Dynamic Frequency Control with Increasing Wind Generation

Gillian Lalor, Julia Ritchie, Shane Rourke, Damian Flynn and Mark J. O'Malley

Abstract — **Frequency control is essential for the secure and stable operation of a power system. With wind penetration increasing rapidly in many power systems, ensuring continuous power system security is vital. The frequency response to a disturbance on the all Ireland system is simulated for a range of installed wind capacities under different system conditions. The purpose of this study is to assess the effects of increased wind generation on system frequency, and the security of the system following such disturbances.**

Index Terms — **Frequency control, power generation control, power system security, wind.**

I. Introduction

As concerns about the impact of conventional electricity generating technologies on the environment continue to grow, there is a trend towards deploying renewable sources of energy. Future targets for renewable energy generation have already been outlined in many countries. In the Republic of Ireland the EU target for renewable energy is 13.2% of electrical energy production by 2010, while the corresponding target for Northern Ireland is 10% [1]. Adoption of wind as a source of energy is well established and technological advances are continually increasing the flexibility and efficiency of wind generation. It is expected that up to 94% of the proposed renewable energy target in Ireland will be achieved using wind generation [2].

The electricity system on the island of Ireland is a small 50 Hz system, with a current peak load in the region of 6,000 MW. The system comprises two AC interconnected power systems, operated by Northern Ireland Electricity (NIE) and ESB National Grid (ESBNG). There is a DC interconnection between Northern Ireland and Scotland, which has a capacity of 500 MW. Due to the relatively small size of the system, frequency excursions are often sizeable and at present a frequency event is defined as a deviation of frequency below 49.5 Hz [3]. System inertia is vital in determining the rate of fall of frequency following such an event – the lower the inertia, the faster the system frequency will fall. Consequently, any reduction in inertial response could be critical following a significant frequency event on the system.

In general, wind turbine generators (WTGs) may be divided into two principal categories: fixed speed and variable speed. Fixed speed WTGs employ an induction generator to convert mechanical energy, generated by the wind turning the wind turbine rotor, into electrical energy. Frequency control and voltage support from such machines is difficult, and they do not provide these ancillary services as a general rule. However, due to the coupling between rotor speed and system frequency through the gearbox, the fixed speed WTG provides an inertial response when the system frequency falls. The magnitude of this response depends on the stored energy of the rotor, in addition to the rate of change of frequency.

There are two classes of variable speed wind turbines. The first is the direct drive wind turbine, which uses a synchronous generator to convert mechanical energy into electrical energy. A power electronics converter connects the stator to the grid, enabling variable speed operation. The second, and more common implementation is the doubly fed induction generator (DFIG). Again, attachment of a power electronics converter, this time to the rotor windings, allows variable speed operation. Variable speed WTGs offer improved ancillary service capabilities over fixed speed machines. One drawback of the effective decoupling of the rotor from the power system is that variable speed WTGs do not provide any inherent inertial response to changing system frequency. Recent studies, however, indicate that, with the addition of a supplementary control loop, it is possible for DFIGs to contribute to the system inertia. Since it is thought that no significant effect on wind turbine aerodynamics will result, it is possible that future installations of DFIGs will include this technology [4].

The availability of an inertial response from the wind turbines is a key factor in determining the effects that increasing wind generation will have on the system. At times of reasonably high wind speeds, or even lower wind speeds with large numbers of installed wind turbines, wind generation may displace conventional generation on the system. At present, there is an installed capacity approaching 270 MW of wind generation on the all Ireland electricity system, with connection agreements in the Republic of Ireland for a further 600 MW. In addition, 1000 MW is also currently planned in the near future on the combined Irish system. If

This work has been conducted in the Electricity Research Centre, University College Dublin, which is supported by the Electricity Supply Board (ESB), ESB National Grid, Commission for Energy Regulation (CER), Cylon Controls and Enterprise Ireland.

Gillian Lalor, Shane Rourke, and Mark J. O'Malley are with Electricity Research Centre, Department of Electronic and Electrical Engineering, University College Dublin, Belfield, Ireland. (e-mail: gill.lalor@ee.ucd.ie, shane.rourke@ee.ucd.ie, mark.omalley@ucd.ie).

Julia Ritchie and Damian Flynn are with the School of Electrical and Electronic Engineering, The Queen's University of Belfast, N. Ireland (e-mail: j.a.ritchie@qub.ac.uk, d.flynn@qub.ac.uk)

wind turbines provide no inertial response, the effect on system inertia would be increasingly detrimental as the proportion of wind increases. As a result, to ensure system reliability, wind could need to be curtailed. An alternative to curtailing wind would be the reduction in size of the largest infeed.

Due to the small size of many wind farms in relation to conventional plant, a large proportion of wind generation is connected as embedded generation at the distribution level in many power systems. However, larger wind farms, in particular offshore developments, may be connected to the transmission system. In the event of a fault on the network, leading to a potential islanding condition, loss-of-mains protection is a requirement for all embedded generation. Wind turbines currently installed on the all Ireland system apply either rate of change of frequency (ROCOF) protection or vector shift protection. Depending on the sensitivity of the protection equipment settings, however, sympathetic tripping of the wind turbines can occur during frequency events on the system. Clearly this poses serious security issues when the system is already attempting to recover from the initial event, especially if large amounts of wind generation are online.

For the above reasons, and recognition of further issues such as load regulation and fault ride through capability, the Transmission System Operator (TSO) in the Republic of Ireland has stated that the proposed levels of wind penetration pose an increased risk in terms of the stability, security and reliability of the all Ireland system. An immediate halt on the increase of wind generation connected to the system has recently been requested until its impact has been thoroughly assessed [5].

The objective of this work is to study the short-term dynamic effects of increasing wind penetration on system frequency control and the reliability of the system.

II. System Model

The electricity system model developed for this study represents an emergency reserve model of the Ireland electricity system. This model of the ESBNG and NIE systems reproduces the primary frequency response following a system event. It is a single busbar model, consisting of dynamic models for each generating unit and a representative dynamic load model. The simulated response is valid for 15-20 s following an event.

The conventional generating capacity of the combined system consists of a combination of thermal generators, gas turbines, hydroelectric generators, combined cycle gas turbines and a single pumped storage station. There is also a HVDC link between Northern Ireland and Scotland. The system is assumed to be in steady state at nominal frequency prior to an event on the system and the change in power output from each unit due to frequency disturbance is calculated in the model. It is possible therefore to neglect units that provide no reserve, with the exception of their contribution to the overall system inertial response.

The inertias of the individual units are combined together to form a single inertia term. This is achieved by summing the kinetic energies of the individual units along with the load to obtain a single kinetic energy value, which is then incorporated in the feedback loop to obtain the system frequency. This simplification is possible by assuming that the frequency at all points on the system is the same, and thus any change in kinetic energy will be felt uniformly throughout the network. The system frequency is calculated by integrating the power imbalance between the load and generation, while taking into account the system inertia.

An initial model of the ESBNG system [6, 7], representative of the small isolated electricity system of the Electricity Supply Board in the Republic of Ireland as it was in 1996, consisted of large thermal generators modelled using simple boiler and steam turbine models [8]. Validation was performed using system data from tests carried out and comparison with previous frequency events that occurred on the system. The pumped storage station at Turlough Hill, with its different operating modes, was also incorporated. Hydroelectric generating units were assumed to provide little or no reserve, due to their small size and the belief that the governors on these units usually operated at the fully open position when online. As such, they were neglected. A simple ramp based model was used to model the primary response of the gas turbine units. The system load was represented using a single model, accounting for the frequency sensitivity of the load. This load model was validated using measurement-based techniques with data from system tests.

A similar dynamic model of the NIE system, as it was circa 1986, developed in order to examine the system reliability and response of units to frequency events on the system was also available [9]. The system generation consisted of a combination of reheat and non-reheat thermal generators, which responded through governor action to any change in frequency.

The two models described above have been combined and updated to provide as accurate a reproduction of the entire Irish electricity system in 2003 as possible with the available knowledge and data. Since the development of the original models, new generating plant that has been introduced onto the system has been incorporated into the updated model and older decommissioned plant has been removed. The interconnector between Northern Ireland and the Republic of Ireland has returned to service and a DC interconnector now exists between Northern Ireland and Scotland.

A major addition to the model is the inclusion of a combined cycle gas turbine (CCGT) representation [10], which is based on existing gas turbine models [11, 12] with the addition of a heat recovery steam generator (HRSG) and steam turbine [13, 14, 15]. The steam turbine may be neglected in this case, apart from its contribution to the system inertia, by assuming that its response is negligible up to 20 seconds following a frequency event.

The developed frequency model of the all Ireland system is being used to study the impact of bringing new and diverse generation, such as wind, onto the Irish system. It is also currently being used in a study of the effects of combined cycle gas turbines on the dynamic response of the system following a frequency event [10].

III. Modelling Wind Generation

The majority of the installed WTGs on the Ireland system at present are of fixed speed technology. It is expected, however, that nearly all future installations will be of variable speed design. As previously outlined, the current technology for variable speed wind turbines means that these units make no contribution to the overall system inertia.

Two different wind models are used in this paper. One model contributes to the system inertia and the other provides no inertia.

It has been assumed in this study that wind turbines provide no reserve in response to changes in the system frequency. Although a mix of ROCOF and vector shift protection equipment is being used on the all Ireland system at present, their principle of operation is similar and, therefore, the model is equipped with ROCOF protection.

IV. Test System

The system model has been modified for the purpose of this study and represents the predicted systems for 2006 and 2009, including the additional generating capacity expected to come online. The model also takes into account the anticipated decommissioning of several units [2, 16]. These years are chosen for convenience, representing planning years in the most recent ESBNG forecast statement [2]. For each year, two extreme cases are considered: winter peak (predicted peak load for the year), and summer night valley (lowest annual load). The load and dispatch for each case were established based on available historical data, and forecasts from ESBNG [2]. In NIE the loads were assumed to be a scaled representation, based on historical relationships, of those on the ESBNG system.

The primary reserve requirement for the all Ireland electricity system is 80% of the largest infeed, which would be 400MW in the case of the winter peak load. The primary reserve requirement is divided between ESBNG and NIE, such that ESBNG provides 210 MW and NIE are responsible for 110 MW. During summer night valley, the largest infeed is limited to 320 MW, and the primary operating reserve requirement is reduced accordingly. During the summer night valley, the pumped storage station at Turlough Hill is pumping and provides a large proportion of the primary operating reserve.

For each year, the predicted level of wind capacity is considered, in conjunction with a base case of no wind generation. These projections are calculated to meet the national indicative targets set out by the EU for the contribution of electricity from renewable energy sources to gross electricity consumption by 2010 as listed earlier [1].

The system is assumed to be in steady state prior to a disturbance on the system. At 5 seconds, the largest infeed (400 MW or 320 MW) is tripped. For different levels of wind penetration, the frequency nadir and the maximum rate of change of frequency are calculated. The increase in primary operating reserve (reserve at frequency nadir) required to offset any increased drop in the system frequency is also calculated if the nadir is lower than in the base case with no wind. It is important to note, however, that as the system inertia is reduced, an increase in primary reserve can reduce the severity of the frequency excursion, but will have no beneficial effect on the rate at which the frequency falls immediately subsequent to the event.

V. Results

A selection of results from the 2009 scenario described in section IV is presented. Projected wind capacity on the 2009 system to meet the EU targets is 1,562 MW, apportioned as 1,200 MW on the ESBNG system, and 362 MW on the NIE system. For both the winter peak and summer night valley scenarios, all 1,562 MW of wind capacity is online, but the power produced by the wind turbines in each case may vary from 10 to 100%. For each scenario, a base case with no wind connected to the system is also included.

A. No inertial response from wind generation

Making the initial assumption that WTGs provide no inertial response, then as the amount of wind generation on the system increases (replacing conventional plant capable of providing an inertial response) the total system inertia will clearly decrease.

In Fig. 1, the impact of increasing the power produced by wind turbines on the system frequency during the 2009 winter peak load is shown. For the base case, when no power is being generated by wind, the frequency drops to a nadir of 49.41 Hz. As the power generated by wind increases to 100% of installed wind capacity, it can be seen that the frequency falls further. So, for example, at 50% of capability, the nadir is 49.39 Hz, while at 100%, the minimum frequency has fallen to 49.36 Hz.

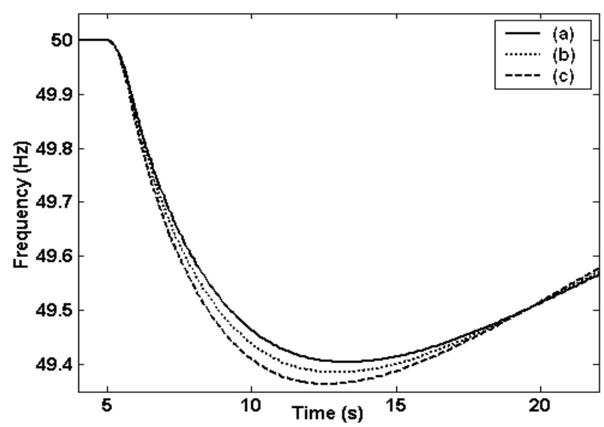

Fig. 1. System frequency following a 400 MW generation trip during the 2009 winter peak, with wind turbines providing no inertia: (a) No wind, (b) wind generating at 50% of installed wind capacity, and (c) wind at 100%.

The effect of reducing the system inertia due to increased wind generation is also apparent on examination of the initial rate at which the frequency falls following the generation trip. As the system inertia is reduced, the maximum rate of change of frequency increases from -0.20 Hz/s for no wind generation, to -0.24 Hz/s when wind is generating at 100% output.

The effect of a 320 MW generation trip on the system frequency during the summer night valley for the 2009 system is illustrated in Fig. 2. The installed wind capacity remains at 1,562 MW and again the wind is assumed to provide no inertia.

Due to the lower system demand during the summer night valley, the proposed level of installed wind in 2009 constitutes a much higher proportion of generation than during the winter peak. Consequently, the effect on the system frequency nadir and the rate at which the frequency falls is more evident.

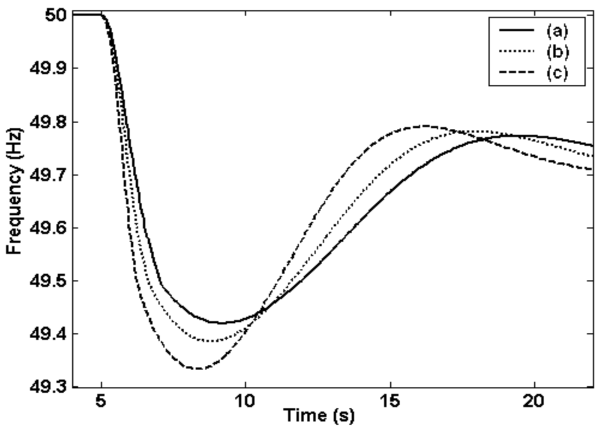

Fig. 2. System frequency following a 320 MW generation trip during the 2009 summer night valley, with wind turbines providing no inertia: (a) No wind, (b) wind generating at 50% of installed wind capacity, and (c) wind at 100%.

The frequency now falls to 49.42 Hz when no wind is generating. When wind is generating at 50% of installed capacity, the frequency nadir falls to 49.38 Hz. The minimum frequency of 49.33 Hz, which is 15% lower than in the base case, occurs when the power from installed wind capacity reaches 100%. This is a significant increase in the frequency deviation and may well cause serious concerns for the security of the system – load shedding on the Irish system begins at a frequency of 49.3 Hz.

The maximum rate of change of frequency for the 2009 summer night valley scenario varies between a minimum value of -0.34 Hz/s with no wind generation, to a maximum of -0.57 Hz/s when all the wind capacity is generating maximum output. As will be discussed later, typical ROCOF settings on the Irish system range between -0.4 and -0.5 Hz/s.

B. *Inertial response provided by wind generation*

Alternatively, it may be assumed that all wind turbines contribute to the system inertia - an inertial constant of 3.5 s as suggested in [17] is used. The results in the previous subsection suggest that problems with increased wind generation are likely to be discovered during periods of low, rather than high, demand. Consequently, the 2009 summer night valley scenario, with 1,562 MW of wind capacity, is illustrated in Fig. 3.

Now, when wind generation is connected to the system, the individual inertias of all the wind turbines contribute to the system inertia. Consequently, at low wind speeds, when wind turbines are operating at low power outputs, the system inertia increases above that for the base case, i.e. wind power displaces only a small proportion of conventional generation with its associated inertia, and yet contributes the full inertial response of the wind capacity. Therefore, when wind is producing 25% of the rated output, the system frequency nadir rises to 49.44 Hz, which is 3.5% above the base case of no wind. The frequency falls at a maximum rate of -0.3 Hz/s, 0.04 Hz/s slower than the base case. At a wind power contribution of 75% of installed wind capacity, the nadir has dropped below the base case minimum frequency, and reached 49.41 Hz. The maximum rate of frequency change has also increased by 8.8% to -0.37 Hz/s.

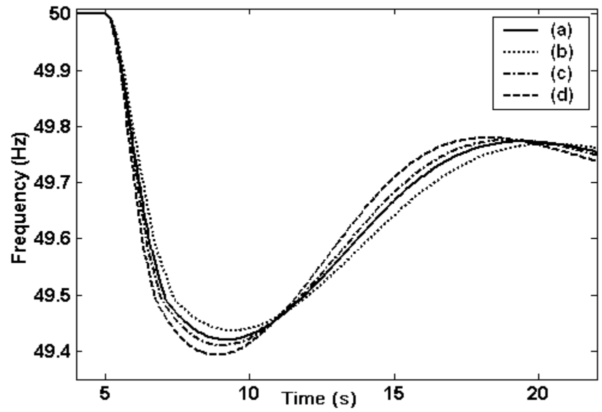

Fig. 3. System frequency following a 320 MW generation trip during the 2009 summer night valley, with wind turbines providing an inertial response: (a) No wind, (b) wind generating at 25% of installed wind capacity, (c) wind at 75%, and (d) wind at 100%.

C. *Scenario comparison and discussion*

The results of Fig. 1-3 demonstrate that increased wind penetration will impact on the frequency nadir and the initial rate of change of frequency. The difference between the two extremes of all, or none, of the turbines providing an inertial response is represented in Fig. 4.

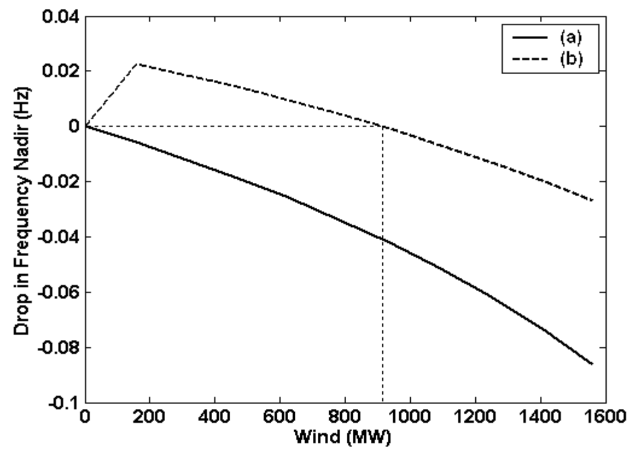

Fig. 4. Increased drop in frequency nadir as wind generation increases: (a) Wind with no inertia and (b) 1,562 MW wind capacity connected providing inertia.

In the case of wind turbines providing no inertia, any wind brought onto the system has a detrimental effect on the frequency nadir, and this effect will be proportional to the amount of wind power being generated. However, if the wind capacity is assumed to provide an inertial response, the system frequency benefits from the additional inertial contribution at low wind capacity factors. This benefit persists until the wind power produced by the installed wind capacity reaches 58.3% (910 MW). For increasing amounts of wind generation beyond this level, the frequency nadir deteriorates. The minimum frequency reached, however, at 100% wind generation is significantly less than when wind contributes to system inertia, with a drop in the frequency nadir of 0.027 Hz (5% below the base case), as compared with 0.087 Hz drop (15% below the base case) without inertial response.

A comparison of the initial rate of change of frequency with increasing wind power generated for the scenarios with, and without, an inertial response is shown in Fig. 5. When wind contributes to the system inertia, the maximum rate at which frequency falls is reduced below the base case for wind power generation levels below 910 MW. As such, for a wind capacity factor of up to 58.3%, the system response to a frequency event is at least equivalent to, if not better than, when no wind generation is online, both in terms of the minimum frequency reached and the maximum rate at which the frequency falls.

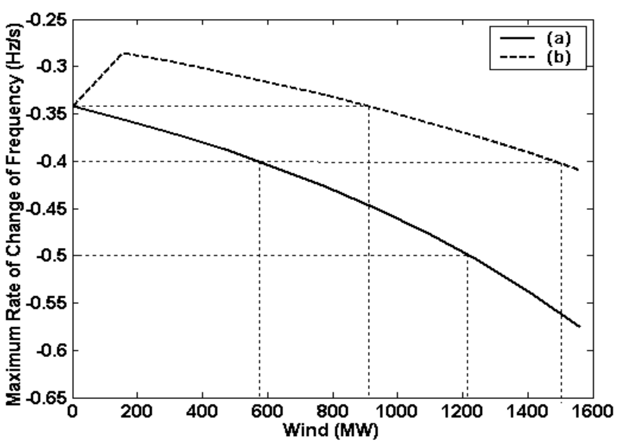

Fig. 5. Increase in rate of change of frequency as wind generation increases: (a) Wind with no inertia, (b) 1,562 MW wind capacity connected providing inertia.

If a ROCOF protection setting of -0.4 Hz/s is assumed for WTGs in the system model, it can be seen that with just 567 MW of wind generation (36.3% of the installed wind capacity) with no inertial response, the maximum rate of change of frequency reaches this limit. Any increase in wind generation beyond this level will cause all the wind generation to be tripped and the frequency to drop below 47 Hz – the minimum frequency for which all generation must remain synchronised to the system [3]. Such a scenario is represented in Fig. 6, with wind generation set at 40% of its capacity. This scenario does not recognize any load shedding that would, of course, occur.

The levels of wind generation considered are extremely probable, implying that wind may need to be curtailed during periods of low demand. If the ROCOF protection setting was increased to -0.5 Hz/s, a wind capacity factor of up to 78% can be tolerated before the ROCOF protection would be triggered in the summer night valley scenario. In contrast, if the wind turbines are assumed to contribute to the system inertia, an initial rate of change of frequency of -0.4 Hz/s is only reached for wind generating at 95% (1484 MW) of capacity. On this basis, the requirement for wind curtailment would be almost negligible.

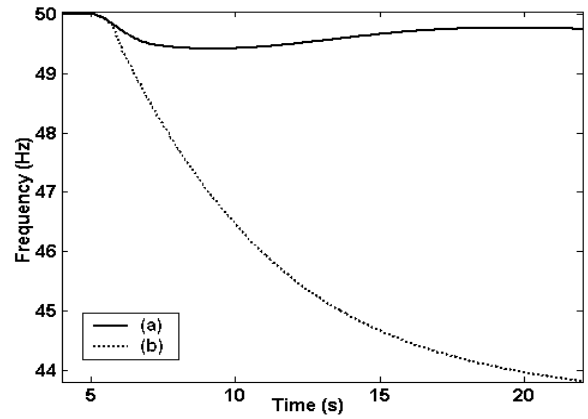

Fig. 6. System frequency following a 320 MW generation trip during the 2009 summer night valley, with wind turbines providing no inertia and ROCOF protection set at 0.4 Hz/s: (a) No wind, (b) wind generating at 40% of capacity.

At each level of wind generation, it is proposed that the frequency nadir should not be less than the base case (assuming no wind generation). This objective can be achieved by increasing the primary reserve on the system at each wind penetration level, as illustrated in Fig. 7.

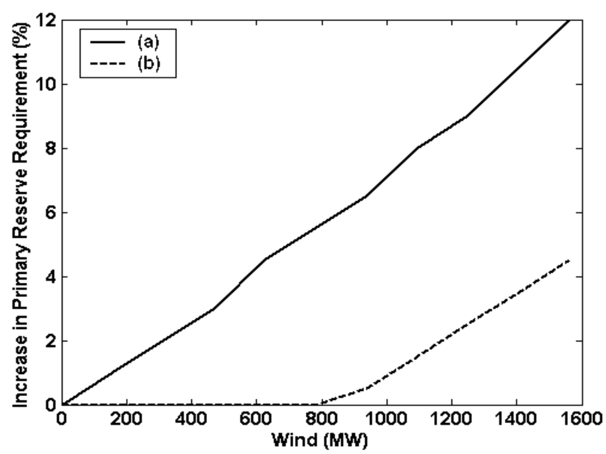

Fig. 7. Increase in primary reserve requirement as wind generation increases: (a) Wind with no inertia, (b) 1562 MW wind capacity connected providing inertia.

Considering first the case where wind provides no inertial contribution, the primary reserve required to return the minimum frequency to the base case increases with wind penetration levels, up to a maximum of 12% when all 1,562 MW of wind is generating at rated output. If wind is instead providing an inertial response, no additional reserve is required up to a capacity factor of 58.3% (from Fig. 4), with the requirement increasing up to a maximum of 4.5% at maximum power production.

VI. Conclusions

This study examines the impact on frequency control of increasing wind generation on the all Ireland electricity system. In particular, a likely representation of the generation system (conventional plant and wind turbines) for the 2009 system is considered.

Two extreme scenarios are examined, whereby all, or none, of the wind turbines provide an inertial response following a frequency transient. In practice, the truth will lie somewhere in between, whereby wind farms will be composed of a mixture of fixed speed and variable speed machines (some of which may incorporate an auxiliary 'inertial' feedback loop), along with any future technologies. If wind provides no inertia, times of low system demand may be problematic. If the installed wind capacity can contribute to system inertia, the adverse effect on system frequency is considerably mitigated. Although additional primary reserve will limit the observed frequency deviation, it will not impact on the initial rate of change of frequency. Additional inertia, such as flywheel technology, is required to reduce the initial rate of change of frequency. As a result, at high levels of wind generation, either the largest infeed needs to be reduced, wind generation needs to be curtailed, or wind turbines should be required to provide an inertial response.

VII. Acknowledgement

The authors gratefully acknowledge the useful discussions and interactions with colleagues in ESB, J. O'Sullivan, D. Barry (ESB National Grid), R. Doherty, E. Denny and A. Keane (ERC).

VIII. References

[1] Directive 2001/77/EC of the European Parliament and the Council of 27 September 2001 on the promotion of electricity produced from renewable energy sources in the internal electricity market, Official Journal of the European Communities, October 2001, L 283, pp. 33-40.
[2] ESB National Grid, "Forecast Statement 2003-2009", http://www.eirgrid.com/.
[3] ESB National Grid, "Grid Code", http://www.eirgrid.com/.
[4] Ekanayake, J.; Holdsworth, L.; Jenkins, N., "Control of DFIG wind turbines," *Power Engineering Journal*, Vol. 17, No. 1, Feb 2003, pp. 28-32.
[5] ESB National Grid Report, "Interim policy on wind connections," CER/03/282, http://www.cer.ie/.
[6] O'Sullivan, J.; O'Malley, M. J., "Identification and validation of dynamic global load model parameters for use in power system simulation," *IEEE Transactions on Power Systems*, Vol. 11, 1996, pp. 851-857.
[7] O'Sullivan, J.; Power, M.; Flynn, M.; O'Malley, M., "Modelling of frequency control in an island system," *Proceedings of IEEE Power Engineering Society 1999 Winter Meeting*, Vol. 1, pp. 574-579.
[8] IEEE Working Group on Prime Mover and Energy Supply Models for System Dynamic Performance, "Dynamic models for fossil fueled steam units in power system studies," *IEEE Transactions on Power Systems*, Vol. 6, No. 2, 1991, pp. 753-76.
[9] Thompson, J. G.; Fox, B., "Adaptive load shedding for isolated power systems," *IEE Proceedings on Generation, Transmission and Distribution*, 1994, Vol. 141, No. 5, pp. 491-496.
[10] Lalor, G.; O'Malley, M., "Frequency Control on an Island Power System with Increasing Proportions of Combined Cycle Gas Turbines," presented at IEEE Powertech Conference, Bologna, June 2003.
[11] Rowen, W.I., "Simplified mathematical representations of heavy-duty gas turbines", ASME, Vol. 105(1), (*Journal of Engineering for Power*, Series A, October 1983), pp. 865-869.
[12] Rowen, W.I., "Simplified mathematical representations of single shaft gas turbines in mechanical drive service", *Turbomachinery International*, July/August 1992, pp. 26-32.
[13] Bagnasco, A.; Delfino, B.; Denegri, G.B.; Massucco, S., "Management and dynamic performances of combined cycle power plants during parallel and islanding operation", *IEEE Transactions On Energy Conversion*, Vol. 13, No. 2, June 1998, pp. 194-201.
[14] Working Group on prime mover and energy supply models for system dynamic performance studies, "Dynamic models for combined cycle plants in power system studies", *IEEE Transactions on Power Systems*, Vol. 9, No. 3, August 1994, pp. 1698-1708.
[15] Zhang, Q; So, P.L., "Dynamic modelling of a combined cycle plant for power system stability studies", *Proceedings of IEEE Power Engineering Society Winter Meeting*, 2000, pp. 1538-1543.
[16] ESB National Grid, "Generation adequacy report 2003-2009", http://www.eirgrid.com/.
[17] Ekanayake, J.B.; Holdsworth, L.; Wu, X; Jenkins, N., Dynamic modelling of doubly fed induction generator wind turbines. *IEEE Transactions on Power Systems*, Vol. 18, No. 2, 2003, pp. 803-809.

IX. Biographies

Gillian Lalor received a B.E. degree in Mechanical Engineering from University College Dublin in 2001. She is currently conducting research for a Ph.D. at University College Dublin, with interests in power system modeling and control.

Julia Ritchie received a B.Eng degree in Electrical and Electronic Engineering from The Queen's University of Belfast in 2000. She is currently studying for a Ph.D. in the area of intelligent control and modelling of power plants and power systems at The Queen's University, Belfast.

Shane Rourke received his B.E. degree from the National University of Ireland in 1999. He has recently completed a M. Eng. Sc. in the Department of Electronic and Electrical Engineering, University College Dublin. His research interests are in power systems economics, operations and control.

Damian Flynn is a lecturer in Power Engineering at The Queen's University of Belfast. His research interests involve an investigation of the effects of embedded generation sources, especially renewables, on the operation of power systems. He is also interested in advanced modelling and control techniques applied to power plant. He is a member of the IEEE

Mark O'Malley received B.E. and Ph.D. degrees from University College Dublin in 1983 and 1987, respectively. He is currently a Professor in University College Dublin with research interests in power systems, control theory and biomedical engineering. He is a senior member of the IEEE.