

Impact of Voltage Dip Induced Delayed Active Power Recovery on Wind Integrated Power Systems

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Abstract: Installed wind power capacity is increasing rapidly in many power systems around the world, with challenging penetration targets set at national, and/or regional level. Wind power, particularly at higher penetration levels, introduces various grid issues, with frequency and voltage stability being particularly critical concerns. Voltage dip induced frequency stability following a network fault in such systems is one potential risk that has so far received limited attention by the research community. With state of the art modelling, the potential impact of a delayed active power recovery from wind generation following a network fault induced voltage dip is investigated. The subsequent voltage oscillations introduced by wind turbines, exacerbating frequency stability, are also examined. Analysis is carried out for a wide range of wind penetration levels and system scenarios, with the results demonstrated on the New England benchmark system.

Keywords: Power System Dynamics, Wind Power Generation, Wind Generator Modelling

NOMENCLATURE

			integral term
CHP	Combined heat and power plant	u_{ref0}	User defined bias in voltage reference
PCC	Point of common coupling	u_{qdip}	Voltage threshold for LVRT detection in q control
RoCoF	Rate of change of frequency		
TSO	Transmission system operator	T_{qord}	Time constant for reactive power order lag
LVRT	Low voltage ride-through	T_{post}	Time duration when post-fault reactive power is injected
WF	Wind farm		
WT	Wind turbine	i_{pmax}	Maximum active current injection
WTT	WT terminal	i_{qmax}	Maximum reactive current injection
F_{UVRT}	Under voltage ride-through flag	i_{qmin}	Minimum reactive current injection
$T_{u\text{filt}q}$	Voltage measurement filter time constant	i_{qh1}	Maximum reactive current injection during dip
$T_{p\text{filt}q}$	Power measurement filter time constant	i_{qpost}	Post-fault reactive current injection
K_{Pq}	Reactive power PI controller proportional gain	i_{pcmd}	Active current command to generator system
K_{iq}	Reactive power PI controller integrator gain	i_{qcmd}	Reactive current command to generator system
K_{Pu}	Voltage PI controller proportional gain	p_{WT}	WTT active power generation
K_{iu}	Voltage PI controller integrator gain	q_{WT}	WTT reactive power generation
u_{db1}	Voltage deadband lower limit	q_{WTmax}	Maximum WTT reactive power
u_{db2}	Voltage deadband upper limit	q_{WTmin}	Minimum WTT reactive power
K_{qv}	Voltage scaling factor for LVRT current	u_{WT}	WTT voltage
u_{max}	Maximum voltage for voltage PI controller integral term	x_{WTref}	WTT reactive power reference, or delta voltage reference, depending on WT control mode
u_{min}	Minimum voltage for voltage PI controller		

1. INTRODUCTION

The last decade has witnessed a significant increase in wind power integration, with ambitious goals set at regional and national level. Currently, global installed wind power capacity has reached 433 GW, with 63 GW added in 2015 alone (GWEC, 2016). The trend of increasing wind power integration is likely to continue into the future, underscoring the need to investigate and understand the impact that wind power has on the secure and reliable operation of such systems. Due to its time-varying nature, limited predictability and controllability, wind generation integration poses a wide spectrum of challenges (Flynn et al., 2016), ranging from short-term frequency deviations (Ilic et al., 2007), dynamic voltage stability (Rather et al., 2014), small signal stability (Mendonca and Lopes, 2005), inertial and rate of change of frequency (RoCoF) issues (O'Sullivan et al., 2014; Rutledge et al., 2012), voltage control challenges (Rather, et al., 2013) to long-term generation-load balancing (Aigner et al., 2012), steady-state voltage control and stability issues (Ma et al., 2010). Further, the impact of such issues of concern for a particular system will depend on system size, wind penetration level, system network configuration, along with the unit commitment / economic dispatch (UC/ED) schedule. Typically, such impacts will be more evident during the night valley/seasonal low-demand periods when instantaneous wind penetration may be significantly high (Fox et al., 2014). Higher penetration levels leading to the displacement of conventional generation, is likely to result in reduced governor response and lower synchronous inertia (Dangelmaier et al., 2011; Pelletier et al., 2012; Rutledge and Flynn, 2015; Sharma et al., 2011), which is in turn likely to reduce frequency stability (Miller et al., 2011; Ela et al., 2013). Furthermore, with older wind turbine technology (type 1 and type 2) their reactive power consumption is related to their real power output, particularly during voltage dips when reactive power absorption by such wind turbines increases sharply, affecting the system dynamics. Transpower (New Zealand) observed that such old technology (fixed speed) wind turbines can reduce the transient stability of the system and generally do not comply with voltage ride through grid code regulations (Transpower, 2008).

Renewable-driven displacement of conventional power plant is leading to diminishing sources of online flexibility / ancillary services, required to maintain secure and stable system operation. Therefore, in order to accommodate higher wind targets, transmission system operators (TSOs), government agencies and other associated regulatory authorities are endeavouring to tackle such issues through updated / more stringent grid codes (Mohseni and Islam, 2012) and / or by considering alternative sources of flexibility / ancillary services, procured either through electricity market arrangements or by installing their own infrastructure (Rather et al., 2013; Abildgaard et al., 2015). More stringent grid codes have, in fact, become one of the major drivers for the development of wind generation technology (Tsili and Papathanassiou, 2009). However, wind turbine technology has considerable implications for system dynamics, primarily due to the decoupling of the rotating mass of variable speed wind turbines (type-3 and type-4) from the electrical grid

(Lalor et al., 2005; Morren et al., 2006). Diminishing online rotational inertia due to displaced conventional power plant, coupled with power electronic interfaced wind turbine technology, has a negative impact on system frequency stability, with implications being more prominent in smaller and isolated grids. Due to diminished inertia, the resulting high rate of change of frequency may result in anti-islanding RoCoF (rate of change of frequency) protection to malfunction, which may result in further frequency variation (Beddoes, 2005).

Wind-driven displacement of conventional power plant, particularly at higher penetration levels is also likely to reduce the net system dynamic reactive power and short-circuit power capacity, required to maintain adequate voltage stability (EirGrid, 2015; Rather et al., 2012). A study on the New Zealand system reported that wind generation, particularly when connected at distribution system has resulted in reduced voltage stability by 10-34% (Transpower, 2007). A similar case study carried out on the projected 2030 Danish power system concluded that at higher penetration levels with conventional power plant displaced by grid code compliant wind turbines, and without considering any new reactive power compensating devices (synchronous condensers, SVCs, etc.), that system stability would be significantly compromised (Rather et al., 2015). The study reported that old technology fixed speed wind turbines deteriorated system stability due to under voltage protection during the LVRT period.

In addition to prominent and widely documented issues associated with wind integration, one particular limitation of wind turbine technology is their delayed active power recovery following significant voltage dips, unlike that seen for a conventional power plant where the active power recovery is relatively fast, in the order of milliseconds. The extent of the active power recovery delay from a wind turbine will depend on the severity and location of the fault (Tsili and Papathanassiou, 2009; Mohamed et al., 2011; John, 2014), with the impact potentially critical for both frequency and dynamic voltage stability. A severe short circuit fault, resulting in a widespread voltage dip in a region hosting substantial wind capacity, may result in a temporary reduction in active power output, which in some cases may exceed the size of the largest infeed, and hence the allocated primary reserve (Rather and Flynn, 2015). Subsequently, the resulting frequency nadir (minimum frequency observed following a disturbance) may breach acceptable limits, leading to underfrequency load shedding, possible outage of wind generators (especially fixed speed wind turbines experiencing a delayed voltage recovery) and, in the worst case, may lead to cascading events resulting in system collapse.

In contrast to the above concerns, the LVRT capability of wind turbine technology has remained a major focus of grid code regulations, ensuring that wind generators not only successfully ride through a fault, but also support the grid during the course of the event (Mohseni and Islam, 2012). However, it is important to observe that due to technology limitations, LVRT capability, as required by grid code regulations, is not equivalent to conventional synchronous

generators that can inject short circuit currents as high as 5-7 times rated values. Therefore, following a short circuit fault, and depending on the (local) voltage recovery profile while adhering to the grid code, the delayed active power recovery, due to physical limitations on the mechanical side of the turbine, may be exacerbated due to a delayed voltage recovery in the fault affected region.

Furthermore, wind turbines are susceptible to eigenswings, particularly due to torsional swings in the shaft (Akhmatov et al., 2000), and these eigenswings are reflected in the terminal voltage and power output. Therefore, fault-induced torsional oscillations introduced in the electrical power output, with a frequency close to the power oscillations (≈ 1 Hz), may consequently impact system stability further. In such cases, especially at higher wind penetration levels, a short circuit fault, followed by a delayed active power recovery, could lead to severe power and voltage oscillations.

Due to the above limitation of a delayed active power recovery in wind turbines, wind integration potentially introduces a new complex coupling between voltage and frequency dynamics in wind integrated systems. A limited number of studies investigating such issues have been reported in the literature: EirGrid is planning to introduce a new ancillary service product ‘fast post-fault active power recovery service’ to mitigate the impact of such an issue, whereby participating units are rewarded for providing a fast responding service (EirGrid, 2014). Rather and Flynn (2015) examined the impact of a delayed voltage recovery from wind turbines, although, in this study, all the wind farms were based on type-3 wind turbines, while limiting wind penetration to 50%. The main contributions of this paper are i) a detailed study of the emerging challenge of ‘voltage dip induced delayed active power recovery’ and its impact on frequency stability in wind integrated systems, while considering both (type-3 and type-4) variable speed wind turbines/farms and penetration levels higher than 50%, thus providing a deep insight of how, and to what extent, this new challenge can impact system frequency stability, ii) potential impacts of voltage dip induced frequency stability and delayed active power recovery on induced power oscillations, demonstrating that at higher penetration levels, such induced power oscillations can further deteriorate system stability, and may subsequently lead to system collapse in the worst cases, if countermeasures are not in place, and iii) highlighting the need for grid codes to revisit active and reactive power priorities during the LVRT period. In addition, this paper incorporates a significant focus on state of the art modelling and different control strategies in practice by the wind industry. Various control models, including active power, reactive power, current and voltage control models, are discussed in detail. Reactive power control strategies that can be adopted to address (sometimes) conflicting LVRT grid code requirements, such as the priority given to reactive or active current injection during a voltage event, have been implemented in WPPs. Additionally, the work presented also includes small signal stability analysis.

The research work is based upon a detailed dynamic network model of the New England system, developed in the DigSILENT PowerFactory environment, and considering a

wide range of wind penetration levels. The remainder of the paper is organised as follows. Section 2 describes the modelling aspects of the adopted test system and the wind farm controls. The study methodology adopted is described in Section 3, while results, along with a discussion, are presented in Section 4, followed by concluding remarks in Section 5.

2. WIND FARM MODELLING

Wind generation technology has evolved over the past few decades, partially driven by stricter grid code regulations. At present, variable speed wind turbines (type-3 and type-4 turbine technology) hold the majority market share amongst the various available wind turbine technologies, and they are expected to maintain this dominance into the future. Reflecting the state of the art technology, the IEC 61400-27-1 standard wind turbine model (IEC 61400-27-1, 2015) is adopted here to represent an aggregate wind farm. The associated control model, shown in Figs. 1 and 2 for type-4 and type-3 wind turbines respectively, includes outer (slow) active and reactive power control loops, and inner (fast) current control loops. The input signals for the active power controller include the reference active power command (p_{WTref}), generator rotor angular speed (ω_{gen}), and the voltage (u_{WT}) measured at the wind turbine terminals, and a feedback measure of the maximum active current command (i_{pmax}). The active power controller generates an active current command (i_{pcmd}) for the generator system, and an aerodynamic power signal (p_{aero}) in type-4 wind turbines, while for type-3 technology, in addition to i_{pcmd} the active power controller also generates a power order command (P_{ord}) for the pitch controller.

The reactive power controller, as shown in Fig. 3, is one of the more critical controllers in a wind turbine, as it plays the dominant role in ensuring grid code LVRT regulation. The reactive power control loop consists of different operating modes during normal operation, such as voltage control ($M_{qG} = 0$), reactive current power control ($M_{qG} = 1$), open loop reactive power control ($M_{qG} = 2$), power factor control ($M_{qG} = 3$), and open loop power factor control ($M_{qG} = 4$). During a fault, detected by the ‘fault detection block’, three different LVRT reactive power control modes are supported, if reactive current injection is to be prioritised over active current injection: voltage dependent reactive current injection ($M_{qLVRT} = 0$), reactive current injection as the summation of the pre-fault value and a voltage dependent reactive current injection value ($M_{qLVRT} = 1$), and reactive current injection controlled as the summation of the pre-fault value, a voltage dependent reactive current injection, and an additional constant reactive current injection to boost voltage recovery ($M_{qLVRT} = 2$). Although grid code regulations in the majority of countries require *reactive* current injection priority during fault events, some countries, such as Ireland, require *active* current injection priority. The LVRT signal (F_{LVRT}) is generated by a fault detection block, which then locks the state of the low order filter, the pre-fault reactive current injection and the limiter states of the various control blocks. Further, as the voltage is measured at the WTT, while the

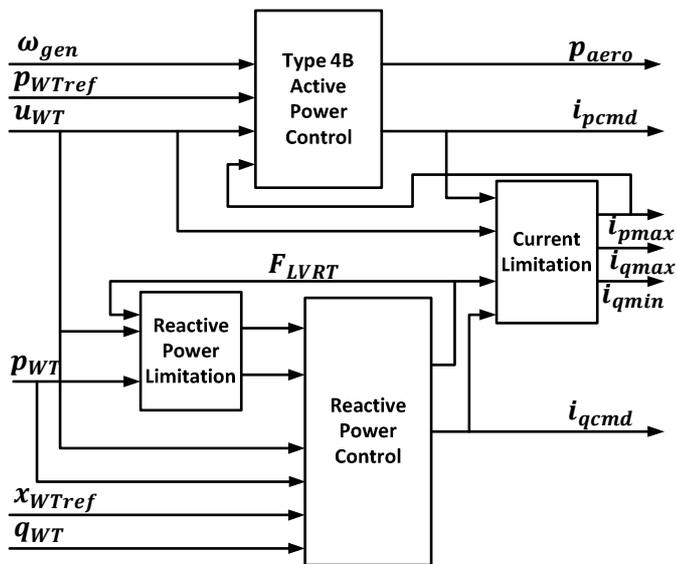


Fig. 1 Type 4B wind turbine control model

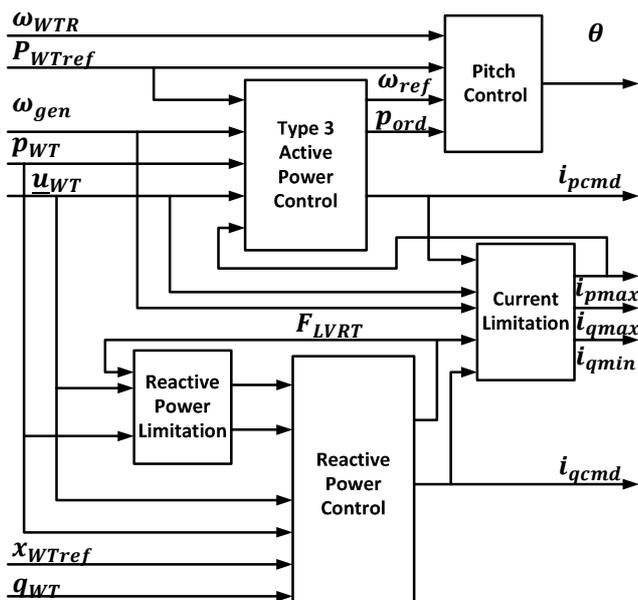


Fig. 2 Type 3 wind turbine control model

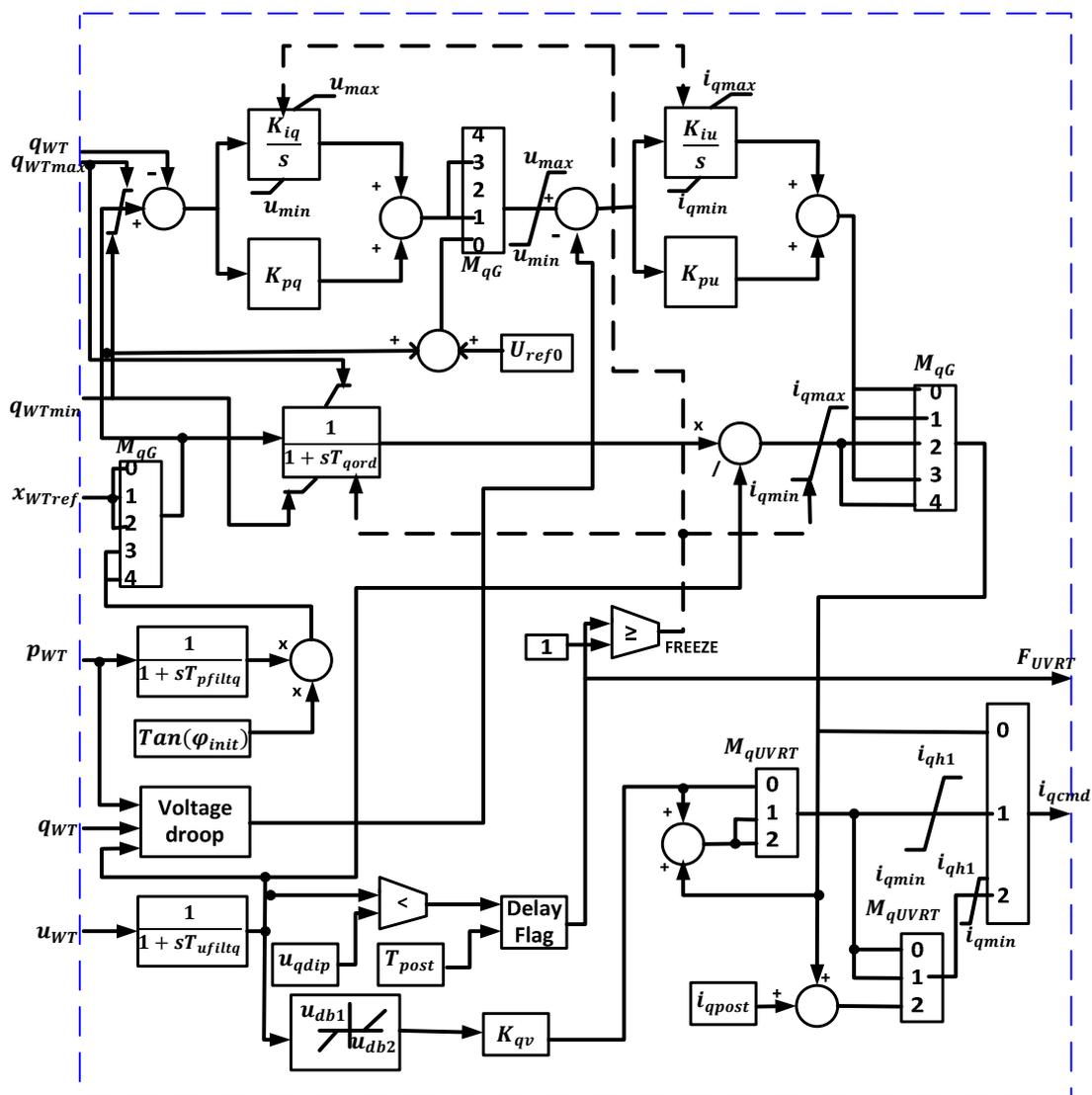


Fig. 3 Reactive power controller

target is actually the PCC voltage, separated from the WTT by some impedance (mainly that of the transformer), the voltage droop block calculates the PCC voltage, u , as given below:

$$u = \sqrt{\left(u_{WT} - r_{drop} \frac{p_{WT}}{u_{WT}} - x_{drop} \frac{p_{WT}}{u_{WT}}\right)^2 + \left(x_{drop} \frac{p_{WT}}{u_{WT}} - r_{drop} \frac{q_{WT}}{u_{WT}}\right)^2}$$

where, r_{drop} and x_{drop} are the real and imaginary components of the voltage drop impedance.

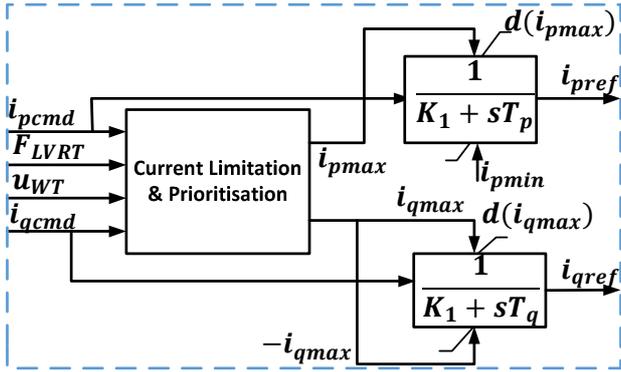


Fig. 4 Current limitation and prioritisation

Limiting the converter currents and prioritisation of active and reactive current injection during normal operation and voltage dips is implemented as shown in Fig. 4, which largely determines the wind turbine response, particularly the prioritisation of active and reactive currents during a LVRT event. Depending on the priority given to active or reactive current, the maximum current limit commands (i_{pmax} , i_{qmax} and i_{min}) are continuously updated and sent to the generator system to ensure that the active and reactive current reference signals are implemented as required by grid code regulations and within maximum limits. This control block also implements the voltage dependency of the active and reactive current limits, which is realised through a lookup table. The aerodynamic system is implemented through a two-dimensional model, where, in addition to pitch angle, the wind speed is also supplied as an input signal. Furthermore, the wind turbine shaft is modelled as a two mass system.

In order to accommodate wind generation in a secure and stable manner, grid code regulations for wind generators are being regularly upgraded, with the LVRT capability of wind turbines being an important focus. The LVRT capability required from wind turbines in a number of different countries is shown in Fig. 5. During the LVRT period, most countries require wind turbines to maximise reactive current injection (within the maximum allowed limit) to control the voltage, although EirGrid's (Ireland) grid code regulation instead demands that active power output should be at least proportional to the terminal voltage, while reactive power injection should be maximised within the remaining margin of the capability limit, to control the local voltage. Due to the fact that Ireland is a synchronously isolated system, and at times wind generation has contributed up to 65% of the

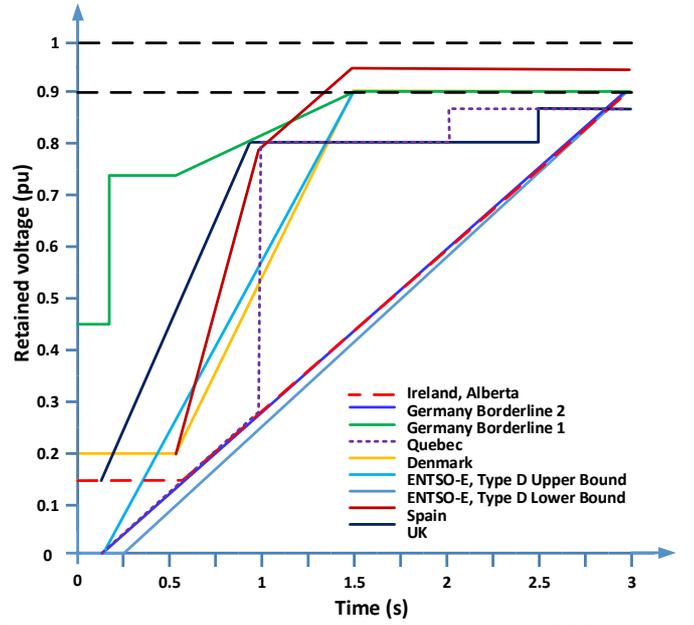


Fig. 5 Low voltage-ride through requirement from WPPs

instantaneous demand, the active power output from each wind power plant (WPP) is prioritised over reactive power injection during voltage dips, in order to minimise the impact of a generation shortfall during the LVRT period (EirGrid, 2013). In order to mitigate various issues introduced by higher penetrations of non-synchronous generation, EirGrid is planning to introduce a set of new ancillary service products, including a post-fault active power recovery service whereby participating units are rewarded for providing a fast responding service (EirGrid, 2014).

3. CASE STUDY AND METHODOLOGY

The 39 bus, 10 machine New England benchmark, representing the New England area of the USA, is considered as the test system (IEEE TF, 2013). The generator at bus 39 represents the rest of the interconnected system in the USA and Canada, while all other generators are connected to the transmission system through step-up transformers. All generators, modelled as 6th order synchronous machines, are equipped with, automatic voltage regulators (AVR), modelled with IEEE type-2 excitation systems (IEEE Std 421.5, 2006), governor controls, modelled as IEEE type-1 speed-governing models (IEEE PES TR1, 2013), and generic power system stabiliser (PSS) models. The developed model has been validated against an IEEE task force report on benchmark systems (IEEE TF, 2013).

The New England system is modified here by integrating seven grid code compliant (EirGrid, 2013) wind farms, including WF1-WF5 (480 MW each), and WF6, WF7 (640 MW), connected at buses 21, 36, 19, 35, 20, 30, 23 and 33 respectively, while displacing conventional generators Gen 3, 4 and 6, each of 850 MW capacity.

WF1, WF5 and WF6 are type-3 wind turbines, while the remaining wind farms are modelled as type-4 wind turbines. Wind farm placement was based upon voltage sensitivity analysis and existing transmission network constraints. In

addition, frequency dependent data taken from IEEE TF (2013) has been modified to a 50 Hz base. The modified wind integrated 42-bus, 14 power plant system is shown in Fig. 6. During normal operation, wind turbines are operated in voltage control mode ($M_{qG} = 0$), while during a fault, reactive power control mode is activated ($M_{qLVRT} = 1$), whereby reactive current injection from a wind turbine is the summation of the pre-fault value and a voltage dependent reactive current. However, irrespective of the reactive power control mode during a voltage dip, the active current injection is prioritised over reactive current injection as required by the Irish grid code.

In order to investigate the impact of a delayed active power recovery following a network fault, a range of representative wind penetration cases (0, 20, 40, 50 and 60%, with respect to system demand) have been considered. Since the study scope emphasises dynamic performance during a relatively short timeframe (<10 seconds), only primary reserve, realised through governor droop control on conventional generators, has been considered, while slower-acting secondary and tertiary reserves have not been represented. The system

demand represented by peak, average and off-peak values, along with the above mentioned wind generation mix, is considered to represent various possible operating conditions. Further, unless mentioned otherwise, the considered fault is a three-phase fault of 150 ms duration applied at bus 33, which, based on voltage sensitivity analysis, is found to be one of the weaker buses, as can be observed from the voltage heat map shown in Fig. 7 for a three-phase fault applied at that bus. The voltage heat map also shows that a fault at bus 33 is one of the more severe faults, as it results in a significant voltage drop in the nearby region.

In order to assess the impact of a delayed active power recovery from wind generation on the system frequency, the underlying grid frequency (Kundur, 1994) is evaluated for the above stated representative wind penetration cases. It is to be noted that during system transients, the frequency does not remain as a global parameter, but rather the local frequency, particularly close to the event, varies with respect to the rest of the system. Therefore, henceforth, the frequency shown here is the underlying (centroid) grid frequency unless mentioned otherwise. It is important to note that the local frequency close to the fault location is likely to be more affected due to the relatively high impact of the voltage dip.

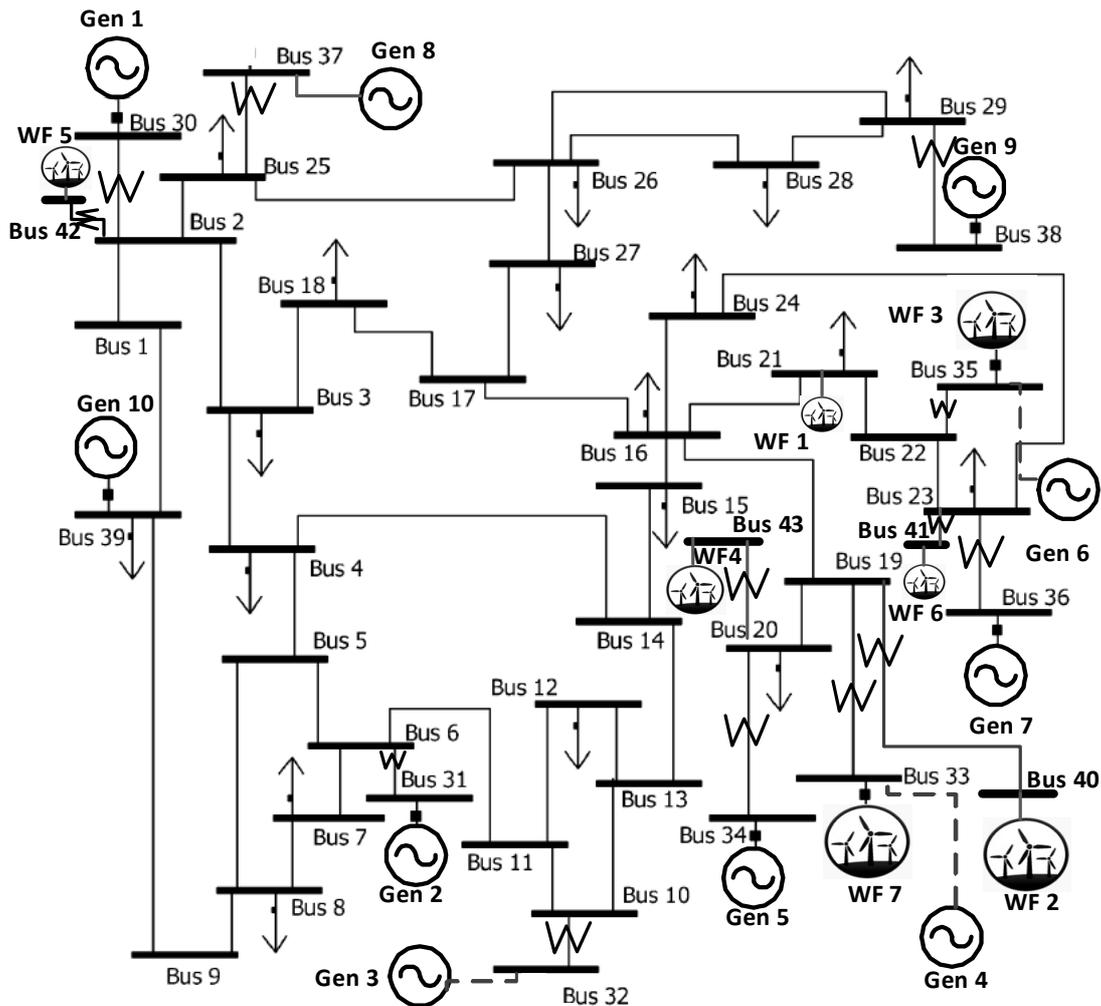


Fig. 6 Wind Integrated New England system

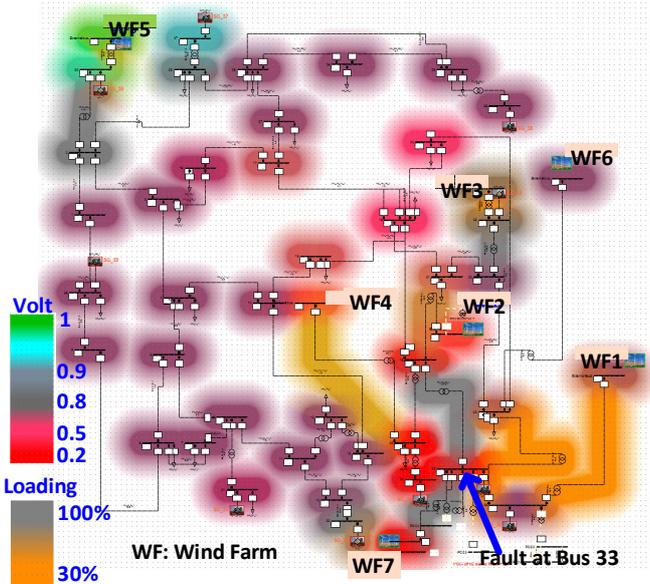


Fig. 7 Voltage heat map for a three-phase fault at bus 33 in wind Integrated New England system

4. RESULTS AND DISCUSSION

4.1 Impact of Delayed Active Power Recovery

Five representative wind penetration levels, as outlined in Section 3, with a peak load of 6000 MW and a three-phase fault duration of 150 ms applied at bus 33, were simulated. Fig. 8 shows the voltage at bus 33 and the aggregate wind power generation for each considered wind penetration level, with all turbines being grid code compliant. The maximum temporary wind power reduction (following fault clearance) for the four wind cases (20-60%) is 600, 850, 1250 and 1850 MW respectively, while the corresponding frequency profiles are shown in Fig. 9. For the 60% wind penetration level, a temporary power reduction of up to 52% from the pre-fault value can be observed, Fig. 8, although even this figure could be higher depending on the location of the wind farms (proximity to the fault location), the depth of the voltage sag and the wind generation level. For higher penetration levels, particularly at 50% and 60%, the maximum wind power reduction exceeds the scheduled primary reserve (although the disturbance is temporary), thus resulting in a steep fall in the system frequency, Fig. 9. Such occurrences, in some cases, could also result in RoCoF values exceeding the protection threshold limits, thus invoking tripping of distributed wind generation. Consequently, system re-dispatch may be required in light of such events. It should be further noted that under-frequency load shedding is not considered here, in order to explore the full impact of the delayed active power recovery. The results also suggest that at lower penetration levels the impact of a fault-induced delayed active power recovery is of less concern, given the lower wind power share and the correspondingly lower value for the maximum temporary power loss. However, at higher wind penetration levels, the temporary generation shortfall (for ≈ 1 s duration here) can be significantly higher, depending on the severity of the voltage dip, the wind power generation level and the aggregate capacity of wind turbines located in the fault affected region.

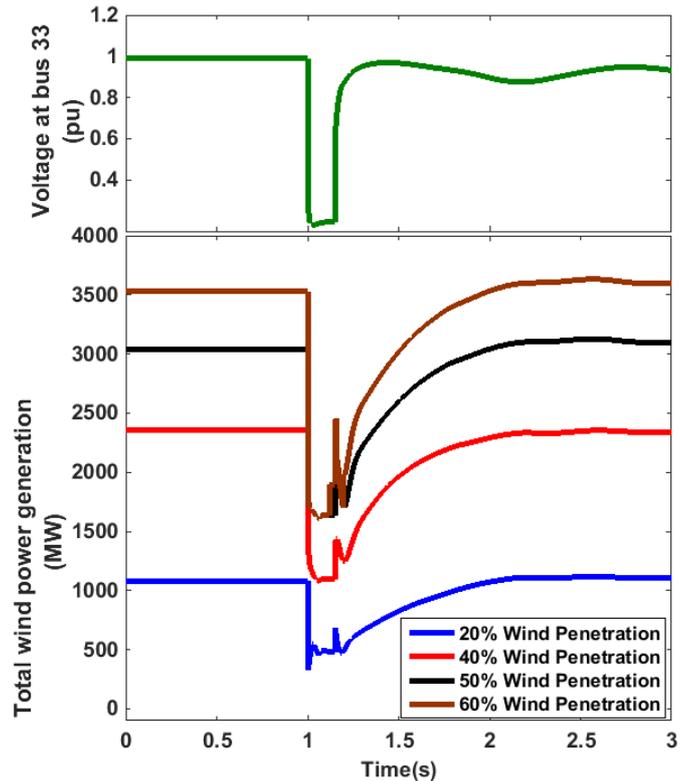


Fig. 8 Total wind power generation with three-phase short circuit fault at bus 33.

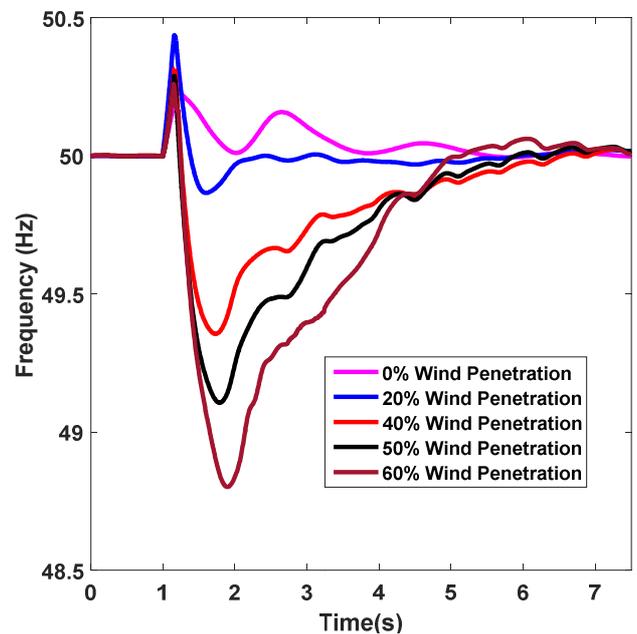


Fig. 9 Frequency response to three-phase fault at bus 33 applied at $t = 1$ s

The reactive power contribution from wind farms is, as per the implemented grid code regulations (EirGrid, 2015), such that active power is contributed in proportion to the voltage observed at the WT terminals during a voltage dip. Fig. 10 shows the voltage at bus 19, the active (direct axis) and reactive (quadrature axis) current, and the reactive power contribution of the wind farm (WF3) connected to the bus. It

is also important to note that the delay in the active power recovery following a voltage dip will be greatly influenced by the active power control mode of the wind turbines. For high wind speeds, when pitch control is activated, the delay in the active power recovery is likely to be greater, as a sudden reduction in active power output, due to a low terminal voltage during the fault, will be counteracted by a reduction in the mechanical power input through a significant change in pitch angle, further delaying the active power recovery to pre-event levels following fault clearance. Therefore, during periods of high wind speed, a delayed active power recovery following a widely seen (fault-induced) voltage dip, particularly in a region with densely clustered wind farms, may have major implications on system operation. Fig. 11 shows the maximum observed wind power reduction for three-phase faults applied at all buses in turn, under different wind penetration levels (20, 40, 50 and 60%) and load scenarios (off-peak, average and peak demand). It can be observed that the wind power dip leading to the power imbalance depends on the operating condition, i.e. demand level and wind penetration level. For a given demand level, the maximum wind power reduction increases with higher penetration levels, which is unsurprising and expected. Further, as the demand increases, the wind power reduction due to a delayed active power recovery also increases due to i) an increased wind generation level, which has been defined here with respect to the system demand (%), and, ii) the system being more stressed at higher demand levels, and the impact of the fault on voltage dips being relatively more severe. Moreover, at higher wind penetration levels, due to fewer committed online conventional plant, the system inertia is expected to be low, rendering the system more vulnerable to a significant frequency nadir due to a temporary wind power reduction. Consequently, the implications of a temporary wind power reduction following a voltage dip are likely to be more severe on isolated systems, as their system inertia is relatively low, and they do not receive fast frequency support from external grids, as would be the case for interconnected systems.

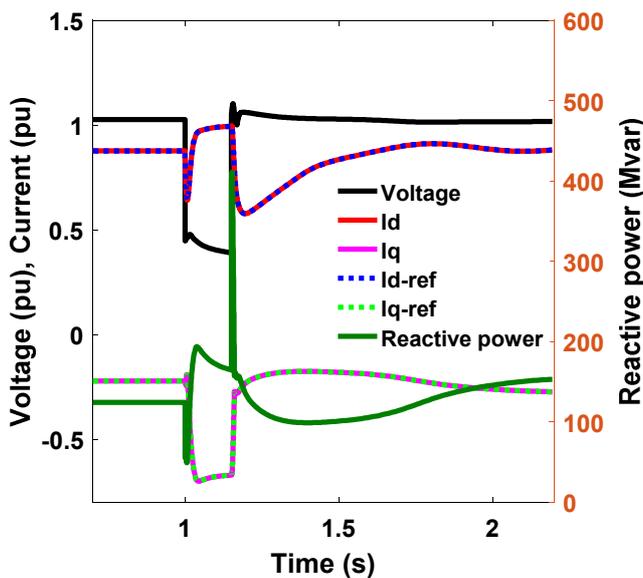


Fig. 10 Reactive and active power/current contribution of WF3

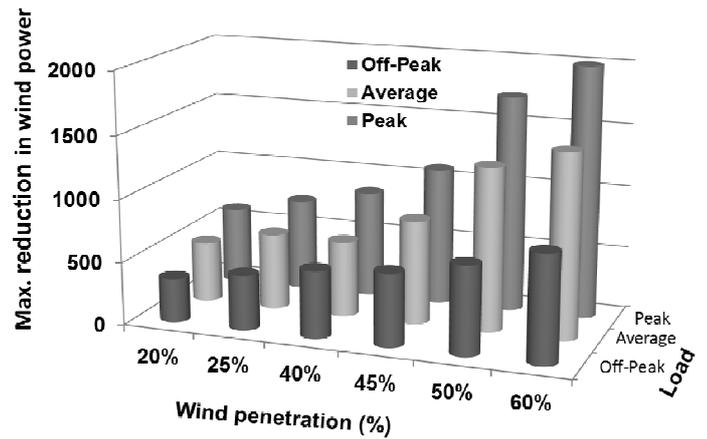


Fig. 11 Maximum instantaneous wind power reduction following three-phase short circuit faults for different load conditions

4.2 Delayed Active Power Recovery following a Generation Outage

Although any reduction in wind power output due to a delayed active power recovery is generally expected to be temporary, the tripping of some generation units, particularly wind generators due to voltage and frequency variations exceeding protection threshold values, may occur in worst case scenarios. With increasing wind penetration, the primary source of dynamic reactive power and short circuit power (conventional power plant) will diminish, with only a reduced number of such plant (primarily required to maintain secure operation) expected to be in operation. In contrast, wind generation technology is more sensitive to voltage variations and they offer comparatively less dynamic reactive power and short circuit power support to the grid, particularly given that they may be connected to the distribution, rather than transmission, network. Therefore, in such cases, a potential dynamic voltage event with a delayed voltage recovery may lead to the following outages: i) old fixed speed technology turbines, with low control flexibility, that generally absorb reactive power during voltage dips, and are permitted to have simple on/off operation, ii) a WPP, if a fault at the point of common coupling (PCC) is cleared by opening a line connecting the WPP to the rest of the grid (a recent example being the outage of the 400 MW Anholt wind farm in Denmark (Energinet.dk, 2015)) and iii) other distributed generation technology, such as distributed combined heat and power plant (CHP), that are allowed to disconnect from the grid following a potential voltage dip (Rather *et al.*, 2014). Therefore, in such scenarios, a delay in the active power recovery, aggravated by a delayed voltage recovery and coupled with a generation outage(s), can be more detrimental to system operation, which may then lead to under-frequency load shedding, or even more severe scenarios.

An example case, where a three-phase fault at bus 33 is cleared after 150 ms by opening a line (connecting to bus 19), resulting in the loss of ≈ 200 MW wind generation capacity, is simulated and the results are shown in Fig. 12. The delayed active power recovery accompanied by the wind generation outage (case II) exacerbates the original power imbalance (1300 MW in Case I) to 1400 MW, and hence the depth of

the frequency excursion. It is important to note that for the specified outage of 200 MW capacity of WF/WTs, the actual outage at the instant of maximum power reduction will be less than 200 MW (≈ 100 MW in this case), as the corresponding wind turbines will be operating at reduced output due to the severe voltage dip at their terminals. Case I considers only a delayed active power recovery without any generator outage. The frequency in Case II is restored back to the nominal range by primary reserve implemented through governor droop control on conventional power plants. Such cases, where a delayed active power recovery is supplemented by wind and other distributed generation outages, could lead to a temporary active power reduction exceeding the largest infeed and hence the available primary reserve (assuming that prior mitigating actions have not been implemented) for the system.

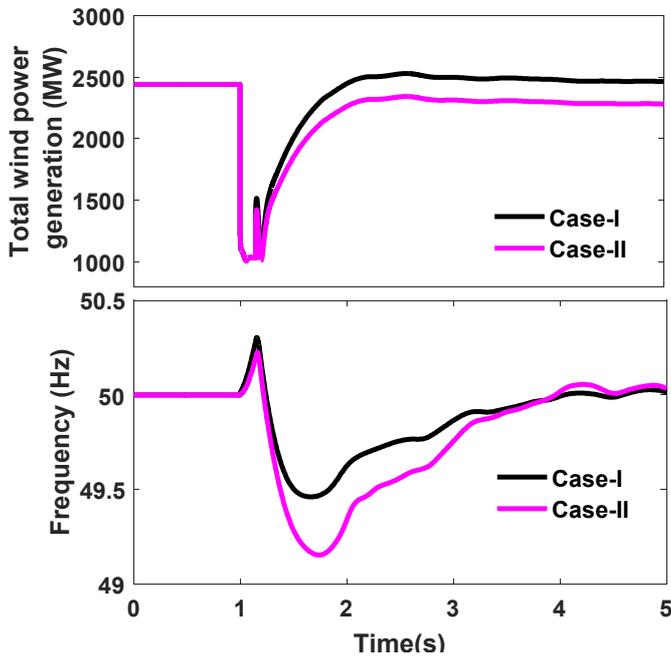


Fig. 12 System response to delayed wind power recovery with generation outage

4.3 Delayed Active Power Recovery with Voltage Oscillations

Wind turbines are susceptible to eigenswings, particularly due to torsional swings in the shaft (Akhmatov *et al.*, 2000) as outlined in Section 1, which may arise due to various factors such as asymmetry in the tower, shadow effects and particularly torsional shaft swings. As described in Section 2, the turbine mechanical structure was modelled as a two-mass system, and, therefore, a fault-induced voltage dip at the wind turbine terminals is likely to excite torsional oscillations in the wind turbine shaft, with the frequency of such mechanical oscillations tending to be around 1.6 - 1.7 Hz. The wind turbine system acts as a low pass filter to such oscillations, and, as a result, the frequency of oscillations introduced in the voltage and power output of a turbine is ≈ 1 Hz, which is close to the frequency of power oscillations (a well-known phenomenon in power systems). Given that the frequency of such oscillations is too high to be completely damped by

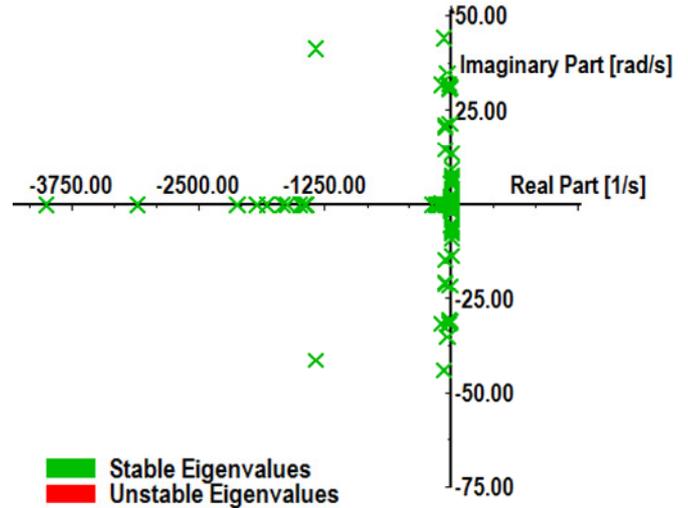


Fig. 13 Eigenvalue plot for wind integrated New England system.

pitch control action, it follows that for a fault-induced severe voltage drop, power and voltage oscillations introduced by torsional oscillations in the mechanical system from a significant proportion of wind turbines, may result in a more system-wide voltage drop. This may then lead to an under-voltage power reduction from variable speed wind turbine technology (type-3, type-4) and under-voltage tripping of less robust generation technology (type-1 and type-2 wind turbines and other distributed generation, such as CHP). Hence, oscillation-induced voltage dips may lead to a second power imbalance in the system, resulting in a second frequency nadir.

In order to establish that the test system is small signal stable, modal analysis has been carried out, with the eigenvalue plot shown in Fig. 13. It can be observed that all the eigenvalues are placed towards the left-hand side (with negative real part) on the x-axis, thus indicating small signal stability. Fig. 14 shows one of the worst case scenarios, where a three-phase fault at bus 19 of 150 ms duration, resulting in a voltage dip, is followed by the delayed active power recovery period from the wind farm connected at bus 19 and nearby wind farms (at buses 20, 33 and 36). Due to a significant voltage drop as a result of the original fault, a substantial portion of the wind farms/turbines introduce power/voltage oscillations into the system. As the oscillations spread across the system, visible from the system demand profile shown in Fig. 14, the oscillation-induced system-wide voltage drop results in a wind power reduction of ≈ 600 MW at $t = 2.18$ s at buses 19, 33 and 36, due to the reasons mentioned above, and leading to a second frequency nadir. (The frequency shown in Fig. 14 is the local frequency measured at bus 33, which is a neighbouring bus to the fault location). Since the second generation shortfall occurs in a relatively short time following the first event, the system dynamics are unlikely to have regained steady-state equilibrium, and hence the second event may result in a severe deterioration in frequency stability as compared to the original disturbance. Along with a reduction in active power output of generators including conventional power plant, the severe voltage drop during the fault also results in a system demand reduction by over 1000

MW (near $t = 1$ s) as the voltage dependent load reduces the power consumption during low voltage conditions, Fig. 14. However, following fault clearance, as conventional power plant output and load consumption quickly recover, a delayed active power recovery from the wind turbines results in a temporary generation-load imbalance, hence leading to a frequency excursion, Fig. 14. It is, however, noted that, in this case study, the oscillations of the wind turbines within a wind farm tend to be in phase as the wind farm is represented by machines connected to the PCC through transformers connected in parallel. At higher penetration levels, the system may experience cascading voltage-induced frequency events, assuming effective countermeasures such as adequate fast frequency reserve including inertial response, dynamic reactive reserve, upgrading of protection schemes, stricter grid codes etc. are not in place (Rather et al., 2014; Flynn et al., 2016).

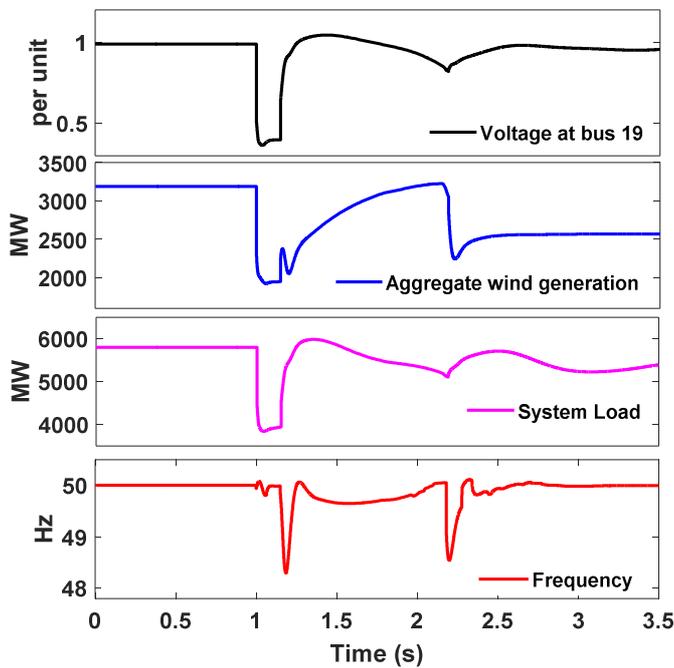


Fig. 14 Double frequency excursion due to voltage dip-delayed active power recovery and induced oscillations.

4.5 Discussion

Large-scale wind penetration introduces various technical issues relating to the secure and reliable operation of such systems, with frequency and voltage stability being the most critical. An emerging issue, with potential implications for system operation, is a temporary power reduction due to a delayed active power recovery from (grid code compliant) wind turbines following a voltage dip seen at the wind turbine terminals. The impact of the temporary power reduction, following a severe voltage dip across a large part of the network, is expected to be more severe at higher wind penetration levels, when the maximum temporary (active power) reduction may result in the breach of acceptable frequency and RoCoF limits. The impact may be exacerbated due to a delayed voltage recovery, with the trip of old technology wind turbines and other distributed generation technology which are not currently bound to support the grid

during the voltage ride through period. Furthermore, depending on the severity of a fault and its proximity to particular wind farm types, the proportion and distribution of type-3 and type-4 wind turbines in the system may affect the presented results.

Within the presented study, the objective was to investigate the potential impacts of a delayed active power recovery from wind turbines following a voltage dip, while exploring the system limits. In the wake of rapidly increasing wind penetrations in many systems, it is, therefore, clear that mitigating measures must be considered and introduced. Various possible solutions, ranging from support from the generation side, through new control and operational strategies, and new network infrastructure, to support from the demand side, can address these emerging challenges. Potential mitigating measures may include:

- Distributed and adequate dynamic reactive power compensation, that will reduce the depth of the voltage dip during a fault and will assist in the fast recovery of the post-fault voltage.
- Introducing fast frequency reserve products that can compensate for the temporary wind power reduction due to the delayed active power recovery.
- Enforcing local compensation at wind farm level, e.g. through adopting stricter grid code regulations.
- Revisiting prioritisation of reactive/active power injection from wind turbines during the LVRT period, recognising that it may not always be best practice to prioritise reactive power injection during a voltage dip: a significant active power output reduction from WPPs can result, depending on the severity of the voltage dip, which may exacerbate the maximum generation shortfall due to a delayed active power recovery.

While implementing such measures will undoubtedly come with various challenges, such as economical constraints in terms of procuring additional ancillary services, installing new network infrastructure (synchronous condensers, SVCs, STATCOMs, etc.), cost implications for the wind industry in making their turbine technology follow stricter grid code compliance, adopting new control and operational strategies, there may be new opportunities for the power industry, such as participating in new ancillary service markets by offering new ancillary service products, supplying new network infrastructure, offering new hardware and firmware technologies for grid code compliance. Such measures may be implemented through an ancillary service market and by appropriate consideration in unit commitment / optimal power flow procedures. The countermeasures discussed above are being investigated by the same authors as part of an ongoing research project.

5. CONCLUSIONS

A potential risk of frequency instability due to a delayed active power recovery from wind farms following a network fault induced voltage dip in large-scale wind integrated power systems has been investigated. It has been demonstrated that

the delayed active power recovery (to avoid mechanical stress on the wind turbine) may pose a potential risk to frequency stability, particularly at higher wind penetration levels. For a system with a significant penetration of variable speed wind turbines (type-3 and type-4), results suggest that the emerging issue of voltage dip induced delayed active power recovery may lead to a temporary generation shortfall, that in some cases may exceed the capacity of the largest infeed (and, therefore, primary reserve) leading to severe frequency nadirs with serious implications on system operation.

The research work also suggests that prioritisation for reactive power injection during a fault induced voltage dip, as required by grid code regulations in most countries, may impact the frequency stability in some cases, particularly in smaller isolated systems. Further, the research study has also shown that a delayed active power recovery, supplemented by the loss of (older, non-grid code compliant) wind generation and/or other distributed generation units, may have further implications on system frequency stability. Due to voltage oscillations introduced by torsional oscillations in wind turbines, the possibility of cascading voltage dip induced frequency events with potential detrimental implications on system frequency stability was also identified.

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