Background on Fast Fault Current Injection

The Power System, traditionally comprised of Synchronous Generating Units directly connected to the Transmission System with the Distribution Systems simply acting as networks to supply the net power to consumers. Under these arrangements, the volume of Generation connected to the Distribution System was very small.

Synchronous Generators also have a unique set of characteristics, the speed of the mechanical shaft rotates in synchronism with the system with contribution to voltage control being achieved by changing the machines excitation. This arrangement also delivers many system benefits which until recently have been taken for granted, for example contribution to System Inertia, fault infeed, contribution to Synchronising torque etc which all have a significant impact on the behaviour and characteristics of the Transmission System.

Under fault conditions, a synchronous machine can supply very high levels of fault current (5 – 7pu current) which is also an important characteristic of Power System Protection (ie equipment necessary to detect, discriminate and isolate faulty items of equipment). This is also an important benefit in maintaining the voltage profile across the System during fault conditions.

The down side is that management of fault levels can sometimes be an issue. In addition, high speed protection systems are required to maintain generator stability. Had the Power System originally been designed with power electronic converters, then the integration of Synchronous plant is likely to have created problems in respect of protection operating times, circuit breaker ratings and the need for adequate levels of system synchronising torque.

So far as fault current injection is concerned, converter based plant has very different characteristics to its synchronous counterparts and this starts to become an issue as the volume of synchronous plant starts to fall away. Certainly studies conducted as part of the System Operability Framework (SOF) have demonstrated that operating the system post 2021 with falling volumes of synchronous generation starts to become an increasing challenge.

Unlike a Synchronous Generator which can supply an instantaneous injection of fault current upon fault inception, this characteristic is not replicated in converter based plant. In addition, as the fault current from a synchronous machine is injected instantaneously upon fault inception (ie as soon as the voltage starts to drop) the fault current injection from all the synchronous generators are in phase with the System.

In a converter based plant, the power output can be configured depending upon the design of the converters control system. In general, the primary purpose is to protect the switching devices (IGBT’s) from excessive currents during faulty conditions. Any form of over rating adds additional cost to the converter.

The problem is that the converter will at best only supply 1 – 1.5pu current (compared to a synchronous generator of 5 - 7pu) and secondly the injection of reactive current to the system is generally delayed as a result that the measurement functions within the controller are i) protecting the IGBT's and ii) determining the system conditions at the connection point prior to providing any form of injection. This design philosophy is an common approach used by many manufacturers and is based on the Phase Locked Loop (PLL) concept. An example of the typical fault current injected from a XMVA Synchronous Generating Unit and a XMVA Power Park Module is shown in Figure 4.1 below.

INSERT FIGURE 4.1

Insert Figure 4.1 (Fault current infeed – Synchronous Plant v Power Park Module)
The problem with this approach is that i) the injection of reactive current is already low (ie 1 – 1.5pu compared to 5 – 7pu) and ii) when fault current in injected it is likely to be several tens of milliseconds after fault inception, so the injection of reactive current is out of phase with the System which further compounds to a diminishing voltage profile across the system during system disturbances.

An illustration of this effect is shown in Figure 4.2(a) and 4.2(b). Figure 4.2(a) shows the effect of a solid three phase short circuit fault at Walpole 400kV substation and the contour of the voltage depression across the system immediately prior to fault clearance. This study has been conducted on the basis of a high volume of synchronous generation. In Figure 4.2(b) the study is repeated although in this case the generation background comprises a high percentage of converter based plant.

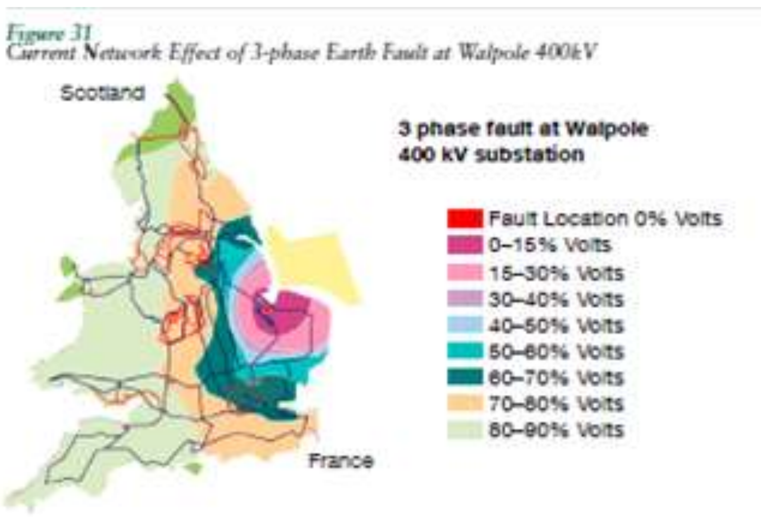


Figure 4.2(a) Effect on Voltage Profile of a solid three phase short circuit fault at Walpole 400kV substation under a high Synchronous Generation background

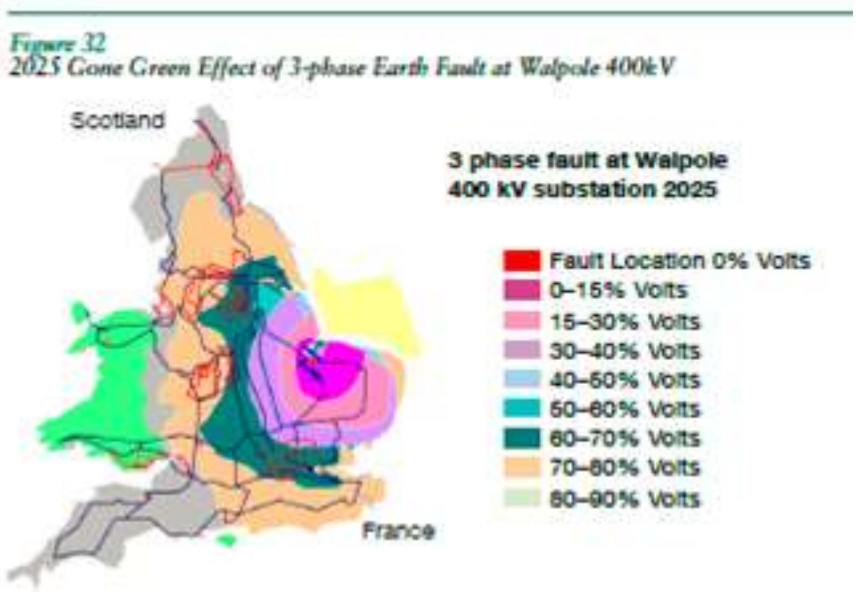


Figure 4.2(b) Effect on Voltage Profile of a solid three phase short circuit fault at Walpole 400kV substation under a high Converter Generation background

To understand these effects in more detail, and develop a set of requirements for fast fault current injection, National Grid ran a set of detailed studies. The details of these studies are shown as a set of slides in Annex 3 of this Workgroup report. These slides were discussed with Workgroup members in April 2017.

In summary, the purpose of the study work was to assess the performance on the Transmission and Distribution System of different converter topologies against that of a system made up mainly of synchronous plant with a view to understanding the impact on the System.

The study considered the effect on the system of
i) Synchronous Generation,
ii) negative demand (i.e. the generator is modelled as negative demand and has no real dynamic effect nor provides any form of fault current)
iii) a standard Static Generator Model with PLL taken directly from the Power Factory library,
iv) A converter model based on PLL technology which also includes Fast Fault Current Injection capability (where changes to the injection of reactive current can be varied (eg delay times, ramp rates and ceiling values) and
v) a Virtual Synchronous Machine model in which the converter controller is set up to reflect the performance of a synchronous machine. An example of the performance from these technologies is shown in Figure 4.3 below.

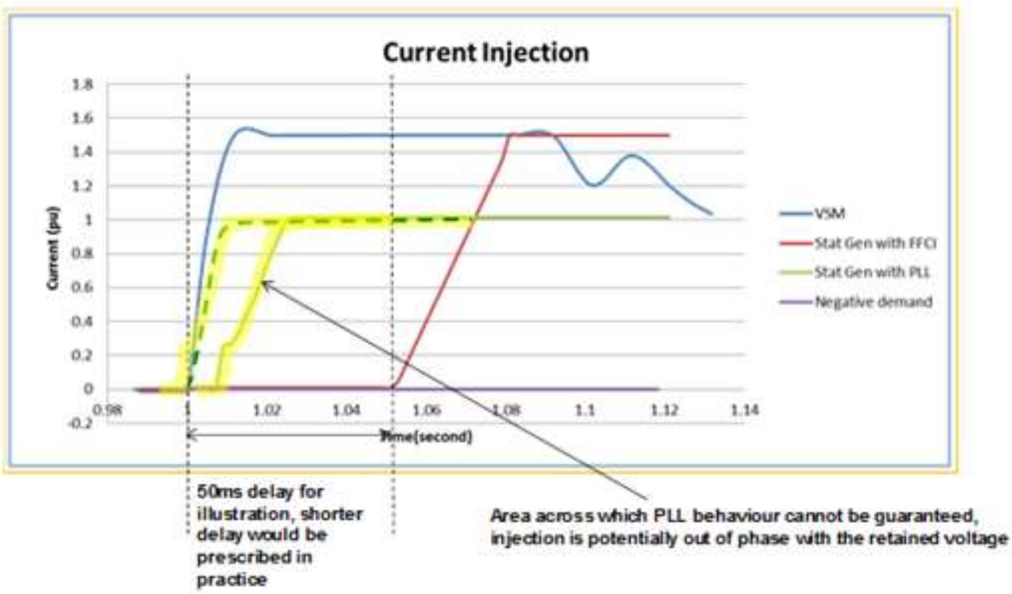


Figure 4.3 – Comparison of Converter performance used to assess the impact on the system under fault conditions.

The concept of the Virtual Synchronous machine is, as its name suggests, aims to control the output of a power electronic converter in the same way as a synchronous machine. The concept is not new with papers and concepts being published on this subject some 20 years ago.

Similar technologies have also found practical applications in the marine industry, but it has not been widely used in public Grid Systems due to the dominance of Synchronous Generation. However, as the volume of Synchronous Generation, particularly at Transmission levels starts to decline, there is growing concern over the ability to operate a power system with very high levels of non synchronous generation.

Conventional converters suffer from two major drawbacks when compared to synchronous generators, these being i) they are unable to supply high fault currents due to the need to protect the converter devices and ii) they are decoupled from the generator and as such do not contribute to System inertia or supply any form of synchronising torque with any form of response being delayed.

The majority of Power Electronic converters use a Phase Locked Loop (PLL) which in essence means the controller aims to keep the phase shift between the input signal and the voltage control oscillator (ie the device which ultimately controls the IGBT's) to zero. The down side of this type of current source control is that it needs to detect a drop in voltage at the converter terminals and then determine any form of phase change before undertaking any processing. Whilst this processing can probably be achieved in 5 cycles (eg 100ms) this speed is still very slow when compared to a Transmission System fault which can be cleared by system protection within say 80ms at 400kV and consequently the need to inject fault current.

In the VSM configuration the converter has slow controls and no PLL so that the phase angle of the voltage source reference oscillator is frozen to the same state it was in prior to the fault. The rate of rise of fault current is initially limited by the output filter components however the converters typically rely on very fast measurement feedback of terminal voltage or current to protect the IGBT's by shutting them down or reducing pulse width. With the current under control or limited, the device then produces fault current within its rating by reducing the internal AC source voltage. Consequently the phase angle of the current drawn is typically determined by the load and is generally reactive in nature which is the same approach of a synchronous machine.

From an electrical perspective, a synchronous machine is basically a balanced 3ph voltage source connected to the system via an impedance that is largely reactive. The frequency and phase angle of this voltage source changes relatively slowly as they are directly related to the angle of the machines rotor which is very heavy and has a high inertia. Likewise the voltage magnitude also changes relatively slowly as it is related to the current in the field which is highly inductive and therefore slow to change.

The AC current however is dependent upon the load and network impedance. Load changes or switching operations such as tripping machines or switching in and out transmission lines, therefore result in very fast network impedance changes. Consequently theis results in almost instantaneous changes in AC current and this explains why conventional synchronous generators naturally respond to load changes instantaneously without having to measure feedback signals such as voltage or frequency. The aim of this proposal is therefore to require converter based generation to behave in the same way as a Synchronous Generator.

This VSM technology offers significant advantages to the System Operator and is also believed to be a lower cost solution than other alternatives such as connection restrictions or the installation of Synchronous Compensators which it is acknowledged are a necessity but would not necessarily be required all year round.

RfG – Fast Fault Current Injection

Antony Johnson / Peter Simango

National Grid – Network Capability

April 2017

Acknowledgements

- The authors of this presentation are indebted to Richard Ierna for his help on the VSM research and associated modelling work.

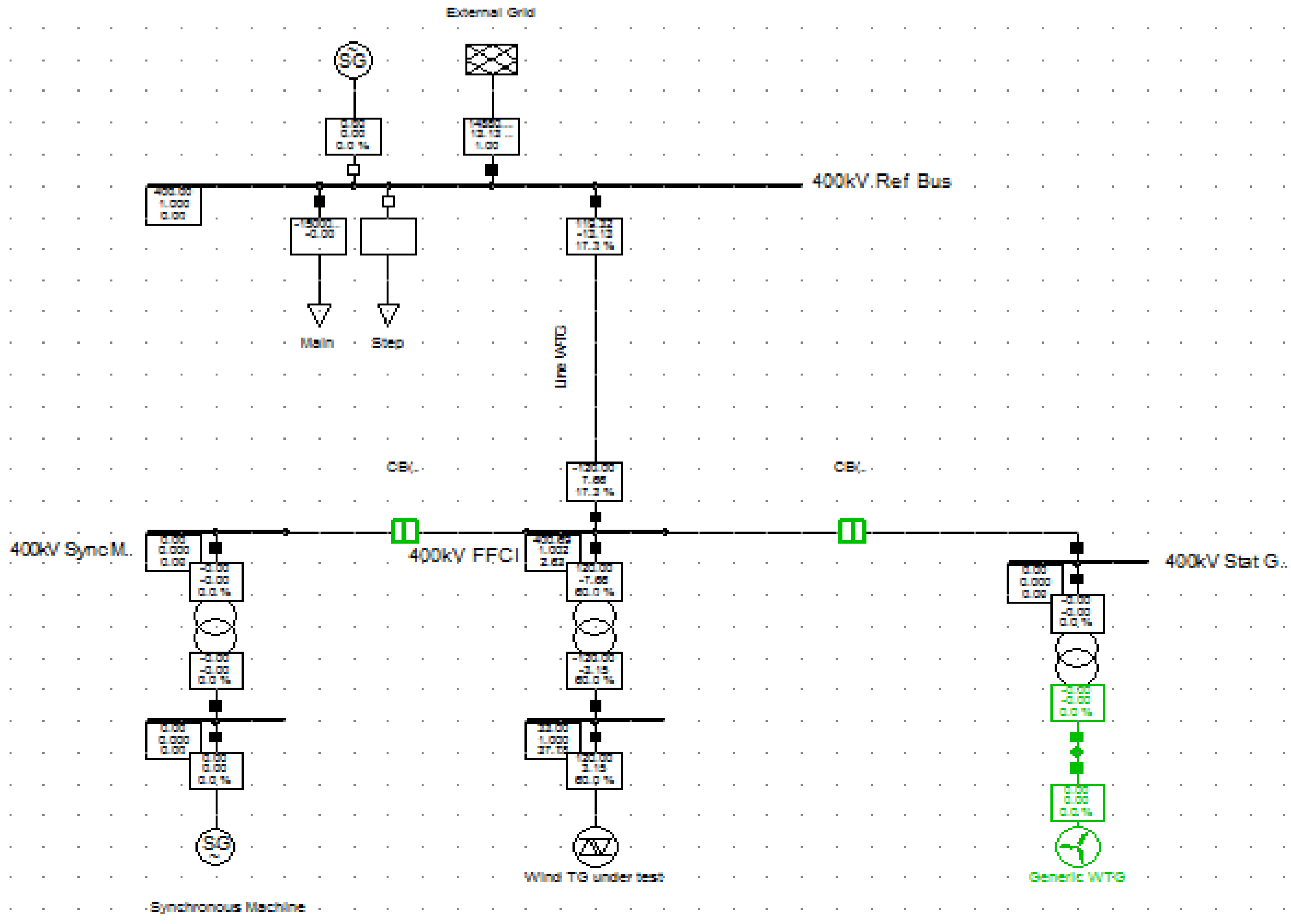
Summary

nationalgrid

- Test Network and proof of concepts
- Test Network Performance – Synchronous Machines
- Test Network Performance – Power Park Modules
  - Variations in Converter based reactive current injection
  - Virtual Synchronous Machine
- Multi Machine Study – South West Study Case
- Assumptions
- Case 1 – Synchronous Generation
- Case 2 - Power Park Modules
  - Conventional Converter
  - Virtual Synchronous Machine
- Summary of Results / Conclusions / Review of Fault Ride Through Voltage against time curves

RfG – Fast Fault Current Injection Test Network / Model Validation

Test Network (Fig1)



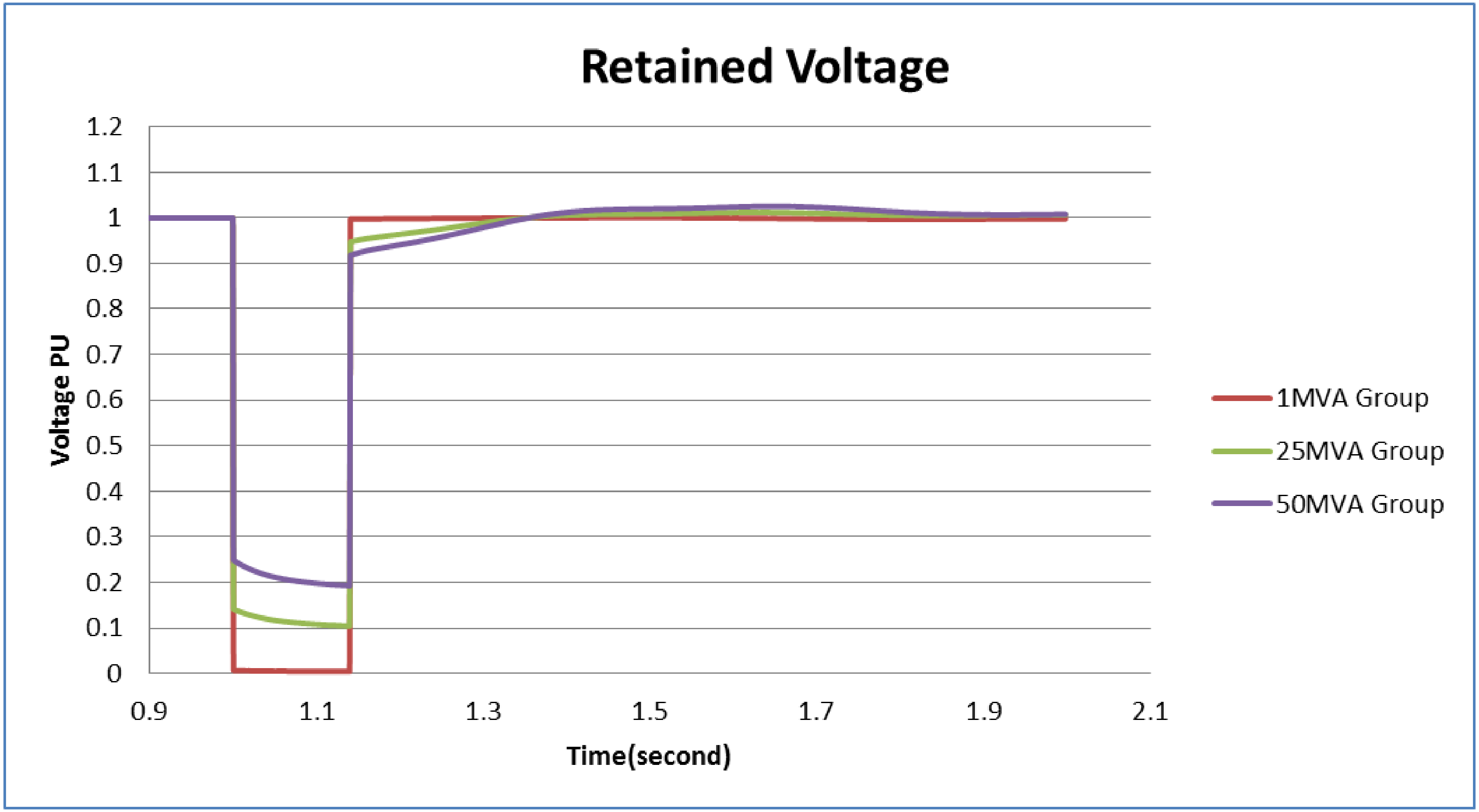
Test Network :Study Assumptions

- A three phase fault was applied at 400kV Ref Bus
- The retained voltage is measured at the machine terminal [33kV]
- Machine Rating assumed to be 1MVA. The number of machines was increased to achieve a higher current injection.

Test Network - Results

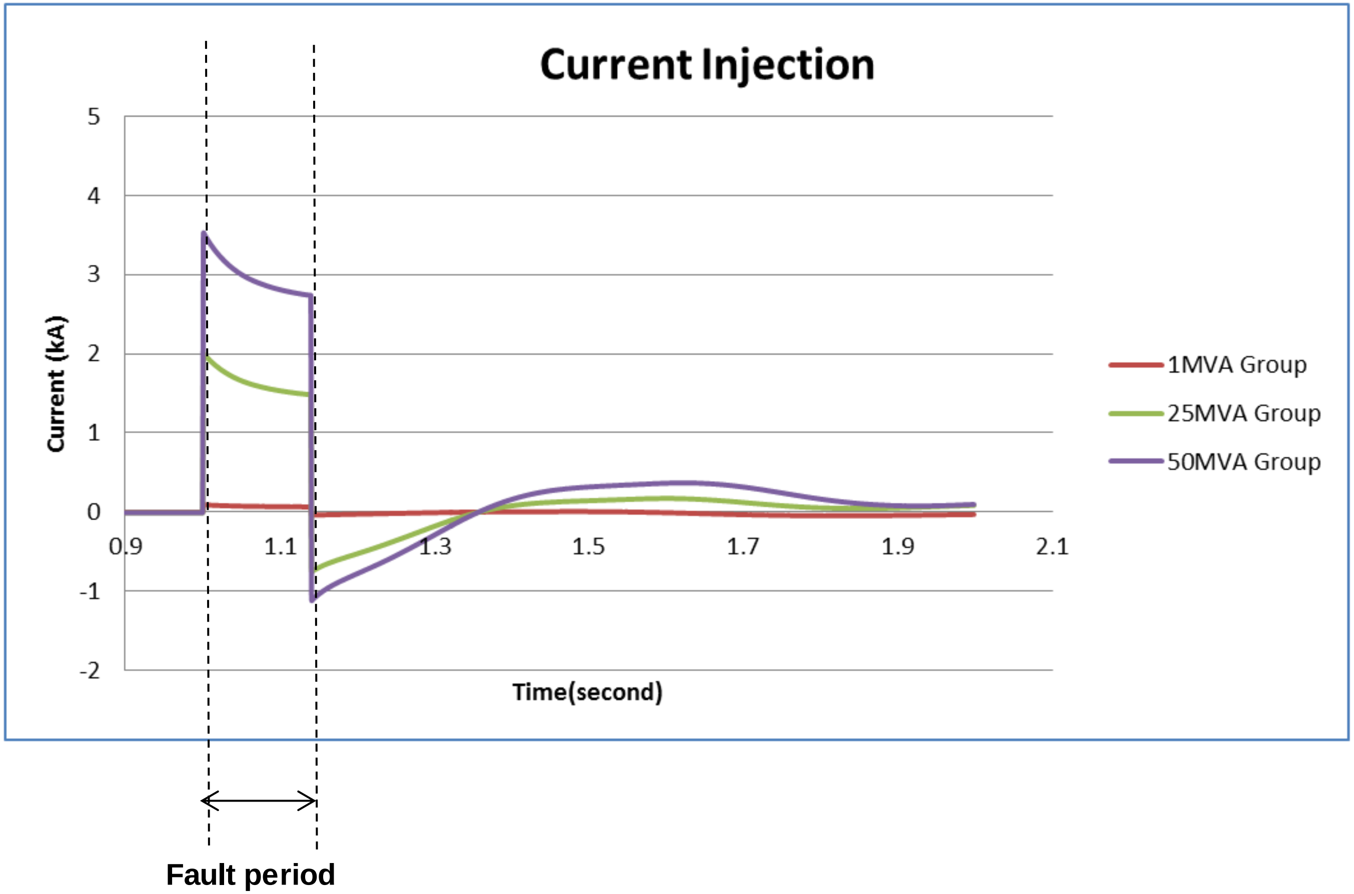
nationalgrid

Effect of Synchronous Plant On Retained Voltage at the Machine terminals



Test Network

Current Injection from Synchronous plant - Fault at 400kV Ref Busbar



Test Network – *Synchronous Plant*

Summary of Results

- The current injection from this group of synchronous plant increases from 0.09kA to 3.5kA as the number of machines increase (i.e. 1MVA – 50MVA).
- The retained voltage at 33kV increases from 0 to 0.24pu as the number of machines increase
- A group of 25MVA machines were sufficient to achieve a retained voltage of 0.14pu after the fault has been applied at 400kV Ref Bus

Test Network

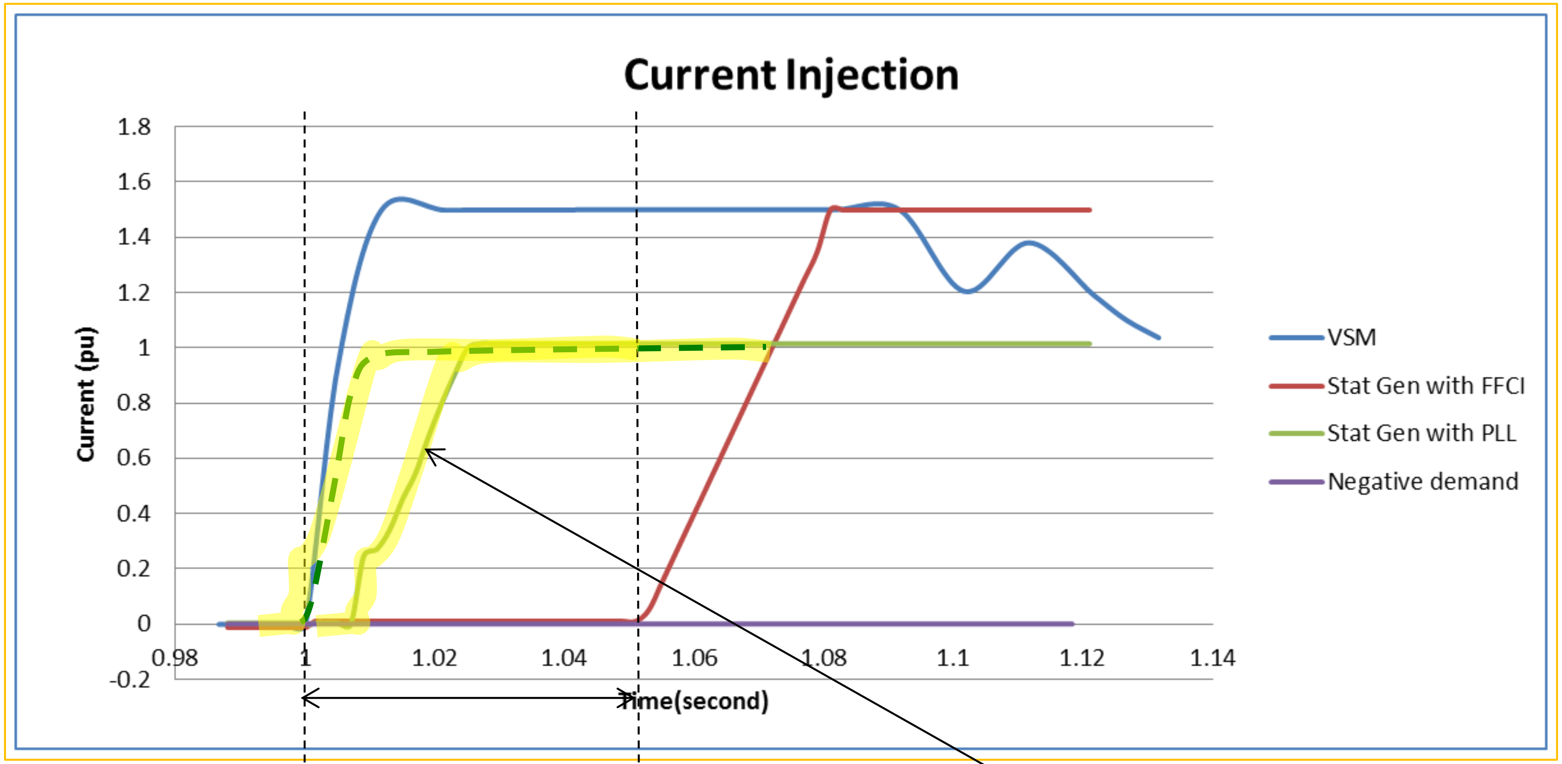
Effect of Power Park Modules with different control actions (PLL, FFCI and VSM)

- *Assumptions*
- The same number of machines as synchronous machines was used
- The asynchronous machine was modelled as a static generator with different controllers
- Retained Voltage and current injection plots obtained

Test Network - Results

Reactive power Injection Comparison

nationalgrid



50ms delay for illustration, shorter delay would be prescribed in practice

Area across which PLL behaviour cannot be guaranteed, injection is potentially out of phase with the retained voltage

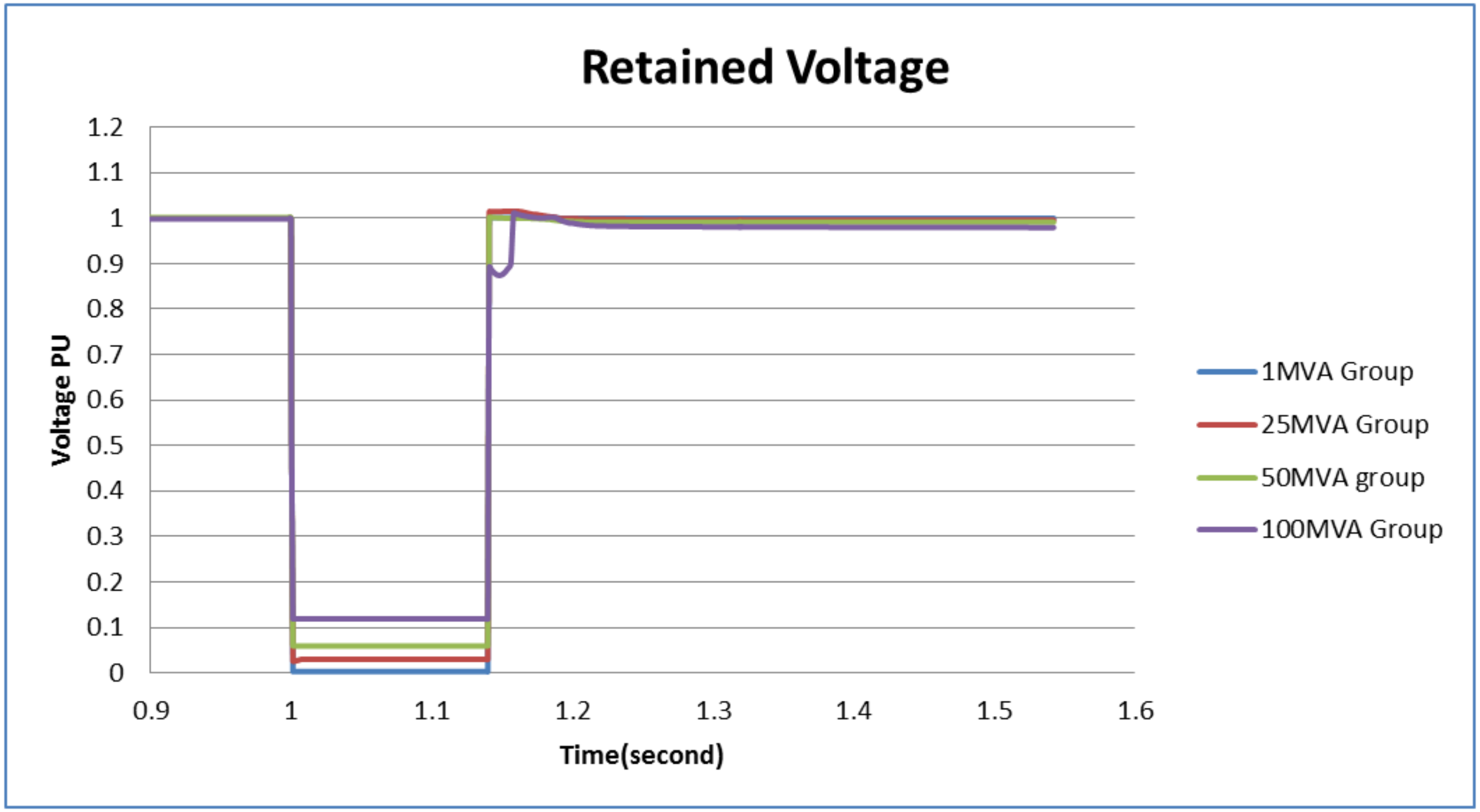
Test Network

Effect of Power Park Modules with PLL control on Retained Voltage at the Machine terminals

- The same number of machines as synchronous machines was used
- The asynchronous machine was modelled as a static generator with PLL control
- Retained Voltage and current injection plots obtained
- Due to the low voltage involved, the switch off threshold (i.e. blocking) was set to zero to allow the static generator to contribute reactive current at these voltages.
- Normally it is the case that for standard PLL controllers a blocking voltage would apply to this timeframe.

Test Network - Results

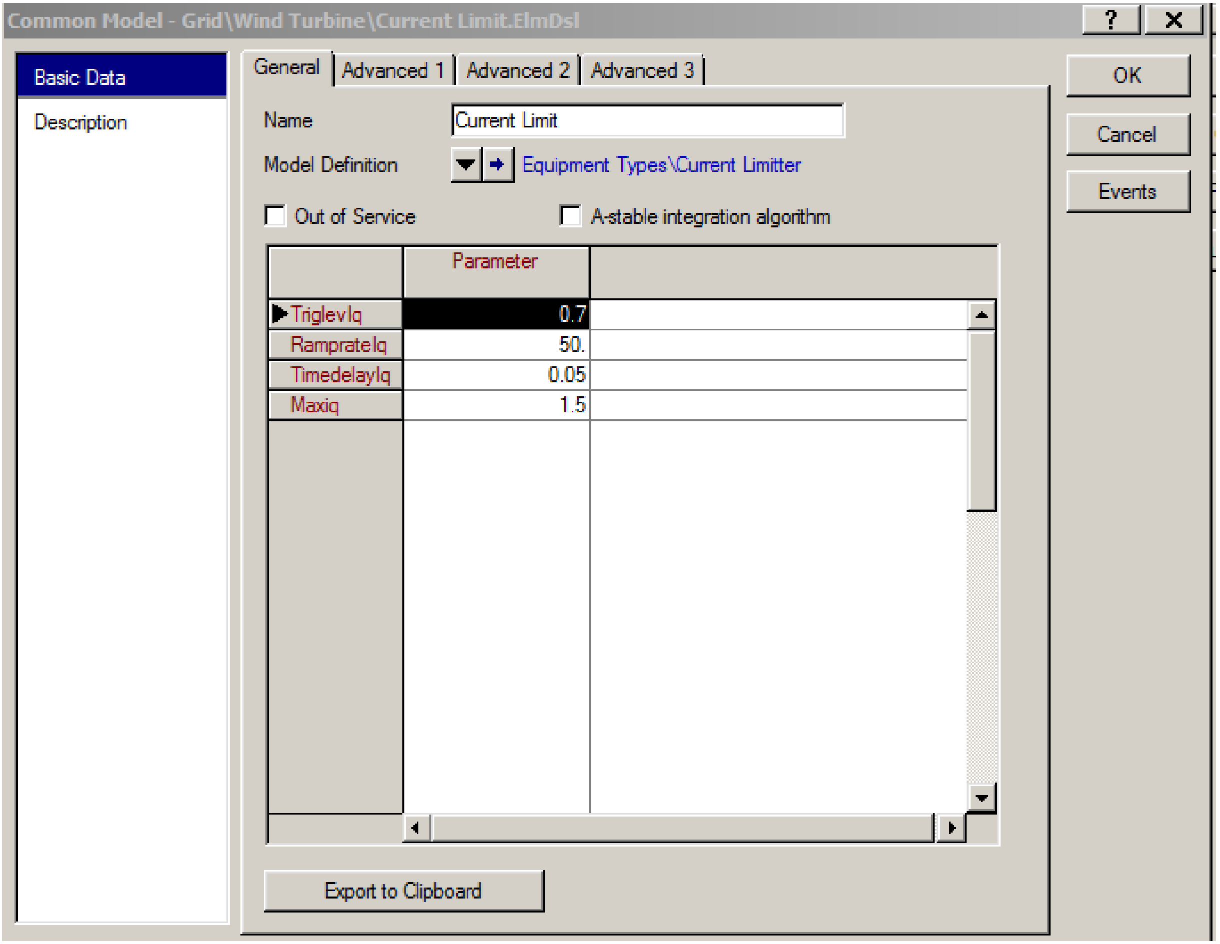
Retained Voltages *of different Capacities of Power Park Module (PLL - No FFCI)**



*** Assumes ideal in phase response of the PLL**

Static Generator

With Fast Fault Current Injection(FFCI) Current limiter Setting



Test Network –

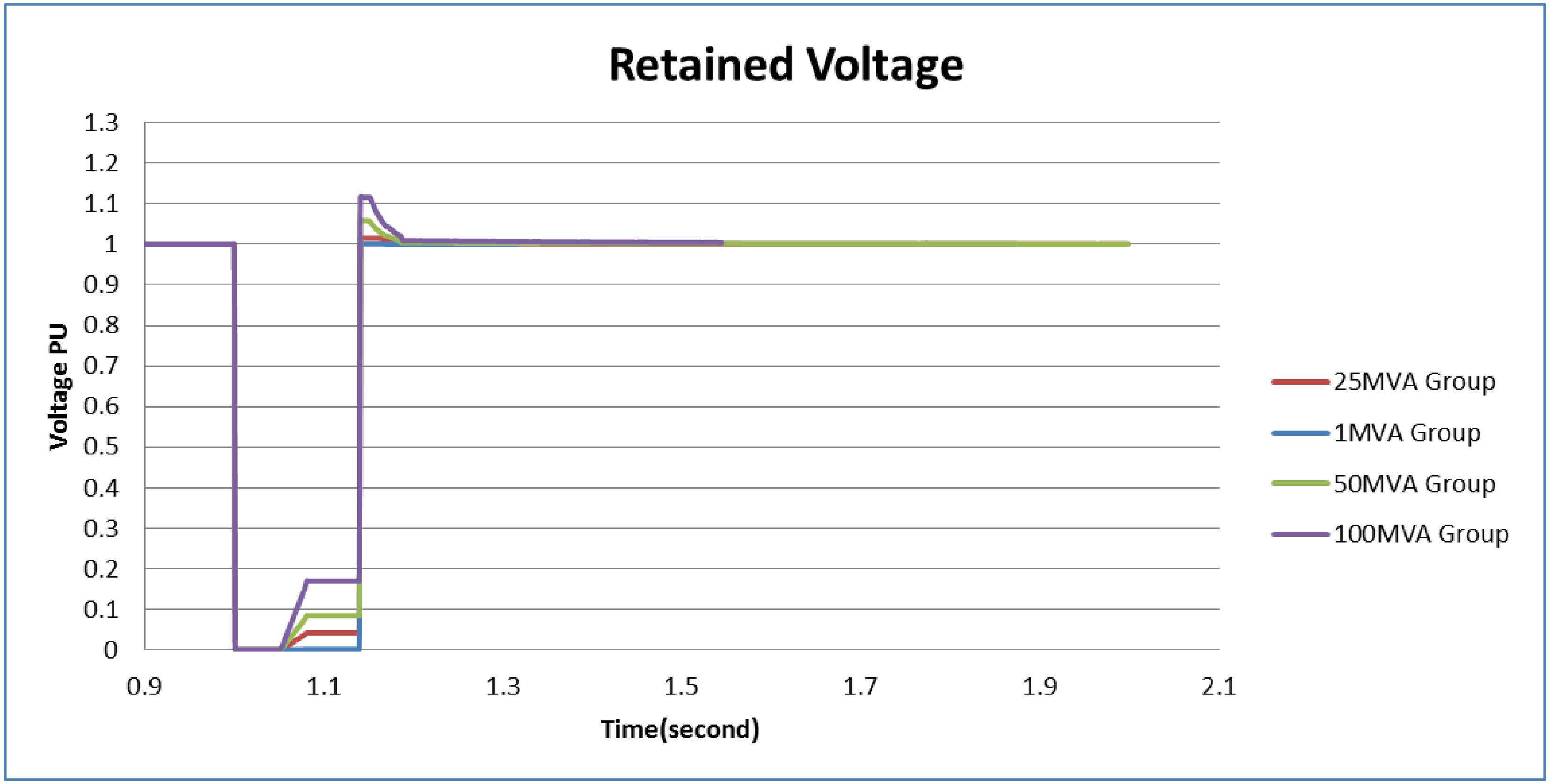
Static Generator with Fast Fault Current Injection (FFCI)

Current Injection (pu)	1.5			
No of Static Generators with FFCI (1MVA each)	**1**	**25**	**50**	**100**
33kV Terminal Voltage[pu]	**0.00**	**0.04**	**0.08**	**0.17**

- The more the machines the better the retained terminal voltage
- As a control function it is desirable to delay the injection to ensure the injection is in phase with retained voltage
- The higher the injection the less the number of machines required to achieve a particular terminal voltage
- Blocking ahead of fault clearance may be required to avoid Transient Over Voltage following the fault, provided reactive and active power is rapidly restored thereafter

Test Network - Results

Retained Voltages *of different Capacities of Power Park Module with FFCI*



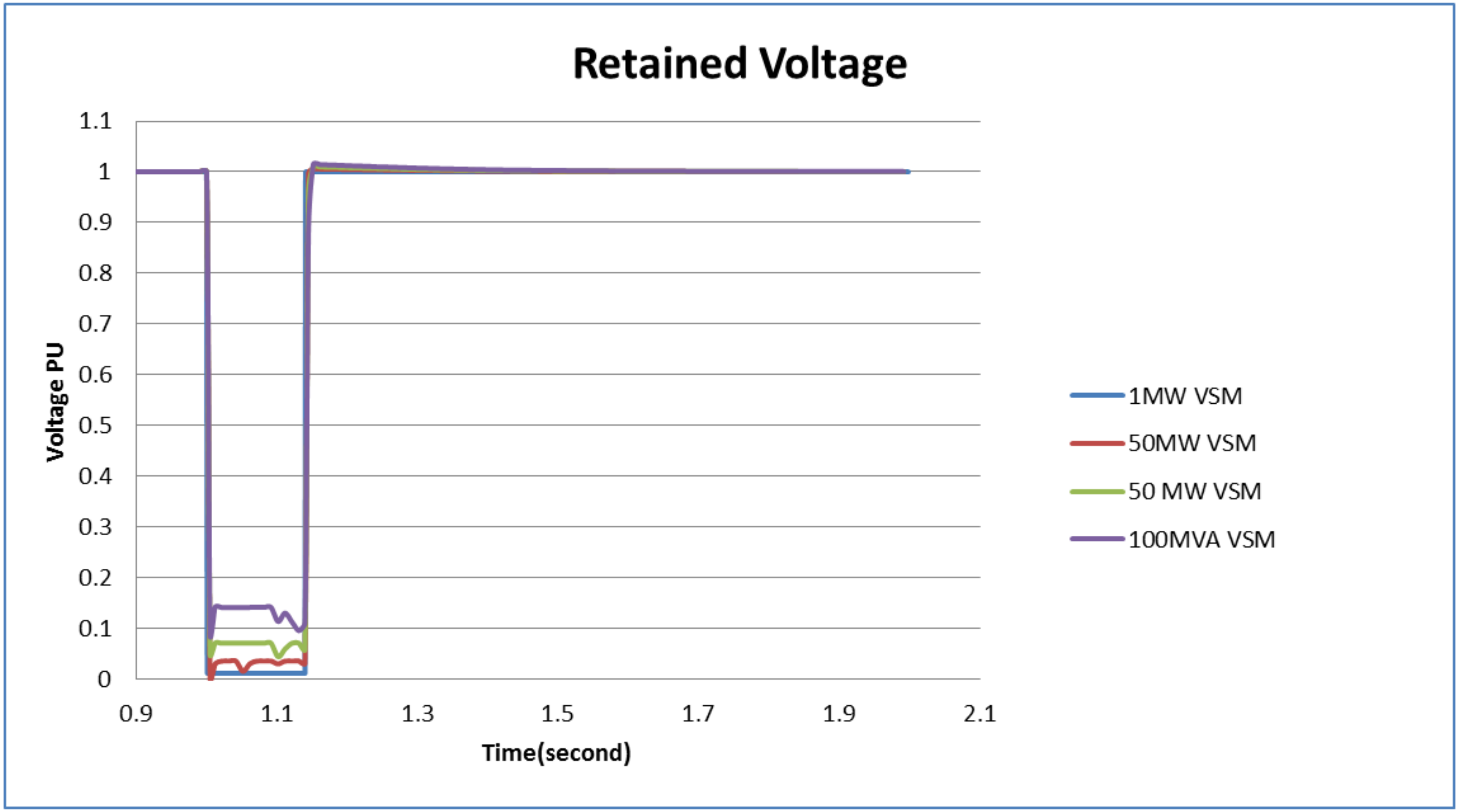
Test Network - Results

VSM Model

- The network is the same as that shown in Fig 1
- VSM technology uses the static generator but the controller has been modified to reflect the behaviour and performance of a VSM.
- The Virtual Synchronous Machine control strategy replicates several aspects of Synchronous machine behaviour such that a response to a phase change is immediate and proportionate to the disturbance, as would be the case for a synchronous machine.

Test Network - Results

Retained Voltages *of different Capacities of Power Park Module with VSM*



Test Network –
VSM Performance

VSM Size	**25**	**50**	**100**
33kV Terminal Voltage[pu]	0.035	0.071	0.141

- The more the machines the better the terminal voltage
- VSM offers better performance than PLL.

Test Network

Retained Voltage - Comparison for the four cases

Option	1MVA	25 MVA	50 MVA	100MVA
Sync. machine Voltage	0.00	0.13	0.24	0.38
Static Generator Voltage (PLL)	0.00	0.03	0.06	0.12
Stat. Gen With FFCI Voltage (Final)	0.00	0.04	0.08	0.17
Static Generator with VSM Control	0.00	0.035	0.071	0.141

- When the number of machines is very low, the contribution from them is insignificant
- A group of synchronous machines will offer more voltage support compared to the same number of other technologies (in Phase)
- Other than Synchronous machine and VSM approaches there are challenges over immediate quantity and quality of support provided.

RfG – Fast Fault Current Injection Multi Machine Study Results South West Study

nationalgrid

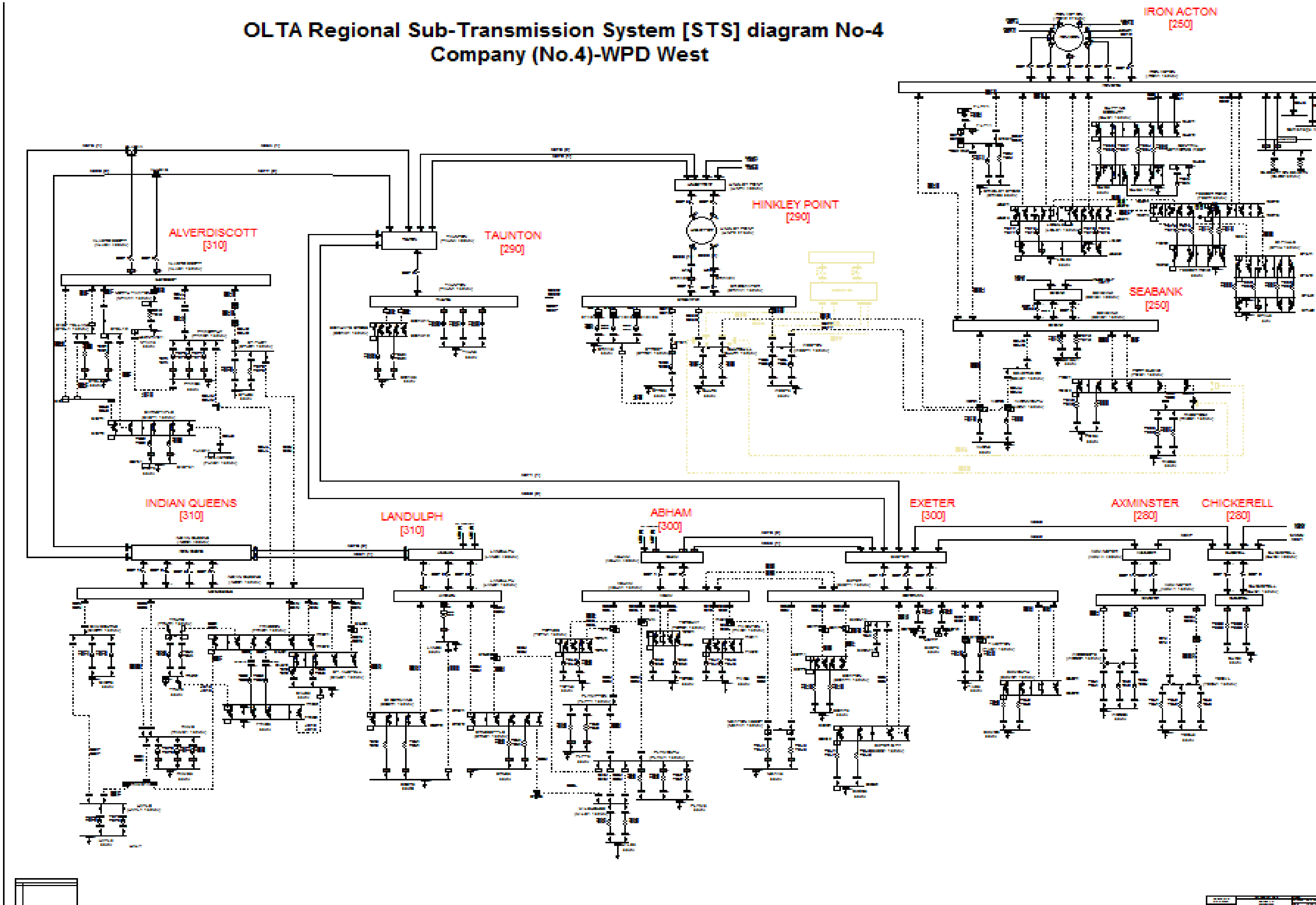
Proposed Study approach and Methodology

nationalgrid

- Full GB Transmission Network
- Includes DNO Networks
- Specific area of interest will focus on an area of the network known to have a high volume of Embedded Generation: South West
- Base case study
  - Intact network conditions
  - System conditions – Max / Min Demand
  - All Embedded Generation initially modelled as negative demand
  - Solid Three phase short circuit fault applied adjacent to Indian Queens 400kV substation
  - Voltage profile assessed across the Transmission and Distribution system during and after the above faults

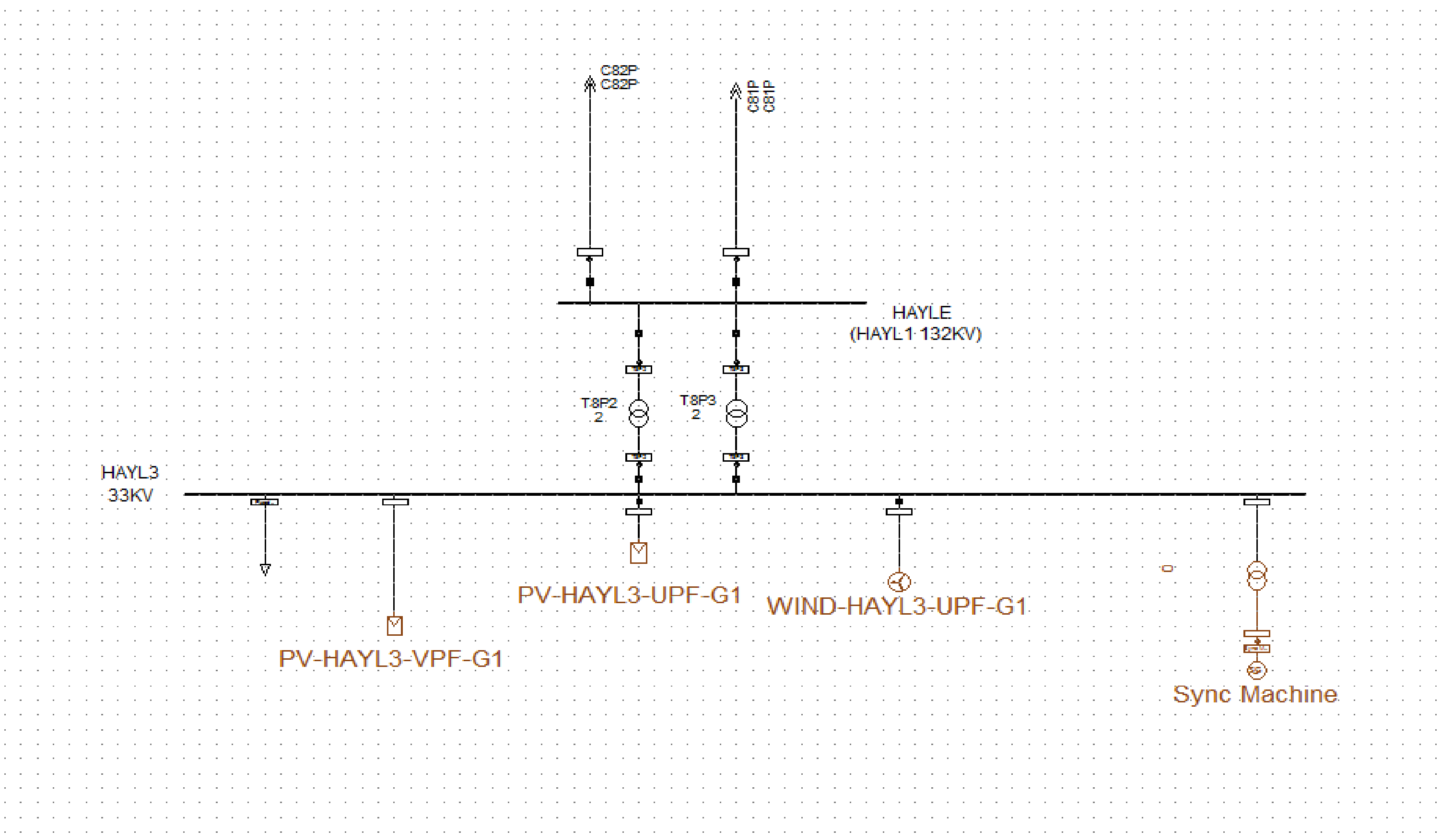
Area Under Study

nationalgrid



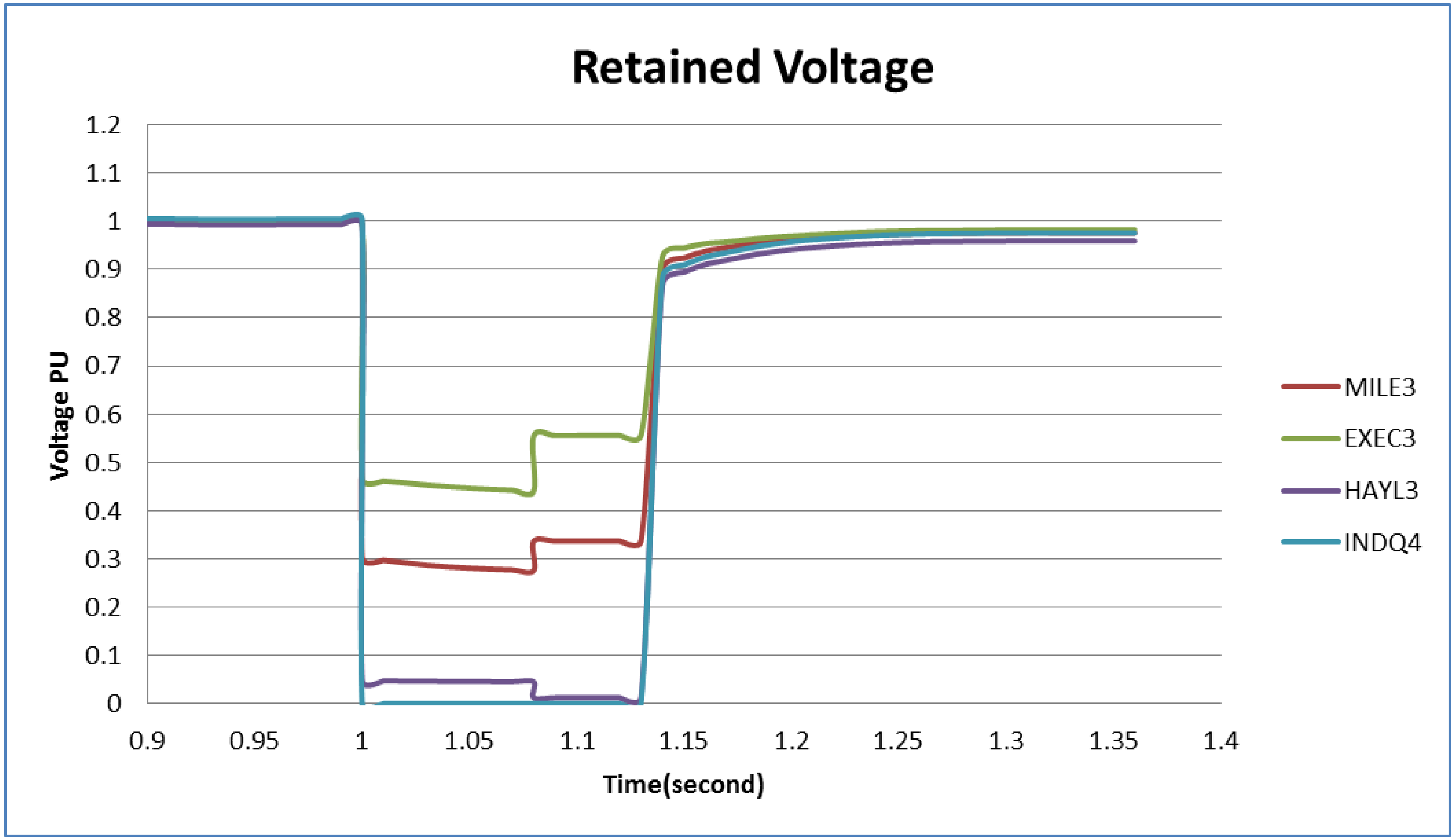
Area Under Study : Hayle

Sync Machine = 13.75MW   Non Synch 37.2MW



Multi Machine System Study
Assumption – Embedded Generation modelled as Negative Demand

- Fault Condition: Solid Three phase double circuit fault between Indian Queens and Taunton substation



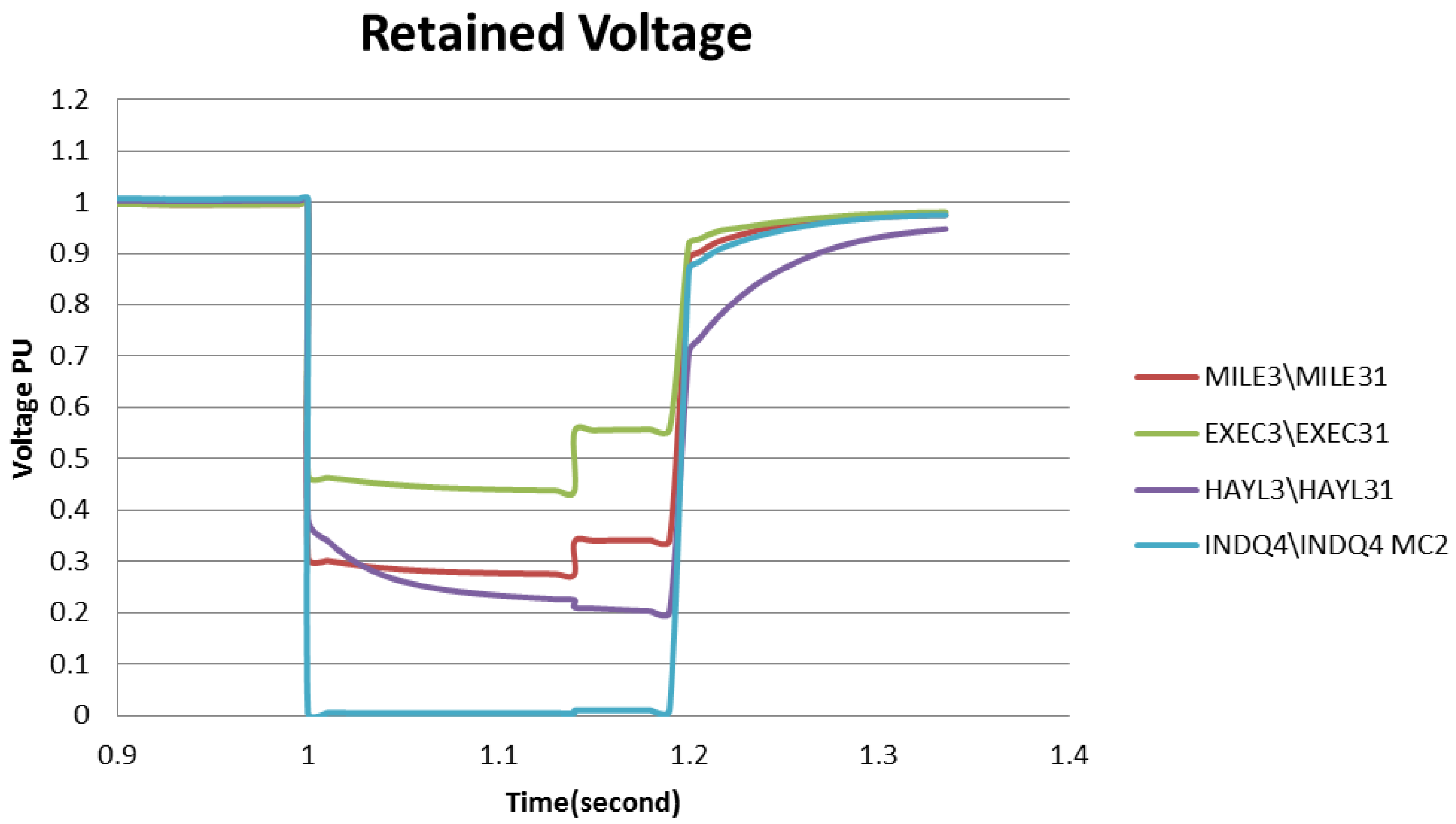
GB System Study Result Summary Negative demand

Node Name	MILE3	EXEC3	HAYL3	INDQ4
Min voltage	0.303	0.467	0.048	0

- The Voltage at the point of fault at 400kV is zero
- A number of busbars have a retained voltage above 10% due to network interconnection
- The minimum voltage at Hayle 33kV busbar during fault is 0.048pu.

GB System Study Result Summary

Embedded Generators - Synchronous Machines



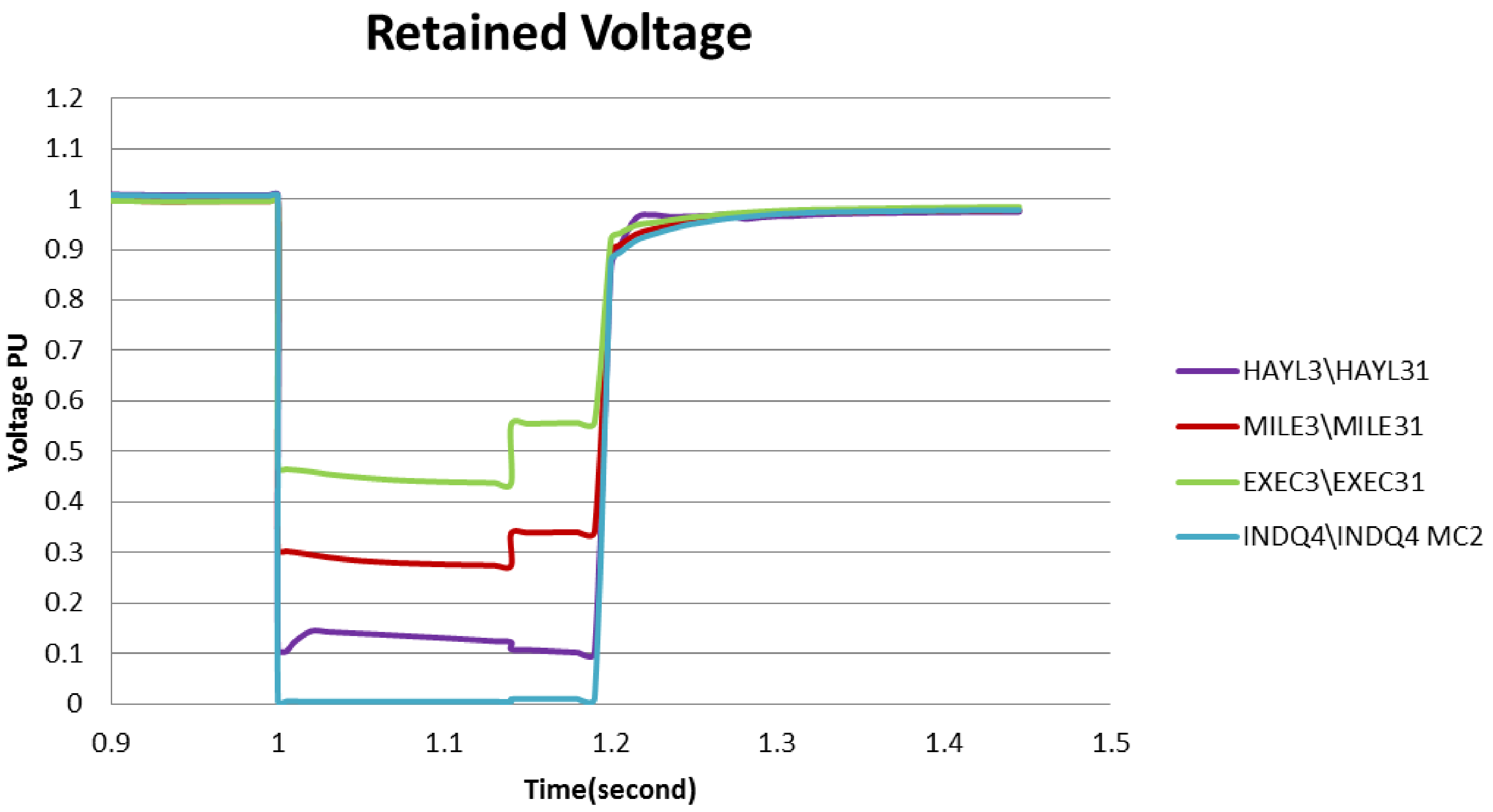
GB System Study Result Summary

Embedded generation synchronous units modelled as synchronous machine

- The Voltage increases with the capacity of synchronous machines
- The Voltage increases with the location of synchronous machines
- The Voltage at Hayle 33 kV substation has increased from 0.048pu to 0.23pu(Minimum)
- This improvement has cascaded to some of the busbars around the network
- Synchronous Plant with a FRT value of Uret of 30% may trip in this case (approx 13.25MW at Hayle), further examples below.

Node Name	MILE3	EXEC3	HAYL3	INDQ4
Min voltage	0.29	0.46	0.23	0.00

GB System Study Result Summary (Embedded non synchronous Generation Modelled as Static Generator only)

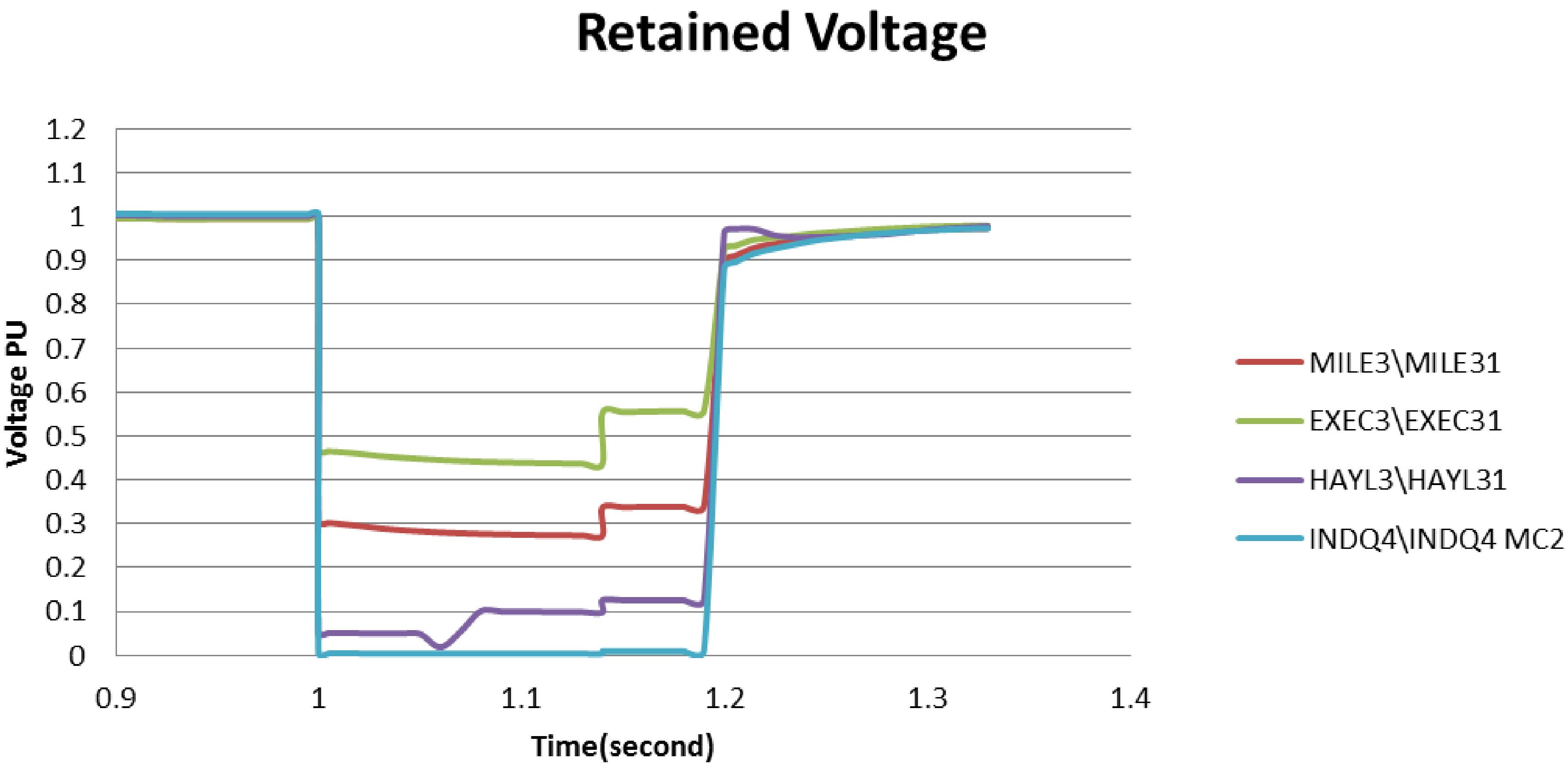


GB System Study Result Summary (Embedded non synchronous Generation Modelled as Static Generator only)

Node Name	MILE3	EXEC3	HAYL3	INDQ4
Min voltage	0.31	0.47	0.11	0.00

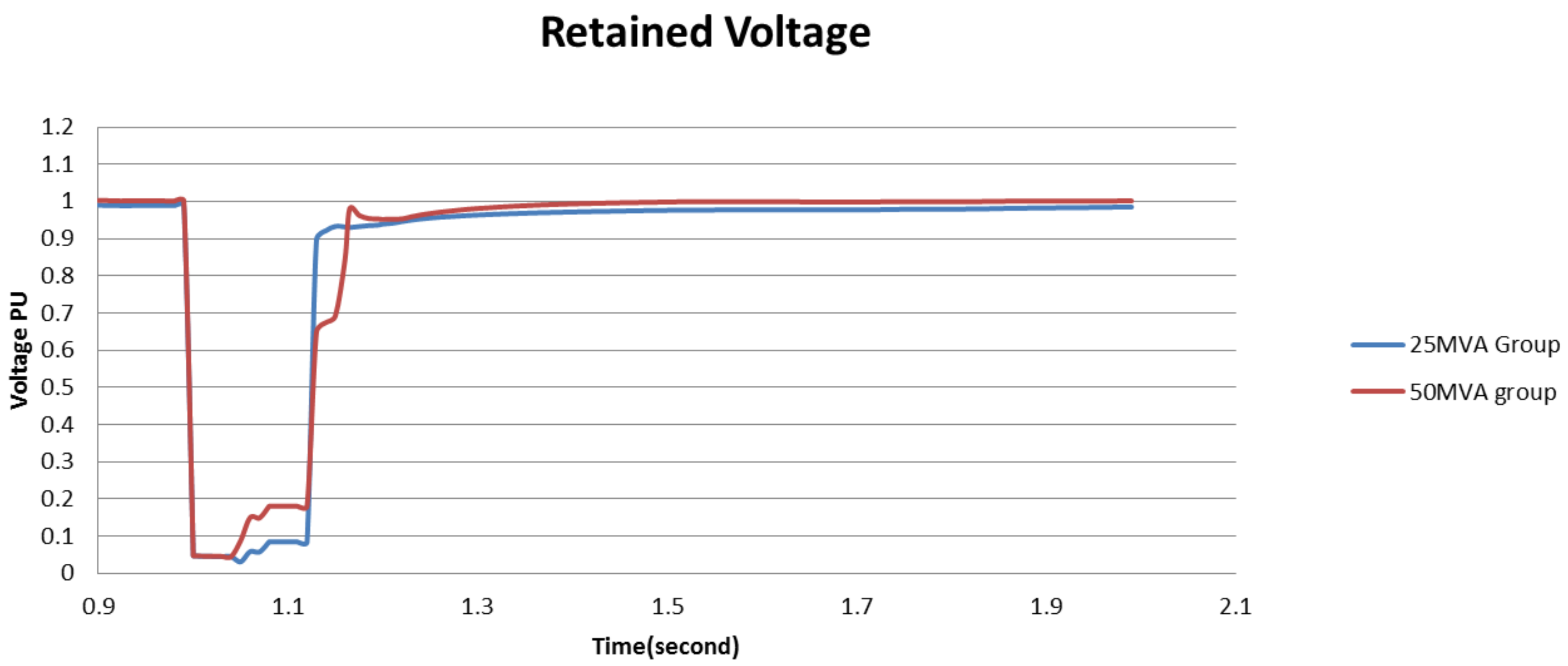
- The Voltage at the point of fault is zero
- The Voltage at Hayle 33kV Substation has increased from 0.048pu to 0.11pu
- PPM's at Hayle 33kV will trip if there is less than 25MVA plant of plant running for a Transmission System fault (retained voltage recorded at 0.08pu). Based on studies we expect there to be approx 37.04 MW running which holds the voltage above 0.11pu (as per above table).

GB System Study Result Summary
(effect of Embedded non-synchronous Generation Modelled as a Static Gen with FFCI only)



GB System Study Result Summary

Retained Voltage for different capacities FFCI



GB System Study Result Summary

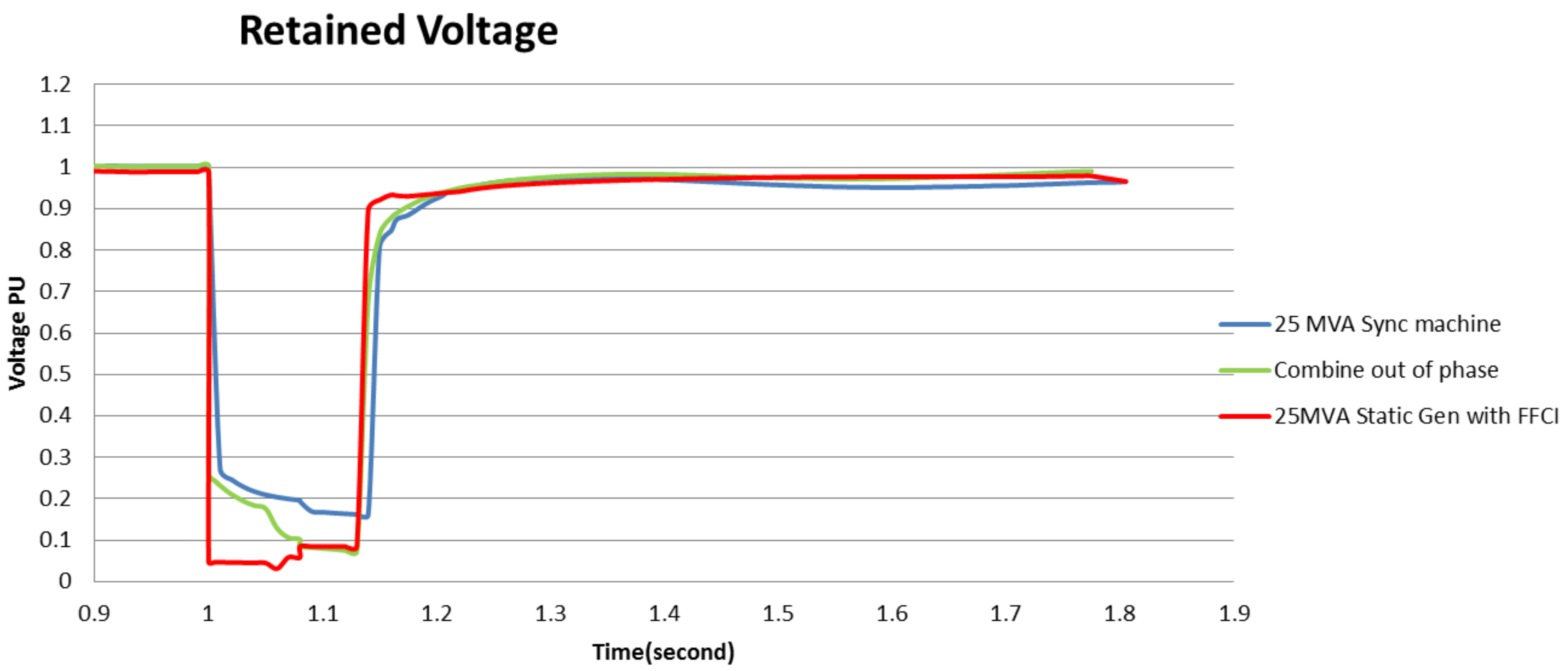
Retained Voltage for different capacities FFCI

Capacity	Initial Voltage	Final Voltage
25MVA Group	0.047	0.058
50MVA Group	0.047	0.149

- With FFCI the delay has a significant effect on the retained voltage

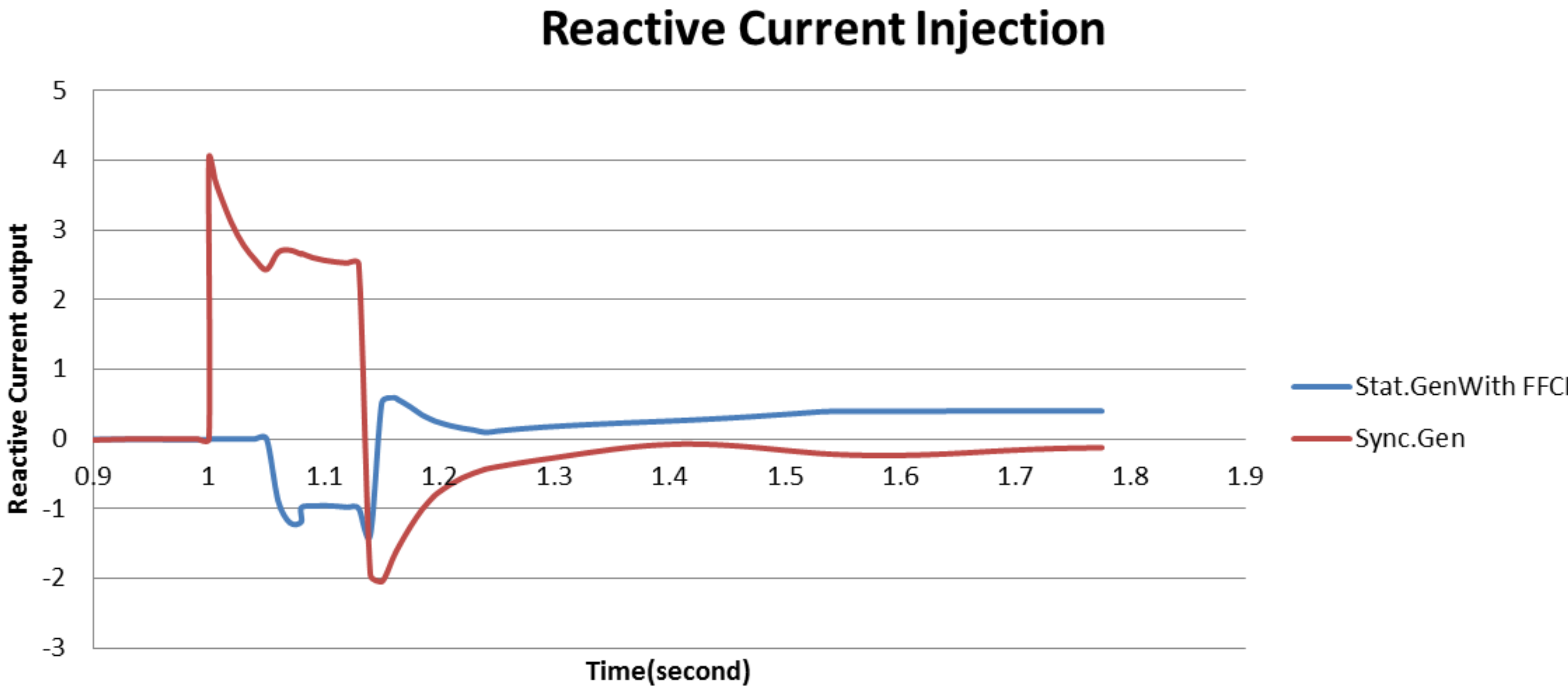
GB System Study Result Summary

Combination of Synchronous machine with static Gen with PLL



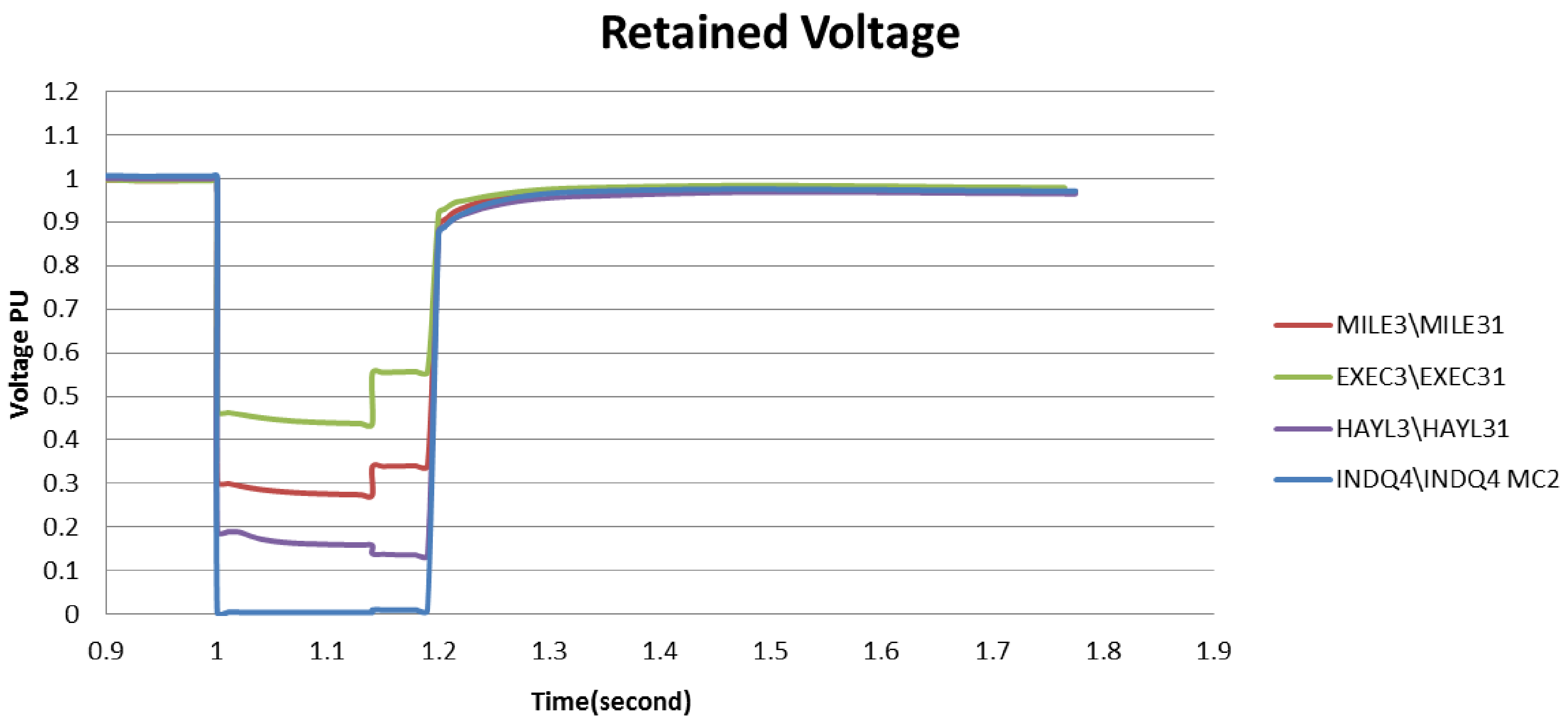
GB System Study Result Summary

Combination of Synchronous machine with static Gen with PLL



GB System Study Result Summary

non- synchronous embedded Generator modelled as VSM only



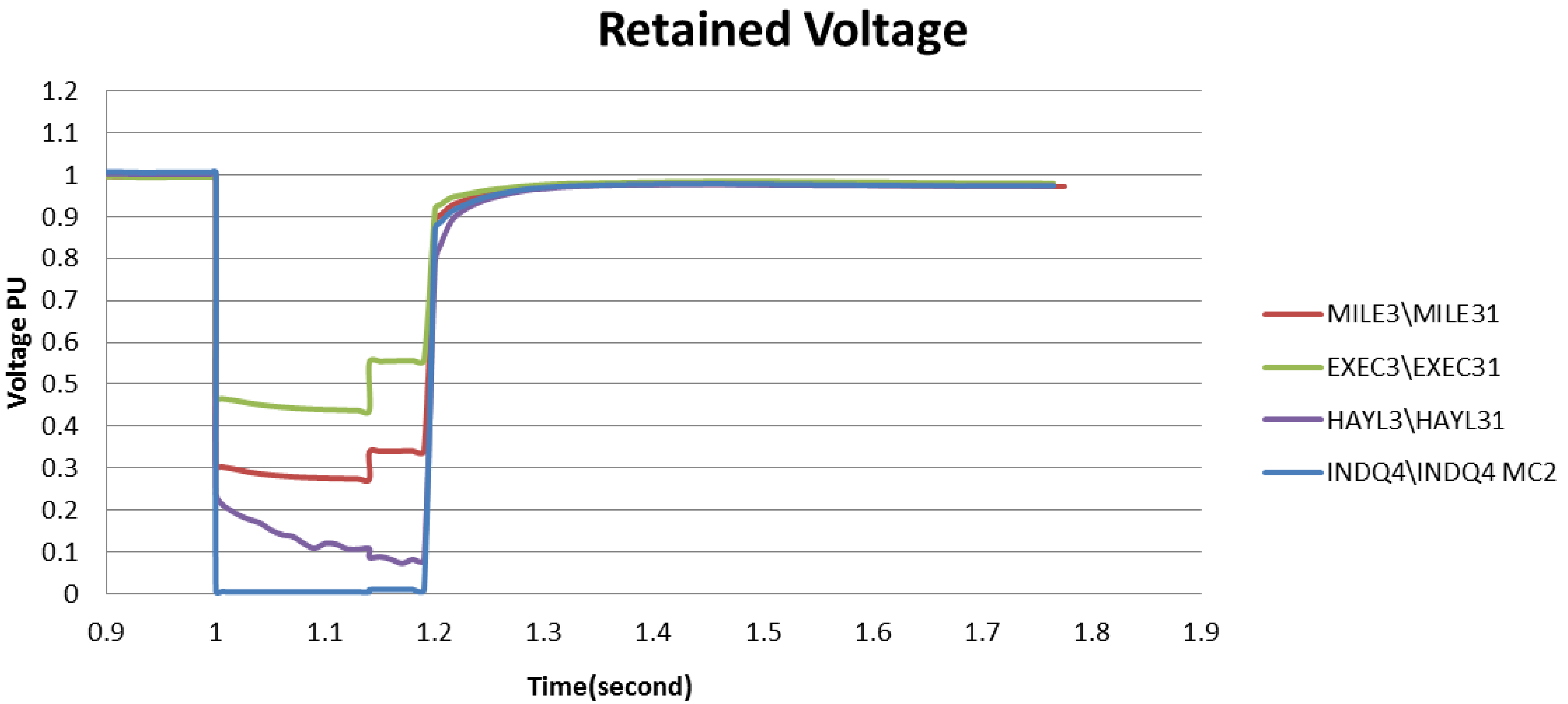
VSM Result Summary

- The retained voltage at HAYLE is greater that 0.1pu

Node Name	MILE3	EXEC3	HAYL3	INDQ4
Min voltage	0.306	0.468	0.191	0.005

GB System Study Result Summary

Combination of Synchronous machine , Static Generator with FFCI and VSM



Result Summary

Combination of Synchronous machine , Static Gen with FFCI and VSM

- The retained voltage at HAYLE if greater than 0.2pu just after the fault for a combination of the three technologies
- Due to higher synchronous fault infeed the phase shift is slower and the PLL is better able to support system voltage
- Early adoption of VSM helps improve areas of the system with already high volumes of PLL technology

Node Name	MILE3	EXEC3	HAYL3	INDQ4
Min voltage	0.28	0.44	0.21 -0.09	0.00

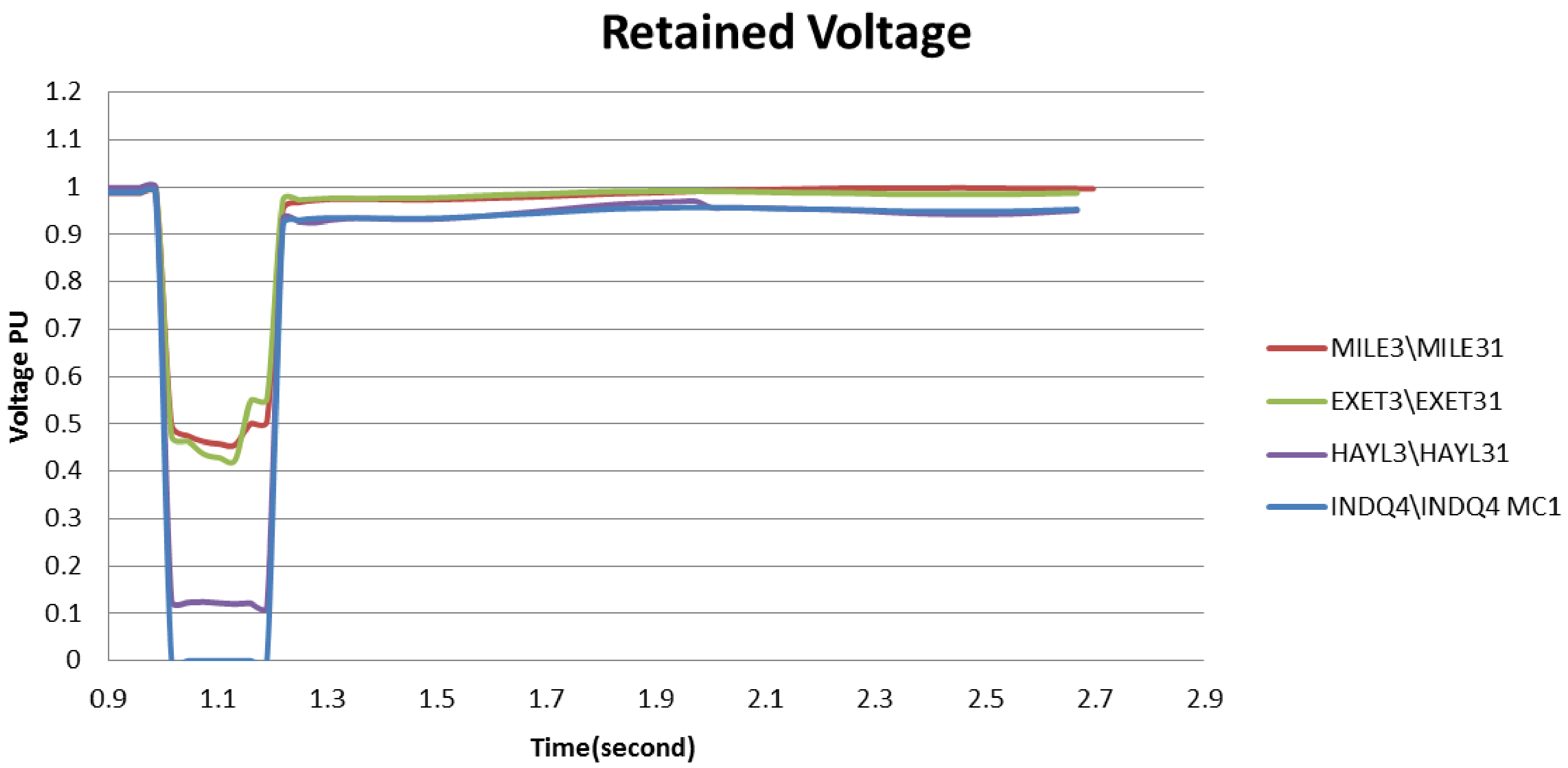
2025 Study case Solar Peak Scenario
Transmission System - Minimum Demand

nationalgrid

- The model Contains small synchronous machines at various busbars with the rest of the embedded generators are modelled as static generators. The total embedded generator output(South West region) is 141MW and 2270MW for synchronous and non synchronous plant respectively.
- The retained Voltage is above 0.1 pu
- Below is the embedded generation output matrix on the three busbars.

	Synchronous[MW]	Non Synchronous[MW]
Milehouse	**21**	**10**
Exeter City	**4**	**86**
Hayle	**13**	**46**

2025 Study case Solar Peak Scenario
Transmission System - Minimum Demand – PLL with FFCI



2025 Study Case Solar Peak Scenario

Transmission System - Minimum Demand (Without VSM)

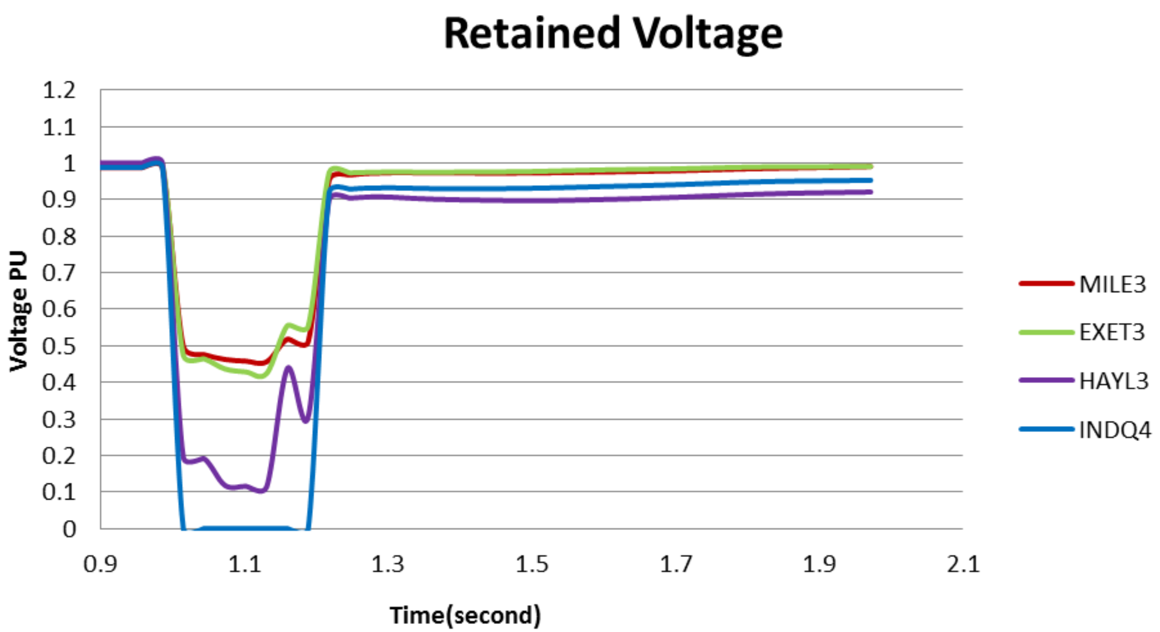
Node Name	MILE3	EXEC3	HAYL3	INDQ4
Min voltage	0.50	0.47	0.13	0.00

- For the 2025 solar peak model the retained voltage is 0.13pu for a combination of synchronous machines and static generators with Fast Fault current injection (FFCI)

2025 Study case Solar Peak Scenario

nationalgrid

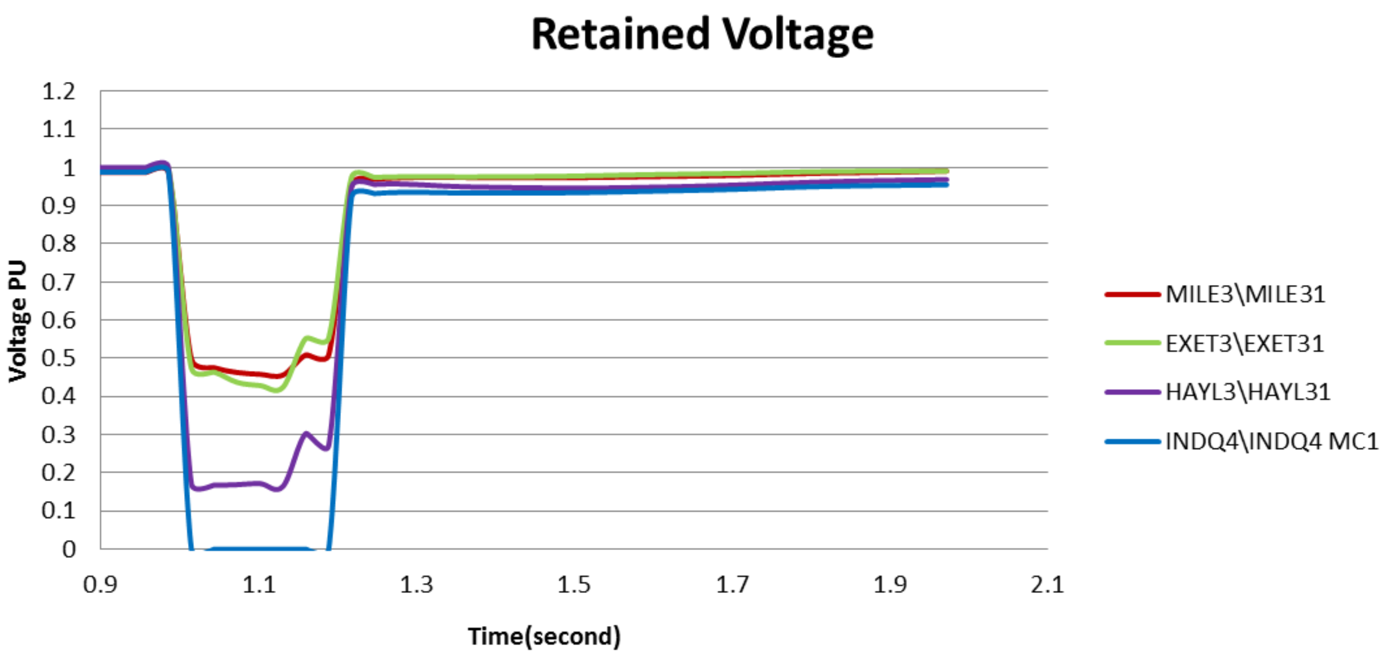
Results With VSM + PLL + Synchronous plant included - Transmission System - Minimum Demand



Node Name	MILE3	EXEC3	HAYL3	INDQ4
Voltage	0.50	0.47	0.19- 0.12	0.00

2025 Study case Solar Peak Scenario

Results With VSM + Synchronous plant included - Transmission System - Minimum Demand



Node Name	MILE3	EXEC3	HAYL3	INDQ4
Voltage	0.50	0.47	0.19	0.00

RfG – Fast Fault Current Injection Update – Results / Conclusions

High Level Observations (1)

- The amount of fault current injected is a function of the volume of Generation at a specific location
- The retained voltage during the period of the fault is a function of the amount of reactive current injected
  - The lower the fault infeed, the lower the retained voltage
- The fault infeed from Synchronous Generation is superior compared to Converter based plant
- The performance from Converter based plant can be modified depending upon the control strategy employed
  - The best performance can be obtained from VSM technology
  - The poorest when modelled as a Negative Demand
  - The performance of PLL based converters will be a function of the delay, response speed and maximum ceiling current (in these studies this was set to 1.5pu)
  - The performance of the PLL is fundamental to getting the phase relationship correct which can result in incorrect current injection and delays in performance

High Level Observations (2)

- If high levels of fast fault current injection are achieved, this helps maintain the voltage profile across the network. VSM can be seen to stabilise local retained voltage against a future greater level of nonsynchronous generation
- Volume of Generation is a primary issue in defining the levels of fast fault current injection required and the retained voltage (Uret)
- Any requirement that is proposed needs to be robust over the range of Transmission System operating conditions (ie max demand to min demand).
- The more generation running (in particular DG - with the wrong control philosophy) the greater the risk of incorrect behaviour hence the need for these requirements which creates self supporting situation.
- The reactive current injected by Synchronous plant is fixed and is a function of the machine parameters.

Constraints / Issues (1)

nationalgrid

- The Transmission System is currently secured to a maximum infrequent infeed loss of 1800MW. If Embedded Generation is lost above this level, the frequency will not be secured without holding of additional reserves or operation of the demand disconnection scheme (initiated at 48.8Hz). Much of the embedded generation connected at lower voltages does not have operational metering to inform the scale of the potential maximum loss.
- Synchronous Generators driven by reciprocating Diesel / Gas engines are unable to ride through voltage dips where the retained voltage is below 30%. There is no known cost effective solution to overcome this issue at the present time. Time frame for tripping to be discussed.
- The best results (highest retained System voltage) for multi machine studies with high converter penetration were obtained with VSM technology included (see slide – 45)
- Based on studies, a Transmission System fault may result in voltage dips at certain busbars as low as 10% retained voltage even with the VSM from converter based plant modelled. This will result in tripping of some Embedded Generation; FRT settings need to balance operational costs with the potential cost of compliance.

Options

nationalgrid

Option	Advantages	Disadvantages
Negative Demand	Do Nothing	Not sustainable- higher maximum loss occurs which cannot easily be tracked or managed. No fault current supplied – System Operability issues / Protection issues
Static Generator with PLL	Potentially gives relatively fast response but delays still exist	Real Converter unlikely to behave in this way Delayed response Anti phase PLL – requires tuning Power System Operational issues High post fault TOV issues Do not contribute to System Services
Static Generator with FFCI	Higher fault current than options 1 and 2	Do not contribute to System Services (e.g no inertia) Delayed response will risk voltage dips below defined voltage against time curve in areas of low synchronous generation Little System benefit unless high volumes connect Still requires manufacturer development of control strategies – but some experience in GB of doing this Still has dependencies upon PLL function
VSM	Offers many system benefits –over and above other options (see next slide) EU may introduce similar requirements in the longer term Offers better long term system performance than other current options No delay in response VSM Technology - current driven by Power System not converter	Unproven technology Requires manufacturer development Solution needs storage technology or primary energy source may need to be curtailed Development timescales unknown Potential Power System Stabilser issues

VSM Summary

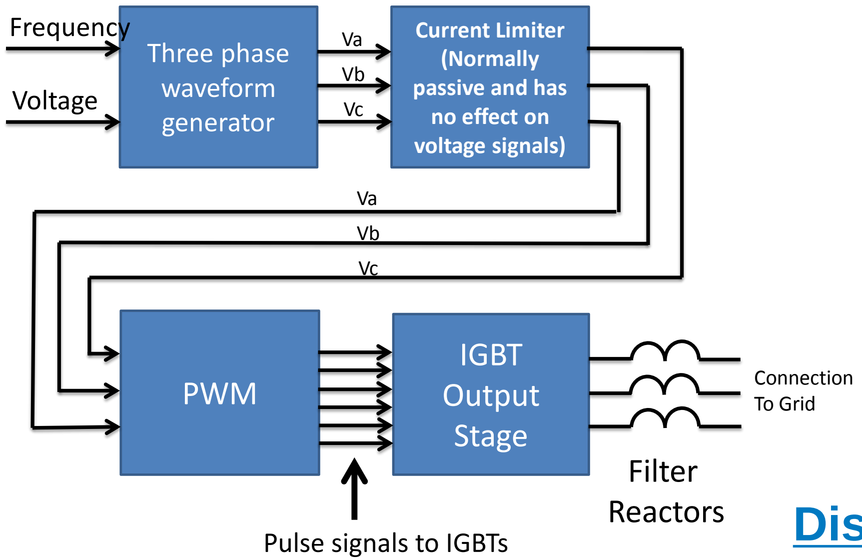
nationalgrid

- VSM has been subject to a whole range of simulation work and a number of papers have been published on this subject (see references published in earlier GC0048 meetings / actions)
- VSM covers a wider range of system events in different scenarios unlike many other solutions, with a better performance
- VSM can be combined with the other solutions, it is not intrusive with the other technologies, these can work together with VSM
- VSM has similar response to Synchronous Machines under generation loss events, the operator can use the same expertise.
- Application, analysis, operation and commercialisation of the services of VSM are similar to those of Synchronous Machines

Virtual Synchronous Machine (VSM)

nationalgrid

3 Phase VSM Output Stage



Changes for VSM

1. Simulate inertia
2. Reduce the bandwidth of F and V to 5Hz

Advantages (main)

1. Contributes to RoCoF
2. Compatible with SG
3. Reduced interaction and HF instability risks
4. Can be modelled in RMS system studies

Disadvantages

1. Requires additional energy (eg storage)
2. Possibility of traditional power system instability

Summary

nationalgrid

- From a Transmission System perspective, the VSM functionality or immediate fault current injection is the preferred option based on the study results in addition to the wider system benefits – see previous slide. It also helps lift the retained voltage (Uret) across the system
- The EU are already looking at these concepts - a one year study is being initiated for Type 1 Grid Forming Converters.
- There could be additional costs to developers. For battery storage and solar projects these are considered to be modest, for wind based plant they could be higher
- The dilemma – From a Network Operators perspective VSM functionality is the preferred solution but it is acknowledged that development time needs to be factored into this and to meet RfG timescales, a solution must be available by May 2019.
- If these timescales cannot be met, then there would still be a requirement for converter based plant to contribute to reactive current injection. The risk is that it could result in manufacturers to develop one solution on an interim basis and then adopt the immediate current injection approach in the longer term which could result in doubling development costs.

High Level Proposals

nationalgrid

- For fast fault current injection an immediate reactive current injection (VSM type functionality or otherwise) would be proposed in the longer term - in the shorter term conventional converters with delays would only be available until 1 Jan 2021?)
- Fault Ride Through Voltage against Time Curves
  - For Type D Power Generating Modules connected at or above 110kV the proposed requirements (circulated in October) would remain unchanged
  - For Type D, C and B Power Park Modules connected below 110kV the requirements would remain as they are
  - For Type C and D Synchronous Power Generating Modules below 110kV the requirements would remain unchanged
  - For Type B Synchronous Power Generating Modules the value of Uret would have to remain at 0.3 pu as no known technical solution is believed to exist
- Synchronous Generators driven by reciprocating engines are limited in size to about 5 MW. Synchronous Generating Units above this size are generally driven by non reciprocating prime movers and not believed to present a problem. A Band B / C threshold of 10MW is therefore proposed.
- Even with these values and based on the studies run, it is possible that small volumes of embedded generation could be lost though these are small (based on the fault at Indian Queens this is limited to about 13MW) even this has low risk due to the higher volumes of embedded generation running

Fast Fault Current Proposals

nationalgrid

FFCI Requirement

Immediate fault current injection

Conventional Converter with delays (Time limited until 1 January 2021?) then VSM type performance would be required

Eg VSM Type Functionality

The delay in response here does however cause concern as it would mean that the retained voltage drops during the initial part of the fault which could have implications for the Voltage against time curves

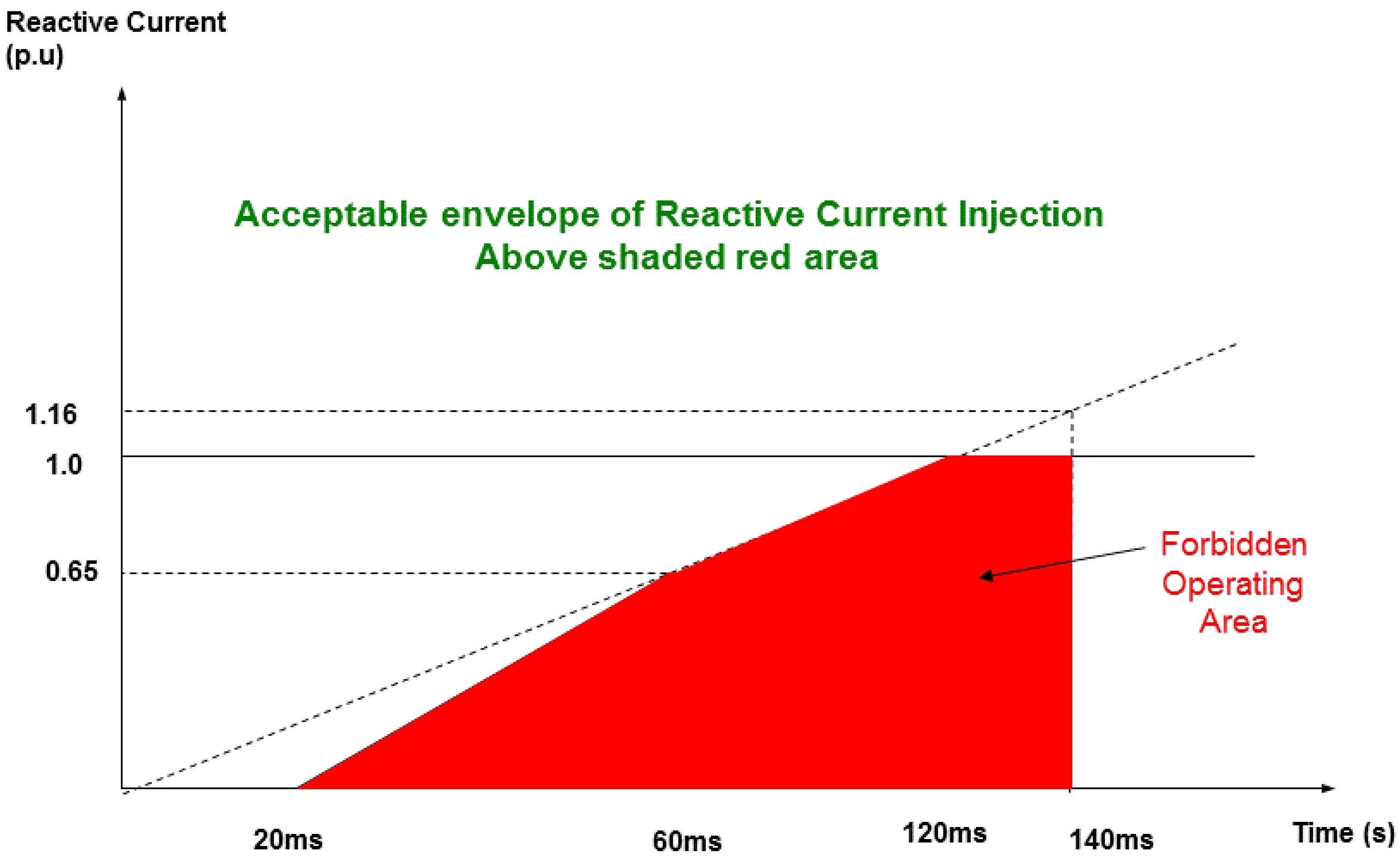
High level proposals for Immediate Reactive Current Injection (VSM Type Performance or Equivalent)

nationalgrid

Requirement	Specification
Point of Fast Fault current injection	Connection Point of Power Park Module
How and when voltage is to be determined as well as the end of the voltage deviation	Current supplied as required by the System
The characteristics of the fast fault current, including the time domain for measuring the voltage deviation and fast fault current from which current and voltage may be measured differently form the method specified in Article 2	Current supplied as required by the System (Voltage Source Converter). This type of technology will limit the current within the capability of the rating of the converter. This would be proposed to be set to 1.5pu (assuming the converter is rated to circa 1.3p.u real power).
The timing and accuracy of the fast fault current, which may include several stages during a fault and after its clearance	Current limit needs to be fast to prevent converter damage
When post fault active power recovery begins based on a voltage criterion	Active Power to be delivered immediately the fault has been cleared providing the current limit has been switched off and system voltage has recovered to nominal levels.
Maximum allowed time for active power recovery	Active Power to be delivered immediately the fault has been cleared providing the current limit has been switched off and system voltage has recovered to nominal levels.
Magnitude and accuracy for active power recovery	Active Power to be restored to 90% of its pre-fault value. Active Power oscillations shall be acceptable provided that the total active energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Energy was constant and the oscillations are adequately damped.

High Level proposals for Conventional Converters

nationalgrid



High level proposals for Conventional Converters

nationalgrid

Requirement	Specification
Point of Fast Fault current injection	Connection Point of Power Park Module
How and when voltage is to be determined as well as the end of the voltage deviation	Each time the voltage at the Connection Point drops below 0.9p.u Blocking Voltage expected to be set at 0.09 pu
The characteristics of the fast fault current, including the time domain for measuring the voltage deviation and fast fault current from which current and voltage may be measured differently form the method specified in Article 2	Each Power Park Module shall be capable of generating maximum Reactive current during the period of the fault without exceeding the transient rating of the Power Park Module. The PLL needs to be disabled in order to maintain the same phase reference
The timing and accuracy of the fast fault current, which may include several stages during a fault and after its clearance	Power Park Module Facility Owner to provide a continuous time trace of reactive current injection before during and after the fault, which demonstrates an acceptable degree of injection within the time period 20-60ms – See previous slide
When post fault active power recovery begins based on a voltage criterion	Active Power Recovery to commence on fault clearance (ie voltage above 0.9p.u, but less than 1.05p,u)
Maximum allowed time for active power recovery	Active Power to be restored within 0.5 seconds of fault clearance (ie voltage above 0.9p.u)
Magnitude and accuracy for active power recovery	Active Power to be restored to 90% of its pre-fault value. Active Power oscillations shall be acceptable provided that the total active energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Energy was constant and the oscillations are adequately damped.

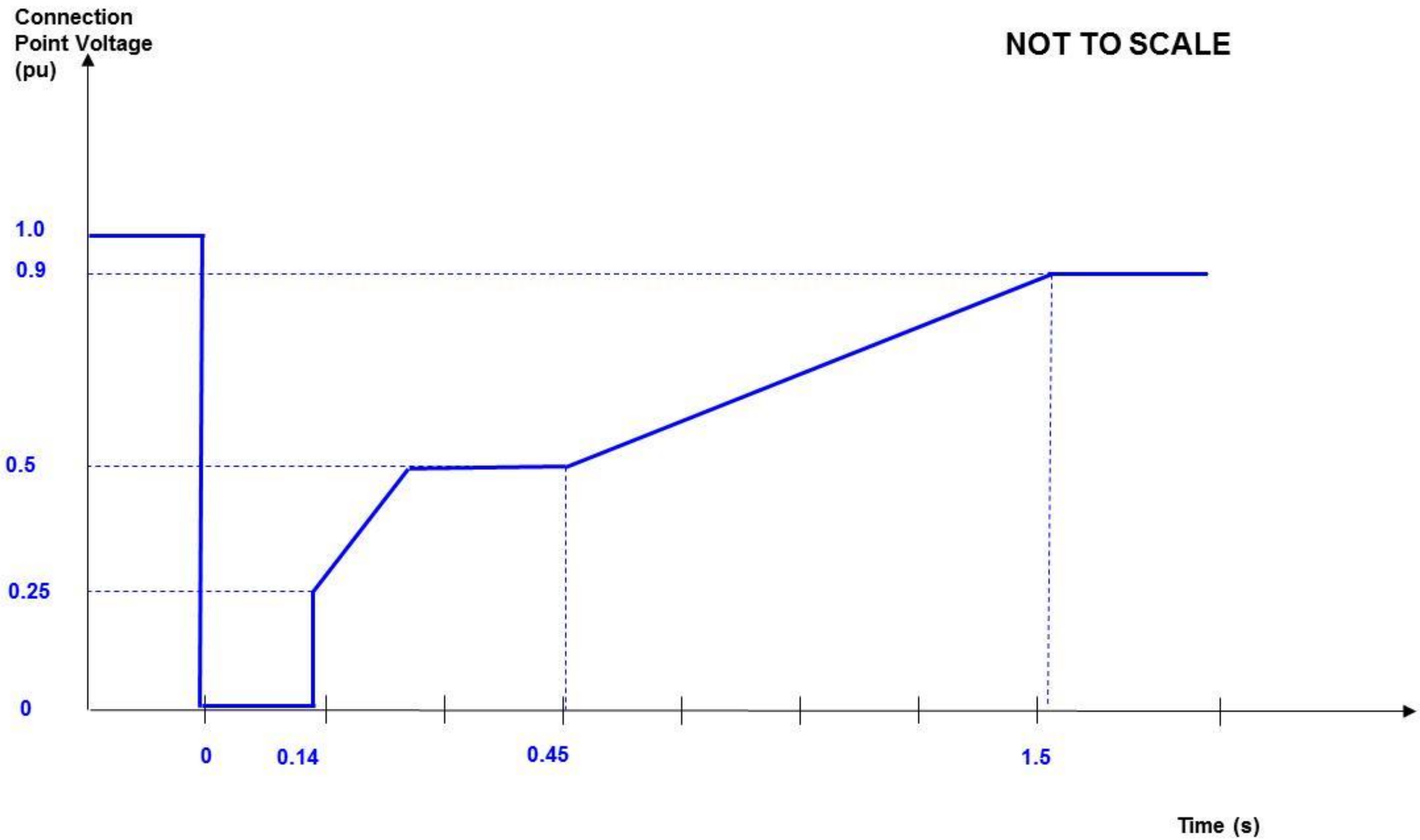
Note

nationalgrid

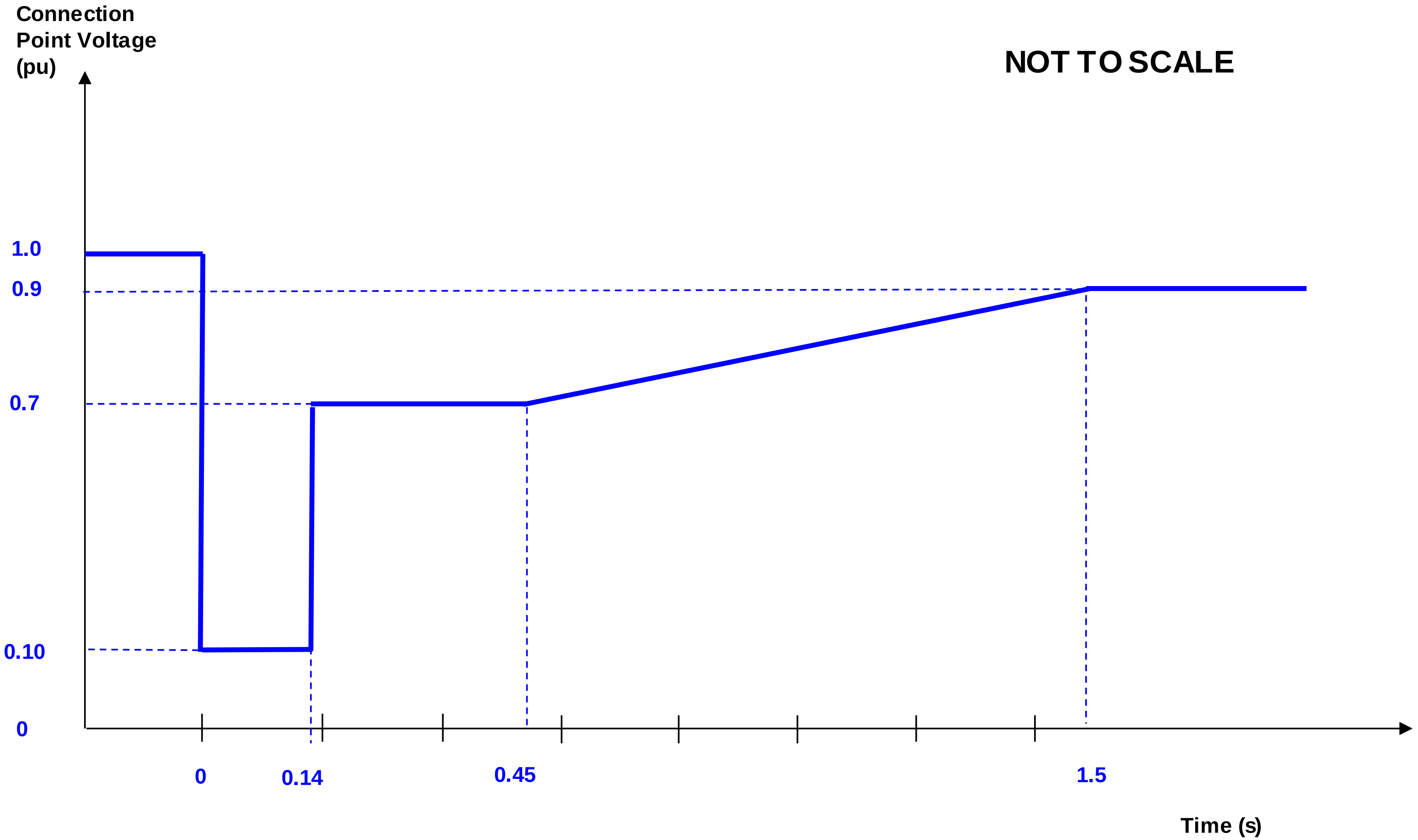
- Whilst the concepts of immediate reactive current injection are being proposed in the longer term, the requirements for fast fault current injection will ultimately be specified in the Grid Code as a functional performance requirement.
- There is no restriction on the equipment used to satisfy these requirements so long as they can meet the functional performance proposed Grid Code.
- This presentation has suggested the approach going forward. The consultation will cover the functional performance requirements in more detail.
- Stakeholder discussions are required on these proposals

RfG Fault Ride Through
Voltage against Time curves

GB Type D Voltage Against Time Curve

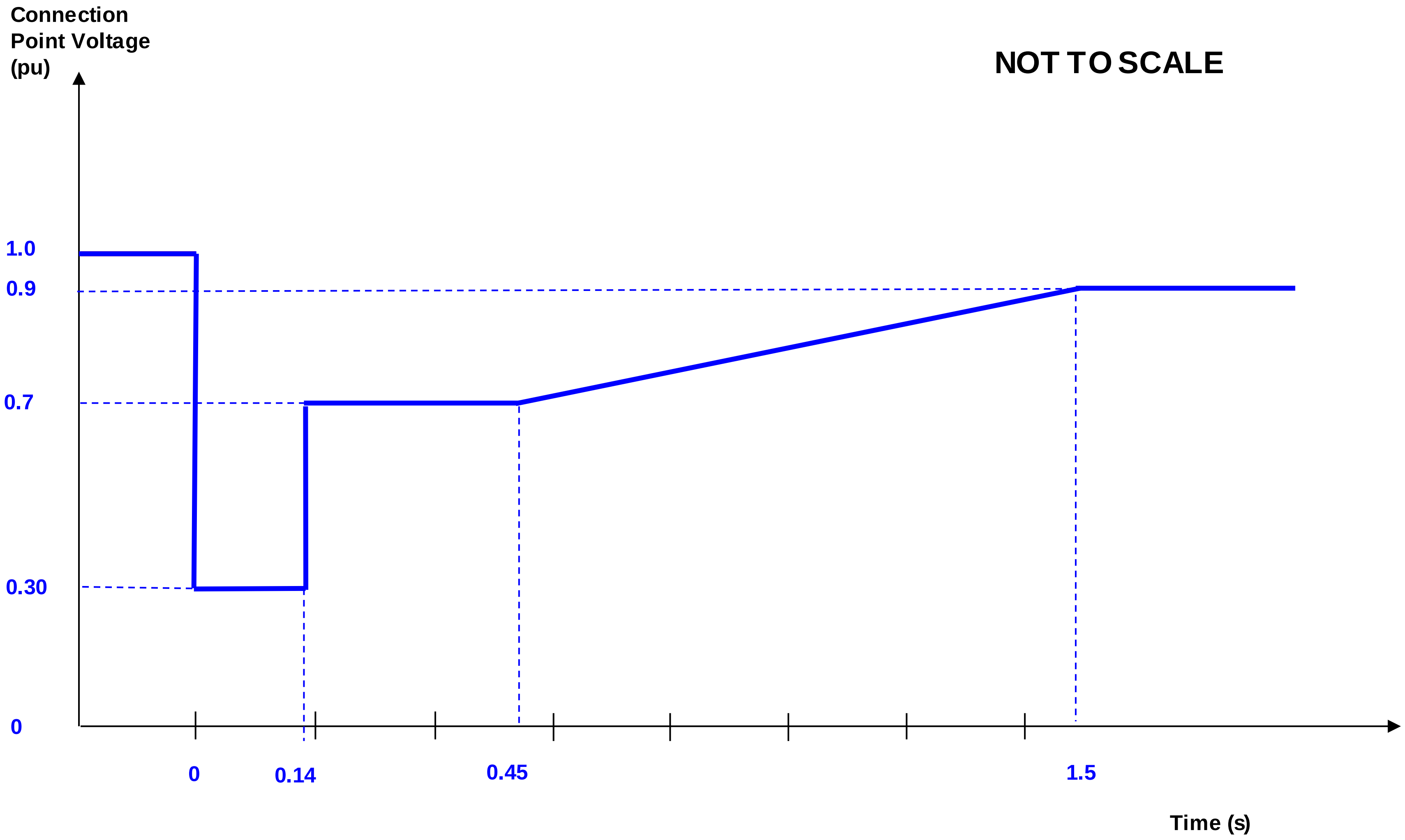


Suggested Voltage Against Time Profile – Type C and D



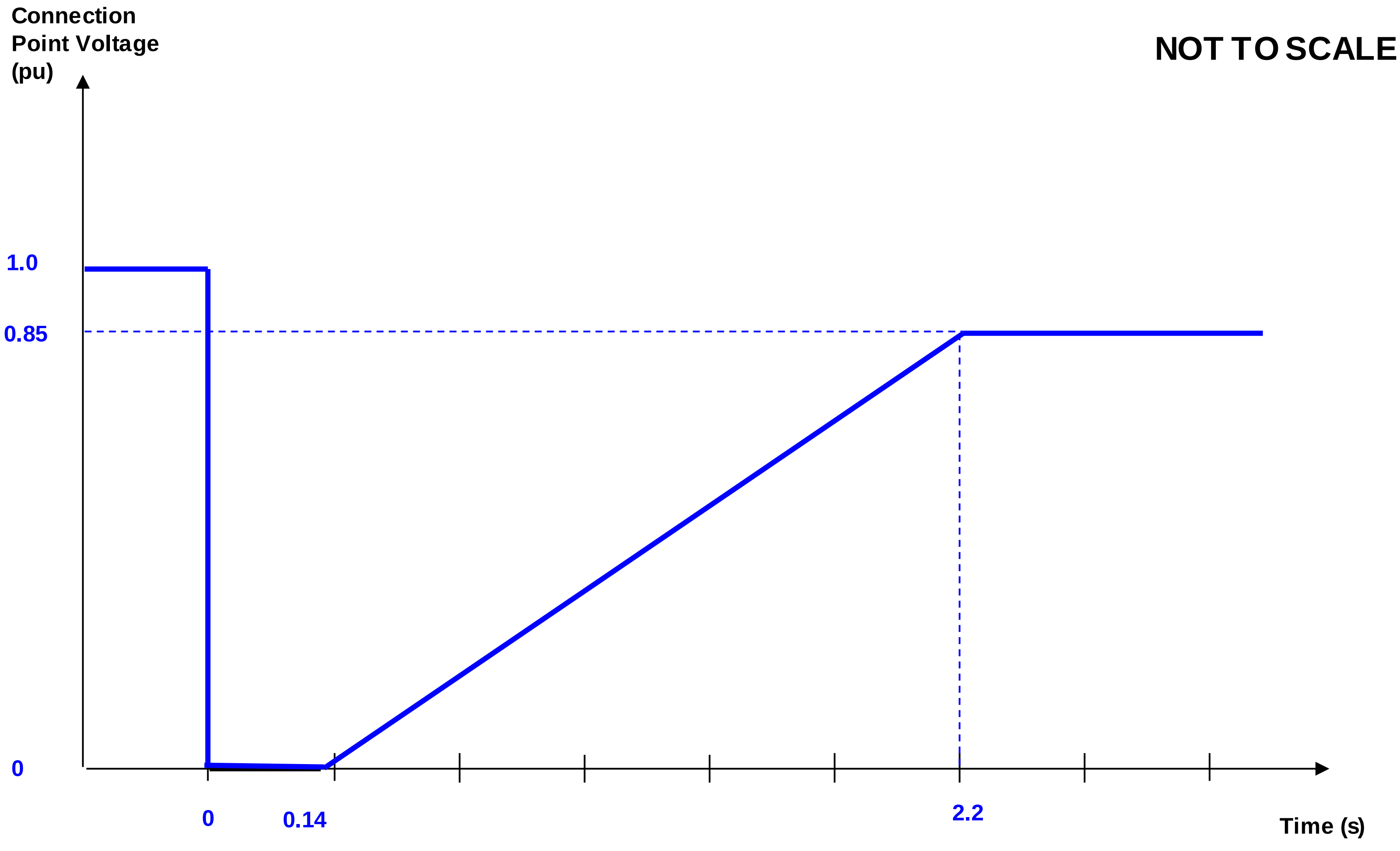
Type B Synchronous Power Generating Modules Connected <110kV

GB Voltage Against Time Profile – Type B



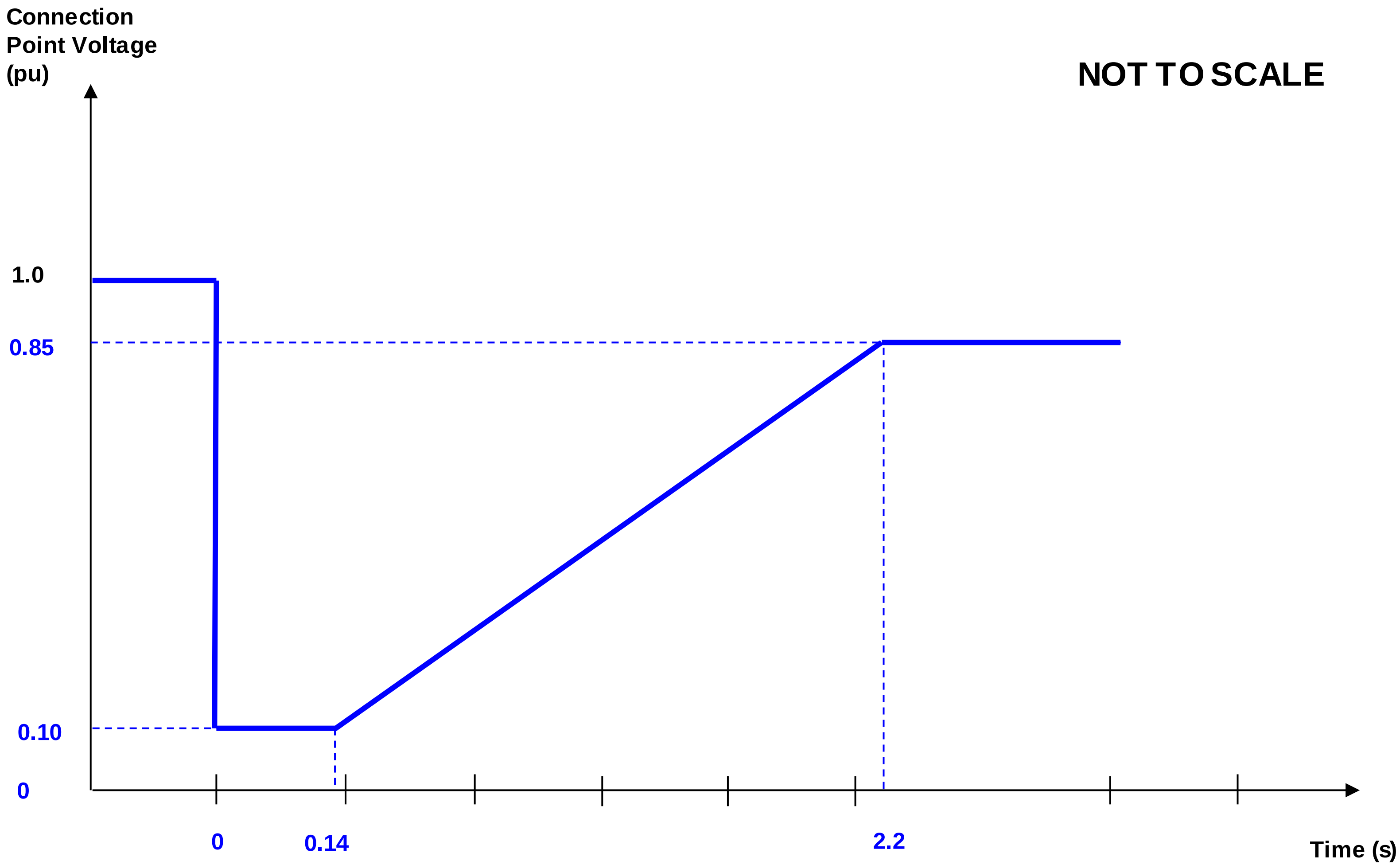
Type D Power Park Modules connected ≥110kV

GB Voltage Against Time Profile – Type D



Type B, C and D Power Park Modules connected <110kV

GB Voltage Against Time Profile - Type B, C and D



Summary

- Immediate current injection may be considered an unproven option but its overall cost is considered to be the lowest and offers many other system benefits. The VSM is an example of such technology – it is not the only option
- Time allowed for manufacturers to develop solutions. Conventional Converters with delays can be used as a short term solution until 1 January 2021? Immediate current injection performance can be employed at any time but conventional converter performance would only be available until 1 January 2021 due to concerns over delays and the effect on system performance.
- Based on current studies, a Transmission System fault will result in voltage dips at certain busbars which could be as low as 10% even with the VSM from converter based plant modelled.
- The proposed voltage against time curves require a value of Uret = 10% for all Type B, C and D Plant connected below 110kV (excluding Type B Synchronous).
- Embedded Generation losses need to be mitigated for major Transmission System faults. Based on the study results, the Band B/C threshold in RfG is recommended to be 10MW; It is believed the potential loss of Embedded Generation including smaller Synchronous machines (up to 10MW) driven by reciprocating engines (with a value of Uret set at 30%) is manageable at these levels.
- Costs are not believed to be excessive for any plant in meeting these Uret values (eg FRT already applies in SHET Transmission area and Offshore for all plant of 10MW and above)
- The EU are looking at these concepts – Type 1 Grid Forming Converter performance

RfG – Fast Fault Current Injection: GB context of case study

nationalgrid

Ben Marshall
National Grid – System Performance (SO)
April 2017

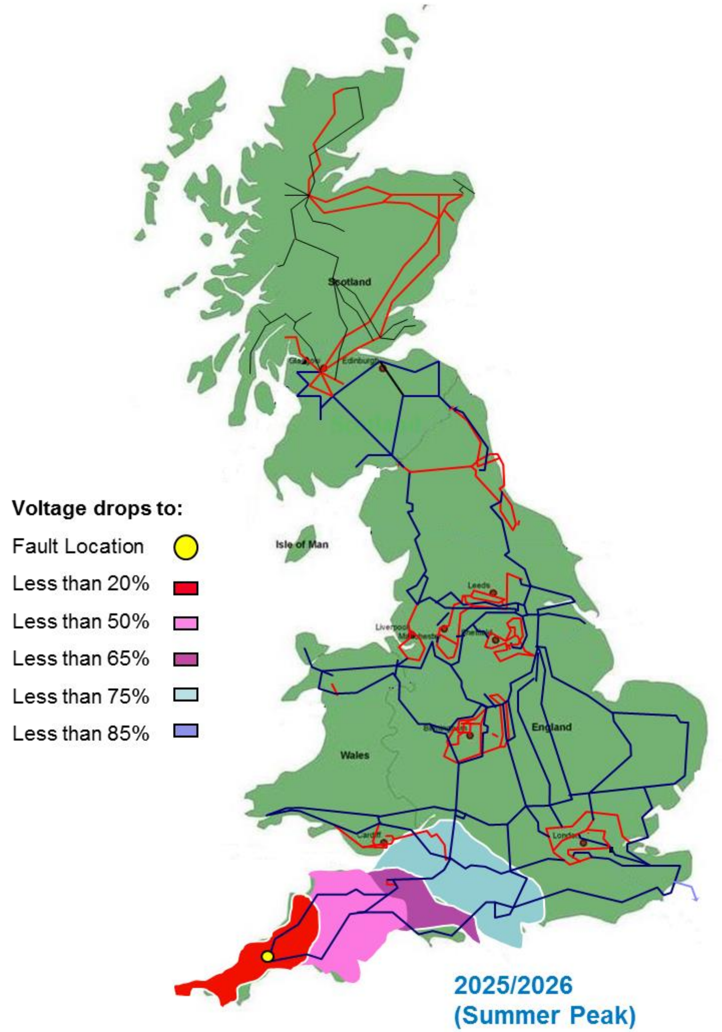
Summary

- Voltage dip propagation contour across SW area.
- How SW compares to other GB regions
- How SCL changes over time in these regions (assuming Tx sources only supporting).
- Conclusions

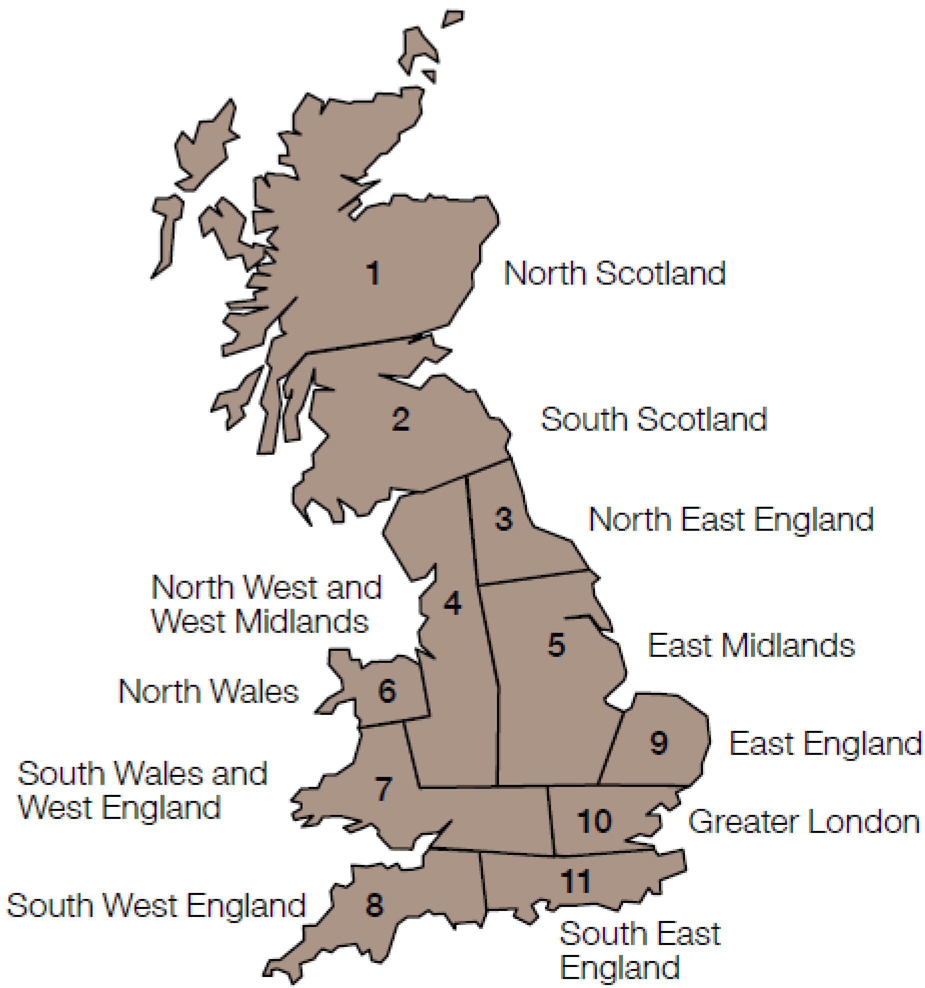
nationalgrid

Voltage dip Propagation across SW area

- For a fault at Indian Queens voltage dip below 0.3 up to Hinkley Point.
- Broad equivalent impact for loss of large machine in area and simulations as discussed.
- High potential for > maximum infeed loss



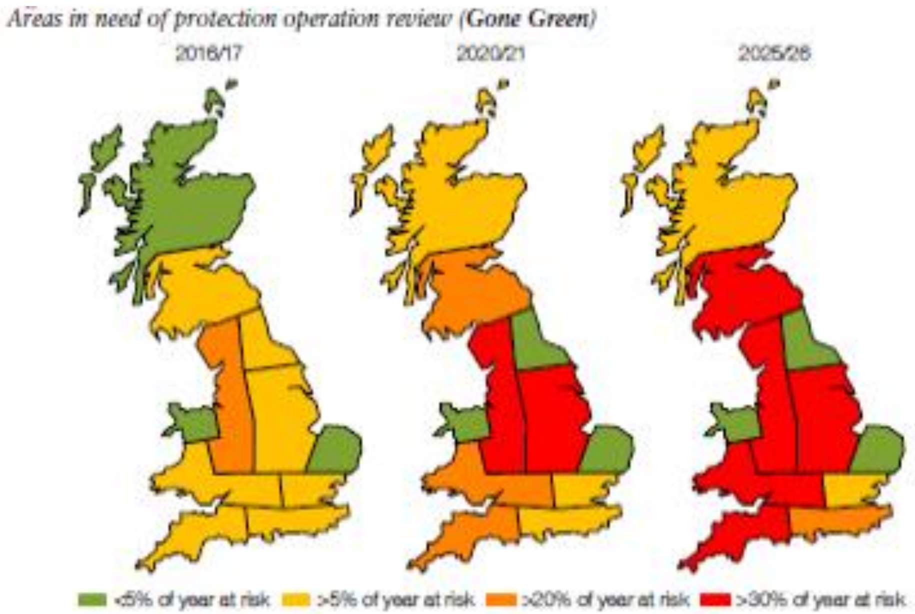
SCL regions of GB

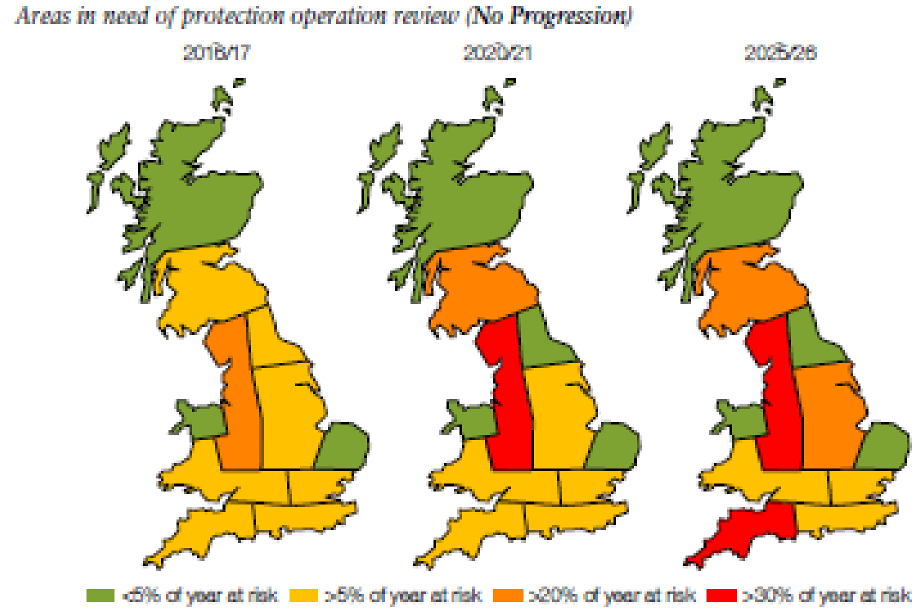


How SW compares to other areas of GB

Area		GC048 study			Future Of Energy documents					
		SCL studied 2025 (kA)	DG installed 2025 (MW)	DG studied 2025 (MW)	FES2025 max DG output (MW)	FES2025 min DG output (MW)	SOF regional SCL min (kA)	SOF regional SCL 95% confidencemin (kA)	SOF regional SCL 95% confidence max (kA)	SOF regional SCL max (kA)
1	North Scotland	N/A	N/A	N/A	1839.5	1167.6	6.8	11.9	16.5	18.6
2	South Scotland	N/A	N/A	N/A	2941.8	2024.4	9.5	13.1	20	21
3	North East England	N/A	N/A	N/A	1360.6	885.4	10.8	14.4	29.3	34.1
4	North West and West Midlands	N/A	N/A	N/A	3338.1	1990.1	0.7	5.7	21.1	22
5	East Midlands	N/A	N/A	N/A	3540.8	2029.3	2.7	7.1	24.4	28.4
6	North Wales	N/A	N/A	N/A	740.1	594.3	13.3	21.6	36.1	38
7	South Wales and West england	N/A	N/A	N/A	3677.3	2300.5	6.4	9.8	26.2	30.4
8	**South West England**	16.3	2522.4	2411	**3213**	**1999.7**	**2.4**	**7.3**	**22.1**	**25.9**
9	East England	N/A	N/A	N/A	3934.5	2543.1	9.1	17.4	41.5	45.6
10	Greater London	N/A	N/A	N/A	1716	1104.4	6.2	14.2	32.4	35.7
11	South East England	23.95345696	N/A	N/A	2059	1268.2	7.6	15.1	27.9	31.7

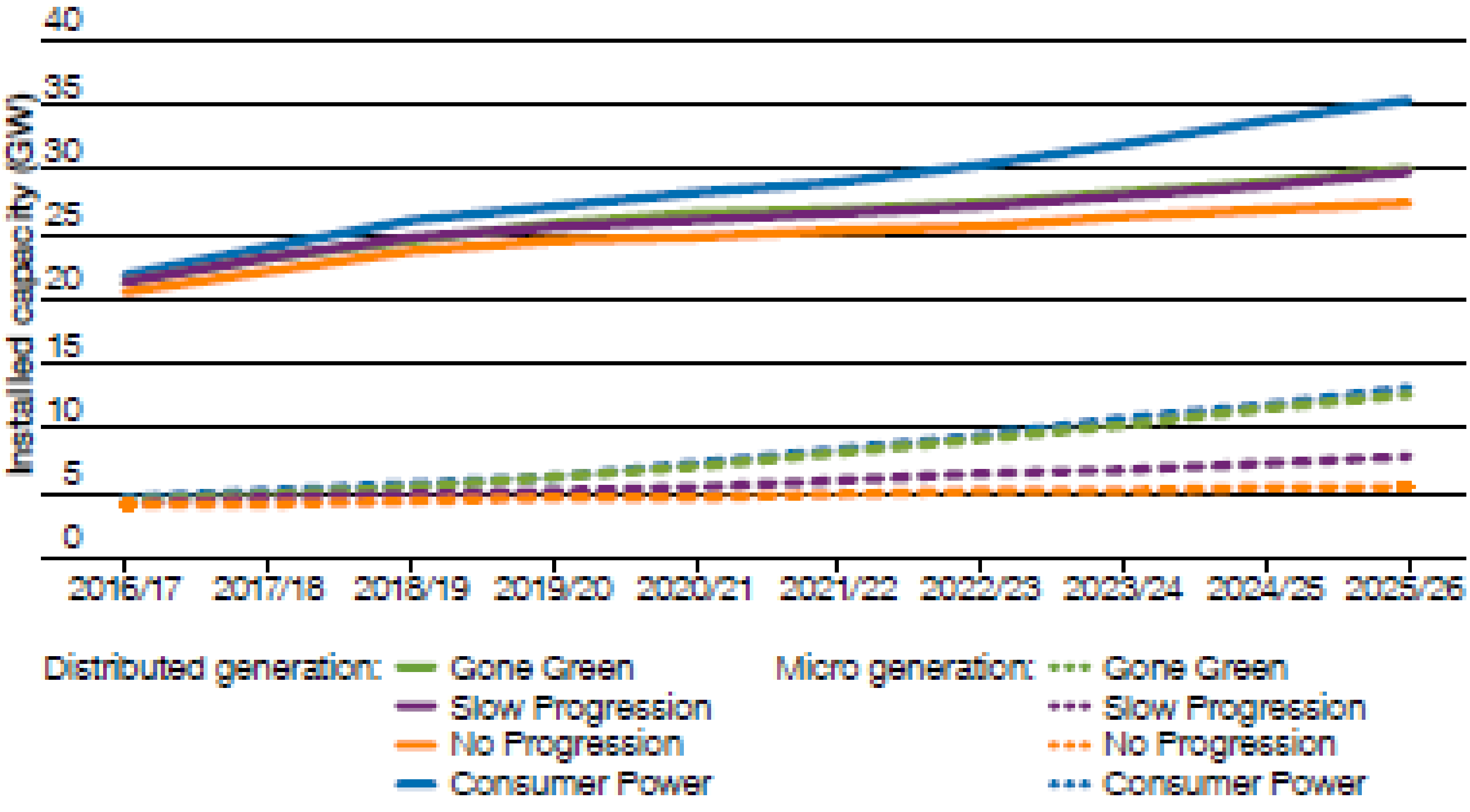
How SCL changes over time





- 2021/2 is a critical juncture as energy environment develops

How DG changes over time



Conclusions

- The SW case study is a credible illustration of the cascade loss risk of DG with transmission plant.
- The study sits in the middle of the FES range for DG contribution and optimistically within the range of potential SCL at the time.
- Across GB, the SW is indicative of most areas of GB other areas except arguably Greater London and North Wales.
- The rate of change of SCL is such in these areas that a response to arrest the displacement effect of transmission resources and increasing levels of non-synchronous capacity would need to be fully addressed early in the next decade to avoid operability challenge with mitigation occurring ahead of this

GC0100 - Fast Fault Current Injection, Fault Ride Through and Banding

Antony Johnson

July 2017

Summary

- Overview - why are Fast Fault Current Injection, Fault Ride Through and Banding related
- Proposals
  - Fast Fault Current Injection
  - Fault ride Through
  - Banding
- Conclusions

Why are Fast Fault Current Injection, Fault Ride Through and Banding related

nationalgrid

- The amount of fault current injected is a function of the volume of Generation at a specific location
- The retained voltage during the period of the fault is a function of the amount of reactive current injected - The lower the fault infeed, the lower the retained voltage seen across the system
- Fault ride performance is the ability of Generation to remain connected and stable under fault conditions. Its assessment is based on the retained voltage at the connection point which is directly related to the fault infeed.
- All Generation needs to play its part in supporting the System under fault conditions.
- A higher fault current infeed will enable a higher retained voltage to be specified as part of the fault ride through requirements.
- RfG specifies Generators are split into Bands. The fault ride through requirements are different between Synchronous and Asynchronous Plant with different parameters permitted between different bands

System Voltage profile under fault conditions – High / Low Synchronous Generation Background

nationalgrid

Figure 31
Current Network Effect of 3-phase Earth Fault at Walpole 400kV

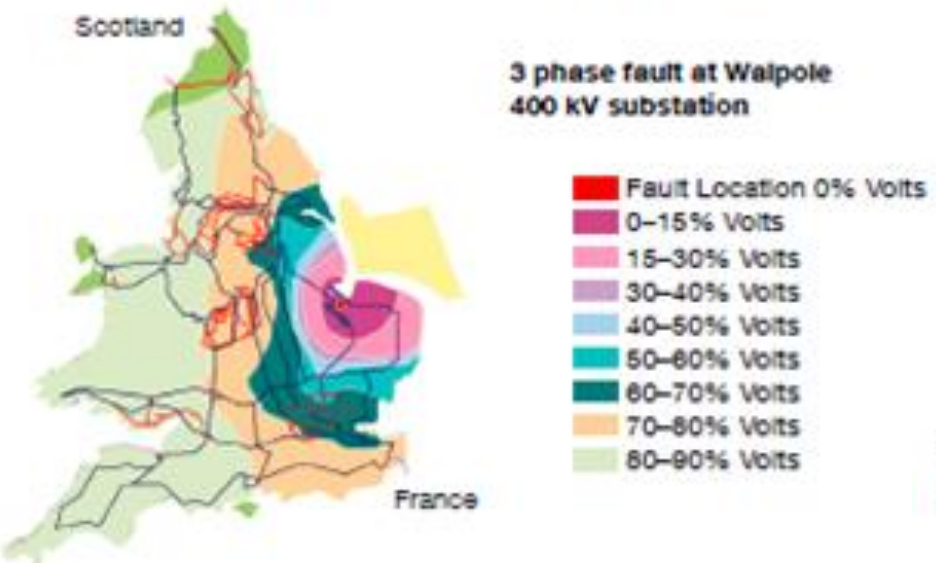
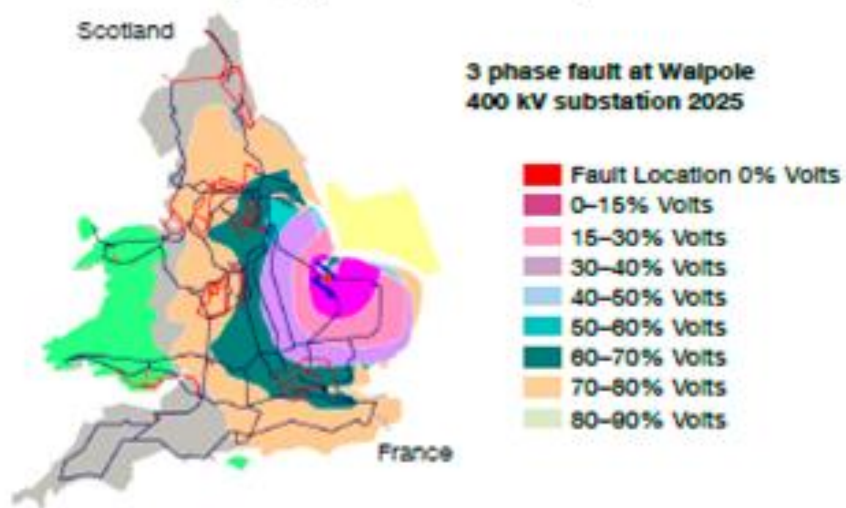


Figure 32
2025 Gone Green Effect of 3-phase Earth Fault at Walpole 400kV



The effect of connecting higher volumes of Converter based plant without FFCI

nationalgrid

- The Transmission System is changing - Large directly connected Synchronous Plant is rapidly being replaced by renewable technologies (eg wind, wave, solar and storage) – many of which utilise Converter based technologies
- Under fault conditions a Synchronous Generator will contribute 5 – 7pu current
- Converter based plant has a limited ability to supply fault current, (1 - 1.25pu current max),
- These effects significantly affect the design and operational characteristics of the System including the ability to maintain resilience and correctly detect and isolate a fault condition.
- At National Grid we want to promote the use of different generation technologies to ensure they grow whilst ensuring the safe, secure and efficient operation of the System.
- The System Operability Framework (SOF) published over the last few years have started to show the impacts on the System of high penetrations of converter based plant

High Converter Penetrations - Options

nationalgrid

- With current technology/models, the system can become unstable when more than 65% of generation is Non-Synchronous
- For the FES 2Degrees, Consumer Power and Slow Progression scenarios it is currently forecast, this level could be exceed by 9.2% -21,3% p.a. in 2023/24 and by 24.6% - 31.6% p.a.in 2026/27.

Key

No	Doesn't Resolve Issue
P I	Potential Improves
Yes	Resolves Issue

Solution	Estimated Cost	RoCoF	Sync Torque/Power (Voltage Stability/Ref)	Prevent Voltage Collapse	Prevent Sub-Sync Osc. / SG Compitable	Hi Freq Stability	RMS Modelling	Fault Level	Post Fault Over Volts	Harmonic & Imbalance	System Level Maturity	Notes
Constrain Asyncronous Generation	Hgh	I	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Proven	These technologies are or have the potential to be Grid Forming / Option 1
Syncronous Compensation	High	I	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Proven	
VSM	Medium	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	P	Modelled	
VSM0H	Low	No	Yes	Yes	No	P	P	P	Yes	P	Modelled	Has the potential to contribute but relies on the above Solutions
Synthetic Inertia	Medium	Yes	No	No	P	No	No	No	No	No	Modelled	
Other NG Projects	Low	Yes	P	Yes	No	No	No	P	P	No	Theoretical	

Timescale (Based on work by SOF team)									
	Now	2019	2019	Now	2020	Now	Now	2025	2025

Fast Fault Current Injection – Power Park Modules and Converter based Plant

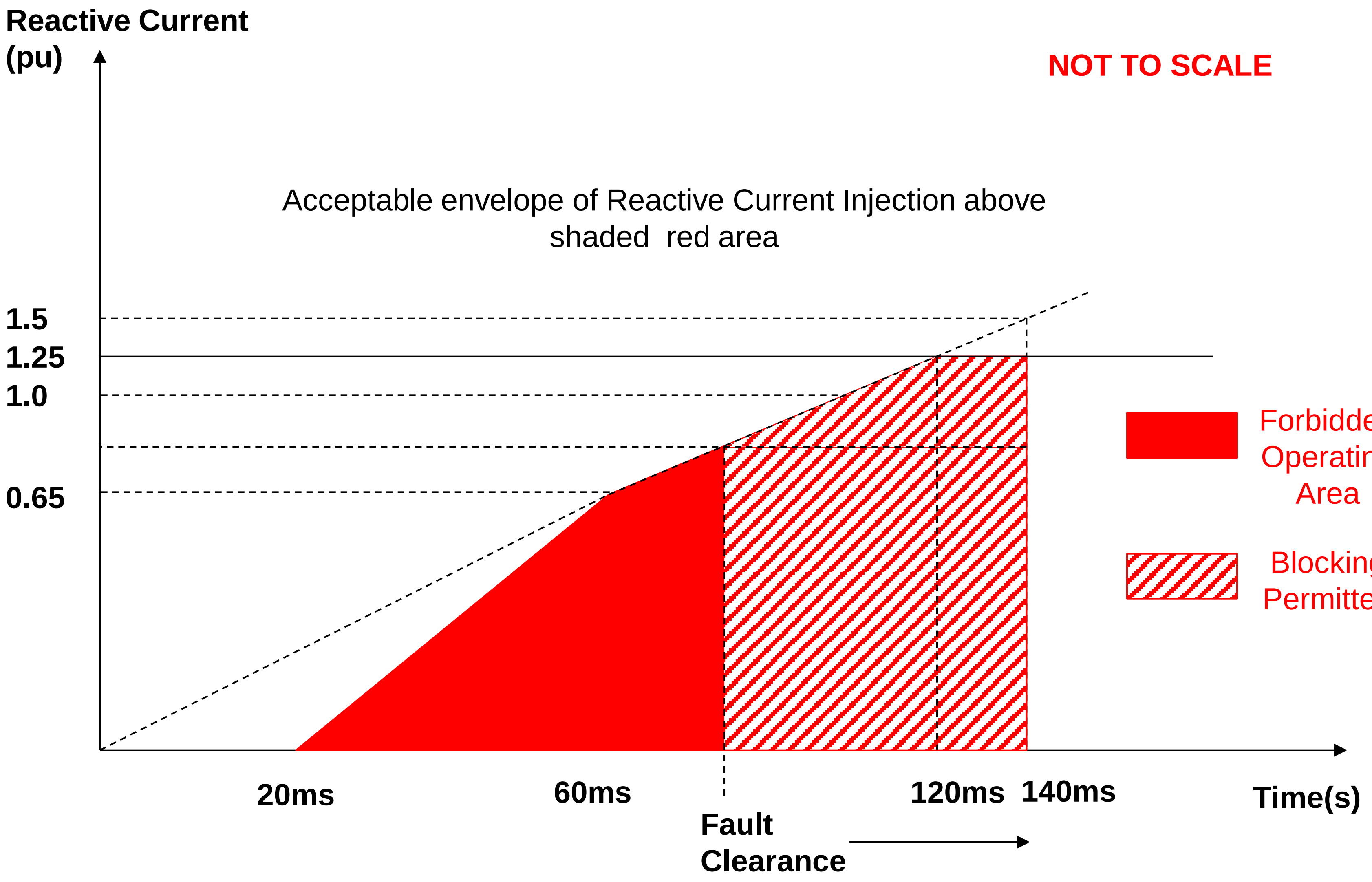
nationalgrid

- In the first quarter of 2017 extensive studies were run to understand the implications and control functions of converter based plant.
- These studies and results were presented to the GC0048 Workgroup in April 2017 available at:-
  - http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589940887
  - http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589940886
- These studies demonstrated the considerable variation in System behaviour as a result of changing the Converter control system. The following key conclusions were drawn from this work
  - The fault current needs to be injected in phase with the System during the fault otherwise both Transmission and Distribution performance is de-graded
  - Higher volumes of Generation connected to the Distribution System have a significant effect on the performance of the System even for Transmission System faults
  - If there is no fault current injection from the converter or it is injected out of phase with the system it places much more onerous requirements on the fault ride through requirements (U_{ret}).
  - Before 2021 there is still a reasonable contribution from Synchronous Generation connected to the System. Post 2021 these levels start to fall away very quickly

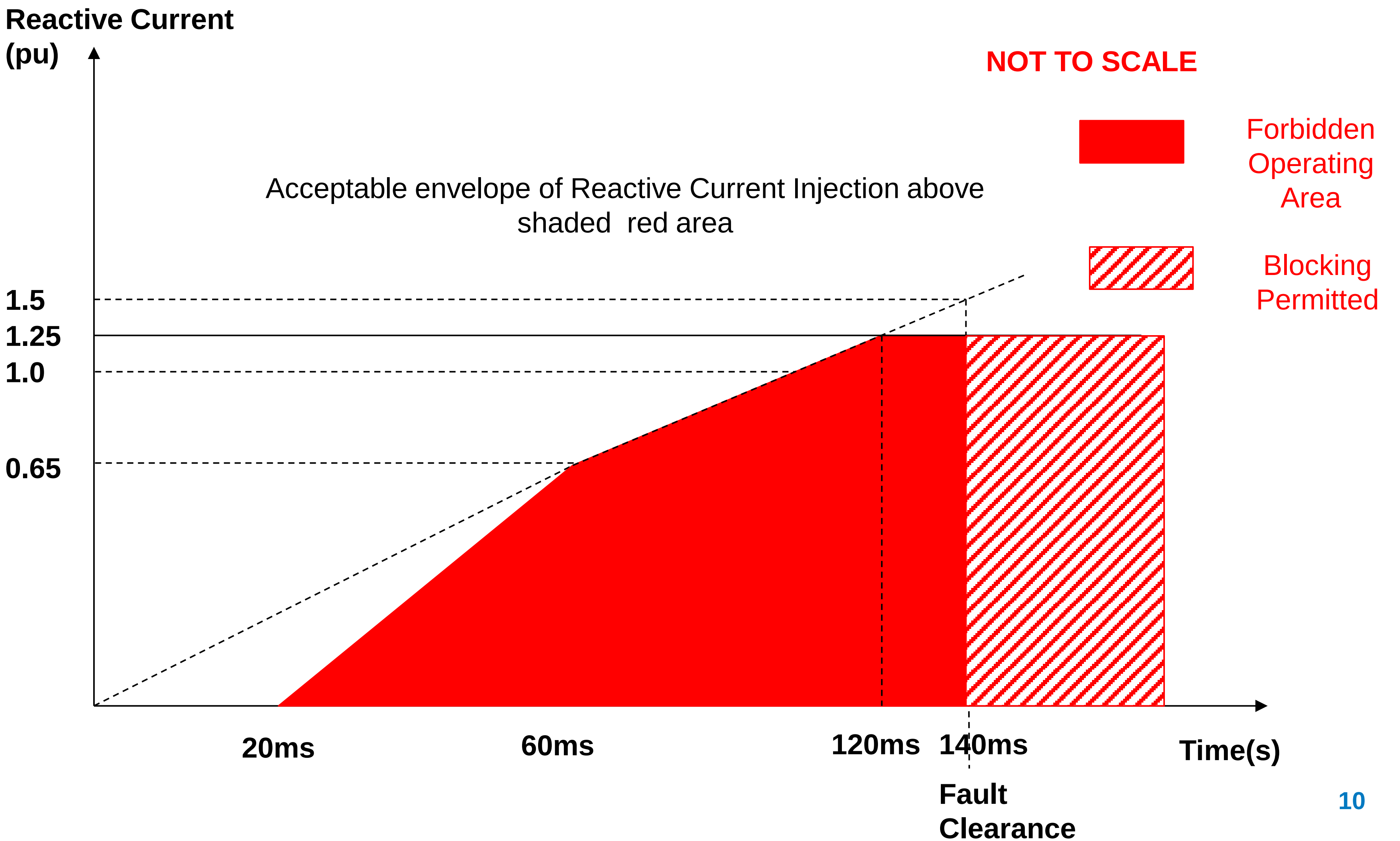
Proposals for Fast Fault Current Injection

- Two Options have been proposed
  - Option 1 – The Converter controller behaves in the same way as a synchronous machine (see attached presentation)
  - Option 2 – Conventional Converter – required to meet a minimum fault current injection requirement – option available only until 1 January 2021
- Option 1 is not new and similar technologies have been employed in the marine industry for several years in addition to a number of detailed studies
- Option 2 has also been employed previously as an option in areas of high converter penetration
- 2021 indicates FFCI (Option 1) as essential in studies presented to GC0048 in April
- The longer it takes for the technology to be implemented, the more onerous the requirements on new plant
- A European working group are investigating the implications of Grid Forming Converters

FFCI Option 2



FFCI Option 2



nationalgrid

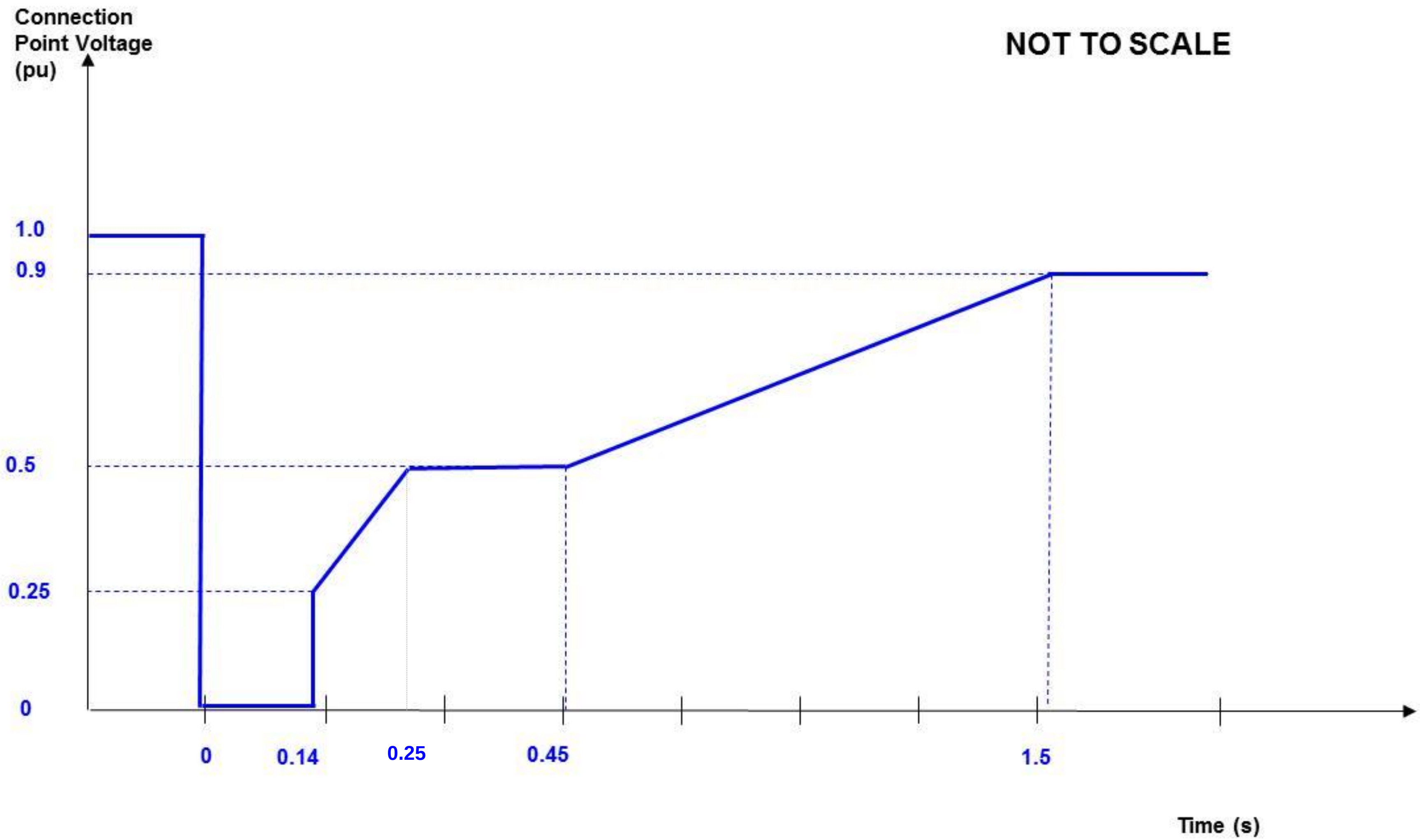
Fault Ride Through (1)

- The retained voltage at the connection point under faulted conditions is a function of the volume of fast fault current injected at the connection point
- For a solid three phase Transmission System fault, zero voltage will be observed at the point of the fault for the duration of the fault.
- For Type D plant connected at 110kV or above, the retained voltage (U_{ret}) would need to be set at zero volts (a mandated requirement under RfG)
- For Type B – D Embedded Plant (excluding Type B Synchronous) system studies (April 2017 GC0048 meeting) indicate requirements for a retained voltage (U_{ret}) of 10% if the assumptions on fast fault current injection are made.
- If Fast Fault Current Injection is not delivered in line with the proposals on slide 8, then the retained voltage (U_{ret}) delivered would need to be reduced to a value in the order of 5%.

Fault Ride Through (2)

- For Type B Synchronous Plant, the value of U_{ret} would need to be set to 30%. This is on the basis that small scale reciprocating plant (ie reciprocating gas and diesel engines) would struggle to meet a lower retained voltage for which there is no known technical solution. It is however recognised that Synchronous Generation is capable of supply high volumes of reactive current under fault conditions.
- The actual shape of the voltage against time curves have been documented and discussed at previous GC0048 Workgroup Meetings – The cost implications of these decisions are covered later in this presentation

GB Type D Voltage Against Time Curve



nationalgrid

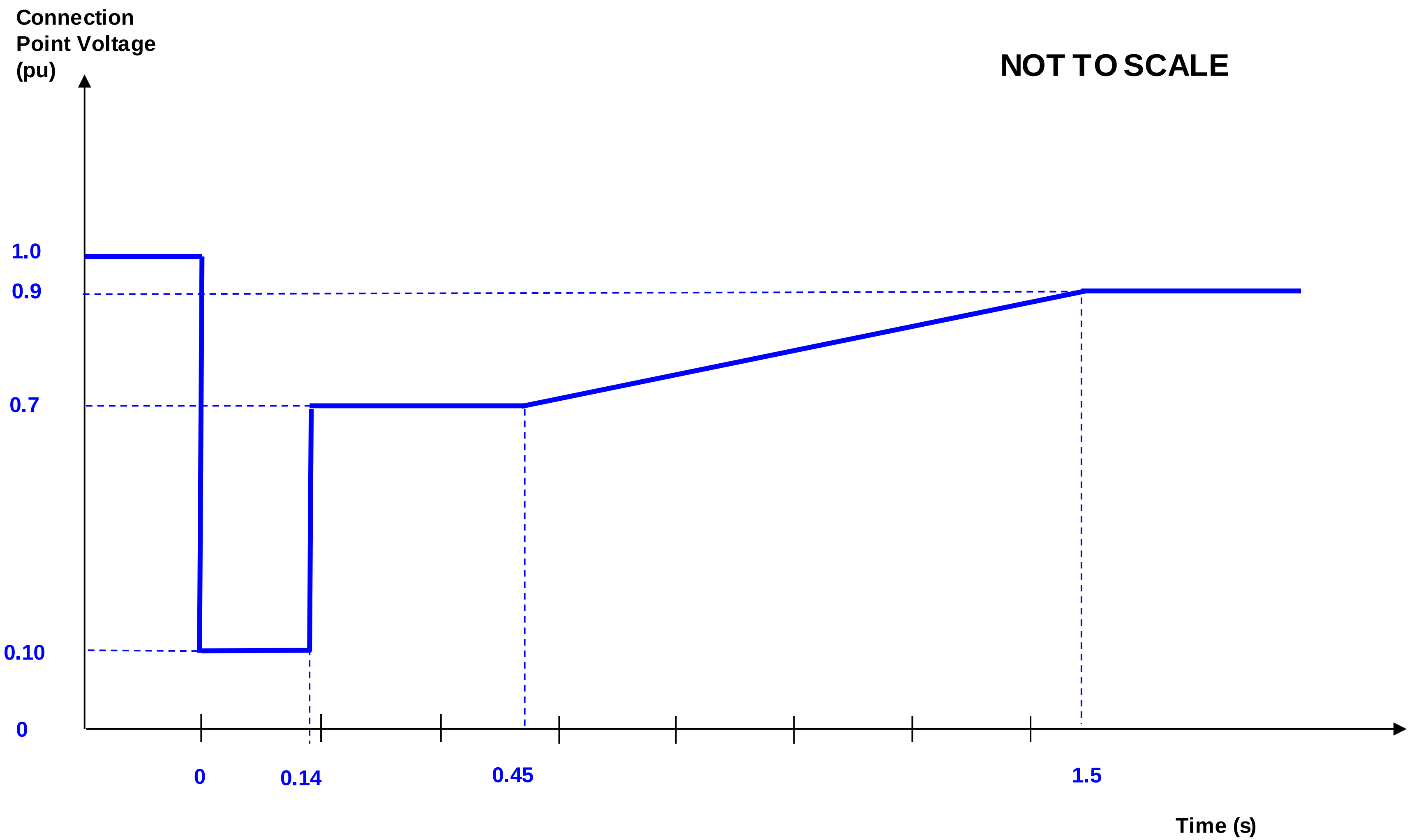
Voltage Against Time Parameters

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}	0	t_{clear}	0.14
U_{clear}	0.25	t_{rec1}	0.25
U_{rec1}	0.5	t_{rec2}	0.45
U_{rec2}	0.9	t_{rec3}	1.5

Table 7.1 – Fault Ride Through Capability of Synchronous Power Generating Modules

Type C and D Synchronous Power Generating Modules Connected <110kV

Suggested Voltage Against Time Profile – Type C and D



nationalgrid

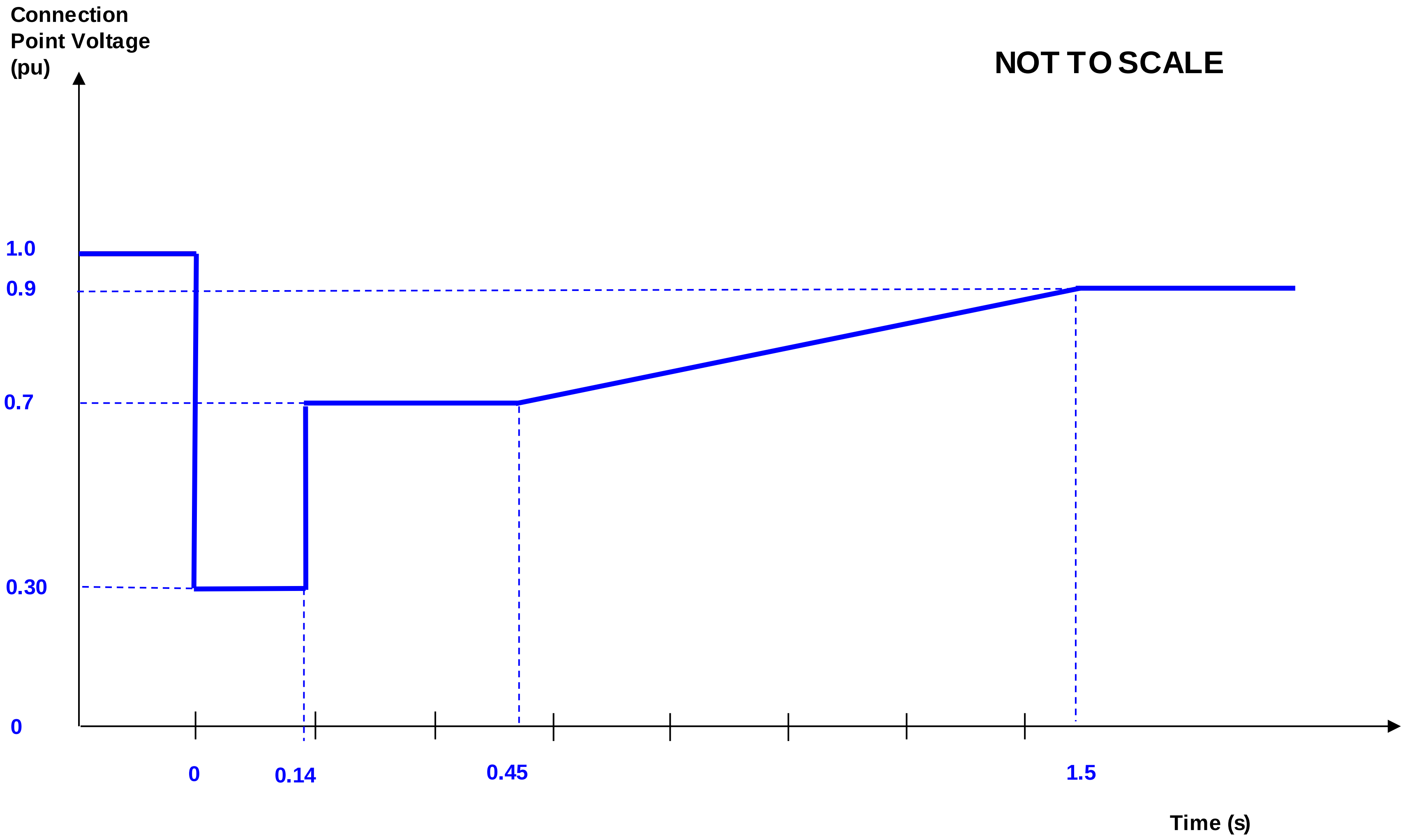
Voltage Against Time Parameter Ranges

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}	0.1	t_{clear}	0.14
U_{clear}	0.7	t_{rec1}	0.14
U_{rec1}	0.7	t_{rec2}	0.45
U_{rec2}	0.9	t_{rec3}	1.5

Table 3.1 – Fault Ride Through Capability of Synchronous Power Generating Modules

Type B Synchronous Power Generating Modules Connected <110kV

GB Voltage Against Time Profile – Type B



nationalgrid

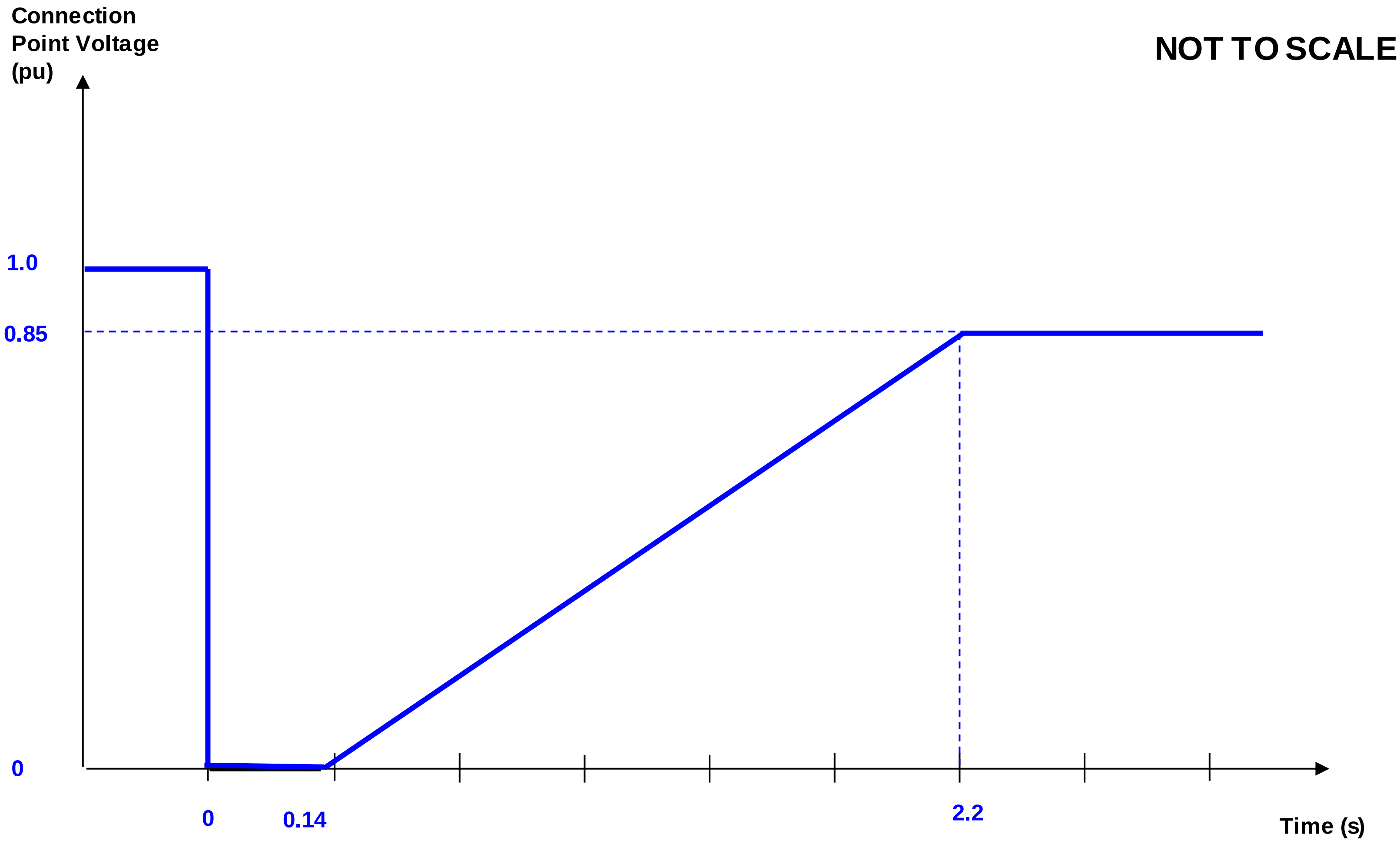
Voltage Against Time Parameter Ranges

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}	0.3	t_{clear}	0.14
U_{clear}	0.7	t_{rec1}	0.14
U_{rec1}	0.7	t_{rec2}	0.45
U_{rec2}	0.9	t_{rec3}	1.5

Table 3.1 – Fault Ride Through Capability of Synchronous Power Generating Modules

Type D Power Park Modules connected ≥110kV

GB Voltage Against Time Profile – Type D



nationalgrid

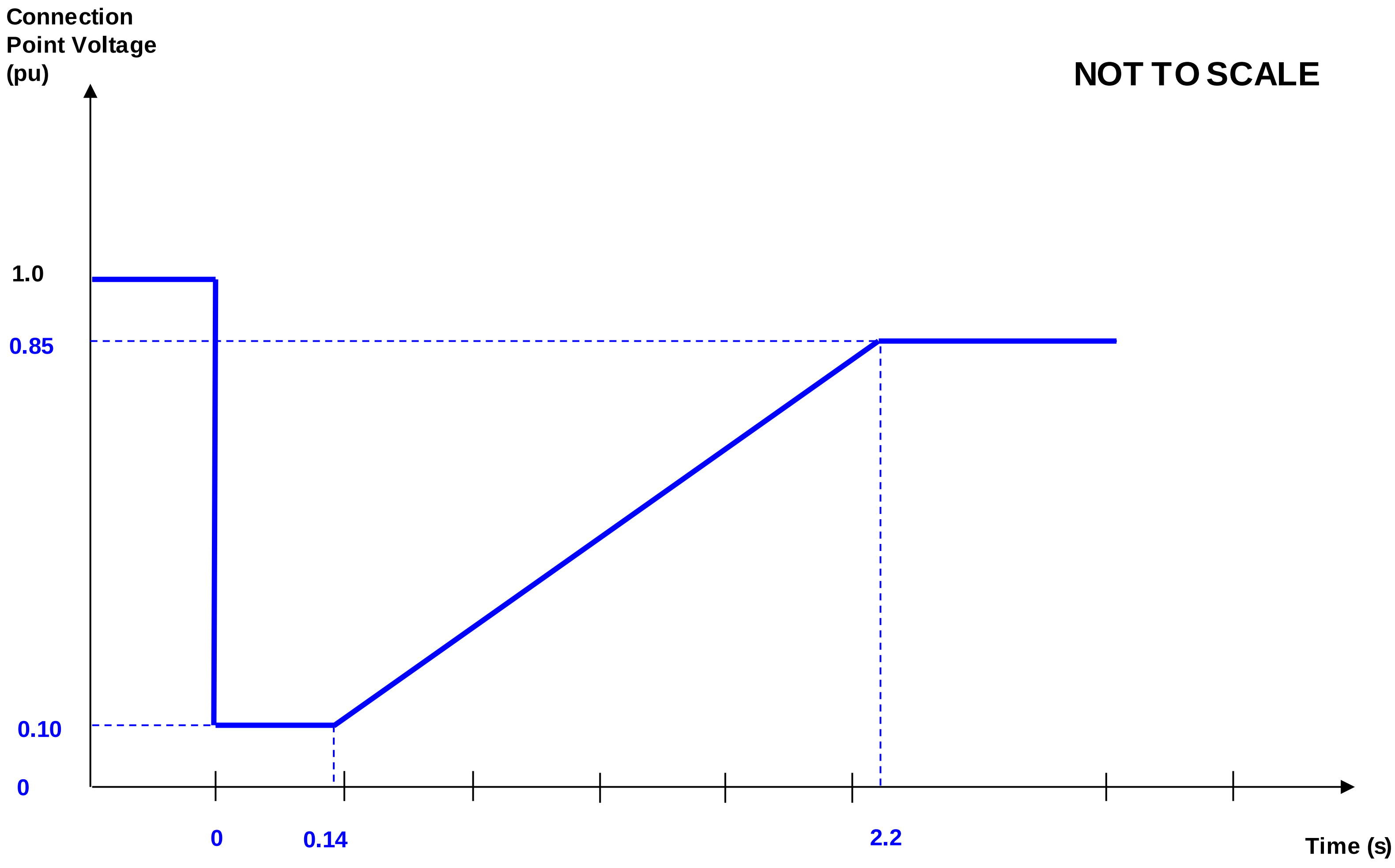
Voltage Against Time Parameters

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}	0	t_{clear}	0.14
U_{clear}	0	t_{rec1}	0.14
U_{rec1}	0	t_{rec2}	0.14
U_{rec2}	0.85	t_{rec3}	2.2

Table 7.2 – Fault Ride Through Capability of Power Park Modules

Type B, C and D Power Park Modules connected <110kV

GB Voltage Against Time Profile - Type B, C and D



nationalgrid

Voltage Against Time Parameters

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}	0.1	t_{clear}	0.14
U_{clear}	0.1	t_{rec1}	0.14
U_{rec1}	0.1	t_{rec2}	0.14
U_{rec2}	0.85	t_{rec3}	2.2

Table 7.2 – Fault Ride Through Capability of Power Park Modules

Banding Introduction

- Three banding options (high/mid/low) were discussed during GC0048
- Under RfG, NGET has to propose a set of Banding Thresholds for the GB Synchronous Area
- The banding values have a close relationship with fast fault current injection and fault ride through requirements
- ***Fast Fault Current Injection and Fault Ride Through apply to Type B and above.***

nationalgrid

RfG Requirements / Band At A Glance

Technical Requirements	Type A	Type B	Type C	Type D
Operation across range of frequencies	•	•	•	•
Rate of change of System Frequency (ROCOF)	•	•	•	•
Limited Frequency Sensitive Mode Over Frequency (LFSM-O)	•	•	•	•
Output Power with falling Frequency	•	•	•	•
Logic Interface (input port) to cease active power production	•	•	•	•
Conditions for automatic reconnection	•	•	•	•
Operation across range of frequencies	•	•	•	•
Ability to reduce Active Power on instruction		•	•	•
Fault Ride Through and Fast Fault Current Injection		•	•	•
Conditions for automatic reconnection following disconnection		•	•	•
Protection and Control		•	•	•
Operational Metering		•	•	•
Reactive Capability		•	•	•
Active Power Controlability			•	•
Frequency Response including LFSM-U			•	•
Monitoring			•	•
Robustness			•	•
System Restoration / Black Start			•	•
Simulation Models			•	•
Rates of Change of Active Power			•	•
Earthing			•	•
Enhanced Reactive Capability and control			•	•
Voltage Ranges				•
Enhanced Fault Ride Through				•
Synchronisation				•
Excitation Performance				•

National Grid Proposal for GB Banding

Band	MW Threshold/Connection Voltage
Band A	800W – 0.99MW and connected at or below 110kV
Band B	1MW – 9.99MW and connected at or below 110KV
Band C	10MW – 49.99MW and connected at or below 110kV
Band D	50MW plus or connected at 110kV or above

Banding - Implications

- For Fault Ride Through, the value of U_{ret} proposed for all Type B – D plant connected below 110kV (excluding Type B Synchronous Plant) has been set to 10%.
  - This has been based on System Studies and assumes a minimum fault infeed as per the FFCI proposals
- For Type B Synchronous Plant the value of U_{ret} has been set to 30%. Note that they will be capable of supplying a reasonable degree of fault current
- Guidance from ENTSO-E has indicated that the voltage against time parameters must be defined for each Band

Banding - Comparison with Proposals of other EU TSOs

nationalgrid

Country	Band A*	Band B*	Band C*	Band D'
Belgium	800W – 250kW	0.25MW – 25MW	25MW – 75MW	75MW plus
France	800W – 1MW	1MW – 18MW	18MW – 36 MW	36MW plus
Netherlands	800W – 1MW	1MW – 50MW	50MW – 60MW	60MW plus
German TSO's	800W – 135kW	0.135MW – 36MW	36 MW – 45MW	45MW plus
Spain	800W – 100kW	0.1 MW – 5MW	5MW – 50MW	50MW plus
Ireland	800W – 100kW	0.1MW – 5MW	5MW – 10MW	10MW plus
GB	800W – 0.99MW	1MW – 9.99MW	10MW – 49.9MW	50MW plus

* Applicable MW threshold and connected below 110kV

' Applicable MW threshold or connected at or above 110kV

Justification for NGET's GC0100 Proposals

- The intention of the EU proposals is based on the principles of non-discrimination and transparency as well as on the principles of optimisation between the highest overall efficiency and lowest total cost for all involved parties.
- Through Stakeholder engagement we have understood technical limitations in setting retained voltage at 30% for Band B Synchronous Reciprocating Plant)
- If Converter based plant does supply reactive current in line with the FFCI proposals, the study run in the South West has indicated that approximately 550MW of Embedded Generation would see voltage drops of below 10% and hence trip. This would equate to approximately £240million/ annum in additional reserve costs alone.
- Without the assumed level of FFC I, lower values of U_{ret} would be required (0.05pu rather than 0.1pu) and it would also place more Band B Synchronous generation at risk from tripping at an estimated cost of £9.2million/annum in reserve costs alone.
- The Studies run in the South West are believed to be representative of the wider System – see next slide

How the South West compares to other areas of GB

Area		GC048 study			Future Of Energy documents					
		SCL studied 2025 (kA)	DG installed 2025 (MW)	DG studied 2025 (MW)	FES2025 max DG output (MW)	FES2025 min DG output (MW)	SOF regional SCL min (kA)	SOF regional SCL 95% confidencemin (kA)	SOF regional SCL 95% confidence max (kA)	SOF regional SCL max (kA)
1	North Scotland	N/A	N/A	N/A	1839.5	1167.6	6.8	11.9	16.5	18.6
2	South Scotland	N/A	N/A	N/A	2941.8	2024.4	9.5	13.1	20	21
3	North East England	N/A	N/A	N/A	1360.6	885.4	10.8	14.4	29.3	34.1
4	North West and West Midlands	N/A	N/A	N/A	3338.1	1990.1	0.7	5.7	21.1	22
5	East Midlands	N/A	N/A	N/A	3540.8	2029.3	2.7	7.1	24.4	28.4
6	North Wales	N/A	N/A	N/A	740.1	594.3	13.3	21.6	36.1	38
7	South Wales and West england	N/A	N/A	N/A	3677.3	2300.5	6.4	9.8	26.2	30.4
8	South West England	**16.3**	**2522.4**	**2411**	**3213**	**1999.7**	**2.4**	**7.3**	**22.1**	**25.9**
9	East England	N/A	N/A	N/A	3934.5	2543.1	9.1	17.4	41.5	45.6
10	Greater London	N/A	N/A	N/A	1716	1104.4	6.2	14.2	32.4	35.7
11	South East England	23.95345696	N/A	N/A	2059	1268.2	7.6	15.1	27.9	31.7

Justification for NGET's GC0100 Proposals

- Larger Synchronous Generators, eg those derived from steam, gas or hydro turbines are not believed to suffer from these issues
- A questionnaire released to GB Stakeholders in 2016 revealed there would be no additional significant costs from a technical perspective if the lower threshold was applied.
- RfG enforces a consistent banding requirement across GB. The proposed Banding applies capabilities currently demonstrated in the North of Scotland across the whole GB System
- The majority of European TSO's are proposing Banding lower than the maximum permitted under RfG
- The Continental Power System is of the order of 10 times larger than the GB System

Conclusions
FFCI / Fault Ride Through

- Based on the study work and analysis completed National Grid recommend the FFCI issues proposed. It is believed that the adoption of this option will result in a saving of approximately £240million / annum in reserve costs alone not including the wider significant benefits of contribution to synchronising torque, fault infeed and inertia.
- The Fault Ride Through voltage against time curves are recommended on the basis of minimum system need. These are based on the assumption of the delivery of FFCI. Without the proposed level of FFC I, lower values of U_{ret} in FRT would be required (0.05pu rather than 0.1pu)
- These measures would not be retrospective and would apply to new plant going forward.

Conclusions
Banding

nationalgrid

- National Grid has lodged its proposal for the GB banding (slide 24)
  - The relationship between FFCI / Fault Ride Through and cost has been demonstrated
  - Without FFCI as proposed we will need to lower the value of U_{ret} (from 0.1pu to 0.05pu). There is also a cost of tripping synchronous generation in a higher band (10MW – 50MW) which would result in reserve costs alone of £9 million / annum.
  - Following public Stakeholder discussions U_{ret} of 0.3pu for Band B Synchronous Plant is proposed
  - The costs to which Generators are exposed for these thresholds was identified to be negligible following the responses to the Stakeholder questionnaire held in 2016, excluding market costs (ie BM participation costs).
  - Parity with European TSO proposals, particularly with regard to cross boarder trade
  - The proposals would apply the same technical requirements across the whole of GB
  - A Band B/C Threshold of 10MW would provide a greater proportion of Generation being capable of contributing to frequency response which drives competition and reduces net cost
  - System Operators will need to continue to operate a safe, secure and economic System against a rapidly changing Generation background
  - RFG Mandates TSO’s to propose banding thresholds

Effects of VSM / Option 1 (Grid Forming) Convertor Control on Penetration Limits of Non-Synchronous Generation (NSG) in the GB Power System

From Zero to 100% NSG using a reduced GB model

Richard Ierna / Andrew Roscoe

Nov 2016 / Jun 2017

Mengran Yu
Adam Dyśko
Campbell Booth
Helge Urdal
Jiebei Zhu

Agenda (35 Minutes Total)

- Future of the GB Network and Anticipated Issues
- Project History and Development of Ideas
- Overview of the Models and Techniques Used
  - Infinite Bus Model
  - 36 Node GB Model
- Technical Requirements for Grid Code
  - Fault Ride Through Work Group GC0048 & GC100
  - Other Requirements

High Convertor Penetration - Options

With current technology/models, the system may become unstable when more than 65% of generation is Non-Synchronous

For the FES 2Degrees, Consumer Power and Slow Progression scenarios, it is currently forecast this level could be exceeded for 800-1800Hrs p.a. in 2023/24 and for 2100-2750Hrs p.a.in 2026/27.

Key

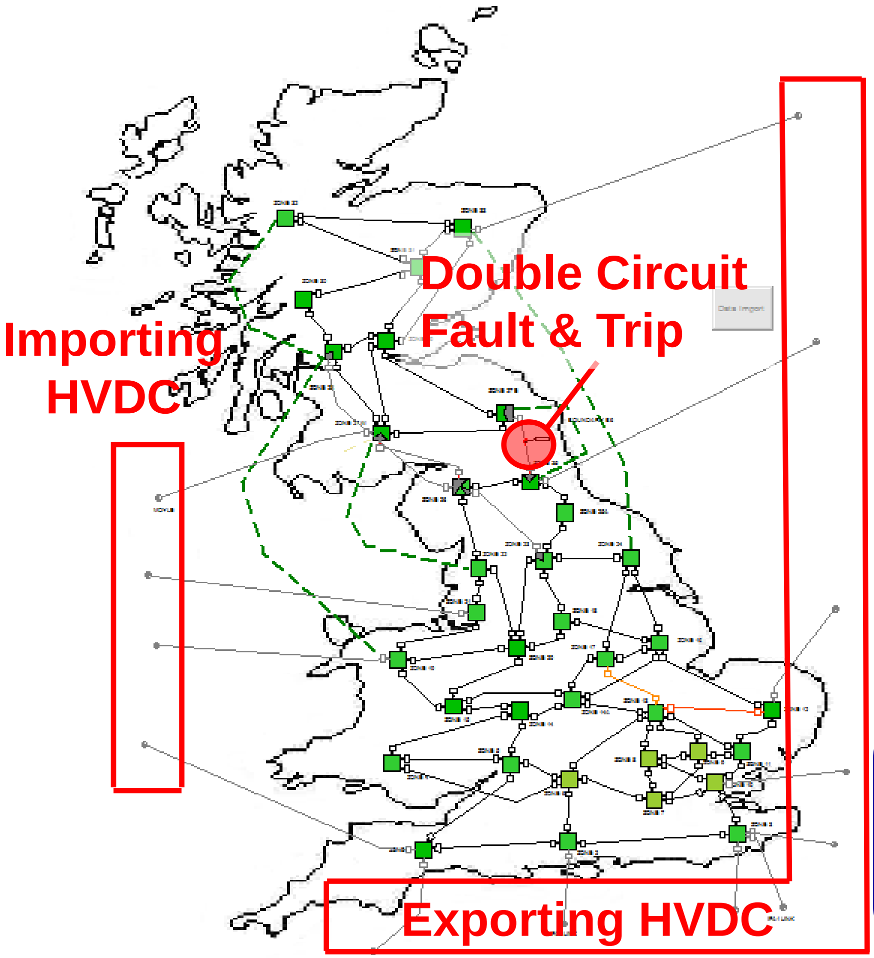
No	Doesn't Resolve Issue
P	Potential
I	Improves
Yes	Resolves Issue

Solution	Estimated Cost	RoCoF	Sync Torque/Power (Voltage Stability/Ref)	Prevent Voltage Collapse	Prevent Sub-Sync Osc. / SG Compitable	Hi Freq Stability	RMS Modelling	Fault Level	Post Fault Over Volts	Harmonic & Imbalance	System Level Maturity	Notes
Constrain Asyncronous Generation	Hgh	I	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Proven	These technologies are or have the potential to be Grid Forming / Option 1
Syncronous Compensation	High	I	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Proven	
VSM	Medium	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	P	Modelled	
VSM0H	Low	No	Yes	Yes	No	P	P	P	Yes	P	Modelled	Has the potential to contribute but relies on the above Solutions
Synthetic Inertia	Medium	Yes	No	No	P	No	No	No	No	No	Modelled	
Other NG Projects	Low	Yes	P	Yes	No	No	No	P	P	No	Theoretical	
Timescale (Based on work by SOF team)		Now	2019	2019	Now	2020	Now	Now	2025	2025		

nationalgrid

2013 Studies – Only 9/26 high NSG scenarios ok

36 Node Reduced GB Network for 2030



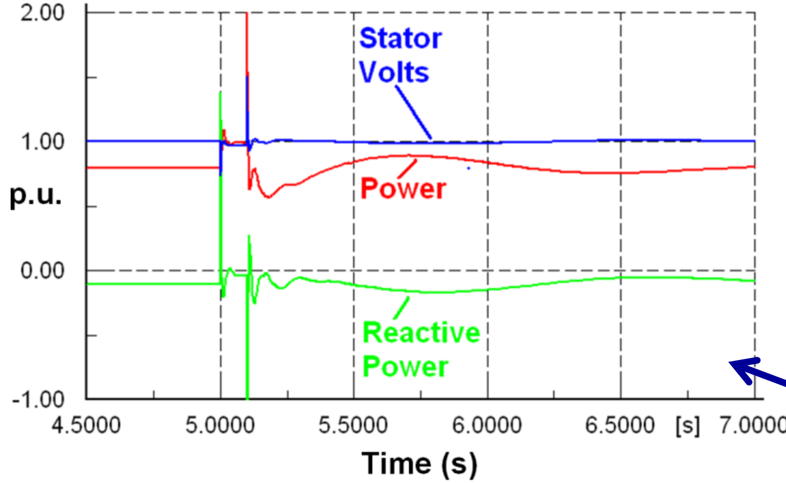
NSG	0 Import HVDC 0 Export HVDC			3GW Import HVDC 10GW Export HVDC			0 Import HVDC 10GW Export HVDC		
	Load (GW)			Load (GW)			Load (GW)		
	40	35	30	40	35	30	40	35	30
Low	OK			OK	OK		OK	OK	OK
Mid				OK			OK	OK	
High			N/A						

NSG is 8GW Solar +
Low: 16.0GW Wind
Mid: 20.5GW Wind
High: 28.5GW Wind

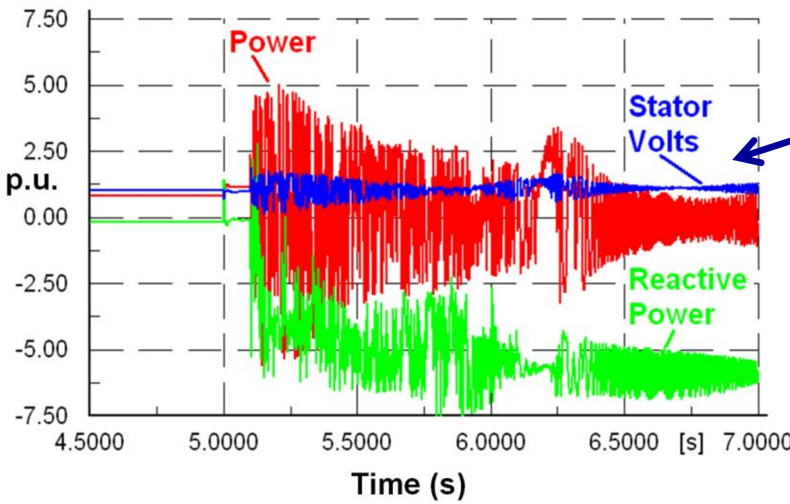
Green cells ok in 2013
Grey cells produced HF instability

2013 Results

2013 – Stable Result



2013 – Unstable Result



NSG	0 Import HVDC			3GW Import HVDC			0 Import HVDC		
	0 Export HVDC			10GW Export HVDC			10GW Export HVDC		
	Load (GW)			Load (GW)			Load (GW)		
	40	35	30	40	35	30	40	35	30
Low	OK			OK	OK		OK	OK	OK
Mid				OK			OK	OK	
High			N/A						

nationalgrid

Step 1 – Add Synthetic Inertia (SEBIR)

Anticipated Outcome:

Improves RoCoF

A – Solves the problem

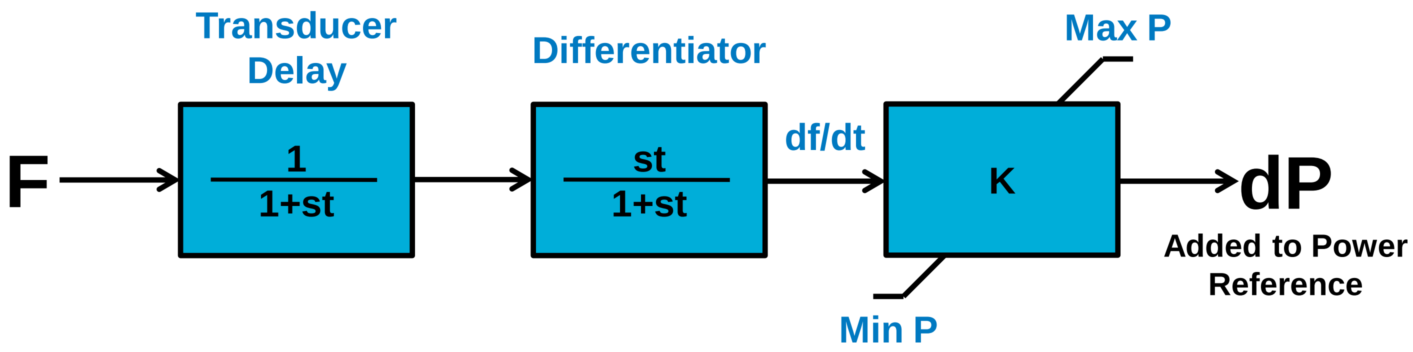
B – Higher % NSG before instability occurs

C – Has no effect

Actual Outcome:

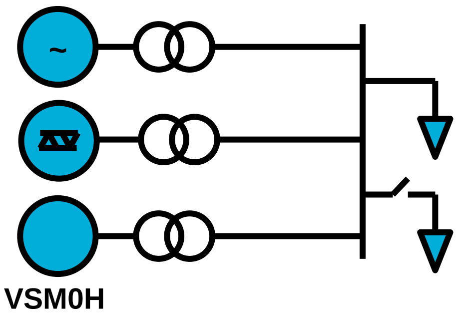
Improves RoCoF

D – Makes the system more unstable in some circumstance



Step 2 – Implement Virtual Synchronous Machine Zero Inertia (VSM0H)

nationalgrid



MATLAB Model used to evaluate VSM0H stability limit

Commonly used in Marine Industry & Micro Grids
Provides stable control & 100% NSG possible
Voltage Source Convertor with no PLL
Droop Frequency and Voltage Control

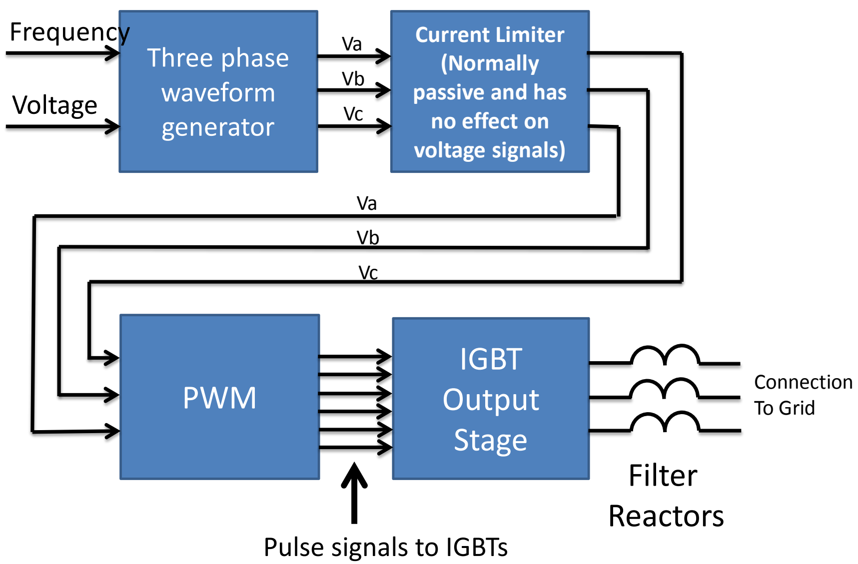
For 100% Convertor Network with zero inertia, a load step change results in a frequency change which occurs in one AC cycle (assuming BOXCAR measurements taken over one cycle)

Step 3 – Implement Virtual Synchronous Machine (VSM)

nationalgrid

Both VSM & VSM0H use similar output stages

3 Phase VSM / VSM0H Output Stage



Changes for VSM

1. Simulate inertia
2. Reduce the bandwidth of F and V to 5Hz

Advantages (main)

1. Contributes to RoCoF
2. Compatible with SG
3. Reduced interaction and HF instability risks
4. Can be modelled in RMS system studies

Disadvantages

1. Requires additional energy
2. Possibility of traditional power system instability

Step 4 / 5 – Implement VSC in the GB Model / Build an Infinite Bus Model

nationalgrid

- Step 4 – Change some convertors in the 36 node model to VSC without dynamic controls
  - Fixed the problem with high frequency instability
  - However this isn't really representative as its equivalent to connecting an infinite bus at multiple point through out the model
- Step 5 – Build a small M/C model and prove it swings / behaves like a synchronous machine model
  - This established that it was possible to model a voltage source convertor which behaved like a synchronous machine

Key Features of the Option 1 Convertor Controller

nationalgrid

- Similar voltage step response
- Without dynamic breaking, swings like SG.
- Can it ride through 500ms Distribution Faults?
- Provides inertial response to df/dt
- Similar frequency sweep characteristic
- Provides immediate energy input without needing to measure changes in volts, power or reactive power

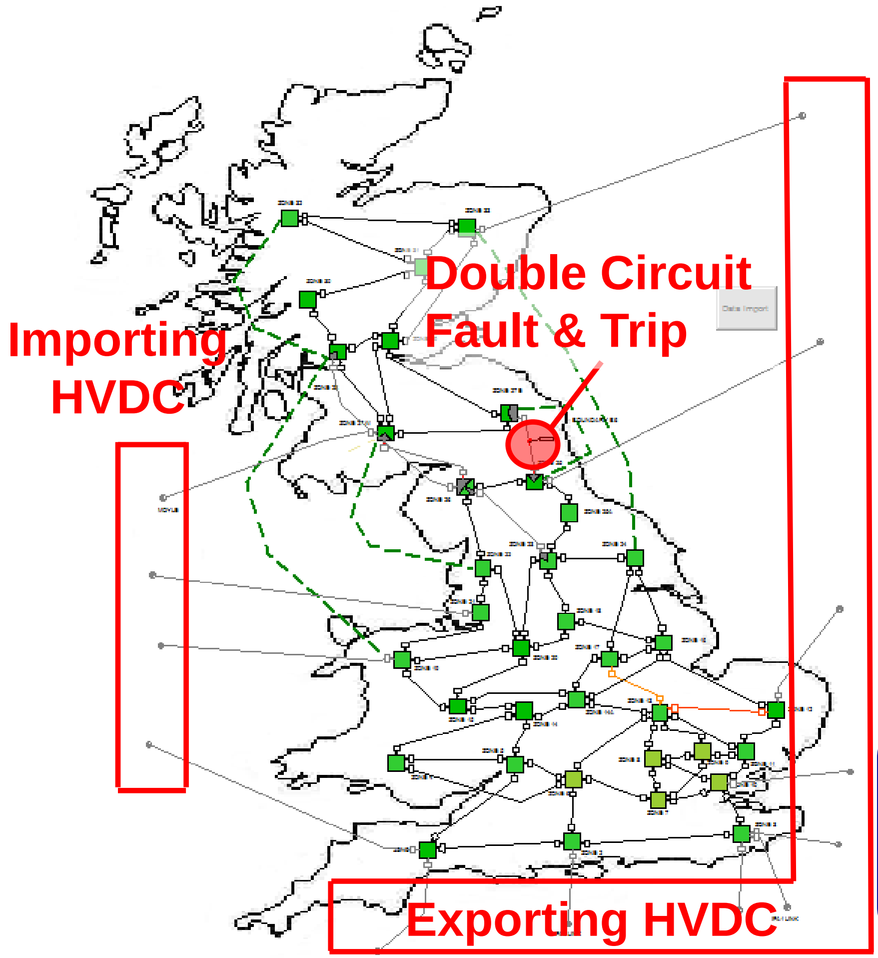
Step 6 – Put the VSM model into the 36 Node Network

- Demonstrate Option 1 (VSM / GF):
  - Stabilises the system
  - That convertors can temporarily come out of VSM mode under overload conditions
  - Network impedances limit the effect of VSM overload propagating across the network and therefore
  - Supports RoCoF & LFDD Relays
- The above provides Network Operators the potential to manage the key differences between Option 1 (VSM / GF) and conventional synchronous machines using RMS models.

nationalgrid

2016 Studies – All high NSG scenarios stable

36 Node Reduced GB Network for 2030



With VSM all scenarios are stable & 100% NSG is possible

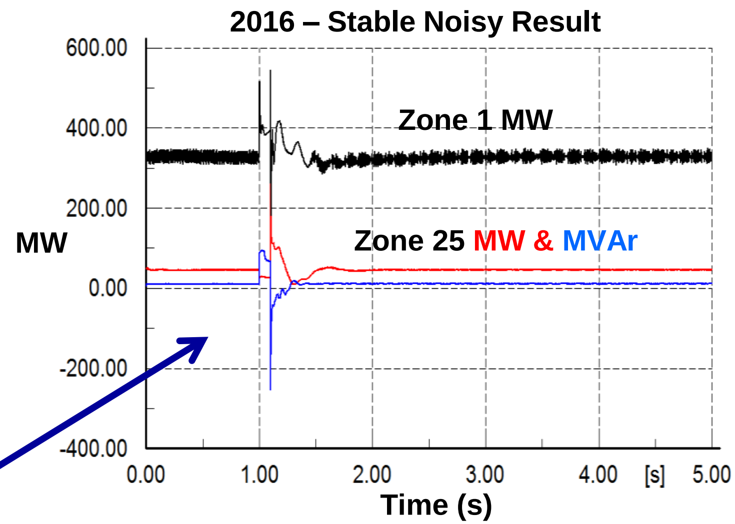
NSG	0 Import HVDC, 0 Export HVDC			3GW Import HVDC, 10GW Export HVDC			0 Import HVDC, 10GW Export HVDC		
	Load (GW)			Load (GW)			Load (GW)		
	40	35	30	40	35	30	40	35	30
Low	1% 60%	10% 25% 69%	10% 25% 80%	1% 54%	1% 60%	10% 68%	1% 48%	1% 15% 53%	1% 60%
Mid	5% 25% 73%	5% 83%	10% 97%	1% 64%	10% 25% 71%	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%

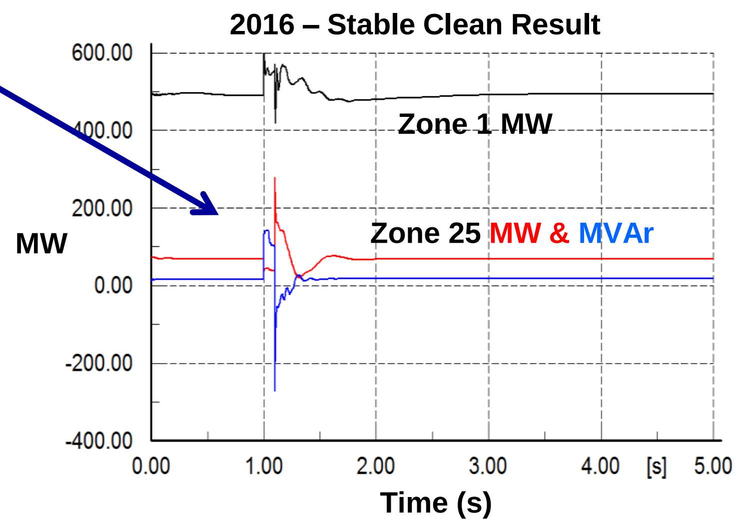
NSG is 8GW Solar +
Low: 16.0GW Wind
Mid: 20.5GW Wind
High: 28.5GW Wind

Green cells ok in 2013
All cells now ok with VSM
% of NSG which is VSM
10% VSM for stability
30% VSM for low noise
93% NSG (7%SG)

Typical results from 2016 studies

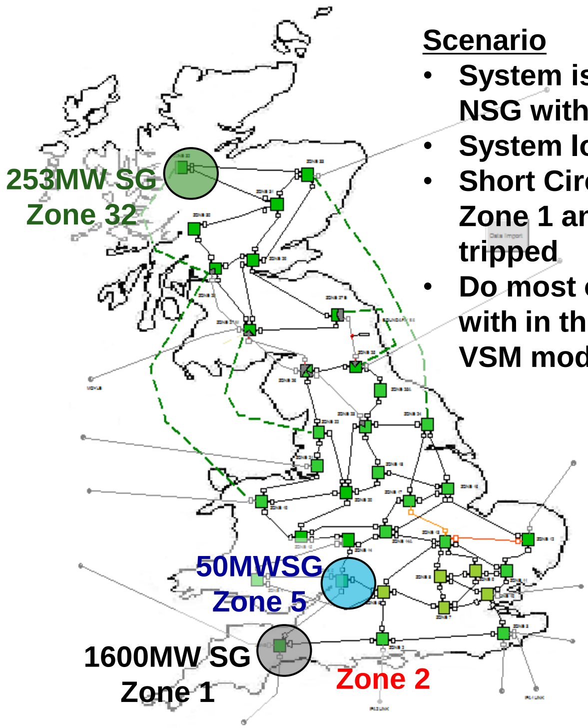
NSG	0 Import HVDC			3GW Import HVDC			0 Import HVDC		
	0 Export HVDC			10GW Export HVDC			10GW Export HVDC		
	Load (GW)			Load (GW)			Load (GW)		
	40	35	30	40	35	30	40	35	30
Low	1% 60%	10% 25% 69%	10% 25% 80%	1% 54%	1% 60%	10% 68%	1% 48%	1% 15% 53%	1% 60%
Mid	5% 25% 73%	5% 83%	10% 97%	1% 64%	10% 25% 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%





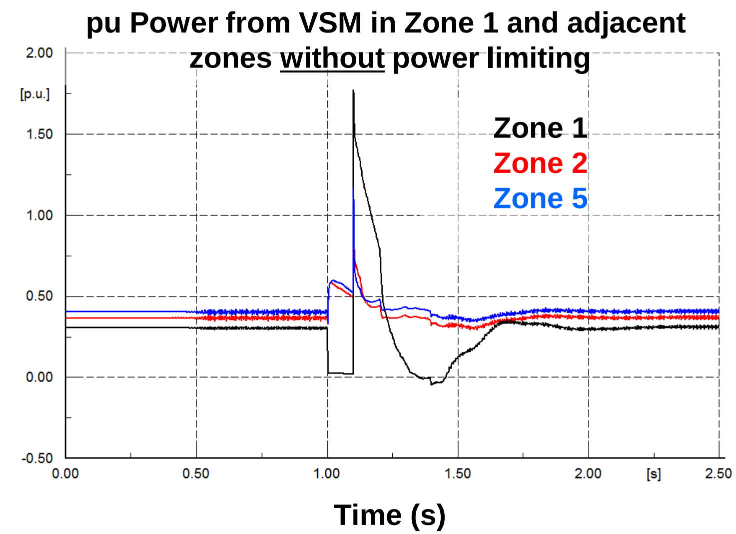
nationalgrid

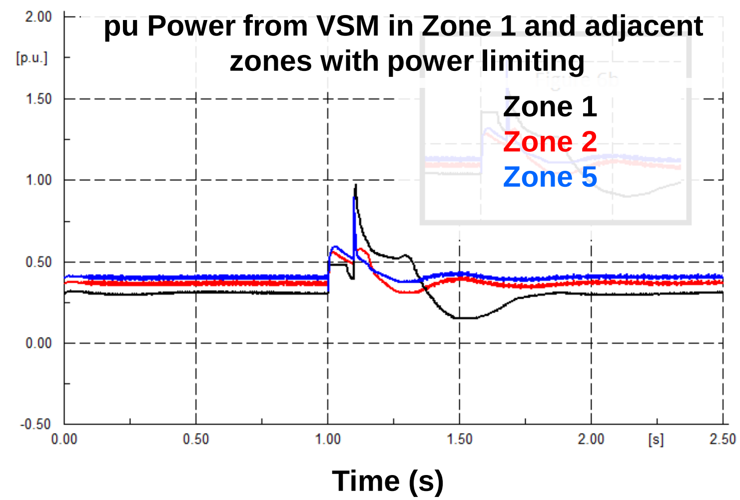
1600MW Trip at 97% NSG with 30GW of Load



Scenario

- System is operating at 97% NSG with SG as shown
- System load is 30GW
- Short Circuit is applied at Zone 1 and the 1600MWSG is tripped
- Do most of the VSM remain with in their stable region i.e. VSM mode?

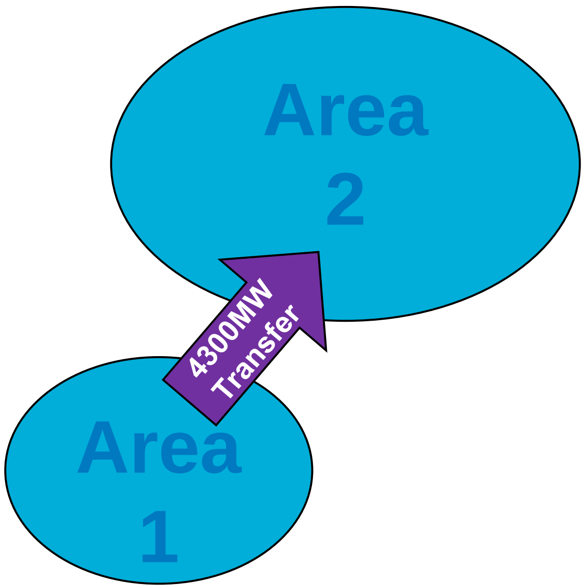




nationalgrid

System Islanding at 93% NSG with 40GW load

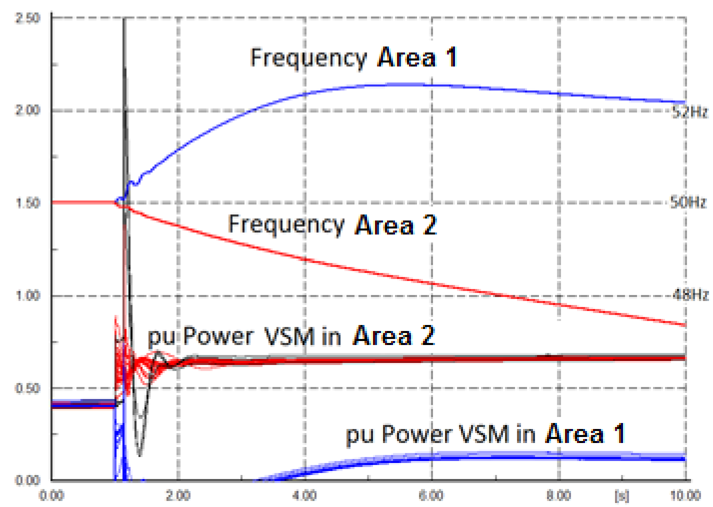
CC.6.3.7 and CP.A.3.6



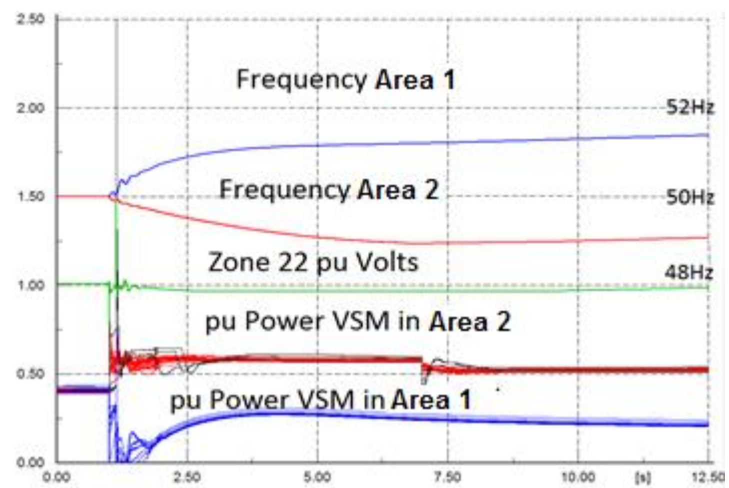
Scenario

- System is operating at 93% NSG
- System load is 40GW
- Short circuit is applied to AC interconnection
- Loss of AC interconnection between exporting Area 1 and importing Area 2
- Does LFDD work?

pu Power from VSM (all zones) without power limiting



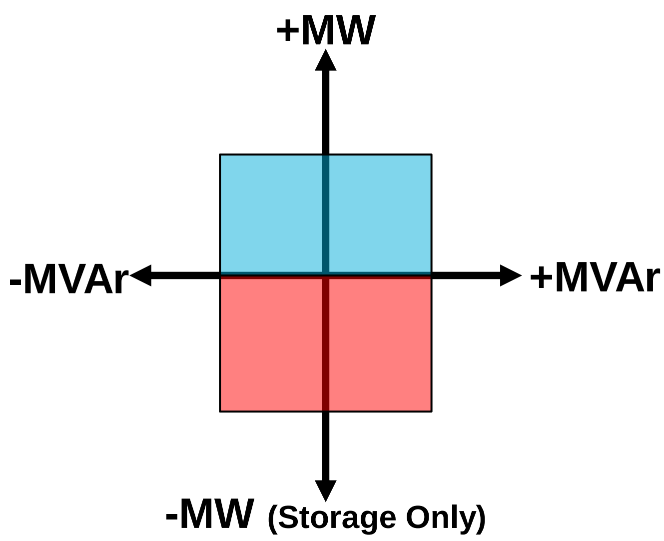
pu Power from VSM (all zones) with power limiting



Requirement Proposal for Option 1 (Grid Forming Convertors - Initial Thoughts)

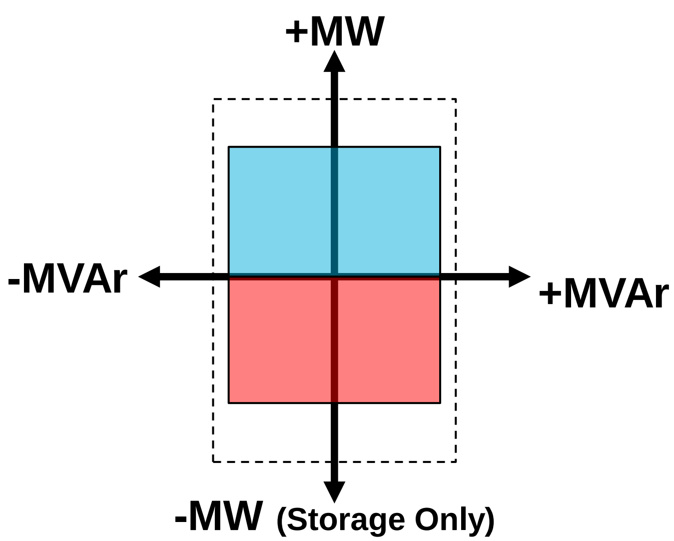
Steady State Capability

- $\pm$0.95 Lead/Lag at 100% Rated Power
- Red region applicable to storage and HVDC only
- Many requirements in this region taking from existing Class 1 requirements



Extended Capability

- Available for 20Secs
- Harmonics & Imbalance as GBGC CC6.1.5, CC6.1.6 & CC6.1.7
- 1.33pu Rated Power (33% on rated power > current operating point)
- 1.5pu current (on rated MW)

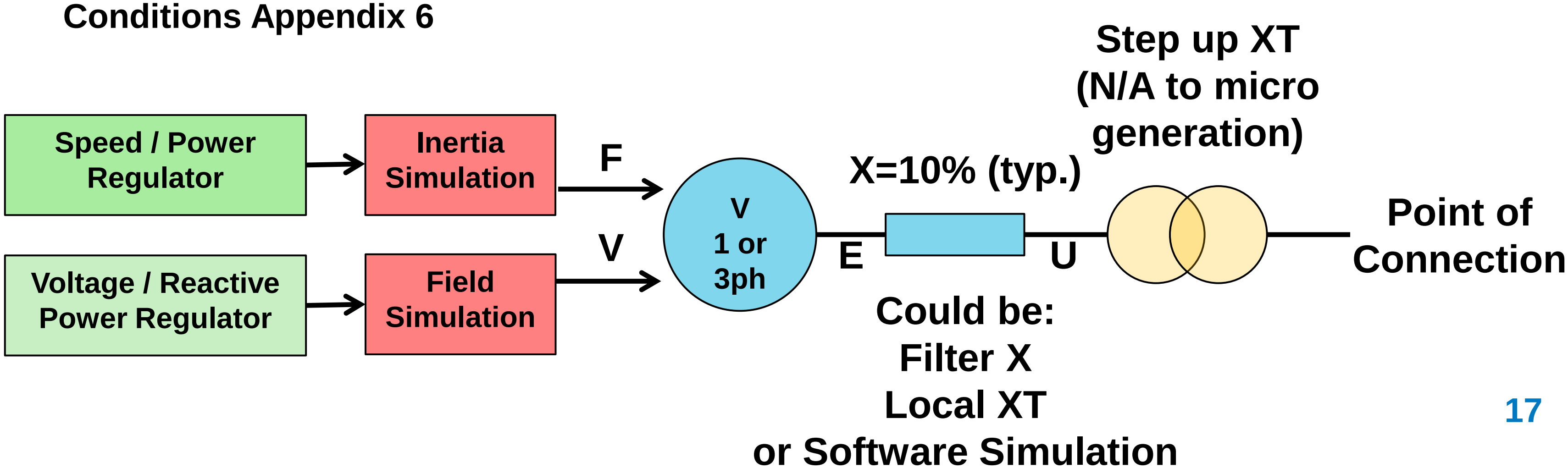


Please Note: Values (e.g. 1.33pu) quoted in these or the following slides are based on the preliminary studies presented here but maybe subject to change if further studies indicate changes are required.

Requirement Proposal for Option 1 (Grid Forming Convertors - Initial Thoughts)

nationalgrid

- Should ***behave*** like a balanced 3ph voltage source behind a constant impedance over the 5Hz to 1kHz band
- Rate of change of frequency should be limited by an equivalent inertia of H=2 to 7s on rated power
- Rapid change to the phase voltages (V), frequency (F) and phase angle in the >5Hz Band are not permitted whilst the operating point remains within the extended capability zone
- Harmonics and / or unbalanced currents will be as GB Grid Code CC6.1.5, CC6.1.6 and CC6.1.7. If the levels stated are exceeded they may be reduced by adjusting the wave shape or phase voltages. The speed at which this occurs may depend on the level.
- Dynamic performance requirements similar to those for GB Grid Code Connection Conditions Appendix 6



Requirement Proposal for Option 1 (Grid Forming Convertors - Initial Thoughts)

nationalgrid

Operation Outside Extended Zone

- If the extended capability zone is breached the device may rapidly reduce real or reactive power, volts or current by reducing pulse width, phase angle, frequency, volts etc. to bring the device back within but not below the extended rating (for 20secs) then normal rating.
- It is anticipated that operation within the extended rating would be followed by operation at less than the previous rating allowing recharging of storage and cooling of power components and that extended rating would be available again after this period. Subsequent cycles would be available on a continuous on going basis provided that on average the device has only operated at full rating.
- Fast Fault Current Injection and Fault Ride Through for Convertors is currently being discussed in Grid Code (GC0048 / GC100) RfG / HVDC Implementation formal working group and can be followed through that forum.

FFCI Option 1 for RfG implementation

Under GB RfG adoption, it is necessary to augment the existing Grid Code definition of current injection. EU RfG requirements drive more robust specification of NSG to address the trends described in the SOF:-

- SOF (System Operability Framework – see National Grid website) illustrates extent of short circuit level decline and its impact upon stability, the ability of generation to ride through faults and for network protection to operate.
- Our studies illustrate the importance of new forms of replacement fault injection to support proposed fault ride through curves which address the issue today. This can be delivered by traditional convertor design choices, to ensure current injection is maximised and not out of phase but relies on a population of Grid Forming Generation.
- However, our studies also illustrate that in order to ensure that across the next 8 years the capability to support fault ride through and voltage against time performance does not degrade, grid forming capability is required from 1st January 2021 onwards. This is the "**FFCI Option 1**" requirement - requiring a short term 1.5p.u. capability and an equivalent inertia of at least 2-7MWs/MVA (for 20s) operating against the principles of VSM as discussed.

nationalgrid

Conclusions

- Implementation of VSM requires additional energy source e.g. storage or operate with headroom
- A higher percentage of VSM convertors results in greater stability and reduces the additional energy / storage requirement for each VSM
- VSM is about power management on a millisecond timescale – Network operators must ensure enough resource is dispatched so that the majority of devices remain in VSM mode
- Next Step – Develop VSM to proof of concept

nationalgrid

References

A. Roscoe, M. Yu, R. Ierna, H. Urdal, A. Dyśko, et al., " A VSM (Virtual Synchronous Machine) Convertor Control Model Suitable for RMS Studies for Resolving System Operator / Owner Challenges " in 15th Wind Integration Workshop, Vienna, 2016.

R. Ierna, A. Roscoe, M. Yu, H. Urdal, A. Dyśko, et al., "Effects of VSM Convertor Control on Penetration Limits of Non-Synchronous Generation in the GB Power System," in 15th Wind Integration Workshop, Vienna, 2016.

H. Urdal, R. Ierna, J. Zhu, C. Ivanov, A. Dahresobh, et al., "System strength considerations in a converter dominated power system," IET Renewable Power Generation, 2015.

M. Yu, A. J. Roscoe, A. Dyśko, C. D. Booth, R. Ierna, et al., "Instantaneous Penetration Level Limits of Non-Synchronous Generation in the British Power System," IET Renewable Power Generation, 2016.

M. Yu, A. Dyśko, C. Booth, A. J. Roscoe, J. Zhu, et al., "Investigations of the Constraints relating to Penetration of Non-Synchronous Generation (NSG) in Future Power Systems," in Protection, Automation & Control World Conference (PACWorld), Glasgow, UK, 2015.

M. Yu, A. Dysko, A. J. Roscoe, C. Booth, R. Ierna, et al., "Effects of Swing Equation-Based Inertial Response (SEBIR) Control on Penetration Limits of Non-Synchronous Generation in the GB Power System," in IET Renewable Power Generation (RPG), Beijing, China, 2015.

M. Yu, A. J. Roscoe, C. Booth, A. Dysko, R. Ierna, et al., "Use of an Inertia-less Virtual Synchronous Machine within Future Power Networks with High Penetrations of Converters," in 19th Power Systems Computation Conference (PSCC), Genoa, Italy, 2016.

Thank you for Listening




Richard Ierna
richard.ierna@nationalgrid.com