File. **Enstore updated guide for GB Grid Forming Converters – V-005**

Issued to. **Antony Johnson and NGESO.**

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

Date. **06 July 2021**.

Contents

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Signed by…Eric A Lewis … Eric A Lewis BSc (Eng) CEng MIET- Company Director. 06-07-2021.

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1. Document guide:

This report is Enstore's opinion of how a future AC Grid could operate and Enstore believes that no changes are required to the final proposed revision of the GBGF Grid Code as voted at the meeting on 21 June 2021 which is being implemented through Grid Code Modification **GC0137.**

The most important new data, in this report, is the need to have sufficient **Active Phase Jump Power** to stabilise the AC Grid equal to the worst case power transient in each local zone of the AC Grid.

All the **Figures,** in this report, were produced by **Enstore** and the **Figures 5.3, 5.4, 5.5, 7.1, 7.3, 8.1, 11.5.2, 14.1, 14.3 & 17.1** are based on public domain data in the **NGESO** records.

In the final proposed revision of the **GBGF** Grid Code the names of certain Definitions were also updated following the comments from **GC0137** work group members. These updates are:

- **Real** is now **Active**.
- **Phase Jump Active Power** is now **Active Phase Jump Power** than has an instantaneous response to an AC Grid **Phase Angle** change, that is specified to start in less than 5 ms.
- **Real Inertia Power** is now **Active Inertia Power** this also has a response that starts in less than 5 ms but take longer to reach the rated value for a **RoCoF** event.
- **Damping Active Power** is now **Active Damping Power**.
- **Control Based Real Power** is now **Active Control Based Power**.
- **Control Based Real Droop Power** is now **Active Frequency Response Power**.

  Active Frequency Response Power is the active power produced by a **GBGF- I** inverter measured one second after the start of a **RoCoF** event.
- **ROCOF Response Power** is now **Active RoCoF Response Power**.

  Active RoCoF Response Power is the sum of **Active Inertia Power** and **Active Frequency Response Power** to enable the design of **GBGF- I** inverters to be optimised to give the maximum active power for a **RoCoF** event.
- **Grid Forming Active Power** is a new definition.

  Grid Forming Active Power is the inherent active power produced by **GBGF** technology that includes **Active Phase Jump Power** plus **Active Inertia Power** and **Active Damping Power.**

This report has added two new terms that are **Active Response Power** that is a common term for the existing definitions of **Primary Response Power** and **Secondary Response power** and **Active Infeed Power** that is the power flowing into a local zone to align the **Initial Grid RoCoF 2** and **Average Grid RoCoF 1** rates.

2. Acronyms.

AIP_1	The **Active Inertia Power produced** for a **RoCoF** rate of -1 Hz / s
ARP_1	The **Active RoCoF Response Power** at 1 second
Droop	A control feature that changes the output power for AC Grid frequency changes
ESS	Energy storage system
EMF	A term used for the internally produced voltage of a synchronous generator
F	Variable frequency in Hz.
Fg	Frequency of the AC Grid
Fi	Frequency at the inverter's **IVS**
Fm	Measured AC Grid frequency
Fr	Resonant frequency of the **NFP** plot.
Fs	Frequency at the AC Grid transformer's secondary output
FSM	Frequency Sensitive Mode as listed in the Grid Code
G1(ω), G3(ω)	Frequency domain gain functions
Gd(ω)	Frequency domain damping function
GBGF- I & -S	**GB Grid Forming** technology for inverters and synchronous generators
GFR	Grid Fault Ride Through
Hg & Hi	Definition of stored energy for the **Active Inertia Power**, see **Section 9**
He	Definition of stored energy for the **Active RoCoF Response Power**, see **Section 9**
Ig, Ig(ω)	AC Grid current in time and frequency domains
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 9**
NFP plot	Network Frequency Perturbation plot
NGESO	National Grid Electricity System Operator
Pc	Power from an auxiliary internal 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
PLL	Phase locked loop
PWM	Pulse Width Modulation
PSS	Power System Stabiliser control function
REP	Reactive power. See Note 1
RGWs	The required inertia in Giga Watt seconds to limit the fault's **RRoCoF**.
RoCoF 1	Average Rate of Change of Frequency in the total AC Grid
RoCoF 2	Initial Rate of Change of Frequency in a local zone of the AC Grid
RRoCoF	The required **RoCoF** rate when the **WCFP** occurs
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
Vs	Voltage at the transformers secondary
WCFP	Worst case fault power
Xin	Impedance of the inverter's transformer and associated inverter impedances
Xtr	Impedance of Grid transformer
Xts	Impedance of **Xtr** plus **Xin**
X"d	Impedance of the generator at 50 Hz
Zac(ω)	Supply impedance in the frequency domain
δig	Angle across the inverter's impedance
j	Imaginary operator = $\sqrt{-1}$
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 of the **NFP** plot's resonance
Φg	Phase angle of the AC Grid's voltages in the Time Domain
Φi	Phase angle of the AC inverter voltages in the Time Domain
1 / s	Integration function in the Time Domain
ζe	Zeta-e = Equivalent **Damping Factor** also called the Equivalent **Damping Ratio**

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

3. Executive summary.

This is a large document that contains data that has not been previously published in any other **Enstore** documents.

This section is a short summary of the most important data contained in this report.

The four **Design Aims** for GB Grid Forming **"GBGF" converters** are:

1. To have a common set of essential requirements for **GBGF converters** that allow for open market competition. This is to enable all the different types of **GBGF converters** to compete for the different **NGESO Services**, that as a minimum include rotating Synchronous Generators, rotating Synchronous Condensers (Compensators), controlled directly connected rotating Flywheels, static **Power Converters** including **HVDC Converters**, **Reactive Compensation** equipment (such as STATCOMs) and Smart Loads or aggregated Electric Vehicles (V2G).
2. To have a common set of essential requirements for **GBGF converters** to form a common core for all existing and future **NGESO Services**.
3. To clearly define each of the essential requirements to promote the development of a range of viable alternative solutions for **GBGF- I** inverters**.**
4. To provide a technology that enables the AC Grid to operate reliably with only nuclear energy plus renewable energy for both normal and fault conditions.

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

We need **GBGF** technology to be able to have an AC Grid system that can reliably operate with only low carbon sources. In the future this is likely to be made up of nuclear power and renewable power connected by static power converters with some use of Hydro Electric power.

As part of this Grid Code modification, **NGESO** uses the term **GBGF-S** for a synchronous generator and **GBGF- I** for an inverter design and all the following data only applies to **GBGF- I** inverters unless otherwise stated.

The most important development is to make **GBGF- I** inverters operate the same way as **GBGF-S** generators in an AC Grid system as shown on **Figure 3.1**, for normal operating conditions. The **Figure 3.1** is shown for a wind turbine system but this development applies to all **GBGF- I** inverters.

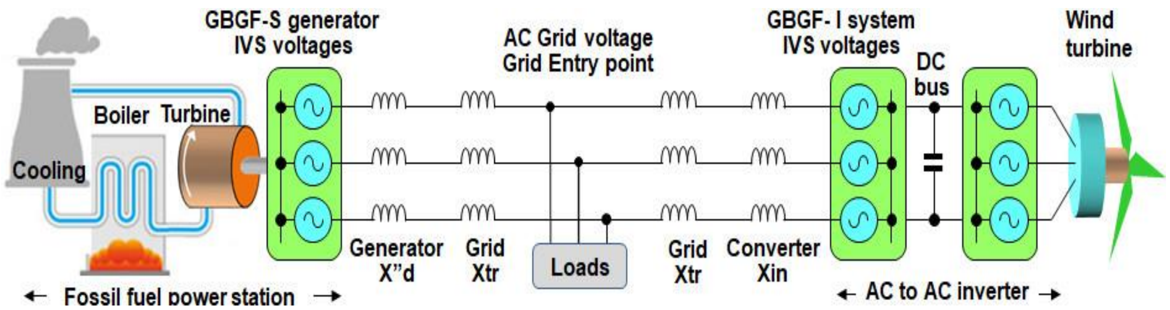

Figure 3.1. AC Grid system.

The **GBGF-S** generator has an Internal Voltage Source "**IVS**" that produces a set of balanced three phase voltages. The **IVS** voltages are also called the **EMF** voltages that do not change rapidly when there is a power transient at the Grid Entry Point. The **GBGF- I** inverter also have an **IVS** that produces a set of balanced three phase voltages that do not change rapidly when there is an AC Grid power transient.

The following statements are the key extracts from the document, that are shown in red text:

- During AC Grid phase jumps at rated voltage, the ability of **GBGF- I** inverters to supply their rated values of **Active Phase Jump Power** within less than one mains cycle is very important in having a stable AC Grid as this is replacing the capability of synchronous plant on a more like for like basis.
- This is probably the main reason for changing from the original control based converter technology to the **GBGF- I** inverter technology.
- The reason for this is that the **Active Phase Jump Power** provides three vital functions:
  - **Function 1.** It limits the phase jump angle change in the AC Grid following a power transient.
  - **Function 2.** It provides the main source of **Synchronising Power** in the AC Grid.
  - **Function 3**. It limits the **Initial RoCoF 2** rate in a local zone of the AC Grid for a power transient.

All of these functions are vital in contributing to System Inertia, managing vector shift and maintaining voltage profiles across the system during disturbed conditions which is a fundamental prerequisite for fault ride through. Traditionally these characteristics have been provided for free by the inherent capabilities of synchronous generation but going forward these services will have to be paid for.

- Network Frequency Perturbation "**NFP**" plots were proposed by **ENTSO-E** and other companies and have been suggested by **NGESO** (or an equivalent) as a way of defining the response of a **GBGF- I** inverter as shown on **Figure 3.2**.
- The **NFP** plot is an important method for showing the resonant frequency, phase changes and the damping of **GBGF- I** inverters which are important to **NGESO** and are also very different compared with existing inverter systems that do not have a low frequency resonance.

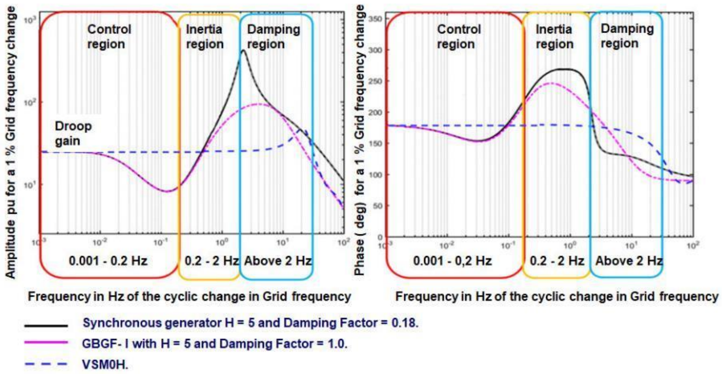

Figure 3.2. ENTSO-E example.

- **Enstore** recommends that the response of a **GBGF- I** inverter to AC Grid phase jumps of 5 and 20 degrees should be provided to **NGESO** with the **NFP** plot data as these are very important for a stable system, see Figures **9.4** and **9.6.**
- Due to the different operating speed ranges the required energy for a **GBGF- I** inverter is approximately 20 % of the energy of the equivalent **GBGF-S** generator as shown on **Figure 9.13.**
- When the **GBGF** work was starting one of the most important questions was "What controls the **RoCoF** rate in the first 20 ms of a system fault?".
- The answer is that the initial AC Grid phase jump instantly produces the **Active Phase Jump Power** which comes from either the rotating inertia of a **GBGF-S** generator or the software inertia of a **GBGF- I** inverter that cause the local frequency to fall exactly like the slower acting **Active Inertia Power**.
- The **Figure 10.1** shows that the **Active Phase Jump Power** is more important than the **Active RoCoF Response Power** in having a stable AC Grid. This change of emphasis has only recently occurred and is not reflected in the previous **GBGF** documents as well as most other Virtual Synchronous Machine **VSM** documents. Many **VSM** documents proposes a wide range of technical solutions that are not acceptable to **NGESO** which is why "**GB**" was added to the name of **GC0137** development.
- That when a power loss occurs the phase angle in the AC Grid will increase until the installed local zone **Active Phase Jump Power** becomes equal to the Worst Case Fault Power "**WCFP".**
- The value of the phase angle change in the AC Grid can be minimized by suppling the **Active Phase Jump Power** at a phase angle like 20 degrees.
- The **Figure 3.3** shows the design optimised for the stacked supply of the Stability Path Finder **NGESO Service** plus the Dynamic curtailment **NGESO Service** plus the Constraint management **NGESO Service** via a single feeder**.**

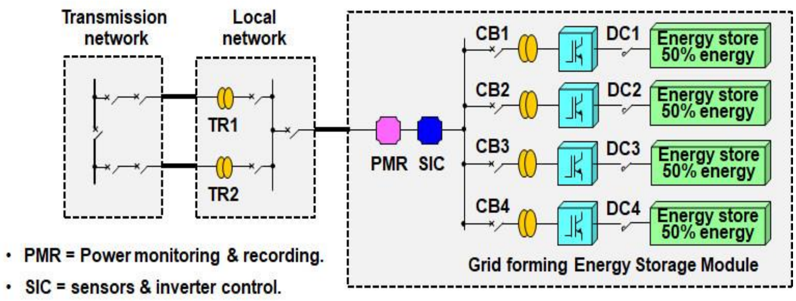

Figure 3.3. System to supply all the three NGESO Services.

The sections 10 to 14 also provide important data.

4. Introduction.

The four **Design Aims** for **GBGF converters** are:

5. To have a common set of essential requirements for **GBGF converters** that allow for open market competition. This is to enable all the different types of **GBGF converters** to compete for the different **NGESO Services**, that as a minimum include rotating Synchronous Generators, rotating Synchronous Condensers (Compensators), controlled directly connected rotating Flywheels, static **Power Converters** including **HVDC Converters**, **Reactive Compensation** equipment (such as STATCOMs) and Smart Loads or aggregated Electric Vehicles (V2G).
6. To have a common set of essential requirements for **GBGF converters** to form a common core for all existing and future **NGESO Services**.
7. To clearly define each of the essential requirements to promote the development of a range of viable alternative solutions for **GBGF- I** inverters**.**
8. To provide a technology that enables the AC Grid to operate reliably with only nuclear energy plus renewable energy for both normal and fault conditions.

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

For **GBGF- I** inverters 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 **Grid Forming 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 **GBGF** 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 have been provided to assist anyone in the understanding of a possible solution for a **GBGF- I** inverter 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.

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

5. Why do we need GB Grid Forming technology.

We need **GB Grid Forming** "**GBGF**" technology to be able to have an AC Grid system that can reliably operate with only low carbon sources. In the future this is likely to be made up of nuclear power and renewable power connected by static power converters with some use of Hydro Electric power.

In the Grid Code **NGESO** uses **GBGF-S** for a synchronous generator and **GBGF- I** for an inverter design and all the following data only applies to **GBGF- I** inverters unless otherwise stated.

The most important development is to make **GBGF- I** inverters operate the same as **GBGF-S** generators in an AC Grid system as shown on **Figure 5.1,** for normal operating conditions. The **Figure 5.1** is shown for a wind turbine system but this development applies to all **GBGF- I** inverters.

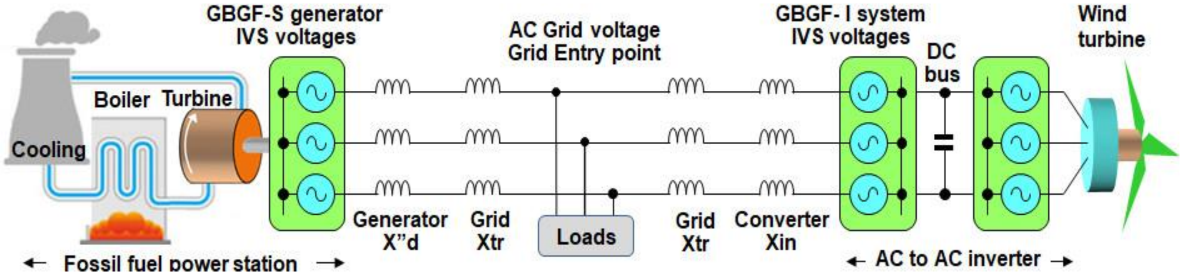

Figure 5.1. AC Grid system.

The **GBGF-S** generator has an Internal Voltage Source "**IVS**" that produces a set of balanced three phase voltages. The **IVS** voltages are also called the **EMF** voltages that do not change rapidly when there is a power transient at the Grid Entry point. The **GBGF- I** inverter also have an **IVS** that produces a set of balanced three phase voltages that do not change rapidly when there is an AC Grid power transient.

Selected 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 imbalance between the generated power and the load power.

When this occurs the following changes happen:

1. The AC Grid's frequency starts 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 from the synchronous generators has a slow response, typically measured in several seconds, and the extra generated power (item 2 above) is immediately taken from the rotating inertia of the synchronous generators.
4. Taking the extra power from the rotating inertia of the synchronous generator causes the rotating speed of the synchronous generator to fall that results in a Rate of Change of Frequency "**RoCoF**" in the AC Grid.
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 Frequency Response**.
7. Under the Grid Code **Primary Frequency Response** is specified to be available within 10 seconds and this then stops the fall of the AC Grid's frequency. This combined with **Secondary Frequency Response** can then enable the System Frequency to recover back to normal 50 Hz operation.
8. The supply of the **Primary Frequency Response and Secondary Frequency Response** is achieved by **NGESO** rewarding selected synchronous generators to operate below their rated output to have a defined value of the **Primary and Secondary Frequency Response** always available.
9. The magnitude of the available **Primary and Secondary Frequency Response** is constantly reviewed by **NGESO** to be sufficient for the likely worst case power transients that could occur which is ultimately defined by the Frequency Control requirements in the Security and Quality of Supply Standards (SQSS)
10. If the supply of **Primary Frequency Response** 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 until 47.8 Hz to stop any extra falls in the AC Grid's frequency. By the time the all the low frequency demand disconnection relays have operated at 47.8 Hz over 50% of National Demand will have been lost.

This set of actions are shown on **Figure 5.2** for a simulated major power transient.

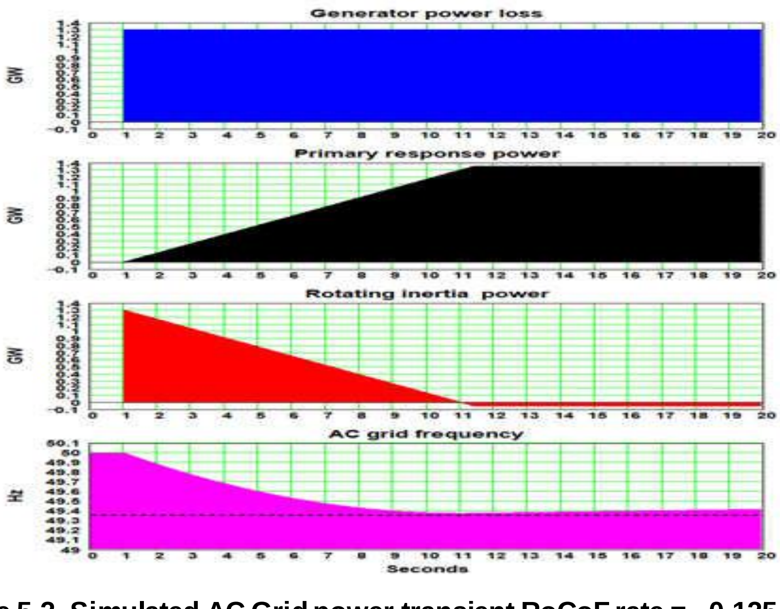

Figure 5.2. Simulated AC Grid power transient RoCoF rate = - 0.125 Hz / s.

When there is a power transient in the AC Grid there will be a phase change in the AC Grid and the **GBGF-S** generator will immediately start to produce a change in its output current.

The **GBGF-S** generator produces 4 **Types** of output current:

- **Type 1. Active Phase Jump Power** for changes in the phase of the AC Grid.
- **Type 2. Active Inertia Power** for a Rate of Change of Frequency "**RoCoF"** event in the AC Grid.
- **Type 3**. **Active Damping Power** for oscillations in the AC Grid.
- **Type 4**. **Active Control Based Power** for changes requested by the control system.

The sum of the **Types 1** to **3** active power is called the **Grid Forming Active Power** that is the inherent active power produced by **GBGF** technology for phase changes in the AC Grid. This is **Phase Based Power** and the **Grid Forming Active Power** is the power that stabalises the AC Grid system.

The **Type 4** power changes are produced by the control system of the **GBGF-S** generator and occur more slowly than the **Grid Forming Power** changes.

The **Figure 5.3** is data for a real AC Grid power transient that shows all the 4 **Types** of active power.

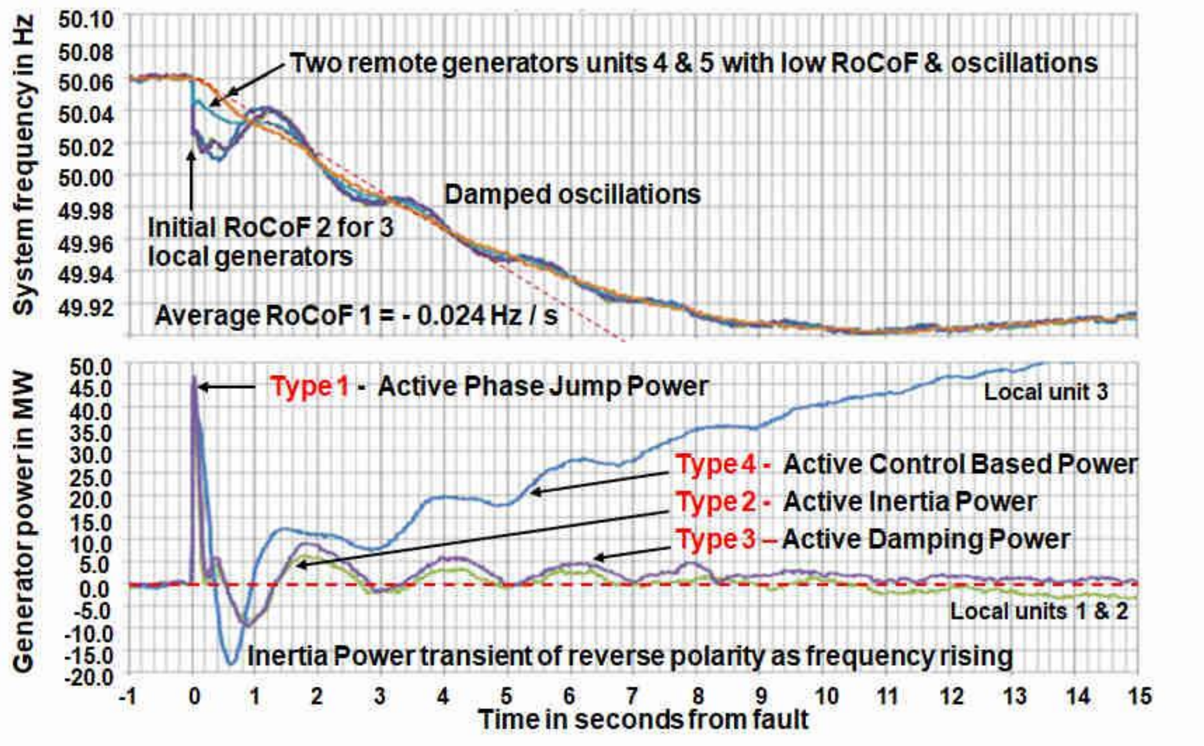

Figure 5.3. Real AC Grid local and remote power transient for 560 MW generators.

The main features of the **Figure 5.3** upper graph are:

- The three generator units 1, 2 & 3 are close to the fault.
- The generators unit 4 is 100 miles from the fault and unit 5 is 200 miles from the fault.
- The **Initial RoCoF 2** rate is very fast for the 3 local generators. The actual initial frequency and the **Initial RoCoF 2** rate has probably been affected by the phase jump as it has a frequency step.
- The 2 remote generators only experience the **Average RoCoF 1** rate of - 0.024 Hz / s.
- The 3 local generators have an initial frequency oscillation before aligning with the **Average RoCoF 1** rate.

The main features of the **Figure 5.3** lower graph are:

- There is a very significant short pulse of **Active Phase Jump Power** at the start of the transient.
- The frequency oscillations produce the **Active Damping Power.**
- The **Active Inertia Power** reduces as the **Average RoCoF 1** rate reduces.
- The local generators units 1 and 2 are operating without **Active Control Based Power**.
- The local generator unit 3 is operating with **Active Control Based Power** in the **FSM** mode.
- That all the three **Types** of the **Grid Forming Power** occur during this power transient.

The **Figure 5.4** shows the response of three 560 MW generators that were 200 miles away from a fault.

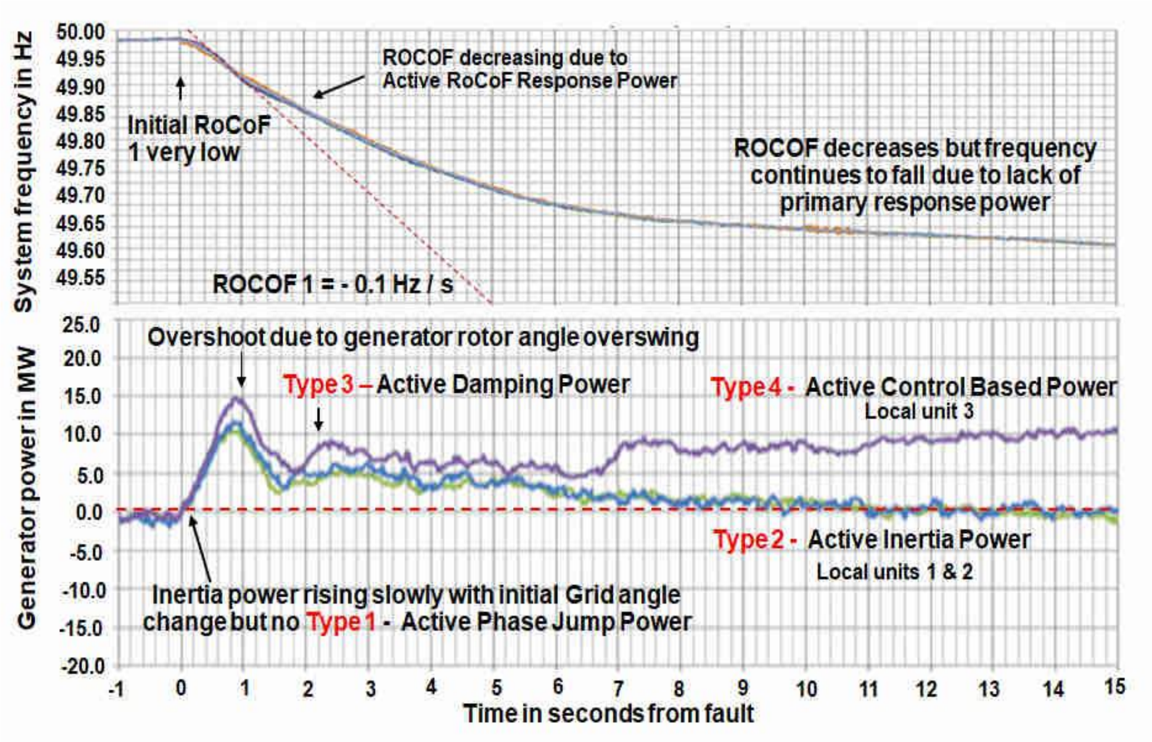

Figure 5.4. Real AC Grid remote power transient for three 560 MW generators.

The main **features of the Figure 5.4 upper graph are:**

- **The Average RoCoF 1** rate was initially very slow for the three generators.

The main features of the **Figure 5.4** lower graph are:

- The generators units 1 and 2 only produce **Active Inertia Power** that has a slow rise time.
- The generator unit 3 is operating with **Active Control Based Power** in the **FSM** mode.
- There is no pulse of **Active Phase Jump Power** at the start of the transient.
- The **Average RoCoF 1** rate produces the **Active Inertia Power** that reduces as the **RoCoF** rate reduces.

The **Figures 5.3** & **5.4** show that **Active Phase Jump Power** is only produced by generators near to a fault due to the phase jump angle that occurs. The figures also show that the **Active Inertia Power** has a slow rise time for the **Average RoCoF 1** rate which arises as there cannot be an instantaneous change in speed.

This effect is shown on **Figure 5.5** which is data from National Grid GC 0079 Grid Code Working Group on the 17/10/2017 showing phase changes for a major AC Grid short circuit fault.

Near to the fault in a local zone, the phase change was 57.48 degrees. In a remote zone the voltage dips were smaller and the associated phase change rapidly reduced to 20 degrees or lower.

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** inverters 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 AC Grid transients.

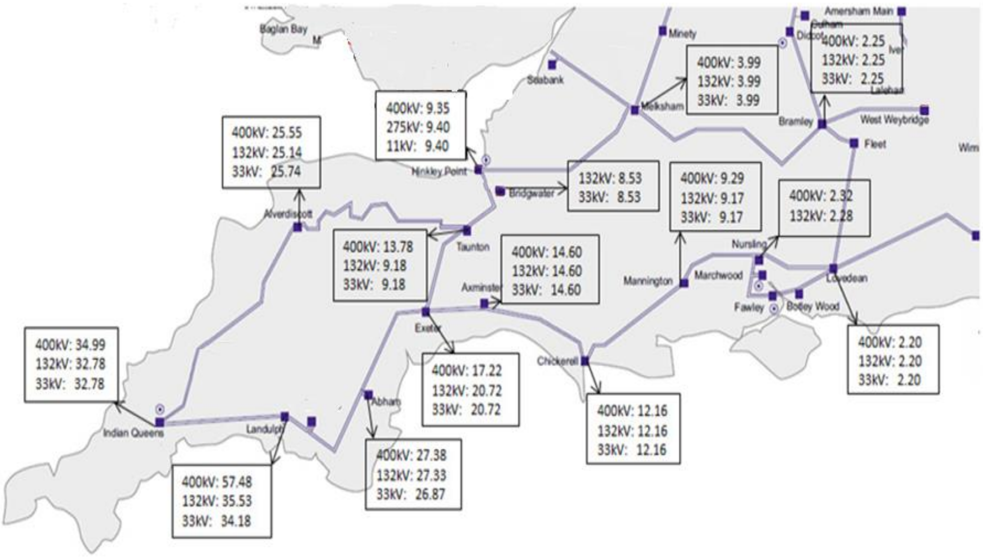

Figure 5.5. Measured site phase data for a short circuit fault.

During these phase jumps at rated voltage, the ability of **GBGF- I** inverters to supply their rated values of **Active Phase Jump Power** within less than one mains cycle is very important in having a stable AC Grid as this is replacing the capability of synchronous plant on a more like for like basis.

This is probably the main reason for changing from the original control based converter technology to the **GBGF- I** inverter technology.

The reason for this is that the **Active Phase Jump Power** provides three vital functions:

- **Function 1.** It limits the phase jump angle change in the AC Grid following a power transient.
- **Function 2.** It provides the main source of **Synchronising Power** in the AC Grid.
- **Function 3**. It limits the **Initial RoCoF 2** rate in a local zone of the AC Grid for a power transient.

The **GBGF- I** inverters must also provide these functions to have a stable AC Grid.

6. What is a GBGF- I inverter.

The essential features of a **GBGF- I** inverter are shown on **Figure 6.1**.

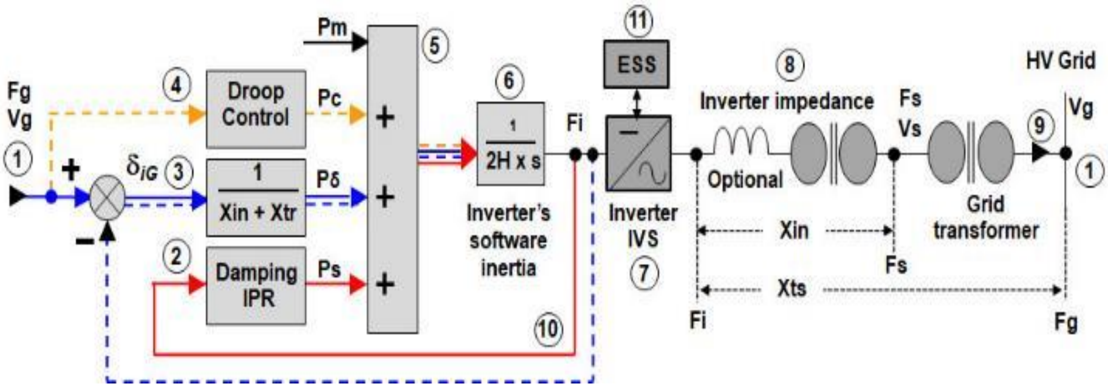

Figure 6.1. GBGF- I inverter.

GBGF- I inverters have an Internal Voltage source "**IVS**" behind a real impedance and the Grid Code does not permit **GBGF- I** inverters with any form of a synthetic (not real) AC supply impedances. The reason is that this requires high bandwidths from the Internal Voltage Source which in turn can give an undesirable performance, particularly in respect of system stability.

When a change in the phase of the AC Grid occurs, the **GBGF-S** generator and the **GBGF- I** inverter both immediately start to produce phase-based AC Grid current without any actions occurring in the associated control systems. The AC impedances of the two systems are very similar so the initial rate of rise of the AC Grid currents are also very similar. The main differences is that the **GBGF- I** inverter uses a fast-acting current limit to avoid tripping for large phase changes.

For externally requested output power changes the **GBGF- I** inverter's control system produces changes in the **IVS** voltages with a bandwidth of less than 5 Hz when operating in normal conditions.

For internal changes in the **GBGF- I** inverter's control system they can have a bandwidth of up to 1000 Hz for all conditions and the same bandwidth applies to AC currents produced by AC Grid phase changes.

The power into the AC Grid is provided by the inverter's Internal Voltage Source "**IVS**" that can use any of the existing power converter circuits using Pulse Width Modulation "**PWM**" or any equivalent technology. To become a **GBGF- I** inverter requires a new control system and the correct rating of the **IVS**.

The most important features of a **GBGF- I** inverter is that the frequency and phase of the inverter's **IVS** can only change slowly, like a **GBFF-S** generator, to provide automatic **Phase Based Power** without any actions by the **GBGF- I** inverter's control system.

The Main Features of **Figure 6.1** are:

1. AC supply with frequency **Fg** and voltage **Vg**.
2. Software based damping function using the supplier's software **IPR** in any viable circuit.
   The circuit shown uses the **Enstore** circuit and software damping function.
3. AC supply impedance with an input of the phase difference of the AC supply and Inverter's **IVS**.
4. **Droop control**, when used, or any other control features.
5. Inverters power balance with the net output to the Software based inertia.
6. Software based inertia that defines the frequency of the **IVS.**
7. Hardware based **IVS** with a slow response to all changes for normal conditions, see **NFP** plot data.
8. AC supply circuit that does not have synthetic (not real) impedances.
9. Current that has an instant response to AC supply phase changes.
10. There are two damping loops, solid red for the software and dotted blue for the AC supply.
11. The Energy Storage System "**ESS**" is needed to supply the **Active Phase Jump Power** and can use any technology.

The system has a closed loop action as shown by the dotted Blue line which produces a response similar to a second order system with a selectable **Damping Factor**. The closed loop action of **Figure 6.1** also ensures that the frequency of the inverter **IVS** output **Vivs(ω)** tracks the frequency of the AC Grid input **Vg(ω),** and this must be maintained during worst case frequency changes by the rating of the **GBGF- I** inverter. This is to avoid the possibility of pole slipping that can occur with **GBGF-S** generators.

The **Damping Factor** is selected to be the optimal value for a specific project and is provided by:

- The losses in the AC supply impedances **Xin** plus **Xtr**.
- The extra damping provided by the software damping function.

The **Active Control Based Power** is the active power output supplied by controlled means that can be manual or automatic by the control system of a **GBGF** system.

For **GBGF- I** inverters this is equivalent to that of a **GBGF-S** generator with a traditional governor coupled to its prime mover.

Active Control Based Power includes the active power changes that results from a change to the Grid Forming Plant Owner's available set points that have a 5 Hz limit on the bandwidth of the provided response. The 5 Hz limit is a standard requirement in the Grid Code to avoid mechanical resonance problems with other connected **GBGF-S** generators.

The response of a typical second order system with a **Damping Factor** of 0.707 is shown on **Figure 6.2.**

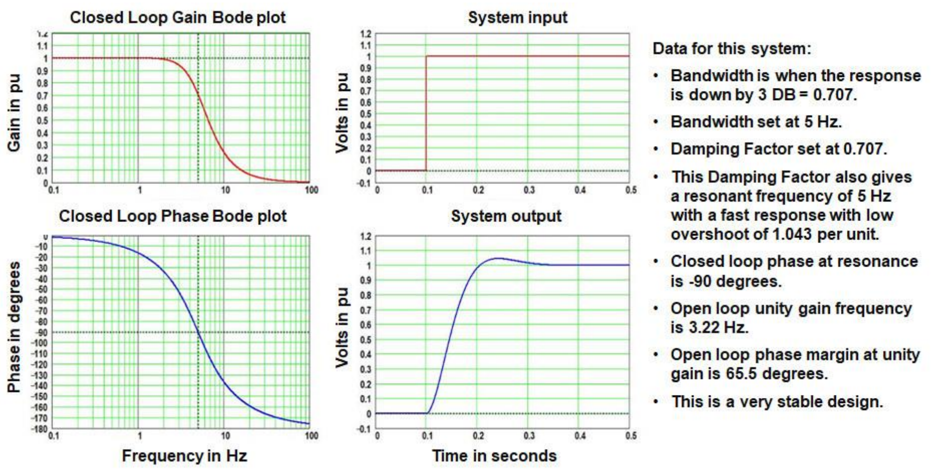

Figure 6.2. Response of a second order system with a 5 Hz bandwidth.

Active Control Based Power also includes active power components produced by the normal operation of a **GBGF- I** inverter that comply with the Engineering Recommendation P28 limits. These active power components do not have a 5 Hz limit on the bandwidth of the provided response as they have a low amplitude defined by the P28 limits.

Active Control Based Power can include many other functions like a Power System Stabiliser or the **Droop control** function shown on **Figure 6.1**.

The closed loop action shown by the dotted blue line on **Figure 6.1** is very important as it ensures that a **GBGF- I** inverter's **IVS** remains synchronised to the AC Grid. For this action to occur for all **RoCoF** events the inverter must no go in to a current limit condition.

The **GBGF- I** Inverter has two **RoCoF** rating values:

- The **IVS** must stay in linear control for a **RoCoF** rate of +/-1 Hz / s which is the allowed maximum.
- The **IVS** must stay synchronised for a **RoCoF** withstand rate of +/- 2 Hz / s to give a safety margin.

To maintain linear control the **GBGF- I** inverter **Peak Current Rating** is based on the following:

- The **Phase Jump Angle Limit** power is defined as the power for a recommended **Phase Jump Angle Limit** angle change of 5 degrees with the system remaining in linear control**.** The 5 degrees is to ensure that all the **GBGF- I** inverters in remote zones continue to operate in the linear mode.
- The **Active RoCoF Response Power,** see **Section 9** for calculating the rating.
- The **Defined Active Damping Power** is based on the **Defined Grid Oscillation Value** which is defined as 0.05 Hz peak to peak at a frequency of 1 Hz.
- The **Active Phase Jump Power** does not occur at the same time as the **Active Inertia Power**.
- The **Active RoCoF Response Power** occurs at the same time as the **Active Damping Power**.
- The system can have an increased **Peak Current Rating** if this is beneficial.
- Each of these currents can have a negative sequence component defined by unbalanced voltage tolerances listed in the Grid Code.

For a **GBGF- I** inverter the **Peak Current Rating** is the larger of three possible ratings:

Rating 1. The registered maximum **steady-state current** plus the maximum additional current to supply the **Active ROCOF Response Power** plus the **Defined Active Damping Power**.

Rating 2. The registered maximum **steady-state current** plus the maximum additional current to supply the **Phase Jump Angle Limit** power.

Rating 3. The maximum **short term total current** defined by the User.

If the **Peak Current Rating** is not based on **Rating 2**, then the system will remain in linear control to a larger phase jump angle change called the **Phase Jump Angle Rating** that is a larger angle than the **Phase Jump Angle Limit** angle recommended to be 5 degrees. For example an **ESS** could have a **Phase Jump Angle Rating** of 20 degrees.

The **GBGF- I** inverter must also remain connected without tripping up to the **Phase Jump Angle Withstand** value of 60 degrees.

There are two operational conditions that will cause a **GBGF- I** inverter to reach the **Peak Current Rating** and go into a current limiting control which are:

- There is a large phase jump angle change. If this occurs the control of the **GBGF- I** inverter will go in to the **Current Limit Mode** and then rapidly regain control to normal operation in a few milli seconds by a fast change of the phase angle of the **IVS**.
- There is a large voltage reduction in the AC Grid's voltage at either the Grid entry point or User system entry point. If this occurs the **GBGF- I** inverter will maintain linear control until it is necessary to go in to the **Current Limit Mode** and to provide the **Fast Fault Current** and **Fault Ride Through** operating modes which will normally last less than 140 milliseconds.

  The AC impedances of **GBGF-S** generators and **GBGF- I** inverters are very similar and the initial rate of rise of the **Fast Fault Current** are also very similar.

When the **GBGF- I** inverter is operating in the **Current Limit Mode** the limitation on the **IVS** only changing slowly do not apply and the control systems uses the relevant control functions to provide a satisfactory operation during and on leaving the **Current Limit Mode.**

7. What are the limits on RoCoF rates.

Following a power transient the frequency of the AC Grid will fall until extra power is applied to recover the frequency back to the standard 50 Hz value.

This effect is shown on **Figure 7.1** that is an extract of a recording made by the **EFCC** project.

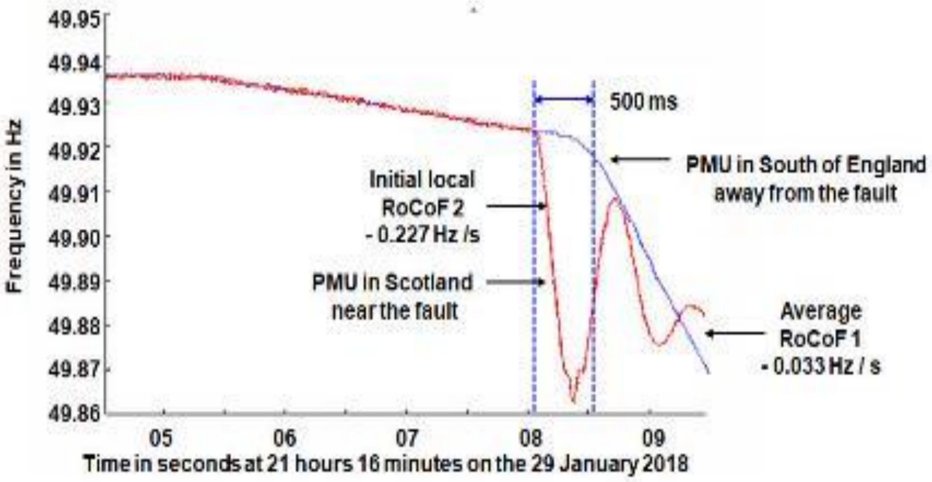

Figure 7.1. RoCoF data from the EFCC recordings.

The observed **RoCoF** rate in the local zone, near to the source of a disturbance, is called the **Initial RoCoF 2** rate that is set by the **Grid Forming Power** in the local zone.

The **Initial RoCoF 2** rate has a maximum value of +/- 1 Hz / s for planning the AC Grid. This value was chosen as it is the specified withstand value for **GBGF-S** generators for a continuous **RoCoF** rate.

This is also the specified maximum operating value for **GBGF- I** inverters working in the linear operating mode. A higher value of +/- 2 Hz / s has been specified as a withstand requirement for **GBGF- I** inverters to remain operational as an extra safety margin.

The observed **RoCoF** rate in the local zone then changes in less than one second to become the **Average RoCoF 1** rate, in line with the other remote zones of the AC Grid.

The **Average RoCoF 1** rate is set by the **Grid Forming Power** of the complete AC Grid system, see **Figure 7.2** and the rate depends on the total AC Grid's inertia and is typically +/- 0.3 Hz / s.

Based on the recorded data the typical time duration at the **Initial RoCoF 2** rate lasts for less than 300 milli seconds and there is data in **Reference 21.2** that suggests that a higher **Initial RoCoF 2** rate could be used.

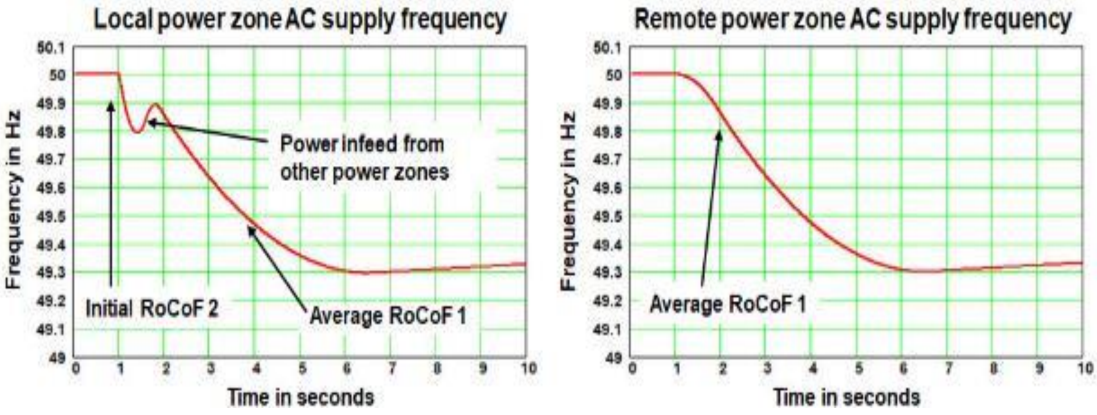

Figure 7.2. Initial and Average RoCoF rates.

For a viable AC Grid system there are two primary **Grid Forming Power** requirements:

1. The available **Grid Forming Power** in any local zone must be sufficient to limit the **Initial RoCoF 2** rate to +/- 1 Hz / s taking in to account the largest power transient that can occur in a local zone.
2. The available **Grid Forming Power** for the complete AC Grid must be sufficient to limit the **Average RoCoF 1** rate 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 required total installed **Grid Forming Power** is then defined by combining these effects.

The increasing use HVDC interconnectors in local zones is increasing the need for **Grid Forming Power** to be installed in local zones as shown on **Figure 7.3**.

The **Figure 7.3** combines the zones of **References 21.1** with the inter connectors of **Reference 21.3** to give a possible UK zonal system proposed by **Enstore**.

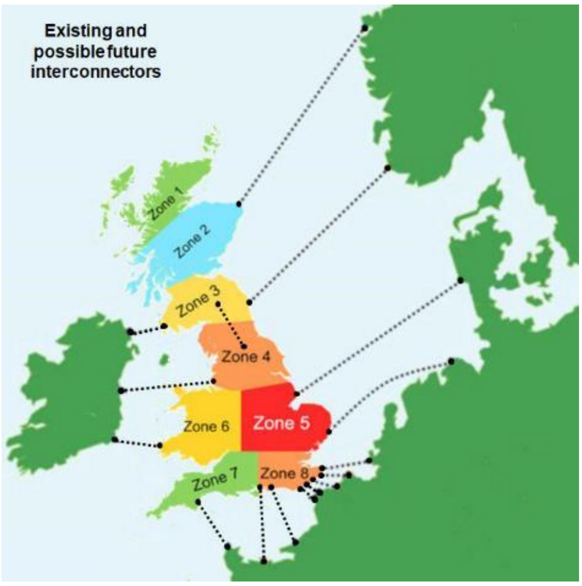

Figure 7.3. Possible UK zonal system.

8. How do GBGF- I inverters interact with the AC Grid.

The interaction of **GBGF- I** inverters with the AC Grid is defined by:

- Network Frequency Perturbation "**NFP**" plots.
- The resonant frequency "**Fr**" of the **NFP** plot.
- Equivalent **Damping Factor** "**ζe**" of the **NFP** plot based on the equivalent second order system.

Network Frequency Perturbation "**NFP**" plots were proposed by **ENTSO-E** and other companies and have been suggested by **NGESO** (or an equivalent) as a way of defining the response of a **GBGF- I** inverter as shown on **Figure 8.1**. The **NFP** plot is an important method for showing the resonant frequency, phase changes and the damping of **GBGF- I** inverters which are important to **NGESO** and are also very different compared with existing inverter systems that do not have a low frequency resonance.

Suppliers can use **NFP** plots or any other viable way for sending data to **NGEO** for a project.

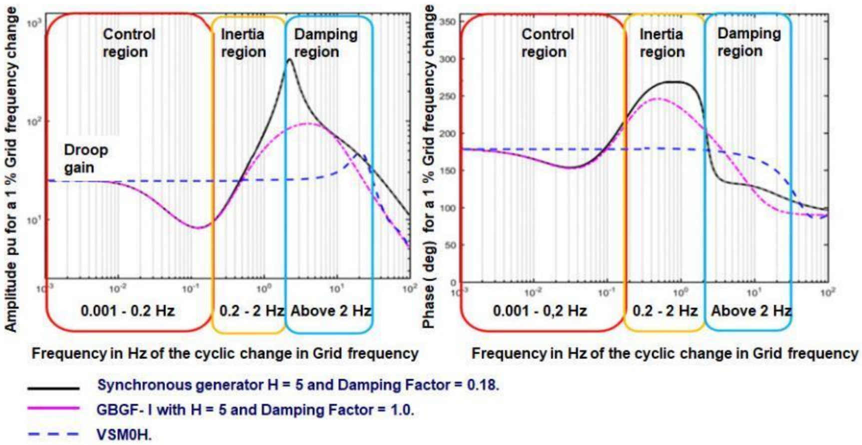

Figure 8.1. ENTSO-E example.

A **NFP** plot can be calculated in the time domain or the frequency domain. When **NFP** plots are produced in the time domain the **NFP** plot can have a range of different test input and output signals to show different response features.

For the **GBGF- I** inverters, the **NFP** plots are normally produced in the frequency domain with a sine wave test input signal with a wide frequency range in to the AC supply that produces the resulting magnitude and phase perturbations in the AC Grid's current.

The amplitude of the test input signal is sufficiently small to keep the system in its linear operating mode and as the AC supply is at 1 per unit the resulting perturbations in the AC Grid's current are also perturbations in the AC Grid's power.

The basic system diagram for a **GBGF- I** inverter with external damping from the AC supply and internal damping from the **Gd (ω)** function is shown on **Figure 8.2** where **R** and **L** are the pu AC impedances. This figure also gives the **NFP** resonant frequency **Fr** with zero internal damping.

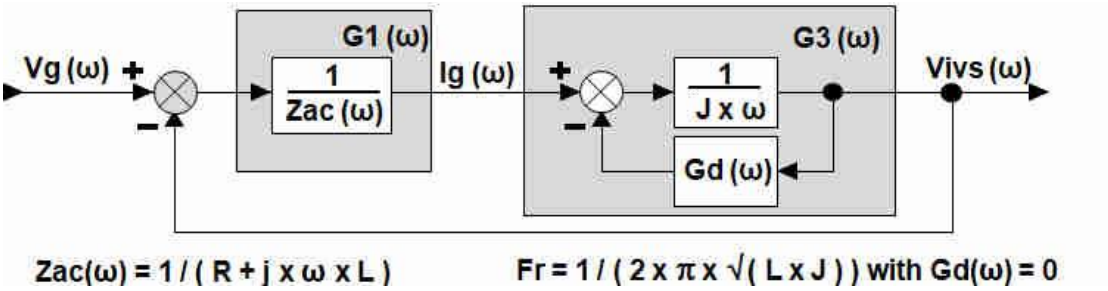

Figure 8.2. System with external damping.

The steps in producing the **NFP** plot are shown on **Figure 8.3.**

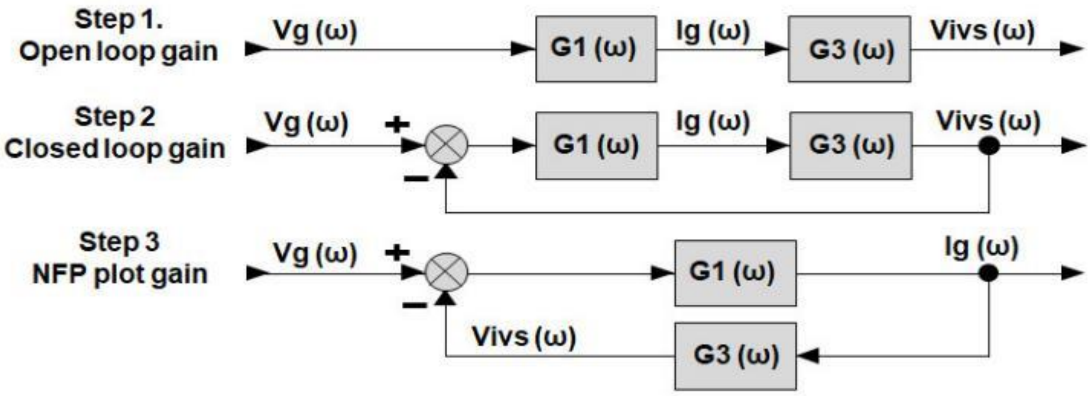

Figure 8.3. Stages in producing the NFP plot in the frequency domain.

The three steps are carried out using standard Bode diagram frequency analysis software and **Enstore** has a program for rapidly producing **NFP** plots and for the **Gd(ω)** software damping algorithm.

The damping function **Gd (ω)** can use a wide range of equations including the **Enstore** equation.

The most basic equation for the damping function is a gain **DE**.

A typical basic **NFP** plot is shown on **Figure 8.4** for an inertia of **Hi = 5** that is **J = 10** and an AC supply inductance of 0.00106 pu (per unit). This is a supply impedance at 50 Hz of 0.333 pu Ohms.

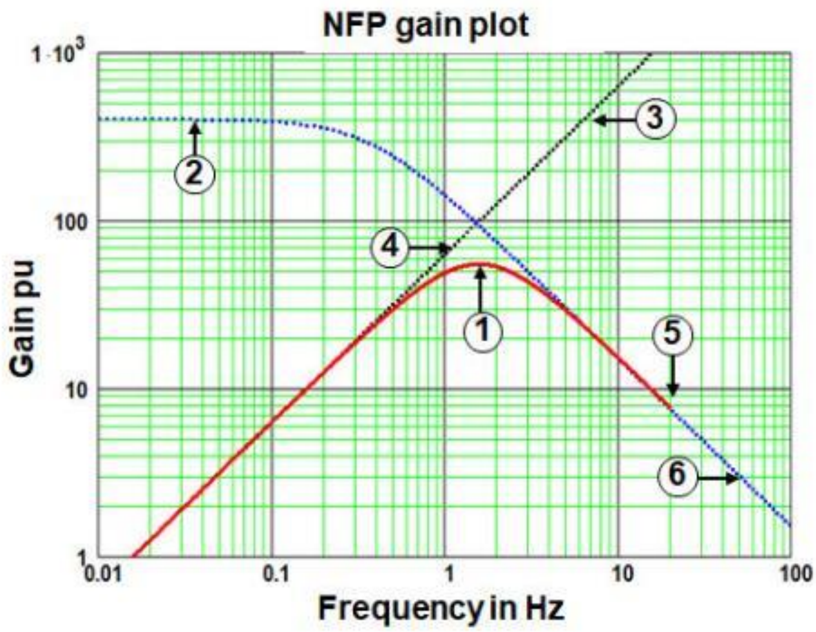

Figure 8.4 Basic NFP plot.

The key features of **Figure 8.4** 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 8.4** 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 8.4** 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. 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** without any internal damping.
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 = **1 / 0.333 = 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 and this is a key topic to be defined in the **Best Practice Guide**.

The systems equivalent **Damping Factor** "**ζe**" can be calculated for any system from the **Nichols** Open Loop Gain versus Open Loop Phase plot that can be produced as part of producing the data on **Figure 8.3.**

To calculate the **ζe** 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 8.5** 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.

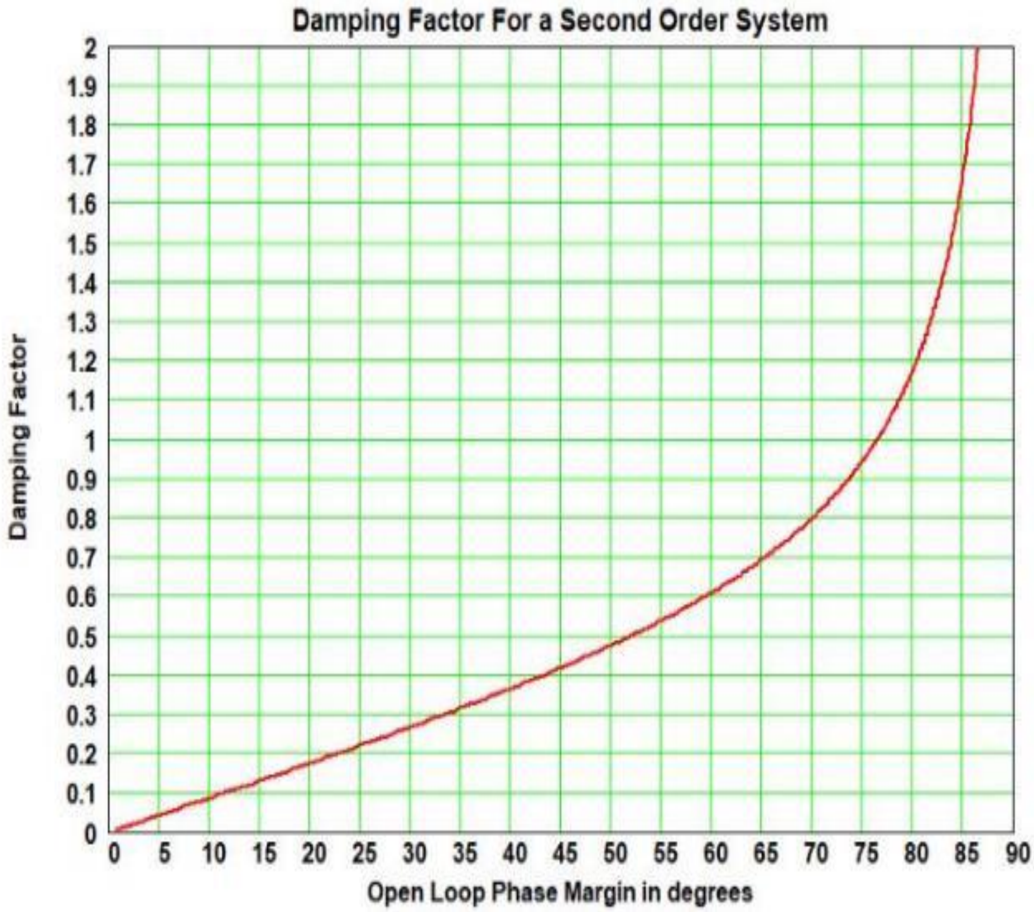

Figure 8.5. Damping Factor graph for a second order system.

The **Figure 8.6** is a full **NFP** plot for a system with low and high damping.

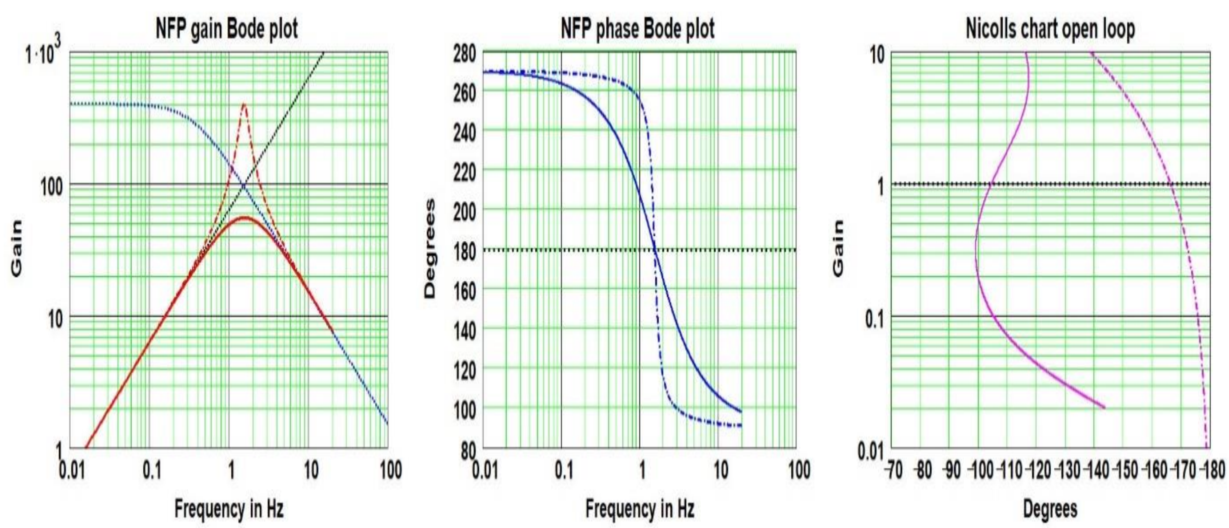

Figure 8.6. Full NFP plot.

The NFP plot with the solid Red line is the data for the **NFP** plot shown on **Figure 8.4** 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 **Nichols Chart** that gives an **Open Loop Phase margin angle** of 75 degrees.
- An equivalent **Damping Factor ζe** of 0.92 for a second order system by using the **Figure 8.5.**
- A **Nichols** plot with an **Open Loop Phase margin angle** that increases as the gain falls which is not a normal shape for a second order system. This shape is the result of the software **Gd(ω)** damping function adding extra damping and extra system stability.

The **NFP** plot with the dotted Red line is the data for the **NFP** plot shown on **Figure 8.4** 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 **Nichols chart** that gives an **Open Loop Phase margin angle** of 14 degrees.
- An equivalent **Damping Factor ζe** of 0.12 for a second order system by using **Figure 8.5.**
- A **Nichols** 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** plots for use on the AC Grid to have a maximum gain of 200 as shown by the upper limit value on **Figure 8.8.**

NFP plots can represent systems with all the required control features as shown on **Figure 8.7** that has low frequency **Droop control**.

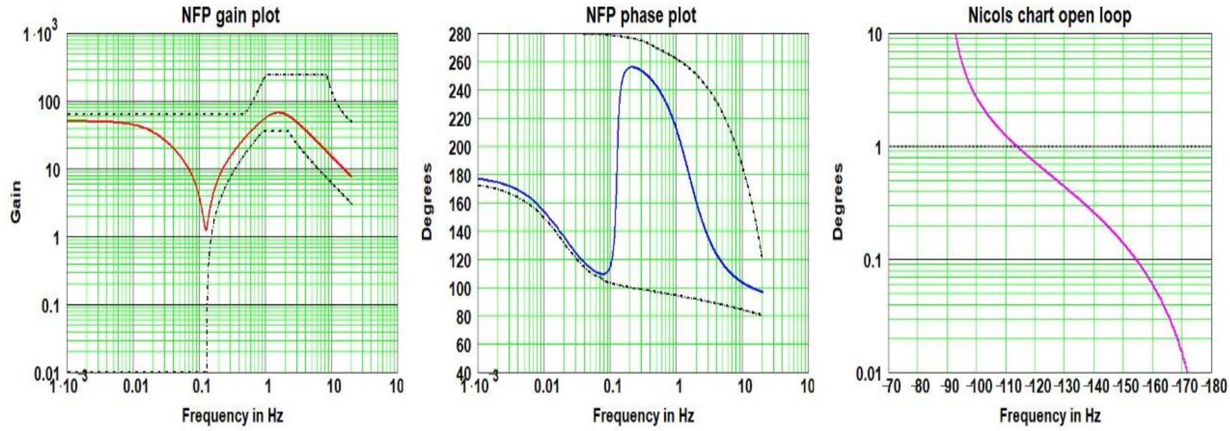

Figure 8.7. NFP plot for a system with low frequency Droop control.

The **Figure 8.7** has upper and lower dotted black lines which are the **Enstore's** proposed limits for an acceptable **NFP** plot which are shown in more detail on **Figure 8.8.**

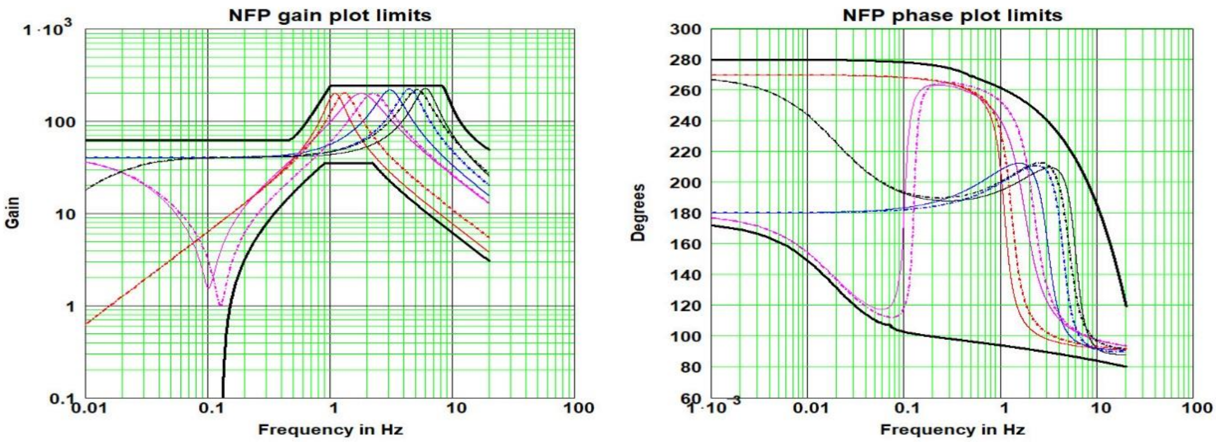

Figure 8.8. Proposed NFP plot limits.

The **Figure 8.8** was produced for a range of **Hi** values, AC supply impedance values and for a set of **Droop control** options 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 system was used it could adversely interact with the existing Power System Stabiliser controls**,** used on existing **GBGF-S** generators 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 **Active Phase Jump Power** is produced for phase jump transients, see **Section 9.**

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 **Best Practice Guide** and these proposed **NFP** plot limits may then need to be revised. To do this validation will require the **NGESO**, as part of the expert group work, to simulate the AC Grid with different **NFP** plot designs to test their compatibility with the existing AC Grid.

9. Inertia and responses of a GBGF systems.

The definition of the Inertia Constant **"H"** for a **GBGF-S** generator is given by **Equation 1.**

- **Equation 1. Hg = (Installed Energy in MWs) / (Installed MVA).**
- In simulation models the symbol **J** is used for Inertia and **J = 2H,** this is needed as inertia is proportional to frequency squared.

The definition of the **Active Inertia Power "AIP"** for a **GBGF-S** generator is given by **Equation 2.**

- **Equation 2. AIP_{ROCOF} = (Hg x Installed MVA x -1 x RoCoF x 2) / (Frequency).**
- The -1 is needed as a positive **AIP** value is given by a negative **RoCoF** rate.

The definition of the **Active Inertia Power** for a **RoCoF** rate of -1 Hz / s is given by **Equation 3.**

- **Equation 3. AIP_1 = (Hg x Installed MVA) / (25).**
- For a system with **Hg = 5** the **AIP_1** is 20 % of the Installed MVA.
- 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.

The **Equations 1** to **3** cannot be used with **GBGF- I** inverters as the **H** value is not related to the energy stored in the inverter and two **GBGF- I** inverter values are defined as **Hi** and **He**.

The definition of the Inertia Constant **"Hi"** for a **GBGF- I inverter** is given by **Equation 4.**

- **Equation 4. Hi = (AIP_1 x 25) / (Installed MVA).**
- Where **AIP_1** is the **Active Inertia Power produced** for a **RoCoF r**ate of -1 Hz / s.
- For a system that produces an **AIP_1** value of 20 % of the Installed MVA the value is **Hi = 5**.

The definition of the Inertia Constant **"He"** for a **GBGF- I inverter** is given by **Equation 5.**

- **Equation 5. He = (ARP_1 x 25) / (Installed MVA).**
- Where **ARP_1** is the **Active RoCoF Response Power** at 1 second with a **RoCoF** rate of 1 Hz / s.
- For a system that produces an **ARP_1** value of 100 % of the Installed MVA the value is **He = 25.**
- The **Equation 5** allows a **GBGF – I** inverter with an **NFP** resonant frequency of **Hi = 5** to deliver a power of 100 % of the Installed MVA by adding extra **Active Frequency Response Power**.

The **Figure 9.1** is the **NFP** plot for a system with **Hi = 5** and a **NFP** plot resonant frequency of 1.55 Hz and an AC supply with a pu inductance of 0.00106 pu which gives an AC supply impedance of 0.333 pu.

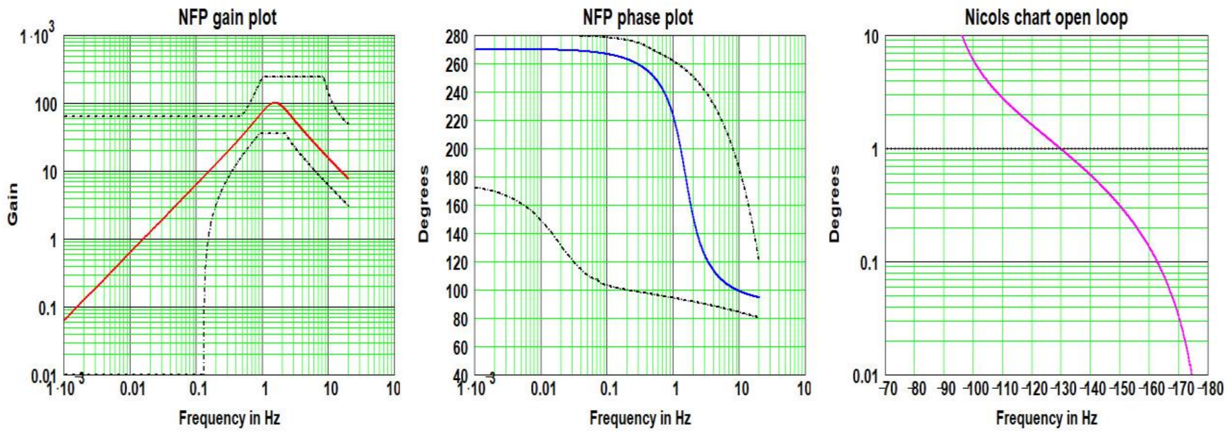

Figure 9.1. NFP plot Hi = 5.

The system has an open loop phase margin of 50 degrees that is an equivalent **Damping Factor** = 0.48 which gives a well damped response. The **Figure 9.2** is the response of this **GBGF- I** inverter for a phase jump of 5 degrees.

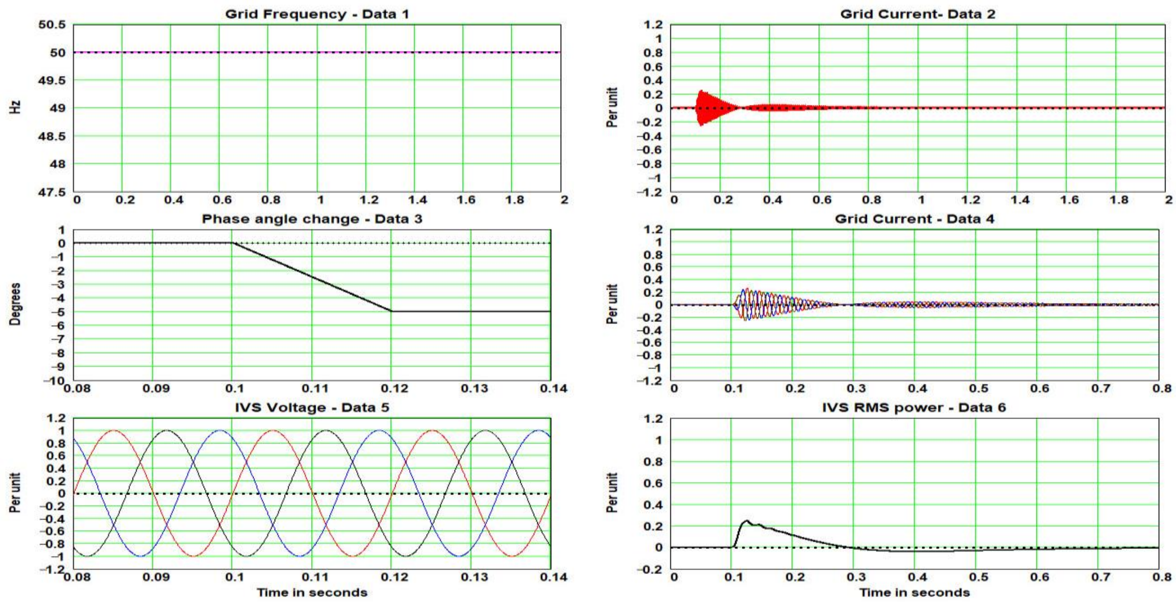

Figure 9.2. Phase Jump response.

The **Figure 9.2** shows:

- For Data 1 the AC Grid's frequency that is constant at 50 Hz.
- For Data 2 the envelope of the line currents for 2 seconds to show the total response.
- For Data 3 the Phase change that was applied over 20 ms at 100 ms to avoid DC components.
- For Data 4 the individual line currents for 0.8 seconds to show more details.
- For Data 5 an expanded view of the inverter's **IVS** voltage to show that they are constant.
- For Data 6 the RMS power.
- The same sets of data are used on the following time based figures.
- The **Active Phase Jump Power** is applied very rapidly but then falls with a response time defined by the **NFP** plot's resonant frequency.
- The standard power equation for a 5 degree phase jump gives a current of **Current = 2 x Vivs x sin (Angle / 2) / Xt = 0.26** pu see **Figure 9.11**.

The **Figure 9.3** is the response of the same **GBGF- I** inverter design for a **RoCoF** rate of -1 Hz / s.

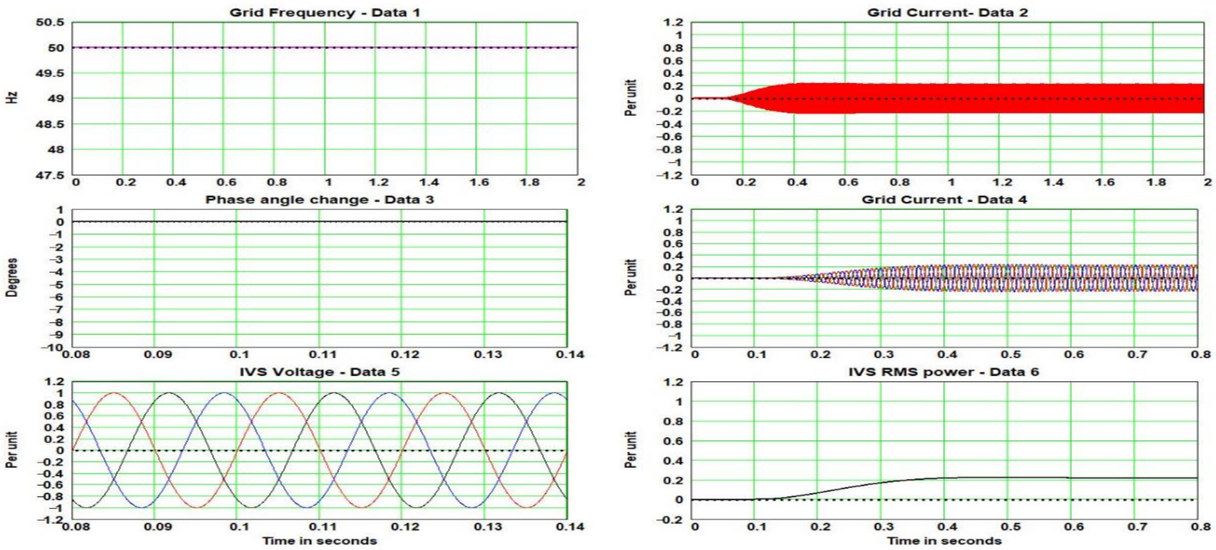

Figure 9.3. RoCoF response.

The **Figure 9.3** shows:

- For Data 1 the AC Grid's frequency has a -1 Hz / s **RoCoF** rate starting at 100 ms.
- For Data 3 that there is not a phase jump.
- For Data 4 that the **Active Inertia Power** has a slow rise time but is then constant.
- The **Active Inertia Power** of 0.2 pu is as predicted by **Equation 4**.

The **Figure 9.4** is the response of this **GBGF- I** inverter design for a 5 degree phase jump plus a **RoCoF** rate of -1 Hz / s both starting at 100 ms.

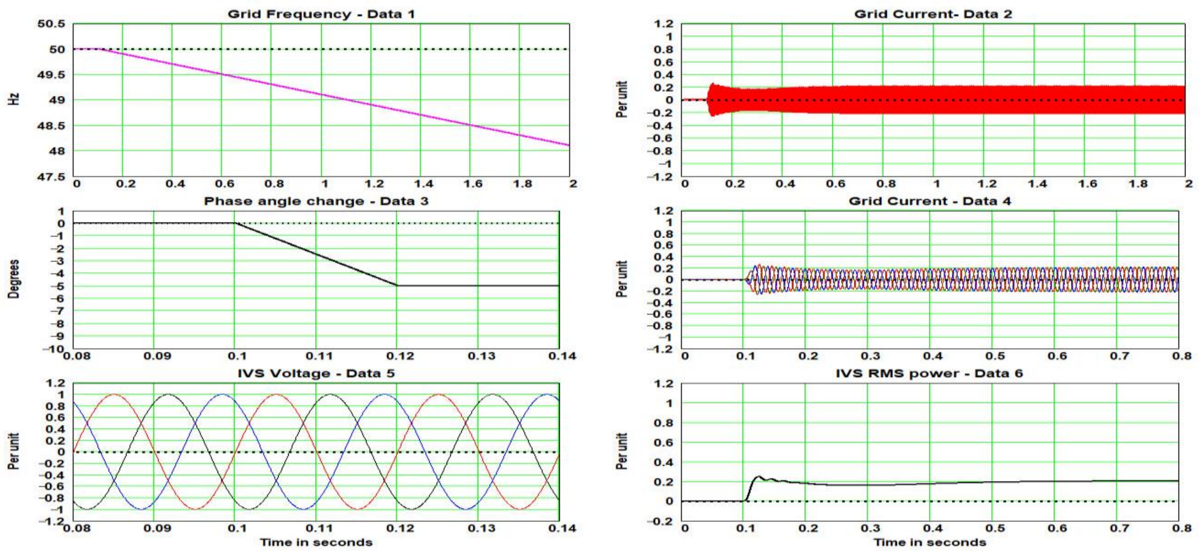

Figure 9.4. Combined Phase Jump plus RoCoF response.

The **Figure 9.4** shows:

- For Data 1 the AC Grid's frequency has a -1 Hz / s **RoCoF** rate starting at 100 ms.
- For Data 3 that there is a phase jump also starting at 100ms.
- For Data 4 that the response is the sum of the **Active Phase Jump Power** plus the **Active Inertia Power** response.

The **Figure 9.5** is the **NFP** plot for a system with **Hi = 25** and a **NFP** plot resonant frequency of 0.69 Hz using the same AC supply impedance.

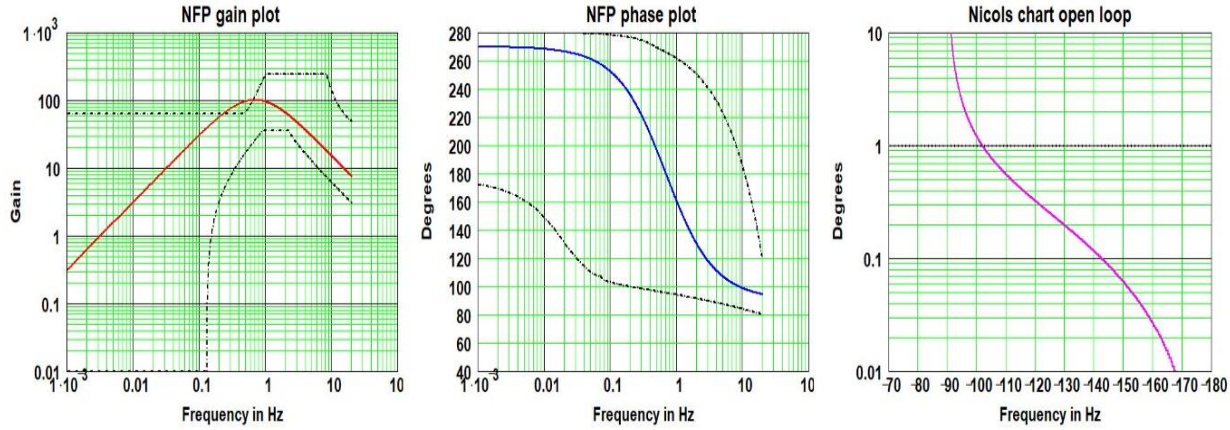

Figure 9.5. NFP plot Hi = 25.

The system has an open loop phase margin of 78 degrees that is an equivalent **Damping Factor** = 1.108 which gives a very well damped response.

Figure 9.6 is the response of an energy storage system that has no continuous power rating with a current limit of 1 pu that gives an **Hi = 25** rating. The response is for a 20 degree phase jump plus a **RoCoF** rate of -1 Hz / s both starting at 100 ms. This response is not possible with existing static power converters.

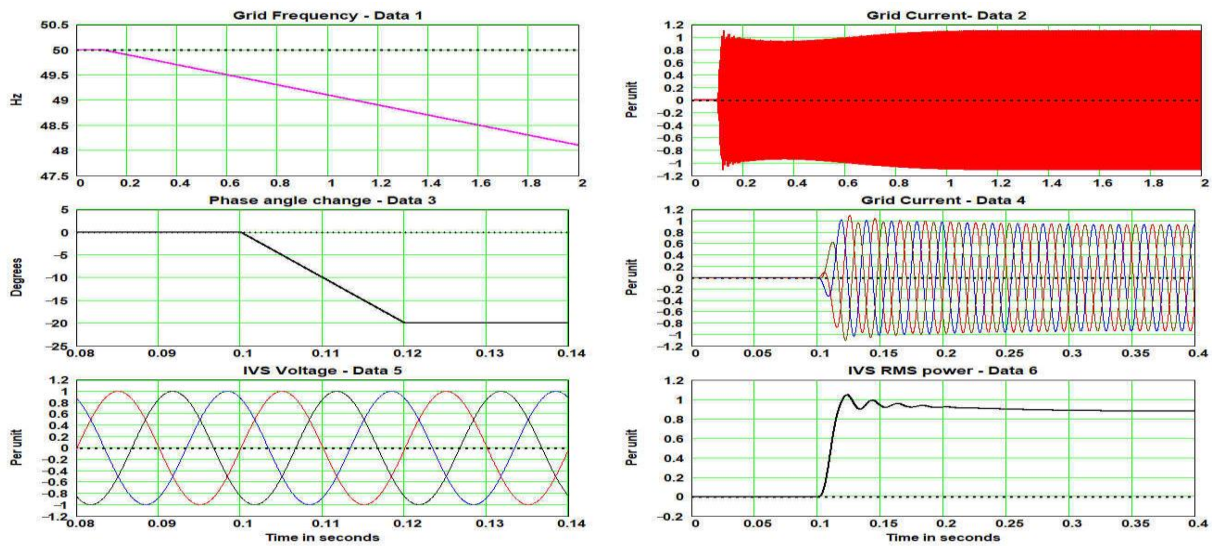

Figure 9.6. Combined Phase Jump plus RoCoF response.

The **Figure 9.6** shows:

- For Data 1 the Grid's frequency has a -1 Hz / s **RoCoF** rate starting at 100 ms.
- For Data 3 that there is a 20 degree phase jump also starting at 100ms.
- For Data 4 the power is produced with no delay and then continues for 2 seconds.
- The **Active Inertia Power** of 1.0 pu is as predicted by **Equation 4**.

This data is for a system that has an **NFP** plot shown on **Figure 9.5** that has a very low resonant frequency of 0.69 Hz. This resonant frequency does not presently occur in the AC Grid and may not be acceptable to **NGESO**.

This data shows that the same **Active Phase Jump Power** and **Active RoCoF Response Power** give the same **RoCoF** which is a very important result.

The system also has a response outside the **NFP** limit lines that may also not be acceptable to **NGESO.**

The **Figure 9.7** shows an **alternative viable design** for the same energy storage system with an **Hi = 5** value giving a **NFP** resonant frequency of 1.55 Hz.

This design uses the **Full Droop control** feature to give an extra **Active Frequency Response Power** to give an **Active RoCoF Response Power** of 1 pu. If required a **Hybrid Droop control** can be used to give the extra **Active Frequency Response Power** but with a lower **NGESO Droop Gain** at low frequencies.

The **Equation 5** gives an **He = 25** value for this design.

This design is why the definitions of the **Active RoCoF Response Power** and the **Equation 5** have been used to give an optimal design with a maximum power response to a **RoCoF** event.

The **Figure 9.7** is the **NFP** plot for a system with **Hi = 5** and a **NFP** plot resonant frequency of 1.55 Hz and an AC supply with a pu inductance of 0.00106 pu which is an AC supply impedance of 0.333 pu.

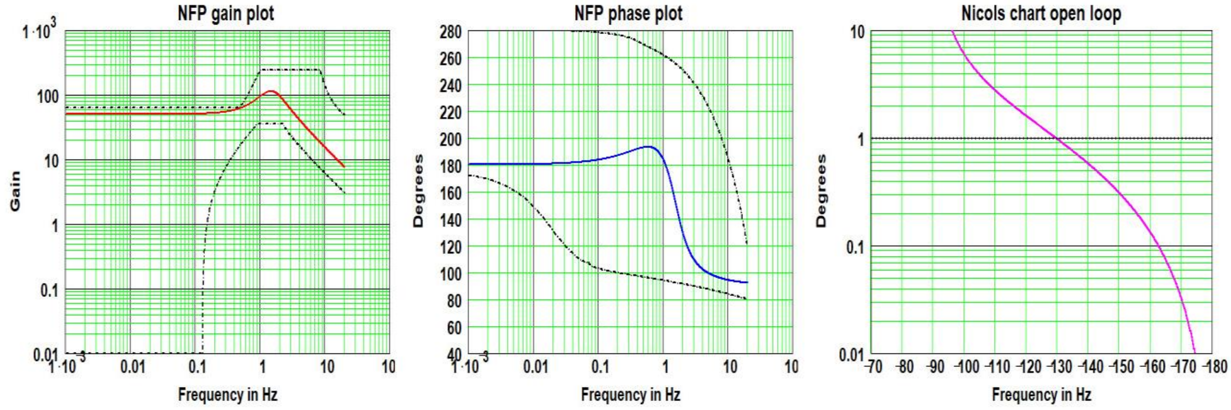

Figure 9.7. NFP plot Hi = 5.

The **Figure 9.8** is the response of this energy storage system that has no continuous power rating with a current limit of 1 pu that gives an **Hi = 5** rating. The response is for a 20 degree phase jump plus a **RoCoF** rate of -1 Hz / s both starting at 100 ms with **Full Droop control**.

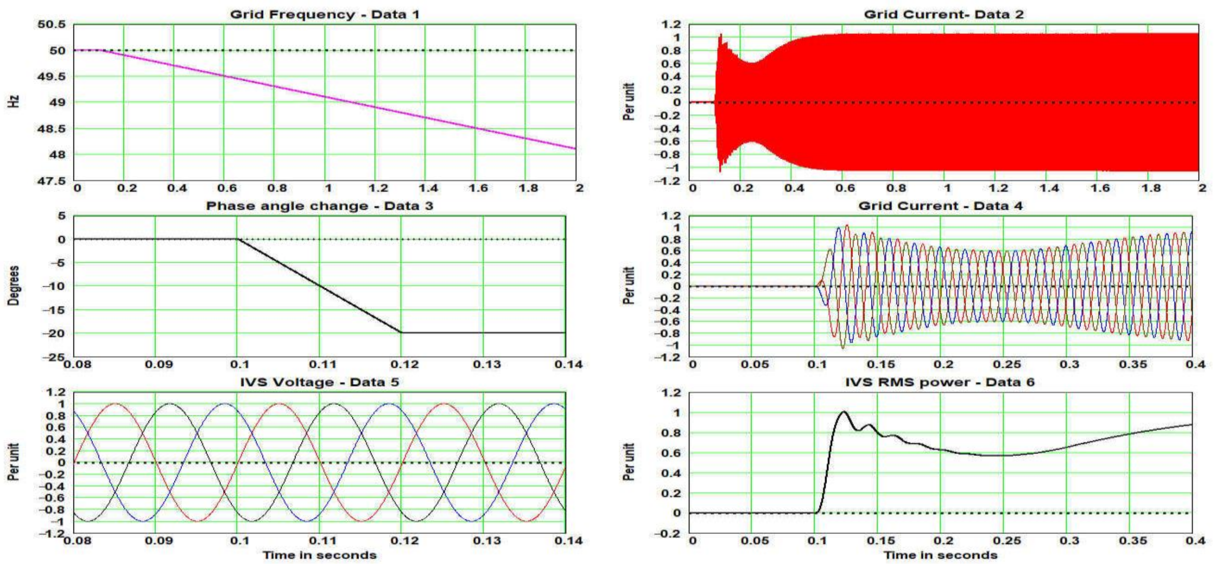

Figure 9.8. Combined Phase Jump plus RoCoF response.

The **Figure 9.8** shows:

- For Data 1 the Grid's frequency has a -1 Hz / s **RoCoF** rate starting at 100 ms.
- For Data 3 that there is a 20 degree phase jump also starting at 100ms.
- For Data 4 that the response is the sum of the phase jump response plus the **RoCoF** response.
- The **Active RoCoF Response Power** of 1.0 pu.

This data is for a system with a response very similar to **Figure 9.6** but with a viable **NFP** plot resonant frequency.

Enstore recommends that the response of a **GBGF- I** inverter to AC Grid phase jumps of 5 and 20 degrees should be provided to **NGESO** with **NFP** plots as these are very important for a stable system.

The typical response of a **GBGF- I** inverter for a short circuit fault in the AC Grid is shown on **Figure 9.9**.

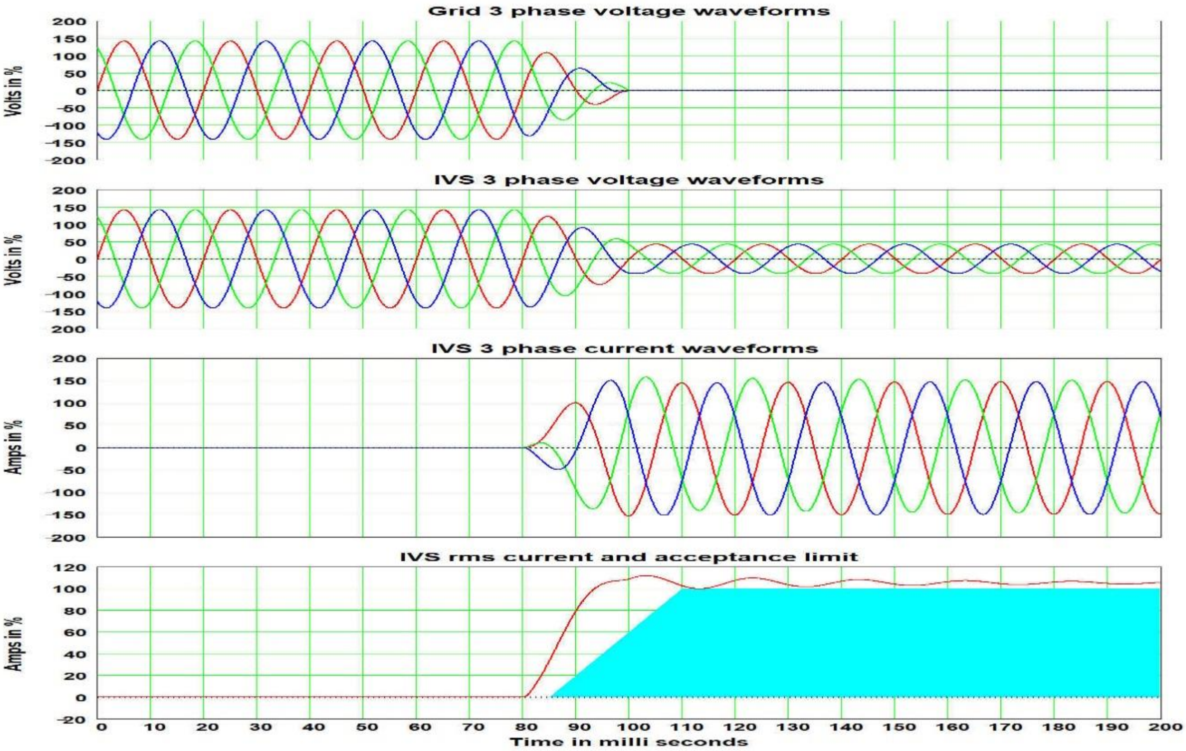

Figure 9.9. Response of a GBGF- I inverter for an AC Grid fault.

The **Figure 9.9** shows:

- The AC Grid's voltages falling to zero in 20 ms.
- The **GBGF- I** inverter **IVS** voltages falling to a voltage to give the **Fast Fault Current**.
- The **GBGF- I** inverters **IVS** current rising to the **Fast Fault Current** value.
- The resulting **RMS** current shown in red. The blue area is the Grid Code requirement.
- This simulation was done for the AC Grid's voltages falling in 20 ms to avoid DC components.
- With a fall time of 0 ms the data is similar with DC components due to the point of wave switching.

The typical response of a **GBGF- I** inverter for a fast fault in the AC Grid is shown on **Figure 9.10**.

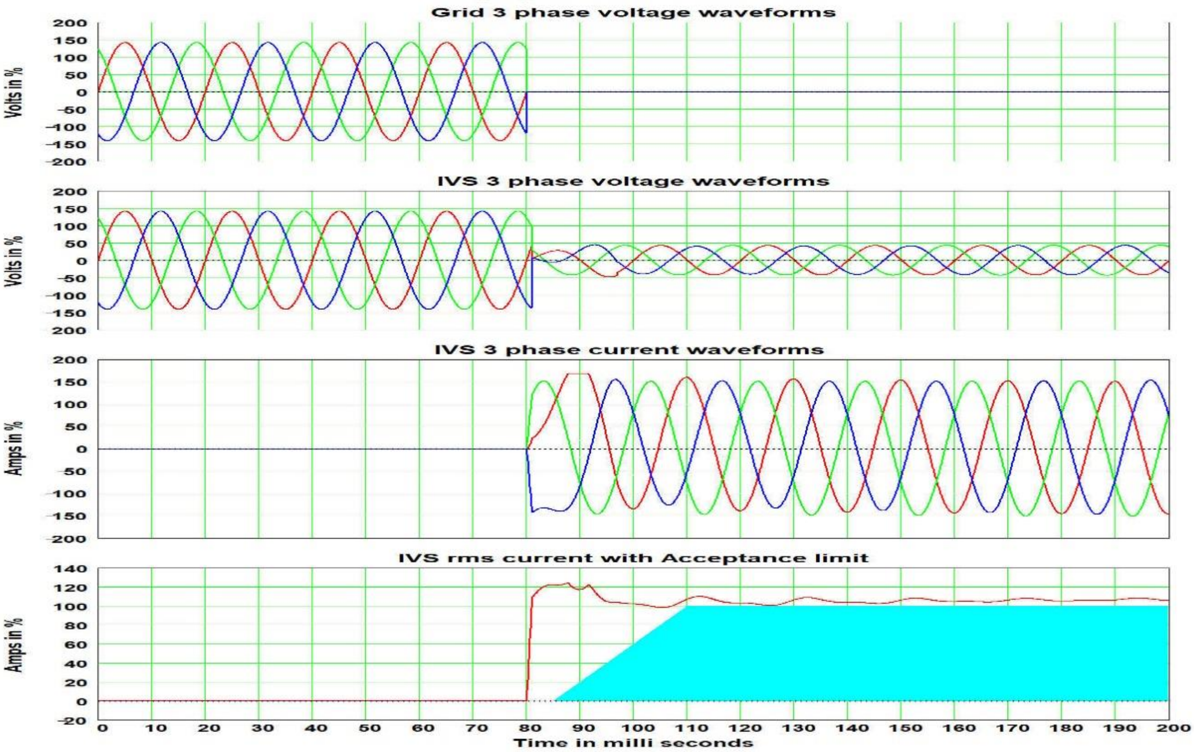

Figure 9.10. Response of a GBGF- I inverter for a fast AC Grid fault.

The **Figure 9.10** shows the AC Grid's voltages falling to zero in 0 ms that requires a very fast acting current limit function.

In addition to calculating the rating of the **Fault Current** rating and the **Active RoCoF Response Power** it is necessary to calculate the rating of the **Active Phase Jump Power** supplied by a **GBGF- I** inverter.

This can be calculated from the standard current equation **Current = 2 x Vivs x sin (Angle / 2) / Xt**. This is plotted on **Figure 9.11** for a range of AC system impedances.

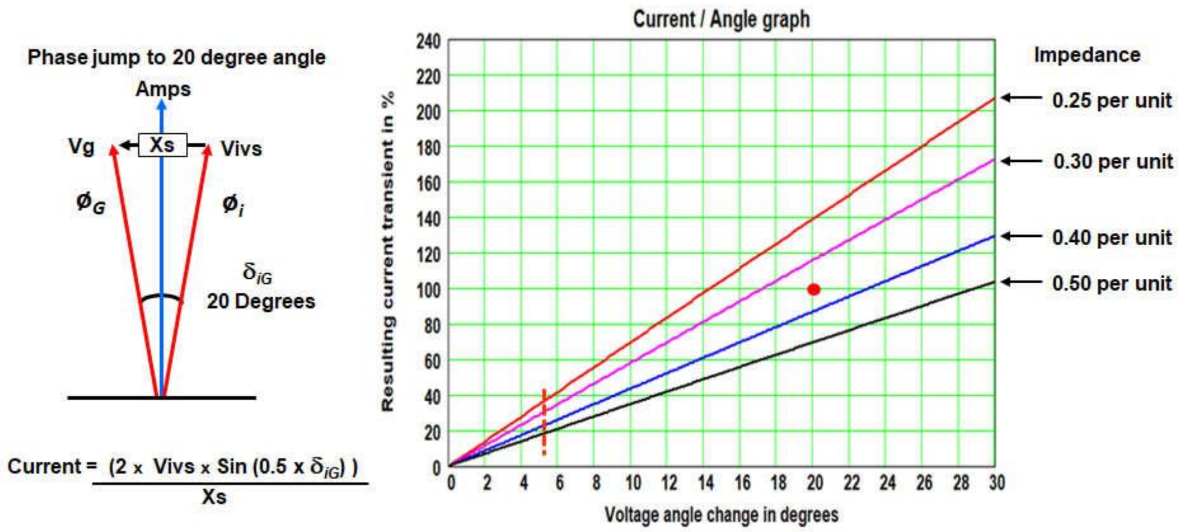

Figure 9.11. Current for a phase jump.

The minimum **Phase Jump Angle Limit** power is defined as the power for a recommended phase jump angle change of 5 degrees with the system remaining in linear control which is shown by the Red dotted line on **Figure 9.11**. This gives a **Phase Jump Angle Rating** power of 0.26 pu for an impedance of 0.33 pu.

For an energy storage system that has no continuous power rating with a current limit of 1 pu has a typical **Phase jump angle withstand** value of 20 degrees, that also depends on the AC supply impedance. This is the Red dot on **Figure 9.11**.

In addition to calculating the rating of the **Active RoCoF Response Power** and the **Active Phase Jump Power** it is also necessary to calculate the required energy for a **GBGF- I** inverter.

The required energy that is delivered into the AC Grid is defined by three conditions:

- A frequency change of 50.5 Hz to 47 Hz.
  This is to ensure the correct operation of the demand disconnection system.
  This is 3.5 Hz which at a **RoCoF** rate of 1 Hz / s will take 3.5 seconds.
  For an **Active RoCoF Response Power** of 100 MW is an export of 350 MJ.
- A frequency change of 49.5 Hz to 52 Hz.
  This is to ensure that generators remain connected.
  This is 2.5 Hz which at a **RoCoF** rate of 1 Hz / s will take 2.5 seconds.
  For an **Active RoCoF Response Power** of 100 MW is an import of 250 MJ.
- A frequency change of 52 Hz to 47 Hz.
  This is to ensure that generators remain connected.
  This is 5 Hz which at a **RoCoF** rate of 1 Hz / s will take 5 seconds.
  For an **Active RoCoF Response Power** of 100 MW is an import of 500 MJ.

The **Figure 9.12** shows the worst case power transients.

On **Figure 9.12** the Energy store is rated to deliver 600 MJ with a no-load value of 350 MJ.

The LH data is for a frequency fall down to 47 Hz that disconnects some loads and then the frequency rises to 52 Hz which has a 100 MJ energy in reserve.

The RH data is for a frequency rise to 52 Hz that disconnects some generators and then the frequency rises to 52 Hz which has a 100 MJ energy in reserve.

The actual size of the required energy store will be larger depending on system losses and the system's design. The actual size of the energy store is essentially the same if lower **RoCoF** rates occurs. For example, if the **RoCoF** rate is lower by a factor of "**PL**" the required power is lower at a value "**PL**" but the time is longer at a time of "**1 / PL**" so the energy is constant.

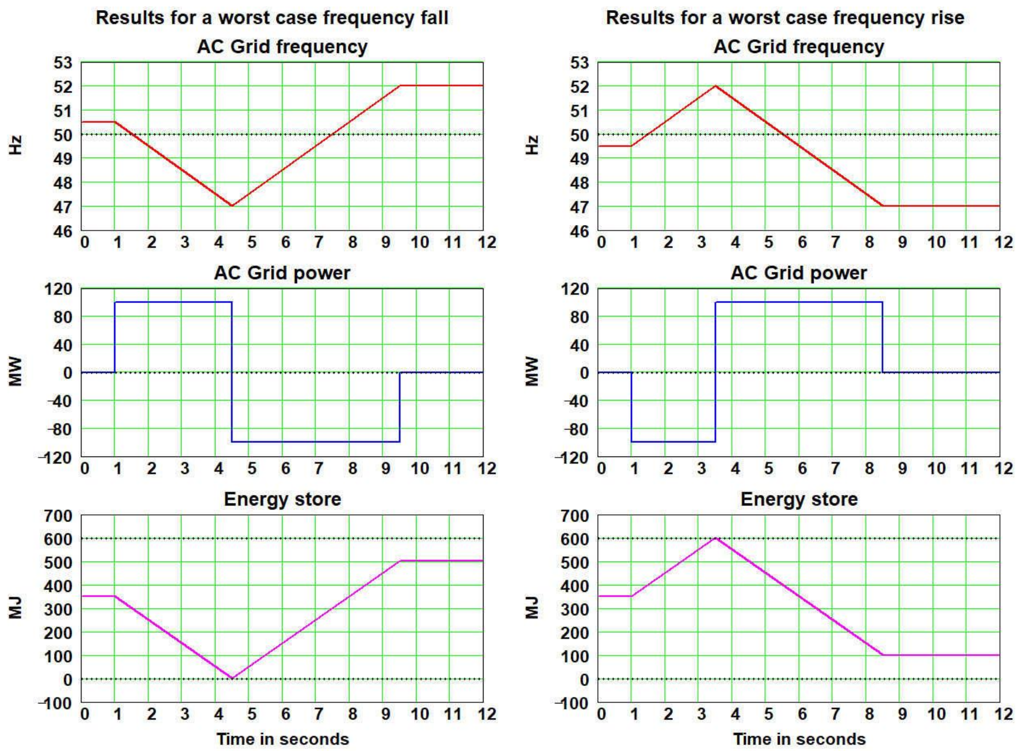

Figure 9.12. Worst case energy requirements.

Due to the different operating speed ranges the required energy for a **GBGF- I** inverter is approximately 20 % of the energy of the equivalent **GBGF-S** generator as shown on **Figure 9.13.**

For a **GBGF- I** inverter the energy store can be zero at 47 Hz but has to operate up to 52 Hz this is an energy range of (1.082 – 0.884) / 0.884 = 0.22 pu while the **GBGF-S** generator has an energy of 1 pu at 50 Hz.

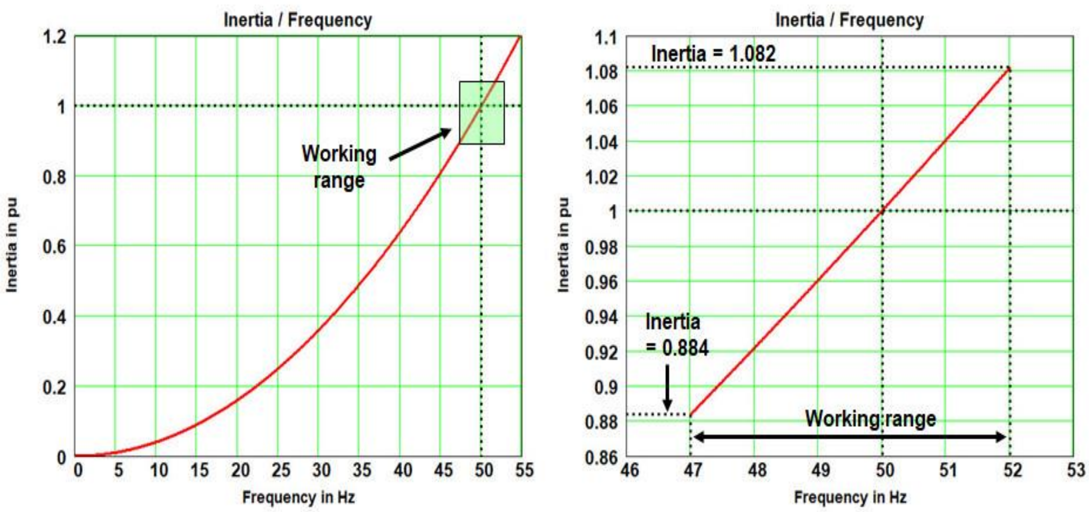

Figure 9.13. Equivalent inertia of GBGF-S & GBGF- I systems.

This can be illustrated by the following comparison.

GBGF-S generator:

- Rated at 100 MVA with Energy **Hg = 5** rating giving a stored energy = 500 MWs from **Equation** 1.
- **Active Inertia Power** at a **RoCoF** rate of 1 Hz / s = (5 x 100) / (25) = 20 MW from **Equation 3**.

GBGF- I inverter:

- Rated at 100 MVA with Energy **Hi = 5** rating giving a stored energy = 120 MWs from **Figure 9.12**.
- **Active Inertia Power** at a **RoCoF** rate of 1 Hz / s = (5 x 100) / (25) = 20 MW from **Equation 4**.

10. Power transients and the corresponding RoCoF rate in the AC Grid.

When the **GBGF** work was starting one of the most important questions was "What controls the **RoCoF** rate in the first 20 ms of a system fault?".

The answer is that the initial AC Grid phase jump instantly produces the **Active Phase Jump Power** which comes from either the rotating inertia of a **GBGF-S** generator or the software inertia of a **GBGF- I** inverter that cause the local frequency to fall exactly like the slower acting **Active Inertia Power**.

This action is shown on **Figure 10.1** that is a simulation of an AC Grid power transient that shows the **Initial RoCoF 2** rate in a typical local zone and the **Average RoCoF 1** rate in a typical remote zone.

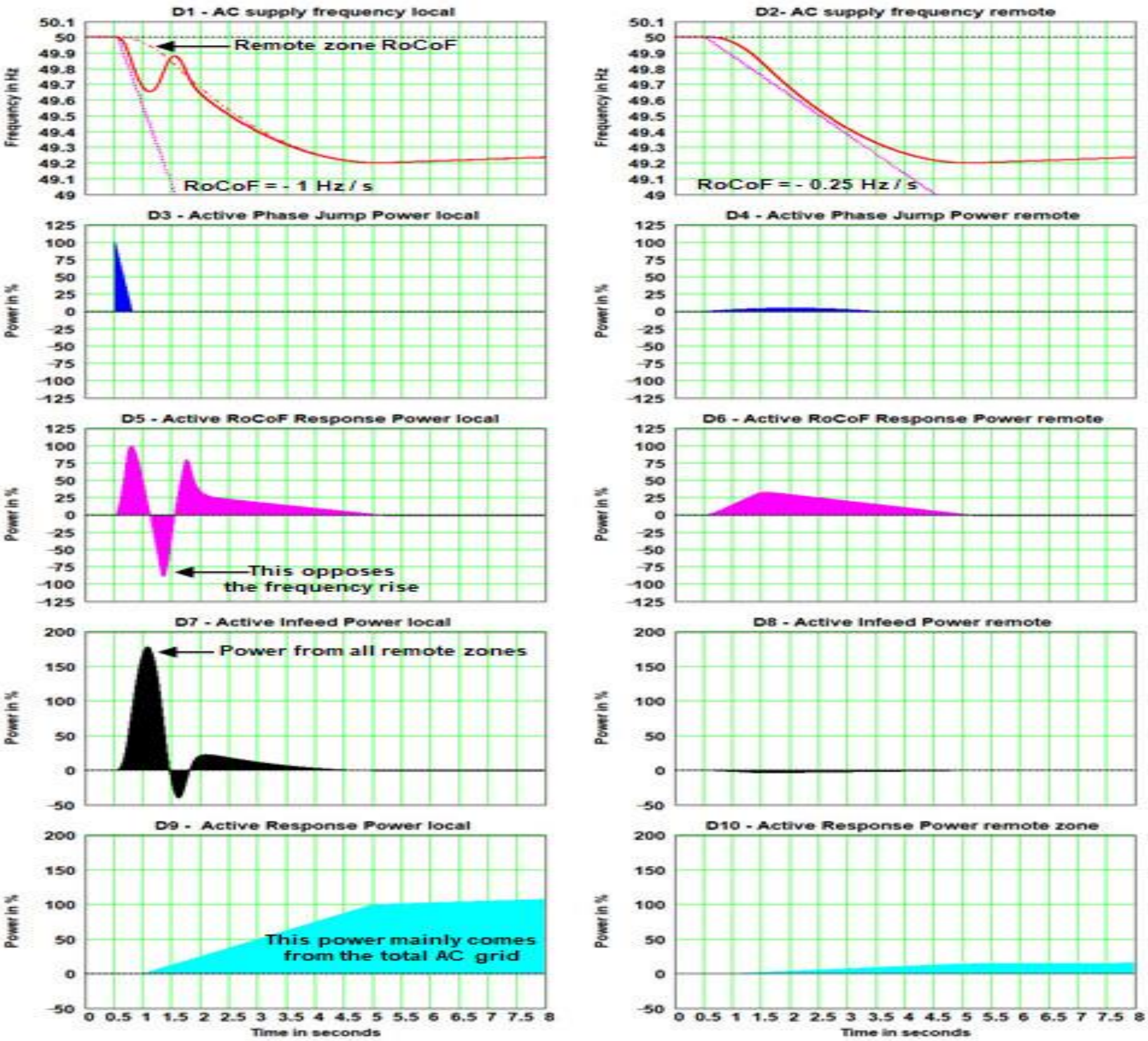

Figure 10.1. Understanding an AC Grid power transient.

The events shown on **Figure 10.1** are:

- The data is for a 100 % power loss transient at a time of 500 ms in a local zone. The local zone and the typical remote zone have the same inertia.
- For the results in **D1** the **Active Phase Jump Power** and the **Active RoCoF Response Power** in the local zone are supplied from the equivalent inertia store of either a **GBGF-S** generator or a **GBGF- I** inverter so both designs will give the same **Initial RoCoF 2** rate of – 1 Hz / s.
- For the results in **D2** the remote zone has an **Average RoCoF 1** rate of - 0.25 Hz / s.
- For the results in **D1** the local zone has an **Initial RoCoF 2** rate of – 1 Hz / s and then the local zone frequency rises to become aligned with the remote zone frequency.
- For the results in **D3** the **Active Phase Jump Power** has an almost instant rise to 100 % power in the local zone that then then falls to zero in approximately 300 ms at a rate set by the resonant frequency of the **NFP** plot.

- For the results in **D4** the **Active Phase Jump Power** in the remote zone is very low as the remote phase change is both lower and slower.
- For the results in **D5** the **Active RoCoF Response Power** then increases in approximately 300 ms as the **Active Phase Jump Power** decreases.
- For the results in **D6** the **Active RoCoF Response Power** response power is smaller and slower in the remote zone.
- For the results in **D7** there is a significant **Active Infeed Power** from the power reserves of the total AC Grid in to the local zone this is what causes the local zone frequency to rise and become aligned with the average Grid's frequency.

  The **Active Infeed Power** causes the local AC Grid's frequency to rapidly rise in **D1**.

  The rapid local frequency rise causes the **Active RoCoF Response Power** in **D5** to reverse**.**

  This is why the **Active Infeed Power** in **D7** is shown with a value approaching 200 %.
- For the results in **D8** in each remote zone there is a small negative output power to provide the **Active Infeed Power** into the local zone.
- After approximately 1000 ms the local and remote frequencies have become into alignment and to limit the fall in AC Grid's frequency the **Active Response Power** in **D9** has to rise to a value of 100 % to be equal to the power transient in a time of approximately 4500 ms.
- At a time of 4500 ms the **Active Response Power** in **D10** has only risen to a low value as the required total **Active Response Power** is supplied by the total AC Grid.

For the equipment in the remote zones the amplitude of the phase jump is significantly reduced by the AC Grid impedances compared with the local zone. The phase jumps in the remote zone also have a slower rate of rise that results in very low **Active Phase Jump Power** requirements in the remote zones.

The equipment in each local zone has to be rated to supply the **Active Phase Jump Power** at a rating equal to the largest predicted power transient in the local zone. This equipment in each local zone also has to be rated to supply the **Active RoCoF Response Power "ARP$_1$"** at the same rating for a **RoCoF** rate of 1 Hz / s.

The **Figure 10.1** shows that the **Active Phase Jump Power** is more important than the **Active RoCoF Response Power** in having a stable AC Grid. This change of emphasis has only recently occurred and is not reflected in the previous **GBGF** documents as well as most other **VSM** documents.

After the **Initial RoCoF 2** rate the **Active Response Power** to reduce the **Average RoCoF 1** rate to zero is supplied by the reserves held in the total AC Grid.

An analysis of the frequency changes in the local zone have shown that they are variations in the phase of the local zone compared with the phase of the remote zone. The phase changes are less than 90 degrees and the local and remote zone frequencies stay synchronised but with a damped phase oscillation that decays due to the **Active Damping Power** that is available.

This reporting of phase changes being reported as frequency changes is a normal effect in most frequency analysis algorithms.

11. A proposed way to design a future AC Grid.

11.1. Equation for the required inertia.

For a power transient the transient **Initial RoCoF 2** rate is higher for a short time based on the local inertia value that then falls to the **Average RoCoF 1** rate, as shown on **Figures 7.1** and **7.2**.

It is also essential that the provision of **Active RoCoF Response Power** is distributed to avoid the local **Initial RoCoF 2** rate exceeding the proposed maximum value of either plus or minus 1 Hz / s.

If the **Initial RoCoF 2** rate exceeds either plus or minus 1 Hz / s there is a risk of other generator's protection tripping that will then increase the power transient and make the recovery even more difficult.

By combining **Equations 1** and **2** a very useful **Equation 6** can be produced:

- **Equation 6. RGWs = (WCFP x -1 x Frequency) / (2 x RRoCoF).**
- **RGWs** **=** The required inertia in Giga Watt seconds to limit the fault's **RRoCoF**.
- **WCFP** **=** The **worst case Fault Power** in Giga Watts causing the **RRoCoF.**
- **RRoCoF =** The required **RoCoF** rate when the **WCFP** occurs.

For example, the data for the worst case fault condition in a historic AC Grid shown on **Figure 5.2** are:

- The historic AC Grid had a **WCFP** = 1.32 **GW** with a maximum **RRoCoF 1 rate** = -0.125 Hz / s
- The **Equation 6** gives **RGWs** = (1.32 x -1 x 50) / (2 x - 0.125) = 264 **GWs** required.

11.2. Defining the worst case Fault Power.

The value of the **WCFP** is increasing due to rating of the generators in nuclear power stations and the rating of the new interconnectors shown on **Figure 7.3.**

A value of **WCFP = 2** GW is proposed for the full AC Grid and the actual value will vary in different local zones.

These values must be finalized by **NGESO**.

11.3. Proposed design for a local zone.

The **Figure 7.3** shows a set of possible local zones that will need to also be finalized by **NGESO**.

The proposed design for a local zone is:

- That when a power loss occurs the phase angle in the AC Grid will increase until the installed local zone **Active Phase Jump Power** becomes equal to the **WCFP.**
- The value of the phase angle change in the AC Grid can be minimized by suppling the **Active Phase Jump Power** at a phase angle like 20 degrees.
- The installed local zone **Active RoCoF Response Power** should also be more than the **WCFP.**
- There is no direct link between these two powers that must be independently analyzed.
- For the **Figure 10.1** with a **WCFP = 2** and a **RRoCoF = -1** Hz / s the **RGWs** = **50** GWs.

11.4. Proposed design for the total AC Grid after the initial local response.

The total AC Grid will have a response very similar to the response of **Figure 10.1** that has a **WCFP = 2** GW that produces a **RRoCoF = - 0.25** Hz / s and the **RGWs** = **200** GWs.

This shows that if the AC Grid has more than 4 local zones the total AC Grid's inertia will determine the **Average RoCoF 1** rate. The required **Active Response Power** will require a rise time of 5 seconds as shown on **Figure 10.1** which is faster than the existing **Primary Response Power** rise time of 10 seconds.

If the **Primary Response Power** design is retained there will be a power gap as shown on **Figure 11.4.1** due to the difference between the **Primary Response Power** and the required **Active Response Power.**

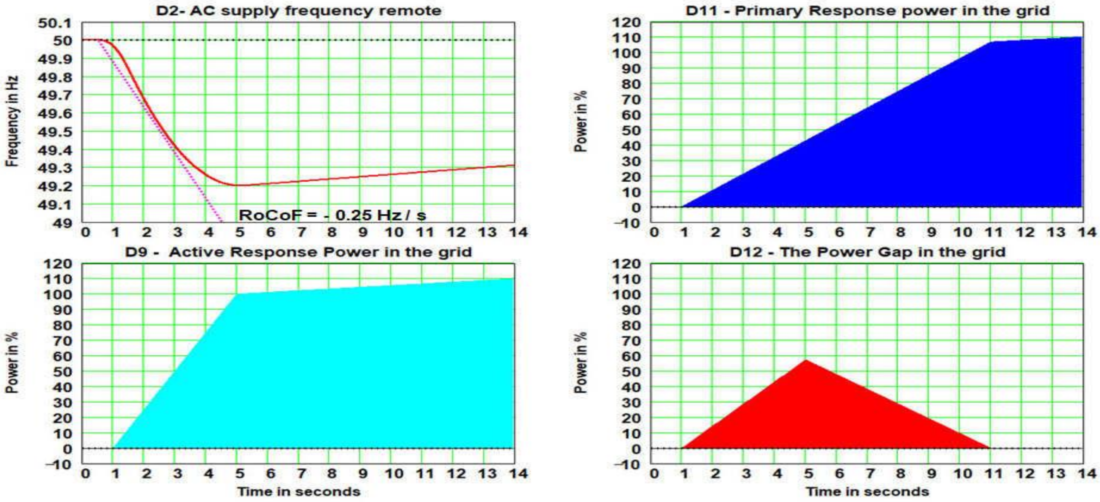

Figure 11.4. The Power Gap.

The **Figure 11.4** simulation shows:

- For the results in **D2** the AC Grid's frequency has an average **RoCoF 1** rate of -0.25 HZ / s.
- For the results in **D9** the **Active Response Power** has a rise time of 4 seconds.
- For the results in **D11** the normal **Primary Response Power** has a rise time of 10 seconds.
- For the results in **D12** the **Power Gap** in the AC Grid lasts 10 seconds with a peak of 60 %.

To avoid the problems of a **Power Gap** requires the use of a system to supply the faster **Active Response Power** this can be provided in many ways including:

- The new **NGESO Dynamic Moderation Service.**
- An extension of the **Stability Path Finder** response requirements, as originally proposed.
- The use of a **Dynamic Containment NGESO Service.**
- The use of a **Constraint Management NGESO Service** with an automatic response to frequency transients.

11.5. Proposed design after the frequency has recovered.

In the future the AC Grid will be operating with a balanced power flow to meet the UK power demand.

If an excess of renewable power is available compared with the GB demand, then it will normally be exported by the interconnectors. This means that extra renewable power will not be readily available when a major power loss occurs.

The use of the **Constraint Management NGESO Service** will give time to enable the power loss to be corrected that can include:

- Restoring tripped interconnectors.
- Use of the remaining interconnectors to trade for the required power.
- Starting of standby fossil fuel power plant.

The AC Grid will also be operated with the controls shown on **Figure 11.5.1** and **11.5.2.**

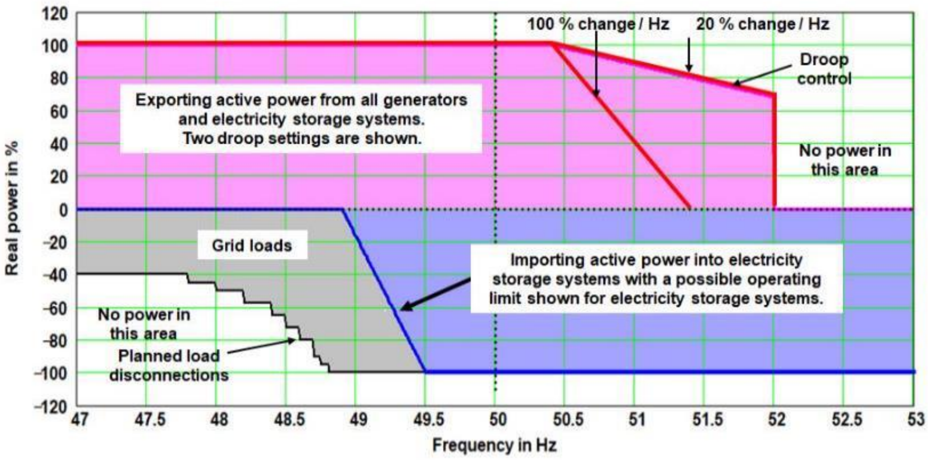

Figure 11.5.1. Proposed power limitation profiles.

The **Figure 11.5.1** has a limitation on the generated power above 50.5 Hz to avoid tripping generators at 52 Hz. The **GBGF- I** inverters have a fast response to implement this action.

The **Figure 11.5.1** also has a limitation on the imported power below 49.5 Hz to avoid reaching the frequency at which planned load disconnections will automatically occur. This limit mainly applies to energy storage systems.

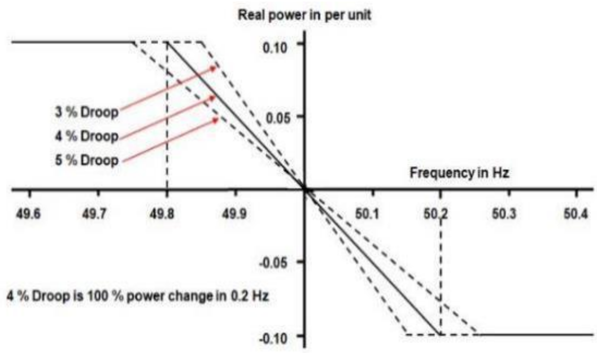

Figure 11.5.2. Droop control.

The **Figure 11.5.2** is a standard **NGESO** requirement that is fitted on a defined number of operating systems to give the control of the AC Grid's frequency and to aid power sharing between generators.

The new **NGESO Dynamic Regulation Service** has a very similar specification.

12. Design of Stability systems.

A future AC Grid will require the appropriate values for the **Active Phase Jump Power** and the **Active RoCoF Response Power** installed in a distributed system by the selection of the most cost-effective equipment. This equipment will in many cases also provide Stacked Benefits for the **Dynamic Containment** and **Constraint Management NGESO Services.**

There are a wide range of equipment that can provide the **Active Phase Jump Power** and the **Active RoCoF Response Power.** The first seven figures shown below all use a synchronous machine.

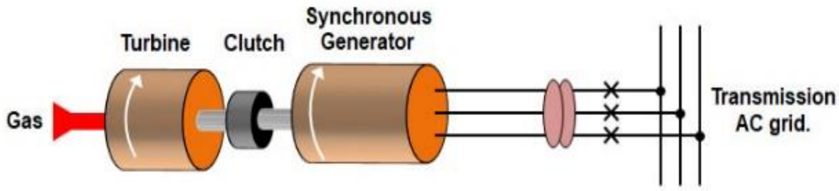

Figure 12.1. Synchronous generator with a clutch.

This system has a clutch between the gas turbine and the synchronous generator. This enables the system to be run up to provide primary power and when this is not required the clutch is opened leaving the generator on line to provide the **Active Phase Jump Power** and the **Active RoCoF Response Power.**

This is an option that is available from some **GBGF-S** generator suppliers. It is also possible to use a GBGF-S generator without a prime mover as shown on **Figure 12.2.**

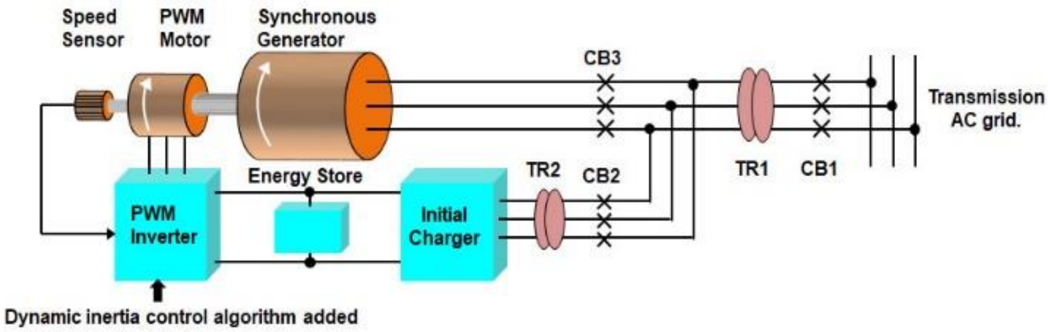

Figure 12.2. Synchronous generator with an Energy Storage system.

This system has a PWM motor to add extra controlled power to the synchronous generator, this can allow the reuse of synchronous generators from decommissioned fossil fuel plants.

When the generator is on line it provides the normal **Active Phase Jump Power** and the **Active RoCoF Response Power.** The PWM motor and PWM inverter can add three extra abilities:

- A constant output power at a rating and time defined by the rating of the energy store.
- Extra **Active Damping Power** via the actions of the PWM inverters control system.
- An increase level of **Active RoCoF Response Power** via the actions of the PWM inverters control system that uses the **Enstore** Dynamic inertia control algorithm.

The Dynamic inertia control algorithm can increase the systems **Hg** value by a factor of up to 5:1 depending on the rating of the PWM motor. This algorithm has been used in industry to dynamically alter the inertia of rotating mechanical parts when they are subjected to applied torque changes without any need for feedback on the value of the applied torque change.

The Initial charger is needed to start the system and it can then be turned off and the energy store is then discharged and recharged via the synchronous generator.

The synchronous generator shown on **Figure 12.1** can also be used with a parallel energy storage system.

This system is shown on **Figure 12.3** which gives a very flexible generating systems with many abilities including:

- Has the same abilities as listed for **Figure 12.1.**
- Can increase the power ramp rates from the combined system.
- Can run the turbine at the optimal constant load for maximum efficiency.
- Can provided the **Active Phase Jump Power** and the **Active RoCoF Response Power** from the generator and energy store working in parallel provided the inverter is a **GBGF- I** inverter.

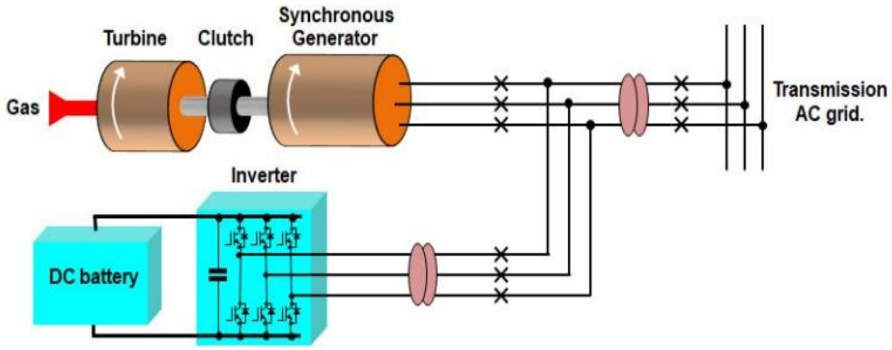

Figure 12.3. Hybrid Synchronous generator.

- Has the same abilities as listed for **Figure 12.1.**
- Can increase the power ramp rates from the combined system.
- Can run the turbine at the optimal constant load for maximum efficiency.
- Can provided the **Active Phase Jump Power** and the **Active RoCoF Response Power** from the generator and energy store working in parallel provided the inverter is a **GBGF- I** inverter.

The **Reference 21.4** has data on this type of system.

Can also use Synchronous Compensators, also called synchronous condensers, to supply **Active Phase Jump Power** and the **Active RoCoF Response Power** as shown on **Figure 12.4.**

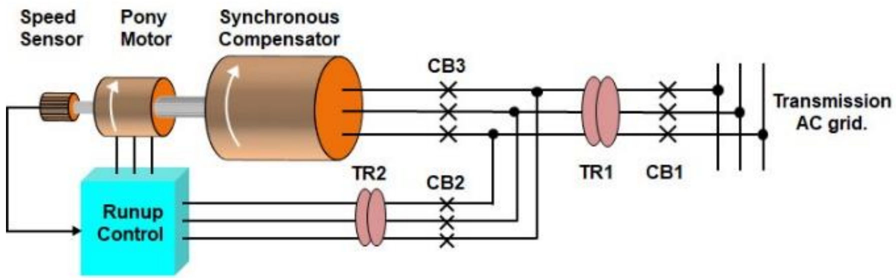

Figure 12.4. Synchronous compensator standard design.

The **Figure 12.5** shows a Synchronous Compensator system that provides **Active Phase Jump Power** and **Active RoCoF Response Power** plus extra abilities**.**

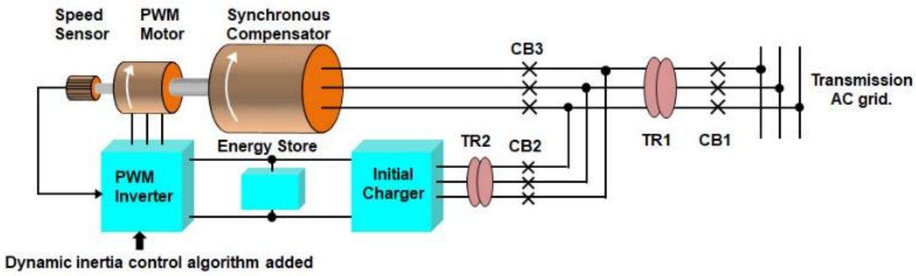

Figure 12.5. Synchronous compensator with energy storage.

The PWM motor replaces the Pony motor that can then add extra controlled power to the synchronous compensator. When the compensator is operating it provides the **Active Phase Jump Power** and the **Active RoCoF Response Power.** The PWM motor and PWM inverter can add three extra abilities:

- A constant output power at a rating and time defined by the rating of the energy store.
- Extra **Active Damping Power** via the actions of the PWM inverters control system.
- An increase level of **Active RoCoF Response Power** via the actions of the PWM inverters control system that uses the **Enstore** Dynamic inertia control algorithm.

The Dynamic inertia control algorithm can increase the systems **Hg** value by a factor of up to 5:1 depending on the rating of the PWM motor. This algorithm has been used in industry to dynamically alter the inertia of rotating mechanical parts when they are subjected to applied torque changes without any need for feedback on the value of the applied torque change.

The Initial charger is needed to start the system and it can then be turned off and the energy store is then discharged and recharged via the synchronous compensator.

Can also use flywheels to supply **Active Phase Jump Power** and the **Active RoCoF Response Power.**

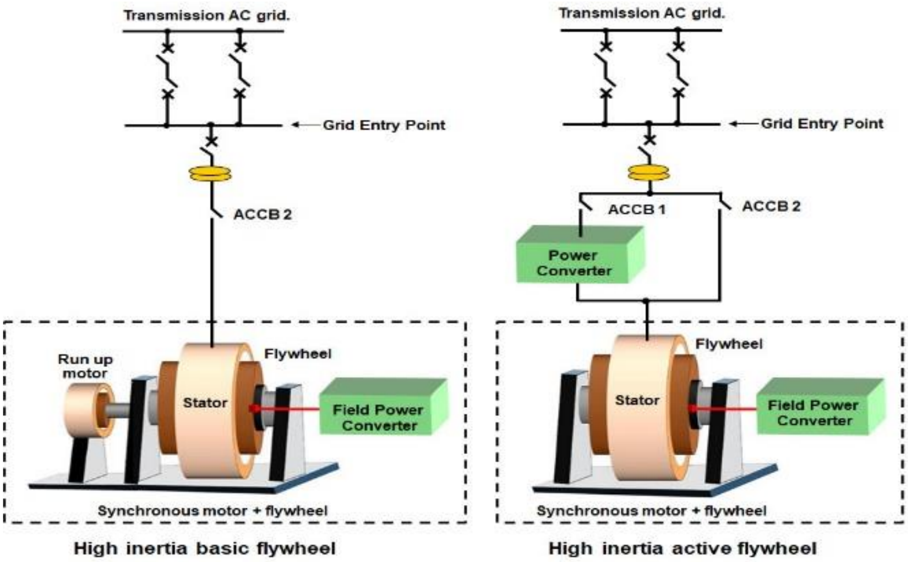

Figure 12.6. High inertia basic flywheel.

The high inertia basic flywheel uses a run up motor and when the flywheel is on line it provides the **Active Phase Jump Power** and the **Active RoCoF Response Power.**

The high inertia active flywheel uses a power converter and when the flywheel is direct on line it provides the **Active Phase Jump Power** and the **Active RoCoF Response Power** like **Figure 12.7.**

The power converter has three operating modes:

- The power converter can run up and synchronise the flywheel to the AC Grid.
- The power converter can extract energy from the flywheel immediately after a **RoCoF** event to add power to the AC Grid to help the AC Grid recover.
- The power converter can delay the recharging of the flywheels stored energy to help the AC Grid recover once the AC Grid's frequency is recovering.

The **Figures 12.1** to **12.6** are typical examples of synchronous generator systems that add **Active Phase Jump Power** and the **Active RoCoF Response Power.**

The **Figure 12.7** is an example of **a GBGF- I** inverter with an **ESS** that supplies the **Active Phase Jump Power** and the **Active RoCoF Response Power.**

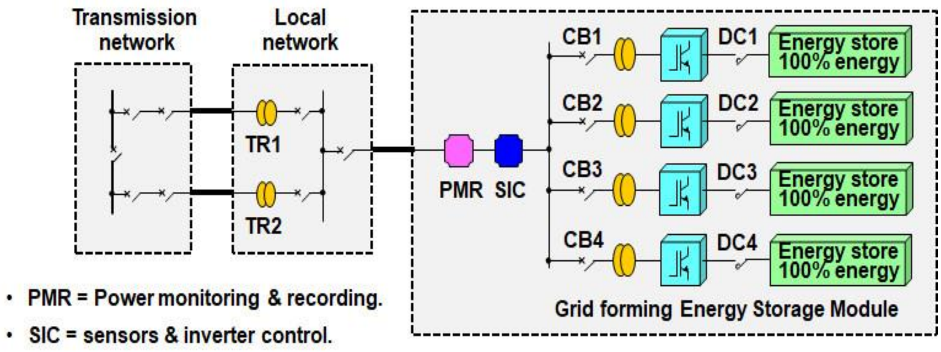

Figure 12.7. The basic GBGF- I inverter Energy Storage System "ESS".

The **GBGF- I** inverters for a high power **ESS** system will typically use many identical sub-systems in parallel, four are shown, connected to one feeder which gives a system with redundancy and high availability. Each sub-system typically has:

- An input circuit breaker, like **CB1**, so that an individual sub-system can be isolated for either maintenance or if an internal fault occurs.
- An AC supply transformer, note some designs can use a common AC supply transformer.
- Individual **GBGF- I** inverters.
- A DC rated circuit breaker, like **DC1**, to isolate a battery. This is essential for Lithium-ion batteries that will be damaged if fully discharged but it is not essential for Ultra capacitor batteries which are probably the optimal storage device for **ESS** systems with a short storage time.
- A set of batteries for the energy store, this system has a storage of 400 %.

The common AC feeder has:

- A Power Monitoring and Recording "**PMR**" facility. This is similar to the EFR concept that independently monitors the operation of the system versus its defined performance requirements and records any failures to respond on a 1 second basis.
- A Sensor and Inverter Control "**SIC**" system that independently implements the required control functions. The **SIC** system is totally independent compared with the **PMR** system.

For the **PMR** function to work will require the sensing and measuring the values of AC Grid phase jumps, AC Grid **RoCoF** events and AC Grid frequency. This is why these measurements are listed in the proposed **GBGF** Grid Code.

The **Figure 12.7** can provide all the proposed **NGESO Services** and any future **NGESO Services** by the correct choice and rating of the batteries. This includes the supply of very long duration **ESS** systems.

The existing **NGESO Services** provided are:

- Stability Path Finder **NGESO Service**
- Dynamic curtailment **NGESO Service**.
- Constraint management **NGESO Service.**

The **Figure 12.8** shows how the **Figure 12.7** design can be used with other systems.

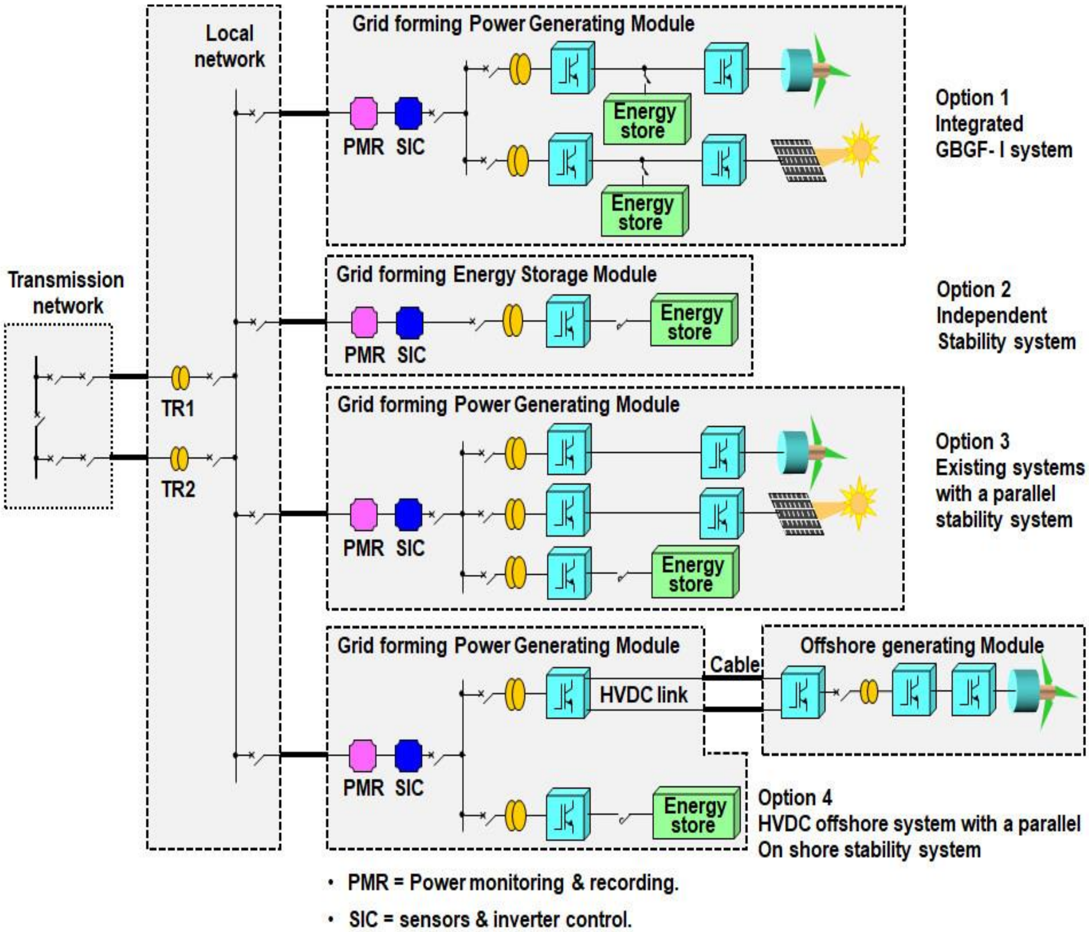

Figure 12.8. Energy producing systems that are GBGF compliant.

The **Option 1** for **Figure 12.8** shows examples of renewable energy systems that have added the required facilities to become directly **GBGF** compliant with integrated energy storage.

The circuits shown are for wind power and solar power systems but this design can be used by all types of renewable energy systems.

The **Option 2** for **Figure 12.8** shows an independent stability system that has been simplified versus **Figure 12.8** that is used for **Options 3** and **4.**

The **Option 3** for **Figure 12.8** shows examples of renewable energy systems using the existing inverter technology that have added the independent stability system facilities to become directly **GBGF** compliant.

The circuits shown are for wind power and solar power systems but this design can be used by all types of renewable energy systems.

When an AC Grid phase jump occurs the inverters using the existing technology deliver the same power as they are using either **PLL** technology or an equivalent technology. The independent stability system then provides the **Active Phase Jump Power**.

The combination gives a fully compliant **GBGF- I** inverter design.

The **Option 4** for **Figure 12.8** shows a possible design for a **GBGF** compliant offshore wind farm connected by a HVDC link to the onshore AC Grid.

To be **GBGF** compliant, requires the supply of the **Active Phase Jump Power** in a few milli seconds plus an operating power margin to deliver this power.

As HVDC links are very expensive **Enstore** believes that adding the added the independent stability system facilities onshore is an optimal solution as shown on the figure. This design has several important benefits.

- The offshore converters are buffered from the phase changes in the onshore AC Grid.
- Can use the existing and proven offshore existing wind farm technology.
- Can use the existing and proven HVDC link technology.
- That if the HVDC link trips the stability system facilities remain operational to help in compensating for the power loss from the HVDC link.
- Avoids trying to get the **Active Phase Jump Power** from the Offshore AC Grid.
- Avoids the need to add energy storage to the HVDC system.
- Avoids the need to have the AC power margin available in the HVDC system.

The same comments also apply to the HVDC interconnector systems.

The **Figure 12.9** shows the design optimised for the stacked supply of the Stability Path Finder **NGESO Service** plus the Dynamic curtailment **NGESO Service** plus the Constraint management **NGESO Service** via a single feeder**.**

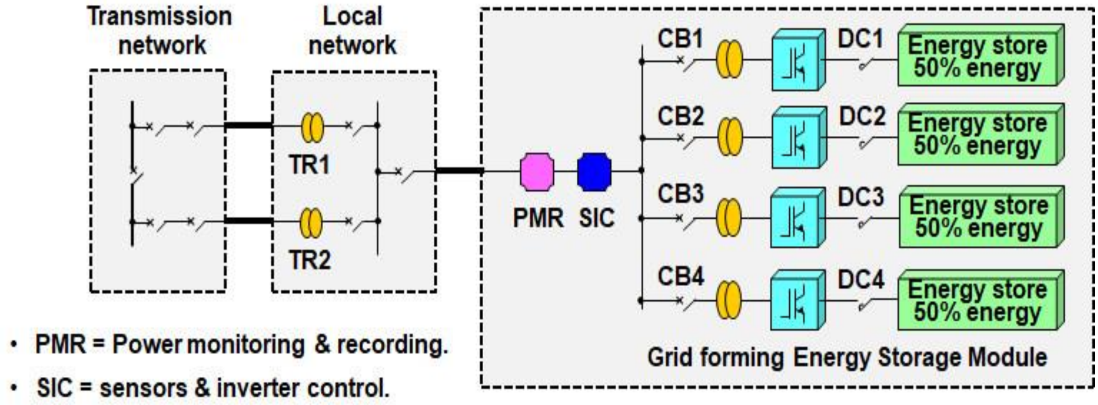

Figure 12.9. System to supply all the three NGESO Services.

The **Figure 12.9** is the same as the **Figure 12.7** apart from the stored energy is 50 % less per inverter.

For a given energy rating this needs twice the number of **GBGF- I** inverters, but this gives a significantly improved set of ratings, and the extra inverter cost is low for systems with a long storage time of 2 Hours as required for the **Constraint Management Service.**

The **Figure 12.9** has the following ratings for a 200 MW rated **Constrain Management** system that uses a **GBGF-** Inverter to give a fully **GB Grid Forming** compliant system.

- The **Constraint Management Service** with 200 MW for 2 hours.
- The **Dynamic Containment Service** with 200 MW of response power even when providing the 200 MW **Constraint Management Service**, or 400 MW when not providing the 200 MW **Constraint Management Service.**
- The **Stability Pathfinder Service** 200 MW of **Active RoCoF Response Power** even when providing the 200 MW **Constraint Management Service**, or 400 MW when not providing the 200 MW **Constraint Management Service.**

- A rating of up to 200 MW of **Active Phase Jump power** even when providing the 200 MW **Constraint Management Service**, or 400 MW when not providing the 200 MW **Constraint Management Service.** This rating depends on the systems AC supply impedance.
- A short circuit current rating providing of 200 %.
- A **GBGF- I** inverter with a 200 % **Peak Current Rating** is used to independently provide all these **NGESO Services**.
- This includes independently providing the **Stability Pathfinder Service** and the **Dynamic Containment Service** while already providing the full rating of the **Constraint Management Service**.

This design requires the **PMR** monitoring and the **SIC** control systems.

Enstore has supplied data to the **GC0137** Grid Code Workgroup that shows how a system can be supplied and monitored to supply the three stacked **NGESO Services** in to the AC Grid via one feeder.

For system like the **Constraint Management Service** that need two or more hours of storage time there are now several alternative technologies that can be used and Lithium-ion systems may not be the optimum storage device, see **References** 21.5 to 21.8.

In **Enstore's** opinion using **GBGF- I** inverters for all future dynamic **NGESO** services will be the most cost-effective way of having the required values of the **Active Phase Jump Power** in each local zone.

13. System testing.

The proposed Grid Code has a comprehensive set of tests to validate a system for the response to:

- Phase jumps.
- **RoCoF** faults.
- Reference changes.
- Short circuit faults.
- AC voltage changes.

The site testing of **GBGF- I** inverters for actual phase jumps and actual **RoCoF** events will normally have to wait for a real AC Grid event to occur.

The **Figure 13.1** shows a typical **GBGF- I** inverter with a 20 second First in – First out "**FIFO**" triggered memory store.

With the appropriate data measured from the AC supply voltage "**Fm**" this **FIFO** memory store will capture significant AC Grid transients for subsequent analysis and this can form the basis of the Power Monitoring Recording "**PMR**" system shown on **Figures 12,7, 12.8 and 12.9.** The FIFO storage method very significantly minimises the data that has to be stored.

There is also a phase jump test that can be validated during testing and also repeated on site by the signal shown on **Figure 13.1**.

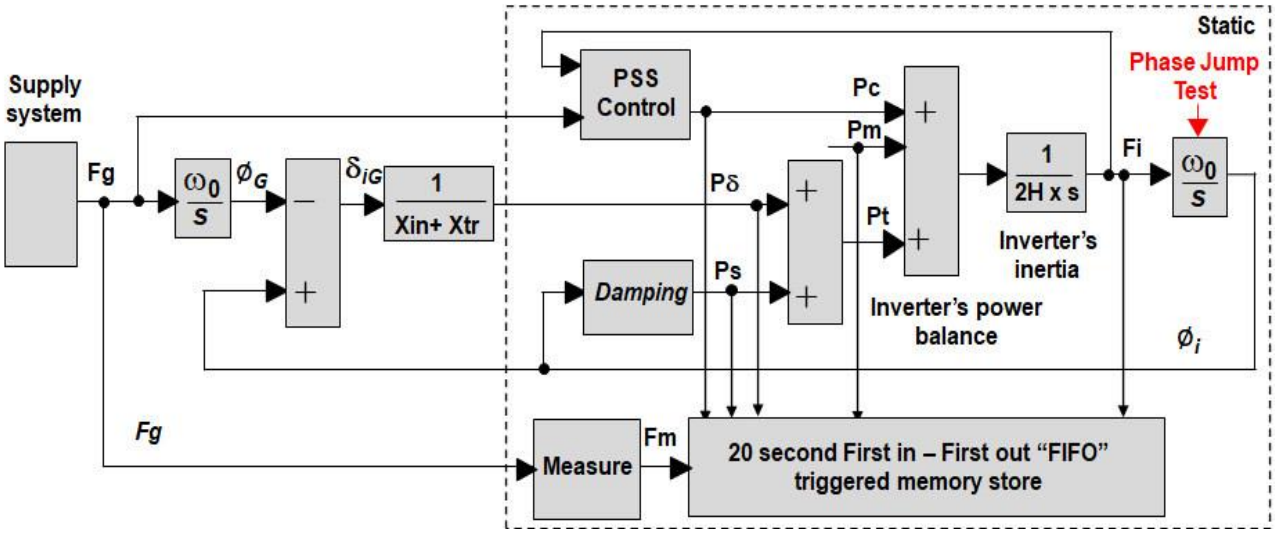

Figure 13.1. GBGF- I inverter recording and test facility.

The phase jump test applies a pre-set phase jump to the inverters **IVS** as this will give results very similar to an AC Grid phase jump. This is the Red test signal on **Figure13.1** and this test can be carried out on site on agreed basis for routine testing.

The **FIFO** recording system has 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** rate and a phase jump angle.

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

- Calculated AC Grid frequency from a standard algorithm logged at a 10 ms rate.
- Calculated AC Grid **RoCoF** rate using a 500 ms rolling average algorithm logged at a 10 ms rate.
- Calculated AC Grid phase jump from a standard algorithm logged at a 10 ms rate.
- Having standard algorithms in each system will give consistent results.

A possible design for these 3 values uses a sampling rate in the range of 1 to 10 microseconds rate for the AC supply voltage 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 AC Grid phase jump is 55.5 microseconds and a **RoCoF** rate of 1 Hz / s is 8.2 microseconds change per AC Grid cycle at 50 Hz.

To validate the design a test waveform can be used as shown on **Figure 13.2.**

The Figure 13.2 uses a test AC Grid voltage waveform with AC supply harmonics plus two 30-degree phase jumps shown on the top two traces plus the **RoCoF** rate profile shown on the middle LH trace with a 2 Hz power oscillation.

And an ideal system will give the measured **RoCoF** rate, frequency and the phase jumps shown on the **Figure 13.2** by the middle RH trace and the two lower traces**.**

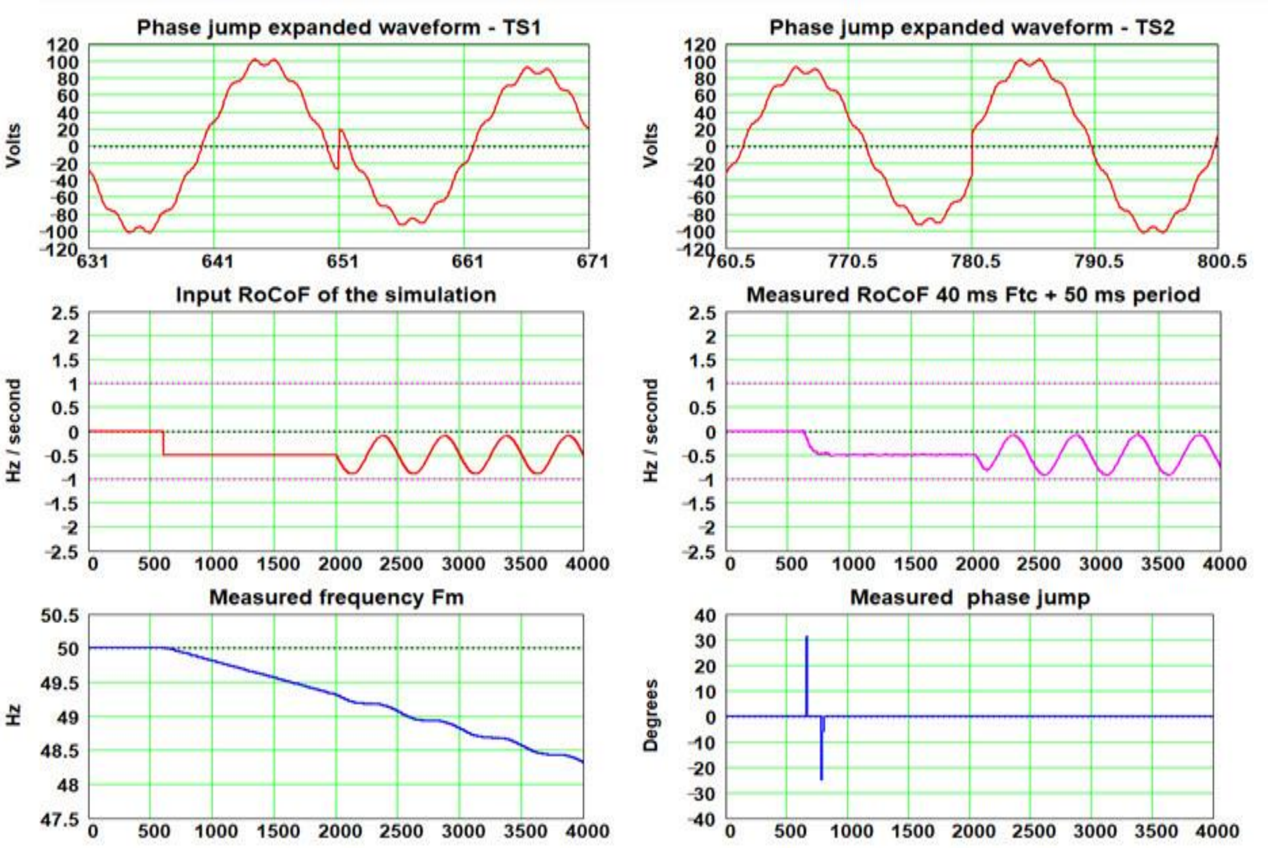

Figure 13.2. Example of frequency calculations with phase angle changes.

These are waveforms that are also very viable for adding **Active Control Based Damping Power**.

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 AC Grid transients occur.

14. The future.

There are large power variations during any 24-hour period and seasonal variations as shown on **Figure 14.1**.

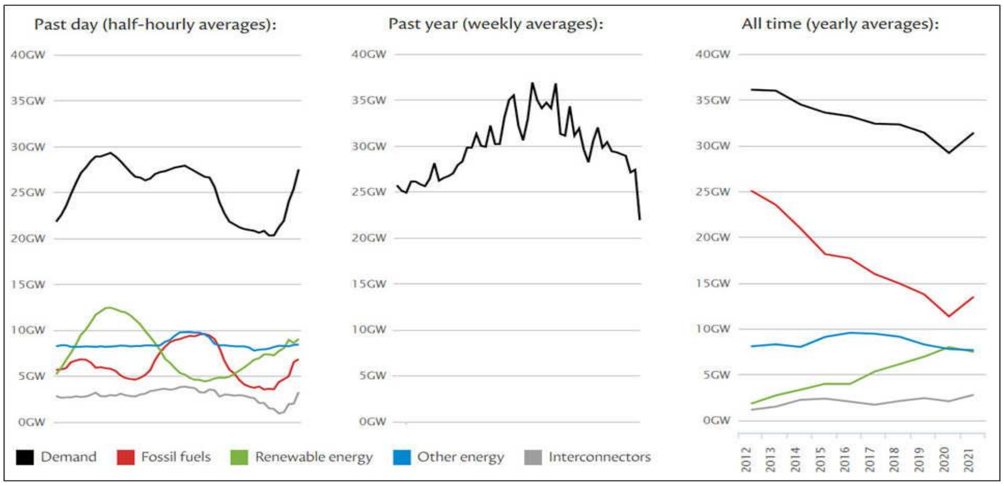

Figure 14.1. Daily and yearly power variations.

The **Figure 14.1** shows that very significant demand changes happen on a daily basis with significant overall changes over a year, using data from the **NGESO** Historic GB Generation Mix Dataset.

The long duration data from 2012 to 2021 shows that the average power demand has fallen with a very large fall in the Fossil Fuel power.

In the future there will be time periods that produce very high levels of the available renewable power being supplied by **GBGF- I** inverters in to the AC Grid above the demand power level. For these conditions the availability of the planned long-distance interconnectors will allow the UK to trade power and make maximum utilisation of renewable power without the need to have constraint payments.

For a future optimal AC 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 AC Grid must be maintained which is why it is essential to develop and deploy **GBGF- I** inverters with the appropriate deployment of **Stability Pathfinder Services**.

There will be other times, especially in winter, when due to atmospheric conditions that only very low levels of renewable energy will be produced at a time of high demand as shown on **Figure 14.2**. This requires the use of sufficient **GBGF-S** generators plus the planned long-distance inter-connectors.

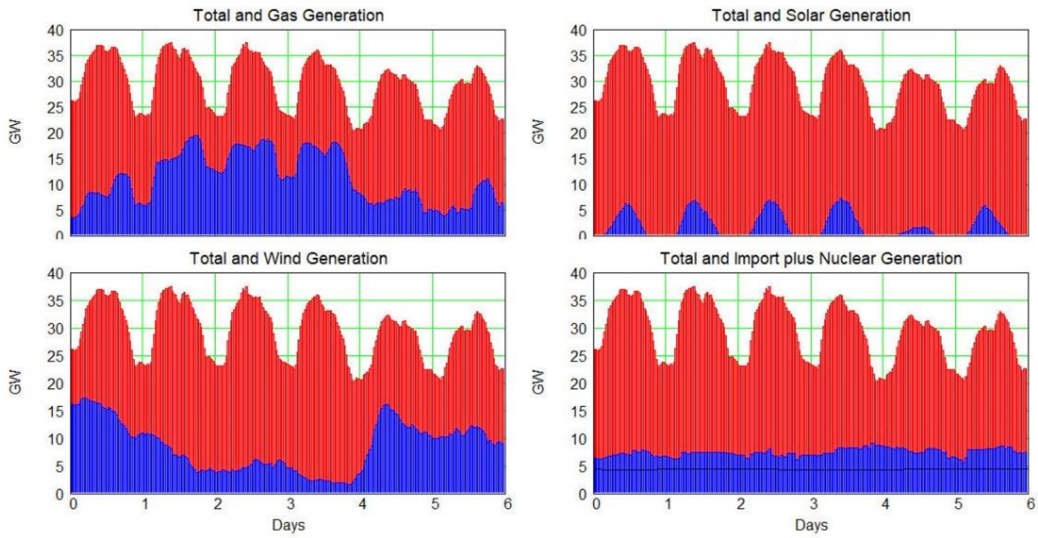

Figure 14.2. Daily power variations – the black line is the nuclear power.

Figure 14.2 shows a 6 day period in early 2021 where there is low wind power on days 1 to 3 followed by a very rapid rise of wind power at the start of day 4. The Gas generation had to respond to these power variations. This uses data from the **NGESO** Historic GB Generation Mix Dataset.

The long-distance inter-connectors are a vital part of a viable future AC Grid system and as they permit less **GBGF-S** generators to be used but this does his increase the need for the appropriate deployment of **Stability Pathfinder Services**.

There is also another very important consideration which is that in the past the AC Grid stability was provided for almost for free as it was made up from the contribution of **Phase Based Power** from many **GBGF-S** generators connected to the AC Grid.

In a future AC Grid using a very high level of **GBGF- I** inverters, the appropriate deployment of the required **Stability Pathfinder Services** will have to be paid for.

If the long-distance inter-connectors with the renewable **GBGF- I** inverters plus nuclear power could reliably provide for all the power variations shown on the **Figure 14.2** then the need for land based UK **GBGF-S** generators would be very small.

However, there are winter weather patterns that can produce virtually zero renewable energy for time periods measured in many days and a secure supply of power is needed for these conditions and some the possible solutions are:

- Very long time **ESS** systems for example the use of flow cells, see **Figure 14.3.**
- Having a guaranteed supply of power via the long distance inter-connectors.
- Having a policy to maintain sufficient **GBGF-S** generator for the worst case conditions. This could even require the running of **GBGF-S** generators on a planned basis with the excess power from **GBGF-S** generators and renewable power being exported via the long distance inter-connectors.

  Many European countries are also planning to remove all fossil fuel generation that could increase the need for GB to retain a viable level of **GBGF-S** generation. This could also increase the value of exported power during periods with low renewable generation in to the countries outside GB.

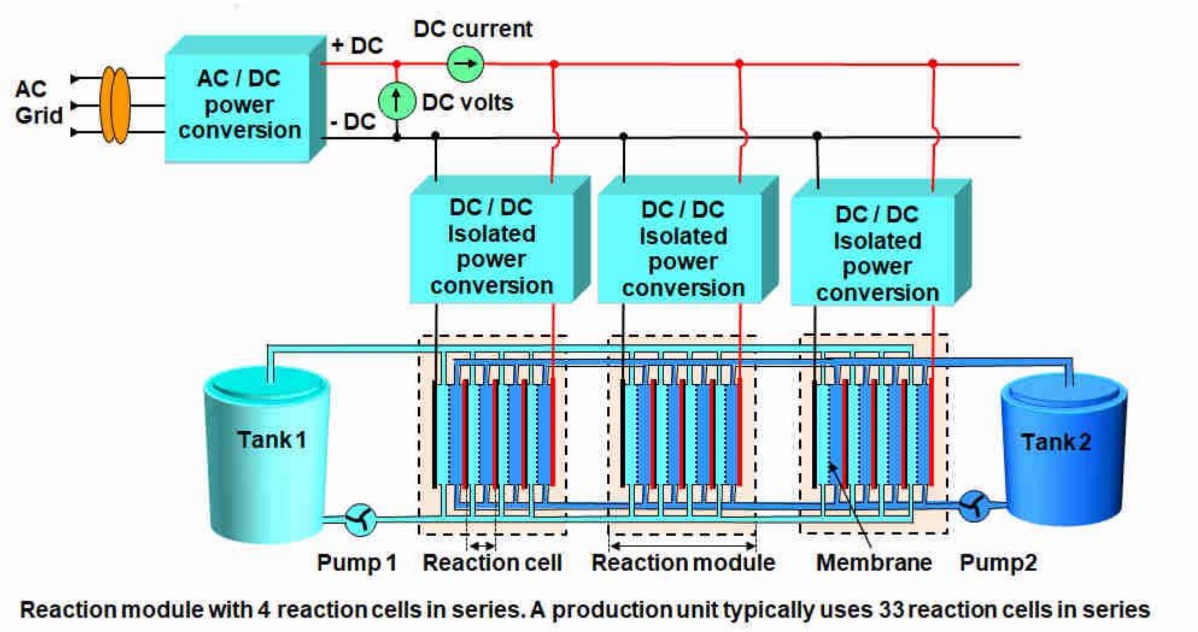

Figure 14.3. Long duration storage with flow cells.

For a flow cell system the essential component is a reaction cell that has a typical maximum voltage of 1.5 volts DC and each reaction cell uses two half cells separated by a membrane, each with the same Vanadium fluid.

The fluid will conduct electricity which leads to unacceptable losses and a low round trip efficiency if a reaction module is built with too many reaction cells in series due to DC current flowing in the fluid pipes between the reaction cells.

For high efficiency a maximum reaction module DC voltage of 50 V DC is typically used which is too low to be directly connected to the DC bus of the AC supply inverter.

Almost all existing flow cell systems solve this problem by using sets of reaction modules in series each with a pair of storage tanks which gives a viable design for storage times of 1 to 4 hours. This also requires the storage tanks to be operating at different DC voltages of up to typically 1000 V DC.

For long storage times one optimum solution in shown on **Figure 14.3** that only uses two very large storage tanks at a low DC voltage.

The 50 V DC of each reaction module is independently converted to 1000 volts DC for the AC supply inverter by isolating DC-to-DC converters. These DC-to-DC converters can now be produced using fast switching silicon carbide devices.

This is an ideal development for the **Department for Business, Energy Industrial Strategy (BEIS) Longer Duration Energy Storage initiative - 15 June 2021.** Flow cells using this fully integrated design have many benefits including:

- Separating the MW rating (reaction cells) from the MWh rating (storage tanks).
- Uses Vanadium, which is readily available, dissolved in dilute sulphuric acid at ambient temperature.
- Vanadium has 4 different oxidisation states, each with a different voltage to store energy directly in the atoms of the fluid. This gives an unlimited number of fully reversible deep operating cycles.
- Each unit cell has a typical maximum voltage of 1.5 volts DC and has two half cells separated by a membrane, each with the same Vanadium fluid.
- A typical module uses 33 unit cells in series to build a cell stack to produce 50 volts DC.
- The current flows in the fluid by proton transfer via the membrane.
- There is no loss of energy in storage with a high round trip efficiency.
- Same fluid in both halves of each unit cell so any membrane fault does not corrupt fluids, and normal operation can continue with a small power loss. Systems using different fluids each side of the membrane have given many problems in prototype systems.
- No materials are deposited on electrodes so can have very long storage times
- To increase the storage time only requires extra fluid in 2 larger tanks.
- Can design system to store energy for MW days as shown on **Figure 14.4.**

Figure 14.4. Long duration storage facility.

A typical supplier of Vanadium flow cell is defined in **Reference 21.7** and there are other suppliers of flow cells see **Reference 21.8** for an iron based flow cell with a 12 hour storage time.

The recharging of Electric Vehicles " **EV** " could significantly increase the required AC Grid power in the evenings and during the night period that could lead to over loading in distribution feeders.

This effect could be reduced by having a required circuit in **EV** chargers that use the low frequency limit, shown on **Figure 11.5.1** for proportionally limiting the power input at low AC Grid frequencies together with a similar feature for proportionally limiting the power input at low AC Grid voltages.

These proportional limits would also provide a control method for the power demand by locally lowering the AC Grid distribution voltage for overload distribution networks.

15. Appendix A. Normal Operating Conditions for GBGF- I inverters.

The normal operating conditions are:

- 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 **Active RoCoF response power** for any **RoCoF** rate below plus / minus 1 Hz / s which is the maximum AC Grid operating value in a local zone as defined in the Grid Code. A **GBGF- I** inverter also has to remain operational up to a withstand value of 2 Hz / s.
- The required **Active Inertia Power** given by **Rated Hi value x Installed MVA / 25.**
- The required **Active RoCoF response power** given by **Rated He value x Installed MVA / 25.**
- Being able to supply the **Defined Active Damping 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** rates below 1 Hz / s the system has to be designed to produce the rated **Active RoCoF Response Power** plus the **Defined Active Damping Power** at the same time without tripping.
- Being able to supply the **Phase Jump Angle Limit** power for a phase jump angle at the **Phase Jump Angle Limit** of 5 degrees. A **GBGF- I** inverter 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.
- For a **GBGF- I** inverter the **Peak Current Rating** is the larger of three possible ratings:
  - **Rating 1.** The registered maximum **steady-state current** plus the maximum additional current to supply the **Active ROCOF Response Power** plus the **Defined Active Damping Power**.
  - **Rating 2.** The registered maximum **steady-state current** plus the maximum additional current to supply the **Phase Jump Angle Limit** power.
  - **Rating 3.** The maximum **short term total current** defined by the User.
- 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 AC Grid voltages, unbalanced currents will flow in the **IVS** of the **GBGF- I** inverter, 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** inverter will supply **Active Damping Power** current to damp AC Grid disturbances.

16. Appendix B. Bandwidth of GBGF- I inverters.

The Bandwidth of **GBGF- I** inverter is defined in section 6 that shows the response of a typical well damped system with a bandwidth of 5 Hz on **Figure 6.2.**

This is important as in the Grid Code section **CC/ECC.A.6.2.5.5** a Power System Stabiliser "**PSS**" 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 – 5 Hz would be judged to be acceptable for this application.

The **Figure 16.1** is a system diagram for a **GBGF- I** inverter with **PSS control**.

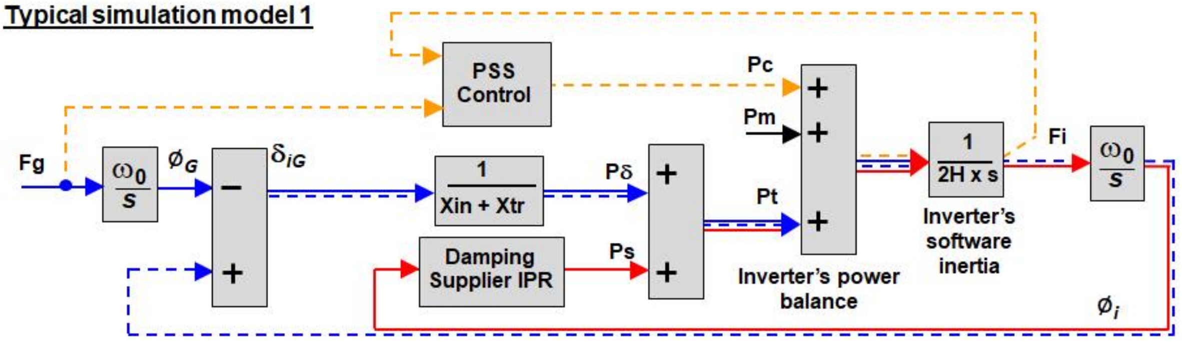

Figure 16.1. GBGF- I inverter with PSS control

This shows the control system for a system with a **PSS control** that operates on the difference between the AC Grid's frequency "**Fg**" and the inverter's 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** generators 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 16.2** is a system diagram for a **GBGF- I** inverter with **Droop control**.

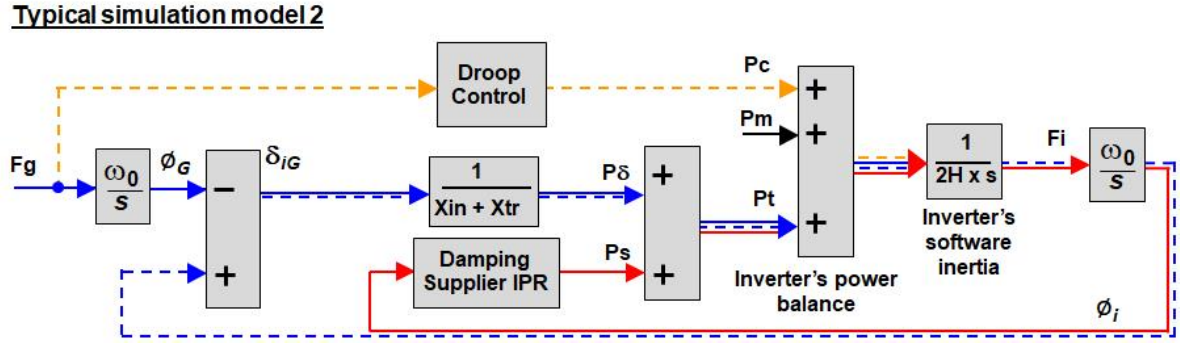

Figure 16.2. GBGF- I inverter damping for a system with Droop control

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

The **Droop control** acts to add extra power when the AC Grid's 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 but it does add damping for AC Grid frequency oscillations.

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 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** inverter 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** generator **PSS control** systems by producing a different phase shifts below 1 Hz in the AC Grid.
- **Active Control Based Power** includes the active power changes that results from a change to the Grid Forming Plant Owner's available set points that have a 5 Hz limit on the bandwidth of the provided response. The 5 Hz limit is a standard requirement in the Grid Code to avoid mechanical resonance problems with other connected **GBGF-S** generators.
- The response of a second order system with a **Damping Factor** of 0.707 is shown on **Figure 6.2.**
- **Active Control Based Power** also includes active power components produced by the normal operation of a **GBGF- I** inverter that comply with the Engineering Recommendation P28 limits. These active power components do not have a 5 Hz limit on the bandwidth of the provided response as they have a low amplitude defined by the P28 limits.
- **Active Control Based Power** can include many other functions like a Power System Stabiliser or the **Droop control** function shown on **Figure 6.1**.
- The AC input impedances of a **GBGF- I** inverter 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 many 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.

17. Appendix C. 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 17.1** but with lower values away from the fault.

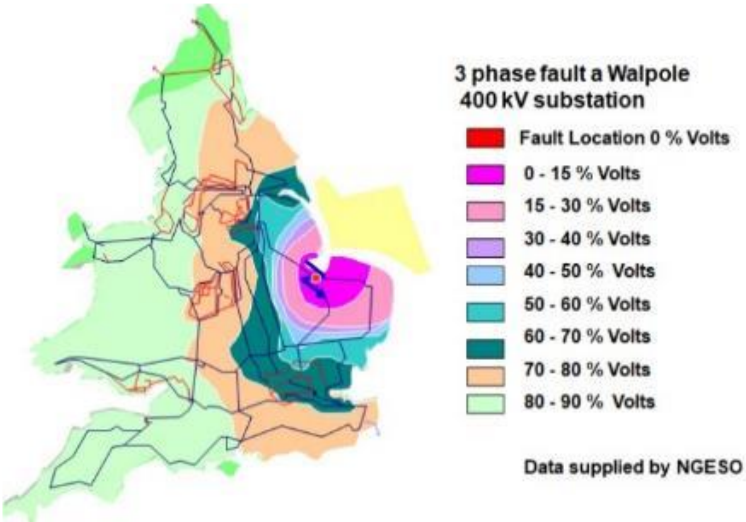

Figure 17.1. Measured site voltage dip data for a short circuit fault.

It is essential that all **GBGF- I** inverters remain operational during this type of fault to help the AC Grid recover. The **Figure 17.2** shows several typical voltage dip profiles.

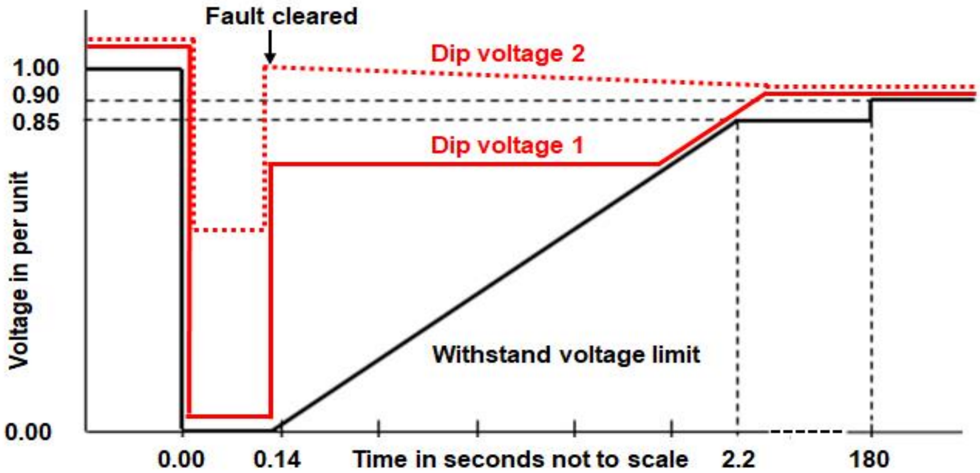

Figure 17.2. Allowed voltage limits for Power Park Modules and HVDC.

For correct operation the plant must remain connected and stable for a fault that causes the voltage at the connection point to fall to zero for 0.14 s. The Black diagonal line between 0.14 s and 2.2 s is the withstand voltage limit for the post fault voltage at the connection point 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 17.2** are typical actual voltage dip waveforms:

- The solid Red line is a voltage dip, at a zero retained voltage level, that rises rapidly up to the **Dip voltage 1** when the fault is cleared. The voltage then recovers to the normal AC Grid voltage value.
- The dotted Red line is a voltage dip, to a medium voltage level, that rises rapidly up to the **Dip voltage 2** when the fault is cleared. The voltage then recovers to the normal AC Grid voltage value.

The required **Peak Current Rating** is shown on **Figure 17.3** that depends on the chosen **Peak Current Rating** and two values are shown for a **Peak Current Rating** of 1.0 and 1.5 pu. For a fault the **GBGF- I** inverter's current should be less than the **Peak Current Rating** but above these lines.

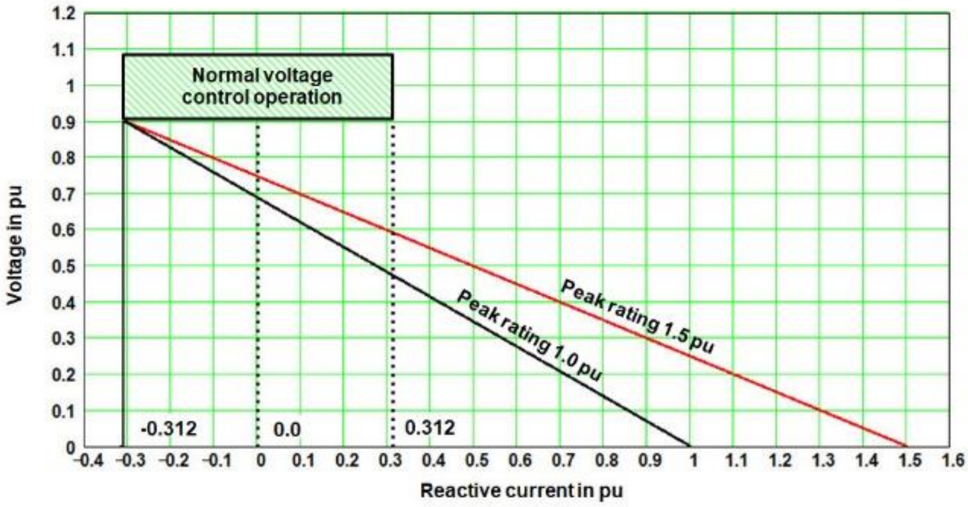

Figure 17.3. Required reactive current in % of Peak Current Rating.

For a **GBGF- I** inverter the production of a dominantly reactive component at 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. The required rate of rise of the **Peak Current Rating** is shown on **Figure 17.4** and current blocking is not allowed. The injected current shall be above the shaded area shown in **Figure 17.4** for the duration of the fault clearance time which for faults on the Transmission System cleared in Main Protection operating times can be up to 140 ms.

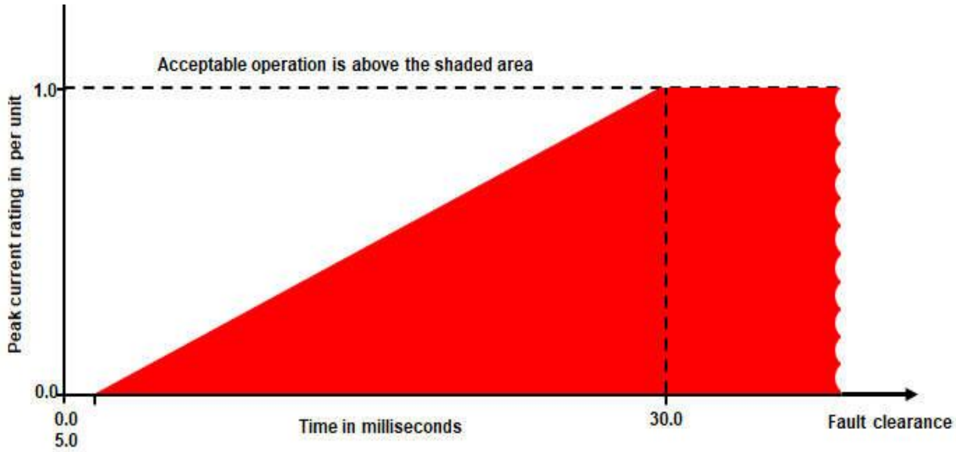

Figure 17.4. Required time response of the fault current.

The operational vectors of a synchronous generator are shown on **Figure 17.5.**

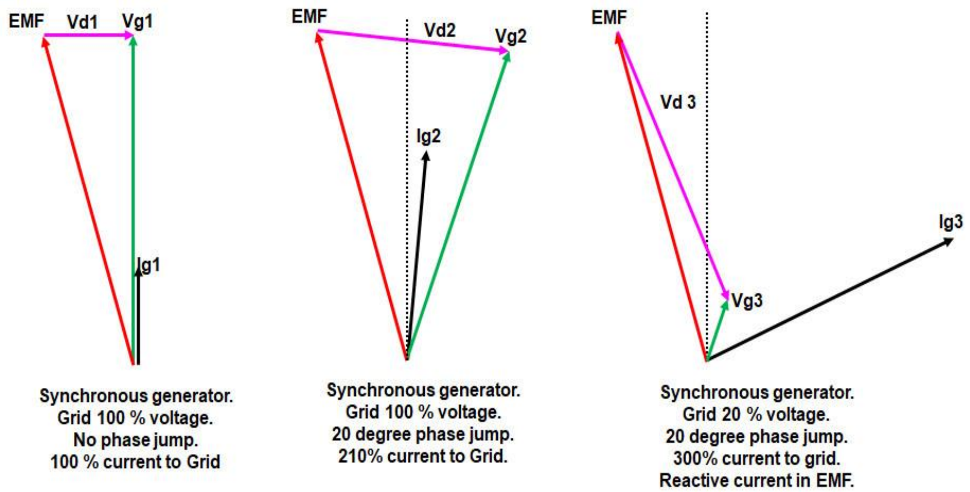

Figure 17.5. GBGF-S generator fault vectors.

The **Figure 17.5** shows three different operating conditions from left to right on the figure.

- **Condition 1.** The generator **EMF** voltage is for the normal operating condition relative to the Grid's voltage **Vg1** at 100%. The voltage difference **Vd1** is generating the current **Ig1** at 100 %. Allowing for the system's impedances the magnitude of **Vd1** is typically 0.3 per unit for rated current.
- **Condition 2**. The AC Grid's voltage **Vg2** is still at 100% but with an immediate 20-degree angle change from **Vg1.** The new voltage difference **Vd2** is generating the current **Ig2** that is a significantly higher current at 210 % compared with **Ig1.**
- **Condition 3**. The AC Grid's voltage **Vg3** has an immediate change to a 20 % voltage plus a 20-degree angle change from **Vg1.** The new voltage difference **Vd3** 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 **EMF** voltage.

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

The corresponding vectors for a **GBGF- I** inverter are shown on **Figure 17.6.**

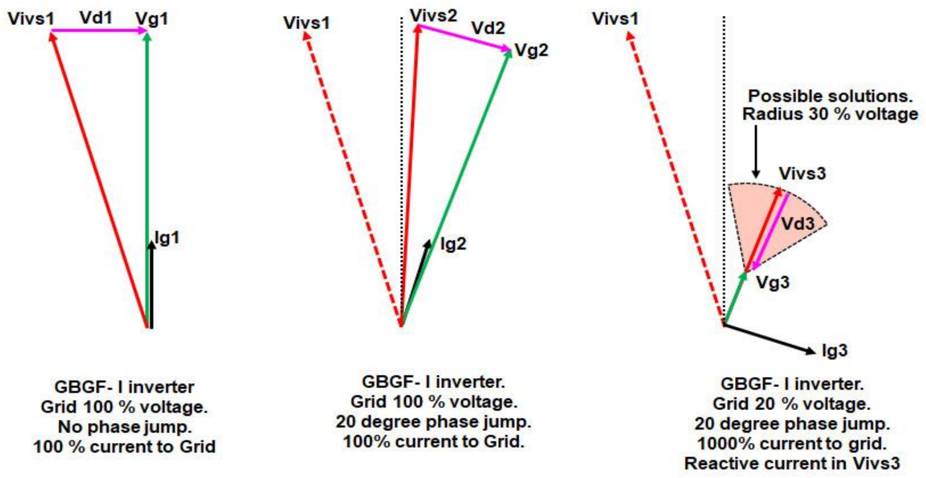

Figure 17.6. GBGF- I inverter fault vectors.

The **Figure 17.6** shows three different operating conditions from left to right on the figure.

- **Condition 1.** The inverter voltage **Vivs1** is for the normal operating condition relative to the AC Grid's voltage **Vg1** at 100%. The voltage difference is **Vd1** is generating the current **Ig1** at 100 %. Allowing for the system's impedances the magnitude of **Vdif1** is typically 0.3 per unit for rated current.
- **Condition 2.** The AC Grid's 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.**

  For a rapid angle change that is less than the **Phase Jump Angle Limit** angle the **GBGF- I** inverter's **IVS** angle does not immediately change which is what produces the **Active Phase Jump Power**.
- **Condition 3.** The AC Grid's voltage **Vg3** has an immediate change to a 20 % voltage plus a 20-degree angle change from **Vg1**. To avoid a trip the converter voltage **Vivs3** has been rapidly reduced in magnitude and at a phase angle so that the new voltage difference **Vdif** is generating the current **Ig3** that is at the rated current value and producing reactive current relative to the **Vivs3** voltage**.**

  The pink circle is the locus of the possible angles for the **Vivs3 voltage** and different angles will give different **Ig3** angles.

  The concept of aligning vectors **Vivs3** and **Vg3** to give dominantly reactive current from the inverter into the AC 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 in **Vivs3**.

The angles listed apply to a transmission connected systems and for **GBGF- I** inverters connected to a distribution network the AC impedances are lower that gives an increased value of the **Active Phase Jump power** for a given AC Grid angle change.

This will need a change in the specifications for distributed connected **GBGF- I** inverters.

18. Appendix D. AC impedances and reactive current requirements.

The **GBGF- I** inverters are designed to automatically and rapidly deliver the export and import of reactive power over the full operating range defined in the Grid Code by having a sufficient voltage margin available, see **Figure 18.1**.

This does not normally apply to **GBGF-S** generators as due to their limited voltage margins; they have to carry out a tap change to deliver an increased magnitude of exporting reactive power that does require time for this to occur.

For future **GBGF- I** inverters the use of tap changers should be allowed if they provide an economic advantage to the Capex cost of the systems, also see **Appendix F** for extra data on optimizing transformer rating and design for **GFR** conditions.

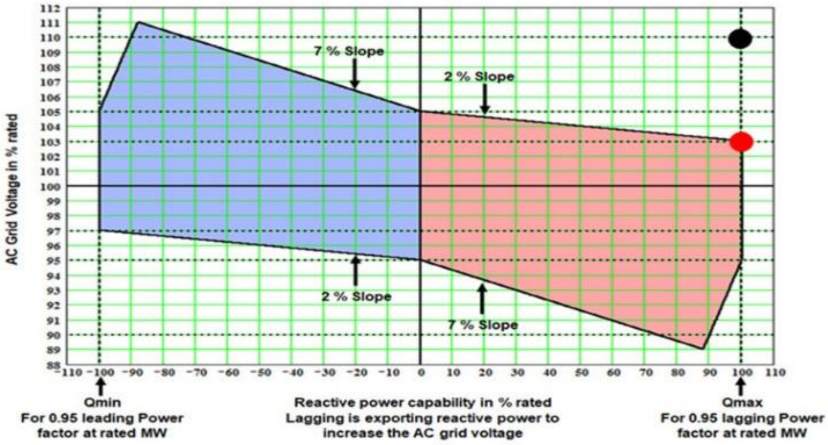

Figure 18.1. Required operational zone for reactive power.

The required **IVS** voltage for a **GBGF- I** inverter depends on the total AC supply impedance as shown on **Figure 18.2**.

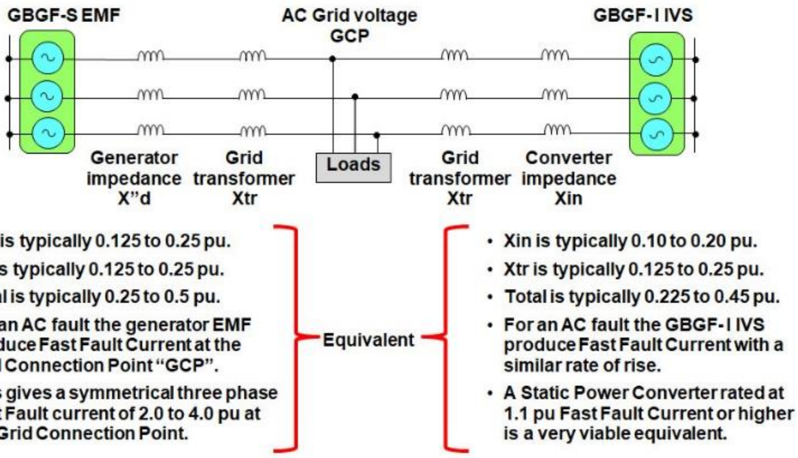

Figure 18.2. AC supply impedances for GBGF-S generators and GBGF- I inverters.

Both **GBGF-S** generators and **GBGF- I** inverters have very similar impedances with very similar initial rate of rise of fault currents.

For the **GBGF-S** generator the **Fast Fault Current** is higher at the generator terminals when a type test is carried out. The **X"d** impedance includes the inductance and losses of the coupled damper winding for normal operating conditions as shown on **Figure 18.4**.

For a short circuit fault the **X"d** correctly calculates the symmetric fault current but then the transient damper winding current decays and the stator current acts to weaken the generator's field current. This reduces the generator's **EMF** voltages and the **Fast Fault Current** magnitudes falls to a lower value.

The circuit to calculate the **IVS** voltage for a **GBGF- I** inverter is shown on **Figure 18.3.**

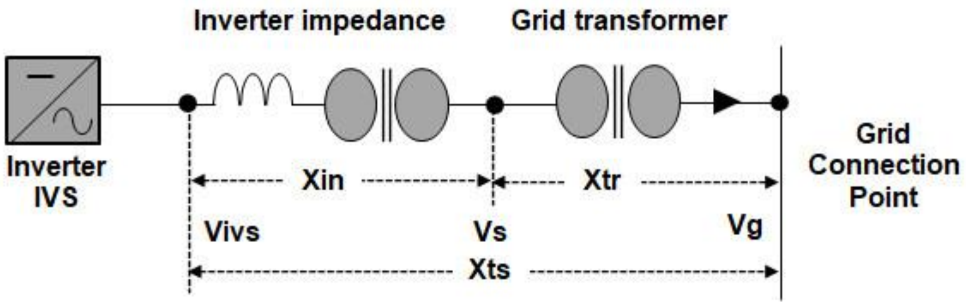

Figure 18.3. AC supply circuit for a GBGF- I inverter.

When reactive current is being supplied via a reactance **Xts** all the voltages **Vg, Vs** and **Vivs** are in phase. This gives the **Equation 7** for a system exporting just reactive power without a transformer tap changer.

Equation 7. **Vivs = Vg + (Xin + Xtr) x Reactive current.**

For an AC power factor of 0.95 the **Reactive current = 0.328 pu.**

For a typical value of **Xts = 0.333** pu and this gives a symmetrical **Fast Fault Current** of 3.0 pu.

This gives **Vivs = 1 + 0.333 x 0328 = 1.109 pu.**

When a **GBGF- I** inverter is exporting active power and reactive power the required **IVS** voltage increases as shown on **Figure 18.4.**

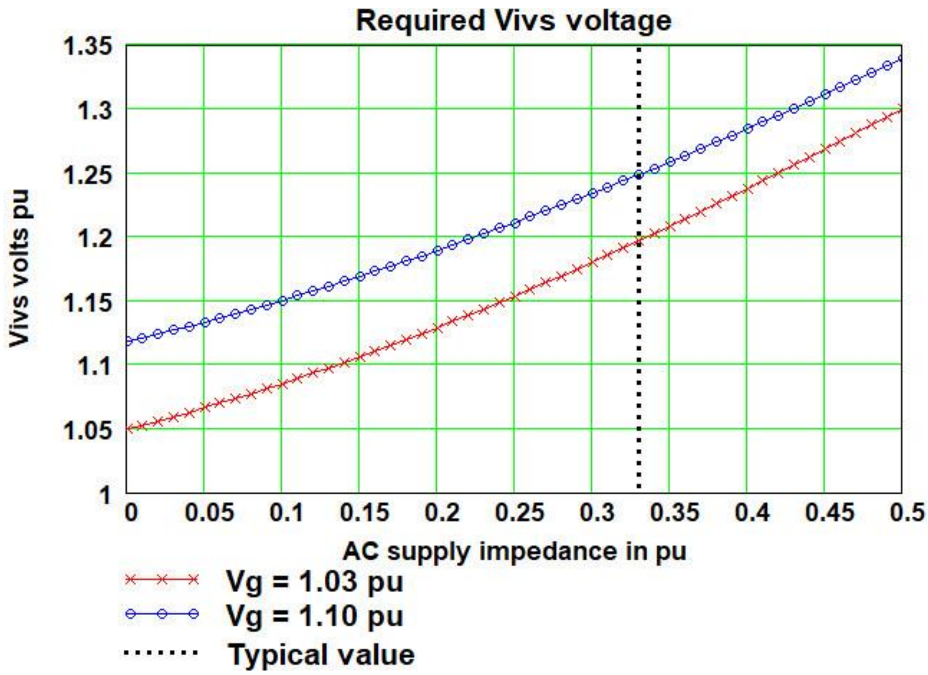

Figure 18.4. The required Vivs voltage for impedances.

The red line on **Figure 18.4** is the required **IVS** voltage to export rated active power plus reactive power at an AC Grid voltage of 1.03 pu which corresponds to the Red dot on **Figure 18.1.**

The blue line on **Figure 18.4** is the required **IVS** voltage to export rated active power plus reactive power at an AC Grid voltage of 1.10 pu which corresponds to the Black dot on **Figure 18.1.** This is required by certain international standards but it is difficult to justify why a system would want to export reactive power at its maximum AC Grid voltage especially as it requires a larger **GBGF- I** inverter.

For **GBGF- I** inverters rated as shown on **Figure 18.4**, this has the benefits of having an immediate fast response for reactive current for all operational conditions.

For **GBGF-S** generators, the required **EMF** voltage is not normally available to meet the rating shown on **Figure 18.5** and they use a tap changer as shown on **Figure 18.5** to provide an export of reactive power.

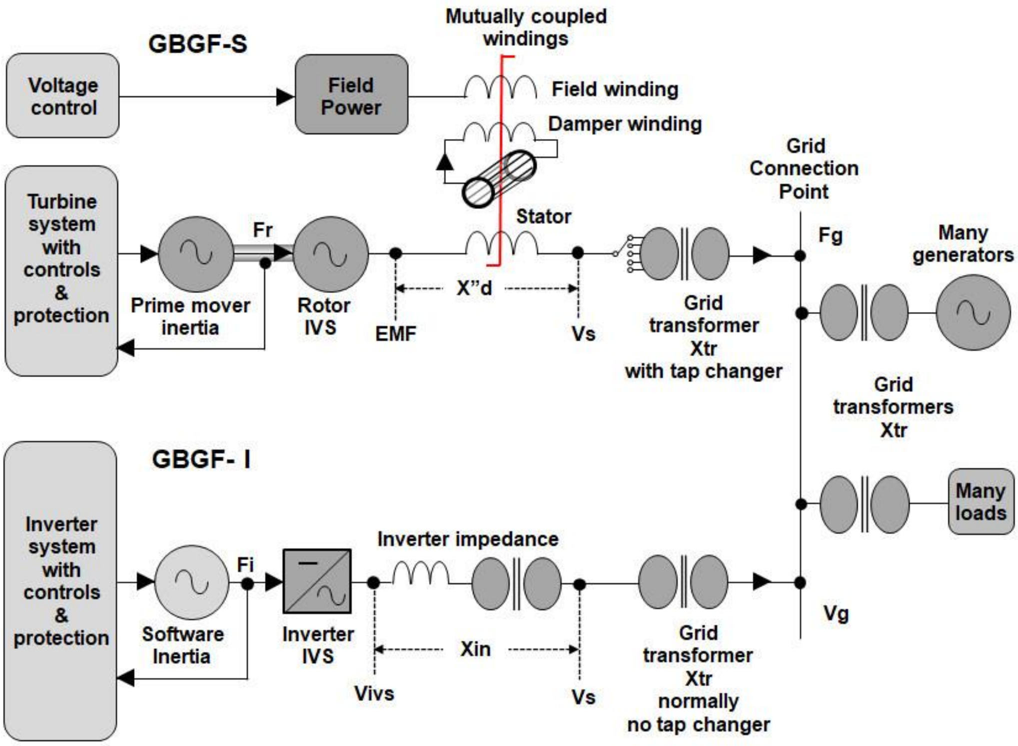

Figure 18.5. Use of tap changers.

For **GBGF-S** generators the tap changer enables the export of reactive power with a lower value of the maximum **EMF** voltage. This is a slower action as a command has to be issued to request a change of the tap changer. A tap changer adds cost to the AC Grid transformer but if this results in a lower cost for **GBGF- I** inverters this is a design option that can be discussed with **NGESO**.

19. Appendix E. Differences from existing static converter technology.

The differences include:

- For normal operating conditions the use of a Phase Locked Loop, or similar technology are not allowed for the control of the **IVS** of a **GBGF- I** inverter.

  PLL are used by existing inverters to give fast changes in the converters phase to match changes in the AC Grid's phase to avoid producing **Active Phase Jump Power**.

  GBGF- I inverters can use **PLL** for systems not involved in normal control like monitoring systems and for control in fault conditions.

- 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 AC Grid harmonic currents that can occur due to the listed normal Operating Conditions. In future, AC 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** that can be significantly increased to meet the requirements of a specific **NGESO Service**, see **Figure 12.9.**
- 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** generators as a **GBGF- I** inverter only has to work over the 47 to 52 Hz AC Grid frequency range. The size of the energy store will be larger depending on the design.
- Having the power available for **RoCoF** rates below +/- 1 Hz / s to produce the rated **Active RoCoF Response Power** plus the **Defined Active Damping 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 **Active 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 to 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 **Active RoCoF Response Power** the required increase in the speed of the wind turbines is unlikely to be available but other control options may be viable.

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 as defined in the Grid Code. This standard control system can then be used with a range of inverters at differing rating for different **NGESO** projects.

For **GBGF- I** inverters the software includes a feature of a **software inertia** model, at the contract defined **Hi** value. The frequency of the **software inertia** falls / rises, at a rate depending on the **Hi** value, when the **Active RoCoF Response Power** is being supplied / absorbed. This is to have an equivalent action to a **GBGF-S** generator.

20. Appendix F. Transformer saturation during GFR recovery.

The operation of a **GBGF- I** inverter after a deep voltage dip also requires fast control and special testing to operate, without tripping, for the waveforms shown on **Figures 20.1** and **20.2** which show real data from a **GFR** fully rated test carried out at a test site**.**

The **Figure 20.2** shows the secondary line voltages, when a fault has been cleared, that are applied to the **GBGF- I** inverter. These voltages have a 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 and the distorted voltage waveforms will require fast current control loops to be retained for a short time period.

This condition is very difficult to simulate, but simulation models are 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** inverter's transformer must also be based on the transformer secondary voltages, applied by the **IVS,** that can be above the voltages on the AC 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** inverter.

The effects shown on **Figure 20.1 & 20.2** can be significantly reduced by specifying a transformer for **GBGF- I** inverters 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 data on **Figure 20.1** 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 data on **Figure 20.2** is an expanded version of the same data, when the fault is cleared, that shows the saturation happening in the transformer's secondary voltages.

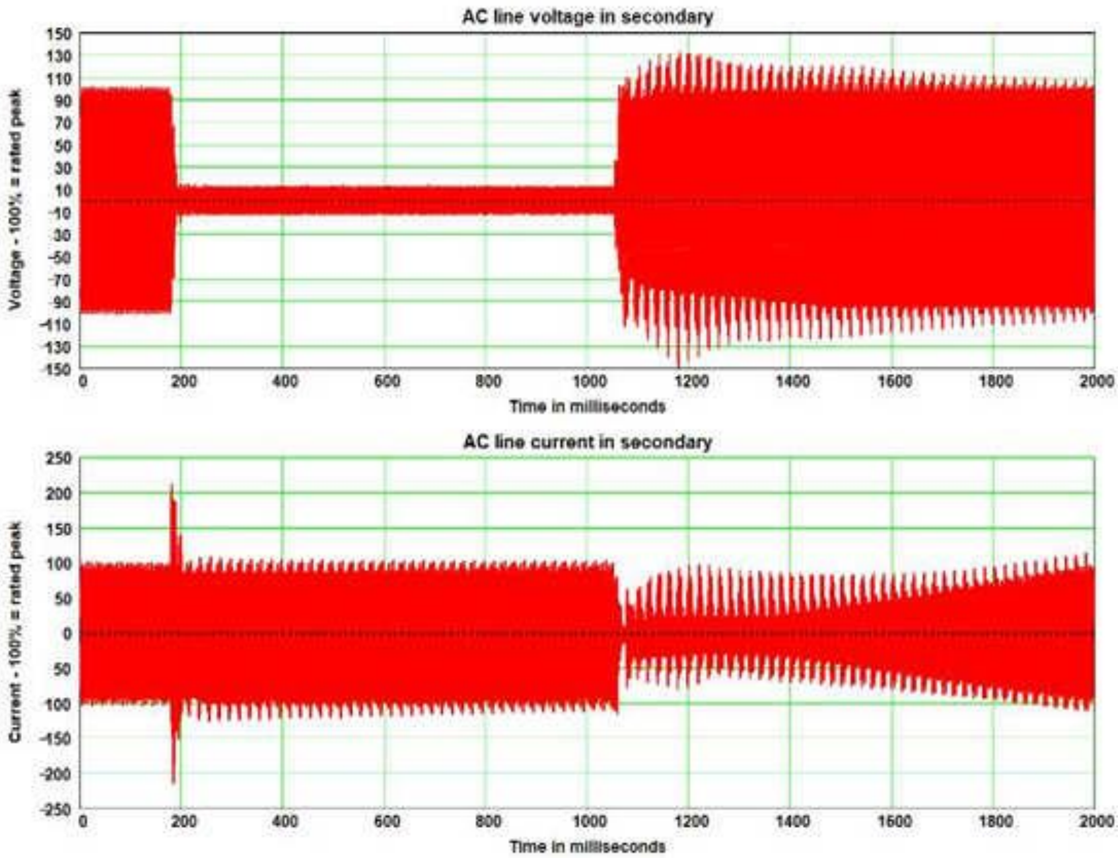

Figure 20.1. Recordings of the site data for a full GFR test.

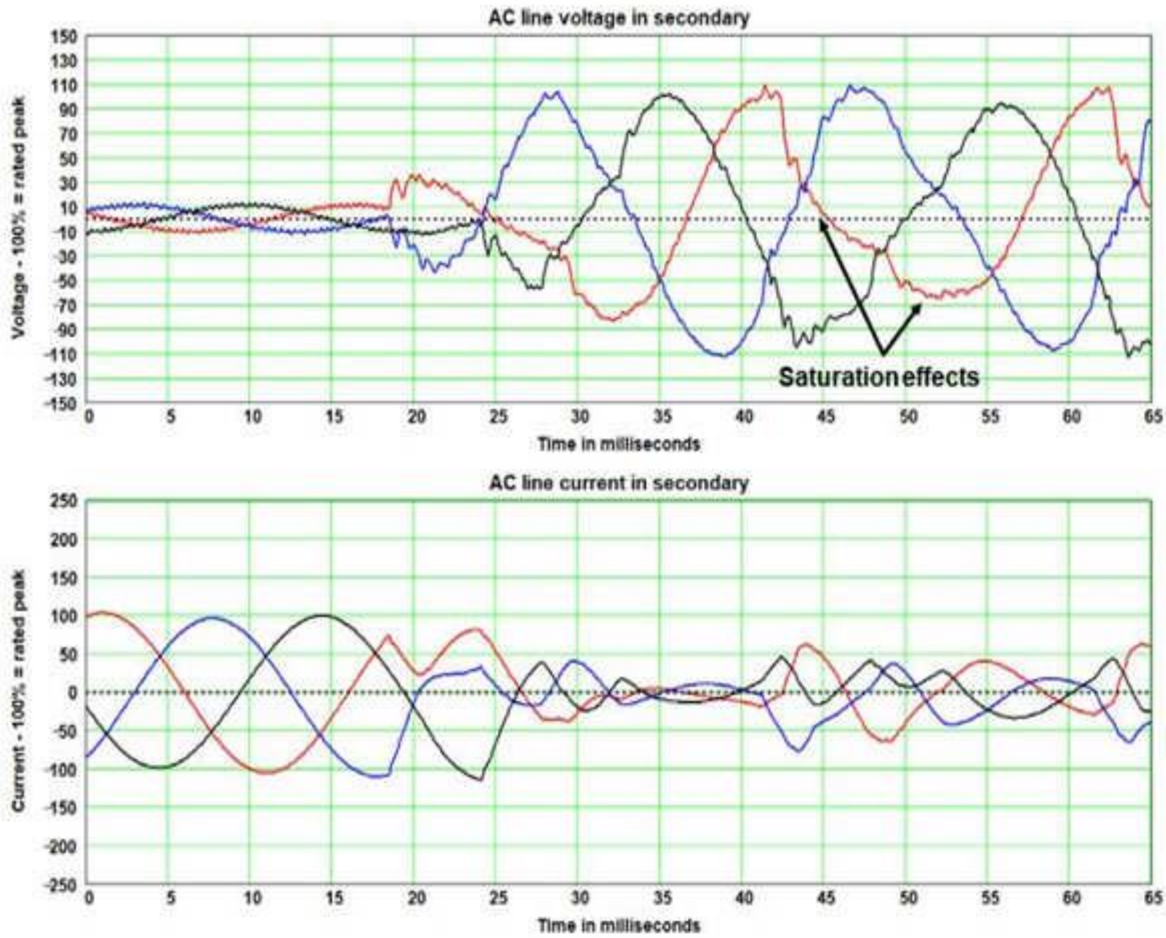

Figure 20.2. Expanded site data following the fault clearance.

21. References.

21.1. The Enhanced Frequency Control Capability (EFCC) Project.

https://www.nationalgrideso.com/document/111541/download

21.2 KEMA an independent analysis on the ability of Generators to ride through Rate of Change of Frequency values up to 2Hz/s.

http://www.eirgridgroup.com/site-files/library/EirGrid/DNV-KEMA_Report_RoCoF_20130208final_.pdf

21.3. Connecting for a smarter future National Grid Interconnectors

https://www.nationalgrid.com/document/118641/download

21.4. GE Thermal Hybrids

https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/services/gas-turbines/thermal-hybrids_R5.pdf

21.5. EOS batteries based on the Eos Znyth (zinc hybrid cathode) battery

https://eosenergystorage.com/products-technology

21.6. Ultra batteries which are an integration lead acid and Ultra capacitors

http://ultrabattery.com/technology/ultrabattery-technology

21.7. Vanadium based flow cells from many suppliers, see.

https://invinity.com/

21.8. Iron based flow cells that claim very low costs for 12 hour storage, see.

https://essinc.com/

22. Modification record.

Issue	Date	By	Details	
V - 005	06/07/2021	E A Lewis	Approved issue.	:.....