Practical Experience of Operating a Grid Forming Wind Park and its Response to System Events

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***Abstract*—Following from smaller-scale investigations of grid-forming converter control applied to wind turbines in 2017-8, this paper describes a much larger trial involving an entire wind park, owned and operated by Scottish Power Renewables. To our knowledge this is the first UK converter-connected wind park to operate in grid-forming mode, and the largest in the world to date. The 23-turbine, 69 MW park ran in grid-forming mode for approximately 6 weeks, exploring inertia contributions of between H = 0.2 s and H = 8 s. A large amount of data was gathered at the turbine and park level, recording responses both to deliberately-induced scenarios, and also to grid events. A number of unscheduled frequency disturbances occurred due to interconnector, CCGT and other trips, to which un-curtailed turbines were able to actively respond. While a significant amount of incremental improvement (software, hardware and energy storage) is still required to deal with the most extreme events which could occur, the turbines are able to provide stable and appropriate response at relatively high inertia levels to the frequency events commonly occurring today.**

Keywords—Grid Forming, Virtual Synchronous Machine, Wind Turbine, Power System Stability

I. Introduction

During 2017 and 2018, several small-scale trials involving up to 3 wind turbine generators (WTGs) in grid forming mode [1] were carried out, and described in [2]. These involved various trial including transitions to islanded mode, and explored different levels of inertia and damping, which are, for a grid-forming virtual synchronous machine (VSM) device, configurable via parameters in real time.

During 2019, building on that experience, the scale of the testing has been increased, in tandem with a large simulation exercise (section II). First a private-owner 6-WTG park in Denmark was used for 2 weeks of testing in January 2019. This was primarily a de-risking exercise, described briefly in section III, in preparation for a much larger trial. The initial trials were augmented by a mechanical vibration assessment at a separate site. The most recent, much larger trial was carried out during May and June 2019, at the Dersalloch wind park in Scotland, which is owned and operated by Scottish Power Renewables (SPR). This is a 23-WTG park, each direct-drive full-converter "D3" WTG having a 3 MW rating, so the park has a maximum power output of 69 MW. The aims, findings and conclusions from this trial are presented in sections V onwards.

II. Simulations for De-risking

Prior to carrying out any of the larger trials presented in this paper, a significant quantity of new simulations were carried out. The simulations were done using the RTDS Real Time Digital Simulator, in combination with a suite of 6 cabinets which contain exact replicas of the control system hardware inside each WTG, running the same versions of firmware that were to be used in the field. This creates a controller-hardware-in-the-loop (CHIL) system which can be used to explore many scenarios in simulation, without having access to (or taking any risks with) the actual WTG power hardware.

The simulations were configured to match the wind park cable/string topologies and grid impedances of the park. In the case of the Dersalloch wind park, significant effort was expended to create an accurate model of the ~10 kM 132 kV line between the wind park and the New Cumnock substation, the (up to) 3 supergrid transformers in circuit there, and a representation of the 275 kV grid including resonances at several frequencies identified in an impedance scan provided by SPEN (Scottish Power Energy Networks).

An interesting aspect of the simulation was the choice of whether to use average-value models, or fully switched PWM models, for the converter bridges. Initial expectations for a VSM style control algorithm would be that an average-value model/interface, in which the CHIL cabinet provides average value voltage levels modulated by the bridge, once per PWM frame, to the RTDS simulation, would be appropriate and accurate, and allow a significant reduction in RTDS computational power required. This is because the bandwidth of the core VSM algorithm should be < 50 Hz [3]. A full-PWM interface between the cabinets and the RTDS is also available. In this mode, the actual gate drive signals from the cabinet optic fibres are ported into the RTDS, which simulates the power electronic bridge in the "sub" time step with a ~850ns resolution, giving >200 "sub" time steps per PWM frame, and a reasonable resolution of the sampled PWM waveform. To explore both options, 3 WTGs were simulated using average-value models, and 3 WTGs were simulated using full-PWM models.

Simulations were run using the 6 WTG cabinets to represent the wind parks, aggregating the WTG models as required to match the actual scale of the park, for example the 6 WTGs were aggregated and scaled to represent 5x12 MW and 1x9 MW WTG in the case of the Dersalloch 69 MW park which in reality has 23 x 3 MW WTGs. Many thousands of combinations of power flow, frequency, voltage, and parameterisation were made, using an automated sequencer, covering hundreds of hours of simulation runtime. This aims to predict any operational scenarios in which any problematic inter-turbine or common-mode turbine-grid interactions might occur.

The CHIL cabinets and RTDS simulation provide a good fidelity of simulation of the converter aspects of the WTG, but do not necessarily provide a full emulation of the rotor-side behaviour, changing wind conditions, tower/blade resonance/damping, etc. Therefore, while the simulations are extremely useful, field testing is still essential and can always reveal problems that simulation does not explore.

III. Field trials at a 6-WTG park

A. Overview

These field trials took place over 2 weeks, at a small private-owner 6-WTG 18 MW park in Denmark, as a de-risking exercise prior to the larger tests in Scotland.

B. Instrumentation

Four of the six turbines were fitted with oscilloscopes, to provide high sample-rate capture of several variables over short periods of time. In addition to this, there are various turbine infrastructure facilities to log variables at lower sample rates (up to 20 Sa/s).

C. Validation of Simulations

A key aim of this initial field trial was to validate the simulation methodology and assess the accuracy of its predictions. While the simulations predicted no particular problems with normal sets of parameterisation under any anticipated grid conditions, problems were predicted to occur if certain controller gain parameters were significantly increased until they exceeded certain critical thresholds. The simulations also predicted the operating points (frequency, active/reactive power, and voltage combinations) at which those problems might be seen.

On site, the turbines were first operated for several days, at different inertia levels, with normal controller gains, and under different test conditions, to verify that no problems were encountered. During this time, various deliberate tests were made. Subsequently, certain controller gains were increased, to put them above the key thresholds identified by the simulations. Then, the turbines were deliberately placed into operating conditions which the simulations suggested might cause problems. Active/reactive power could be manipulated at will (wind permitting), and local grid voltage affected, but grid frequency was fixed by the wider network.

A good agreement was found between real behaviour and the simulation results provided by the full-PWM model simulations. However, the agreement with the average-value model simulations was less good. This was, at first, a little surprising. However, within the turbines the core controller runtime code does not link directly with the PWM gate drive signals. In between the core controller and the gate drive signals are further algorithms and subsystems which set the exact placement of the PWM pulse on/off times, and coordinate dead-time placement across all the bridge devices, etc. This is an active algorithm, and part of the closed-loop system. This is the reason that its inclusion in the full-PWM-model simulations makes them more accurate than the average-value model simulations, which does not include the PWM-pulse placement subsystem.

This was an important finding, and consequently only the output of the PWM-model turbine simulations was used for the final prediction of behaviour at the 23-WTG park.

D. Other lessons learnt

A number of other improvements to the methodology were identified, which would be important before a larger trial:

- In order to correlate data between turbines (for example to differentiate inter-turbine from common-mode interactions), and to correlate data between different data-gathering systems, every data stream needs to be exactly time synchronised to UTC, using GPS-quality systems (e.g. pps signals or synchronisation).
- Continuous high-sample-rate data logging 24/7 is required to capture grid events that can happen at any time without warning.
- Carrying out field trials with ≥6 turbines requires electronic access to the turbines in a "batch" mode so that parameters and commands can be changed/sent in a timely manner, ideally to many turbines at one time. Managing this process requires a very different approach to running tests on just one or two turbines. Most of the turbines are out-of-sight, and there are not enough computer screens to monitor each turbine individually.
- Prior to the tests (and simulations) a new monitoring/trip algorithm was installed within the turbine software. This quantifies the (optionally filtered) AC RMS ripple on active power export, with configurable trip settings. Simulations and field trials verified that it was fast and effective at protecting the individual turbines during any abnormal or non-predictable events. Verification was achieved by deliberately exceeding certain controller gains to induce such power ripples.

IV. Vibration Analysis

The use of a grid forming algorithm on the grid-side converter, compared to a traditional current-control (CC) algorithm, produces a different profile of power ripple frequency components. One reason for this is that the VSM algorithm tends to mitigate voltage unbalance by providing unbalanced current and this equates to a ~100 Hz power ripple in a 50 Hz system. (Inter)harmonic and flicker mitigation can lead to other frequency components of power ripple [4]. In addition, the fact that the converter is a switched device can lead to other modulation products which can feed back around the closed-loop control system. For all these reasons, the power ripple spectra is different for a VSM device than for a CC device.

The power ripple can be absorbed on the DC bus if it has a high capacitance, or some kind of additional energy buffer installed. However, in the absence of high capacitance, i.e. for most commercially available WTGs, the power ripple can be passed to the generator/rotor side, especially if the frequency of the power ripple is low.

Data was gathered from a single WTG at a park in Denmark, which also incorporated mechanical vibration sensors to directly measure the effects at the generator side. Operating this WTG in both CC and VSM modes allowed a comparison between power ripple profiles in the two modes.

The VSM mode of operation does lead to higher levels of power ripple and vibration at certain frequencies and operating points. The power ripples of most concern are those that fall at frequencies close to natural resonant frequencies of the generator, rotor and tower. However, the final conclusion was that the difference in levels was insignificant compared to the existing levels of power ripple and mechanical vibration which already occur using the CC algorithm when the WTG is operating towards its nominal rated power output. At the mid-level and high-power outputs of the turbine, where vibrations are largest, the power ripple signatures of CC and VSM appeared to be very similar. Therefore, the conclusion was that running a limited-duration VSM-mode trial would have no measurable impact on turbine lifetime. Further assessment would be required to consider operation over more extended durations.

V. Dersalloch Wind Park Trials Setup

A. Instrumentation

Following experience with the 6-WTG park, DEWEtron data loggers were used for the 23-WTG park field trials. Four of the 23 WTGs were instrumented with these units, allowing high-sample rate capture of:

- 3-phase voltages at the LV busbar of the converter filters.
- 3-phase bridge currents
- 8 selectable controller variables from the turbine

The DEWEtron units were synchronised with NTP time to within ~5ms, and also had a channel dedicated to monitoring a GPS 1pps signal, that allowed (during post-processing) time-synchronisation and temperature-corrected sample rates of the final data to within typically <10 µs (RMS sample time accuracy) across all four instruments and seamless monotonically-sampled dataset extractions up to 20 minutes long. These 4 units gathered ~12 TB of raw data over the 6 week trial, running essentially non-stop for that time.

Additionally, up to 20 Sa/s of a much wider variety of signals was logged from all 23 WTGs, time synchronised to the NTP clock. These signals can be viewed in real-time on-site (or remotely), and were also logged on a 24/7 basis.

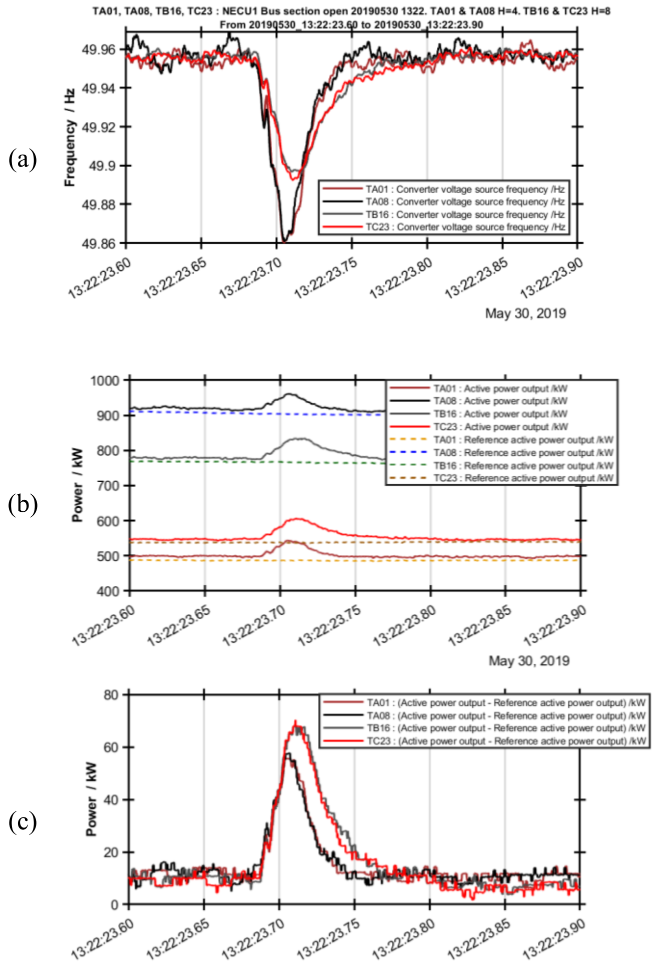

Fig. 1. Response to a small negative-going phase step. (a) WTG converter voltage source frequency. (b) active powers and reference powers. (c) (active power minus reference power)

Furthermore, SPR installed their own independent DEWEtron instrument connected to the MV side of the MV:HV grid transformer serving the entire wind park. This was time-synchronised directly to its own dedicated GPS unit.

Results presented in this paper are taken from all these different sources as appropriate.

B. Parameter sets

Several different turbine parameterisations were explored during the test period. A general picture is given in TABLE I. In addition, for certain deliberately-induced tests (such as the planned phase step in section VI.A), short-term modifications were made to parameterisations.

TABLE I. WTG Parameterisations

07-10 May	1, 4, 11, 17, then 23 WTGs grid-forming at H = 0.2 s (remainder still in CC)
11-19 May	Park off-line (HV maintenance)
20-21 May	1, 4, 11, 17, then 23 WTGs grid-forming at H = 0.2 s (remainder still in CC)
22-24 May	8 WTGs at H = 4 s, 15 WTGs at H = 0.2 s Aggregate park inertia H ≈ 1.5 s
24/5 – 6/6 (14 days)	23 WTGs grid-forming at H = 4 s
6-25 June (19 days)	20 WTGs at H = 8 s, 3 WTGs at H = 4 s. Aggregate park inertia H ≈ 7.5 s

VI. Notable Events and Results

Only a fraction of the findings can be presented in this paper. During the test period several deliberate tests were carried out. However, the GB system was also generous in terms of actual system events that occurred during the test period, at a variety of different turbine inertia levels and during times of quite different wind conditions. Therefore, for the length of the test period, the results contain a usefully diverse set of logged events with interesting features.

A. Response to phase step

On 30th May, SPR, SPEN and National Grid Electricity System Operator (NGESO) arranged for bus sections at the New Cumnock substation to be decoupled. This affected the grid impedance and caused a small 0.2-0.4° phase step to occur at the wind park. When a SM (synchronous machine) within a large power system is exposed to such a negative-going phase step, a burst of additional power floods out, due to the increased stator-rotor angle δ, which tends to decelerate the rotor until it reaches a new steady-state position in equilibrium with the power provided by all other grid-connected generators. A similar response is expected of a grid-forming converter.

The response to the phase step is as expected, with the response of 4 turbines shown in Fig. 1. The pu impedance of each WTGs filter and transformer is ~14%, so the instantaneous power transient will be of the order of:

$$\Delta P \approx \frac{S_{rating}}{X_{pu}} \times \delta \times \frac{2\pi}{360} \tag{1}$$

so that a phase step of δ = 0.2° at a 3 MW turbine might draw out an initial peak power of around 75 kW that will decay at a speed inversely proportional to the inertia. This is roughly what happens. Fig. 1 (a) shows that the internal voltage source frequency of two turbines set to H = 4 s (TA01 & TA08) moved faster (and in half the time) to adjust to the new phase angle, compared to the two turbines set to H = 8 s (TB16 and TC23).

The active power responses, and the internal active power references (the power setpoint, accounting for wind etc. but without including any grid-forming inertial response), are shown in Fig. 1 (b) - the 4 WTGs are operating a different power levels. The difference between the actual output power and the reference power, for each WTG, shown in Fig. 1 (c), reveals the action of the grid-forming VSM behaviour. For a phase step, the magnitude of the initial power response is not proportional to the inertia setting, but the length of time (i.e. energy dispatched) is proportional to the inertia setting. In Fig. 1 (c), there does seem to be a small increase in instantaneous power for the WTGs with higher inertia (TB16 and TC23). However, it is not proportional, and is likely due to a combination of active power measurement window (~1 cycle, which does not truly represent instantaneous power), VSM damping terms, and the decaying nature of the response with time.

Large phase steps in excess of 10 degrees need to be dealt with in a similar manner to low-voltage fault ride through. Developing robust algorithms for this in grid-forming converters is a significant challenge. By (1), for a 10 degree step, the power deviation is > 1 pu, so the core grid-forming algorithm needs additional intervention to avoid over-currents when phase steps exceed 5-10°, depending on the pre-existing power output.

B. IFA trip 31 May 2019 13:19. Park H = 4 s

On 31st May, the IFA (Interconnexion France-Angleterre) tripped, with an infeed loss of ~1GW. ROCOF peaked at ~-0.11 Hz/s (Fig. 2), with a frequency drop of nearly 0.5 Hz. At this time the entire windpark was operating at H = 4 s, and at a power level of ~50 MW of the 69MW capacity. The traditional estimation of additional power infeed during a constant-ROCOF event follows (2):

$$\Delta P \approx -\frac{2 \times H \times S_{Rating}}{f_0} \times \frac{df}{dt} \tag{2}$$

For this event the prediction is ~1.2 MW, but it must be remembered that (2) does not account for dynamic effects when ROCOF is changing, especially at the beginning of such events. Neither does (2) account for the 2nd-order nature of a SM or VSM response, in which there are (and must be) damping terms as well as inertia terms.

The total windpark power output, is shown in Fig. 2 (c). There is clearly a power increase of approaching 1 MW, but it occurs during a period when available park power from wind was falling at ~200 kW/s. This is shown by the sum of converter reference powers in Fig. 2 (c). Plotting the difference between these two signals reveals the response that the VSM algorithm produces, shown in Fig. 2 (d), which is roughly in-line with the approximate 1.2 MW prediction.

In this event, the windspeed was good (but falling), with the rotor speeds sitting towards the maximum speed of 16 RPM, storing plenty of energy, compared to the energy needed to deliver H = 4s over a 0.5 Hz drop. Consequently, rotor speeds and pitch angles are hardly affected (and not plotted) during this event. There is little evidence of post-event power reduction/recovery required, in this example.

The GB system inertia at the event time can be estimated using (2), with ΔP = -1 GW, to reveal HS ≈ 250 GVAs. At the same time, the park inertia was HS = 69*4 = 276 MVAs, offering approximately 0.1% of the available GB system inertia. If H = 8 had been configured, this figure would been 0.2%.

C. IFA trip 12 June 2019 17:44. Park H = 7.5 s

On 12th June IFA tripped again, with a resulting ROCOF of ~-0.08 Hz/s, and a frequency drop of ~0.35 Hz. This time, the park was operating with an aggregate inertia of H = 7.5 s (TABLE I.). Again, by chance, available wind power from the park was dropping during the event, by ~50 kW/s. The response of the park is shown in Fig. 3, which can be compared to Fig. 2. Although the ROCOF is smaller than the 31st May event, the response is larger, due to the almost doubled park inertia. The dropping background windspeed does, however, act to counter some of the response.

Of particular interest in this event is that ROCOF becomes positive during the network recovery (Fig. 2 (a) & (b)), and the turbines respond by reducing their power output (Fig. 3 (c) & (d)), as expected from a device with inertia. The output power becomes less than the reference power. The same behaviour also occurred during the 31st May event. The scales required for Fig. 2 (c) make it difficult to resolve, but the effect can be seen in Fig. 2 (d).

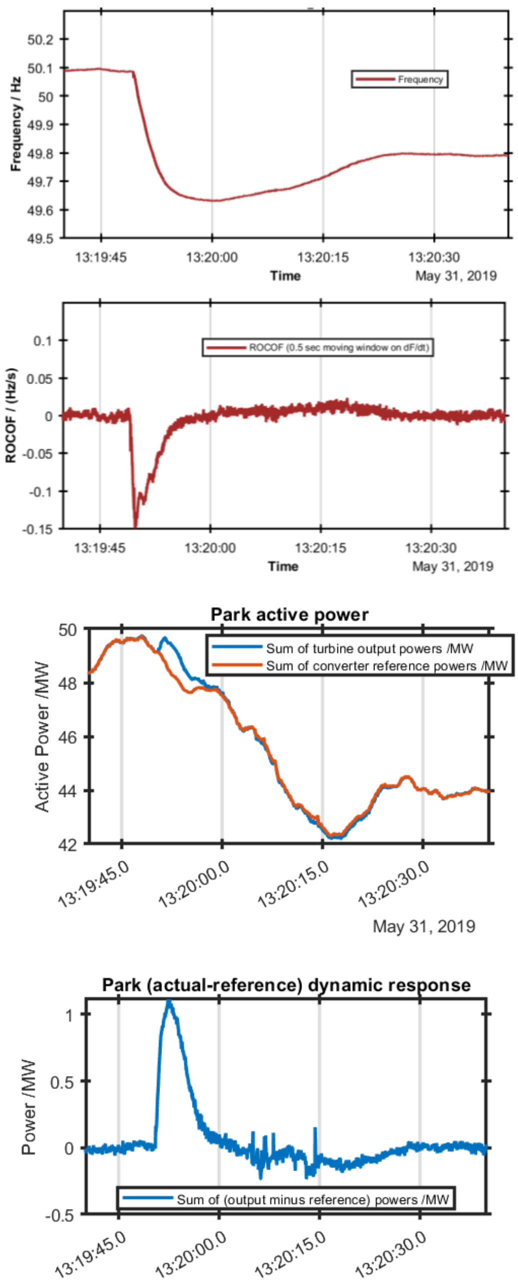

Fig. 2. Response to IFA trip with windpark H = 4 s. (a) SPR 33kV PQ analyser frequency. (b) SPR 33 kV PQ analyser ROCOF (c) Park output power and reference (d) Park output power minus reference

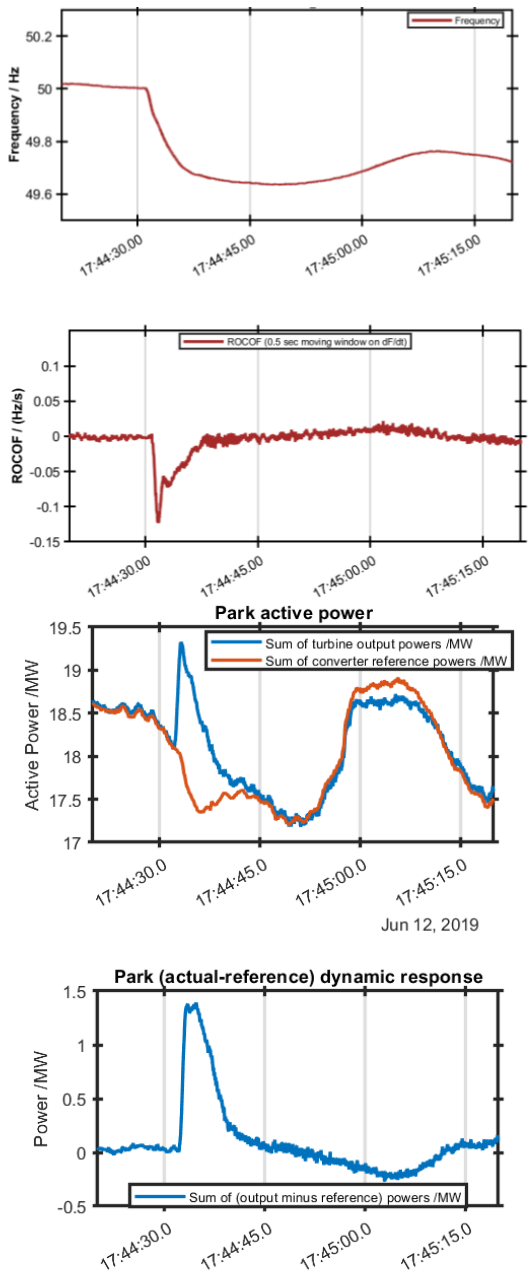

Fig. 3. Response to IFA trip with windpark H = 7.5 s. (a) SPR 33kV PQ analyser frequency. (b) SPR 33 kV PQ analyser ROCOF (c) Park output power and reference (d) Park output power minus reference

D. Frequency event 20th June 2019 14:58. Park H = 7.5 s

On 20th June another frequency event (root cause not known by authors) occurred, with a ROCOF ≈ -0.06 Hz/s, and a frequency drop of ~-0.4 Hz. On this occasion, wind happened to be increasing (on average) across the park as the event occurred (though not at every turbine). By (2) the expected response with H = 7.5 s would be ~1.2 MW. The actual park response is in-line with this value (Fig. 4).

E. Synthetic event, -1 Hz/s, 3 Hz drop. Park H= 8 s

None of the events described thus far had a noticeable effect on WTG DC bus voltages, rotor speeds, or pitch angles.

This is because the ROCOF and frequency deviations, although significant events, were not large compared to the worst possible deviations which might occur in a small or islanded power system, or might be specified in grid-code conditions. The amount of extra energy extracted from each turbine was of the order of 60 kW for 5 seconds, i.e. about 300 kJ, or 0.08 kWh.

To explore the turbines behaviour under much more significant disturbances than are seen naturally during the test period, it is possible to inject a disturbance into the converter control algorithm. This makes the grid-forming VSM algorithm behave with a power response that mimics what would happen during the given frequency profile.

Using this system, many events were emulated. The most extreme involved all 23 WTGs being set to H = 8 s inertia, and being subjected to a -1 Hz/s emulated frequency slide, with a 3 Hz frequency drop (for example from 50.5 to 47.5 Hz).

(a)

(b)

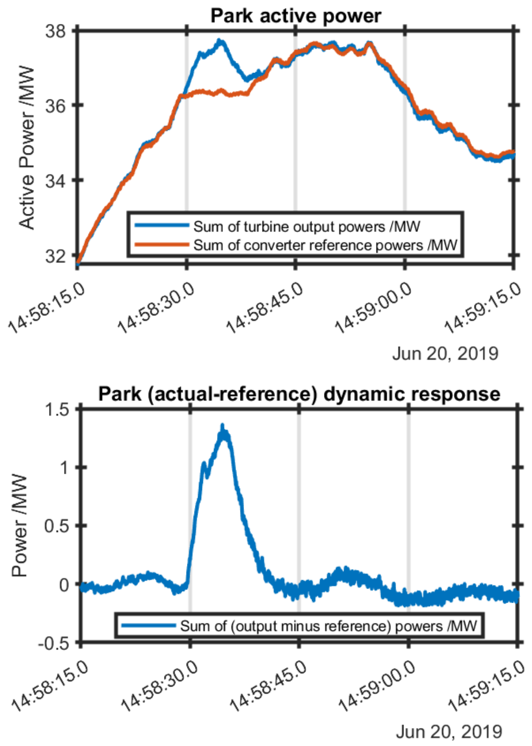

Fig. 4. Response to event 20th June 2019 with windpark H = 7.5 s. (a) Park output power and reference (b) Park output power minus reference

The emulation system requires all turbines' clocks to be exactly synchronised to the NTP server, so that the event can be triggered synchronously in all turbines' control systems. This NTP synchronisation is not always 100% reliable, although turbines' clocks free-run with reasonable accuracy if they temporarily drop out of exact synchronisation.

During this event, 19 of the 23 WTGs were exactly synchronised to NTP time and emulated the event. The total effective aggregate inertia was therefore H = 8 s across a reduced 19-WTG 57 MW park.

The amount of energy required to respond to this event (per turbine) is much larger than the 300 kJ needed for the natural events encountered thus far. By (2) the park response should be a peak of ~18 MW, i.e. ~1 MW per turbine. The event lasts 3 seconds so the energy required per turbine is approximately 3 MJ, 0.8 kWh. This is about 10 times that required for the natural events encountered.

The turbine and park responses are approximately as expected, as shown in Fig. 5 (a) & (b). The amount of energy extracted in this case has a significant effect on the rotor speed. The mean, maximum and minimum rotor speeds across the park during the event are shown in Fig. 5 (c). The reductions in rotor speed are significant. No turbines are spilling power at the beginning of the event, and so there is no effect on the blade pitches, which are all in the normal position for maximum power extraction.

This case clearly demonstrates that there are limits to what can be achieved on the WTG, without additional energy storage or pre-event curtailment. During the event, while the converters are attempting to respond with ~1 MW each, the reducing rotor speeds cause the turbine controllers to gradually reduce the reference powers, in turn gradually reducing the absolute power infeed as the event unfolds. the event also leaves the turbines with a post-event recovery period, during which a reduced power is produced until rotor speeds recover.

(a)

(b)

(c)

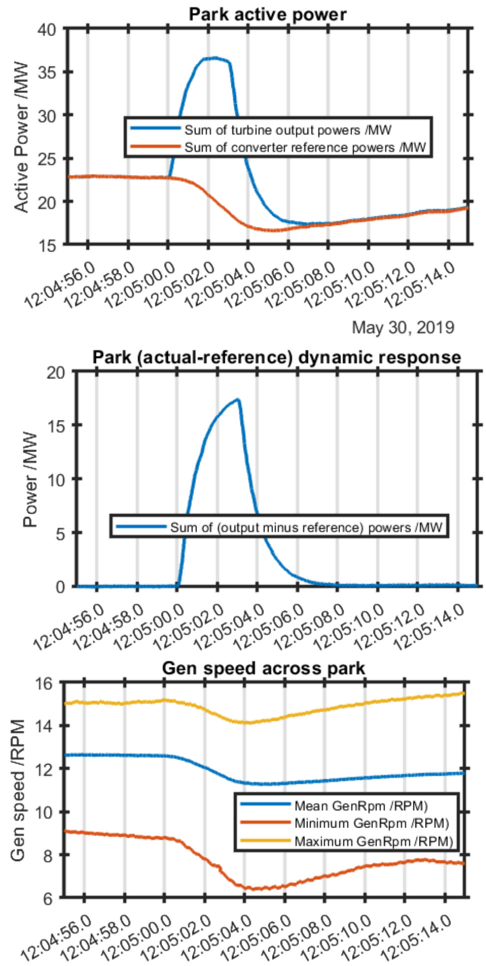

Fig. 5. Response to emulated -1 Hz/s, 3 Hz drop emulated event with 57 MW of turbines at H = 8 s. (a) Park output power and reference (b) Park output power minus reference (c) Generator (rotor) speeds

As it happens, one turbine within the park was only producing 400 kW at the start of the event, much lower than most of the rest of the turbines, simply due to local wind conditions. This turbine is the one causing the minimum generator speed shown in Fig. 5 (c). As a result of the ~1 MW additional power response, the rotor speed slowed to below 6.7 RPM and the turbine actually cut-out at that time (12:05:06). This shows that operating at high values of inertia, during the most severe events, at low windspeeds, without any additional energy available aside that stored in the rotor, can be counter-productive in terms of positive power response.

VII. Other Miscellaneous Findings

There were many other events during the test period, which cannot be reported in a short paper. These included 3 more significant frequency events, one due to a 600 MW CCGT trip, and two for which the root cause is not known. These have been at least superficially investigated, but much more post-analysis could be done, using the high sample-rate data, of these events and others over the entire test period.

Some of the individual turbine responses were made at times of reasonably high wind speed, but despite this there are a couple of occasions when those individual turbine responses dip significantly (by up to 400 kW) at around the same time that an inertial response of ~60 kW is being made, simply due to locally fluctuating wind conditions.

In general, on an individual turbine basis, even with high inertia settings up to H = 8 s, when exposed to common ~0.1 Hz/s ROCOF events, it can be sometimes be difficult or impossible to pick out the inertial response from the background power ramps due to fluctuating windspeed conditions. Only by taking a park-level aggregation with at least 10 (and in this case 23) turbines can a clear picture be obtained, if the only available measurand is the final active power output. To understand the response better, or with smaller numbers of turbines, additional logs of the turbines' internal reference power are extremely helpful, to disaggregate the effects of wind from the response which the grid-forming VSM converter is attempting to make.During some of the events, some of the turbines were operating at extremely low power output, or at zero power. When operating at zero power, the turbines entered "Voltage control mode" during which time they still provided ancillary services including grid-forming VSM behaviour. However, there is zero energy stored in the rotor at these times, and the only energy stored (in the absence of any additional energy buffer) is within the small capacitance on the DC link.

When operating at low/zero power, the turbines could only deliver reduced/small additional power/energy responses when subjected to negative ROCOF or negative-going phase steps. Conversely, during positive-ROCOF or positive-going phase steps, incoming energy cannot be dealt with by reducing rotor power, and so DC bus voltage rises until clamped. No turbine trips were caused by these mechanisms, but they were observed at times.

VIII. Conclusions

The 69 MW wind park operated successfully in grid forming mode for nearly 6 weeks, including 2 weeks at an inertia of H = 4 s and nearly 3 weeks at H = 7.5 s (aggregate). During that time, 6 significant frequency deviation events occurred with ROCOF levels up to ~-0.1 Hz/s and frequency drops up to ~0.5 Hz. The turbines, as a park, were able to respond to all these events, autonomously and immediately, with power responses appropriate to the inertia levels configured. This is useful information in the context of new initiatives such as [5] [6]. No turbine trips due to stalling, over-power, over-current etc. were encountered during the grid events.

However, even at the park level, with 23 turbines, natural windspeed fluctuations can cause power output changes of similar magnitudes (and rates of power change) as the typical inertial responses to a 0.1 Hz/s event. The turbines' ability to respond is also extremely small if the turbines are operating at very low powers, or at zero power ("Voltage control mode").

When larger frequency events are considered, for instance 1 Hz/s and 3 Hz drops, the turbines will attempt to respond proportionately, and the windspeed fluctuations will become less significant in comparison. However, the energy required to provide the appropriate response to such an event, with H = 4 s or H = 8 s, is significant. Without additional energy storage, the large events can significantly reduce the rotor speeds and draw the turbines into recovery periods during which their power output is reduced. If not enough wind is available, and rotor speeds are initially low, then attempting to provide the full response can slow the rotors below cut-out speed. This reduces power infeed to zero on the turbine(s) affected, which would be the exact opposite to the desired effect.

To counter this possibility, one option is to allow the parameterised inertia H to vary in real time, with each turbine offering high H when the wind and rotor speed is appropriate, and a tapered reduction of H when wind and rotor speeds are lower. Although it was not an issue during field testing, a similar tapered reduction of H may be required at high wind/rotor speeds, even though plenty of energy is available. This could be required to avoid the turbine entering an over-power or over-current situation if an additional significant response is required. While dynamic H is a technical option, it presents compliance/market/reward challenges if the provision of inertia directly brings revenue or is required by grid codes. Curtailment and deliberate sub-maximal power tracking are also options. There are many option permutations for managing all these considerations.

Of course, additional energy storage, either within the existing turbine DC bus, or as a separate parallel converter-connected device, would allow a more guaranteed response over a wider range of operating conditions - but at not insignificant additional cost.

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