; each scenario has appropriate generation capacity to meet the requirement of Security of Supply and the existing nuclear power stations are assumed to extend their lives in all scenarios with different durations. In this paper, the GG scenario has been selected for future system performance studies which is also the main scenario analysed by National Grid due to particularly high penetration of renewables and resulting low inertia of the system.

Thus, additional 8 onshore wind plants are added into zones 1, 2, 3, 4, 5, 6, 9 and 13. In this study the DFIG model is used to represent wind farms in all study zones. The offshore wind is represented as negative load and the influence of the fully rated converter connection (HVDC) is neglected in this case.

3.2 Transmission line reinforcements

Due to the high penetration levels of wind in Scotland, the power transfer across several boundaries may need reinforcements. Based on the ETYS, following several reinforcements are made:

1. Seven transmission lines are rebuilt connecting study zones 1, 2, 4, 5, 6, 7 and 8. The updated transmission line data (marked in orange in Figure 1) reflect these changes by including the information provided by ETYS "Transmission circuit change 2012 to 2021".
2. All transmission lines previously assumed as single circuits in [13] have been replaced with double-circuits.
3. Two new HVDC links are added to the system: 2GW Eastern HVDC link from Peterhead to England and 2.4GW Western HVDC link from Deeside to Hunterston. The VSCDCT model in PSS/E was used to implement these lines.

3.3 Generation and demand update for 2020

Demand is defined as transmission peak demand including losses which is 56GW in 2012 and is anticipated to increase to 57.7GW in 2020.

Generation is assumed to meet CO_2 emission requirements for all targets by the year 2020, 2030 and 2050 in GG scenario: wind reaches 25GW which needs an increase of 18 GW to 2020; coal plant decreases by 7GW from existing 25GW to 18GW in 2020; 3GW increase in Gas/CHP capacity and 5GW nuclear capacity increases by the year 2020.

4. Rate of change of frequency

The case studies presented in this section are based on the GG scenario tuned to the summer minimum demand situation which is of major concern. Two different distributions of wind energy resources are considered:

a) wind energy is distributed evenly throughout the UK (equal distribution denoted as ED) and;

b) uneven distribution with 10% wind energy in the North and 70% in the South (NS) according to the ETSY [3].

The following sections investigate the impact of three influencing factors on the rate of change of frequency in the system: amount of lost generation, amount of primary frequency response, and frequency dependency of load.

4.1 Different amount of generation loss

During the summer minimum demand, the system total inertia is lower than during the winter peak which results in higher rates of change of frequency. According to the ETSY, the minimum demand in the year 2020 is estimated as 23000MW. The constant load is assumed for the purpose of investigating the worst case (highest ROCOF) at first. Two different amounts of generation loss are considered (1000MW and 1800MW) which represent the current and future largest single generator size. The loss of generation is applied in two different places: in the middle of UK (nodes N8 and N9 as indicated in Figure 1), and in the south of UK (nodes N12, N14 and N15 in Figure 1). The ROCOF is calculated as a three cycle average based on the simulation data for the purpose of testing whether there is a risk of the protection relays to be tripped during loss of generations. The test results under varying wind penetration levels are presented in Tables 1 and 2.

Table 1. System ROCOF during loss of 1000MW generation

	Wind penetration level						
	10%	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**
ED middle	-0.357	-0.394	-0.427	-0.476	-0.545	-0.636	-0.731
NS middle	-0.395	-0.423	-0.465	-0.506	-0.565	-0.653	-0.749
ED south	-0.450	-0.482	-0.537	-0.580	-0.627	-0.651	-0.756
NS south	-0.388	-0.422	-0.460	-0.501	-0.564	-0.636	-0.728

Table 2. System ROCOF during loss of 1800MW generation

Wind penetration level							
	10%	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**
ED middle	-0.634	-0.705	-0.776	-0.879	-1.017	-1.231	-1.469
NS middle	-0.670	-0.714	-0.809	-0.910	-1.026	-1.256	-1.539
ED south	-0.793	-0.854	-0.941	-1.032	-1.172	-1.375	-1.566
NS south	-0.743	-0.781	-0.930	-1.028	-1.105	-1.314	-1.438

Under the 1000MW loss of generation, all ROCOF values are within the new G59 recommended setting limits of $1Hzs^{-1}$. In this case there is no risk of further loss of generation due to spurious LOM protection tripping during the disturbance. However, the situation is much worse if 1800MW generation loss is assumed.

For the disturbance applied near the middle part of the network, the higher ROCOF can be found in the north and central part in both ED and NS distribution conditions. Under ED condition, the highest ROCOF occurs at bus 19 ($-1.469\ Hzs^{-1}$) while under NS condition, it reaches ($-1.539\ Hzs^{-1}$). All these values exceed the new proposed settings of $1Hzs^{-1}$. From the results it can also be inferred that the ROCOF threshold of $1Hzs^{-1}$ is reached when at wind penetration level of approximately 50%. Additionally, it should be noted that the ROCOF values are relatively smaller under ED condition than that under NS condition in this case. Although the DFIG is partially decoupled from the grid, it is not completely inertia-less if the wind turbine real power (P) is regulated according to [6]. The decrease of the ω_s is compensated by the i_{qr} which may lead to an increase in electric torque T_e. Thus, the onshore DFIG may still provide small amount of inertia support to the grid during disturbances.

The results are somewhat different when the disturbance occurs in the south. In this case the system ROCOF exceeds $1Hzs^{-1}$ if when the wind penetration level of approximately 40% is reached.

To further investigate the influence of the amount of generation loss on the ROCOF, the amount of generation loss was increased gradually from 1000MW while the wind penetration level was fixed to 70%. In this case it was found that the ROCOF reaches $1Hzs^{-1}$ when the generation loss is 1335MW and 1370MW for ED and NS conditions respectively.

The above results clearly highlight that additional actions are needed in order to maintain system integrity under future generation scenarios. One option is to further increase the ROCOF protection setting or introduce additional time delays to avoid spurious tripping in response to momentary high ROCOF value. However, by doing so, the non-detection zone of the anti-islanding protection will be increased which can cause undesirable hazards in the network.

4.2 Different amount of primary frequency response

The above case shows the potential risk that high ROCOF (higher than $1Hzs^{-1}$) may occur when the largest loss of generation limit increases to 1800MW. This section explores if the provision of additional primary frequency response can somewhat help this situation (perhaps provided by non-synchronous generators as a special service in the future [2]). Therefore, in the UK model the amount of primary frequency response (PFR) was increased from 10% to 20% in order to verify if this may help to reduce the ROCOF. The loss of generation is assumed to have occurred in the middle part. The results are shown in Table 3 and illustrated in Figure 3.

It can be seen that the ROCOF has been reduced with the additional 10% primary frequency response. For both AD and NS distribution conditions, the highest ROCOF is contained within $1Hzs^{-1}$ even with wind penetration level reaching 50%.

Table 3. ROCOF of system during loss of 1800MW generation: 10%(PFR) vs 20%(PFR)

PFR	10% vs 20% (10% Penetration)		10% vs 20% (30% Penetration)		10% vs 20% (50% Penetration)		10% vs 20% (70% Penetration)	
ED	-0.635	-0.592	-0.776	-0.745	-1.028	-0.955	-1.470	-1.305
NS	-0.671	-0.645	-0.809	-0.776	-1.027	-0.963	-1.539	-1.378

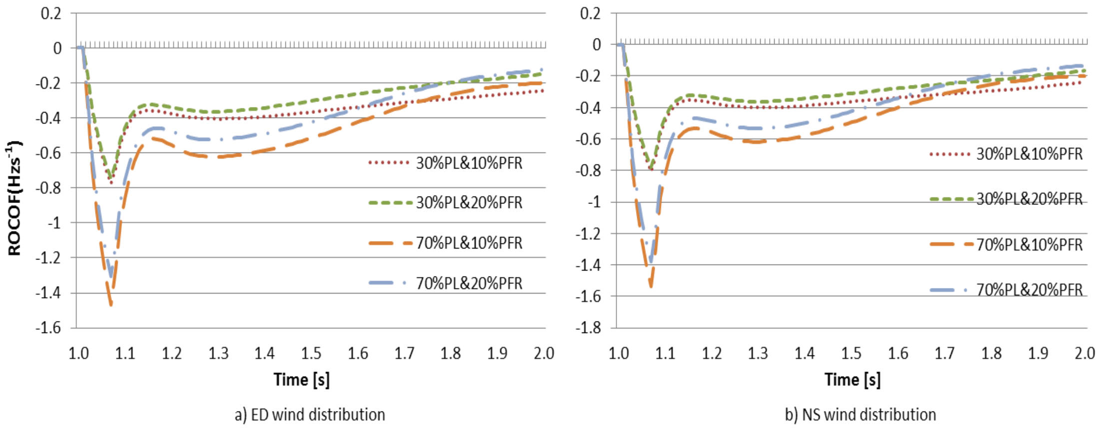

Figure 3. System ROCOF during loss of 1800MW generation at changing PFR

However, it is evident that even at 20% PFR the improvement is not significant and the ROCOF values are still higher than $1Hzs^{-1}$ if wind penetration level increases above 50%. Therefore, in the future it may be necessary to seek additional transient active power support during the loss of generation using other techniques capable of providing near instantaneous response such as synthetic inertia or wind turbine de-loading [2, 7].

4.3 Load response to frequency deviation

In this section frequency dependency of loads is investigated. It is assumed that 1% frequency deviation results in 1%-4% active power demand variation (APD) [27]. The tests are based on ED wind distributed condition. The disturbances are applied in the middle section of the network. The highest ROCOF values for increasing wind penetration level are presented in Table 4.

Table 4. System ROCOF during loss of 1800MW generation under varying APD

ED	Constant	1%APD	2%APD	3%APD	4%APD
10%	-0.634	-0.628	-0.623	-0.617	-0.611
30%	-0.776	-0.767	-0.758	-0.750	-0.741
50%	-1.017	-1.010	-0.995	-0.981	-0.967
70%	-1.469	-1.441	-1.418	-1.394	-1.372

Results indicate that the frequency dependent load has a definite ability to reduce the ROCOF even though the improvement does not appear dramatic. Therefore, the amount of change in active power demand corresponding to 1% frequency deviation was further increased to 20% in order to determine whether more significant reduction of ROCOF is achievable. It is envisaged that higher values of APD may be implemented in the future using, for example, fast demand shedding [2, 28].

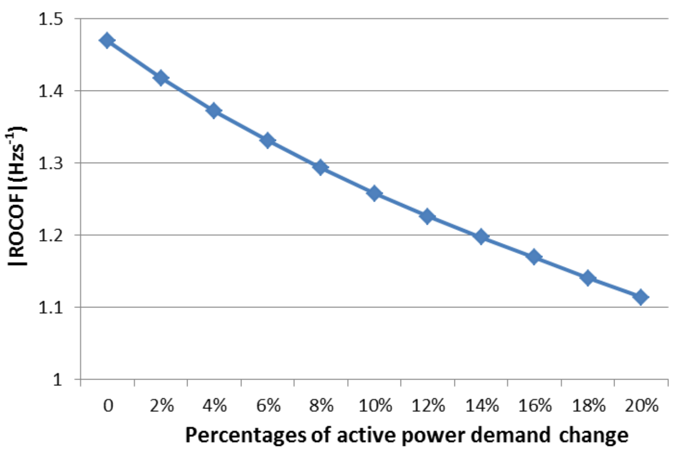

Figure 4. ROCOF at increasing frequency dependency of demand (70% wind penetration)

It can be seen from Figure 4, the relation between the amount of active power demand response and ROCOF is generally not linear. The improvement is more significant within the first 6% and gradually reduces as the demand response is increased. Nonetheless, the highest ROCOF under 70% wind penetration is still higher than 1Hzs^{-1} which indicates that frequency dependent demand response alone cannot provide a complete solution to the issue of high ROCOF.

5. Transient stability

5.1 Voltage recovery

The reactive power performance of the PSS/E WT3 model during the dynamic frequency response is first tested. The test is based on 60% wind power penetration evenly distributed (ED) during the winter peak operating condition. The system critical fault clearance time (CFCT) is used for assessing the system transient stability. A three phase to ground line fault on line 6-7 is added at 1s, the fault is cleared by tripping a faulted transmission line (i.e. one of the two parallel circuits). The value of CFCT 80ms as defined in NGET [1] is used. The test results presented in Figure 5 indicate that with the help of voltage control feedback loop, it is possible to maintain the system stability after the fault is cleared while the bus voltage collapse without this control loop activated.

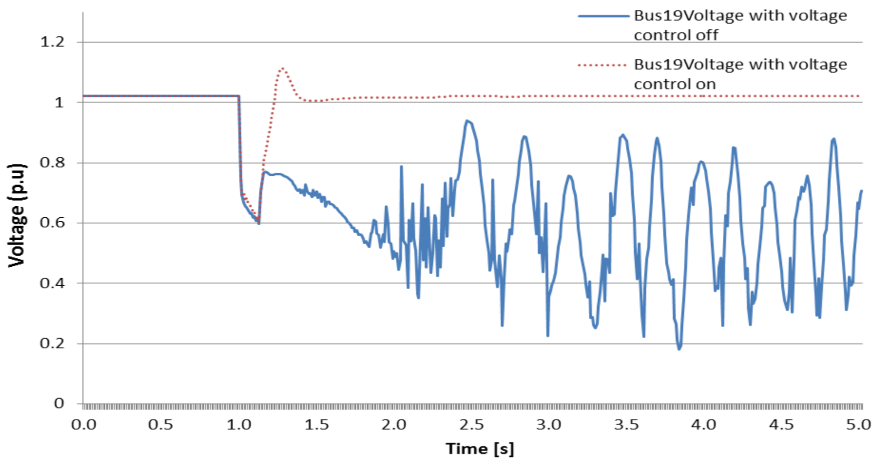

Figure 5. Bus 6 Voltage with DFIG voltage control on/off under 80ms Fault

For the purpose of testing how the system stability is affected by the wind farm under different penetration levels, two three-phase ground faults are applied at transmission line between buses 6 and 7 (the west connection between Scotland and England) and between buses 8 and 10 (transfer of the largest power flow in the system). The wind penetration is varied from 0% to 70%. The reactive power controls are available for all the DFIGs in the system. These tests are based on the winter peak condition. The system critical fault clearance times are shown in Table 5.

Table 5. Critical fault clearance time at three phase to ground fault with penetration from 0%-70% based on winter peak condition

Wind Distribution	Penetration Level	Fault 6-7 [ms]	Power Flow [MW]	Fault 8-10 [ms]	Power Flow [MW]
ED	0%	367	214.4	176	2491.0
	10%	350	342.8	168	2611.6
	20%	328	728.0	156	2732.4
	30%	301	983.8	137	2841.2
	40%	252	1237.6	110	2944.8
	50%	188	1488.9	75	3041.4
	60%	130	1736.7	48	3129.7
	70%	58	1981.6	28	3211.2
NS	0%	367	214.4	176	2491.0
	10%	360	260.7	205	2372
	20%	356	311.6	216	2227
	30%	350	362.3	224	2083.9
	40%	340	412.3	312	1936.5
	50%	322	463.2	266	1790.0
	60%	298	513.8	212	1647.3
	70%	246	563.5	142	1497.9

From Table 5, it can be seen that the system critical fault clearance times are decreasing with the increasing penetration levels of wind except in the NS cases with fault on the line 8-10 where the increase of the CFCT can be initially observed. Changing distribution of wind generation alters the power flow pattern in the UK system which historically has always been unidirectional, i.e. from the north to the south. Although the ability of DFIG to support voltage is limited by the MVAr export capability during transient period which may reduce the transient stability of the system, the reduced power flow also reduces the effect of the fault which increases the CFCT. Due to this reason, the general system transient stability performance is much better in the case where wind farms are distributed 10% in North and 70% in South (NS) than that in the evenly distributed condition (ED). Moreover, it should be noted that some simulated CFCTs are shorter than 80ms (which is the shortest fault clearance time used in the UK Grid Code) under ED conditions when the wind penetration level is above 50%. Thus, solutions should be worked out to address this issue such as the investment in reactive power compensation devices in the centre of the network where large numbers of coal plants will be decommissioned in the future. To verify this solution 5 static var compensators (SVC) have been added to the central part of the equivalent model (nodes 5, 6, 7, 8 and 9) with 300MVAr rating each. For example, for a fault on line 6-7 with ED 70% condition the result shows that with the help of the added SVCs, the system can remain stable and the voltage is able to recover back to its pre-fault value. The CFCT is increased to 84ms in this case which satisfies the minimum 80ms requirement.

5.2 Double circuit trip of the western Scottish-English interconnector

In order to test the effectiveness of the two new HVDC connections between Scotland and England in enhancing the transmission capability of the network, a simulation study was performed where the fault described in section 5.1 is cleared after 80ms by tripping both circuits connecting Strathaven and Harker (buses 6 and 7) which represents the loss of western interconnector between Scotland and England.

From Figure 6 it can be seen that under ED conditions the system loses synchronism at 50% penetration level without HVDC connection added to the network and this is improved to 60% when two HVDC links are introduced. However, with NS distribution condition, the system can withstand this disturbance under all simulated penetration cases. Similarly to Case 5.1, the effect of different wind distribution scenarios (ED and NS) is clearly demonstrated which leads to the change of power flow throughout the UK. In NS scenario the pressure of power transfer from Scotland to England is considerably reduced compared to that of ED scenario which improves overall transient stability of the system. Furthermore, the system damping performance is improved with the increasing levels of the wind integration. Although the DFIG is decoupled from the network, it is still equipped with an excitation control system which can provide fast voltage regulation. Therefore, introducing the DFIG into the system can improve system damping performance. At the same time it is known that transient stability margin is reduced [25].

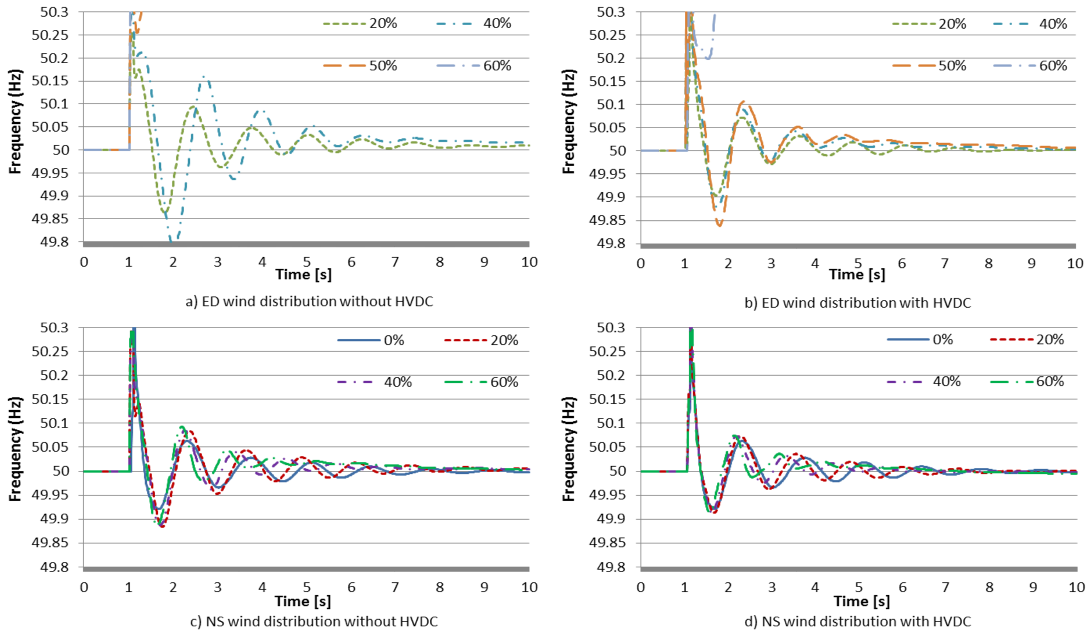

Figure 6. Loss of Scottish-England interconnetor

5.3 Extreme high wind penetration case

In this case the penetration level of wind is continually increased to investigate whether it is possible to replace almost all the conventional generators by wind turbines in order to achieve stable operation under 100% wind penetration conditions during summer minimum. The result shows that the system can operate in a stable manner with wind penetration up to 93%. Above 93% penetration level, the system will loss synchronism. The reason for that is possibly because the total amount of conventional synchronous generators are not enough to synchronous the whole network frequency. In order to ensure the system frequency can be maintained at 50Hz, additional 90MW synchronous generators support (an increase from 2010MW into 2100MW) is needed. Therefore, it is necessary and important for the system operators to assess the total amount of synchronous generators that must be available on the specific day in the future especially during the high wind conditions.

6. Conclusion

The key contributions and findings of this paper are as follows:

First, an equivalent UK transmission network based on National Grid annual reports is established for stability studies and successfully extended to represent a future UK transmission system with high penetration of wind. For the purpose of investigating future system performance, the proposed amended network is based mainly on the so called Gone Green scenario proposed in [3].

Second, concerning future risks, the system rate of change of frequency (ROCOF) setting is one of the most important issues to be resolved. In all studied cases, the ROCOF during loss of 1800MW generation is above $1\mathrm{Hz\,s^{-1}}$ when the wind penetration level exceeds 40%. With additional primary frequency response or frequency dependency of load, it is possible to reduce the ROCOF. However, the system still faces the risk of high ROCOF values exceeding $1\mathrm{Hzs^{-1}}$ when the wind penetration level reached 60%. The results clearly indicate that none of considered solutions alone can fully address the problem of high ROCOF in the future. Detailed cost benefit analysis is needed to determine the best course of action, i.e. whether to increase the ROCOF setting further, introduce inertia support from the DFIG, introduce frequency dependent demand, or most likely to utilise a combination of all influencing factors.

Third, it is demonstrated that the system is able to remain stable with sudden loss of western connections from Scotland to England in most cases except for the 60% and 70% equal distribution wind conditions. Also, it is concluded that the North South wind distribution condition has better transient stability than the equal distribution wind condition since the power flow pressures across each boundary are relatively small. Still with the case of a network with increasingly high wind penetration, it is shown the system transient stability will significantly decrease due to the limited reactive power capability of DIFG. In some cases, the network CFCT is less than 80ms. Future instability of the network to the point of loss of synchronism is possible even during normal operating conditions if no action is taken.

7. References

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Appendix

GE WT3 DFIG Model Parameter

X_{eq}	0.8	T_P	0.05
K_{pll}	30	F_n	1
K_{ipll}	0	ωP_{min}	0.69
P_{llmax}	0.1	ωP_{20}	0.78
P_{rated}	1.5	ωP_{40}	0.98
T_{fv}	0.15	ωP_{60}	1.12
K_{pv}	18	P_{min}	0.74
K_{IV}	5	ωP_{100}	1.2
X_c	0.05	VW	1.25
T_{FP}	0.05	H	4.95
K_{IP}	0.6	$DAMP$	0
P_{MX}	1.12	K_{aero}	0.007
P_{MN}	0.1	$Theta2$	21.98
Q_{MX}	0.296	H_{tfrac}	0.875
Q_{MN}	-0.436	$Freq_1$	1.8
IP_{MAX}	1.1	D_{shaft}	1.5
T_{RV}	0.05	T_p	0.3
RP_{MX}	0.45	K_{pp}	150
RP_{MN}	-0.45	K_{ip}	25
$T_{\_Power}$	5	K_{pc}	3
K_{qi}	0	K_{ic}	30
V_{MNCL}	0.9	$TetaMn$	0
V_{MXCL}	1.2	$TetaMx$	27
K_{qv}	40	$RTetaMx$	10
XIQ_{MN}	-0.5	P_{MX}	1
XIQ_{MX}	0.4		
J+27	0.05		