Quantification of the Equivalent Synchronous Rotating Inertia Available from Synthetic Inertia Response of Wind Turbines

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1 Abstract

Consider the case that a TSO imposes a maximum RoCoF (rate of change of frequency) requirement in a power system. Then, if some conventional generators are to be replaced by wind turbines, it is necessary to know how much equivalent inertia, (i.e. synthetic inertia) should be obtained from a wind turbine, such that the RoCoF requirement is not compromised. This study aims to establish a quantifiable relationship between synthetic inertia response of wind turbines and equivalent synchronous inertia ("H" in the swing equation). In other words, how many wind turbines with a certain synthetic inertia can replace a conventional generator with a given size and inertia H, such that the RoCoF in case of a load event is unchanged. Such a relation between available synthetic inertia from wind turbines and synchronous rotating inertia is important in order to ensure power system security while increasing wind power penetration in the electrical grid.

The basic idea behind a synthetic inertia response from wind turbines is to have a controller that increases electrical power output when the frequency is decreasing. This essentially means that kinetic energy is extracted from the turbine rotor, decreasing the rotational speed. In order to re-accelerate the rotor speed and obtain the optimal aerodynamic efficiency the active power output must be reduced below its optimal active power output, namely the mechanical input power, which will cause a positive acceleration of the rotor speed.

A simple two-bus radial grid is used for the investigation. Loads are made frequency independent, and all governors are taken out of service in order to see only the effect from wind turbine synthetic inertia response. Three cases are defined: a base case, a reduced inertia case and a reduced inertia with wind turbine support case. A load step is simulated and the average RoCoF during the first 500 ms is measured. The number of wind turbine generators is increased until the wind turbine support RoCoF matches the base case RoCoF.

The results show that the equivalent inertia available from wind turbines is independent of the size of the load step, and with controller gain $K_{fast} = 8$, it is estimated that one turbine can replace approximately 16 MWs of rotating inertia.

This study considers only the implication on RoCoF when replacing conventional generators with wind turbines. In reality, other aspects should be considered as well such as maintaining a minimum firm capacity, or adequate frequency support (primary reserves). However, the results in this study show that during the first 500 ms, the synthetic inertia contribution from wind turbines behave very much like real rotating inertia, and that equipping wind turbine with a synthetic inertia controller can effectively decrease RoCoF following transient disturbances.

Contents

2 Introduction

When a conventional power plant is replaced by a wind power plant, the available rotating inertia in the power system is reduced. This will cause the power system to become less stiff, causing the initial rate of change of frequency (RoCoF) to increase when a load demand increase in the power system occurs (or other transient phenomena). However, if the wind turbines are equipped with a Temporary Frequency Response controller (TFR), then it is possible for the wind power plants to provide an inertial response, which is measured as a temporary increase in the active power output of the wind turbine. This study seeks to quantify the number of wind turbines with TFR required in order to maintain the initial rate of change of frequency when a load demand increase occurs in the power system. Quantifying the required number of wind turbines that need to be installed to compensate for a certain amount of removed rotating inertia can assist transmission system operators (TSOs) in maintaining maximum RoCoF requirements, as the power system transitions towards a greener electricity sector with more converter-based generation.

3 Theory

Modern wind turbines are interfaced to the grid through power electronics (type C and D), which means that these wind turbines do not have a natural inertial response. Although type C wind turbines have a natural inertial response, since the stator is connected directly to the grid, then due to its active power output being controlled by the fast acting control system of the rotor converters, then its natural inertial response is limited. Whereas, the type D wind turbine uses a full converter, meaning it is fully decoupled from the electrical grid. When a conventional power plant is replaced, then both its inertia and inertial response is lost. Therefore, to enable type C and D wind turbines to provide an inertial response, a controller which can temporarily increase the active power output of the wind turbine is required. This makes it possible to achieve the same initial RoCoF prior to removing the conventional power plant for a given load demand change. This type of controller is referred to as a Synthetic Inertia Controller (SIC).

It should be stressed that an inertial response is not identical to a frequency response. An inertial response is the instantaneous change in electrical output power, P_e of the generator when a load change occur in the system. P_e changes instantaneously when the generator is connected directly to the electrical grid, otherwise Kirchhoff's voltage law would not be satisfied. Moreover, if the load is shared by several generators then for a load demand change each generator's electrical power will change by a certain amount, $\Delta P_{e,i}$ depending on the location of the event. Hence, the total change in the electrical power is equal to the load demand change and is given by, $\Delta P_e = \sum_{i=1}^{n} \Delta P_{e,i}$, where $P_e = \Delta P_{e,i} + P_{e0,i}$ in eq. (3.1) with $P_{e0,i}$ being the electrical output power prior to the load demand change.

A frequency response, on the other hand, is the action performed by the governor to change the mechanical input power, P_m, in order to match the new electrical output power. This action is also referred to as primary frequency control. By matching the mechanical power and electrical power, the acceleration of the rotor speed becomes zero, i.e. the accelerating power acting on the rotor, $P_a = P_m - P_e = 0$.

The swing equation expressed in p.u. for a single generator is given by,

$$\frac{d\omega_{m,pu}}{dt} = \frac{(P_m - P_e - D(\omega_{m,pu} - \omega_{0,pu}))}{2H} \tag{3.1}$$

where $\omega_{m,pu} = \frac{\omega_m}{\omega_{m,base}}$ is the mechanical rotor speed in p.u. and $\omega_{0,pu} = \frac{\omega_0}{\omega_{m,base}} = 1\ p.u.$ is the synchronous mechanical speed of the rotor in p.u. $H = \frac{J\omega_{m,base}}{2S_{mach}}$ is the inertia constant on the generator's MVA base, S_{mach} and J is the inertia of the rotor and prime mover. In addition, this study does not consider frequency dependent loads, hence the load-damping constant, $D = 0$.

Generally the following applies, $\omega_m = \frac{2}{p} \cdot \omega_e$, where ω_e is the angular velocity of the field in the electrical grid, ω_m is the mechanical rotor speed and p is the number of poles on the stator. However, in p.u. then $\omega_{m,pu} = \omega_{e,pu}$, due to the definition of the two bases, $\omega_{e,base} = 2\pi 50 Hz$ and $\omega_{m,base} = \frac{2}{p} \cdot \omega_{e,base}$. Hence, (3.1) directly expresses the change in the electrical grid's frequency.

When a load demand increase occurs, then P_e of the conventional power plants instantly increases, causing a mismatch $P_a = P_m - P_e$. As seen from (3.1), the mismatch will cause $\frac{d\omega_{m,pu}}{dt} < 0$, and depending on the mismatch a given RoCoF will be obtained. If a TSO decides to replace a conventional power plant with a wind farm of either type C or D wind turbines, then inertia has been removed from the system. However, if the wind turbines are able to provide an inertial response, then they can lower the instantaneous power difference P_a in (3.1) by injecting active power into the electrical grid. This will result in a reduced RoCoF. However, the wind turbines are only able to provide an inertial response for a limited amount of time, since this extra power output means that the turbine rotor will slow down. The aerodynamic efficiency of the rotor will decrease due to deviation from the optimal tip speed ratio. Therefore, synthetic inertia response is only temporary, as the rotor cannot be allowed to slow down too much. In order to increase the wind turbine's rotor speed back to optimal speed (which depends on the wind speed), then the active power output of the wind turbine has to be reduced below its mechanical input power, which results in a similar accelerating power as for conventional power plants. This action is performed by the MPPT (Maximum Power Point Tracking) controller.

According to [1], the inertial response from a single wind turbine equipped with a SIC is proportional to $\frac{d\omega_{m,pu}}{dt}$.

$$P_{e,SIC} = \omega_{m,pu} K_{SIC} \frac{d\omega_{m,pu}}{dt} \tag{3.2}$$

K_{SIC} is the proportional control gain in p.u. of the SIC and converts the measured RoCoF, $\frac{d\omega_{m,pu}}{dt}$ into an active power, $P_{e,SIC}$.

Hence the swing equation from (3.1) can be rewritten as (excluding the frequency dependency of the load):

$$\frac{d\omega_{m,pu}}{dt} = \frac{(P_m - P_e - \omega_{m,pu}K_{SIC}\frac{d\omega_{m,pu}}{dt})}{2H} \tag{3.3}$$

Which after isolating the derivative of the frequency, $\frac{d\omega_{m,pu}}{dt}$ becomes

$$\frac{d\omega_{m,pu}}{dt} = \frac{P_m - P_e}{2H + \omega_{m,pu}K_{SIC}} \tag{3.4}$$

where $K_{fast} = \omega_{m,pu}K_{SIC}$ in PowerFactory.

The SIC in PowerFactory receives a $P_{ref} = P_{e0}$, which is determined during the initialization, and then it receives the frequency from the electrical grid. All the units in SIC controller in PowerFactory are in p.u. Firstly, the controller computes the derivative of the frequency, $\frac{s}{1+sT_{fast}}$, where T_{fast} is a time constant in seconds. The derivative of the frequency is then converted into a power signal by multiplying with K_{fast}.

4 Methodology

The system used in this study, which is shown in Figure 4.1, is a radial grid composed of two synchronous generators, one of 600 MVA and H = 5.75 s and one of 100 MVA. The inertia constant of the 100 MVA generator is varied from 2 to 8 seconds, depending on the study case. It is mentioned that the governors of the generators are disabled since the project is focused on the inertial response of the system in the very beginning of the load event, and that the generators are equipped with an AVR, namely avrIEEET1. Moreover, two transformers of 600 MVA, one step-up (20/220 kV) and one step-down (220/20 kV) are present, while the connection between the generators and the load is established by an 220 kV overhead transmission line of 10 km. The system also includes a number of Type C wind turbines. The initial load is 300 MW, 0 MVAr.

Three study cases are defined:

- Base case - both the large (600 MVA) and the smaller generator (100 MVA, with varying inertia constant H) are connected.
- Reduced inertia case - only the large generator is connected.
- WT support (and reduced inertia) - large generator and number of wind turbines equipped with an SIC.

The objective of this investigation is to figure out how many wind turbines are needed, such that the initial RoCoF following a load step is the same in the wind turbine support case as in the base case. Then we say that this amount of wind turbines have an equivalent synthetic inertia response as the inertia of the removed (small) generator.

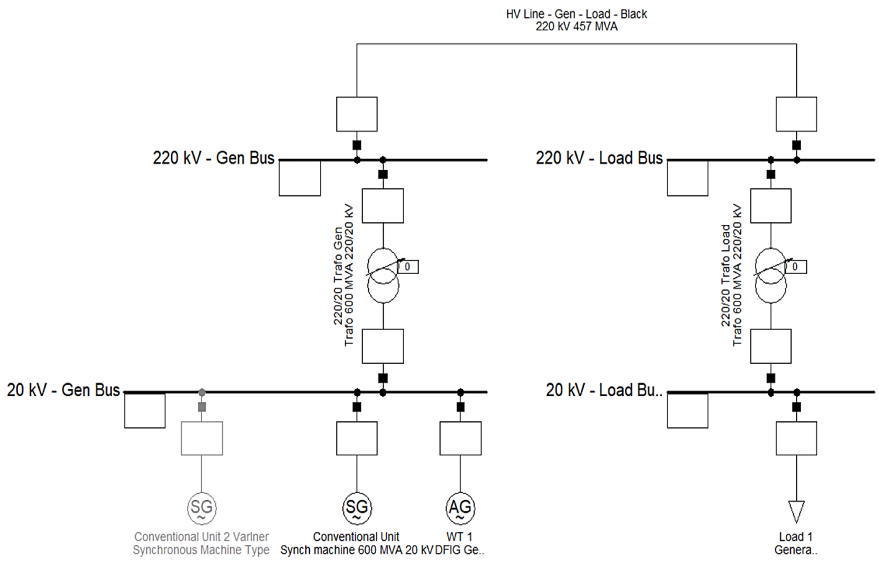


Figure 4.1: Radial Grid - The Grid Under Investigation.

Initially, an appropriate gain of the synthetic inertia controller should be selected. This gain, namely K_{fast}, has been set such that to the wind turbine does not exceed its operating limits and does not disconnect due to under/over speeding from its protection system operation. Therefore the two extreme cases of maximum and minimum wind power production should be investigated. In order to identify this maximum gain, the most severe load step (100 MW) and minimum wind production (0.3 MW) were selected. From simulations, the maximum gain value has been found equal to $K_{fast} = 8$. Afterwards, in order to evaluate that the WT does not exceed its operating limits (6.3 MW, 7 MVA), the most severe load step (100 MW) and maximum wind production (6 MW) are selected. In this case, the simulation results show that $K_{fast} = 8$ is safe to be used also in high wind production while respecting generator limits and most importantly the converter limits.

Now, the RoCoF measurements will be explained. The RoCoF values are determined as the average rate of change of frequency during the first 500 ms following a load step. The equivalent inertia available from WTs with SIC is determined by the following simple procedure (inspired by [2]).

- Simulate the frequency response for the base case and the reduced inertia case, where the small generator is removed.
- Increase the number of WTs with inertial support until the RoCoF during the first 500 ms is the same as or less than the base case.

- Then the synthetic inertia of the WTs is equivalent to the inertia of the removed generator.

Figure 4.2 shows the procedure of establishing the inertia equivalence. In this example with a 60 MW load step and $P_{WT} = 4.8MW$, 47 WTs with $K_{fast} = 8$ were necessary to compensate for a conventional generator with $100MVA \cdot 8s = 800MWs$ of rotational kinetic energy. The inertia of the remaining large generator is held constant at $600MVA \cdot 5.75s = 3450MWs$. Hence, the system inertia dropped from 4250 MWs to 3450 MWs, and 47 WTs could compensate for this loss (in terms of initial RoCoF).

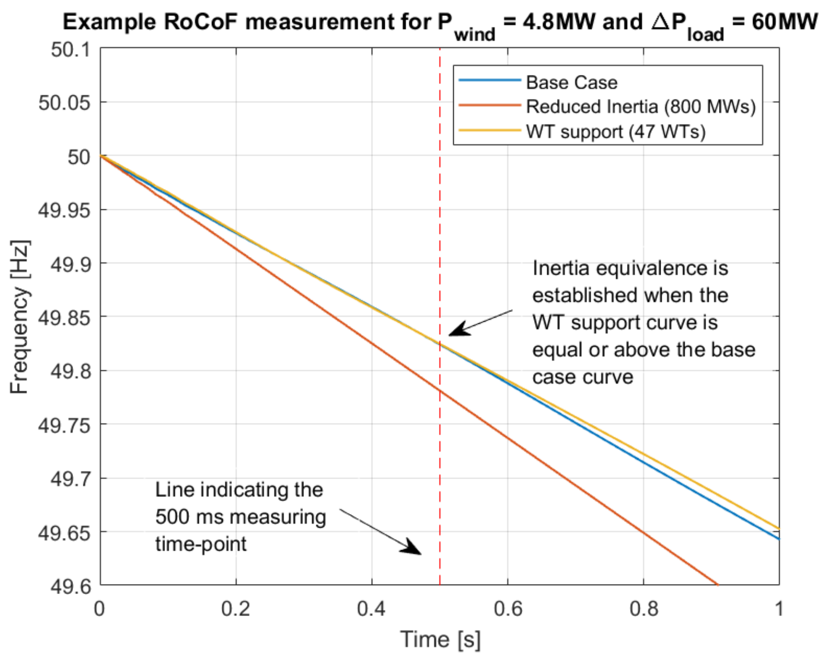


Figure 4.2: Example of a RoCoF measurement for a 60 MW load step. The removed generator had H = 8s, and hence the reduced inertia cases has $100MVA \cdot 8s = 800MWs$ less rotational kinetic energy than the base case. 47 WTs with $K_{fast} = 8$ were necessary to compensate for this reduction. Note that the frequency keeps decreasing because the governors are taken out of service.

5 Results

Results for the equivalent inertia available from wind turbine synthetic inertia are obtained using the radial grid using the procedure explained in section 4. The rotational energy of the remaining generator is kept constant at 3450 MWs.

5.1 Radial grid

Results were obtained for five different load steps and four wind speeds. Figure 5.1 shows the required number of wind turbines versus removed inertia and the load step with $K_{Fast} = 8$ in

PowerFactory, illustrated as a 3D clustered bar chart. It is observed that the WT inertial response does not depend on the load step but only on the removed rotational inertia.

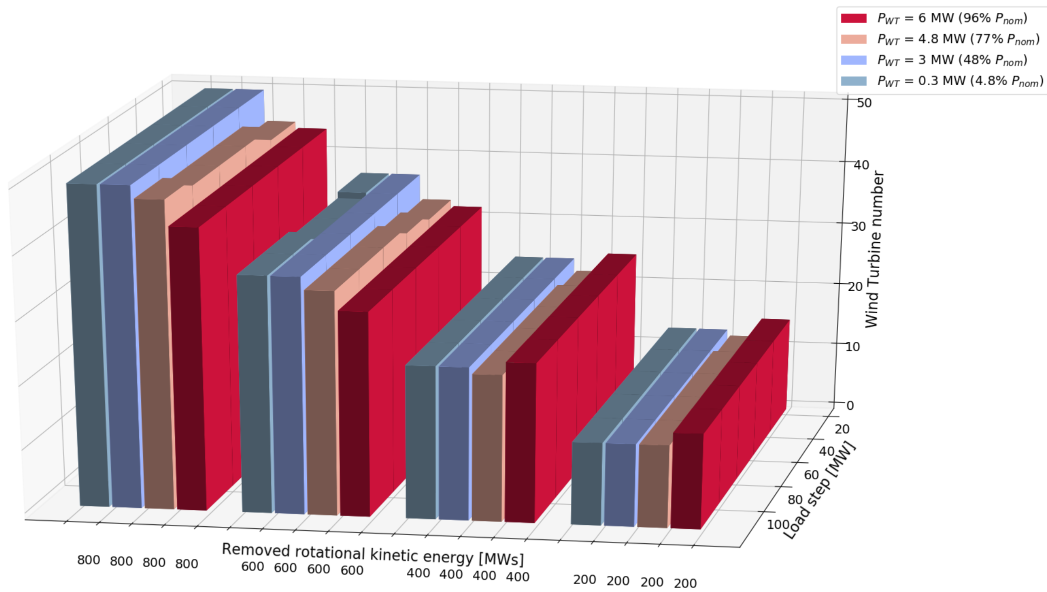


Figure 5.1: Number of WTs required to compensate for the removal of different amounts of rotational energy for different load steps.

Since the number of WTs required to replace a given amount of rotating inertia does not depend on the load step, it is more appropriate to plot the number of WTs as a function of equivalent inertia. This is shown on figure 5.2.

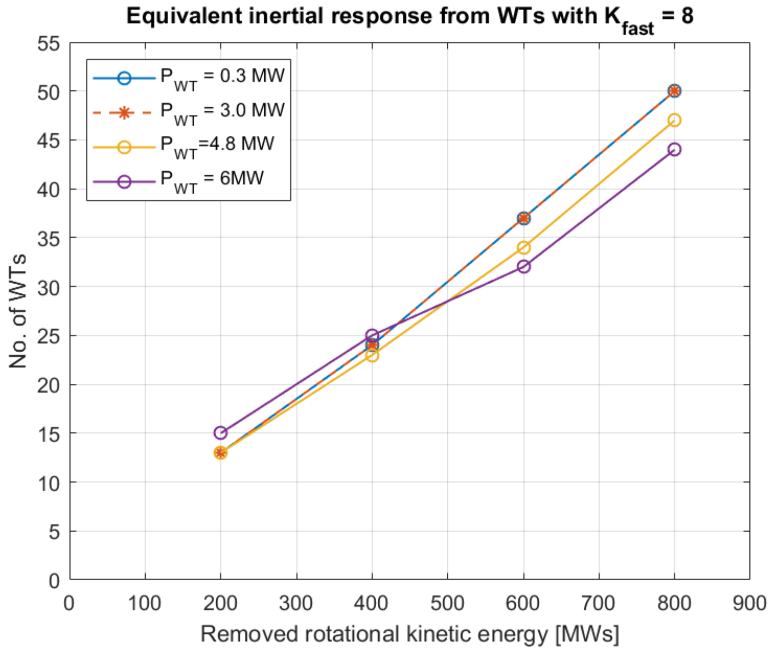


Figure 5.2: Number of WTs necessary to replace a certain amount of inertia in the radial grid.

The relationship between WTs and equivalent inertia is approximately linear. A rough estimate for the equivalent inertia of a wind turbine with $K_{fast} = 8$ is therefore 1 WT $\approx$ 16 MWs.

There seems to be some strange behaviour in that the 6 MW is above the other curves at low inertia, and then becomes lower at high removed inertia. This might be due to the measurement method. Because the synthetic inertia response is slower than a real inertial response, the WT support curve in Figure 4.2 will initially drop below the base case and then at some point cross once the WT support kicks in. The crossing-point crossing point varies with wind speed. This means that taking only one measurement at 500 ms might be uncertain. It would have been better if the RoCoF had been measured as an average over many time points. However, despite this uncertainty, the results are still relatively consistent, as is seen on both Figure 5.1 and 5.2.

5.2 Test on meshed grid

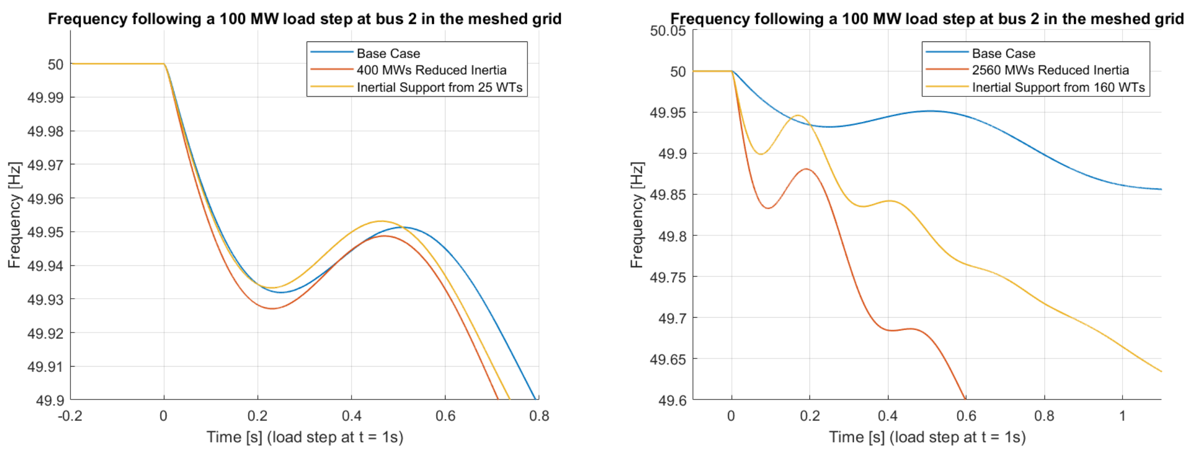
The performance of the methodology of this project is evaluated using the meshed grid, which has been provided in lecture 8 of the course. The purpose of this evaluation is to assess if the results obtained from the radial grid can be transferred to the meshed grid. The medium wind high load scenario is used, and all governors are again taken out of service, to only see the effect of the wind turbines. Total system inertia before any changes were made was 18000 MWs.

The comparison will be based on the frequency at bus 2 following a 100 MW load step. The frequency response is computed for a base case as well as a case with 400 MWs of reduced inertia.

This reduction is obtained by decreasing the inertia constant from 5 s to 4.33 s for the 600 MVA Hydro-power-plant at bus 2. Based on figure 5.2, it was found that one WT with $K_{fast} = 8$ could compensate for approximately 16 MWs of rotating inertia. Therefore this corresponds to frequency support from the following number of WTs:

$$\frac{(5s - 4.33s) \cdot 600MVA}{16\frac{MWs}{WT}} = 25 \text{ WT} \tag{5.1}$$

Therefore, a SIC is added to 25 WTs at bus 2 and the frequency responses are compared. The results are shown in Figure 5.3a.



(a) (b)

Figure 5.3: Frequency responses at bus 2 in the meshed grid following a 100MW load step at bus 2. The left plot (a) shows the situation with 25 WTs replacing 400 MWs of inertia, and the right plot (b) shows the case when 160 WTs replace 2560 MWs of inertia.

As seen in Figure 5.3a the frequency with WT support follows the base case quite closely, which supports our result that 1 WT can replace roughly 16 MWs without changing the average RoCoF during the first 500 ms. Unlike in the radial grid, the frequency oscillates, due to the meshed system being much larger with longer transmission lines and more rotating machines. The period of oscillation is clearly less in the reduced inertia cases. The synthetic inertia support from WTs helps keep up the frequency during the first few hundreds of milliseconds, however it does not affect the frequency of inter-machine oscillations.

It was also tested whether all 160 WTs at bus 2 could replace $160 \cdot 16$ MWs $= 2560$ MWs of rotating inertia, by adding a SIC. These results are shown in Figure 5.3b. In this case, we see that the response of the wind turbines is not nearly enough to compensate for the lost rotational inertia. This might indicate that the equivalent inertia of WTs is not linear for replacing large amounts of rotating inertia.

6 Discussion

One of the interesting findings of this investigation is that there are some restrictions on the available choice of controller gain K_{fast}. If K_{fast} is greater than 8, then there is a risk that the turbine will disconnect at low wind speed (due to low rotational speed protection) due to under-speed protection (this depends both on the value of K_{fast} and the response time of conventional generator governors). Likewise, at rated power output, there is risk that the inertial response might cause the active power output to exceed the power rating of the turbine. However, higher K_{fast} gains will allow the turbines to provide better inertial support at intermediate wind speeds. For instance, if $K_{fast} = 40$, then the 160 turbines in the meshed grid would be able to compensate for the reduction of 2560 MWs of inertia.

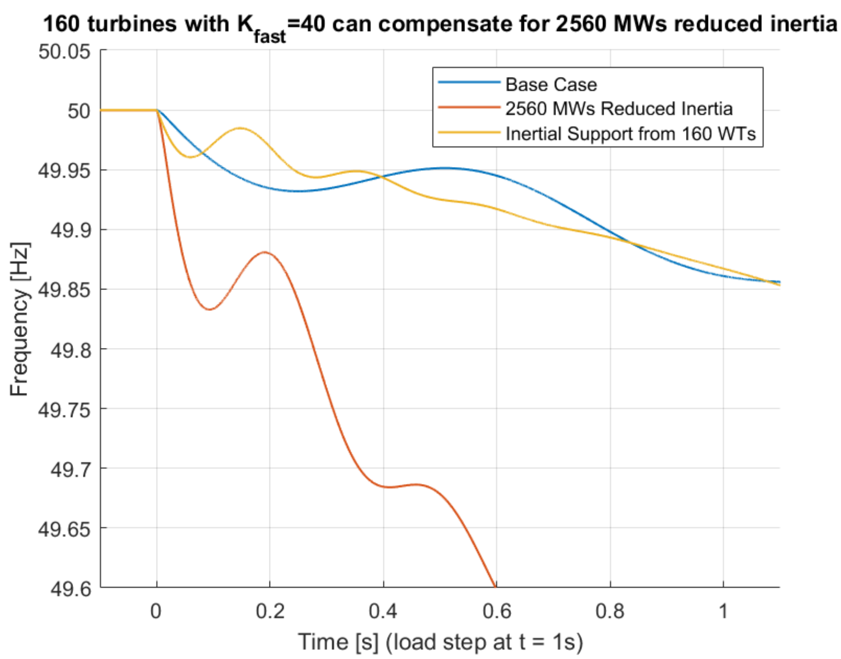


Figure 6.1: With $K_{fast} = 40$, the 160 WTs in the meshed grid can compensate for 2560 MWs of reduced inertia.

Clearly, there is more potential inertial support if K_{fast} is allowed to be greater than 8, and perhaps vary with turbine rotor speed (which is indicative of wind speed) or power output. For example, some proposed regulations could be that K_{fast} should be 8 at less than 10% or more than 90% of rated power output, and higher K_{fast} values in between.

No controller dead-band was used in this investigation. This simplified the SIC controller action, however, it also means that the controller reacts every time it senses a rate of change of frequency. This means that the controller will activate often, causing frequent mechanical stress on the wind turbine rotor and hub. From a mechanical materials fatigue perspective, it would be preferable to use a small dead-band in real applications.

Regarding the influence of the wind speed on the inertia support from WTs, it was noticed in some cases that the required number of WTs was different for different wind speeds. This could be due to the Maximum Power Point Tracking (MPPT) controller influencing the synthetic inertia response of the WT. When the synthetic inertia controller activates, it changes the generator's rotor speed (usually extracts kinetic energy and hence slows down the rotor). Therefore, the MPPT Power setpoint is decreased as well, because the MPPT seeks to re-accelerate the rotor to obtain the optimal tip speed ratio. It might be the case that the MPPT reacts differently at different wind speeds, which would explain that the inertia response could vary with wind speed.

7 Conclusion and future investigations

This study has attempted to make a quantitative estimate of the equivalent inertia available from wind turbines with a SIC controller, in terms of initial RoCoF following a load step event. A simple two-bus radial grid topology was used for this analysis. The results show that the synthetic inertia response of the turbines is independent of load step and wind speed, and that the number of turbines necessary increase (approximately) linearly with removed inertia (see Figure 5.2) (at least for small amounts of reduced inertia). Due to this apparent linearity, it was estimated that one wind turbine with $K_{fast} = 8$ is equivalent to 16 MWs of inertia. If higher values of K_{fast} is used, then the inertial response becomes stronger. $K_{fast} = 8$ was identified as the maximum gain which ensures that the wind turbines do not disconnect from the grid at low wind speeds (due to low speed protection) or exceed rated power output at high wind speeds.

A further investigation could be to better utilize the synthetic inertia of the turbines at intermediate wind speeds. Hence, extend the design such that the value of K_{fast} varies with generator speed. Additionally, a dead-band could be included in a future work, in order to reduce the mechanical stress on the wind turbine. Finally, a greater time scale could be investigated, including also the governors and study the effect of inertial controller in the entire frequency transient.

8 References

[1] Michel Rezkalla et al. *Comparison between synthetic inertia and fast frequency containment control based on single phase EVs in a microgrid*. Applied Energy, June 2017.

[2] Michel Rezkalla and Mattia Marinelli. *Augmenting System Inertia Through Fast Acting Reserve – A power System Case Study with High Penetration of Wind Power*. Proceedings of 54th International Universities Power Engineering Conference IEEE, 2020.