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# A Technical & Economic Evaluation of Inertial Response From Wind Generators and Synchronous Condensers

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**ABSTRACT** Frequency stability in today's power systems has become more critical than ever due to the growing contribution of renewable energy sources. This situation has arisen because of the electro-mechanical decoupling between renewable generation sources and the main grid caused by their connection through power electronic converters. This paper designs two synthetic inertia controllers that adhere to the grid code requirements from two different countries and then to utilize them to aid in the integration of high levels of wind power penetration in a test power system. The controllers are designed for a full converter wind turbine generator and are validated in an EMT real-time simulation with isolated testing at different wind speeds and different wind power penetration. The role of synchronous inertia in maintaining frequency stability is also explored through the use of synchronous condensers. Finally, the economic aspect of inertia is discussed, using the real-world example of the Bornholm island power system.

**INDEX TERMS** Converter-dominated systems, frequency stability, synthetic inertia, synchronous condenser, wind power plant.

## I. INTRODUCTION

Electricity is one of the most widely used commodities in the world today, and its share of global final energy consumption has doubled over the past forty years. Electric power systems form the backbone of the production, delivery and use of electricity. Therefore, efficient and reliable system operation is of the utmost importance to ensure efficient transmission of electricity from generation to load centres. While the technical, economic and market challenges associated with power system operation have historically been well understood, the large-scale introduction of modern variable renewable energy sources brings a new wave of operational challenges [1].

To account for the importance of a stable system frequency, generators in a power system are equipped with control mechanisms that allow them to respond to changes in system frequency both independently and on demand. In traditional power plants this takes the form of governor droop control. This allows a generator to increase its output by a certain

percentage for each Hz that the system frequency drops below its nominal value and decrease its power output by the same percentage when the system frequency exceeds its nominal value [2]. When wind turbine generators (WTGs) were first installed in the 1980s, they were synchronously connected to the power system just like traditional power plants. However with breakthroughs made in power electronics, modern WTGs can now operate at multiple speeds as they are not electro-mechanically coupled with the system [3]. This has the benefit of much greater efficiency in WTG operation, but unfortunately disables them from providing a natural frequency response [4]. This means that as traditional synchronous generators are gradually phased out for asynchronous renewable energies, the total amount of inertia in a power system drops and in the moments following a mismatch in generation and consumption in a power system, the rate of change of frequency (ROCOF) increases [5].

So the challenge relating to inertial response and frequency stability in low inertia systems is perhaps one of the greatest challenges facing power system operators in coming years, and one of the biggest barriers to furthering the integration of renewable energy sources into the power system.

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However, over the past decade important research has proved the ability of WTGs to provide services to enhance frequency stability, namely their ability to provide a form of emulated inertia which is also called synthetic inertia [6]–[9]. Synthetic inertia is defined as the fast delivery of additional power by a WTG relative to a frequency deviation in the grid. This capability, while still in its infancy in terms of practical experience [10], is offered by several turbine manufacturers today [11].

The motivation of this work lies in the fact that, following over a decade of research, synthetic inertia is becoming a required capability for Wind Power Plants (WPPs) around the world. This transition from academic research to commercial implementation is deeply interesting, and has led to the main focus of this work being placed on the design of synthetic inertia controllers to adhere to current and future grid code requirements, and to test the extent of which the provision of synthetic inertia can aid in the integration of wind power into the power system. Of course, it is well understood that synthetic inertia alone cannot solve the frequency stability issues of power systems with large penetrations of renewable generation and so therefore synchronous condensers (SCs) are also included in this study. SC has been considered as a potential technical solution for stability services in renewable-based power systems [7], [12]. The goal of the study is to design synthetic inertia controllers to be installed in a WPP to aid in the integration of high levels of wind power in the test system. The first controller adheres to the Canadian transmission system operator (TSO) Hydro-Quebec, as this is the only place where synthetic inertia is a requirement for WPPs. The second controller is designed to adhere to the future requirements that are currently being defined by the TSO in the UK, National Grid. The reason two controllers were designed is to allow for the comparison of the different requirements being demanded of WPPs by the two TSOs, and to identify areas in which further specification is needed.

While the literature surrounding synthetic inertia is mature, there are still many aspects that are unknown, particularly in relation to the economics. REServices was the first study that investigated wind and solar based grid support services at an EU level. It has provided technical and economic guidelines and recommendations for the design of a European market for ancillary services, as well as for future network codes within the Third Liberalisation Package [13]. It covers the topic of synthetic inertia through the assessment of the new ancillary service Fast Frequency Response (FFR), defined as the injection of active power in response to a grid frequency deviation within 2s [14]. Through this consultation, a utilisation cost for FFR was estimated to be 0.16 €/MWh. As FFR is not a service that is currently provided by any WPPs, the actual costs incurred through additional maintenance from the provision of FFR is unknown. Therefore, this figure is purely a speculative figure from industry on the reduction of WTG lifetime caused by additional loading during synthetic inertia response. A more concrete figure is provided for the investment cost associated with the software

upgrade required to enable FFR in WTGs. This is presented as 2,000 €/MW [15]. Along with the economic assessment of the provision of frequency support from various technologies, this work aims to offer results which can aid in the future planning of low inertia power systems.

The rest of the paper is organized as follows. Section II presents the international Grid codes for inertia requirements that are issued by different TSOs worldwide. The Synthetic inertia controller design based on the Canadian and Great Britain (GB) Grid codes are investigated in section III. In section IV, the case study and results are discussed and analyzed. An economic assessment of the provision of synchronous and synthetic inertia from various technologies is examined in Section V. Some important conclusions are finally drawn in section VI.

## II. INTERNATIONAL GRID CODES FOR INERTIA REQUIREMENTS

A grid code is a document drafted by the TSO of each transmission system in the world. It outlines the requirements that must be met by each device wishing to connect to either the transmission or the distribution system [16]. The requirements vary according to the power capacity in question and the voltage level at which that device wishes to connect. The grid code requirements discussed below are integrated into the synthetic inertia controllers designed in this work, with the aim of assessing whether these requirements can be met, and to identify areas in which the requirements need further clarification.

### A. GRID CODES FOR HYDRO-QUEBEC CANADA

The TSO responsible for the transmission system in Quebec, Canada, were the first to make an official requirement for WPPs to offer inertial response capabilities to the grid. In 2005 the revised grid code for Hydro-Quebec stated that: “The facilities of a wind generating plant whose rated output is greater than 10 MW must be designed to be able to be equipped with a frequency control system. The manufacturer must design this system and install it as soon as it is available. This frequency control system shall help reduce large (greater than 0.5 Hz), short-term (less than 10 s) frequency deviations on the power system. The frequency control system must reduce large, short-term frequency deviations at least as much as does the inertial response of a conventional generator whose inertia (H) equals 3.5 s. This target performance is met, for instance, when the frequency control system varies the real power dynamically and rapidly by about 5% for 10 s when a large, short-term frequency deviation occurs on the power system” [17].

While this revision was made in 2005, it is worth noting that the capability did not become commercially available until after 2010. Nonetheless, valuable findings have been made from the practical experience of Enercon turbines equipped with inertia emulation capabilities in this region since 2012 [10].

In 2018, another revision was updated [18] which stated for under-frequency condition as follows: “Wind generating stations with a rated power greater than 10 MW must be equipped with a frequency control system. For under-frequency condition: Activated at a given frequency threshold to order full overproduction or to order overproduction proportional to frequency deviation. Order a maximum momentary real power overproduction equal to at least 6% of rated power of each wind generator in service. Provide a maximum overproduction duration of at least 9 s (from the start of power ramp up to the start of power ramp down). Limit real power decrease during energy recovery (if needed) to approximately 20% of rated power.” This revision is more specific for different stages compared to the one in 2005, but the triggered scheme for inertial response is still based on frequency deviation.

**B. FUTURE ENTSO-E INERTIA REQUIREMENTS**

No TSO in Europe has placed requirements on WPPs to provide synthetic inertia to date. This is due to the fact that the countries with the largest penetrations of renewable energy are also well interconnected to neighbouring systems, meaning that frequency stability has not been a major concern of the power system operators in the Continental European grid. Major exceptions to this are Ireland and the UK, which are more isolated than the rest of the European grids.

Nonetheless ENTSO-E, the European Network of Transmission System Operators for Electricity, have indicated that inertial response capabilities will be mandatory for many WPPs [19]. In the ENTSO-E draft connection codes published in 2012 [20], it was stated that all WPPs with a rated output power greater than or equal to 50 MW, or with a connection point greater than or equal to 110 kV, must provide synthetic inertia for the purposes of supporting frequency stability in the given system. This requirement is to be placed on both onshore and offshore WPPs in the coming years [6].

**C. FUTURE INERTIA REQUIREMENTS IN NATIONAL GRID, UK**

Published concurrently with the ENTSO-E draft connection codes of 2012, National Grid, the TSO in the UK, also published future grid code requirements for WPPs regarding synthetic inertia [21]. Unlike the Canadian requirements that are based on an absolute frequency deviation of 0.5 Hz from the nominal value (50 Hz in the UK, 60 Hz in Canada,) the UK requirements stipulate an increase in power output as a percentage of nominal power depending on the ROCOF caused by a given frequency event [22]. The specific requirements are shown in Fig. 1.

These requirements indicate a maximum increase in power output of 5.4% of rated power for a ROCOF greater than or equal to 0.325 Hz/s. The maximum allowable activation time according to Fig. 1 is 200 ms, however the duration of the response has not yet been defined. Furthermore the minimum allowable power output during recovery is equal to 5% below nominal power output (assuming the WPP was operating at

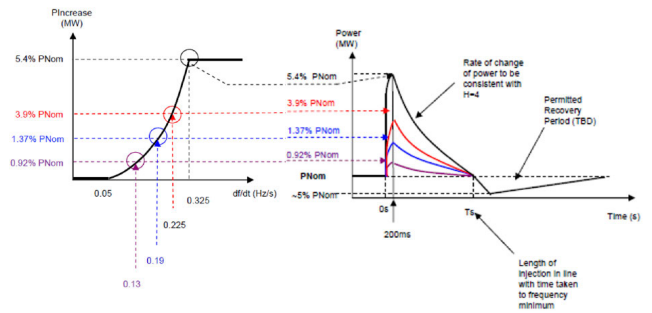


FIGURE 1. Future inertial requirements in GB.

nominal output at the triggering of the frequency event) but the allowable recovery time has also not yet been defined. Finally, there is no clear indication of when the requirements will be implemented by National Grid [23].

**III. SYNTHETIC INERTIA CONTROLLER DESIGN**

Synthetic inertia provision from the wind power plant involves the extraction of kinetic energy from the generator rotor. This is done by supplying an additional power signal that pulls the WTG away from its Maximum power point tracking (MPPT) curve, decelerates the rotor, and then allows the WTG to return to normal operation when the the response has been given. Figure 2 shows the relationship between the power output and rotor speed during providing synthetic inertia for the system. Taking an example when the system frequency drops, point A indicates the starting point where the WTG operates along its MPPT curve. When the synthetic inertial response is activated, an additional power signal is generated which causes the WTG to operate at point B, with a higher output power and a lower rotational speed. In order for the WTG to return to its starting point, it must first operate at point C, with a lower output power and lower rotational speed, from which point it can accelerate to regain its original operating point at A.

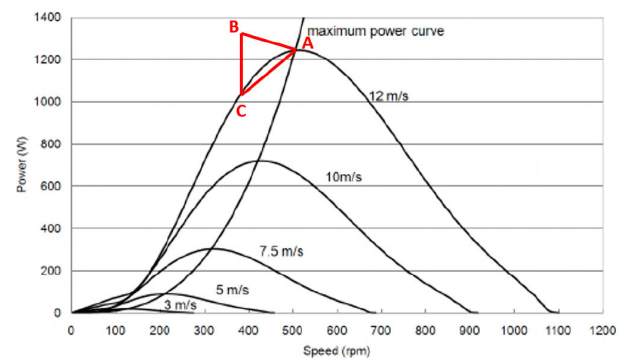


FIGURE 2. Synthetic inertia control trajectory relative to MPPT curve.

**A. CANADIAN CONTROLLER DESIGN**

Figures 3 and 4 show the control diagram and how it implemented in RSCAD for the Canadian synthetic inertia

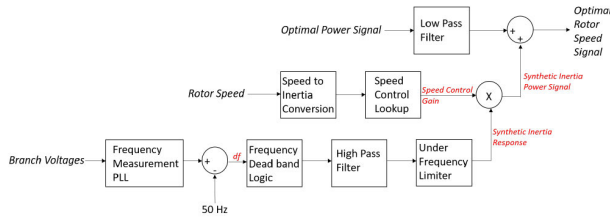


FIGURE 3. Canadian synthetic inertia controller.

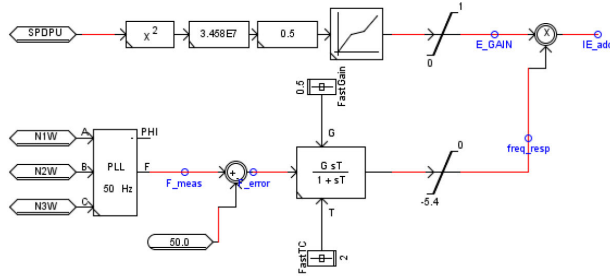


FIGURE 4. Core of the inertial emulation controller for Canada.

control incorporating the MPPT curve. There are two tiers in the control diagram. The first one is called controller response calculation where the frequency measurement via a phase-locked loop taking the WTG terminal voltage as the input is compared to the nominal frequency to compute the frequency deviation. Then this signal is passed through a high pass filter to create a synthetic inertia response with a fixed time constant. A frequency dead band and a limiter are added to the loop to ensure that the controller only responds when under-frequency event occurs. The second tier is speed control block where the rotor speed is translated into the available inertia value, then passed through a speed control lookup to create a control gain. The purpose of this adaptive gain is to curtail the inertial response of the controller when the speed, and hence the available inertia, of the turbine is below the rated level. It is only natural that this adaptive gain is limited to between 0 and 1. Information given by Siemens confirmed that the rotational speed of the WTG rotor shaft during cut-in is 0.33 p.u., therefore this controller limits the inertial response to a speed of 0.4 p.u. to allow for a small buffer between the lower limit of the response speed and the minimum allowable rotational speed of the WTG.

**B. GREAT BRITAIN CONTROLLER DESIGN**

Figure 5 shows the block diagram for the GB synthetic inertia controller. The GB grid code requirement stipulates that the synthetic inertial response should be triggered by the ROCOF, rather than an absolute frequency value. Therefore, after the frequency is measured it is then converted to a  $df/dt$  signal. While the control structure is the same as the previous controller, the tuning values of the high pass filter are different as its function is to create a  $df/dt$  signal rather than a response signal. This  $df/dt$  signal is then passed through a

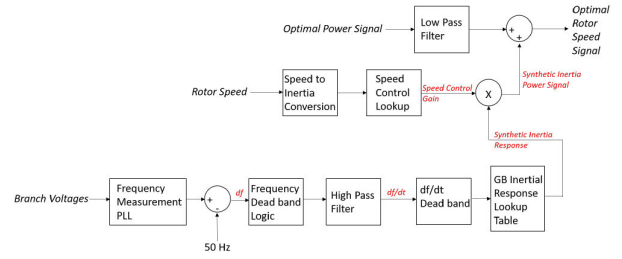


FIGURE 5. GB synthetic inertia controller.

dead-band to ensure avoid false triggering of the controller. Following this block is the look up table which dictates the power increase response relative to the  $df/dt$  value. Due to limitations in look up table functionality in RSCAD, this was instead implemented as its mathematical function as Fig. 6, described as follows:

$$\Delta P = -633.95\left(\frac{df}{dt}\right)^3 - 389.56\left(\frac{df}{dt}\right)^2 - 47.66\frac{df}{dt} + 1.5502 \tag{1}$$

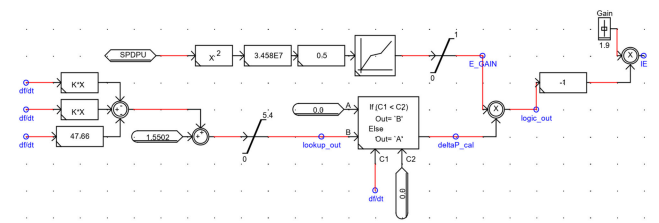


FIGURE 6. Core of the inertial emulation controller for GB.

**IV. CASE STUDY**

The controllers are first validated at turbine level with a WTG connected to an infinite bus and an RL load. Then a large scale testing for the controllers are implemented with IEEE 9 bus system.

**A. CONTROLLER VALIDATION**

Figure 7 shows the testing system used for validating the controller. The controllers are tested at both rated wind speed and below rated wind speed. The frequency threshold at which the synthetic inertia controller should be triggered in the Hydro-Quebec grid code is 49.5 Hz [24]. Therefore the

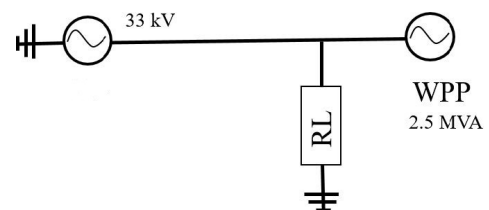


FIGURE 7. WTG connected to an infinite.

tuning of the controllers was carried out to maximise the response given for a frequency deviation of 0.5 Hz.

Figure 8 illustrates the controller responses at rated wind speed. The inherent difference between the two controllers lies in their triggering mechanisms. The Canadian controller is  $\Delta f$  triggered, meaning it relinquishes its maximum value of kinetic energy to the grid when the frequency deviation is highest. However, the GB controller is  $df/dt$  triggered, therefore its highest power output occurs at the point when  $df/dt$  is highest, which is always immediately following the frequency event. This is reason that the blue signal precedes the red in both power and speed plots in Fig. 8.

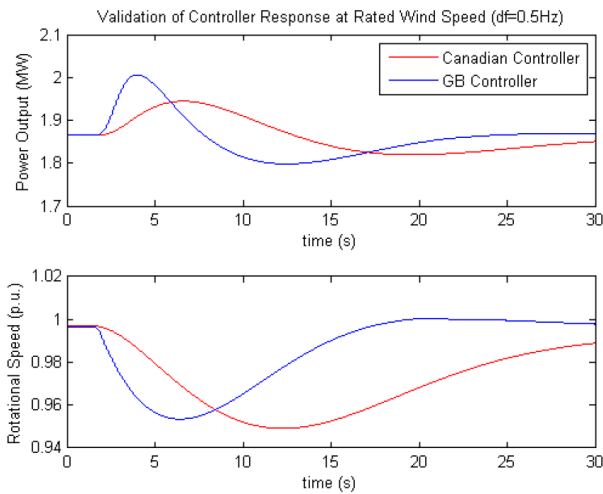


FIGURE 8. Validation of controller response at rated wind speed.

Validation testing was also carried out at below rated wind speed to ensure the correct operation of the speed control component. Low wind speed validation was carried out at 7 m/s, assuming a 6 m/s cut-in speed for the given WTG. Figure 9 shows the controller response characteristics for the same frequency deviation as the previous section. A similar response pattern is observed that indicates that a frequency deviation of 0.5 Hz does not cause significant deceleration in the WTG rotor. This is a positive finding, as it indicates that the additional loading on the WTG rotor caused by the provision of synthetic inertia may not be severe, given that 0.5 Hz is a very serious frequency deviation in large power systems such as the Nordic or CE grids.

It is worth noting that the reason that there is a slight difference between the signals of the two controllers during low wind speed validation is due to human error, the testing of the Canadian controller was carried out at exactly 7 m/s, however the testing of the GB controller was carried out at 6.7 m/s. This however does not detract from the fact that the validation testing show both controllers to be robust for both large and extreme frequency deviations at both rated and low wind speed.

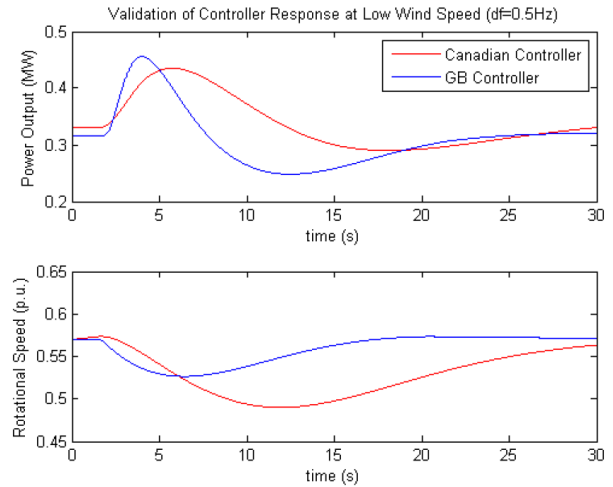


FIGURE 9. Validation of controller response at low wind speed.

### B. SCENARIO ANALYSIS

The IEEE nine-bus system is utilized for the large scale testing of the synthetic inertia controllers in this section as shown in Fig. 10. A WPP is installed at the same node as G3. A total of 6 scenarios are simulated, starting with 0% wind penetration and increasing in steps of 10% until the system can no longer achieve stable operation. This method of scenario analysis allows for the comparison between the two different synthetic inertia controllers for gradual increases in system wind power penetration, and also the gradual addition of supplementary synchronous inertia in the form of synchronous condensers when it is required by the system.

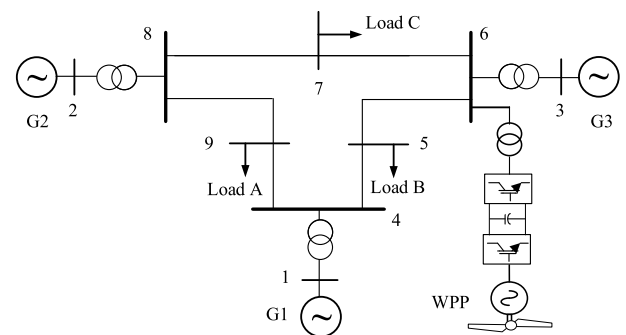


FIGURE 10. IEEE nine bus system with WPP integration.

For the first scenario, the initial output value of this WPP is set to 10% of the system load. This is then increased in steps of 10% until a wind penetration of 50% is achieved in the system. To accommodate this, the capacity and active power dispatch of G3 is gradually reduced until it is fully phased out. Following this the capacity and active power dispatch of G2 is also reduced. The aim of this is to maintain the same total system capacity, while increasing the capacity share of renewable generation. In higher wind penetration scenarios it is deemed necessary to also install synchronous condensers for the purposes of synchronous inertia enhancement.

The placement and effect of the synchronous condensers is further discussed in the next section.

The same fault, the loss of G1 (providing 53 MW), is maintained throughout all scenarios. It is also important to note that as the wind power penetration increases in each scenario, the active power dispatch and the MVA capacity of the remaining synchronous generators is scaled down accordingly. Failing to scale down the generator total capacity would simply lead to a bigger gap between active power dispatch and maximum possible active power output, meaning that there would be an increase in the primary reserves of the power system. In order to maintain homogeneity across the scenarios, the total system capacity was kept constant. The dispatch values of each of the system components throughout the scenarios are listed in Table 1.

TABLE 1. Generation dispatch for various scenarios.

Scenarios	10%		20%		30%		40%		50%	
	MW	MVA	MW	MVA	MW	MVA	MW	MVA	MW	MVA
G1	53	147.5	53	147.5	53	147.5	53	147.5	53	147.5
G2	182	500	182	500	174	450	140	390	106	280
G3	54	217	22	87	0	0	0	0	0	0
Wind	32	42.5	64	85	97	127.5	128	170	160	212.5
SynCon	0	0	0	0	0	0	0	100	0	100
SyncCon1	0	0	0	0	0	0	0	0	0	100
SyncCon2	0	0	0	0	0	0	0	0	0	100

1) 10% AND 20% WPP PENETRATION

At 10% wind penetration the active power output of the WPP at rated wind speed equals 33 MW. When the disturbance occurs, frequency nadir is improved with both two controllers but not significant as a small penetration of WPP capacity as shown in Fig. 11, only approximately 0.02 Hz enhancement. The higher WPP capacity penetration, the more enhancement for frequency nadir.

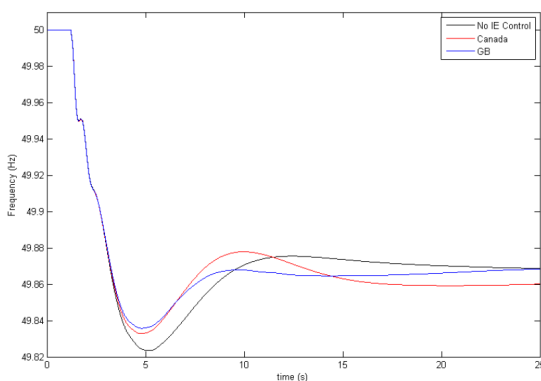


FIGURE 11. System frequency response at 10% wind penetration.

With 20% WPP penetration scenario, the GB controller provides better improvement in terms of frequency nadir and settling time as seen in the blue line in Fig. 12. To explain for this as seen from power and speed of WPP in Fig. 13: the peak power output response from the WPP under Canadian control is 72 MW and occurs 6.2 seconds after the loss of G1

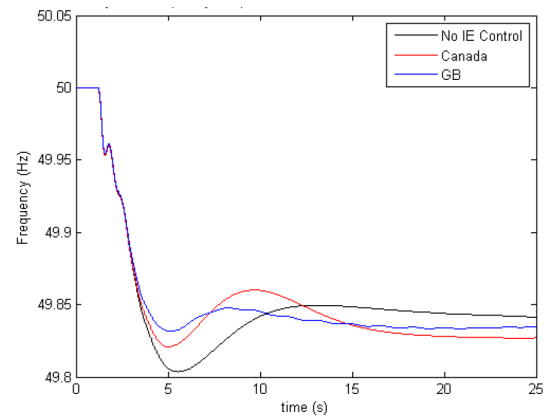


FIGURE 12. System frequency response at 20% wind penetration.

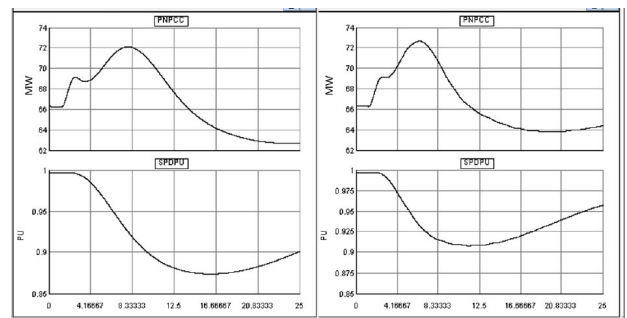


FIGURE 13. Active power and rotor speed responses of WPP at 20% wind Penetration, Canadian control (left) and GB control (right).

at  $t=1.25$  s, whereas the peak power from the WPP under GB control is higher at 72.8 MW and occurs slightly earlier at 5 seconds following the frequency event. Furthermore the lowest rotational speed reached by each WTG of the WPP under Canadian control is 0.875 p.u. and the corresponding GB value is higher at 0.91 p.u. The lower deceleration incurred when under GB control is due to a smaller volume of kinetic energy being offered to the system when responding to the frequency event. This is what enables the WPP to recover faster when under GB control in comparison to the Canadian controller. The ROCOF following the loss of G1 is unaffected by either of the controllers, for all three cases is  $-1.39$  Hz/s.

2) 30% WPP PENETRATION

This scenario marks the complete phasing out of generator G3 as the generation requirement at this node is now fully covered by the WPP with an active power output of 97 MW.

An improvement of 0.03 Hz of the frequency nadir is observed from 49.83 Hz to 49.86 Hz by both of the controllers as in Fig. 14. However, this is the first scenario in which a secondary frequency dip occurs. As previously discussed, WTGs operating at less than or equal to rated wind speed require a period of recovery following a synthetic inertial response, in order to allow their rotors to re-accelerate to pre-event speeds. The recovery period causes a noticeable secondary frequency nadir in this scenario due to the significant penetration of wind power generation in the grid.

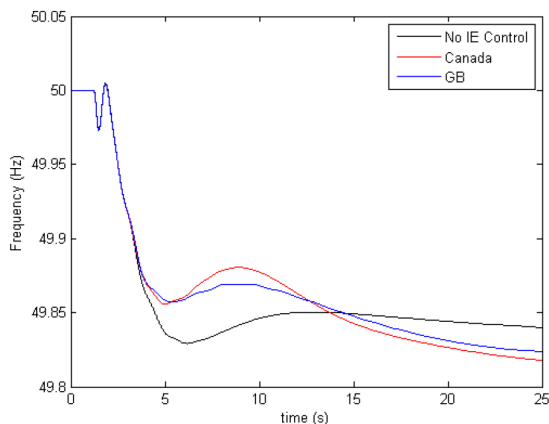


FIGURE 14. System frequency response at 30% wind penetration.

Furthermore, there is no control strategy in place to distribute the recovery period of the WPP over time, but rather each of the 54 WTGs are recovering their original rotor speed at exactly the same time, causing extra strain to the frequency stability of the system.

The ROCOF values for the 30% penetration case are  $-1.52$  Hz/s,  $-1.47$  Hz/s, and  $-1.48$  Hz/s respectively. It is also clear that the instantaneous ROCOF values are deteriorating with the increasing quantity of wind power active in the system. Compared to the previous scenario, the ROCOF has degraded from  $-1.33$  Hz/s to  $-1.52$  Hz/s with 10% and 30% WPP penetration without synthetic inertia control enabled, respectively.

### 3) 40% WPP PENETRATION

The significance of this scenario is that in which system stability is lost eventually due to a lack of synchronous inertia. To remedy this problem a synchronous condenser is added to the system alongside Load B at Bus 6. The resulting frequency response following this addition is plotted in Fig. 15 in black. It shows that even without any synthetic inertia controllers activated, the addition of the synchronous condenser allows for smooth and stable system operation. It is also interesting to note that the frequency nadir is much lower following the addition of an SC due to the power loss of SC.

Once again the instantaneous ROCOF following the frequency event remains relatively unaffected, with values of 1.37 Hz/s, 1.31 Hz/s and 1.35 Hz/s for the case without control, with the Canadian controller, and with the GB controller respectively. However, what is interesting to note is that when the value for instantaneous ROCOF for this scenario is compared to the previous, a reduction of 0.15 Hz/s is seen. This improvement in ROCOF following the loss of G1 can be attributed to the installation of the SC. This shows the clear benefit to system frequency stability that is offered by SCs. The improvement in the primary frequency nadir is significant, with an increase of 0.07 Hz and 0.08 Hz from each controller respectively. As with the previous scenario there is an obvious secondary frequency drop caused by a

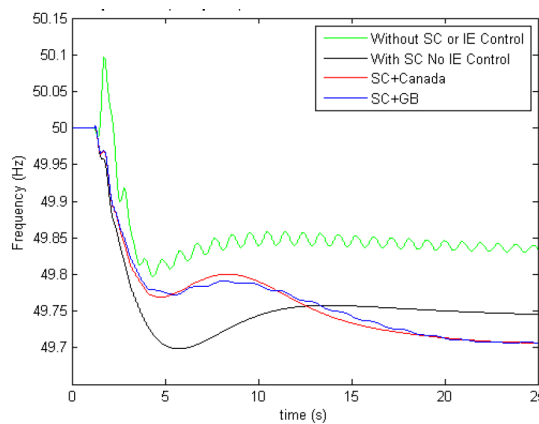


FIGURE 15. System frequency response at 40% wind penetration.

large volume of kinetic energy being recovered from the grid to the WTG rotors without any distribution or control.

### 4) 50% WPP PENETRATION

The final scenario that was fully explored was that of 50% wind penetration. This gave an initial dispatch of 160 MW of wind power, with G2 supplying approximately 108 MW and, as per the previous scenarios, G1 supplying 53 MW. The same system configuration as the 40% scenario was initially trialed; however this was quickly seen to be unstable. To remedy this, additional synchronous condensers were added to the system.

Figure 16 presents one unstable case for the 50% scenario and two alternatives that result in stable post-fault system operation. While the addition of a third synchronous condenser has a negative effect on the frequency nadir of the system due to increased active power losses, it offers a decrease of instantaneous ROCOF. The resulting frequency nadir, plotted in yellow in Fig. 16, is 49.59 Hz. This is initially significantly improved upon by both Canadian and GB controllers to a value of 49.7 Hz (an increase in  $\Delta f$  of 0.11 Hz) however this benefit is quickly counteracted by large secondary frequency

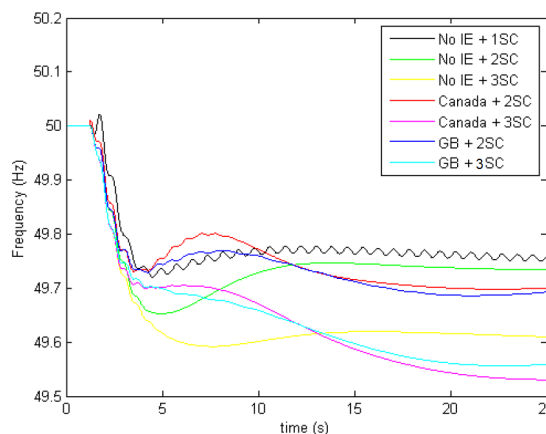


FIGURE 16. System frequency response at 50% wind penetration.

dip that is caused by the controllers. Without synthetic inertia control, the frequency stabilises to 49.61 Hz, however at the end of the simulation time frame, the Canadian controller frequency signal lies 0.08 Hz below this at 49.53 Hz, and the GB frequency signal lies 0.05 Hz below this at 49.56 Hz. It was ensured that both controllers allowed for system frequency stabilisation to the correct value.

## 5) SUMMARY

The validation of testing of two synthetic inertia controllers which adhere to different grid code requirements, the compelling conclusion that can be drawn is these requirements can all be met. Both absolute frequency deviation and ROCOF triggers have been proven to work, and it has been proven that a WPP can be controlled to increase its power output relative to a frequency deviation for time periods in the range of 5-10 s.

However, the more valuable outcome of the study lies in the identification of specifications lacking from current grid code literature surrounding synthetic inertia as follows:

**Activation Time:** This specification itself also depends on the goals of the TSO in question regarding the use of synthetic inertia. If, as described in the Irish case, the service is being used to prevent ROCOF events, then extremely fast activation and delivery times are required, e.g. 100 ms and 200 ms respectively [25].

However, as shown in the scenario analysis, if the goal is to reduce the frequency nadir that occurs following a frequency event, then much larger activation and delivery times can still provide valuable results. Therefore further clarification is required from TSOs as to the aim of synthetic inertia in the power system in question and, following this, appropriate values for activation and delivery times should be given.

**Power Injection:** Figure 1 indicates a requirement to increase power production by a maximum of 5.4% relative to nominal power output. However the Canadian grid code stipulates simply at least 6% increase in power output for at least 9s. The context of the power injection should be clearly stated in all grid codes. While a power increase relative to rated WTG power is simpler to implement as it is a constant value, a power increase relative to current, or pre-fault, power output is perhaps more feasible to implement for WTGs operating below rated wind speed.

**Recovery Period:** This is the most important specification for synthetic inertia that has not been sufficiently detailed in any grid code. The results of the scenario analysis show that even with the limit real power decrease (20%) during energy recovery applied in CA control, without a coordinated with any supplementary control placed in the control of the recovery period, a second frequency event can easily be caused by WTGs, especially at high penetrations of wind power. It is recommended that the duration of the recovery period be specified by the TSO in the synthetic inertia requirements. Additionally, a coordinated synthetic inertia of WPPs with a supplementary control should be considered to avoid the second frequency event.

## V. ECONOMIC ASPECTS OF INERTIA

One of the original objectives of the work was to determine whether it was cheaper to utilise synthetic inertia from wind power or synchronous inertia from synchronous condensers to enhance the frequency stability of a small power system. However, it soon became clear that the question, both from a technical and an economic perspective, is not one or the other, but rather how can the two work together to provide a technically and economically viable solution?

This part examines the island power system of Bornholm, an island off the coast of Denmark [26]. It was chosen for analysis as it is a small power system with a high penetration of wind power. The system frequency on the island is analysed for one year to quantify the deviations that occur. The data is then used to make an economic assessment of the feasibility of using synthetic inertia from wind power on the island to assist in frequency control. Operated by Østkraft, the local distribution system operator, the peak load on Bornholm is 56 MW spread across approximately 28,000 customers. The system can be operated in island mode, and this is in fact done for one month each year. The voltage level of the distribution system is split across 60 kV and 10 kV.

There are fifteen (15) 60 kV/10 kV substations on the island of Bornholm, the substation of Aakirkeby was chosen for the collection of frequency data. This is because it is the connection point of a 6 MW wind farm, making the frequency measurements relevant to the synthetic inertia study, and it also gave the most recent full year of frequency data from June 1st 2014 to May 31st 2015. A total of 444 frequency deviations were recorded for the period of June 2014 to May 2015. These were split almost equally with 227 under-frequency and 217 over-frequency events. The largest deviations recorded were 49.445 Hz on July 13th as shown in Fig. 17 and 50.074 Hz on July 27th. Given that both of the extreme events occur in July, it is speculated that this is the month in 2014 in which Bornholm operates in island mode. Figure 18 illustrates the quantity of under and over frequency events recorded each month. While the major deviations occurred in July, the biggest quantity of events occurred in August, with 23 events each from over and under frequency, totalling 46 events.

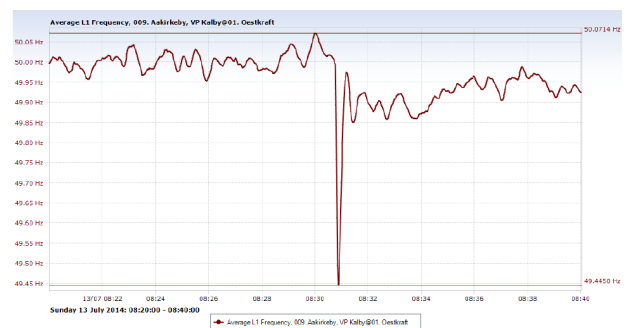


FIGURE 17. Under-frequency event at Aakirkeby on July 13th 2014.



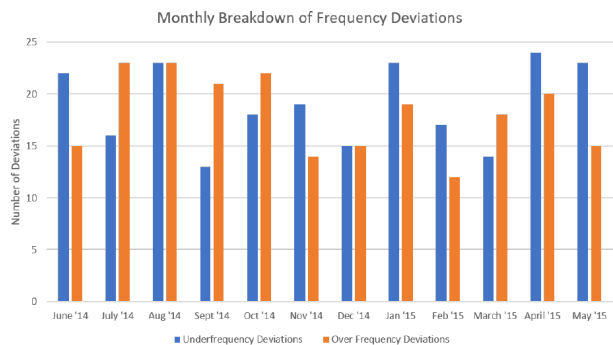


FIGURE 18. Monthly breakdown of frequency deviations on Bornholm.

The frequency measurements were taken at Aakirkeby substation, to which a 6 MW WPP is attached. Therefore, if this WPP was to provide FFR through synthetic inertia, the capital costs are easily estimated to €12,000. Furthermore, if the WPP was to react to all 444 frequency deviations in the given period, by providing additional active power to the value of 10% of the pre-event power for a duration of 10 seconds, given a cost of 0.16 €/MWh, then the operational costs would only amount to the negligible value €0.03 per year. If, pending further research, the utilisation cost of synthetic inertia is in fact this low, then the economic case for this service is very positive. It is unlikely that other technologies would be able to compete directly with it on this basis, however they could be more favourable in terms of flexibility and other factors.

The standard capital cost for a synchronous condenser is in the range of 350,000 €/MVA. If a direct comparison were made, it is clear that due to much lower investment costs, synthetic inertia from WTGs appears economically favourable over synchronous inertia from SCs. However, performing a direct comparison of the two services is not balanced for the following reasons:

The response characteristic from WTGs and SCs is different, where under current control designs SCs are better suited to reducing instantaneous ROCOF and WTGs are more capable of improving frequency nadir.

Comparing a synchronous condenser with another technology purely on the basis of its inertial response is not fair, as firstly an SC provides multiple other system benefits including voltage support and short circuit power enhancement [27], [28]. Secondly the lifetime of an SC often exceeds 40 years, at least double that of a typical WPP.

The REServices project has made significant progress in estimating the costs associated with enabling renewable energies to provide ancillary services. However, for the case of synchronous condensers where the capital costs are already known, studies are needed to estimate the distribution of costs across the various and ever increasing number of ancillary services which SCs can provide, for instance power oscillation damping controller as investigated in [29]. Furthermore, the size and location of synchronous condensers should also be considered in investment [30].

## VI. CONCLUSION

This paper has proven the ability of WTGs to provide a synthetic inertial response by increasing their active power output relative to a frequency deviation for a short period of time. Two different controllers based on Great Britain and Canada grid codes were designed and incorporated into WTG rotor control, including a speed controller to protect WTGs from deceleration below a rotational speed of 0.4 p.u. The controllers were validated for operation at different wind speeds (12 m/s and 7 m/s).

During testing the controller with the  $df/dt$  triggering mechanism (GB) outperformed the controller with the  $\Delta f$  triggering mechanism (Canada) as it was able to provide a higher peak power output with a lower overall volume of energy, resulting in a lower deceleration and hence a smaller recovery period.

Simulations were carried out on a nine-bus test system for the loss of one generator for scenarios of wind penetration increasing from 10% to 50%. The first scenario in which a synchronous condenser is required for stable system operation to be achieved following the loss of G1 is 40% wind penetration. The final scenario with 50% wind penetration involved the integration of 160 MW of wind power, and the installation of 3 synchronous condensers located in each corner of the system to strengthen the system frequency. It is understood however, that this is a particularly severe case for the nine-bus system due to a poor frequency support, where following the loss of G1 only a single synchronous generator and a single wind farm remain. In larger systems with more generators and a more diverse reserve contingents it is likely that more wind power could be integrated. From these scenarios, it can be concluded that by combining the responses of SCs and synthetic inertia from WTGs, a significant enhancement in system frequency stability can be achieved.

While exact costs are unknown, the economic outlook for the provision of synthetic inertia from wind seems favourable as power systems that experience problems with frequency deviations commonly already feature large penetrations of wind power. It can be concluded that economic comparison of synthetic inertia from WTGs and synchronous inertia from SCs is complex as they provide complimentary rather than competing services. SCs also provide a full suite of system stability services that must also be included in the evaluation. In addition, the long operational life of an SC leads to an investment recovery period that may be inherently different for the two technologies.

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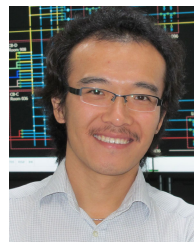
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