Effects of VSM Convertor Control on Penetration Limits of Non-Synchronous Generation in the GB Power System

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Abstract — **2013 saw the presentation of a paper [1][2] to the wind integration workshop, which demonstrated 26 high convertor penetration scenarios, 17 of which introduced a type of instability in RMS models previously unseen by the researchers. It also provided an indication of the constraints necessary if NSG levels where to be limited, potentially placing practical limits on the amount of NSG which could be accommodated. It demonstrated that Synchronous Compensation (SC) could be used to mitigate these and other problems but this is believed to be an expensive solution.**

Further publications have demonstrated that convertor instability at high NSG extends beyond RMS models and is believed to occur in real systems [3]. In addition, Swing Equation Based Inertial Response (SEBIR) control, sometimes referred to as "Synthetic Inertia", has been shown to be ineffective as a countermeasure against the instability observed in [1][2] and can in some circumstances make it worse [4][5]. Whilst SEBIR improves RoCoF, its inability to address the wider range of problems resulted in the need for more comprehensive solutions.

Several authors have proposed converters using principles aligned with VSM and VSM0H concepts and controllers using these concepts exist within marine power networks.

This paper returns to the studies presented in [1][2], which used a reduced 36 node GB model in PowerFactory (PF). However here, some of the convertors are replaced with VSM convertor models described in [6] to investigate the effects on Instantaneous Penetration Level (IPL) limit of NSG in terms of transient stability and steady-state stability. These and further results presented demonstrate the potential of VSM, in mitigating the effects of various challenges associated with high NSG, potentially allowing 100% penetration.

Keywords- Non Synchronous Generation (NSG), Virtual Synchronous Machine (VSM), Convertor Control, Penetration Level Limit, Power System Stability

I. INTRODUCTION

With the predicted continued growth of renewable generation and the desire of policy makers to further reduce CO2 emissions, there is a need to identify solutions which allow increasing amounts of renewable NSG to connect. It has been shown through modelling [1][2], that exceeding 65% NSG penetration may result in real system instability, or inability to model the system using current modelling techniques and models submitted to the GB SO (Great Britain System Operator). Further research [7][8][9] has provided additional evidence regarding the limit of stability.

Models for all NSG embedded and transmission connected projects, currently submitted to the GB SO can be classified as convertors of a type referred to in this paper, as Direct Quadrature Current Injection (DQCI). These convertors are represented as constant current sources capable of injecting real or reactive current relative to the measured voltage at their terminals. They are typically fast acting, utilising Phase Lock Loops (PLL) to synchronise with the voltage source they are connected to, which is assumed to be stable and with a fault level significantly higher than the converter rating. It should be noted that in these models, most modern converters described as Voltage Source Converters (VSC) are often actually modelled as current sources.

With much new generation being smaller scale and distribution connected, the detailed planning, analysis and compliance processes typically applied to large scale generation projects are simply impractical. Robust solutions which address potential problems are therefore required.

Only the lowest frequency dynamics, considering aggregations of embedded converters, can be included in a system-wide model. Modelling any potential super-synchronous interactions between converters in the 50-1 kHz range is not practical or possible for any single entity. Therefore, general system dynamics of power flows and voltage control can only be understood by the operator if the bulk of devices have control bandwidths which are <<50Hz.

The conventional DQCI converters used in existing wind, solar-PV, and VSC-HVDC devices have control bandwidths and potentially resonant modes at frequencies higher than 100 Hz, in order to control their current waveform shapes. Clearly, then, the DQCI control architecture, alone, does not provide a path towards a 100% renewable generation scenario.

Ambiguity and misunderstanding surrounds the terms "synthetic inertia" and "virtual inertia" in much of the existing literature. Great care should be taken when using these and other terms and regarding the descriptions of converters which emulate SG in some way. There are at least 3 fundamentally different ways of providing converter responses which (in some way) emulate SG behaviour.

The lowest-risk method of providing "synthetic inertia" for manufacturers, is to take an existing DQCI converter and augment the active power control with an adjustment based on a measure of Rate of Change of Frequency (RoCoF) and a chosen per-unit inertia H, based on the well-known swing equation [10][11][12]. This technique was investigated in [4][5] and given the term SEBIR. While this technique does provide a "Fast Frequency Response", as a result of the time needed to complete the RoCoF measurement and close the control loop, means the response is not truly inertial. Also, the presence of the DQCI inner current loop retains the high-frequency dynamic control-loop components. In fact, the total achievable penetration of converters was shown to be reduced by using SEBIR. It can provide "Fast Frequency Response" but not "Inertia", and it does not provide any mitigation of voltage power quality (unbalance, (inter-) harmonics for example).

On the other hand, a converter which behaves as controlled voltage source, producing a balanced three-phase voltage set behind an inductive filter impedance, with the control bandwidths set to <5 Hz, provides the plug-and-play functionality required to:

- Allow the system to be modelled at an aggregated and system level.
- Allows the converters to mitigate voltage power quality (e.g. unbalance or (inter-)harmonics) in a stable manner, in proportion to the converter ratings and per-unit filter impedance magnitudes.
- Allows converters to operate at extremely low fault levels – indeed to the fully islanded case including black-start scenarios.
- Allows converters to supply unbalanced and harmonic currents to unbalanced and non-linear loads, when loads require this.
- Provides the highest probability of network stability with 100% converter penetrations.

With the results of the intervening research [1-2][4-9][13] being positive and those of VSM in particular looking promising, the original studies responsible for initiating this research, were rerun in order to establish the effects of implementing VSM at some future date. The results are very positive as VSM would appear to be very effective. In addition the results correlated relatively well with earlier EMT studies using a simplified network [13].

Whilst the results presented are very encouraging, VSM and VSM0H are not the only research being undertaken or considered by the GB SO. Nevertheless, these control strategies point to a solution which is comprehensive in nature, resolving multiple issues. They may be particularly suited to applications where detailed studies are impractical e.g. small and medium scale embedded applications.

II. NETWORK OWNERS AND OPERATIONS PERSPECTIVE

With ever higher penetration of DQCI convertors, for SO's and TO's, there are various significant areas of concerns [6], most notably:

1. Increased Rate of Change of Frequency (RoCoF)
2. Loss of synchronising torque/power and reference voltage
3. Possibility of high frequency instability and controller interaction
4. In adequacies of RMS models and the associated difficulties with modelling the electricity system
5. Reduced and possibly delayed fault in feed and associated challenges in transmission system protection performance
6. Possibility of voltage instability during or post fault e.g. collapse, blocking or over voltage post fault
7. Potential for sub-synchronous oscillations and interaction with conventional machines
8. Potentially increased sensitivity to load imbalance and harmonics

Typically for penetration levels below 50% [1][2][7][13] the remaining traditional synchronous plant provides the appropriate response, mitigating against these effects and allowing normal system operation and modelling. However it is anticipated at some point between 50 and 80% (various estimates exist [1][2][7][13]) one or more of these effects will adversely affect operation and / or modelling.

III. VIRTUAL SYNCHRONOUS MACHINES (VSM)

Reference [6] describes how VSM convertors mitigate against all but the reduced fault level. Fundamental features of this type of VSM convertor, which facilitate this improvement in performance, are implemented in the model presented here. These in the main but not exclusively, relate to the output stage which differs from DQCI as it is essentially a voltage or pseudo voltage source e.g. Pulse Width Modulated (PWM) switched valves e.g. Insulated Gate Bipolar Transistors (IGBT), connected to the network through a filter reactor, which for these studies had an impedance of 10% on rated value.

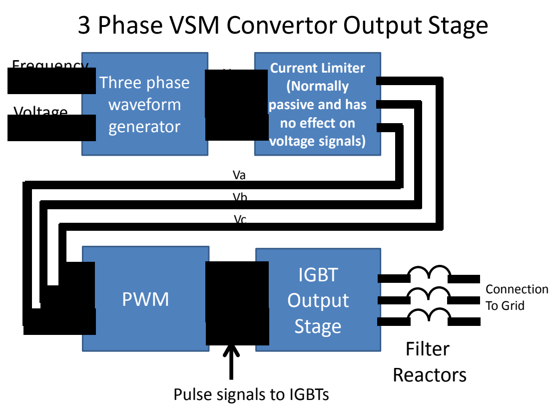

Figure 1 – VSM Convertor Network Interface

The models presented here are implemented in DigSILENT's PowerFactory V15 and use the same Statgen element used to model DQCI convertors. However critically for VSM the Statgen is set to voltage source mode.

In a real convertor this might be implemented as shown above in Figure 1, where the output stage (in this case shown as IGBT switches) is controlled by a three phase waveform generator and coupled to the network by a three or single phase filter reactor, depending on the application. Under normal circumstances the current limiter is entirely passive and has no effect on the signals passing through it. The current limiters primary function is to protect the IGBT's in the event of a fault / short circuit and maintains an output current which is within the device rating. It may be implemented as shown or directly limit pulse duration or use some other method.

The PWM generator turns the voltage signals into pulses which switch the IGBT's to produce a stepped voltage or pulsed / pseudo voltage on the convertor side of the filter.

Most importantly the 'Voltage' and 'Frequency' control signals used to control the three phase waveform generator are bandwidth limited to attenuate frequency >4Hz. Assuming the DC input to the convertor is appropriately managed, this attenuation at 4Hz and above, limits the rate of change of the AC frequency, angle and voltage output from the convertor. This eliminates the possibility of many of the higher frequency interactions and explains how this type of convertor reduces the risk associated with several of the issues raised earlier. In many cases, it avoids the need for EMT modelling. Only control actions associated with current and power limiting and convertor protection are high bandwidth as they must operate quickly to prevent damage.

From the networks perspective, the convertor is a voltage source and the current drawn is therefore largely determined by the network. This is a significant advantage as it results in an almost instantaneous (sub 50/60Hz cycle) response to load changes, switching events and faults.

In addition for current limit strategies which maintain the same phase reference from the waveform generator and only seek to limit the current by reducing the volts, the proportion of reactive and real power injected during the fault is determined by the network and filter and not the control system. This approach provides better voltage support during and post fault. It also avoids the possibility of over voltage on fault clearance. Post fault over voltage in conventional DQCI convertors can result from delays in the control system reducing the injected reactive current when the fault is cleared.

Whilst VSM convertors may produce more harmonics than traditional Synchronous Generators (SG) they are essentially a voltage source from which conventional DQCI converters PLL's can obtain a phase reference.

IV. Potential Disadvantages / Counter Measures

There are some potential disadvantages with Voltage Source Convertors. The load current may change rapidly, may be unbalanced and / or contain harmonics resulting in increased and higher frequency ripple current on the DC side of the convertor. Consequently, the components used would have to be appropriately rated.

It is possible to reduce the harmonic or unbalanced ripple current by modifying the magnitude of the voltage on each phase or the shape of the convertor output waveform. Provided the control action associated with the waveform modification is likewise limited in bandwidth, preferably to between 0.1Hz and 4Hz, it is conceivable this could be carried out without the associated risk of injecting higher frequency disturbance. In specific applications it may be necessary to allow higher bandwidth control actions. This may only be safely managed through detailed studies and testing. Rapid changes in load current require an energy source which can respond accordingly or some form of additional energy storage. The amount of additional energy required depends on the proportion VSM and SG to DQCI.

Whilst the reduction in bandwidth considerably reduces many potential risks associated with high levels of NSG, it could reintroduce classical power system instability, as observed with conventional SG.

V. Power System Oscilation Damping

Unlike conventional SG where many of the parameters are defined by the physical design of the machine, in VSM they are implemented as variables in software and could be changed in real time with no additional hardware cost. The model demonstrated here has several damping options which can be applied to the angle/frequency and has similar effects to mechanical damping or damper windings (see [6]). It is also possible to modulate the voltage produced like a conventional PSS for SG.

Unlike SG, VSM damping can be increased significantly without incurring extra cost or real energy loss. Damping through voltage modulation is much simpler to implement as it can be applied after all the phase lags.

In the models used here we have also implemented the equivalent of dynamic breaking. When fitted to SG there are significant cost implications, as breaking resistors must be fitted. For VSM however, the changes largely affect the software and as a consequence should not impact cost. As result of this feature VSM is significantly more stable post fault and should improve overall system performance [6]. It is also worth pointing out that not only is dynamic breaking desirable from a power system performance perspective, it is also a necessary design feature of this VSM algorithm. Without it, the power swings at the convertor terminals, post fault, can result in 2pu rated current and power [6].

VI. Current & Power Limiting and Fault Level

It has been shown [14] that delayed and reduced fault in-feed from convertors could lead to mal-operation of existing transmission protection relays and faults not being detected. Appropriate fault in feed is also needed to ensure voltage recovery. It is anticipated that recovery maybe more problematic in the future as the V^2 load reduction effect lessons, due to voltage support from embedded generation and increased electronic load.

Whilst it is accepted that the convertor output current must be limited to provide economic convertor solutions, there is also a need to ensure voltage recovery and correct operation of the protection. The current limit within the convertors used in the model presented here, have been configured to operate with all of these factors in mind.

Providing current limiting within 1.1pu of the rating of the DQCI convertor is relatively straight forward as they are modelled as a constant current source. It is simply a matter of limiting the control signals to the Statgen elements within the PowerFactory model.

For the VSM convertor, being a voltage source it is more difficult to limit the current. The voltage control signal needs to be reduced to achieve this, when a fault is applied. The current limiter consists of a PI controller which acts on an error signal derived from subtracting the reactive current from a limit level. However this results in a high initial fault current due to the delay of the controller. A further modification which limits the output voltage of the convertor to within 15% of the measured terminal volts largely overcomes the problem. Typically the fault in feed is initially limited to 1.5pu reducing to 1.25pu in 80ms.

These levels have been selected as reasonable for the purpose of these studies, in anticipation that VSM technology would have higher ratings due to the power requirements. 3ph balanced faults are applied in the studies presented here, which are typically used for worst case stability analysis. For real equipment, most faults are single phase to earth and the limiter would ideally apply limits only on phases that require current limiting.

The techniques presented here provide a useful means of using RMS studies to understand the effects at a system level. In practice manufacturers have many options regarding implementation of the current limit, such as measuring the current within each arm of the bridge or output valve. Similarly it is conceivable that analysis tool providers may include current limiting within the voltage source elements as a standard feature. These may operate in a different manor, avoiding or reducing the initial overshoot to 1.5pu. This would be a better solution, provided they are representative of the real equipment.

VII. Simulation Scenarios

Previous research demonstrated VSM0H [13] allows increased penetration of renewable NSG based energy sources. In addition, VSM, with the exception of the reduced fault level, should mitigate many of the concerns discussed earlier. It was therefore decided to perform following studies on the original 36 node reduced GB model:

1. Rerun the 26 study cases [1][2] to see what proportion of VSM convertors is needed to rectify the original problem.
2. Study how VSM convertors mitigate against RoCoF and support system frequency. Two studies were performed:
    a. Trip 1600MW of generation in Zone 1 and observe the effects on frequency.
    b. System split between Scotland and the rest of GB

The same 2013 model was used, as paper [1], consisting of 36 identical substations. To produce it, the full GB network with reinforcements for 2030 was divided into 36 zones. A centrally located substation in each zone was picked and the impedance (R, X and B) between each centrally located substation calculated and used to establish the circuits between the zones. Circuit components such as Quad Boosters were omitted but series capacitors were included. Each zones substation in the reduced model consists of eight conventional generation types and two convertors all labelled by their fuel type e.g. Nuclear, Gas Turbine, Hydro, Biomass, Other etc. and NSG Wind and Marine. "Other" represented combined embedded SG and synchronous compensation, if this option is selected.

In the original study [1][2] "Wind" represented both Transmission and Distribution connected wind farms and "Marine" represented the marine and solar generation, again both distribution and transmission connected. However in these studies Statgen "Wind" is used for all DQCI and "Marine" for all VSM in each zone.

All conventional generation is fitted with a very basic governor which provides a degree of frequency control. The AVR choice was considered more critical, consequently validated generic models were used. The models used offered a range of options e.g. 2 or 3pu forcing, PSS1A or no PSS, rotating (300ms) or static (50ms) excitation and range of machine sizes. Appropriate excitation systems were selected for each fuel type,

A spread sheet was used to create the 26 scenarios by dispatching generation zone by zone, prioritising by fuel type and scaling the MVA of each machine and step up transformer accordingly. Unused generation was put out of service. Loads connected at each substation were similarly scaled. Where appropriate HVDC was connected at each substation and automatically dispatched. Reactive support was modelled using PowerFactory SVS elements, which were used to represent reactive components i.e. capacitors, reactors and Static Var Compensators (SVC).

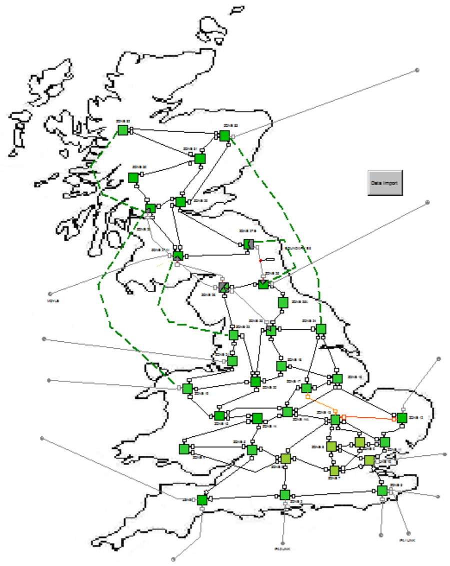

Figure 2 – 36 Substation Model of GB

Basic dynamics controls were applied to all HVDC, static generators and SVS's. The controls applied to the convertors and HVDC were all identical and consisted of a PI voltage controller with reactive power droop to control the reactive current of the Statgen's. The control of real current was setup to simulate Limited Frequency Sensitive Mode (LFSM) for most studies and Frequency Sensitive Mode (FSM) where indicated in the results. The VSM model is identical to and described in detail in [6] which presents a variety of test scenarios and results for VSM and SG on a 15GW bus e.g. voltage steps, faults etc.

VIII. System Stability Studies

The original 26 scenarios described in the earlier paper [1][2] which applied the equivalent of a double circuit fault and trip on the Scottish border, were then retested but with a PowerFactory variation active and a modification to the spread sheet. The scenario presented apply to 2030 as in [1, 2] and considers a system with 15.8GW of Solar, 6.8GW of DNO and 49.6GW of TSO Wind and 800MW of Marine. It is assumed that all NSG is connected but de-loaded.

The modification to spread sheet allowed a proportion of the aggregated convertor generation in each zone, to be dispatched as VSM adjusting the DQCI accordingly, to establish the proportion required to stabilise the network.

Table 1, shows the results from the 26 study cases. The study cases include combinations of total system load (Distribution and Transmission) of: 30, 35 and 40GW. HVDC Import from Ireland and Export to Europe of: 0GW Import / Export, 3GW Import / 10GW Export and 0GW Import / 10GW Export. Low, Mid and High NSG penetration where Low NSG was 8GW Solar, 16GW of TSO and DNO Wind and Marine, For Mid NSG wind is increased to 20.5GW and for High the wind is 28.5GW.

The colour coding of the cells indicates which were stable or unstable in the original 2013 studies, where green is stable and yellow unstable. In these studies all cases are stable with the exception of the blue N/A case (where there is a load imbalance). The adjacent yellow cell also has a load imbalance <1GW and so the load was simply increased.

NSG	0 Import HVDC 0 Export HVDC			3GW Import HVDC 10GW Export HVDC			0 Import HVDC 10GW Export HVDC		
	Load (GW)			Load (GW)			Load (GW)		
	40	35	30	40	35	30	40	35	30
Low	1 60	10 25 69	10 25 80	1 54	1 60	10 68	1 48	1 15 53	1 60
Mid	5 25 73	5 83	10 97	1 64	10 25 71	10 80	1 58	1 20 64	10 73
High	15 97	20 30 103	N/A	10 80	10 89	15 35 100	10 25 74	10 82	10 30 93

Table 1 – % VSM of the 26 Study Cases

The proportion of NSG installed as VSM for each case was incremented in steps of 5% to see how much was required to stabilise the network.

In some cases two percentages of VSM are presented. The first number represents the amount required to achieve stability with typically <±5% noise. The second number is the %VSM required for clean results. The third number is the percentage penetration of NSG for the scenario. For example the top 2nd from left hand cell indicates that 69% percent of the generation is NSG and 31% SG and that 10% of the NSG must be VSM for stability and 25% of the NSG must be VSM for a low noise result.

Figure 3 shows a result with noise and Figure 4 a clean result. Two figures are given, as the 2013 paper [1][2] considered the result in Figure 3 acceptable on the basis that this was typically all that could be achieved at that time.

It may be of interest to note that the frame rate (i.e. the time step size) used by the model affect the results. For National Grids system model, a fixed frame rate of 10ms is used but in these studies this was found to be inadequate and produced noisy or unstable results. For the results presented here and in 2013 2ms was used. It may be beneficial to use a variable step size but this needs further investigation.

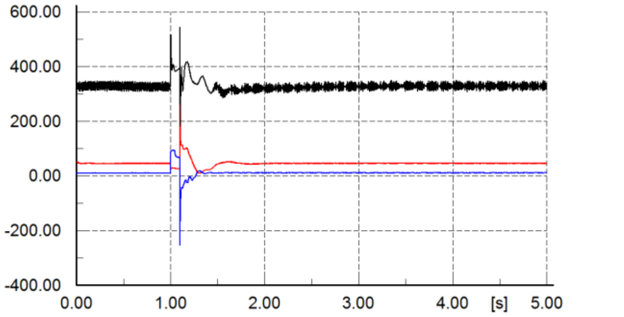

Figure 3 – Noisy "Acceptable" Results for 103% NSG 20% VSM (VSM Zone 1 MW Black, 107 MVA VSM Zone 25 MW Red and MVAr Blue)

It was also noted that for some of the "Acceptably Noisy" cases relatively small changes to the control system could push the result to unstable e.g. changing the lower limit on the VSM voltage control PI term from 0 to -1.2 for study case at 93% NSG (see [6] for details of the model).

Finally it is worth noting that increasing the proportion of VSM reduces the amount of response and capability from each convertor that's required. In Figure 4, Zone 25 (which is close to the fault) is dispatched to 50MW and incurs peak power (ignoring spikes) of 146MW on a base capacity of 107MVA. In Figure 5 75MW is dispatched and incurs a peak of 186MW on a base of 161MVA. Consequently increasing the % of VSM improves stability and reduces the additional energy and convertor rating required.

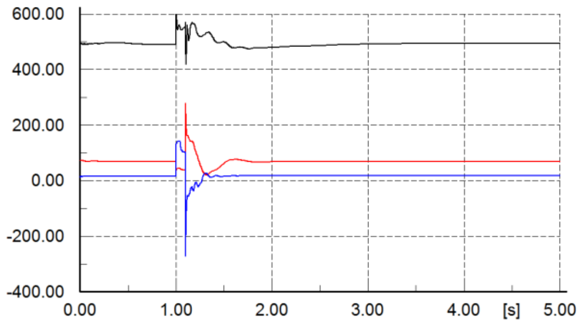

Figure 4 – VSM "Clean" Results 103% NSG (Zone 1 VSM MW Black, Zone 25 VSM MW Red & MVAr Blue)

IX. 1600MW SG Trip With 97% NSG & 100% NSG

Having established system stability for all 26 scenarios it was decided to carry out further studies that would push the model and VSM controller, using high NSG to understand any limitations. Under the first of these a fault is applied to the 1600MW generator and it is disconnected.

From Table 1 the scenario is Mid NSG, no international import or export, with 30GW load, resulting in 97% NSG with only 3% SG on the system. 25% of the Convertors are VSM leaving 75% as DQCI. The SG consists of 1600MW in Zone 1 (bottom south east), 49MW in the adjacent Zone 5 and 253MW in Zone 32 which is located at the most northern substation. After the fault the system recovers and then the remaining SG in Zones 5 and 32 are tripped (10 seconds later) but only to demonstrate the model can operate at 100% NSG. The results for the second trip and 100% NSG operation are not shown as there was nothing significant in the traces.

Most VSM incur manageable increases in power on their MVA rating (e.g. Zone 2 130MW to 168MW on a base of 350MVA & the bus bar volts changed from 1.02 to 1.06pu).

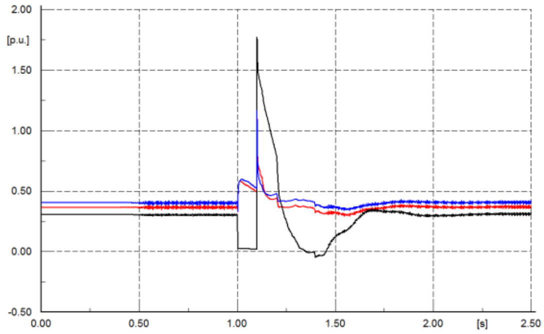

Figure 5 – pu real (power) current for VSM in Zone 1-Black, 2-Red and 5- Blue with 1600MW loss in Zone 1

However, it is particularly interesting to look at the VSM which is connected to the same bus bar as the 1600MW machine. If we use the model as presented in [6] we can see from Figure 5 that it goes into current limit during the fault as expected. However, after clearance, the loss of 1600MW momentarily causes the converter to experience very high load current. This is partially due to a very high transient over voltage caused by the DQCI and SVS injecting reactive current during the fault and taking time to remove it post fault. The bus bar voltage peaks at 1.42pu and the VSM absorbs reactive power during this period but produces real power at 1890MW on a base of 1020MVA.

1600MW loss at 97% NSG is severe case, never the less it is arguably conceivable and/or desirable in 15-20 years. The results showed the system was ok and survived and all the VSM with the exception of Zone 1 experience manageable changes in power. The extra power required in the adjacent zones sees a peak change of 0.25pu but zone 1 changes from 0.6 to a peak of 1.5 or greater. Ideally this would be reduced in the interest of finding a more economical solution. Therefore from:

$$P = \frac{V.E.Sin(\delta)}{X} \qquad (1)$$

Where P is power, V is the terminal volts, E is the convertor output volts, δ is the operating angle of the convertor i.e. the angle between V and E and X is the filter reactance. We see we have various parameter we could adjust to reduce P.

It was noted that substation post fault voltage rose to 1.5pu which is clearly unacceptable. There were two reasons, first the SVS and DQCI generation where trying to inject VAr's into the fault. Secondly the reduced model locates all reactive support for zone 1 in a single SVS.

The substation volts were brought under control by switching out an SVS and limiting the reactive range of the DQCI so that post-fault it was 1.05pu. The local load 1527MW was moved to the LV side of the VSM step up transformer to better represent embedded generation.

Fast phase back was added to the VSM control system. This consists of an integrator subtracted from the phase angle of the output waveform generator. Its output is normally 0 but if the power limit is exceeded it rapidly increases, forcing the convertor operating angle δ to reduce by up to 180 degrees, reducing active power. The results of these combined effects are shown in figure 6.

Increasing the step up transformer impedance from 22% to 33% produced the reduction, see Figure 6b. Increasing the % of VSM reduces the p.u. load change requiring less response. This or locating other smaller SG in the area would therefore further manage the requirement. Reducing E, the convertor output voltage, can also reduce the power transfer and potentially reduces the load volts and therefore load current.

Finally it is also possible that when operating outside the device rating, the VSM may switch to VSC or DQCI mode or some combination. However in this state, it is probable many of the stabilising benefits would be lost. This could be acceptable if normal operation is resumed quickly and the effect remains localised and the overloads/mode changes don't propagate from substation to substation, causing instability. It was thought it might be particularly problematic when part of the system is islanded.

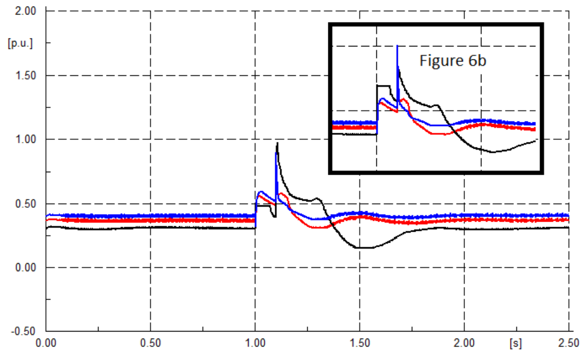

Figure 6 – 2040MVA Zone 1 VSM (50%) with local load and fast phase back on (MW Red / MVAr Blue)

X. System Split with 4.4GW of Transfer

In this scenario a double circuit fault was applied to circuits crossing the England / Scotland border, after which both double circuit's trip splitting the system. It is assumed the HVDC link between England and Scotland is operating at 2GW and AC the transfer is about 4.4GW. No increase in HVDC occurs after islanding. This is an extreme case but is useful to understand VSM behaviour under such demanding conditions as SG would be expected to survive but with load disconnection.

As with the previous study 25% of the NSG is VSM and 75% is DQCI. From Table 1 the scenario is High NSG, no international import or export, with 40GW load. The fault occurs at 1 second and both double circuits have tripped at 1.1seconds. Figure 7 shows the effect on the power of all 36 Zones VSM convertors and the frequency in England/Wales and Scotland. The red lines indicate what happens in England/Wales and the blue Scotland. The black line shows VSM power at the Zones in England closest to the border, as these incur the biggest increases in power.

Within ms of the circuit breakers opening, the power delivered from Scotland must be replaced, if complete or partial collapse is to be avoided. SEBIR, load side response and LCC / DQCI HVDC will be too slow if measurements are required before taking action. The required power is delivered from SG, VSM and possibly VSC convertors.

If the VSM is overloaded and current limits, this can be managed to some degree but reducing power passes the requirement on to the remaining SG and other VSMs. Proliferation of this effect throughout the system must be avoided to prevent collapse or instability.

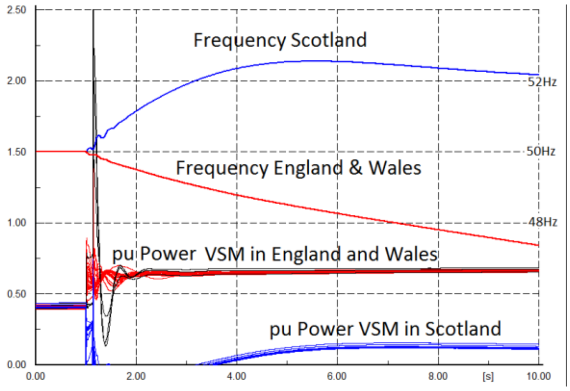

Figure 7 – VSM pu Power Output and Frequency for England, Wales and Scotland

With 25% of the convertors VSM, the results indicate that the VSM is required on average to deliver about a 0.3pu unit increase in power but this is not initially evenly spread. VSM local to the split are required to delivery very high levels of transient power and this clearly needs addressing.

With only the VSM in frequency response (on 4% droop) and the VSM and SG providing RoCoF support the frequency in Scotland goes outside of 52Hz and the VSM power is initially negative. The frequency in England/Wales reduces rapidly and would normally result LF (Low Frequency) relays operating at 48.8Hz, disconnecting load.

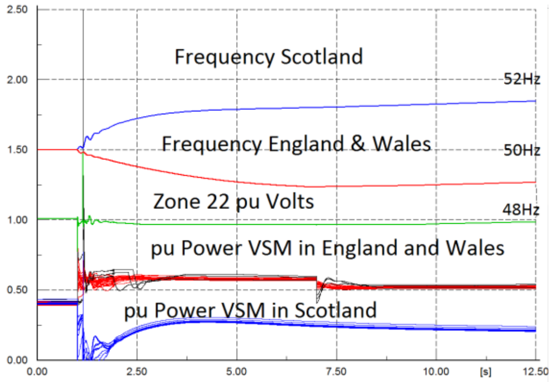

Figure 8 –Frequency, Volts & VSM Power, System Spilt

The fast phase back current limiter, described earlier was switched on, with a limit setting of 0.2pu. This rapidly transfers the excess load away from the VSM in Northern England, suppressing the spike and limiting power. Figure 8 also shows the effect of this and additional actions taken to limit power from the VSM. Firstly SEBIR control is added to the DQCI convertors which reduces or increases their energy output in proportion to rate of change of frequency (RoCoF i.e. df/dt). This is limited to -0.2pu for the high frequency events and +0.02pu for the low frequency event. In the low frequency direction it is actually assumed to be 0 for renewable generation but is added here to simulate some battery sources and load side response.

The VSM also reduces its output voltage by up to 10% to reduce power output and this help limit the output power increase to +0.2pu. However this is not effective if other generators and reactive sources restore the voltage, especially those which are embedded in the Distribution Networks. Consequently the SEBIR control in the DCQI convertor also reduces the voltage set points by up to 5%.

It can be argued that reducing the voltage is not a good method for managing such events and that there are far better strategies, such as increasing the capability or quantity of VSM, reducing the pu power increase required from each device or having HVDC in standby. However it was implemented to demonstrate how E in equation (1) can significantly reduce power for RoCoF if all reactive sources, especially those close to the load, coordinate their actions.

After 7 seconds the frequency is 48.8Hz and the LF relays disconnect 717MW of load. The frequency and voltage then return. Frequency support (FSM Mode) is provided by 10% of the DQCI at 4% droop and reduced in the VSM by increasing the power droop from 4 to 5%.

XI. Disconnection On Islanding

With droop frequency and voltage control, the VSM model demonstrated here and in [6], provides extended capability. This has significant benefits for the SO, as it could initially provide support during major system events, such as generation loss or a system split and helps with RoCoF, Voltage and possibly Frequency management. This provides decision time for control room operations staff.

However this capability is also potential problem for DNO's, as islanded parts of their system which are balanced within the capability of the VSM, could providing their own local frequency management. DNO's typically prefer such islands to shut down. Remaining live may be not be safe and in many circumstances makes it more difficult / hazardous to reconnect the island to the grid. Islanding detection in the form of RoCoF would no longer work.

Alternative tripping arrangements would need to be found e.g. support the system for a short period (10 minutes if there's enough stored energy) then ramp the frequency reference to balance the power output back to the level of the energy source, resulting in frequency rising or falling after the initial 10-minute period initiating high/low tripping.

XII. Conclusions

It is estimated the highest instantaneous penetration of convertors in GB today is around 50%. With a predicted limit of stable operation of 65% drawing nearer, solutions to a host of challenges are needed. Whilst Virtual Synchronous Machine (VSM) converter control strategy is a relatively new technology, the studies presented here (if replicated in real systems) have the potential to allow stable operation with 100% Non-Synchronous Generation (NSG).

The results presented here and in paper [6] which describes this VSM and another model in more detail, present two implementations of the same convertor, one to demonstrate a narrow range of issues in depth and the other for evaluation on a full synchronous network, like GB.

The minimum quantity of VSM required to prevent the system developing high frequency instability, is dependent on its ability to deliver additional energy and the remaining SG. The 10% marginal cases studied, correlates well with earlier studies using a different approach without inertia contribution, namely VSM0H and demonstrates that much of the very high frequency phenomena are damped out by the use of VSM type voltage source convertors. This is in sharp contrast to the presently dominant DQCI control even if SEBIR (synthetic inertia) is added.

The analysis in this paper supported by analysis in [6] demonstrates that the proposed approach would have a significant benefit across all eight identified challenges for operation close to 100% penetration of NSG for a complete synchronous area (and incidentally also 8 similar challenges identified in 2013 from within the wind industry [15]).

1. Increased RoCoF (Rate of Change of Frequency)
2. Loss of synchronising torque and reference voltage
3. Possibility of high frequency instability and controller interaction
4. Inadequacies of RMS models and the associated difficulties with modelling the electricity system
5. Reduced and possibly delayed fault in feed and associated challenges in protection performance
6. Possibility of voltage instability during or post fault e.g. collapse, blocking or over voltage post fault
7. Potential for sub-synchronous oscillations and interaction with conventional machines
8. Potential sensitivity to load imbalance and harmonics

The results indicate that the VSM controls could be added to either HVDC, large scale transmission connected wind power or be deeply embedded. Even when deeply embedded and poorly coupled to the load and other generation, VSM with simulated dynamic breaking, can have significant benefits. This in combination with its ability to support RoCoF, voltage and frequency and bandwidth limiting of the control systems, ensuring interactions with other plant/control systems are minimized, makes it an ideal candidate for “fit & forget” deeply embedded applications.

To make a move from R&D activity (current position) to implementation (needed to operate at increased penetration), one possible sequence is:

1. Timely further research to confirm and extend the analysis undertaken here.
2. Wide industry discussion of this and similar work undertaken including initial high level risk analysis.
3. Translation of the specific solution demonstrated here to a set of system performance characteristics suitable for specification at connection points. These need to allow alternative approaches which can deliver solutions to the range of challenges e.g. fast fault contributions, converter blocking volts and RoCoF.
4. Determine when the altered converter performance becomes critical in system operation to mitigate massive increases in ancillary services costs (mainly through constraining off renewables). EirGrid has already indicated a roughly five fold increase by 2020 (from 5% to 25% of total electricity cost).
5. Decide the mechanism to implement the specified system performance characteristic, mandate through industry codes, creation of voluntary markets or a mixture of the two. This will require the mix and geographical spread of the capability, across HVDC, large transmission connected wind and small distributed (wind, solar and storage).

If these results are demonstrated in real systems, then critically VSM has demonstrated the potential to provide the necessary foundation in the form of a stable voltage reference, for the existing generation DQCI convertors. Then very high penetrations of convertor generation could be achieved by installing significant proportions of VSM or equivalent performance controllers in suitable quantities in the appropriate time scales.

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