Topic. Design of **GB Grid Forming Converters**.

File. **Enstore's updated guide for GB Grid Forming Converters – V-004**

Issued to. Members of GC0137 and other interested persons.

Signed by. **E A Lewis** Eric Lewis Company director **Enstore**.

Date. **24 March 2021**.

Contents

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Acknowledgments:

- The **Figures 0.2, 4.4, 8.2.1, 8.9.1, 8.9.3, 8.10.1, 9.2, 10.2.8 & 10.2.9** were all produced by Enstore based on public domain data in the **NGESO** records.
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Document guide:

This document " **Enstore's updated guide for GB Grid Forming Converters – V-004** " is based on the previous document " **Enstore's guide for GB Grid Forming Converters – V001"** that was issued to provide data on the previous issue of the proposed Grid code.

The next issue of the proposed Grid code is about to be released and the new changes are described in Sections 1 to 5 of this document.

The sections 1 to 6 of the previous document have been retained but are re-numbered as Sections 6 to 10 of this document with a few tracked changes.

This document also has a Section 0 added that is a basic introduction to AC grid power transients and has a Section 11 that is a summary of the most important items.

Acronyms.

AVC	Automatic voltage control
Droop	A control feature that changes the output power for Grid frequency changes
EMF	A term used for the internally produced voltage of a synchronous generator
F	Variable frequency in Hz.
Fg	Frequency at the Grid
Fi	Frequency at the inverter's **IVS**
Fm	Measured AC Grid's frequency
Fr	Frequency at the rotor's **IVS**
Fs	Frequency at the Grid transformers secondary
FSM	Frequency Sensitive Mode as listed in the Grid Code
Frs	Frequency **Fr - Fs**
G1(ω), G2(ω)	Frequency domain gain functions
Gd(ω)	Frequency domain damping function
GBGF- I	GB Grid Forming technology from inverters
GBGF-S	GB Grid Forming technology from synchronous generators
GFR	Grid Fault Ride Through
H	Definition of stored energy, see **Section 8.12**
Ig, Ig(ω)	Grid current in time and frequency domains
In1, In2	Input control signals
Inverter	The parts & software that produces the **IVS** but excludes external impedances
IVS	Internal voltage source of an **GBGF** system
J	Inertia parameter in 1 / per unit / second, see **Section 8.12**
NFP	Network Frequency Perturbation
NGESO	National Grid Electricity System Operator
Pc	Power from an auxiliary control system
Pd	Damping power in the damper windings
Pδ	Damping power from the losses in the AC system
Pin	Power input from a source of power and energy
Pm	Power control signal
Ps	Damping signal from the software damping function
Pt	Total of Ps and Pδ
PWM	Pulse Width Modulation
REP	Reactive power. See Note 1
RoCoF	Rate of Change of Frequency
Vc	Voltage output of the voltage control system
Vg, Vg(ω)	Voltage of the AC Grid in the time and frequency domains
Vivs, Vivs(ω)	Voltage of the IVS in time and frequency domains
Vr	Voltage reference to the voltage control system
Vs	Voltage at the transformers secondary
VSM0H	A tern used for **GBGF- I** systems with a low software based inertia
Xin	Impedance of the Grid's transformer
Xtr	Impedance of inverter transformer
Xw(Frs)	Impedance of the generator versus the **Frs** frequency
X"d	Impedance of the generator at 50 Hz
Zac(ω)	Impedance of the AC supply in the frequency domain
δig	Angle across the inverter's impedance
j	Imaginary operator = √ -1
t	Time in seconds
ω	Angular frequency in radians per second = **2 x π x F**
ωo	Angular frequency in radians per second of the 50 Hz AC Grid's frequency
ωr	Angular frequency in radians per second at the **NFP** plot resonance
Φg	Phase angle of the AC Grid voltages in the Time Domain
Φi	Phase angle of the AC inverter voltages in the Time Domain
π	Pi
1 / s	Integration function in the Time Domain
ζ	Zeta = Damping factor also called the Damping ratio

Note 1. A reactive current does require the transfer of real power in to and out of any item, for example an inductor when viewed on an instantaneous basis, but the real power sums to zero on a per cycle basis.

0. Introduction to AC grid power transients.

This **Section** explains the operation of the AC grid when a power loss transient occurs.

If the generated power equals the load power in the AC grid the AC grid's frequency will be constant, but when a change in the load power occurs the AC grid's frequency will start to change.

The rotating synchronous generators have a control system that varies their generated power, to respond to changes in the AC grid's frequency, with a dead band of plus / minus 0.015 Hz.

The result is that for normal steady state operation the generated power equals the load power and the AC grid's frequency is then constant either at 50 Hz or very near to 50 Hz.

A sudden loss of the generated power can occur if a synchronous generator trips that then gives an unbalance between the generated power and the load power.

When this occurs the following changes happen:

1. The AC grid's frequency start to fall and the **phase angle** between the synchronous generator's internal EMF voltage and the AC grid's voltage starts to increase.
2. This increase in the **phase angle** causes the synchronous generator to generate extra power.
3. This primary power of the synchronous generators has a slow response, typically measured in several seconds, and the extra generated power is immediately taken from the rotating inertia of the synchronous generators.
4. Taking the extra power from the rotating inertia of the synchronous generators causes the AC grid's frequency to fall that results in a Rate of Change of Frequency "**RoCoF**".
5. The AC grid's frequency will then continue to fall, at this **RoCoF** rate, until extra generated power becomes available.
6. This extra generated power is provided by several synchronous generators that are running at a power level below their rated output that can then respond to provide this extra generated power that is called the **Primary Response power.**
7. The **Primary Response power** is specified to be available within 10 seconds and this then stops the fall of the AC grid's frequency that can then recover back to a normal 50 Hz operation.
8. The supply of the **Primary Response power** is achieved by **NGESO** rewarding selected synchronous generators to operate below their rated output to have a defined value of the **Primary Response power** always available.
9. The magnitude of the available **Primary Response power** is constantly reviewed by **NGESO** to be sufficient for the likely worst case power transients that could occur.
10. If the supply of **Primary Response power** is not sufficient to supply the lost power the AC grid's frequency will continue to fall. If this occurs a set of automatic load disconnections will happen, as a last resort, starting at 48.8 Hz to stop any extra falls in the AC grid's frequency.

This set of actions are shown on **Figure 0.1** for a simulated major power transient.

For the **Figure 0.1** the data is:

- A typical AC Grid system in 2012 with 52 GVA capacity with an inertia **H** value **= 5**.
- A worst-case grid power transient loss of 1.3 GW at a time of 1 second.
- An immediate production of 1.3 GW of **Inertia power.**
- A production of the **Primary Response power** to 1.3 GW within 10 seconds to limit the fall in the AC grid's frequency to 49.35 Hz.
- The **Primary Response power** then increasing further to recover the AC grid's frequency back to 50.0 Hz.
- An initial **RoCoF** rate of 0.125 Hz / second.

The equations that explain the **Figure 0.1** are:

- **Equation 1. Energy in GWs = H x Installed GVA.**
- **Equation 2. RoCoF = (Grid power transient in GW x - 25) / Installed GWs.**

The **Equation 1** gives **Energy in GWs = 5 x 52 = 260 GWs.**

The **Equation 2** gives **RoCoF = 1.3 x -25 / 260 = - 0.125 Hz / s.**

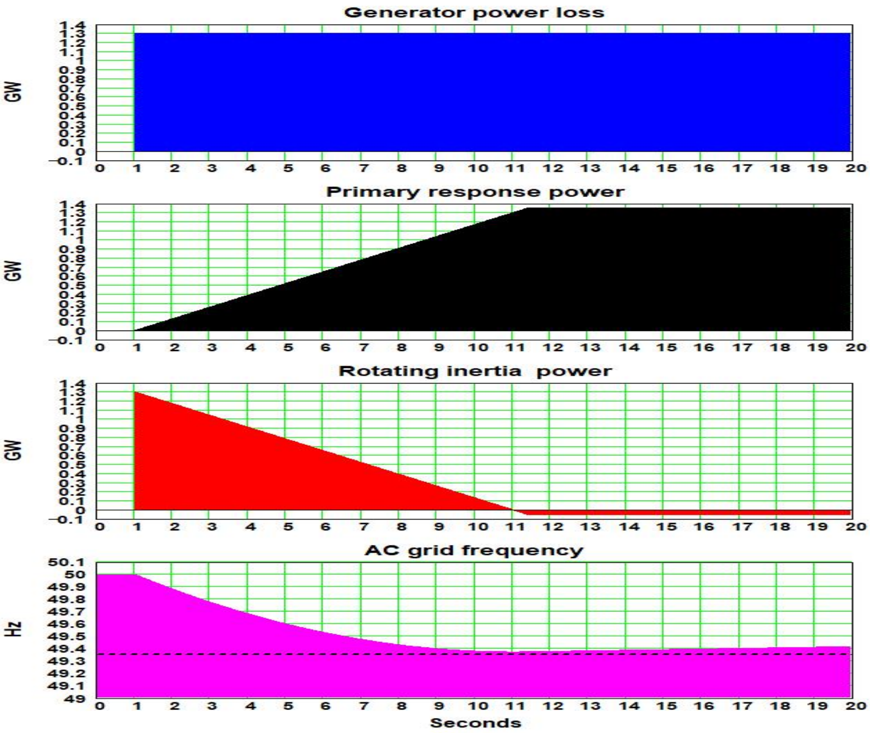

Figure 0.1. Simulated worst case existing power transient.

There have been very few examples of frequency transients that required automatic load disconnections and the **Figure 0.2** shows the 27th May 2008 power transient.

This was the very rare trip of two independent power stations within less than 2 minutes.

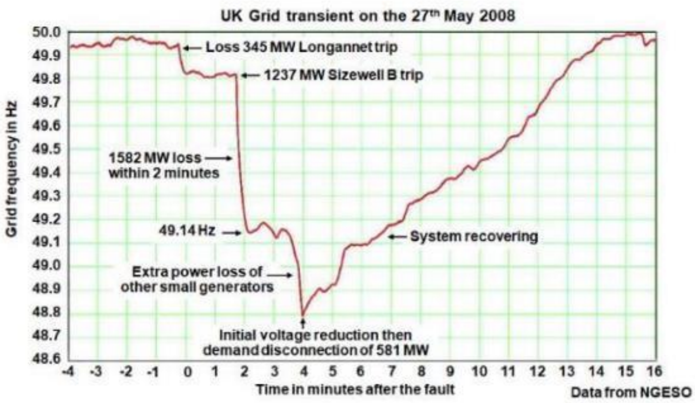

Figure 0.2. The real 2008 power transient.

The next major power transient with load disconnections is shown on the **Figure 4.4** that happened on the 9th August 2019. The transient started following a lightning strike in to switchgear at Eaton Socon that caused a grid fault that was correctly cleared in 150 ms.

This grid disturbance caused two generators to trip within 1 second which is very abnormal and led to over 1 million users being disconnected after the time delay shown on **Figure 4.4.**

The rotating synchronous generators produce **4 Types** of real power to stabilise the AC Grid:

- **Type 1** is **Phase based** real **Phase Jump Active power** for **phase angle** changes in the AC grid.
- **Type 2** is **Phase based** real **Inertia power** for **RoCoF** in the AC grid**.**
- **Type 3** is **Phase based** real **Damping Active Power** for oscillations in the AC grid**.**
- **Type 4** is **Control based** real **Control power** to produce extra generated power in the AC grid.

Most importantly the **Phase based** changes immediately starts to be produced by a rotating synchronous generator without any changes in the associated generator's control system.

These **4 Types** of real power can be seen on **Figure 8.2.1** that shows real site transient data.

Almost all renewable systems are presently connected to the AC grid by existing static **Power Converters** that use the Phase Locked Loop technology to keep their generated power constant when changes occur in the **phase angle** of the AC grid. This technology stops them producing the **3 Types** of **Phase based** power.

When existing rotating synchronous generators are replaced by an equivalent rating of existing static **Power Converters** the lack of the **3 Types** of the **Phase based** power reduce the stability of the AC grid.

In particular the lack of the **Phase based** real **Inertia power** results in an increase of the **RoCoF** value when synchronous generators are replaced by an equivalent rating of existing static **Power Converters.**

To keep the AC grid stable it has been necessary, in certain periods, to limit the use of the available renewable energy so that sufficient rotating synchronous generators could remain in operation on the AC grid to supply sufficient values of the **3 Types** of **Phased based** power.

This then results in compensation payments to the operators of the renewable energy systems.

It is also been predicted that the connection of extra renewable energy systems will need to be curtailed in the future if they are connected to the AC grid by the existing design of static **Power Converters.**

To be able to use the maximum renewable energy requires the development of the **GB Grid Forming** static **Power Converter** technology "**GBGF- I**" This technology is to have a design of static **Power Converters** that operate like **GB Grid Forming** rotating synchronous "**GBGF-S**" generators and produce the same **3 Types** of **Phase based** real power.

The basis of achieving this is shown on the **Figure 8.2.3.**

The challenges faced by the AC grid have also been increased by several other **Factors** including:

- **Factor 1.** The largest likely power loss is increasing to 2 GW.
  This is due to the rating of new nuclear power stations and new HVDC interconnectors.
- **Factor 2.** The **EFCC** data has shown that **RoCoF** rates are significantly higher near to a transient.
  This is shown on the **Figure 8.9.3.**
- **Factor 3.** The largest likely power change can now be of either polarity.
  This is due to the new HVDC interconnectors shown on **Figure 9.2** that allows the GB to become an importer and exporter of surplus energy.

As a result of these **Factors** it is planned to allow the maximum RoCoF rate to be increased to 1 Hz / s in a local zone near to the source of a power transient as shown on **Figure 8.9.4.**

The **Equation 2** can be rewritten as **Equation 3**.

- **Equation 3. Installed GWs = (Grid power transient in GW x - 25) / RoCoF.**

The **Equation 3** gives **Installed GWs = 2 x -25 = 50 GWs** per zone.

If there were 8 GB zones this requires an installation of 400 GWs in the future and the fast response **Primary Response power** also has to be rated at 2 GW.

It is also important to understand the rating and the effects of the **Phase Jump Active power** at the start of a **RoCoF** event because when there is a power loss transient in the AC grid it will normally start with an initial phase jump transient followed by the **RoCoF** transient.

During a **RoCoF** event the power flow in the AC grid has to be supplied and at the start of the **RoCoF** event the initial power loss is supplied by the **Phase Jump Active Power**.

As the **Phase Jump Active Power** decays, as shown by the **Figure 3.7** the **RoCoF Response Power** then provides the AC grid power. This action also gives time for the **RoCoF Response Power** to rise as shown on **Figures 4.2** and **4.3**.

The rating of the **Phase Jump Active Power** also has to be considered on a local zone basis for a stable grid system. For a possible future power loss transient of 2 GW this requires a 2 GW power available in the local zone for both the **Phase Jump Active Power** and the **RoCoF Response Power**.

For the proposed **NGESO Stability Pathfinder Service** a system that does not have a continuous power rating the **Phase Jump Active Power** and the **RoCoF Response Power** will be equal to the systems rated power and will typically operate in the linear **GBGF** mode for phase jumps up to typically 20 degrees based on the **Figure 8.9.2.**

For the proposed **NGESO Stability Pathfinder Service** a system that has a continuous power rating the **Phase Jump Active Power** and the **RoCoF Response Power** will be equal but lower than the systems rated power. The power will be provided for phase jumps up to 5 degrees based on the Section 7 limits.

These design proposals mean that in zones away from a fault the **GBGF- I** systems will operate in the linear mode without going into a current limit which is a very important requirement for a stable AC grid.

The result of these changes are shown on **Figure 0.3.**

For the **Figure 0.3** the data is:

- A typical future AC Grid system for a local zone with 10 GVA capacity with an inertia **H** value **= 5**.
- A worst-case grid power transient loss of 2 GW at a time of 1 second.
- An immediate production of 2 GW of the **Phase Jump Active power** plus the following **RoCoF Response Power** that is supplied from the energy store of the **GBGF- I** system that causes the frequency of the **IVS** to fall as occurs in **GBGF-S** generators.
- A production of the fast response **Primary Response power** to 2 GW within 1 seconds to limit the fall in the AC grid's frequency to 49.5 Hz.
- The **Primary Response power** then increases further to recover the AC grid's frequency back to 50.0 Hz.
- An initial **RoCoF** rate of 1.0 Hz / second.

This data shows that the response time for the **Primary Response power** is not possible by using synchronous generators but it is possible by using **GBGF-I** systems with the required level of stored energy.

The required stored energy for a **GBGF-I** system is 20 % of the stored energy of an equivalent rotating synchronous generator as defined in **Section** 8.5.

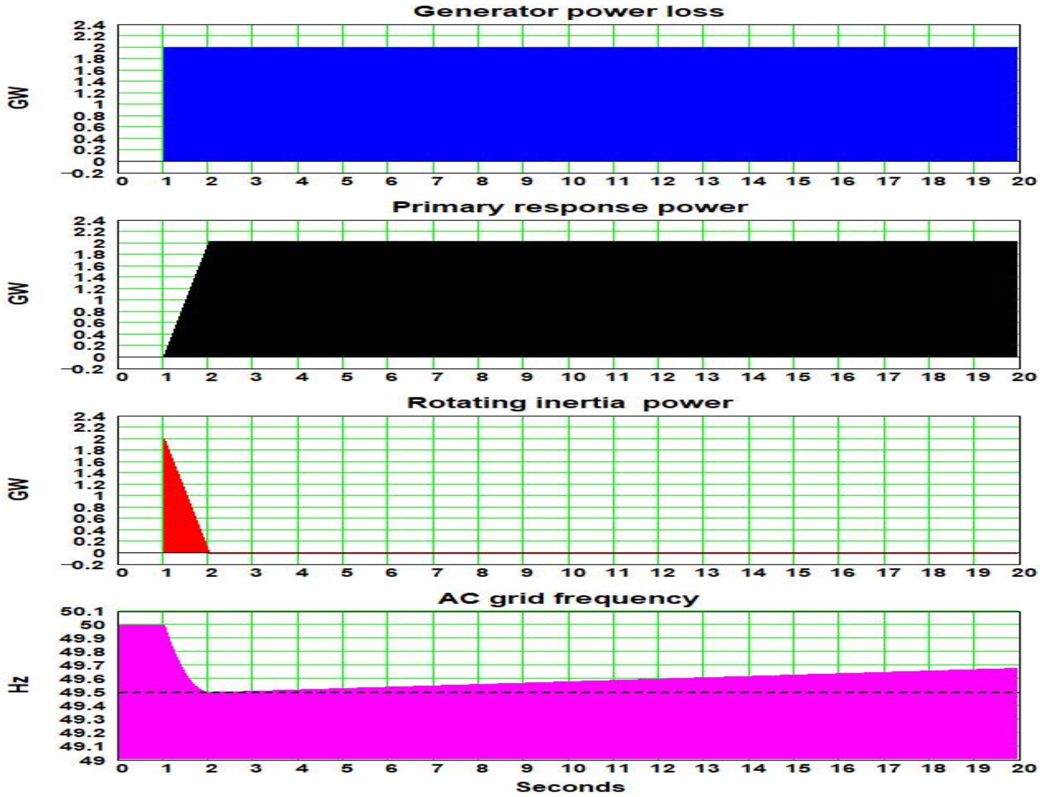

Figure 0.3. Simulated worst case future local power transient

A **GBGF-I** system can provide the **4 Types** of power as supplied by a **GBGF-S** generator.

During the initial phase of developing **GBGF-I** systems the focus was on providing an equivalent value of **Type 2 Phase based** real **Inertia power** for **RoCoF** in the AC grid**.**

The latest studies have shown the following:

- That the **Type 1 Phase based** real **Phase Jump Active power** has a very fast 5 ms response as shown by **Figure 3.7**.
- That the **Phase Jump Active power** is essential for stabalising the AC Grid.
- That the **Inertia power** is applied more slowly especially for system with high **H** values that can occur in energy storage systems.
- That for some systems the time to reach the full **Inertia power** can be 1 second see **Figure 4.2.**

- That for some systems the use of the **Type 4 Control based** real **Control power** can give a significant increase of the **GBGF-I** systems power for **RoCoF** events see **Figures 4.3** and **8.2.1.**

To provide an optimal design of **GBGF- I** systems the term **RoCoF response power** has now been defined. The definition of **RoCoF response power** is that for **RoCoF** transients the resulting real power can be beneficially provided by either or both of the following depending on the design of a system:

- **Phase based** real **Inertia power** for AC grid **RoCoF** changes**.**
- **Control based** real **Droop power** for AC grid frequency changes.

To have a fully stabilised AC grid it is essential to have a power reserve available of 2 GW to deal with sudden power transients and the prosed **NGESO** services for Stability control, Dynamic containment and Constraint management can provide this ability.

Due to limiting the RoCoF to 1 Hz / s on a zonal basis will require~~s~~ a distributed system with several local zones. If eight local zones are needed this gives an estimate of 16 GW of installed response capability.

This capability will also give the ability to:

- Use the maximum value of renewable energy in real time.
- Eliminate constraint payments.
- Provide the required value of **Primary response power** with a one second response.
- Respond to power transients and constraint problems.
- Smooth the variability of renewable energy systems.
- Import and export power on a well controlled 30-minute basis.
- Have very constant prices for electricity on the AC grid that will make energy trading less viable.

A set of Constraint management systems using the **GBGF- I** technology, each rated at 200 MW for 2 hours, with the stacked abilities shown on **Figure 9.3** can provide the basis for a fully stable future AC grid system with 100 % of the power coming from nuclear power plus renewable energy.

1. New developments.

This report is an update based on the previous report "**Enstore's guide for GB Grid Forming Converters – V001".**

The **Sections 1** to **5** of this report now contain all the new data relating to the proposed changes in the next issue of the **GBGF** Grid code. The **Sections 0** to **3** of the previous report are now in **Sections 6** to **10** of this report with any updates that were required.

The responsibility for defining **NFP** plots will be the responsibility of the proposed expert group to produce the "**NFP Best Practice Guide or Equivalent**" and **NGESO** will be starting this group.

Enstore has produced two tools in 2021 for investigating the details of **NFP** plots:

- **Enstore's NFP Tool Set** to rapidly produce **NFP** plots.
- **Enstore's Damping algorithm** that can rapidly change the damping of the system's closed loop response as shown on **Figure 3.1** by the **Gd(ω)** control function.

These tools are the IPR property of **Enstore** and have been used to provide the data in this report.

2. Definition of GBGF- S and GBGF- I systems.

In investigating **NFP** plots it has become clear that many new features can only be implemented with inverter based systems.

It is also clear that producing **NFP** plots is easier for inverter based systems, that are fundamentally based on defined software algorithms, and that they are a very good way of showing the performance of inverter based systems.

For synchronous generator systems suppliers have an agreed a well-established method of specifying their performance to **NGESO**.

The proposed Grid code has two new definitions:

- **GBGF-S** for data applicable only to **GBGF** synchronous generators based systems.
- **GBGF- I** for data applicable only to **GBGF** inverter based systems.

In the proposed Grid code, the data for **GBGF-S** systems will be specified in the standard way without the need for **NFP** plots and **GBGF- I** systems will be specified by **NFP** gain plus phase plots plus other data, that includes a **Nicholls chart** as shown on **Figure 3.5,** and the calculated equivalent **Damping Factor.**

3. Guide to NFP plots.

NFP plots can be calculated in the time domain by injecting a low amplitude sinewave for a wide range of frequencies to produce the full set of results needed for one **NFP** plot. This analysis method requires a large number of simulations and the complex equations do not give an understanding of **NFP** plots.

NFP plots can also be calculated in the frequency domain that gives very rapid results and produces results that assist in the understanding of **NFP** plots for **GBGF- I** systems. The **Figure 3.1** shows how **NFP** plots are calculated in the frequency domain for a very basic system.

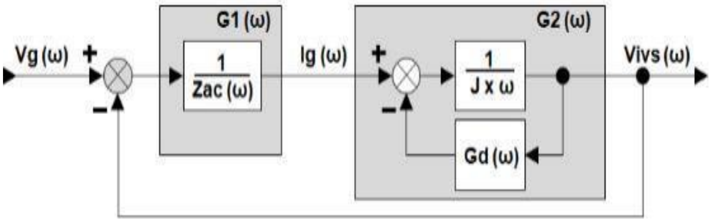

Figure 3.1. Calculating NFP plots.

The input is the AC Grid voltage **Vg(ω)** and the output is the inverters **Internal Voltage Source** "**IVS**" that produces the voltage **Vivs(ω).**

The AC current **Ig(ω)** is produced by the voltage difference acting via the AC supply impedance **Zac(ω).**

The **Ig(ω)** current acts on the **software inertia J** to alter the frequency of **Vivs(w)** voltage.

There is a damping function **Gd(ω)** around the **software inertia J** to give increased closed loop damping.

The result is two functions **G1(ω)** and **G2 (ω)** that are used on **Figure 3.2** to calculate the **NFP** plot data.

At present there is no standard software equations for the **Gd(ω)** function and suppliers can use any viable set of circuits and equations to provide this function.

The **NFP** plots in the guide have been produced using the **Enstore** damping software function that does have the circuit shown on the **Figure 3.1**. The **Figure 3.2** shows the steps in producing an **NFP** plot.

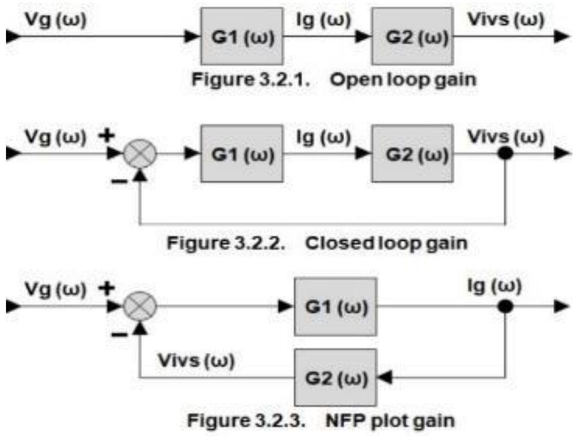

Figure 3.2.1 to 3.2.3 producing an NFP plot.

The two functions **G1(ω)** and **G2 ω)** are used to produce the Open Loop gain as shown on **Figure 3.2.1.**

Then the Closed Loop gain is calculated as shown on **Figure 3.2.2** and then the **NFP** gain is calculated as shown on **Figure 3.2.3.**

These figures are for the most basic system. For a real project many more function blocks would be used to add extra control like either a Power System Stabalising "**PSS**" **control** or a **Droop control** but the core concept is the same. The same applies to extra function blocks for measurement time delays, the response time of the inverter switching devices and the processor's time delay.

Figure 3.3 is an **NFP** plot for a system with:

- **H = 5** that needs a **J** function = 10.
- An AC supply with a per unit resistance of 0.0025 ohms and a per unit inductance of 0.00106 Henries. This is an AC impedance of 0.333 per unit at 50 Hz that gives a 3 per unit fault current.
- A high level of damping with a resonant frequency of 1.55 Hz.

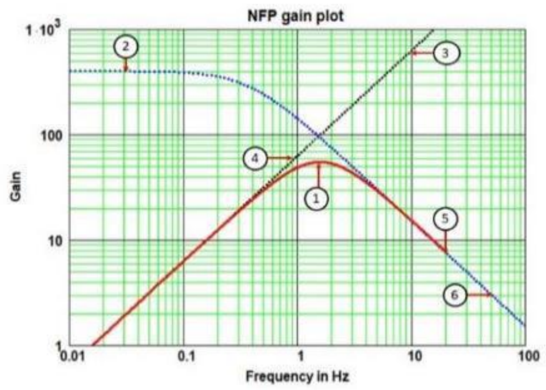

Figure 3.3. Basic NFP plot.

The AC supply resistance has been set to a low value to give the results shown on **Figure 3.5**.

The key features of **Figure 3.3** are:

1. This is the **NFP** plot with a well-defined resonant peak at 1.55 Hz with high damping.
2. This is the admittance of the AC supply function. On **Figure 3.1** at high frequencies the **IVS** is not changing so this line defines the high frequency part of the **NFP** plot.
3. This is the admittance of the Inertia function. On **Figure 3.1** at low frequencies the **IVS** has to be at the same frequency as the AC Grid. This means that the AC current is defined by the input to the **software inertia** function without damping. This line defines the low frequency part of the **NFP** plot as **Ig(ω) = Vivs(ω) x J x ω** which at low frequencies gives **Ig(ω) = Vg(ω) x J x ω.**
4. At 1 Hz on the line item 3 the admittance of the **software inertia** is **J x 2 x Pi** = **5 x 2 x Pi** = **62.8**.
5. The **NFP** plot is stopped at 20 Hz because the **NFP** test input gives unacceptable results at frequencies near to the AC Grid's frequency.
6. At 50 Hz on the line item 6 the admittance of the AC supply = 3.0.

For a full set of data on an **NFP** plots the value of the system's **Damping Factor** needs to be defined.

The **Damping Factor** value can be calculated, for some **NFP** plots, by a simple equation and a full equation may be produced by the proposed new expert group that will be producing the "**NFP Best Practice Guide or Equivalent** ".

The systems equivalent **Damping Factor** can also be calculated from the **Nicholls** Open Loop Gain versus Open Loop Phase plot that can be produced as part of producing the data on **Figure 3.2.1.**

To calculate the equivalent **Damping Factor** the "**Open Loop Phase margin angle**" is measured from the **Nicholls** plot for an Open Loop Gain of 1.0. The systems equivalent **Damping Factor** is then calculated from the standard chart, shown on **Figure 3.4** that gives the actual **Damping Factor** from the **Open Loop Phase margin angle** for a standard second order unity feedback system. For systems with high damping the equivalent **Damping Factor** can be calculated as 0.5 / Closed loop gain at resonance.

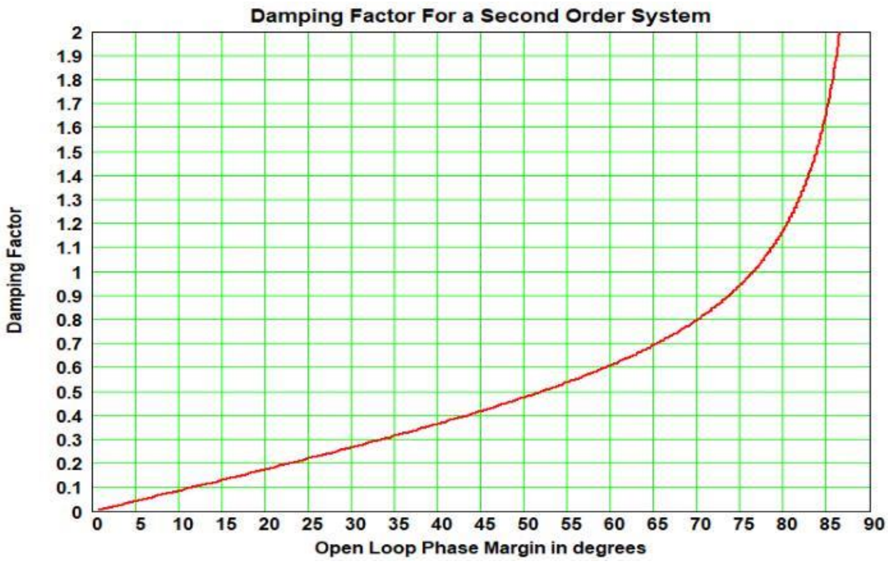

Figure 3.4. Damping Factor graph for a second order system.

The **Figure 3.5** is an **NFP** plot for the data used for **Figure 3.3** plus an extra **NFP** plot with only the damping from the AC supply.

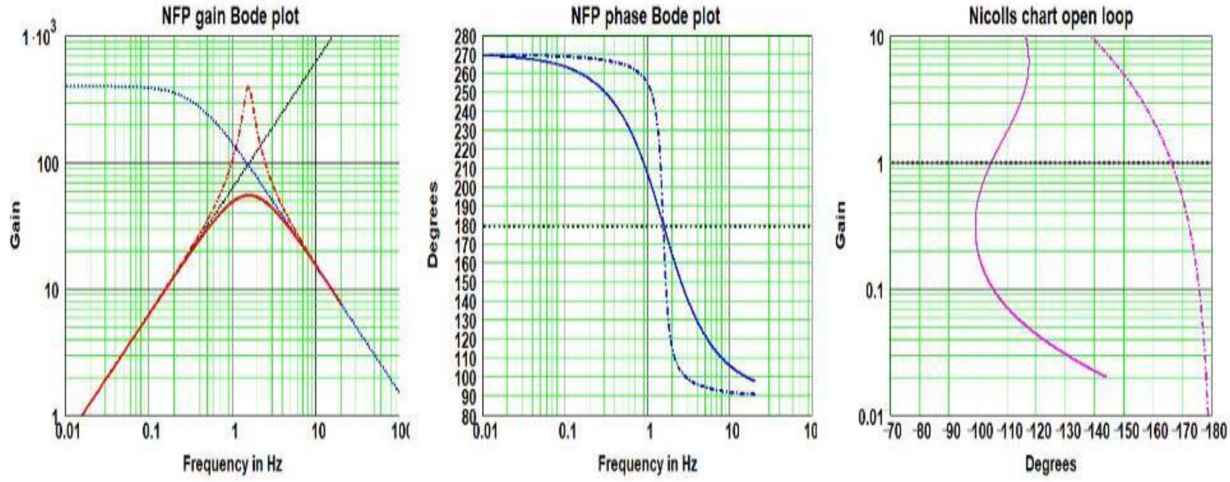

Figure 3.5. Example of an NFP plot plus a Nicholls chart all with 2 values of damping.

The NFP plot with the solid lines is the data for the **NFP** plot shown on **Figure 3.3** and has:

- An **NFP** gain plot peak of 55 that is produced by the added damping from the **Gd(ω)** function.
- An **NFP** phase plot with a slow rate of change of phase at the resonant frequency.
- An impedance at the resonant frequency that is resistive.
- An **NFP** phase plot with a phase shift of 180 degrees at the resonant frequency of 1.55 Hz.
- A **Nicholls chart** that gives an **Open Loop Phase margin angle** of 75 degrees.
- An equivalent **Damping Factor** of 0.92 for a second order system by using the **Figure 3.4.**
- A **Nicholls** plot with an **Open Loop Phase margin angle** that increases as the gain falls which is not normal for a second order systems. This shape is the result of the software **Gd(ω)** damping function adding extra damping and system stability.

The **NFP** plot with the dotted lines is the data for the **NFP** plot shown on **Figure 3.3** with the added damping set to zero and has:

- An **NFP** gain plot peak of 400 that is produced defined by the damping from the AC supply.
- An **NFP** phase plot with a very fast rate of change of phase at the resonant frequency.
- An impedance at the resonant frequency that is resistive.
- An **NFP** phase plot with a phase shift of 180 degrees at the resonant frequency of 1.55 Hz.
- A **Nicholls chart** that gives an **Open Loop Phase margin angle** of 14 degrees.
- An equivalent **Damping Factor** of 0.12 for a second order system by using the **Figure 3.4.**
- A **Nicholls** plot with an **Open Loop Phase margin angle** that is a more normal shape for a second order system.
- The resistance of the AC supply has been set to a very low value to produce an **NFP** plot with low damping and this can occur with a low power inverter on a stiff AC supply network.
- This shape of this **NFP** plot is undesirable in an AC system due to the rapid phase changes.

The **Enstore** proposal is to limit **NFP** plot for use on the AC Grid to have a maximum gain of 200.

For certain systems the **NFP** plot may not have a defined peak making it difficult to define the resonant frequency of the **NFP** plot.

For these systems the resonant frequency can also be found for the frequency at which the phase shift on the associated **NFP** phase plot is 180 degrees.

Examples of NFP plots with different control features are listed in **Section 5.**

There is also a need to set limits for the acceptance of **NFP** plots to validate that any specific **NFP** plot is acceptable to the AC Grid. The proposed **Enstore** data on the acceptable limits for **NFP** plots is shown on **Figure 3.6** by the four solid black lines.

Data set 01 - AC Grid acceptance limits with multiple AC Grid plots.

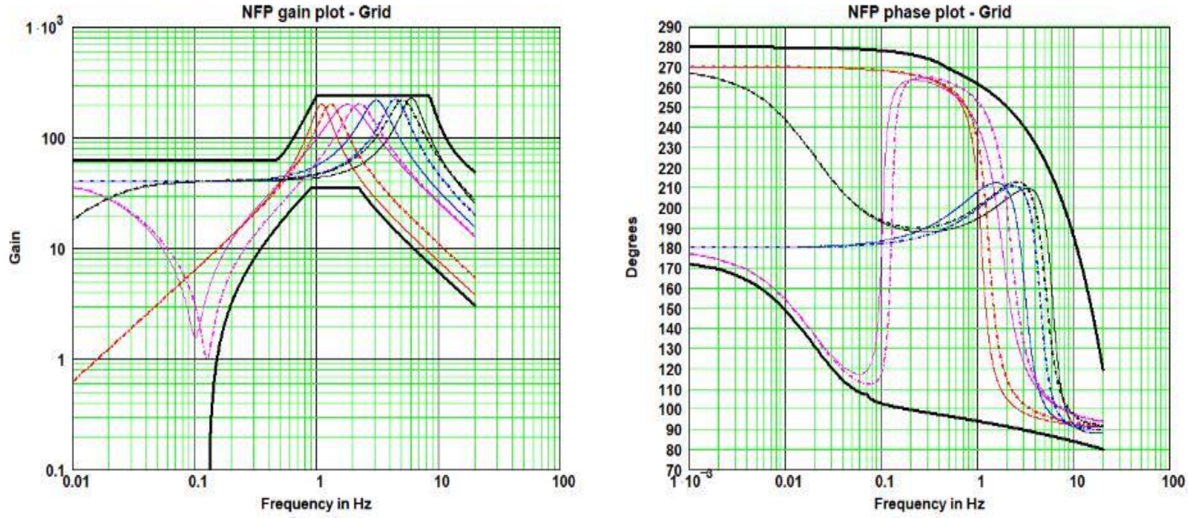

Figure 3.6. Proposed NFP plot limits.

The **Figure 3.6** was produced for a range of **H** values, AC supply impedance values and for the **Droop control** options, defined in **Section 5**, to give resonant frequencies in the range of 1 Hz to 10 Hz.

The lower 1 Hz frequency limit was chosen to avoid introducing **NFP** plots with very low resonant frequencies that do not presently exist in the AC Grid. If this type of sys was used it could adversely interact with the existing **PSS controls,** used on **GBGF-S** systems, by producing different phase shifts in the AC grid below 1 Hz.

The upper 10 Hz frequency can occur with small systems on a distribution AC Grid and the 10 Hz limit was chosen to ensure that a viable time response for the **Phase Jump Active power** is produced for phase jump transients as shown on **Figures 3.7.**

The **Damping Factor** was set to a low value to give an **NFP** plot gain maximum of 200 with **No Droop** control and lower **Damping Factors** were not used as the results all lay within the limits.

These limits must be validated by the proposed expert group that will be producing the "**NFP Best Practice Guide or Equivalent**" and these proposed **NFP** plot limits may then need to be revised.

The next issue of the Grid code should state that the **NFP Best Practice Guide or Equivalent will have** data on the limits for **NFP** plots so that any changes in these limits will not affect future issue of the Grid code. The Figures in **Section 5** include these proposed **NFP** plot limits.

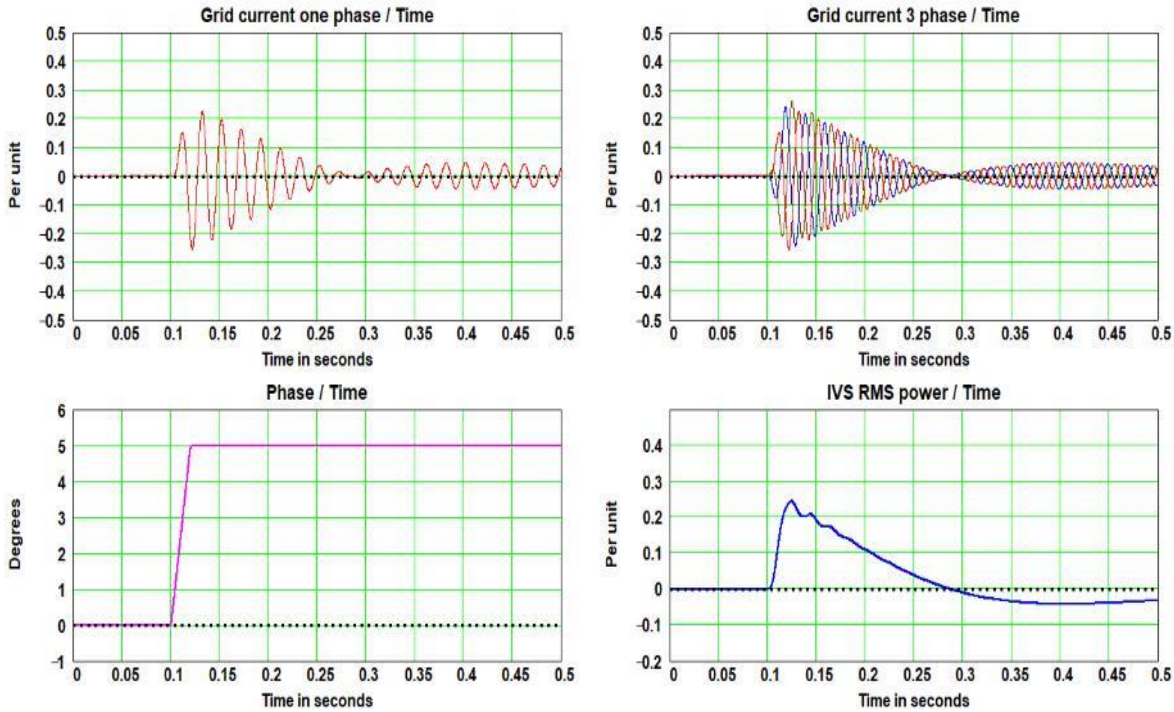

Figure 3.7. Response of a GBGF- I system to a phase change applied over 20 ms.

4. Design of systems supplying power for RoCoF events.

The design of large Grid connected energy storage systems that only provided real **Inertia power** at the system full rating will typically result in systems with a **H = 25**, based on the previously published equation for defining the **RoCoF response power**.

- **Rated H value = (25 x RP1) / (Installed MVA) ………. Equation 4.**
- **RP1 = RoCoF response power in MW produced for a RoCoF transient of 1 Hz / s.**

This gives a typical **NFP** plot shown on **Figure 4.1** for a system with **H = 25** plus a **No Droop control** and the AC supply impedance as used on the other **NFP** plots.

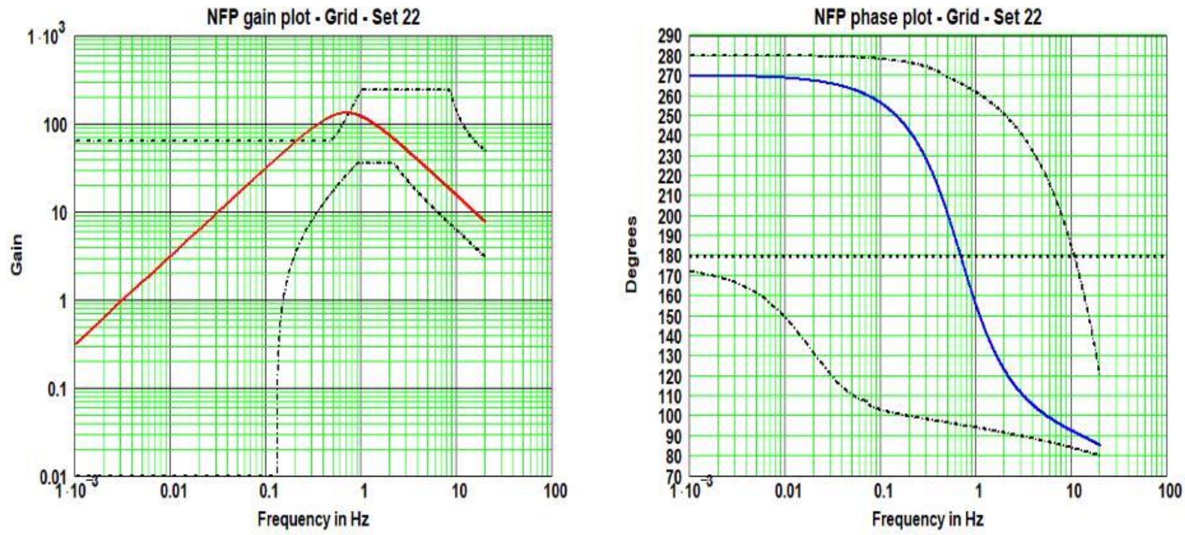

Figure 4.1. NFP plot H = 25

This Figure is an **NFP** plot for **H = 25** with a very high equivalent **Damping Factor** of 0.95 plus a resonant frequency of 0.69 Hz, that is well outside the proposed **Enstore** limits for acceptable **NFP** plots.

Enstore considers that the resonant frequency of 0.69 Hz could well cause incompatibility issues with the AC Grid as this is a resonant frequency that does not exist in the present AC Grid and could could adversely interact with the existing Power system Stabalising "**PSS**" controls used on **GBGF-S** systems, by producing a different phase shifts below 1 Hz in the AC grid.

A simulation of this system in the time domain shows that the real **RoCoF response power** produced also has a very slow response time due to the low resonant frequency as shown by the **Figure 4.2.**

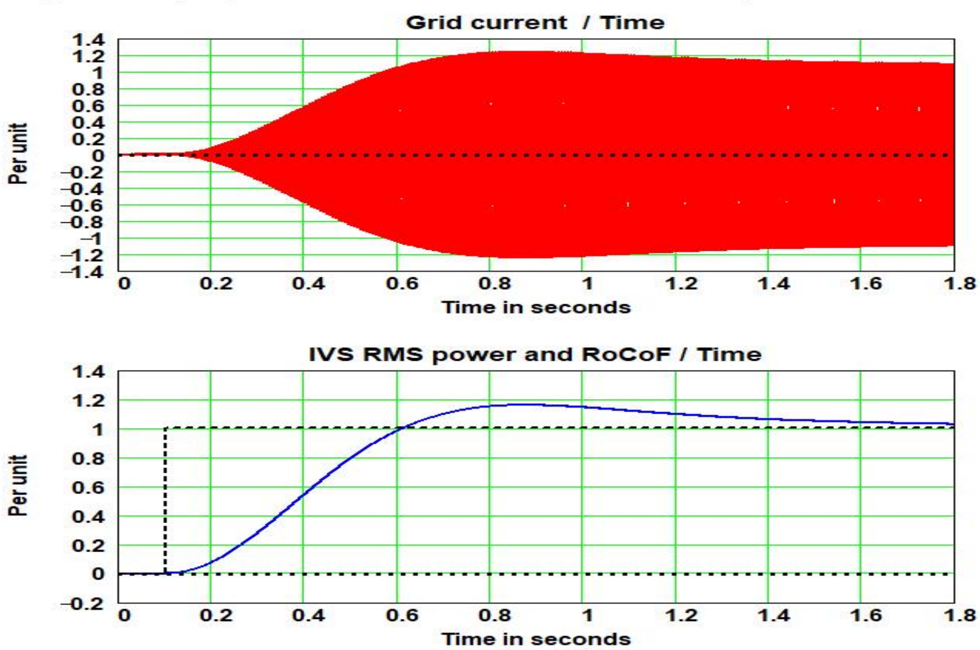

Figure 4.2. RoCoF time response for H = 25 with No Droop control.

The **RoCoF** response shown on the **Figure 4.2** has a slow response due to the following details for a **RoCoF** rate of -1 Hz / s.

- At 50 Hz one cycle is 20,000 μs and after one second the one cycle at 49 Hz is 20,408 μs.
- The one second change has 49.5 cycles which is a change of 8.25 μs in the first mains cycle.
- In the first mains cycle this is a change of 8.25 x 360 / 20,000 = 0.14 degrees per mains cycle.
- With a supply impedance of 0.333 per unit the power equation requires a 20 degree change for 1.0 pu power, as shown by the standard power equation Power = 2 x V_G x V_i x Sin (20 x 0.5) / Xs.

This is why the real Inertia Power response has a significant time to reach the **RP1** value.

The **Figure 4.2** is for a **RoCoF** of 1 Hz / s applied at 0.1 seconds for a **H = 25** system with good damping.

Enstore has investigated alternative designs, and a **GBGF- I** system with a higher resonant frequency and **Full Droop control** can give a virtually identical **RoCoF response power** as shown on **Figure 4.3.**

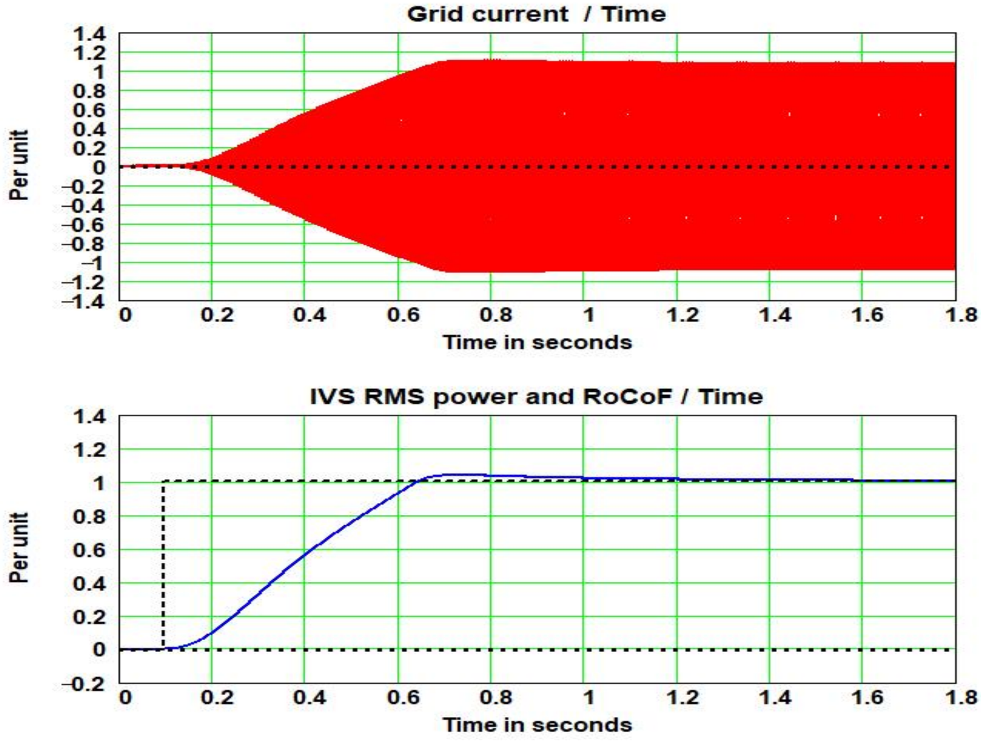

Figure 4.3. RoCoF time response for H = 5 with Full Droop control.

The **Figure 4.3** is for a **RoCoF** of 1 Hz / s applied at 0.1 seconds for a **H = 5** system with good damping. The added **Full Droop control** gives a **RoCoF response power** as good as the **H = 25** system but with an acceptable Grid resonance frequency of 1.6 Hz.

The **Full Droop control** is very similar to the **Primary Response power** but with a time to the full **RoCoF response power** of less than one second, which is possible with **GBGF- I** systems.

This design also has a resonant frequency that is compatible with the AC Grid and with further development this design could give an even faster **RoCoF response power.**

This same **RoCoF response power** occurs for **NFP** plots with a wide range of compatible resonant frequencies of up to 10 Hz. The **Full Droop control** response of **Figure 4.3** is based on a frequency input signal updating every 20 ms with a high immunity to phase jumps.

To be able to use theses designs with a **GBGF- I** there is a very significant proposed change that is required in the Grid code.

The very significant proposed change is that the Grid code should focus on real **Phase Jump Active power,** as shown on **Figure 3.7,** as the most important and inherent benefit of **GBGF** technology**.**

In **Enstore's** opinion the lack of **Phase Jump Active power** was a contributing factor at the start of the UK Grid transient shown on **Figure 4.4** that resulted in over one million users being disconnected**.**

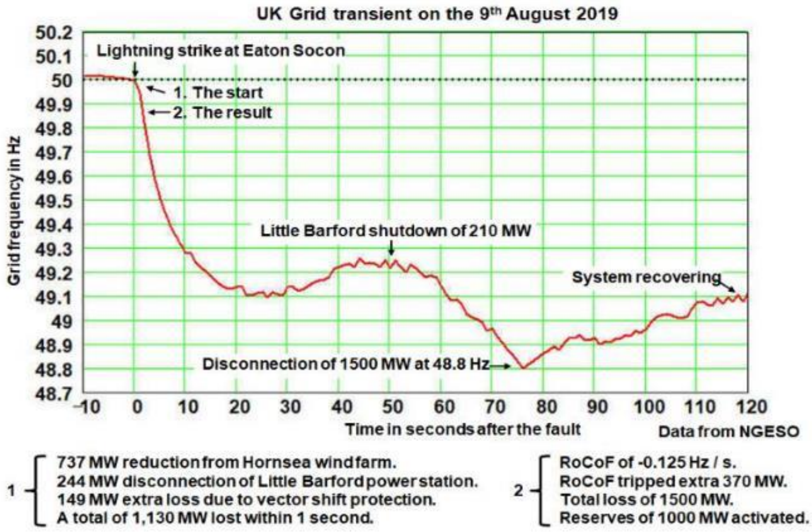

Figure 4.4. UK Grid transient.

The most important proposed Grid code changes is to include a definition of **RoCoF response power.**

The definition of **RoCoF response power** is that for **RoCoF** transients the resulting real power can be beneficially provided by either or both of the following depending on the design of a system:

- **Phase based** real **Inertia power.**
- **Control based** real **Droop power**.

This is an important change that permits the optimal **RoCoF response power,** as shown on **Figure 8.2.1,** to be provided by a wide range of systems without requiring very low **NFP** plot resonant frequencies.

This combination of **Phase based** real **Inertia power** and **Control based** real **Droop power** can be seen on **Figure 8.2.1** for Unit 3.

5. Data on new Droop control modes.

To provide the benefits listed in **Section 4**. requires the use of at least 4 types of **Droop control**.

5.1. No Droop control.

This is selected by **NGESO** when a no **Droop control** action is required for selected installations. This exists in the Grid code.

This control can be supplied by **GBG-S** and **GBGF- I** systems.

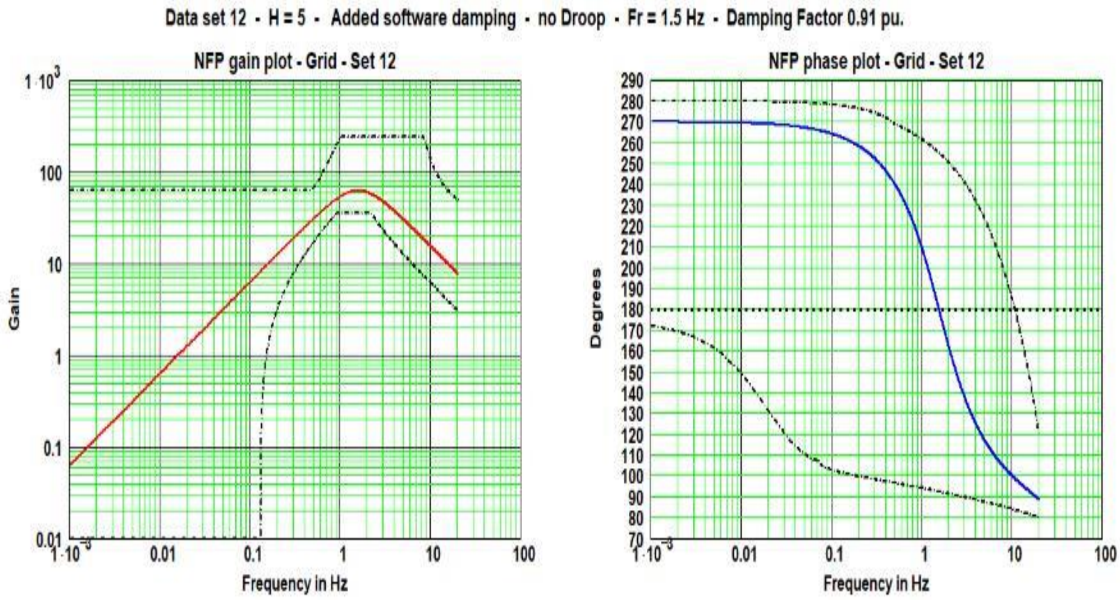

Figure 5.1. No Droop control for a H = 5 system.

5.2. Low Frequency "LF" Droop control.

This is the **NGESO FSM** mode **Droop control** that is only active at low frequencies.

For **GBGF-S** systems this naturally occurs due to the control limitations of these generators.

This **Droop control** can also be used with **GBGF- I** systems.

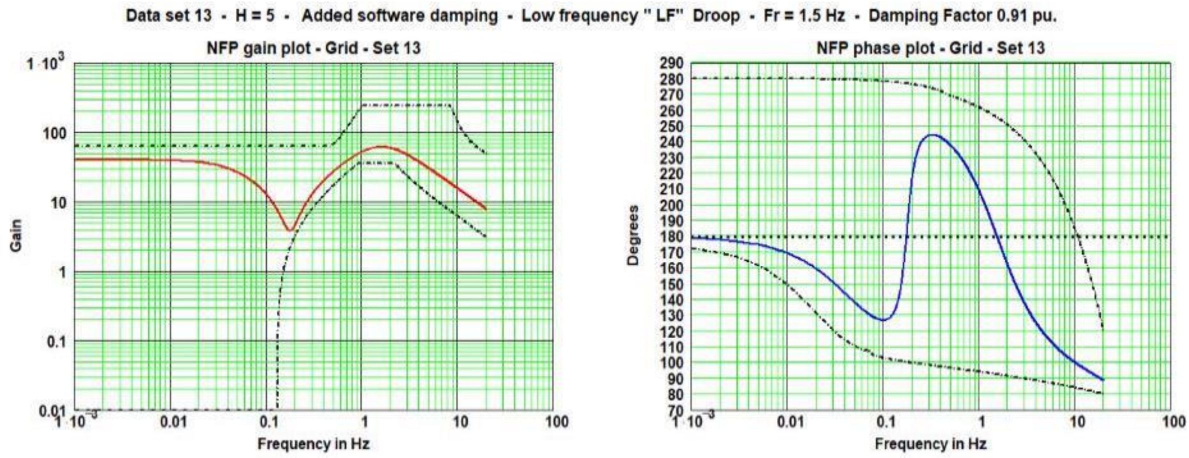

Figure 5.2. LF Droop control for a H = 5 system.5.3. Full Droop control.

This is **Droop control** that is active at all frequencies that is only possible with **GBGF- I** systems.

This is the basis of **Enstore's** equivalent design to **LF Droop control** for providing the **RoCoF response power**.

This the same **Droop** gain of 40 at all frequencies.

The **Full Droop control** does not change the damping of the closed loop system but does alter the gain peak of the **NFP** gain plot, see **Section 8.8** for more details.

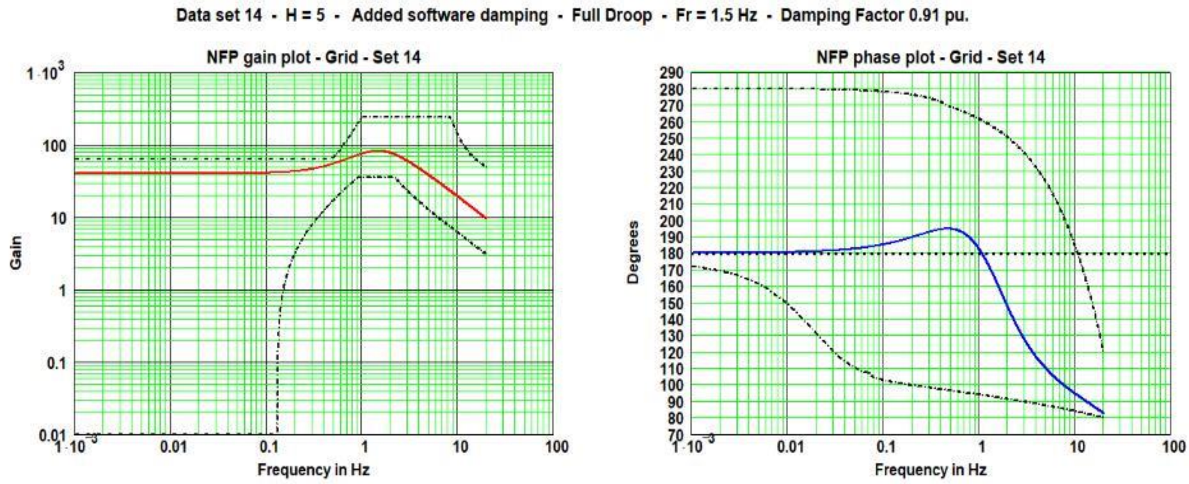

Figure 5.3. Full Droop control for a H = 5 system.

5.4. Hybrid Droop control.

This is **Droop control** that is not active at low frequencies which is possible with **GBGF- I** systems. This is the basis of **Enstore's** equivalent design to **No Droop** system for providing the **RoCoF response power**.

If required this **Hybrid Droop control** can have different values of the Drop Gain at low and higher frequencies.

This is to provide the **NGESO LF Droop control** at low frequencies and the optimum **Full Droop control** for providing the **RoCoF response power**.

The **Figure 5.4** has zero **Droop** gain at very low frequencies but a higher **Droop** gain near the resonant peak to provide **RoCof response power**.

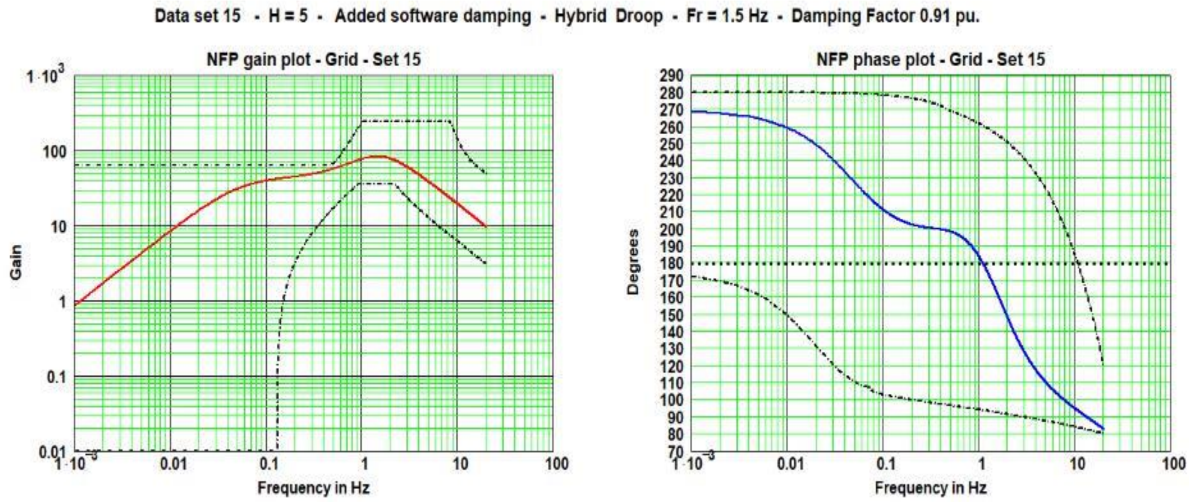

Figure 5.4. Hybrid Droop control – 1 for a H = 5 system.

The **Figure 5.5** has a lower **Droop** gain at very low frequencies but a higher **Droop** gain near the resonant peak to provide the **RoCoF response power** for a **H = 5** system.

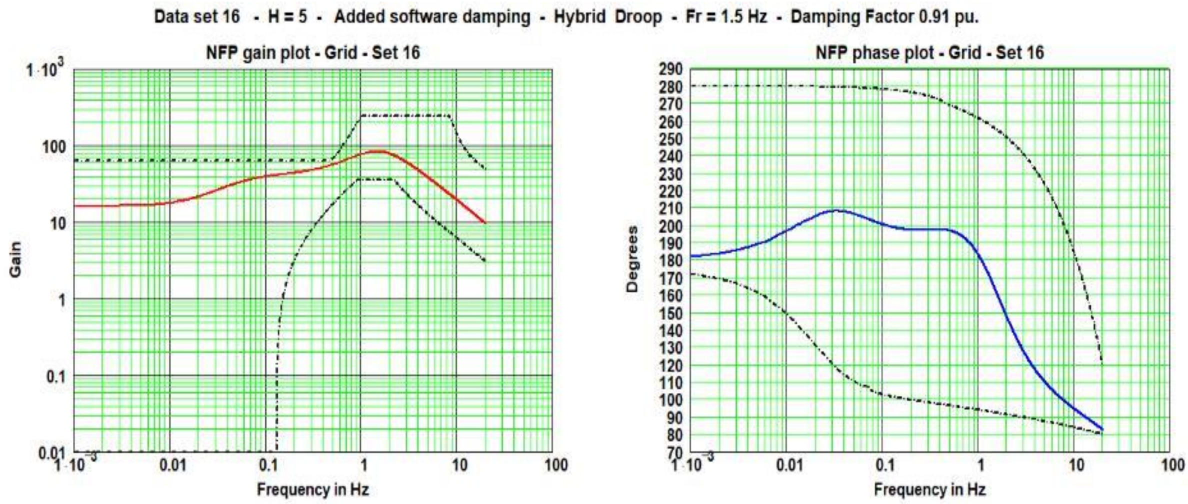

Figure 5.5. Hybrid Droop control – 2 for a H = 5 system.

The **Figure 5.6** is an **NFP** plot, very similar to **Figure 5.5** for a **H = 0.2** system.

This is for a system with a resonance at 10 Hz, that is just within the limits for acceptable **NFP** plots.

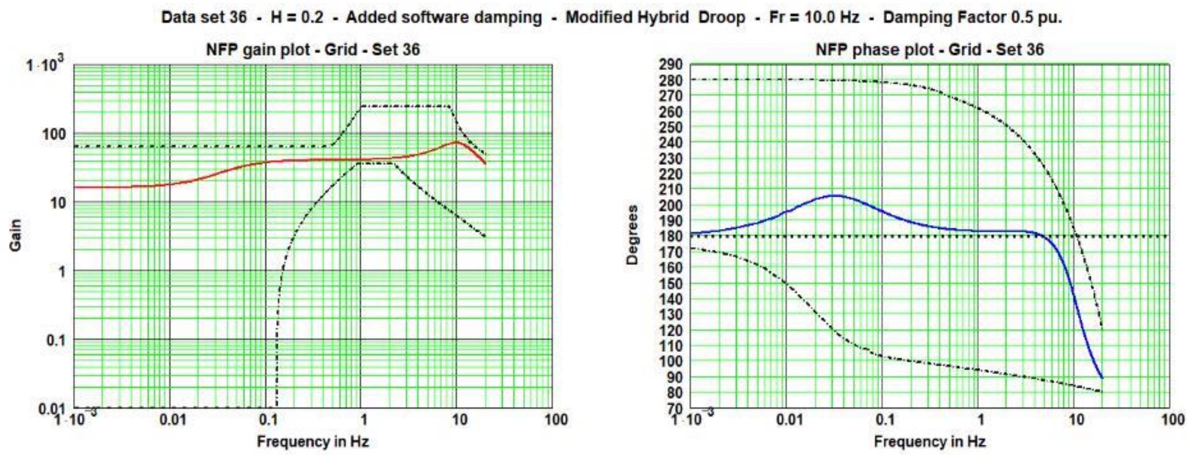

Figure 5.6. Hybrid Droop control – 3 for a H = 0.2 system.

The **Figures 5.5** and **5.6** show that can use the **Hybrid Droop control** to provide **RoCoF response power** for systems with a wide range of **H** values.

6. Revised basic aims.

The use of existing static **Power Converters** to provide a synthetic Inertia response has been investigated and demonstrated by many companies using **Control based power.**

As a result of these investigations, the use of existing static **Power Converters** to provide a Grid stabilising ability, that only includes a synthetic Inertia response, has been rejected by **NGESO** and **ENTSO-E** as being too slow for meeting the stability and Inertia requirements of future Grid systems that are using very high levels of renewable power from either solar power, wind power and all other sources of renewable energy.

To provide a viable solution, **GBGF** technology uses **Phase based power** which is produced when changes in the phase of the AC Grid directly produce a change in the **GBGF- I's** power without any actions occurring in the **GBGF- I's** control system.

The supply of real **Phase Jump Active power**, real **RoCoF response power**, and **Damping Active Power** is an inherent property of a **GBGF- I** system but only if the associated control system provides the required actions defined for **GBGF** technology. This is why a new converter control system and hardware design is needed.

The development of **GBGF- I** system has the aim of being able to supply real **Phase Jump Active power**, real **RoCoF response power** and **Damping Active Power** as fast as the same power supplied by Synchronous generators.

The four **Design Aims** for **GB Grid Forming Converters** are:

- To have a common set of essential requirements for **GB Grid Forming Converters** that allow for open market competition. This is to enable all the different types of **GB Grid Forming Converters** to compete for the different **NGESO Services**, that as a minimum include rotating Synchronous Generators, rotating Synchronous Condensers (Compensators) and static **Power Converters** including **HVDC Converters**.
- To have a common set of essential requirements that define the technical abilities of **GB Grid Forming Converters** to form a common core for all existing and future **NGESO Services**.
- To clearly define each of the essential requirements to promote the development of a range of viable alternative solutions for **GB Grid Forming Converters**.
- To provide a technology that enables 100 % of renewable energy to be used in the Grid with reliable operation for both normal and fault conditions.

These **Design Aims** are needed to maintain the Inertia and the stability of the **GB** Grid when high volumes of energy sources are connected to the **GB** Grid by static **Power Converters**, some of which may not be **GBGF- I systems**.

For **GBGF- I** systems that have a source of continuous power, like wind and solar power systems, it is essential that an independent fast acting energy store is used inside the system to ensure the correct delivery of the **RoCoF response power** and to avoid the "**Double Frequency Dip**" effects produced by the designs of some existing static **Power Converters**

This document does have data on a limited number of technical features, that are not essential abilities of a **GB Grid Forming Converter**. These non-essential features have been included as they may only be required for one or more **NGESO Commercial Service(s)**.

The simplified block diagrams in this document**,** can be freely used, and have been provided to assist the workgroup members in the understanding of a possible solution for a **GBGF- I** system design.

Each supplier is totally free to develop their own technology to meet the **GBGF** technology specification and requirements including block diagrams, simulations and hardware with any relevant **IPR** protection.

Any data released by a supplier to **NGESO** on their **GBGF** technology, including block diagrams, simulations and hardware with be treated as strictly confidential.

The **VSM0H** technology is included in the Grid code as it meets all the **GBGF** technology requirements and this will be beneficial to **NGESO**.

7. Revised operating limits.

To have a comprehensive guide to **GBGF- I** systems the following seven new definitions and values were proposed in the previous version of this guide:

- **Phase jump angle limit** = 5 degrees for system operation without reaching the **Peak Current Rating** value when operating at the rated voltage. See **Sections 8.9 & 8.10** for more details.
- **Phase jump angle withstand** = 60 degrees for system operation without tripping at the rated voltage as this is a typical **NGESO** reclosing setting. Larger phase jump angles will occur during Grid short circuit faults. See **Sections 8.9 & 8.10** for more details.
- **Phase jump angle rating** which is the angle that a system provides that can be equal to or larger than the **Phase jump angle limit**.
- **Standard maximum Damping Factor** (Zeta) = 1.0 per unit for testing the control system.
- **Standard minimum Damping Factor** (Zeta) = 0.1 per unit for testing the control system.
- **Range of Inertia H values =** 0.2 to 25 for testing the control system, ***lower limit now revised.***
- **Grid oscillation value** = 0.05 Hz peak to peak at 1 Hz for rating the **defined Damping Active Power**.

These seven items are shown at these values in this document but these definitions and values need to be reviewed by **NGESO** which could result in changed definitions and values.

There are two existing definitions relating to the operation of **GBGF- I systems:**

- **RoCoF operating limit** = 1.0 Hz / s for system operation without reaching the **Peak Current Rating** value when operating at the rated voltage which is the proposed maximum value of the **RoCoF** in the AC Grid.
- **RoCoF withstand limit** = 2.0 Hz / s for **GBGF**- I systems system operation without tripping at the rated voltage to provide an operating margin and to also line up with **ENTSO-E**.

8. An overview of GBGF technology.

8.1. Typical GBGF circuits.

Figure 8.1.1 shows a comparison of a synchronous generator, on the part of diagram, which would have its own natural **GBGF-S** capability and a **GBGF – I** systems on the bottom part of diagram.

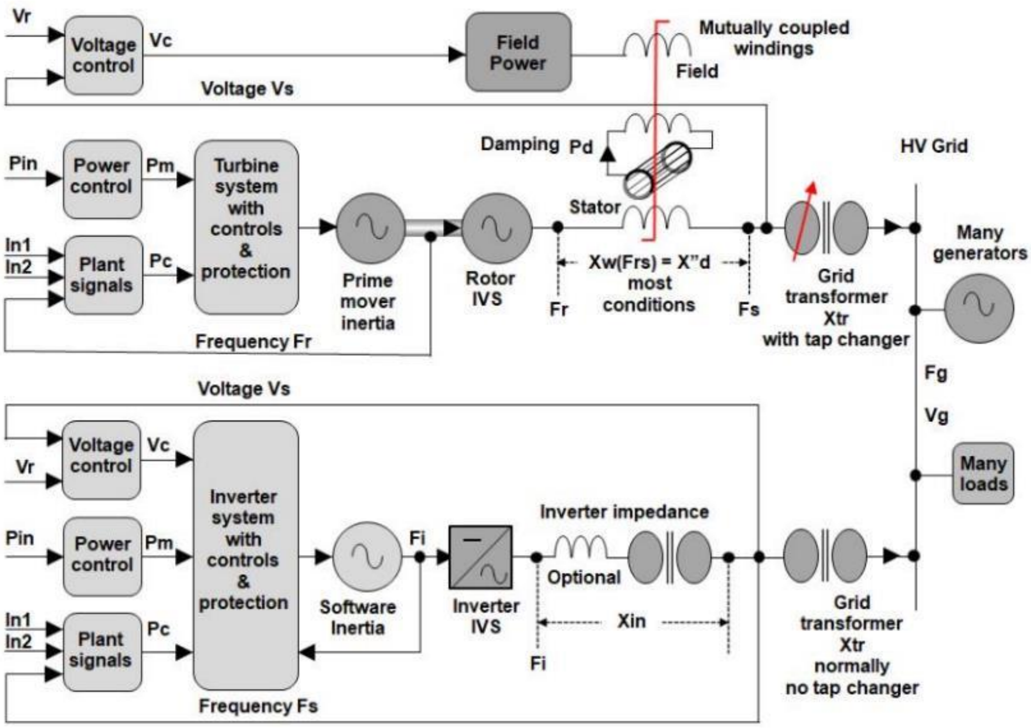

Figure 8.1.1 GBGF-S and GBGF- I circuits.

8.2. The Key features of GBGF- I systems for Normal Operating Conditions:

- That it operates, for the Normal Operating Conditions defined in **Section 8.3**, in the same way as a synchronous generator to maintain the stability of the Grid when a synchronous generator is replaced by a **GBGF- I** systems of the same **MVA** and **H** rating.
- That it operates as an **Internal Voltage Source** "**IVS**" behind an effective reactance, over a wide frequency range from near DC to over 1 kHz.
- The **Grid Forming** Plant can change its delivered steady state real power by varying either the voltage or phase of the **GBGF- I's Internal Voltage Source** but only at a low bandwidth below 5Hz when it is working under the Normal Operating conditions listed in **Section 8.3**.
- That the fundamental voltage component of the **IVS** is a set of balanced 3 phase positive sequence voltages that only change slowly, that operate synchronously with the Grid and do not immediately react rapidly to changes in the phase of the Grid for the Normal Operating conditions.
- That the **IVS** supplies **Phase based Phase Jump Active power, RoCoF response power** and **Damping Active Power** in the same way that a **GBGF-S** system operates, see **Figure 8.2.1** that shows the responses of five synchronous generators for a Grid power loss.
- The **IVS** also supplies reactive power for changes in the AC supply voltage.
- That the initial production of the **Phase based powers** are produced without any actions by the Inverter's control system.
- That it supplies the **RoCoF response power** by using a software feature that causes the frequency of the inverter's **IVS** to fall / rise when the inverter is supplying output / input AC power. This is shown diagrammatically as the **software inertia** on **Figure 8.1.1** and this action can be implemented by the appropriate features in a supplier's **GBGF- I** system.
- That it has the option of a Black start ability for all types of power generation.

The Grid code contains several defined **Control based power** responses that must only be produced with a bandwidth below 5 Hz. This is to avoid producing damaging resonances in other User's Plant connected to the System, notably synchronous generators, for example see Grid code CC.A.6.2.5.5.

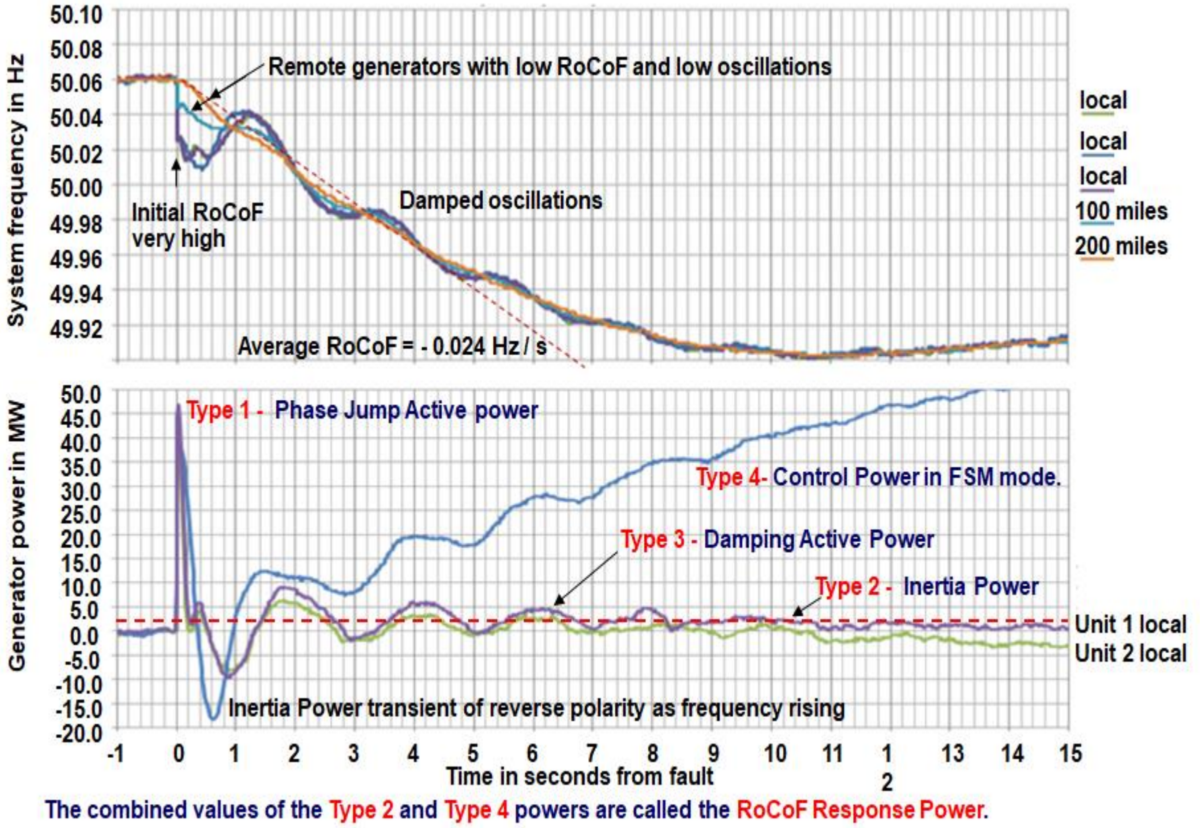

Figure 8.2.1. Site data for 3 local and 2 remote synchronous generators.

The unit 3 is supplying a high value of extra power that is in line with the revised definition of **RoCoF response power.** The figure also shows the effects on the **RoCoF** at local and remote zones.

The main features of the **Figure 8.2.1** are:

- There is a short pulse of **Phase Jump Active power** at the start of the transient.
- The **Initial Grid RoCoF** is very fast for the three local generators. The actual initial frequency and **RoCoF** data has probably been affected by the phase jump as it has a frequency step.
- The two remote generators only experience the **Average Grid RoCoF** of – 0.024 Hz / s.
- The three local generators have a frequency oscillation to align with the **Average Grid RoCoF**.
- This produces the **Damping Active Power** that reduces the oscillations.
- Two local generators produce the **RoCoF response power** that reduces as the **RoCoF** reduces.
- One of the local generators is also producing an increased power as it is operating in **FSM** mode.
- **Figure 8.2.1** shows that all three **Types** of **Phased based power** occur during this transient.
- **Figure 8.2.1** also shows why it is essential to consider the Grid's Inertia on a local zone basis as well as on a total Grid basis as this causes the faster **Initial Grid RoCoF** and the slower **Average Grid RoCoF.**
- **Figure 8.2.1** also shows that it is essential to have a frequency recording system operating on a mains cycle basis that is not affected by Grid phase jumps.

When a major Generation or Demand loss occurs (which also tends to coincide with a transient) and the Grid's frequency starts to recover, **GBGF-S** systems absorb energy to restore their stored energy which delays the recovery.

For **GBGF-I** systems, the stored energy is specified to provide the full **RoCoF response power** for Grid frequency transients for either 50.5 Hz down to 47 Hz or from 49.5 Hz to 52 Hz this is to ensure the correct operation of the Automatic Low Frequency Demand Disconnection Scheme and the Generator Trip Protection for an extreme worst-case fault. This is vitally important so that the full benefits of the low frequency demand disconnection scheme can be realised, otherwise there is the risk of all the demand being tripped after the Grid frequency has collapsed. The actual required energy does not depend on the actual RoCoF rates and a system test is illustrated on **Figure 8.13.1**.

This means that for more normal **RoCoF** faults, with a smaller frequency change~~fall of less than 1 Hz/s~~, that the **GBGF- I** systems inherently have sufficient energy to provide the **RoCoF response power** for up to 2 subsequent~~,~~ or more~~,~~ normal **RoCoF** faults. **GBGF- I** systems ~~and~~ can also delay the recharging of their energy stores until the Grid's frequency has recovered also shown on **Figure 8.13.1**.

This enables the **GBGF- I** systems to export active power to assist in recovering the Grid's frequency which is a significant benefit of **GBGF- I** systems.

For additional protection a **GBGF- I** systems have a limit on the importing of power with a type of **Droop control** starting at 49.5 Hz and reaching zero imported power at 48.9 Hz. see **Figure 8.2.2.**

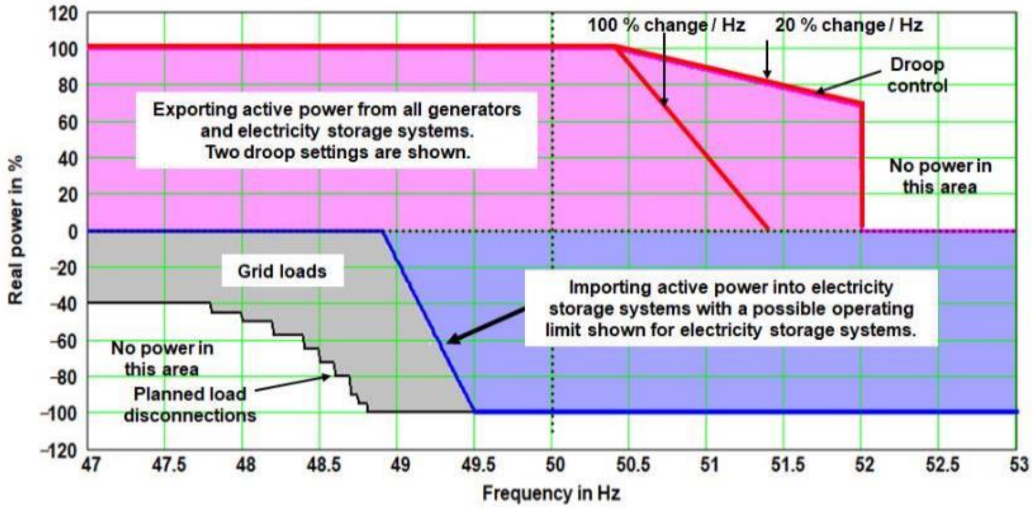

Figure 8.2.2. Proposed power limitation Droop profiles.

All of these important features ensure that for a **GBGF-I** system, operating under Normal Operating Conditions, will produce very stable operation that eliminates the instability risks present in the technology used in existing static **Power Converters**.

The **Figure 8.2.3.** is a summary of the key benefits of **GBGF** technology.

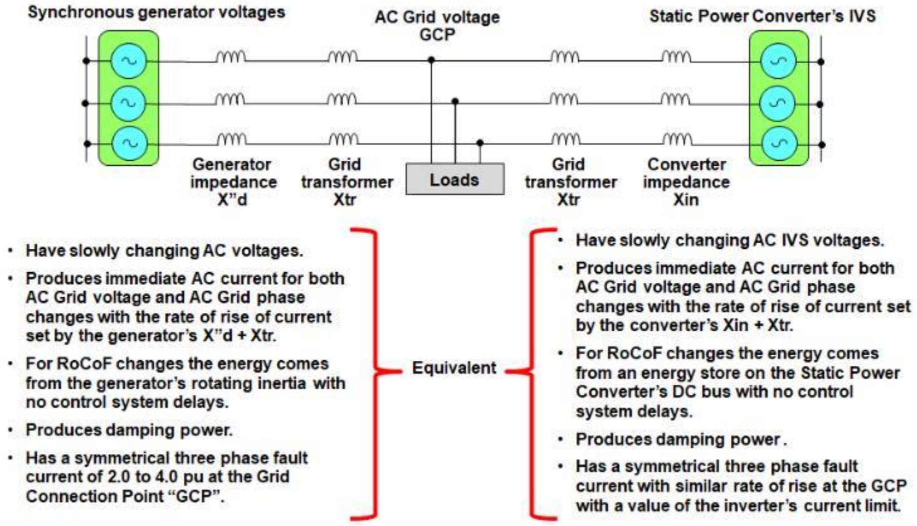

Figure 8.2.3. Summary of GBGF-S and GBGF- I technology.

The system's operations for abnormal conditions are defined in **Section 8.4.**

8.3. The Normal Operating Conditions for GBGF- I systems are defined as:

- A voltage magnitude within the standard range defined in the Grid code.
- A voltage unbalance ratio within the standard range defined in the Grid code, See **Note 1.**
- A frequency within the standard range of 47 Hz to 52 Hz as defined in the Grid code.
- A power factor within the standard range defined in the Grid code.
- Being able to supply the required **RoCoF response power** for any **RoCoF** below 1 Hz / s which is the maximum Grid operating value in a local zone as defined in the Grid code. A **GBGF- I** system also has to remain operational up to a withstand value of 2 Hz / s.
- The required **RoCoF response power** is given by **Rated H value x Installed MVA / 25.**
- Being able to supply the **defined Damping Active Power** for the defined **Grid oscillation value** of 0.05 Hz peak to peak frequency variation at an oscillation frequency of 1 Hz.
- For **RoCoF** events below 1 Hz / s the system has to be designed to produce the rated **RoCoF response power** plus the **defined Damping Active Power** at the same time without tripping.
- Being able to supply the **Phase jump angle limit** power for Grid phase jump angles at the **Phase jump angle limit** of 5 degrees. A **GBGF- I** system design also has to remain operational up to the **Phase jump angle withstand** value of 60 degrees.
- Operating with a constant response when operating at a current below the **Peak Current Rating** condition. The **Peak Current Rating** will be the larger of:
    - The rated **RoCoF response power** plus the **defined Damping Active Power**.
    - The required **Phase jump angle limit power**.
    - The maximum current defined by the supplier, see **Figure 9.3** for an example.
- Being able to recover to normal operation after multiple repetitive **Grid Fault Ride Through** "**GFR**" operations as defined in the Grid code, see ECC.6.3.15.10 (iii).

Note 1 for unbalanced voltages:

- If there are unbalanced Grid voltages, unbalanced currents will flow in the **IVS** of the **GBGF- I** system, this can inherently produce negative sequence currents. **Enstore** estimates that this equates to a 2 % extra current rating for a system with 30 % impedance.
- Each phase of a **GBGF- I** system will supply **Damping Active Power** current to damp Grid disturbances.
- The **software damping** of **GBGF- I** systems provide good damping of Grid disturbances.

8.4. The Abnormal Operating Conditions for GBGF- I systems.

For Grid voltages below the standard range the operation changes to provide the well proven **GFR** operation and this requires the ability to limit the effects of unbalanced voltages including a single-phase and three phase voltage short circuits.

This is needed to provide a technology that enables 100 % of renewable energy to be used in the Grid with reliable operation for both normal and fault conditions.

For a deep voltage dip the system will supply the contract **Peak Current Rating** starting within less than 5 milliseconds and at a level defined in **Section 8.10**.

In the initial issue of the proposed Grid code for the **Peak Current Rating** produced by voltage dips the aim was **to not change** the phase angle of the **IVS,** but subsequent studies have shown that this is not viable for all voltage dip conditions as detailed in **Section 8.10**.

For the **GFR** condition the Grid code also requires the ability to operate with a number of **GFR** events that occur in a short time period to operate with multiple trips and reclose actions.

If a combination of power for **RoCoF response power**, **Phase Jump Active power** and **Damping Active Power** occur simultaneously, that require a **Peak Current Rating** action, there is no need to prioritise these powers as they all produce real power.

There are four **Operating Modes** for a **GBGF- I** system:

8.4.1. Operating Mode 1. This is for a Grid voltage above 0.9 pu and not at the **Peak Current Rating**.

- This provides a linear GB **Grid Forming** ability.
- ECC.6.3.8.4.1 has a requirement that Each type C and type D Onshore Power Park Module, Onshore HVDC Converter and OTSDUW Plant and Apparatus shall be fitted with a continuously acting **Automatic control system to provide control of the voltage "AVC"** at the Grid entry point or user system entry point.
- In **Operating Mode 1** the **AVC** will constantly adjust the supplied reactive current.

8.4.2 Operating Modes 2. This is for a Grid voltage above 0.9 pu and at the **Peak Current Rating**.

- This will normally be caused by a large rapid Grid phase jump. This will normally need a change of the angle of the **Internal Voltage Source** to avoid a trip and the system will then rapidly resumes normal **Operating Mode 1** operation.
- In **Operating Mode 2** will constantly adjust the supplied reactive current.

8.4.3 Operating Modes 3. This is for a Grid voltage below 0.9 pu but not at the **Peak Current Ra**

- This can happen with systems with a high value of the **Peak Current Rating,** e.g.150 %.
- This requires the magnitude, frequency and phase of the **IVS** to be changed to respond to phase jumps.
- In a synchronous generator the **AVC** will act to boost the generator's excitation, primarily to maintain the short circuit current, but this action is not needed for a **GBGF- I system** as it produces an incorrect action as the **IVS** voltage must fall.
- In **Operating Mode 3** the **AVC** action is suspended and the control signal of the **AVC** is stored for future re-use.

8.4.4. Operating Mode 4. This is for a Grid voltage below 0.9 pu and at the **Peak Current Rating**.

- This requires the magnitude, frequency and phase of the **IVS** to be changed. This is needed for the **IVS** to produce dominantly reactive current that then does not change the frequency of the **IVS**. This is to have the same action compared with a synchronous generator, see **Section 8.10.**
- In **Operating Mode 4** the **AVC** action is suspended and the control signal of the **AVC** is stored for future re-use.

8.4.5. Operation when returning to Operating Modes 1 or 2.

- The **AVC** action is allowed to restart with a smooth change from the previously stored value to the new control value.
- This is to give a smooth transition when resuming operation in **Operating Modes 1 or 2**

8.5. Differences of GBGF-I systems from existing static converter technology.

The differences include:

- Avoiding the use of a Phase Locked Loop, or similar technology, that traditional inverters use to give fast changes in the converters phase to match changes in the Grid's phase.
- Avoiding the use in Normal Operating Conditions of a continuously operating high bandwidth D + Q loop, or similar technology, to maintain constant output power when the Grid's phase changes. These have been responsible for instability problems on real wind turbine systems.
- To accept and withstand the unbalanced currents that occur due to the listed Normal Operating Conditions.
- The ability to accept and withstand the Grid harmonic currents that can occur due to the listed Normal Operating Conditions. In future, Grid harmonic voltages can occur from 50 Hz to over 250 kHz in frequency regions with limits that are not defined in most existing standards.

  The IEC 60533 Electromagnetic Compatibility Standard in Table 3 does give a viable guide to allowed harmonic voltages in this frequency region. If internal harmonic filters are used they should have sufficient passive damping to operate with this range of harmonic conditions.
- A totally new inverter control system to implement the feature of **software inertia** and **software damping**. **NGESO** cannot give a definitive guide on how to implement these features as the supplying company must use its own individual design with the appropriate **IPR** protection. There are companies and academic institutions that can give advice on implementing these features.
- To have the option of a changed converter with a **Peak Current Rating** value that can be significantly increased to meet the requirements of a specific **NGESO Service**, see **Figure 9.3.**
- A supply of sufficient power and energy from an energy store to meet the specified bi-directional Inertia interface power requirements. This is typically a delivered energy equal to 20 % of the equivalent **GBGF-S** system as a **GBGF- I** system only has to work over the 47 to 52 Hz Grid frequency range. The size of the energy store will be larger depending on the design.
- Having the power available for **RoCoF** events below 1 Hz / s to produce the rated **RoCoF response power** plus the **defined Damping Active Power** without tripping.

  The use of stored energy on the rotating blades of a wind turbine has been fully investigated to see if they provide a viable energy store but this is not a viable solution for two reasons:
  - If exporting **RoCoF response power**, the reduction in the speed of the wind turbines then results in a reduction, for a time, in the follow up steady power that can be delivered which (under certain conditions – particularly when operating close to rated wind speed) can result in significant falls in output power resulting in a double frequency dip. A correction to address this issue either requires a large increase in the cost and rating of the required **Primary response power** or spilling wind prior the disturbance. The only real way to address this issue through a wind farm is either to spill wind pre fault or install a storage facility at site.
  - If importing the **RoCoF response power** the required increase in the speed of the wind turbines is unlikely to be available.

Due to these changes, the standard control system for a new **GBGF-I** system will be required to pass a new set of performance requirements, see **Section 8.13**. This standard control system can then be used with a range of inverters at differing rating for different **NGESO** projects.

For **GBGF- I** systems the software includes a feature of a **software inertia** model, at the contract defined **H** value. The frequency of the **software inertia** falls / rises, at a rate depending on the **H** value, when the **RoCoF response power** is being supplied / absorbed. This is to have an equivalent action to a **GBGF-S** system.

8.6. System design parameters for GBGF- I systems:

- The system's response shown on a Network Frequency Perturbation "**NFP"** plot does depend on the supply impedances and for **GBGF- I** systems the **Xtr** and **Xin** impedances are constant versus the operating conditions and are easily obtained from the relevant supplier.
- For **GBGF-S** systems the **Xtr** impedances is constant versus the operating conditions but the **Xw(Frs)** stator impedances do vary with the operating conditions due to the actions of the three mutually coupled windings see **Figure 8.1.1.**
- For **GBGF-S** systems, operating in the Normal Operating Conditions, any changes in the Stator winding current is mutually coupled to the Damper winding and this combination gives the **X"d** impedance and the fast T"d time constant.

- For **GBGF-S** systems operating with a short circuit fault, the current in the damper winding rapidly decays to zero and then the Stator winding current is mutually coupled to the Field winding and this combination gives the X'd impedance and the much slower T'd time constant. This action causes the field current to reduce which then reduces the synchronous generator's EMF and the stator current falls.

  Many publications represent this as being equivalent to an increase in the stator windings impedance but this is not a correct explanation.

- For **GBGF-S** systems due to the mutual coupling, the stator winding impedance **Xw(Frs),** on **Figure 8.1.1**, does increase at very low values of the rotor to supply slip frequency **Frs** but for all Normal Operating Conditions the stator winding impedance **Xw(Frs)** is equal to the **X"d** and **T"d** values that are easily obtained from the relevant supplier.

- In this document, the **Damping Factor** value has the identical meaning as the **Damping Ratio** value.

- For **GBGF- I** systems the **software inertia** model also requires a **software damping** feature. This does not require any real power so a high **Damping Factor** can be used compared with synchronous generators.

- The **NGESO** standard is that the frequency **Droop** (as required for the Frequency Governor) is defined in CC 6.3.7 (ii) or ECC.6.3.7.3.3(i) as being site set on site in the range of 3 to 5 %. A 3% **Droop** is a 100 % power change for a 3% change of 50 Hz, which is a 1.5 Hz frequency change. For Power Park Modules the voltage control system is set to a Slope of between 2 – 7% with a default value of 4% (CC/ECC.A.7).

- The range of **Droop** settings, when used, are shown on **Figure 8.6.1.** and do not affect the damping of the closed loop system.

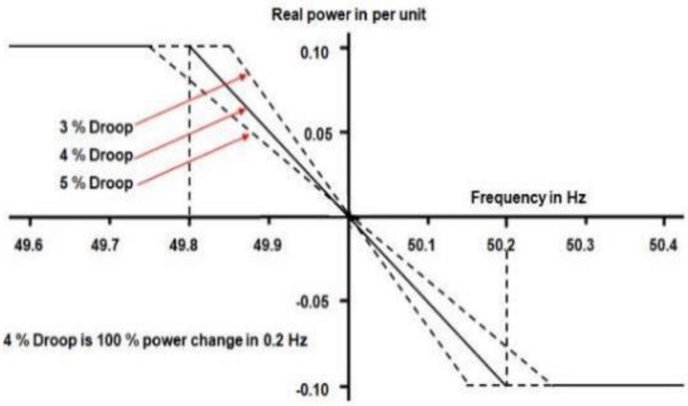

Figure 8.6.1. Droop control.

- The **Hybrid Droop control** shown on **Figures 5.5** and **5.6** enables the **NGESO** droop value to be used at low frequencies and the **RoCoF Response** value to be used at higher frequencies.

- For a **GBGF-I** system for a given contract design it will have a **Smallest Damping Factor** that is defined by the losses in the AC supply system.

- For **GBGF- I** system it should have a parameter that can adjust the **Damping Factor** at the rated **H** value in the range of at least the **Standard minimum Damping factor** of 0.1 per unit up to the **Standard maximum Damping Factor** of 1.0 per unit, when any control features that affect the closed loop damping, like the **PSS control**, are set at zero.

- The associated **NFP** plots are used to show the systems operation but this is for a system operating on its own without any consideration of the Grid's requirements.

- To have standard data for comparison the **Damping Factor** used for any initial **NFP** plots is 0.7.

- For a **GBGF- I** system a high **Damping Factor** gives a more stable system but with a slower response compared with a design that has a lower **Damping Factor.** The contract defined **Damping Factor** used for a given site application will be agreed between the supplier and **NGESO**. Hence, there is a tradeoff between the rate of active power injection and damping of the injected response. **Figure 8.8.1** shows a typical well Damped fast response.

- **The** expert group that is going to produce the "**NFP Best Practice Guide or Equivalent**" will be issuing a guide that includes data on equivalent **Damping Factor** and **NFP** plots.

8.7. Supply of reactive current by GBGF-I systems:

- The **GBGF- I** systems are normally designed to automatically and rapidly deliver the export and import of reactive current over the full operating range defined in the Grid code by having a sufficient voltage margin available, see **Figure 8.7.1**.
- This does not normally apply to **GBGF-S** systems as due to their limited voltage margins; they have to carry out a tap change to deliver an increased magnitude of exporting reactive current that does require time for this to occur.
- For future **GBGF- I** systems the use of tap changers should be allowed if they provide an economic advantage to the Capex cost of the systems, also see **Section 10.2** for extra data on optimizing transformer rating and design for **GFR** conditions.

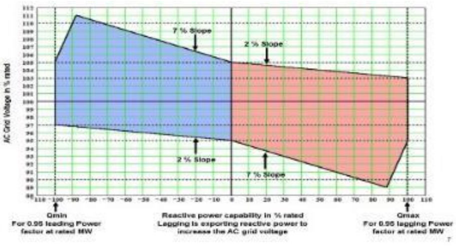

Figure 8.7.1. Required operational zone for reactive power.

8.8. Bandwidth requirements for GBGF- I systems.

The Bandwidth for a typical well damped system with a 5 Hz control Bandwidth is shown on **Figure 8.8.1.**

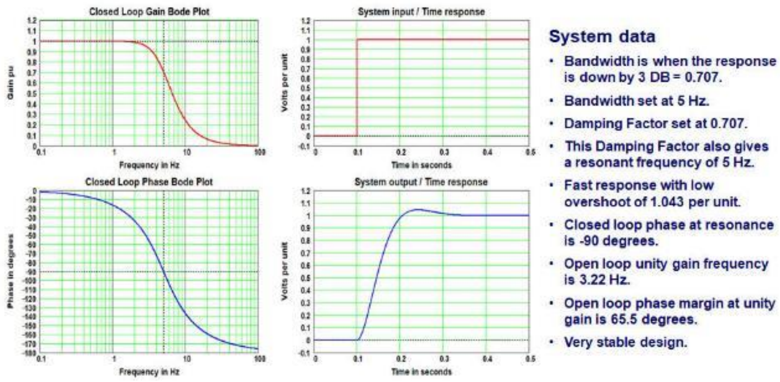

Figure 8.8.1. Typical responses of a 5 Hz bandwidth system.

This allows for low amplitude changes to occur above 5 Hz but would be very low by 20 Hz. Certain control systems in a **GBGF- I** system need to have a 5 Hz response to align with the Grid code specifications for example CC/ECC.A.6.2.5.5 and CC/ECC.A.7.2.5.2.

In the case of **CC/ECC.A.6.2.5.5** The Power System Stabiliser shall include elements that limit the bandwidth of the output signal. The bandwidth limiting must ensure that the highest frequency of response cannot excite torsional oscillations on other plant connected to the network. A bandwidth of 0 - 5Hz would be judged to be acceptable for this application.

The **Figure 8.8.2** is a system diagram for a **GBGF- I** system with **PSS control**.

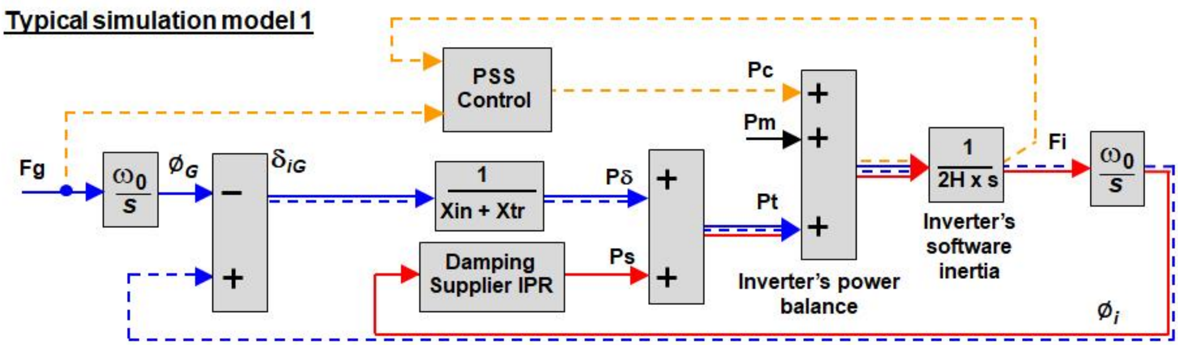

Figure 8.8.2. GBGF- I system with PSS control

This shows the control system for a system with a Power System Stabilisation System "**PSS**" **control** that operates on the difference between the Grid frequency "**Fg**" and the inverter frequency **"Fi**".

The **PSS control** acts to add damping to oscillations in the AC Grid system and the software function will have a bandwidth "**Fpss**".

The **PSS control** will also add damping to the closed loop system around the inverter's software function provided that the bandwidth **Fpss** is active at the resonant frequency of the closed loop system.

The **PSS control** does act to add extra current for an **NFP** plot input test at the frequencies where the bandwidth **Fpss** has a significant gain. This causes a change in the shape of the **NFP** plot at the frequencies below **Fpss.**

Many **GBGF-S** systems with **PSS control** systems have a slow response that does not provide extra damping of the closed loop system.

For the **Damping factor** of the closed loop system:

1. The minimum value is set by the AC terms **Xin** + **Xtr**.
2. The **PSS control** can add extra damping to the closed loop system**.**
3. The normal operating value is set by the item 1 plus the **Damping suppliers IPR** function and the **PSS control**.
4. The **Ps** term is given by the damping provided by the "**Damping supplier IPR**" function block. The **Figures** shows one circuit that can supply the damping, this is the circuit used by the **Enstore's damping IPR** to produce the **NFP** plots, but any viable circuit design can be used.

The **Figure 8.8.3** is a system diagram for a **GBGF- I** system with **Droop control**.

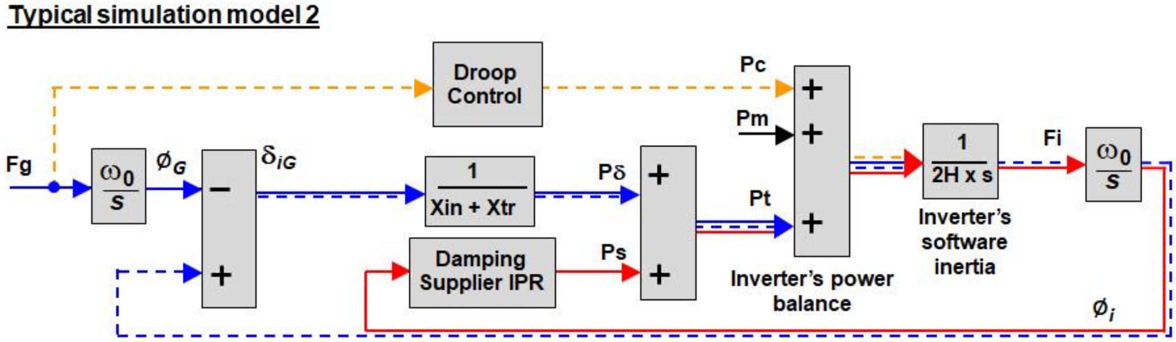

Figure 8.8.3. GBGF- I damping for a system with Droop control

This shows the control system for a system with a **Droop control** that operates based only on the Grid frequency "**Fg**".

The **Droop control** acts to add extra power when the AC Grid frequency changes and the software function will have a bandwidth "**Fdroop**".

The **Droop control** does not add damping to the closed loop system around the inverter's software function.

The **Droop control** does act to add extra current for an **NFP** plot input test at the frequencies where the bandwidth **Fdroop** has a significant gain. This causes a vertical shift on the **NFP** plot at the frequencies below **Fdroop.**

For the **Damping factor** of the closed loop system:

1. The minimum value is set by the AC terms **Xin** + **Xtr**.
2. The normal operating value is set by the item 1 plus the **Damping suppliers IPR** function.
3. The **Droop control** cannot add extra damping to the closed loop system.
4. The **Ps** term is given by the damping provided by the "**Damping supplier IPR" function block**. The Figures shows one circuit that can supply the damping, this is the circuit used by the **Enstore's damping IPR** to produce the **NFP** plots, but any viable circuit design can be used.

The revised data on the systems Bandwidth for operating in the linear mode is:

- Almost all **NFP** gain plots have a maximum peak value that occurs at the resonant frequency of the closed loop system. If the **NFP** plot has a very high **Damping Factor** the gain peak may not occur and the resonant frequency is then defined by the frequency at which the **NFP** phase plot has a value of 180 degrees.
- This peak defines the maximum frequency at which the **IVS** associated system responds to changes in the phase angle of the AC Grid.

- The maximum resonant frequency of an **NFP** plot is limited to less than 10 Hz to provide a viable response to changes in the phase angle of the AC Grid. In closed loop systems it is normal for the inner control loops to have a faster response than the outer slower control loops. This then ensures that the slower outer loops can implement the desired maximum 5 Hz response times.
- When sudden changes occur in the phase angle of the AC Grid a **GBGF- I** system the **IVS** will inherently produce an AC supply current with transient harmonic components that can exceed 1000 Hz.
- The minimum resonant frequency of an **NFP** plot is limited to 1 Hz to avoid creating new very low resonant frequencies in the AC Grid by the **IVS** and to avoid possible problems with existing **GBGF-S PSS control** systems by producing a different phase shifts below 1 Hz in the AC grid.
- The **NGESO** existing requirements for a maximum of a 5 Hz response will continue to apply to all control features. This is interpreted to mean that the output current of a **GBGF- I** system will not produce continuous AC currents in the with harmonics above 5 Hz when the AC Grid is operating in stable conditions.
- A **GBGF-I** system will produce an output current with harmonics to damp AC Grid oscillations that exist. The AC Grid oscillations are normally below 5 Hz which complies with the **NGESO** existing requirements for a maximum of a 5 Hz response.
- To provide a good damping response, at up to 5 Hz, the internal operation bandwidth of the **GBGF-I's** control software needs to operate much faster than 5 Hz and has no bandwidth limitations apart from meeting the maximum resonant frequency of an **NFP** plot limit of 10 Hz.
- There can be internal variations in the power **Pm** from the primary energy source that will cause low frequency continuous harmonics in the AC supply. A good example is a wave energy converter. These power harmonics in the AC supply are acceptable provided they are lower than the limits set in G5 / 5 for all harmonics including Inter-harmonics and the flicker requirements set in P28.
- The AC input impedances of a **GBGF- I** system will often contain a harmonic filter circuit that will reduce the levels of any exported harmonics of the **IVS** to the standard for harmonic emissions.
- The harmonic filter circuits will inherently act to absorb harmonic currents from any pre-existing harmonic voltages in the AC Grid from other sources. This has been shown to be beneficial on may projects and these harmonic filter circuits must be continuously rated to absorb harmonics at all the defined harmonic frequencies in the emission standards.

  In addition, these harmonic filter circuits will have one or more internal resonant frequencies and the passive damping in the harmonic filter circuits must be designed to avoid increasing the pre-existing harmonic voltages in the AC Grid from other sources.

This design will produce the change in frequency of the Inverters **software inertia** due to the Pt power when **RoCoF** events occur using the bandwidth of the loops listed above. This keeps the system synchronised to the Grid.

The **NFP** data defines the characteristics of a given **GBGF- I** design independent of the Grid and a guide to understanding the **Damping Factor** from a **NFP** plot will be issued by **NGESO**.

A **GBGF- I** system can have a very well Damped **IVS** unlike the **IVS** of **GBGF-S** systems that can be under damped. This ability does help to stabilise the local Grid.

The **Control based** real **damping power** provided by a **GBGF- I** system can also be increased to suit the needs of a particular Grid and as the **GBGF- I** system have a good Bandwidth they can provide good additional damping.

The acceptance test data is being produced that will define the expected operation for within Normal Operating Conditions and for operation outside the Normal Operating Conditions. Some of these tests require the application of specified Grid voltage waveforms and there are test companies/test institutes that have these abilities.

The revised data on the systems Bandwidth for operating outside the linear mode is:

The control system of the **IVS** has to have the ability to rapidly change the amplitude and phase of the **IVS** to maintain the system in an operating condition either at or below the to the contract's **Peak Current Rating** value.

This includes having the ability to operate with unbalanced AC supply voltages as shown on **Figure 10.2.9.**

8.9. Phase jumps in the AC Grid and RoCoF effects in local & remote zones.

Figure 8.9.1 is data from National Grid GC 0079 Grid code Working Group on the 17/10/2017 showing phase changes for a major Grid short circuit fault. Near the fault in a local zone, the phase change was 57.48 degrees but at a low voltage dip away from the fault, in a remote zone, the phase changes rapidly reduced to 20 degrees or lower.

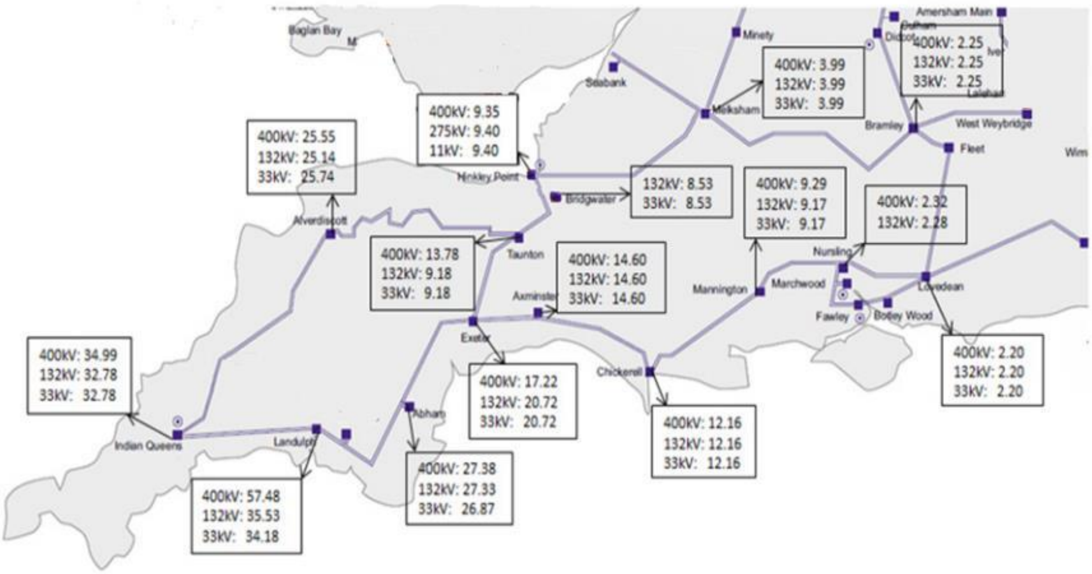

Figure 8.9.1. Measured site phase data for a short circuit fault.

These jumps occur very rapidly near the fault and become smaller with a slower rise time away from the fault due to the distributed impedances and Inertia of the Grid.

For large voltage dip faults, the local synchronous generators are supplying a high level of **Fault Current** but as this is mainly reactive power the mechanical stress levels inside a synchronous generator are reduced compared with a phase jump fault at the normal operating voltage level.

For large voltage dip faults, **GBGF- I** systems will rapidly supply their **Peak Current Rating.**

A large phase jump can occur, in less than one mains cycle, at rated voltage when rapid power changes occur. For example, the trip of a nuclear power station. The defined **Phase jump angle withstand** value is 60 degrees, at rated voltage, but this can produce very high stress levels in synchronous generators at a level that could significantly reduce the generator's life time.

The occurrence of 60 degree phase jumps, at rated voltage, is very rare and many synchronous generators may never experience this transient, and the magnitude of frequent phase jump angles is more likely to be near to 20 degrees at rated voltage for normal Grid transients.

A **GBGF- I** system has as a minimum rating of the 5 degree **Phase jump angle** and will have a proportional current response for lower phase jump angles. For larger phase jump angles, the current will be the **Peak Current Rating**. **Figure 8.9.2** shows the resulting current value for angle changes if they are not limited**.** The use of a minimum **Phase jump angle limit** rating is important to keep a large section of the total Grid operating in linear control for normal Grid transients.

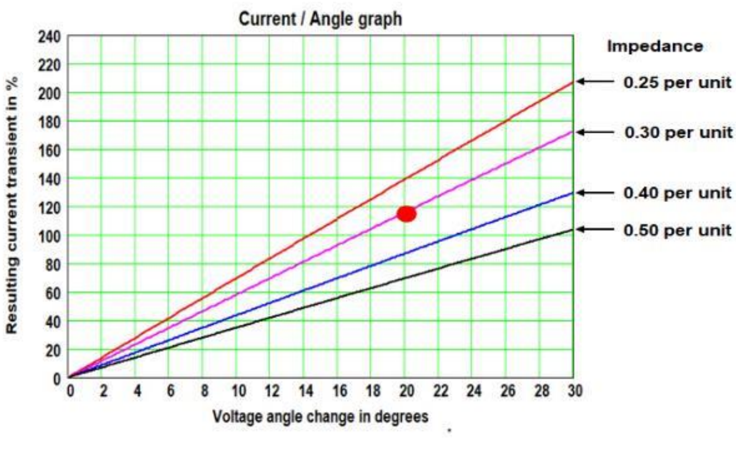

Figure 8.9.2. Resulting Phase Jump Active power versus phase angel change.

During these phase jumps at rated voltage, the ability of **GBGF- I** systems to supply their rated values of real **Phase Jump Active power** within less than one mains cycle is very important in having a stable Grid as listed in Section 0.

This is one of the main reasons for changing from the original **Control based** converter technology to the **GBGF- I** system technology.

The phase jump angles that occur during short circuit faults can have significantly higher values up to 90 degrees.

Figure 8.9.1 shows that the effects of a phase jump decrease away from the source of a disturbance.

An identical effect happens with the observed **RoCoF** rate.

This effect is shown on **Figure 8.9.2** that was recorded by the **EFCC** project.

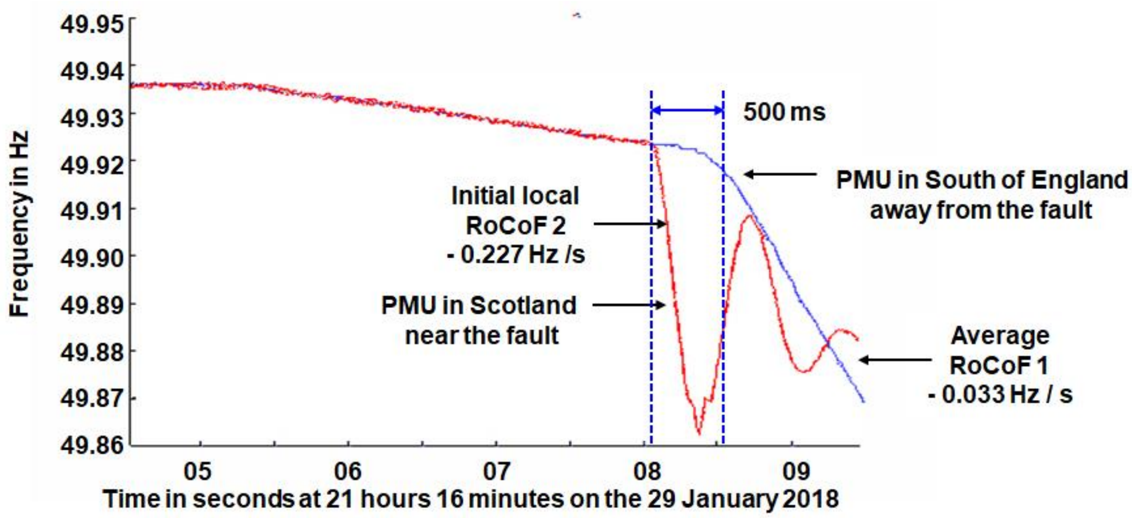

Figure 8.9.3. Resulting RoCoF effects in difference zones.

The observed **RoCoF** rate in the local zone, near to the source of a disturbance, is called the **Initial Grid RoCoF** rate that is determined by the effective **RoCoF response power** plus the **Phase Jump Active Power** in the local zone.

The observed **RoCoF** rate in the local zone then changes in less than one second to become the **Average Grid RoCoF** rate, in the remote zones, is determined by the effective **RoCoF response power** for the complete Grid system, see **Figure 8.9.**

For a viable grid system there are two basic **RoCoF response power** requirements:

1. The available **RoCoF response power** in any local zone must be sufficient to limit the **Initial Grid RoCoF** to 1 Hz / s taking in to account the largest power transient that can occur in a local zone.
2. The available **RoCoF response power** for the complete AC Grid must be sufficient to limit the **Average Grid RoCoF** to a value to be defined by **NGESO** taking in to account the largest power transient that can occur in the complete AC Grid.

The total installed **RoCoF response power** is then defined by combining these effects.

The increasing use HVDC interconnectors in local zones is increasing the need for **RoCoF response power** to be installed in local zones.

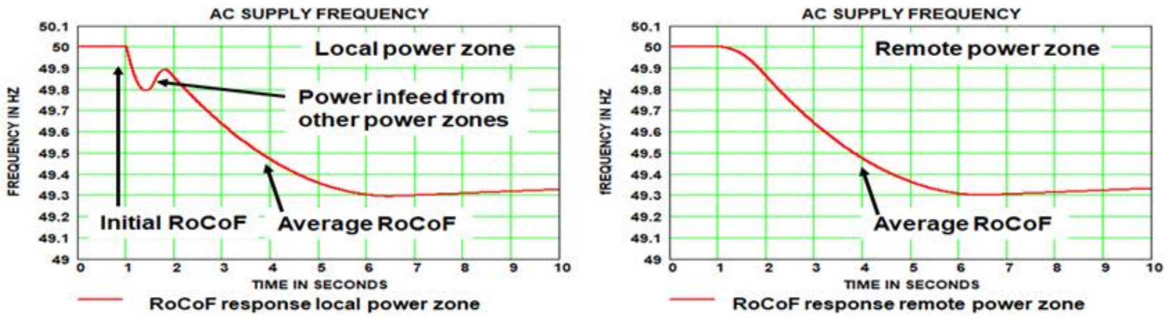

Figure 8.9.4. Resulting RoCoF effects in local and remote zones

8.10. Voltage dips in the AC Grid.

When a deep voltage dip happens in the Transmission system the resulting voltage dips are seen over a wide area as shown on the **Figure 8.10.1.**

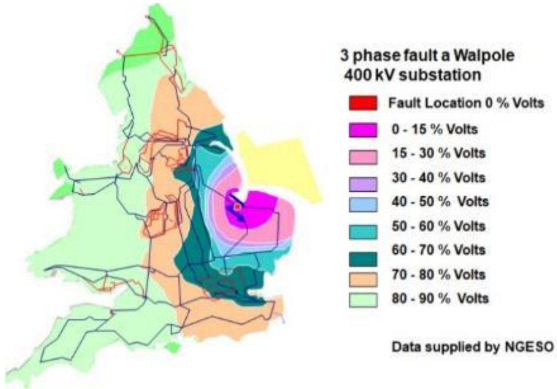

Figure 8.10.1. Measured site voltage dip data for a short circuit fault.

It is essential that all **GBGF- I** systems remain operational during this type of fault to help the Grid recover. The **Figure 8.10.2** shows several typical voltage dip profiles.

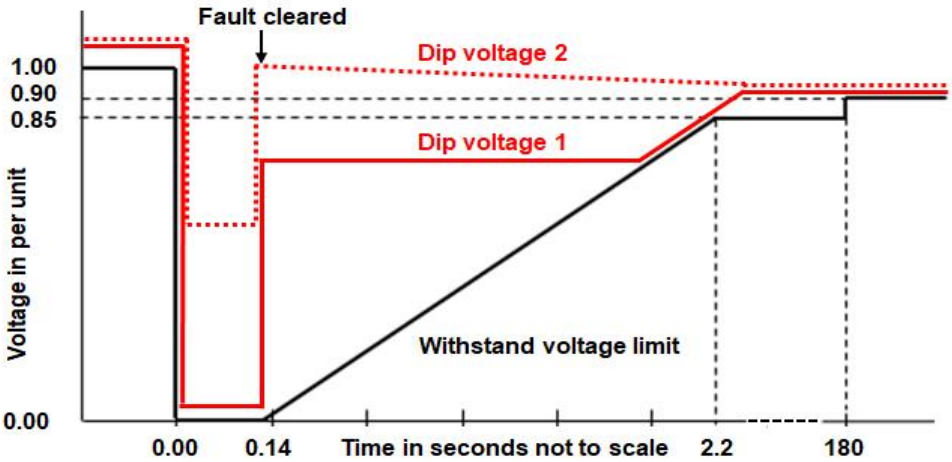

Figure 8.10.2. Allowed voltage limits for Power Park Modules and HVDC.

The solid black line on **Figure 8.10.2** are the voltage values for which the converters must remain above in operation. This **Figure** is based on the **Figure** ECC.6.3.15.6 and other graphs are given in the Grid code.

For correct operation the plant must remain connected and stable for a fault causing the voltage at the connection point to fall to zero for 0.14 s. The diagonal line between 0.14 s and 2.2 s is the withstand voltage limit for the post fault voltage after the fault.

This withstand voltage limit is a function of the topology of the network, and the volume and type of generation connected. If the post fault voltage is below the heavy black line then tripping is permitted.

The Red lines on **Figure 8.10.2** are typical actual voltage dip waveforms:

- The solid Red line is a voltage dip, to a very low retained voltage level, that rises rapidly up to the **Dip voltage 1** when the fault is cleared. The voltage eventually recovers to the normal Grid voltage value.
- The dotted Red line is a voltage dip, to a medium retained voltage level, that rises rapidly up to the **Dip voltage** when the fault is cleared. The voltage then rises above the normal Grid voltage value and eventually recovers to the normal Grid voltage value.

The required **Peak Current Rating** value is shown on **Figure 8.10.3** which is based on and supersedes the **Figure** ECC.6.3.16(a). The shape of the **Figure 8.10.3** depends on the chosen **Peak Current Rating** and the **Figure** shows the data for **Peak Current Rating of 1.0 and 1.*5* pu*.***

The proposal is that the **GBGF- I** specification in ECC.6.3.19 will include a fast fault current injection specification rather than requiring amendments to ECC.6.3.16.

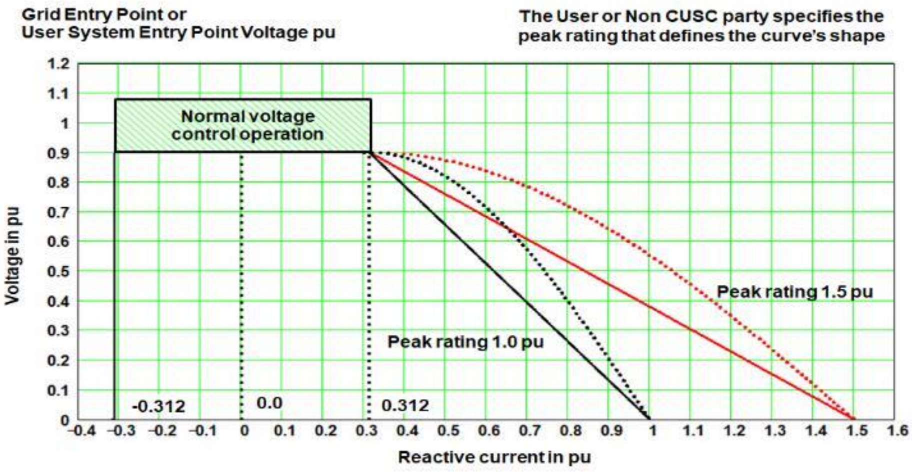

Figure 8.10.3. Required reactive current in % of Peak Current Rating.

On **Figure 8.10.3** the dotted lines are the maximum possible reactive current and the solid lines are the acceptance values. The method of producing dominantly reactive current is shown on the **Figure 8.10.6** for the **VS4** voltage.

The production of a dominantly reactive component of the **Peak Current Rating,** from the **IVS,** is very important as it does not cause the frequency of the **software inertia** to change. This is similar to the action of a synchronous generator.

Suppliers must implement a viable control to achieve this operation and, if needed, **Enstore** has extra data available.

The required rate of rise of the **Peak Current Rating** value is shown on **Figure 8.10.4** which is based on and supersedes the **Figure** ECC.6.3.16(b) & (c). This includes **not allowing** any blocking.

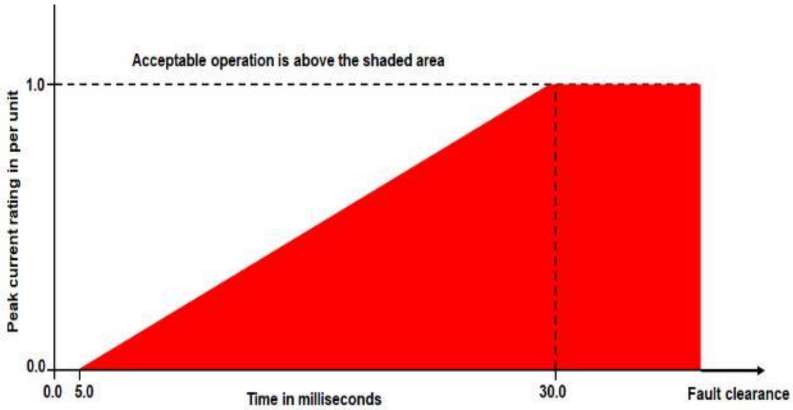

Figure 8.10.4. Required time response of the fault current.

The operational vectors of a synchronous generator are shown on **Figure 8.10.5.**

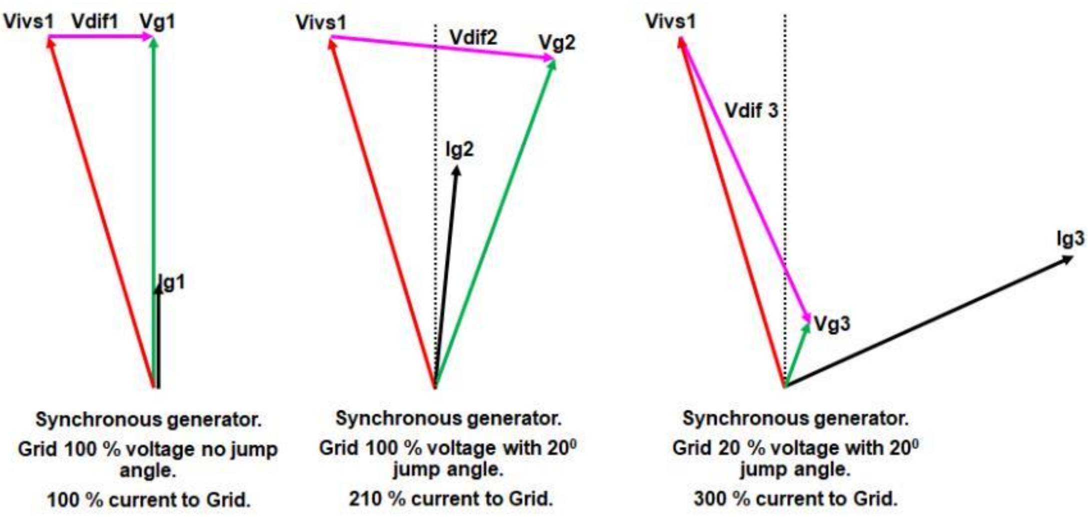

Figure 8.10.5. GBGF-S system fault vectors.

The **Figure 8.10.5** shows three different operating conditions 1 to 3 from left to right on the figure.

- **Condition 1.** The data for the generator voltage **Vivs1** is for the normal operating condition relative to the Grid voltage **Vg1** at 100%. The voltage difference is **Vdif1** that is generating the real power current **Ig1** at 100 %. Allowing for the system's impedances the magnitude of **Vdif1** is 0.3 per unit for rated current.
- **Condition 2**. The data for the Grid voltage **Vg2** is still at 100% but with an immediate 20-degree angle change from **Vg1.** The new voltage difference **Vdif2** is generating the current **Ig2** that is a significantly higher current at 210 % compared with **Ig1.**
- **Condition 3**. The data for the Grid voltage **Vg3** is now with an immediate change to a 20 % voltage plus the 20-degree angle change from **Vg1.** The new voltage difference **Vdif3** is generating the current **Ig3** that is a significantly higher current at 300 % compared with **Ig1.** For this condition the current **Ig3** is dominantly a reactive current relative to the generator's voltage **Vivs1**

The production of reactive current does not change the frequency of the generators EMF.

The corresponding vectors for a **GBGF- I** system are shown on **Figure 8.10.6.**

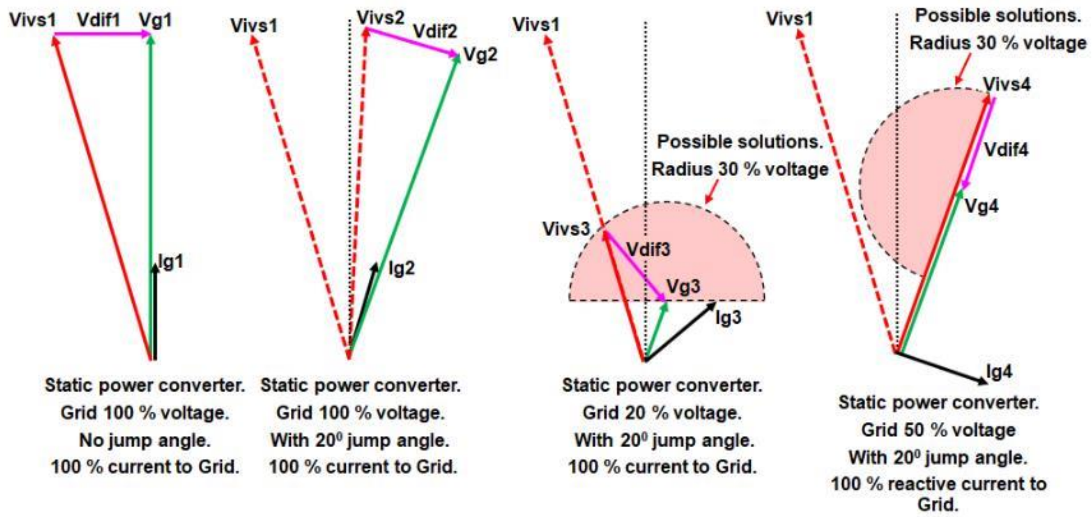

Figure 8.10.6. GBGF-I stems fault vectors.

The **Figure 8.10.6** shows four different operating 1 to 4 conditions from left to right on the figure.

- **Condition 1.** The data for the converter voltage **Vins1** is for the normal operating condition relative to the Grid voltage **Vg1** at 100%. The voltage difference is **Vdif1** that is generating the real power current **Ig1** at 100 %. Allowing for the system's impedances the magnitude of **Vdif1** is 0.3 per unit for rated current.
- **Condition 2.** The data for the Grid voltage **Vg2** is still at 100% but with an immediate 20-degree angle change from **Vg1.** To avoid a trip the converters voltage **Vivs2** has been rapidly rotated so that the new voltage difference **Vivs2** is generating the current **Ig2** that is at the rated current value**.** A different angle change would give the required **Peak Current Rating** value**.**
- **Condition 3.** The data for the Grid voltage **Vg3** is now with an immediate change to a 20 % voltage plus the 20-degree angle change from **Vg1.** To avoid a trip the converter voltage **Vivs3** has been rapidly reduced in magnitude, at the same phase angle, so that the new voltage difference **Vdif** is generating the current **Ig3** that is at the rated current value**.** The pink circle is the locus of the possible values for the **Vivs3**. To give a dominantly reactive current relative to the voltage **Viv3** will need a different angle as indicated by the **Condition 4** data**.**
- **Condition 4.** The data for the Grid voltage **Vivs4** is now with an immediate change to a 50 % voltage plus the 20 degree change from **Vg1**. To avoid a trip the converters voltage **Vivs4** has been rapidly reduced in magnitude but also needs a different phase angle. The new voltage difference **Vdif4** is generating the current **Ig4** that is at the rated current value. For this condition the current **Ig4** is dominantly reactive current relative to the **Vivs4** and **Vg4** voltages.

The concept of aligning vectors **Vivs4** and **Vg4** to give dominantly reactive current from the inverter into the Grid is how the vectors **Vivs** and **Vg** can produce reactive current by the correct angle and magnitude of the **Vivs** voltage vector for different voltage dip conditions.

For the condition with zero value for **VG** a reduced magnitude for the **VS** voltage will still give a dominantly reactive current condition.

8.11. VSM0H designs.

The **VSM0H** technology has been reviewed and the **VSM0H** technology is included in this data as it is compliant with the **GBGF- I** technology.

VSM0H designs can contribute to fault infeed and operate in synchronism with the rest of the system in the same way as a synchronous generator and will supply a defined level of **RoCoF response power.**

This combination of benefits versus cost will be beneficial to **NGESO** for specific applications particularly in supporting the Grid locally during voltage disturbances, limiting vector shift and maintaining an adequate voltage profile during and after the fault. These requirements are important in particular for fault ride through and for the benefits to Transmission and DNO Systems under disturbed conditions.

The **Figure 8.11.1** is the latest summary for the **GBGF** designs.

Comparison of Converter Technology

Capability	GBGF-S	GBGF-I	Conventional
Phase Based Phase Jump Power in one cycle	Yes	Yes	No
RoCoF response Power	Yes	Yes	No
Damping Power	Yes	Yes	Yes
Operate in Synchronism with the System	Yes	Yes	Yes
Contribution to Fault infeed	Yes - High	Yes – As specified	Yes - Limited
Avoids producing current harmonics > 5 Hz	Yes	Yes	No

For the avoidance of doubt GBGF-I includes VSM0H converters

Figure 8.11.1. System comparison data.

8.12. Definition of H.

The proposed definition of **H** is "**The ratio of the stored energy to the continuous MVA rating of a synchronous generator".**

In simulation models the symbol **J** is used for Inertia and **J = 2H**.

This difference is the result of the **J** definition in linear mechanics which is that:

- **Angular torque** = (**Inertia J**) x (**Rate of change of Angular frequency**) but **H** depends on Angular frequency squared.
- For small frequency changes this give the result that a change in **H** squared = 2 x change in **H.**

  The definition of the effective **H** value for systems with **Droop control** is proposed as:

The definition of **H** for **GBGF- I** systems providing **RoCoF** power is:

- **Rated H value = (25 x RP1) / (Installed MVA) .... Equation 4.**
- **RP1 = RoCoF response power in MW produced for a RoCoF transient of 1 Hz / s.**

For full compliance with the **GBGF** specification this level of response power must available for both directions of the frequency change and for the specified frequency range.

8.13. Design of GBGF- I systems and design validation.

The first step in designing a **GBGF- I** system for a specific project is to carry out a preliminary design study and if any requirements require clarification, they can be resolved by discussions with **NGESO**.

It is also possible for a developer to offer a **GBGF- I** capability using plant de-rating – for example a **GBGF- I** functionality could be provided for say 100MW rated plant which is only run at say 80MW, the surplus used to provide the spare energy source.

The supplier can then submit a preliminary **NFP** plot, plus the rating Table data, to **NGESO** for preliminary approval (Tables 1.0 and 2.0 of the Draft Grid code Specification Legal Text) The **NFP** plot being derived from their equivalent circuit.

To design the hardware for a specific **GBGF- I** system the key parameters to be defined are:

1. The systems **MW** and **MVAr** rating to give the **MVA** nominal rating. The MVA nominal rating is the value at 100 % Grid operating voltage, at 1.0 power factor and no extra added power. A higher peak MVA rating will occur for a range of operating conditions.
2. The systems Inertia factor "**H**" based on the **RoCoF response power** produced.
3. The data on the systems AC impedances.
4. If relevant the **NGESO** Balancing (Commercial) **Service** being provided.
5. The value of the stored energy and power that has to be delivered in to the Grid.

These five Key parameters define the system's **IVS** voltage and current ratings for:

6. The **RoCoF response power.**
7. The **defined Damping Active Power.**
8. The real **Phase jump angle limit power.**
9. The inverter's maximum **IVS** voltage for the worst-case condition.

This then enables the following to be calculated:

10. The contract's **Peak Current Rating** that is the larger of:
    - The **RoCoF response power** plus the **defined Damping Active Power**.
    - The **Phase jump angle limit power.**
    - The maximum current defined by the supplier, see **Figure 9.3** for an example.

The contract's **Phase jump angle rating in degrees** based on the **Peak Current Rating**.

11. The contract's actual **Smallest Damping Factor**.
12. The contract values required for the internal **stored power** and **energy**.

This process can then be iterated if any of these values require a change.

The associated control system also needs to be developed as a standalone item suitable for use with a range of inverter hardware and ratings and the two key software parameters are:

13. The range of the **Inertia factor** "**H**" that the system can provide. This should cover the defined **Range of Inertia H values** of **H = 0.2** to **H = 25**.
14. The range of the **Damping Factor** "Zeta" that the system can provide. This should cover the defined range of Zeta = **standard Minimum Damping Factor** to Zeta = **standard Maximum Damping Factor**.

This will enable a standard control system design to be validated for use with a range of different inverters with different power ratings and applications.

The control system then needs to be validated versus providing the required performance that includes:

- Producing a prototype for validation testing in line with a mutually agreed set of tests.
- The prototype must use the control system proposed for a fully rated design but the associated inverter can be at a lower rating, for example 1 MW.
- The validation tests will include a range of test waveforms:
    - A set of **RoCoF** tests at different values, see **Figure 8.13.1**.
    - A set of phase jump tests at different values.
    - A set of Grid oscillation tests at different values.
    - Grid voltage unbalance tests.
    - Conditions causing the **Peak Current Rating** at rated voltage with real and reactive power.
    - Conditions for a Grid fault ride through test.
    - Conditions producing the **Peak Current Rating** test.
    - System islanding test.
    - System tripping test.
- The validation tests will include the Phase jump test listed below to line up with site testing.
- The validation tests can either be carried out either In House or in a viable commercial test facility. There are companies able to do this testing.
- A full report can then be submitted to **NGESO** for approval. This will include the full test results and a simulation and reports submitted to **NGESO** will be treated as strictly confidential.

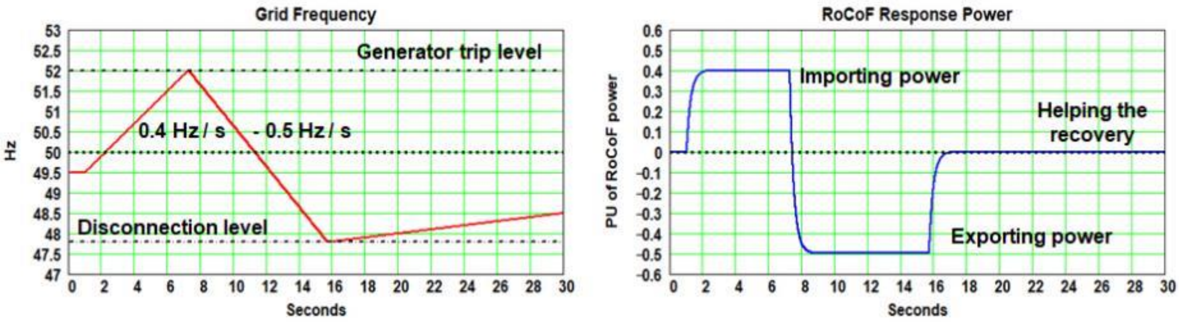

Figure 8.13.1. A typical worse case frequency RoCoF test.

For **GBGF- I** systems there is a phase jump test that can be repeated on site.

This is shown on **Figure 8.13.2.**

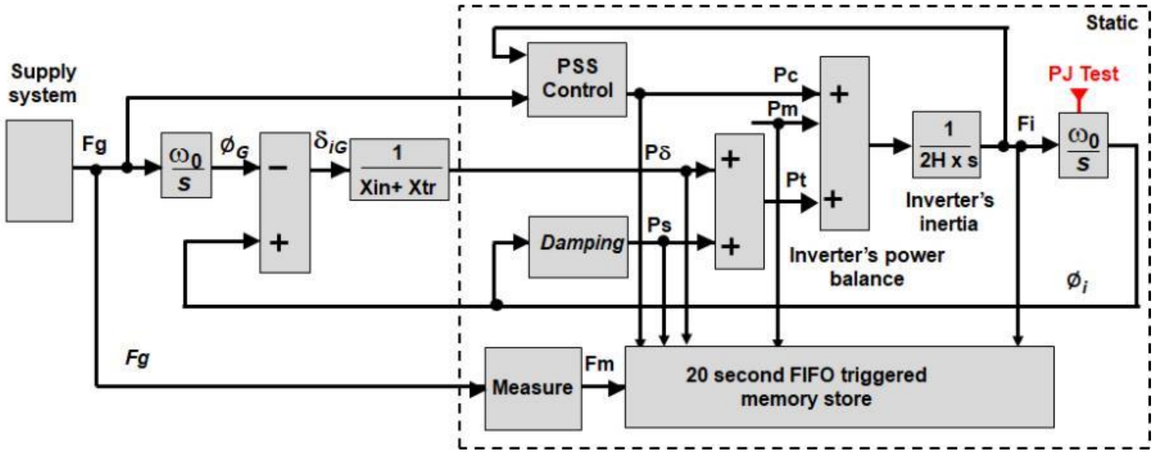

Figure 8.13.2. GBGF- I system test and monitoring.

The phase jump test it to apply an instant pre-set phase jump to the inverters **IVS** as this will give results very similar to a Grid phase jump. This is the Red test signal on **Figure 8.13.2**.

This test can be carried out on site on agreed basis for routine testing.

For a full onsite system validation a **RoCoF** test is needed and this is best carried out by waiting for a real R**oCoF** event to occur. This needs to be recorded and a possible method is shown on **Figure 8.13.2**.

The History recording system has the following features that have been used and proven in many high-power converter systems. This system can be based on the **NGESO** Dynamic System Monitoring Technical Specification TS 3.24.70.

This technical specification records a set of defined data at a rate of 256 samples per mains cycle which is a sample every 78 micro seconds, which is a sampling rate of 12.9 kHz.

This data rate is sufficient for subsequent analysis of system waveforms but it is too slow for a post event calculation of Frequency, **RoCoF** and a Phase jump angle.

The ideal system would have an extra feature added to give high speed measuring of the Grid voltage waveforms to provide the following logged data:

- Calculated Grid frequency logged at a 10 ms rate, with high immunity to phase jumps.
- Calculated Grid **RoCoF** logged at a 100 ms rate, with high immunity to phase jumps.
- Calculated Grid phase jump data logged at a 10 ms rate.

The Enstore design for these 3 values uses a sampling rate of 1 microsecond rate to calculate and then store the 3 extra items of logged data. The reason for this sampling rate is that the time change in one mains cycle for a one-degree Grid Phase Jump is 55.5 microseconds and a RoCoF rate of 1 Hz / s is 8.2 microseconds.

To validate the design uses a test waveform that produces results see **Figure 8.13.3**.

The Figure 8.13.3 shows a test Grid voltage waveform with two 30-degree phase jumps shown on the top two traces plus the **RoCoF** profile shown on the middle LH trace with a 2 Hz power oscillation.

The AC Grid voltage waveform was used as an input to an **Enstore's** advanced frequency measuring software that has a high immunity to phase jumps when calculating Grid frequency and **RoCoF** data.

This gave the measured **RoCoF**, frequency and the phase jumps shown on the Figure **8.13.3**.

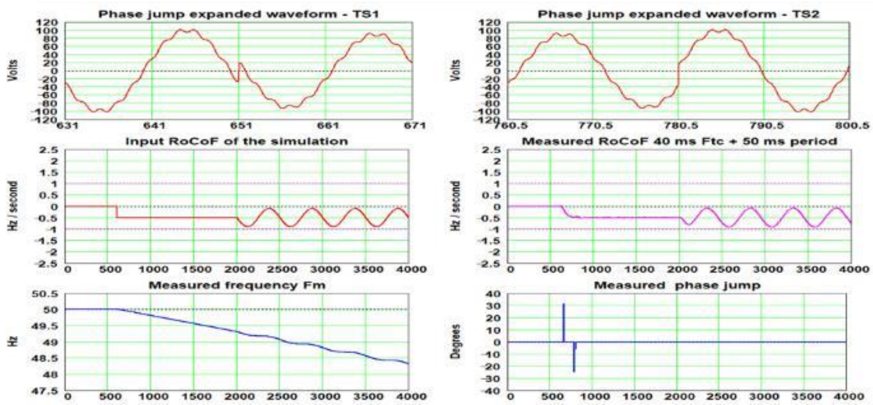

Figure 8.13.3. Example of frequency calculations with phase angle changes.

These are waveforms that are also very viable for adding **Control based** real **damping power**.

To make retrieval of detected events per plant the following extra features are also desirable:

- A twenty second First in First out "FIFO" data store for all the Recorded data with a new input every 78 micro seconds. The FIFO storage is stopped after 10 s by input triggers, outside of a pre-set value, for Frequency, **RoCoF** and Phase jumps.
- Storage of each set of the captured data for 10 s before and 10 s after an event that is then available for retrieval via a secure internet connection.
- The FIFO store is then restarted to catch subsequent events.
- The stored data is retrieved via the internet with an accurate GPS time stamp.
- A test input to give a pre-set phase jump in **Fi** for a lab and site test ability.

The stored data is retrieved via the internet with an accurate GPS time stamp for comparison with other **NGESO** captured data. This enables the systems operation to be validated when Grid transients occur.

Typical settings could be to capture and store data for frequency changes larger than +/- 0.5 Hz, phase jumps larger than +/- 5 degrees and **RoCoF** events larger than +/- 0.15 Hz / s.

9. The future.

There are large power variations during any 24-hour period and seasonal variations as shown on **Figure 9.1**.

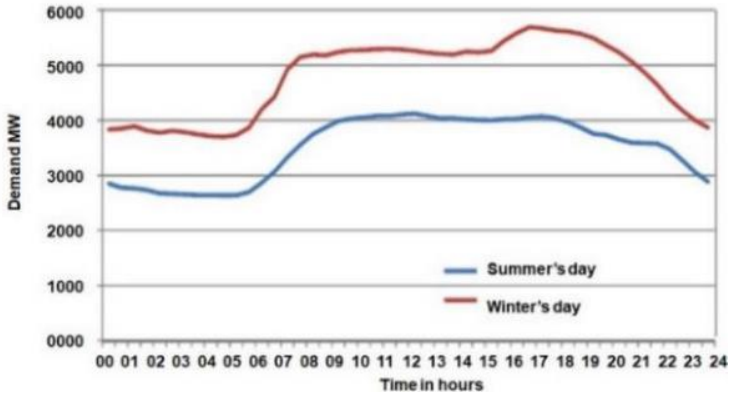

Figure 9.1. Daily power variations.

In the future there will be time periods that produce very high levels of renewable energy being supplied via **GBGF- I** systems in to the Grid. For a future optimal Grid in these time periods there will be a low level of **GB Grid Forming** synchronous generators operating apart from the nuclear power synchronous generators.

In these time periods the stability of the Grid must be maintained which is why it is essential to develop and deploy **GBGF- I** technology.

There will be other times, especially in winter, when due to atmospheric conditions that very low levels of renewable energy (particularly wind) will be produced at a time of high demand. This requires an increased level of **GB Grid Forming** synchronous generators plus long-distance inter-connectors, see **Figure 9.2.**

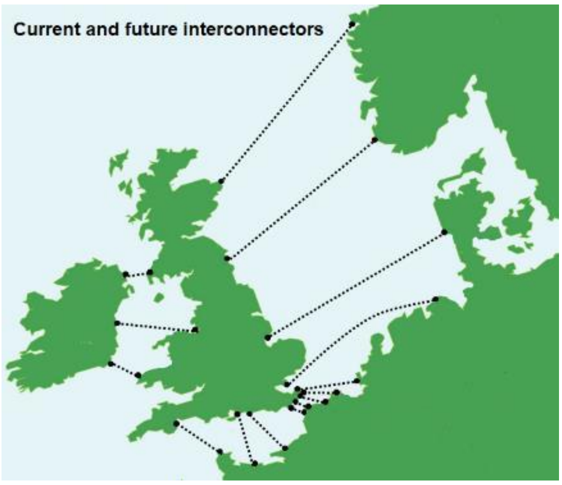

Figure 9.2. NGESO interconnectors.

The long-distance inter-connectors are a vital part of a viable Grid system and as they permit less synchronous generators to be used this increase the need for **software inertia**.

There is also another very important consideration which is that in the past **GB** Grid the Inertia required for Grid stability was provided for almost for free as it was made up from the contribution of many rotating synchronous generation connected to the Grid, an effect which was a biproduct from the technology employed. In a future **GB GRID** made up of converter based plant the required Inertia for Grid stability will have to be paid for.

Finding the optimal Grid design will pose profound questions for the owners of the **GBGF-S** generators, the owners of the **GBGF- I systems** and **NGESO.**

The **Figure 9.3** shows a stacked benefit system which can include **software inertia** at a very low extra cost compared with the cost of a basic **Constraint management** design.

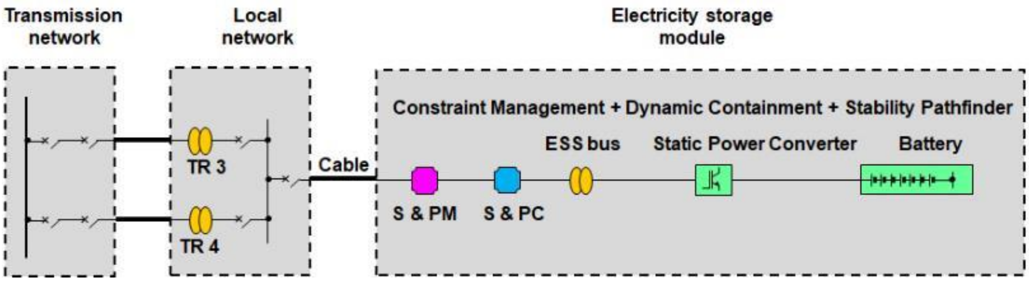

Figure 9.3. A Stacked benefit system.

This system uses a **GBGF-I** system to provide the key component of a fully integrated system for either the **Grid Forming** market, the Stability Market or a future Inertia market that stacks with other markets such as:

- The proposed **NGESO Constraint management Service** with 200 MW for 2 hours.
- The proposed **NGESO Dynamic Containment Service** with 200 MW of response power.
- The proposed **NGESO Stability Pathfinder Service** 200 MW of **RoCoF response power**.
- A **Peak Current Rating** providing at least 200 MVA.
- A **GBGF- I** system with a 200 % **Peak Current Rating is used** to independently provide all these **NGESO Services**. For this design the inverter cost is a small % of the battery cost which makes a 200 % **Peak Current Rating** very cost effective, especially when the benefits are considered.

The **GBGF- I** systems will use many identical units in parallel which gives a system with redundancy and high availability with one set of batteries rated for all the duties.

A **GBGF- I** system can also supply **Phase Jump Active power** and **RoCoF response power** to add **Grid Forming** abilities to new and existing systems including HVDC as shown on **Figure 9.4**.

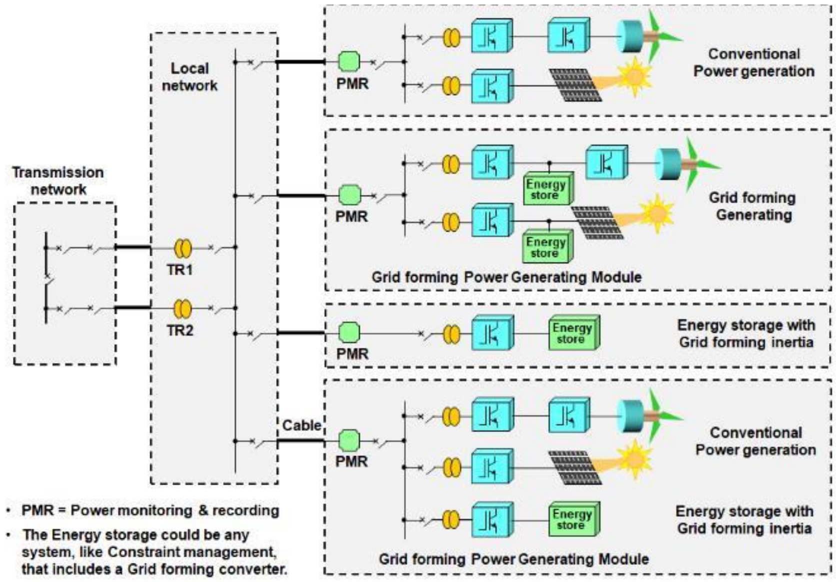

Figure 9.4. Alternative ways to add Inertia.

The **Figure 9.4** shows:

- **On the first circuit** a convention power generating module with wind and solar renewable power.
- **On the second circuit** a **Grid Forming** power generating module with wind and solar renewable power with the **Phase Jump Active power** and **RoCoF response power** integrated in to the **GB Grid Forming** inverters.
- **On the third circuit** a standalone **Grid Forming** module that provides the **Phase Jump Active power** and **RoCoF response power**.
- **On the fourth circuit** a convention power generating module with wind and solar renewable power that has been converted to have a **Grid Forming** ability by adding a **Grid Forming** module that provides the **Phase Jump Active power** and **RoCoF response power**.

The ability to upgrade existing renewable energy systems to have a **Grid Forming** ability, by the addition of an extra inverter system, could become an essential part of the Grid, especially if **NGESO** create an Inertia market.

These Inertia facilities are vitally needed when major GB Grid transients occur and online transient recording systems should be available, on each Inertia facility, to capture in high definition the GB Grid voltage and power transient changes that occur to provide stored data on the actual Grid frequency, phase jump and **RoCoF** values with an accurate time stamp.

10. Design of GBGF-I systems in the frequency and time domains.

10.1. Frequency domain analysis.

Frequency domain analysis uses models like that shown in **Figure 8.8.2** for analysing the system's operation.

The **Frequency domain** results are presented over a range of frequencies that have many benefits including:

- They can be rapidly simulated.
- It is one of the main methods used by most companies in designing the control system, and the operation, of a static **Power Converter.**
- They are used by **NGESO** for large scale Grid simulations as they can be produced with an acceptable computation time.
- They are the basis for rapidly producing **NFP** plots for a given design.
- They give very good results for a range of frequencies.

The **Figure 10.1.1** shows a typical AC supply impedance model with **Frequency domain** data.

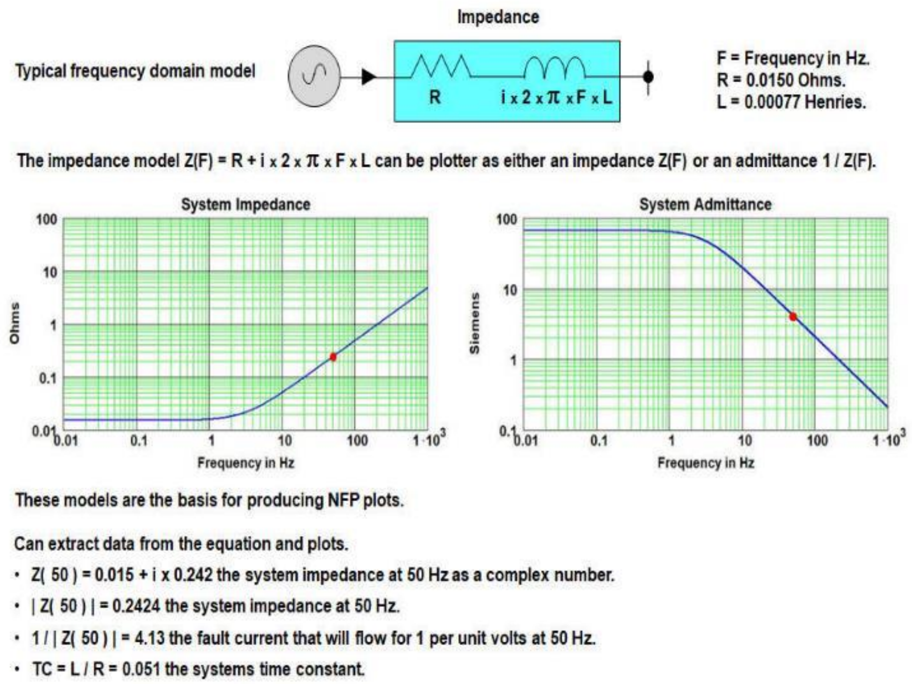

Figure 10.1.1. Frequency domain data for an AC impedance

The **Figure 10.1.1**. shows:

- A typical **Frequency domain** function block.
- The impedance versus frequency that is used for calculating the gain of a system.
- The admittance versus frequency that is using for calculating **NFP** plots.

The **Frequency domain** data for several functions can easily be combined to provide results for a large system.

The **Frequency domain** model can be used to produce amplitude versus time data as shown on the **Figure 10.1.2.**

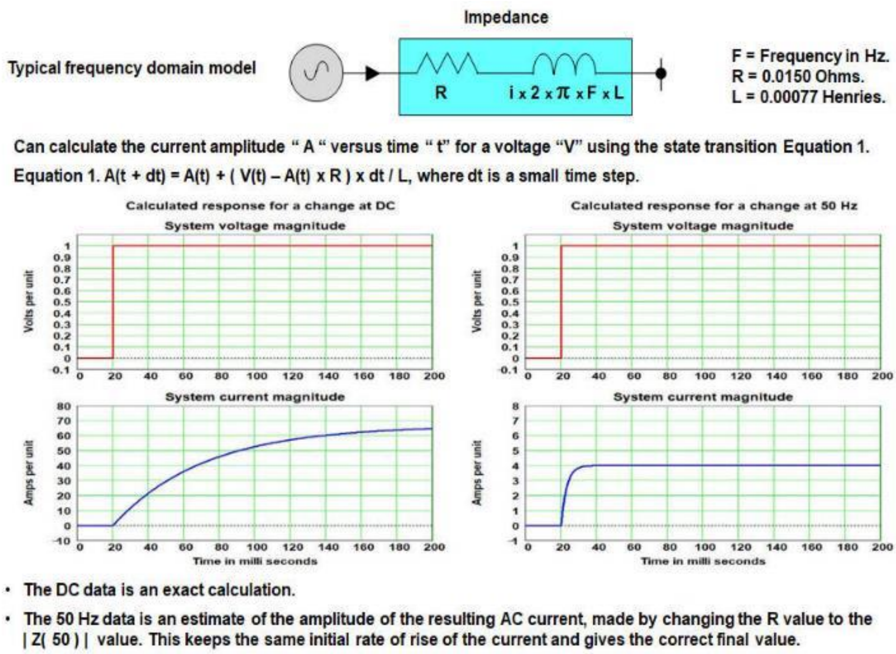

Figure 10.1.2. Frequency domain amplitude / time data for an AC impedance

The data for the amplitude, of a change at 50 Hz, is only valid for a change applied over at least 20 ms.

For accurate calculation of the exact current waveforms at 50 Hz, including point of wave switching effects, a **Time domain** simulation is used.

10.2. Time domain analysis.

Time domain analysis is used to examine the exact waveforms produced for any steady state or transient event by simultaneously solving the relevant set of equation with very small time steps.

The time steps for modelling a static **Power Converter** are often in the microsecond range that then requires a very large and long computer analysis time. This is why this analysis method is not used for simulating large Grid systems.

There are several standard software programs that use varying length time steps depending of the changes that are occurring for example MATLAB Simulink.

The run time can also be reduced by minimising the level of detail that is being simulated.

The static **Power Converter** can be modelled with all the static switches operating with **PWM** control to produce exact **IVS** voltage waveforms with harmonics.

The following examples of **Time Domain** simulations have modelled the **IVS** of a static **Power Converter** as fully controlled voltages without the **PWM** harmonics. This is viable for understanding the actions of a **GB Grid Forming converter.**

The **Figures 10.2.1** to **10.2.3** are **Time Domain** simulations of three different Grid transients with rates of change of the transient being at 20 ms or slower. These results have balanced 3 phase waveforms without DC components.

The **Figure 10.12.4** explains why Grid transients with rates of change of the transient shorter than 20 ms produce unbalance transients with DC components that rapidly decay.

The **Figures 10.2.5** to **10.2.7** are **Time Domain** simulations of the same three different Grid transients with rates of change of the transient being at 0 ms. These results have unbalanced 3 phase waveforms with DC components.

When a power transient occurs, the effects are almost instantaneous at the location of the fault, but for systems away from the location of the fault the Grid impedances reduce the magnitude and the rate of change of the transient. This effect is shown on **Figures 10.9.1** and **10.10.1**.

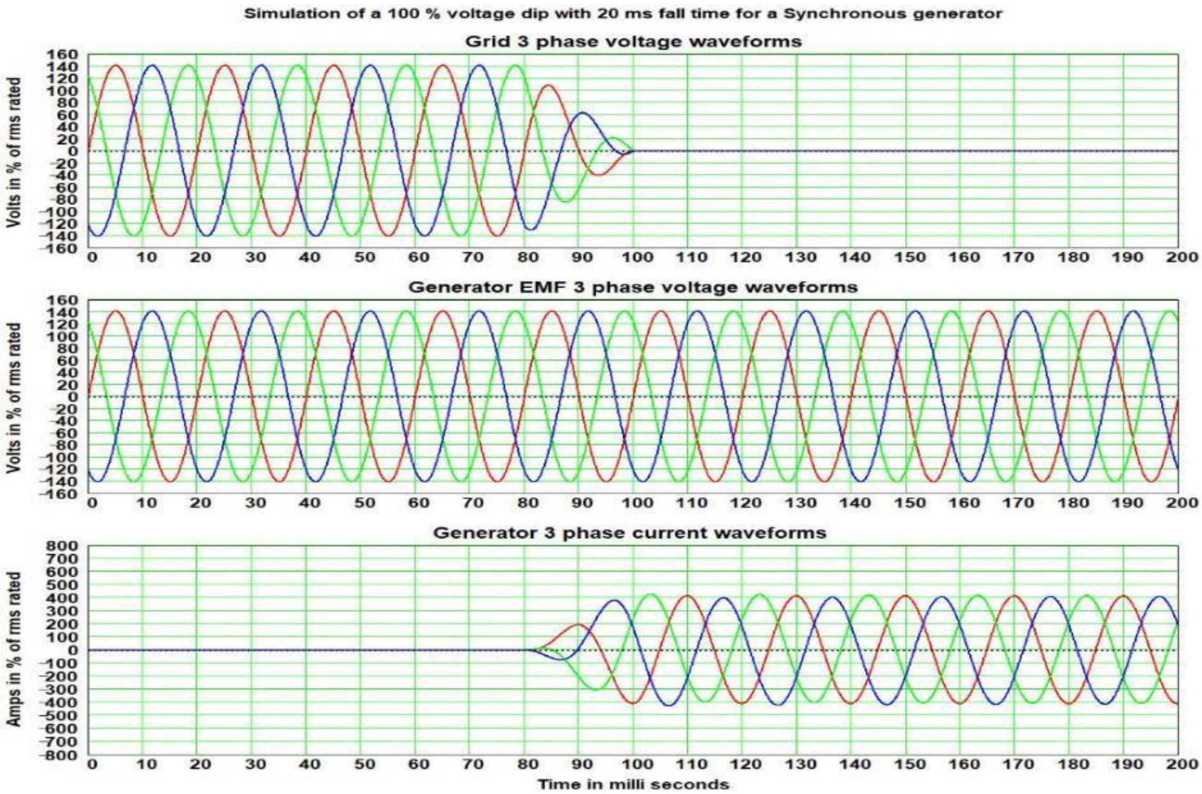

Figure 10.2.1. 100% voltage dip in 20ms for a generator

The **Figure 10.2.1** is for a short circuit of a generator, away from a fault, with a voltage fall time of 20 ms.

The **Figure 10.2.1** has balanced waveforms that shows that the magnitude of the fault currents can also be accurately predicted by **Frequency Domain** methods, see **Figure 10.1.2.**

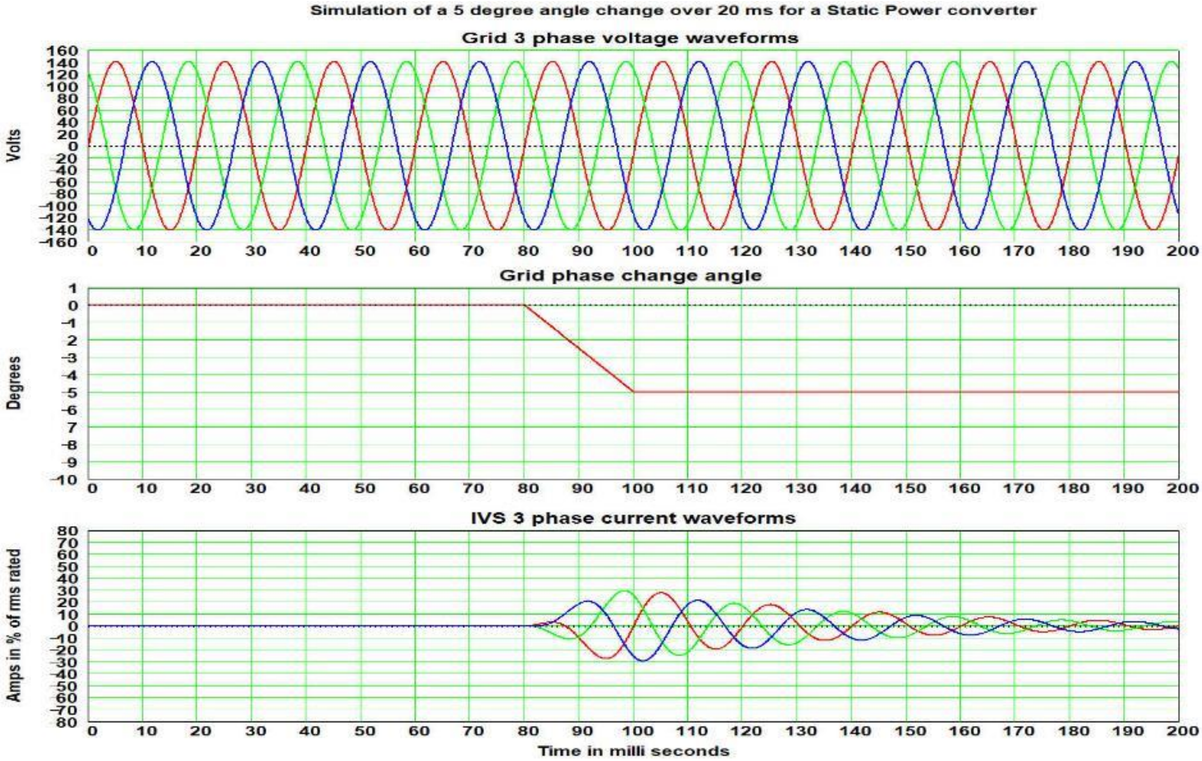

Figure 10.2.2. Five degree angle change in 20ms for a GBGF- I system.

The **Figure 10.2.2** is for a phase change applied to a **GBGF- I** system, away from a fault, with a phase change time of 20 ms which cannot be seen in the Grid's voltage waveform. The **Figure 10.2.2** has balanced waveforms which is very important for the operation and rating of **GBGF- I** systems away from the location of the phase change. The control system rapidly adapts to this change.

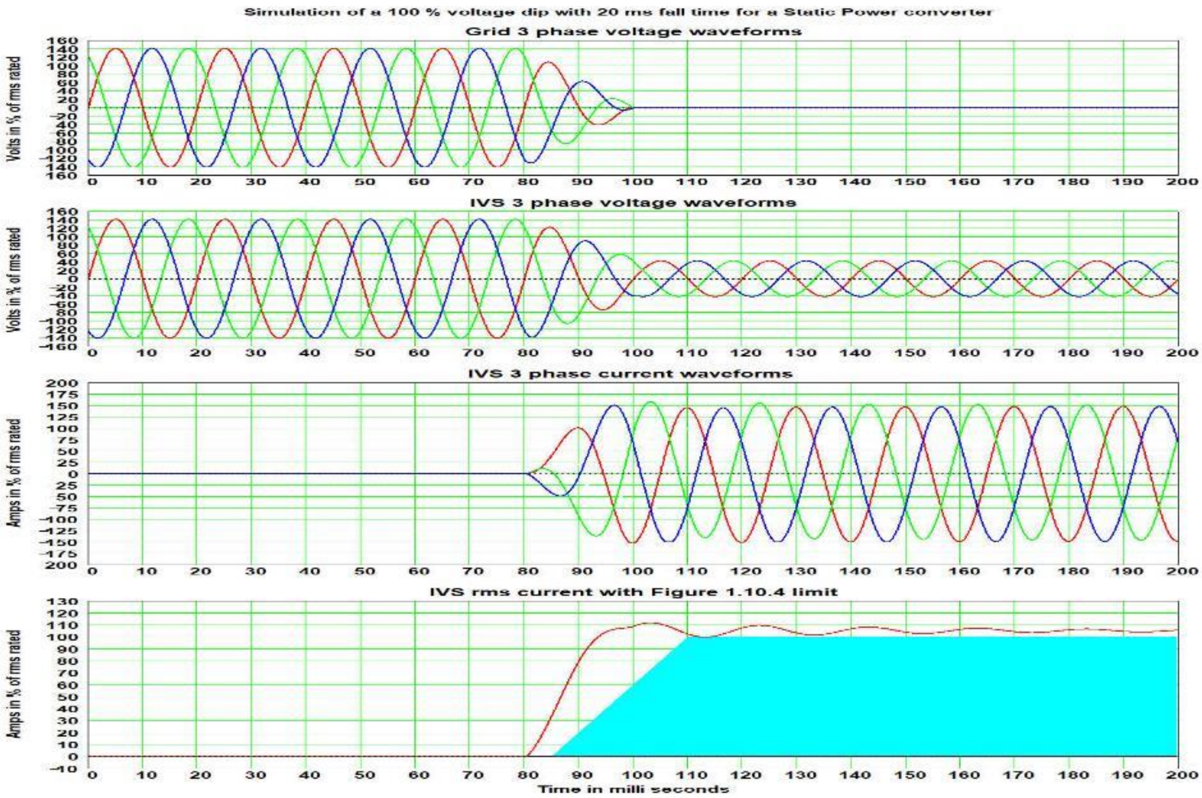

Figure 10.2.3. 100% voltage dip in 20ms for a GBGF- I system

The **Figure 10.2.3** is for a short circuit of a **GBGF- I** system, away from a fault, with a voltage fall time of 20 ms. The **Figure 10.2.2** has balanced waveforms which is very important for the operation and rating of a **GBGF- I** system away from a short circuit fault. The shaded blue area is the required **RMS** time response of the fault current as shown on the **Figure 8.10.4**.

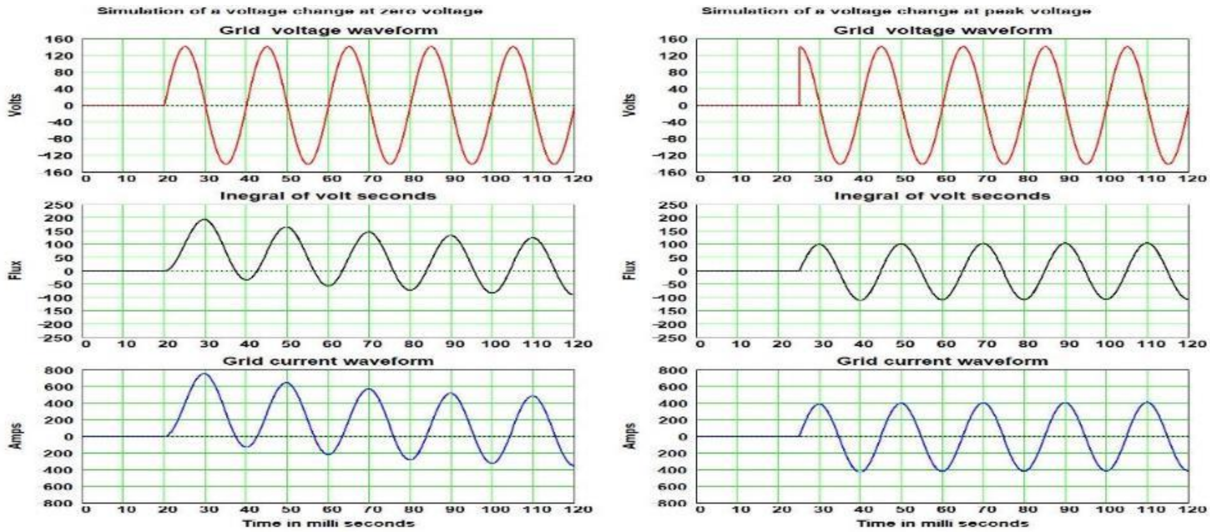

Figure 10.2.4. DC transients in an inductor due to point of wave switching

When an instantaneous change occurs the point of the application in the voltage's cycle can produce a decaying DC component, as shown on **Figure 10.2.4,** that can also double the value of the initial peak.

The AC supply impedances for a **GBGF- I** system are dominantly an inductive circuit. The time in the mains cycle when a fault occurs produces different values for the **Integral of the volt-seconds** applied to the supply's inductance. This produces the DC components shown on the **Figure 10.2.4** that decay at a rate defined by the circuit's resistance.

For a three-phase system this inherently produces unbalanced 3 phase currents see the next figures.

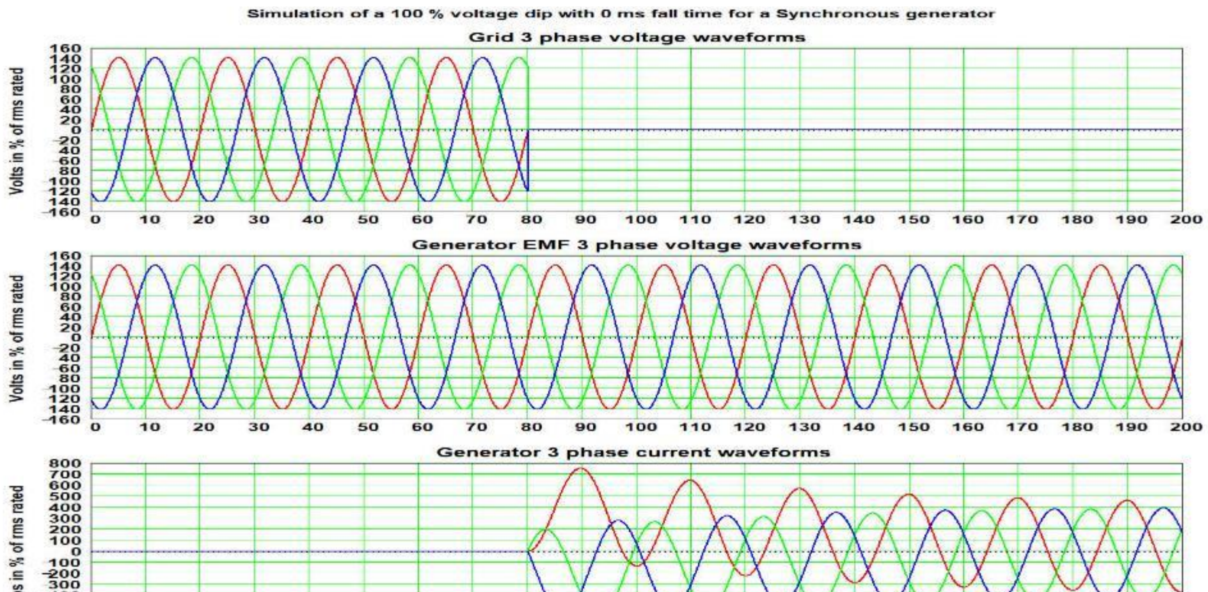

Figure 10.2.5. 100% voltage dip in 0ms for a generator

The **Figure 10.2.5** is for a short circuit on a generator, near to a fault, with a voltage fall time of 0 ms.

The **Figure 10.2.5** shows the doubling of the initial peak together with the decaying DC current component and very unbalanced currents. To correctly detect these fault currents any associated current sensors must be specified to the correct protection grade.

For modern high efficiency generators, the current waveform in one or more phases, may not have a current zero for a time period that can be over 100 ms. For these generators the tripping system must have a definite minimum time delay to ensure the safe operation of the associated AC circuit breakers.

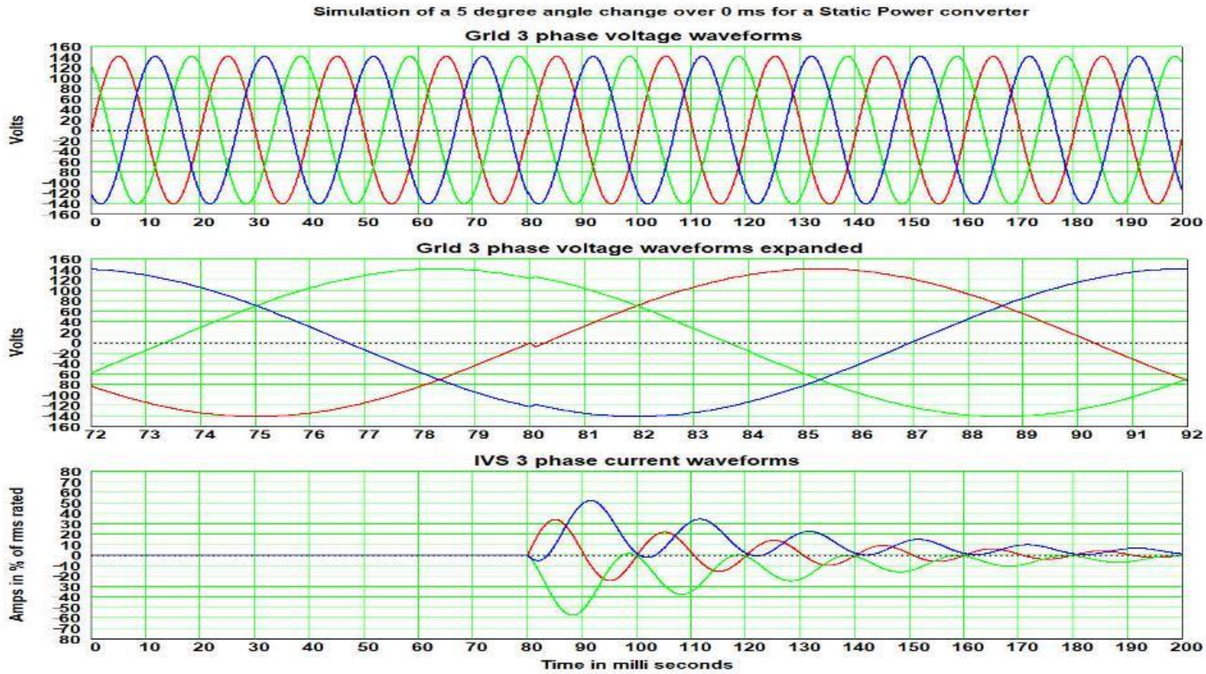

Figure 10.2.6. Five degree angle change in 0 ms for a GBGF- I system.

The **Figure 10.2.6** is for a phase change applied to a **GBGF- I** system, near to a fault, with a phase change time of 0 ms. The **Figure 10.2.2** has very unbalanced waveforms which is very important for the operation and rating of a **GBGF- I** system near to a phase change.

The expanded time scale shows the 5 degree phase change which is a small phase disturbance, but the control of the **IVS** voltages have to occur very rapidly and may need unbalanced **IVS** voltages to adapt to this change.

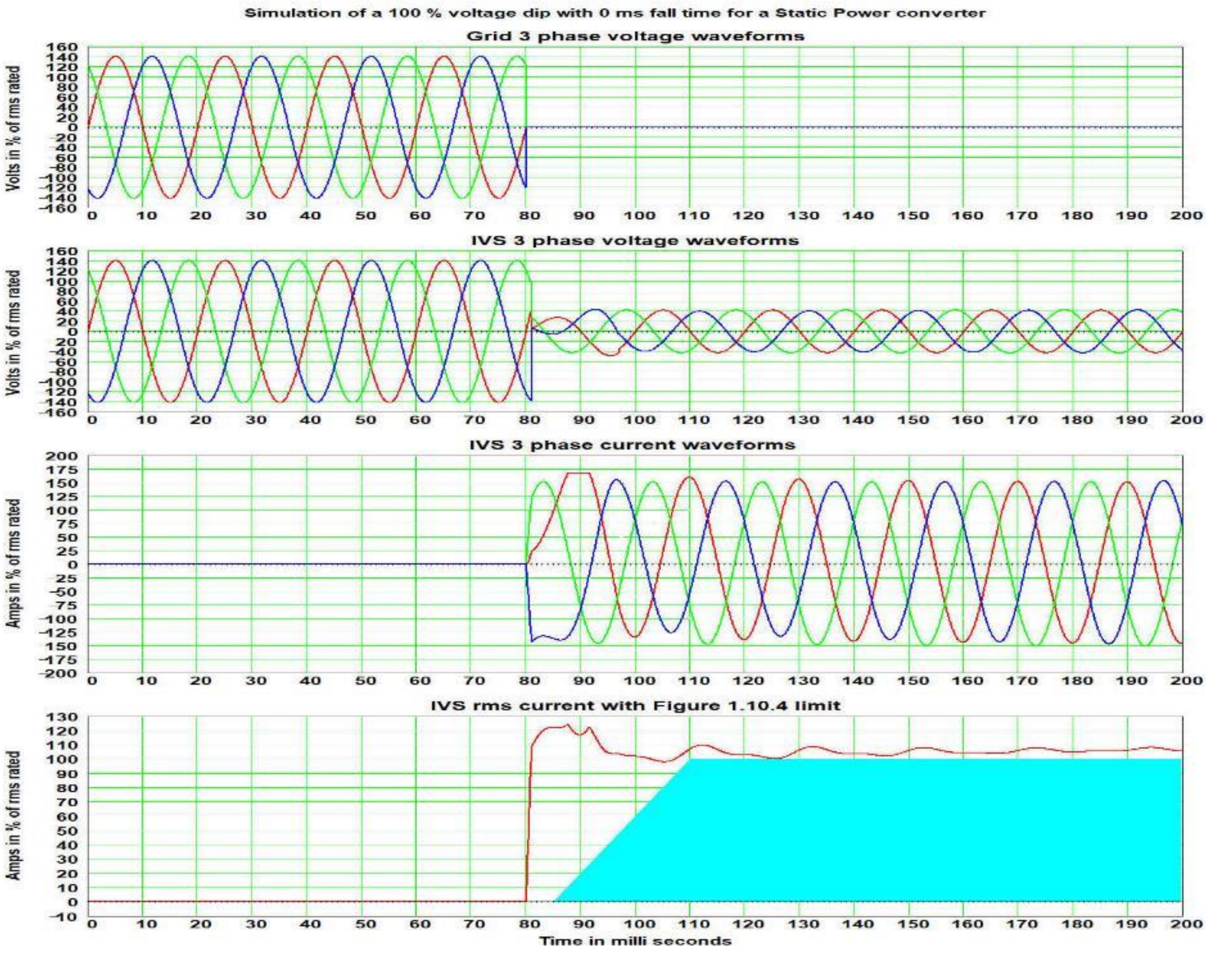

Figure 10.2.7. 100% voltage dip in 0ms for a GBGF- I system.

The **Figure 10.2.7** is for a short circuit of a **GBGF- I** system, that is near to a fault, with a voltage fall time of 0 ms. The **Figure 10.2.2** has very unbalanced waveforms which is very important for the operation and rating of a **GBGF- I** system near to the fault.

The control of the **IVS** voltages have to occur very rapidly and may need unbalanced **IVS** voltages plus fast current clipping to limit the peak currents. The shaded blue area is the required **RMS** time response of the fault current as shown on the **Figure 8.10.4**.

The **Figures 10.2.1** to **10.2.7** show the very different waveforms that occur in locations where the transient occurs over a time of 20 ms or longer, versus the waveforms that occur for occur in locations where the transient occurs over a time of 20 ms to 0 ms.

This difference has the following important effects for a **GBGF- I** system:

- The control can limit the resulting currents to the contract's **Peak Current Rating** at locations away from the fault as the resulting currents are balanced 3 phase waveforms.
- The control can stay in the linear **GB Grid Forming Mode** for Grid phase changes that are at or smaller than the **Phase jump angle limit** that is recommended to be set at 5 degrees.
- That for major power transients the action of the Grid is to reduce the magnitude and increase the change time of the power transients in locations away from the fault, so that the majority of the Grid's **GBGF- I** systems will stay in the linear **GB Grid Forming Mode** to help the Grid recover.
- That the testing of a **GBGF- I** system requires test to be done with both a 0 ms transient change time and a 20 ms transient change time. This is needed for phase change tests and voltage dip tests.

The operation of a **GBGF- I** system after a deep voltage dip also requires fast control and special testing to operate, without tripping, for the waveforms shown on **Figures 10.2.8** and **10.2.9** which show real data from a **GFR** fully rated test carried out at a test site**.**

The **Figure 10.2.98** shows the secondary line voltages that are applied to the **GBGF- I** systems that have very distorted voltage waveforms due to the associated transformer operating with magnetic saturation, that is very similar to normal initial switch on conditions.

This condition occurs because the **IVS** has to be reduced to a very low voltage for deep voltage dips.

When the fault is cleared the sudden voltage rise produces magnetic saturation in the associate transformer.

This condition is a very difficult to simulate, but simulation models area available, but it does require the correct test set up to reproduce these effects in validating a system on test.

The rating of the saturation flux level for a **GBGF- I** system's transformer must also be based on the transformer secondary voltages, applied by the **IVS,** that can be above the voltages on the Grid side of the transformer.

This is the opposite of the rating method for the transformers used by most industrial static **Power Converters** used for applying power to a motor. Transformers of this type can be unsatisfactory without a rating change for use with **GBGF- I** systems.

The effects shown on **Figure 10.2.8 & 9** can be significantly reduced by specifying a transformer for **GBGF- I** systems designed to operate at a lower flux saturation level when operating at the maximum **IVS** voltage output. This does not alter the transformers MVA rating but does require a transformer with a larger laminated steel core cross section using conventional lamination materials.

The upper set of traces on **Figure 10.2.8** is real site data for the system on test. This shows the transformer's 3 phase secondary voltages and currents. The data is for a complete GFR event test carried out at an approval test site on a full-scale system.

The lower set of traces on **Figure 10.2.9** is an expanded version of the same data, when the fault is cleared, that shows the saturation happening in the transformer's secondary voltages.

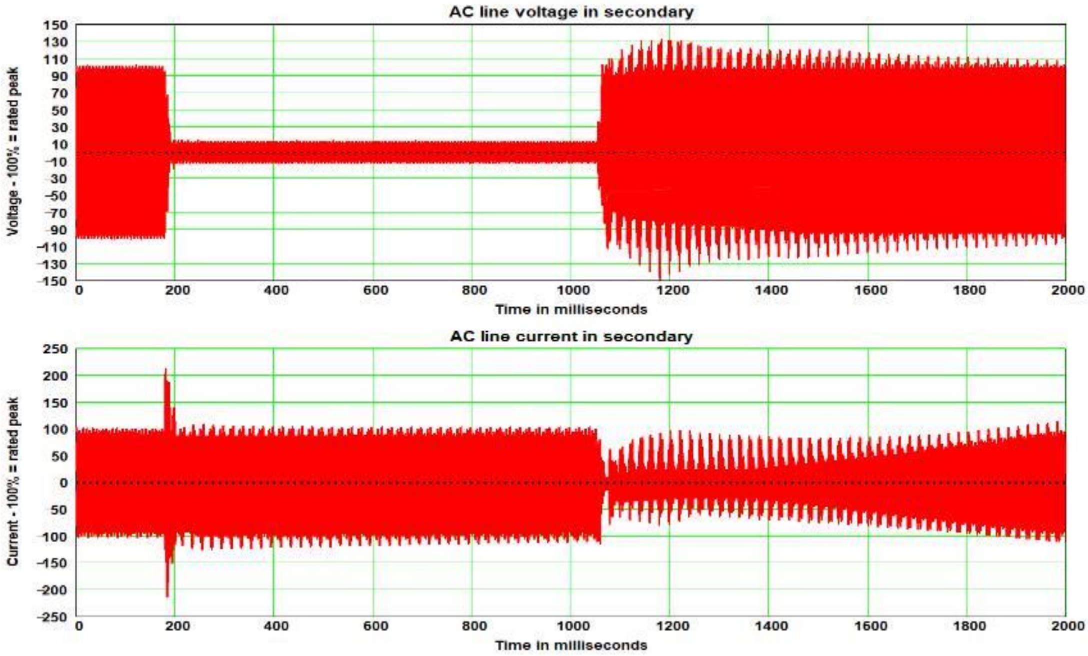

Figure 10.2.8. Recordings of the site data for a full GFR test.

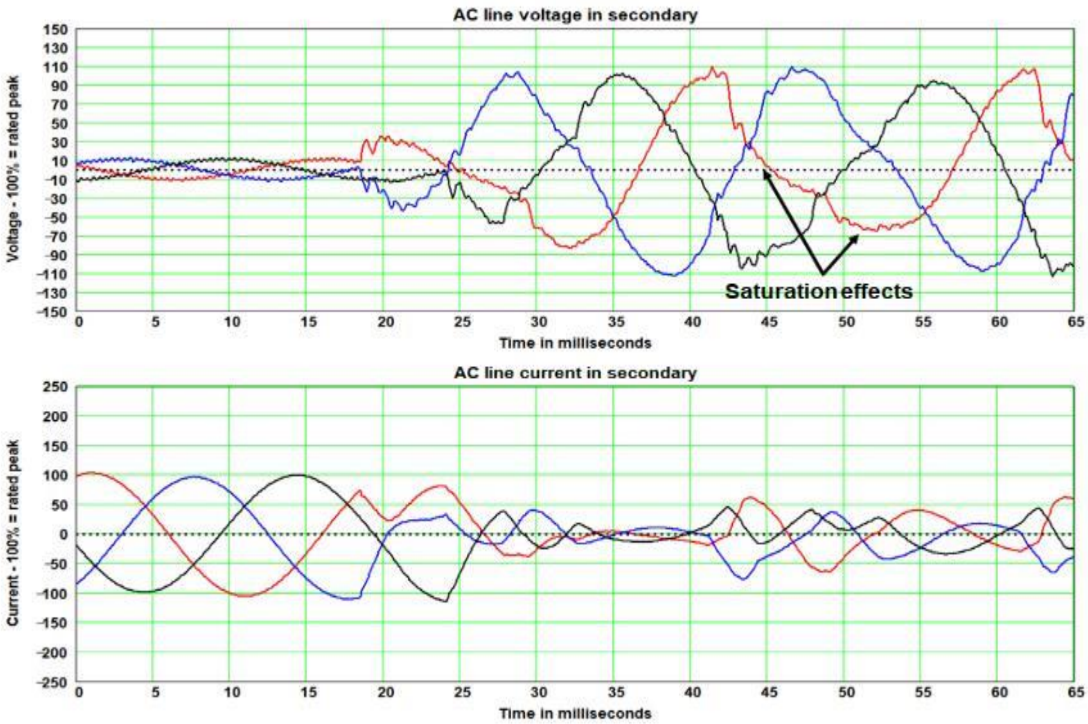

Figure 10.2.9. Expanded site data following the fault clearance

11. Summary of important items

This section is a summary of the main changes and other important data.

1. The proposed Grid code has two new system definitions:

   - **GBGF-S** for data applicable only to **GBGF** synchronous generators based systems.
   - **GBGF- I** for data applicable only to **GBGF** inverter based systems.

   This is to enable which feature apply to the two systems.

2. The proposed Grid code has a new power definition as the latest studies have shown the following:

   - That the **Type 1 Phase based** real **Phase Jump Active power** has a very fast 5 ms response.
   - That the **Phase Jump Active power** is essential for stabilising the AC Grid especially at the start of a power transient that causes a **RoCoF** event.
   - That the **Inertia power** is applied more slowly especially for system with high **H** values that can occur in energy storage systems.
   - That for some systems the time to reach the full **Inertia power** can be 1 second.
   - That for some systems the use of the **Type 4 Control based** real **Control power** can give a significant increase of the **GBGF-I** systems power for **RoCoF** events.

   To provide an optimal design of **GBGF- I** systems the term **RoCoF response power** has now been defined.

   The definition of **RoCoF response power** is that for **RoCoF** transients the resulting real power can be beneficially provided by either or both of the following depending on the design of a system:

   - **Phase based** real **Inertia power** for AC grid **RoCoF** changes.
   - **Control based** real **Droop power** for AC grid frequency changes.

3. That The rating of the **Phase Jump Active Power** also has to be considered on a local zone basis for a stable grid system. For a possible future power loss transient of 2 GW this requires a 2 GW power available in the local zone for both the **Phase Jump Active Power** and the **RoCoF Response Power**.

4. To have a comprehensive guide to **GBGF- I** systems the following seven new definitions and values were proposed in the previous version of this guide:

   - **Phase jump angle limit** = 5 degrees for system operation without reaching the **Peak Current Rating** value when operating at the rated voltage.
   - **Phase jump angle withstand** = 60 degrees for system operation without tripping at the rated voltage as this is a typical **NGESO** reclosing setting. Larger phase jump angles will occur during Grid short circuit faults.
   - **Phase jump angle rating** which is the angle that a system provides that can be equal to or larger than the **Phase jump angle limit**.
   - **Standard maximum Damping Factor** (Zeta) = 1.0 per unit for testing the control system.
   - **Standard minimum Damping Factor** (Zeta) = 0.1 per unit for testing the control system.
   - **Range of Inertia H values =** 0.2 to 25 for testing the control system.
   - **Grid oscillation value** = 0.05 Hz peak to peak at 1 Hz for rating the **defined Damping Active Power**.

5. The definition of the contract's **Peak Current Rating** that is the larger of:

   - The **RoCoF response power** plus the **defined Damping Active Power**.
   - The **Phase jump angle limit power.**
   - The maximum current defined by the supplier, see **Figure 9.3** for an example.

12. Modification record.

Issue	Date	By	Details
V-001	09/03/2021	E A Lewis	This data for the Sections 1 to 5 is new. The remaining Sections are copies from the previous guide with updates especially for Sections 8.8 - Bandwidth and 8.11 – VSM0H. Due to all the sections being changed a tracked version was not possible.
V-002	17/03/2021	E A Lewis	Section 0 added without tracking as all new text.
V-003	20/03/2021	E A Lewis	Original Equation 1 now Equation 4 in Sections 4 and 8.12 Tracked text corrected for Equations 1 to 4. Tracked text added above Figure 3.4.
V-004	24/03/3021	E A Lewis	All previous tracked changes listed in V-002 & V-003 accepted. Acknowledgements simplified. Important new text added in Section 0 pages 6 and 7. Important new tracked text added above Figure 8.2.2. Figures 8.2.1, 8.9.1, 8.9.3, 8.13.1 & 9.2 updated, not tracked. Section 11 added.