GRID FORMING CAPABILITY OF POWER PARK MODULES

REPORT ON TECHNICAL REQUIREMENTS

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This work is supported by the following associations. In addition, a scientific research institute (HTW Berlin) contributed to the discussions and provided simulation studies that appear in the report.

ENTSO-E, the European Network of Transmission System Operators for Electricity, is the association for the cooperation of the European transmission system operators. The 39 member TSOs, representing 35 countries, are responsible for the secure and coordinated operation of Europe's electricity system, the largest interconnected electrical grid in the world. In addition to its core, historical role in technical cooperation, ENTSO-E is also the common voice of TSOs.

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ENTSO-E Mission Statement

ENTSO-E, the European Network of Transmission System Operators for Electricity, **is the association of the European transmission system operators** (TSOs). The **40 member TSOs, representing 36 countries**, are responsible for the secure and coordinated operation of Europe's electricity system, the **largest interconnected electrical grid in the world**.

Before ENTSO-E was established in 2009, there was a long history of cooperation among European transmission operators, dating back to the creation of the electrical synchronous areas and interconnections which were established in the 1950s.

In its present form, ENTSO-E was founded to fulfil the common mission of the European TSO community: to power our society. At its core, European consumers rely upon a secure and efficient electricity system. Our electricity transmission grid, and its secure operation, is the backbone of the power system, thereby supporting the vitality of our society. ENTSO-E was created **to ensure the efficiency and security of the pan-European interconnected power system** across all time frames within the internal energy market and its extension to the interconnected countries.

ENTSO-E is working to secure a carbon-neutral future. The transition is a shared political objective throughout the continent and necessitates a much more electrified economy where sustainable, efficient and secure electricity becomes even more important. **Our Vision: "a power system for a carbon-neutral Europe"*** shows that this is within our reach, but additional work is necessary to make it a reality.

In its Strategic Roadmap presented in 2024, ENTSO-E has organised its activities around two interlinked pillars, reflecting this dual role:

- "Prepare for the future" to organise a power system for a carbon-neutral Europe; and
- "Manage the present" to ensure a secure and efficient power system for Europe.

ENTSO-E is ready to meet the ambitions of Net Zero, the challenges of today and those of the future for the benefit of consumers, by working together with all stakeholders and policymakers.

* https://vision.entsoe.eu/

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Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
AEMO	Australian Energy Market Operator
APO	Active Power Overshoot
BESS	Battery Energy Storage System
C-HIL	Control-Hardware-in-the-Loop
CNC	Connection Network Code
DFIG	Doubly Fed Induction Generator
EC	European Commission
EG	Expert Group
EHV	Extra High Voltage
EMT	Electromagnetic Transient
ENTSO-E	European Network of Transmission System Operators for Electricity
ESM	Electricity Storage Module
ESU	Electricity Storage Unit
EUT	Equipment Under Test
FNN	Forum Netztechnik/Netzbetrieb
FSM	Frequency Sensitive Mode
GB	Great Britain
GFM	Grid Forming
HIL	Hardware-in-the-Loop
HV	High Voltage
HVDC	High Voltage Direct Current
IBR	Inverter Based Resources
IGD	Implementation Guidance Document
LFSM	Limited Frequency Sensitive Mode
LV	Low Voltage
MV	Medium Voltage
NC	Network Code
NC RfG	Network Code Requirements for Generators
NESO	National Energy System Operator

NRA	National Regulatory Authority
OEM	Original Equipment Manufacturer
OVRT	Over Voltage Ride Through
PCS	Power Collection System
PGU	Power Generating Unit
PoC	Point of Connection
PPM	Power Park Module
pu	Per Unit
PV	Photovoltaic
RfG	Requirements for Generators
RMS	Root Mean Square
RoCoF	Rate of Change of Frequency
RSO	Relevant System Operator
SCR	Short-Circuit Ratio
SIL	Software-in-the-Loop
STATCOM	Static Synchronous Compensator
TG	Technical Group
TG GFC	Technical Group on Grid Forming Capability
TRL	Technology Readiness Level
TSO	Transmission System Operator
UVRT	Under Voltage Ride Through
V2G	Vehicle-to-Grid
VSM	Virtual Synchronous Machine
WTG	Wind Turbine Generators

EXECUTIVE SUMMARY

In the context of defining Grid Forming (GFM) requirements for Power Park Modules (PPM) as well as Electricity Storage Modules (ESM),[1] this report proposes a non-binding approach of detailing GFM technical requirements in the national implementation of the amended Network Code on Requirements for Generators (NC RfG).

In addition to outlining detailed requirements, it proposes a range of parameters and compliance tests for GFM-capable PPMs.

To the best of ENTSO-E's knowledge, and without prejudice to existing patents, the report adopts a technology-neutral stance, providing a patent-free and technology-agnostic framework for defining technical requirements for GFM capabilities for PPMs. This approach is intended to ensure independence from specific control implementations or manufacturer patents issued before the report's publication date, thereby fostering an environment conducive to innovation.

[1] *According to the draft NC RfG 2.0, a V2G (Vehicle-to-Grid) electric vehicle and its associated V2G electric vehicle supply equipment with a bidirectional functionality is regarded as an ESM and must meet GFM requirements if its maximum capacity is greater than or equal to 1 MW*

1 Introduction

1.1 Context and background

On 19 December 2023, the Agency for the Cooperation of Energy Regulators (ACER) submitted its recommendations to the European Commission (EC) for amending the Connection Network Code (CNC) Requirements for Generators (known as the NC RfG Regulation).[2] The ACER recommendation is hereinafter referred to as draft NC RfG 2.0. This proposal is based on input and feedback received from different stakeholders gathered during an initial consultation process, a formal process requested by the EC. Notably, it includes Grid Forming (GFM) requirements for Power Park Modules (PPM) based on input from the Expert Group (EG) on Advanced Capabilities for Grids with a High Share of PPM.[3]

To facilitate the national implementation of NC RfG 2.0 and address stakeholders' concerns about harmonising requirements while respecting national system needs, ENTSO-E will release an Implementation Guidance Document (IGD) proposing detailed GFM requirements after the publication of the amended NC RfG Regulation, expected in late 2025, following a delegated act of the EC.

To prepare and advance the work of this future IGD, ENTSO-E published in May 2024 a first version of the present technical report (the Phase I report[4]). Afterwards, to consult with stakeholders on the report, ENTSO-E established in June 2024 a Technical Group on Grid Forming Capability (TG GFC) with some European stakeholders (CENELEC, the Energy Storage Europe Association, EU DSO entity, SolarPower Europe and Wind Europe).

Based on the discussions of this TG and the feedback received from stakeholders, ENTSO-E is publishing the present second consolidated version of the report (the Phase II report). The purpose of this non-binding report is to provide technical guidelines regarding the GFM requirements of the draft NC RfG 2.0. Based on this technical report, ENTSO-E plans to publish a non-binding IGD once the EC has adopted the final version of the NC RfG 2.0. To the extent required, national network codes should also be amended to implement GFM requirements under national law.

It is worth noting that GFM technical requirements as auxiliary services have been recently adopted by system operators in Great Britain (GB) and Australia. The National Energy System Operator (NESO) published the GB GFM Best Practice Guide in April 2023[5] and the Guidance Notes in September 2023 following the inclusion of GFM requirements into the GB Grid Code (GC0137 - Minimum Specification Required for Provision of GB GFM Capability),[6] and the Australian Energy Market Operator (AEMO) released a Core Requirements Test Framework in January 2024 to complement

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[2] *ACER proposes amendments to the electricity grid connection network codes | www.acer.europa.eu*
[3] *GC-ESC EG ACPPM Report version 1.00 (windows.net)*
[4] *https://eepublicdownloads.entsoe.eu/clean-documents/Publications/SOC/20240503_First_interim_report_in_technical_requirements.pdf*
[5] *download (nationalgrideso.com)*
[6] *THE GRID CODE (nationalgrideso.com)*

the Voluntary Specification for GFM Inverters.[7,8] Within the EU, at least one Member State, namely Germany, published in July 2024 a guideline document[9] recommending requirements for an inertia market based on GFM PPMs.

1.2 Objective and scope

The objective of this task force is to provide recommendations for technical GFM requirements for PPMs including Electricity Storage Modules (ESMs), while remaining agnostic of the specific controller implementation. In accordance with Article 6(6) of the draft NC RfG 2.0, ESM shall provide the requirement of GFM in both infeed and consumption mode.[10]

The technical requirements presented in this report are intended to describe the GFM capabilities of PPMs and ESMs of types A-D, according to the determination of significance as defined in Article 5 of the draft NC RfG 2.0.

1.3 Report outline

The remainder of this report is organised as follows:

- Chapter 2 outlines the GFM requirements for PPMs proposed for inclusion in the draft NC RfG 2.0, which ACER has submitted to the EC for approval. It also provides a framework for interpreting and detailing these requirements during national implementation of the draft NC RfG 2.0.

- Chapter 3 provides recommendations for compliance verification through testing and/or simulations of GFM PPMs.

- Appendix A presents the specific needs for the Nordic synchronous area to limit transient frequency deviations.

- Appendix B includes the description of an exemplary droop-based control loop and parametrisation for a virtual synchronous machine implementation.

- Appendix C analyses the physical concepts underlying these needs and requirements, including the physical response of an ideal system to disturbances.

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[7] *https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/grid-forming-inverters-jan 2024.pdf?la=en*
[8] *https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2023/gfm-voluntary-spec.pdf*
[9] *Technische Anforderungen an Netzbildende Eigenschaften inklusive der Bereitstellung von Momentanreserve. FNN Hinweis Netzbildende Eigenschaften V2.0*
[10] *According to draft NC RfG 2.0, a V2G (Vehicle-to-Grid) electric vehicle and its associated V2G electric vehicle supply equipment with a bidirectional functionality is regarded as an ESM and must meet GFM requirements if its maximum capacity is greater than or equal to 1 MW*

- Appendix D describes the ability of some inverters to switch from GFM to non-GFM capabilities and vice versa.
- Appendix E presents specifications for inertia requirements.
- Appendix F proposes numerical examples to evaluate the synthetic inertia contribution of a Power Generating Unit (PGU) within its capability limits.
- Appendix G presents the positions of stakeholders who support this report but whose views deviate from the content presented in this report.

The appendices of this report provide additional background necessary to understand the simulations presented as a minimum GFM implementation. It should be noted that these control schemes are neither binding nor intended to restrict GFM implementation due to patent ownership or other legal obligations. Compliance evaluation should be based on verifying behaviour in tests and simulations rather than assessing the specific implementation.

1.4 Nomenclature

The unit parameters[11] used in this report are defined in Table 1. Moreover, the definitions of the draft NC RfG 2.0 are applied in this report.

Note that for the purposes of this document, the per-unit (pu) values for PGU are computed based on the following:

- U_{BASE_PGU} = nominal PGU terminal voltage
- S_{BASE_PGU} = nominal PGU active power
- I_{BASE_PGU} = nominal PGU current, defined as the ratio of S_{BASE_PGU} to U_{BASE_PGU}

And for PPM:

- U_{BASE_PPM}= nominal voltage of Point of Connection (PoC)
- S_{BASE_PPM} = nominal PPM active power (P_{max})
- I_{BASE_PPM} = nominal PPM current, defined as the ratio of S_{BASE_PPM} to U_{BASE_PPM}

[11] *International unit system values are presented in uppercase, pu values in lowercase, and underlining indicates complex/phasor values consisting of magnitude and angle.*

Table 1: Unit parameters

Parameter or value unit	Description	Comment
PGU	Power generating unit, which in this report also includes electricity storage units	
$\underline{u}_{\mathrm{PGU}}$	Voltage phasor of the power generating unit in pu	at LV, MV, or HV terminals[12]
$\underline{u}_{\mathrm{Inv}}$	Internal inverter voltage phasor at power generating unit in pu	
$\underline{u}_{G}$	Voltage phasor of the grid equivalent in pu	
$\underline{z}_{G}$	Complex impedance of grid equivalent in pu	
$\underline{z}_{\mathrm{Tr}}$	Unit LV/MV transformer and, if applicable, MV/HV transformer complex impedance in pu	
$\underline{z}_{\mathrm{Filt}}$	Unit LV/MV filter complex impedance in pu	R and L only
$\underline{z}_{\mathrm{Eff}}$	Unit effective complex impedance in pu	
x_{Eff}	Unit effective reactance in pu	
$\underline{z}_{\mathrm{Control}}$	Effective complex impedance virtually provided by the control in pu	
$\underline{z}_{\mathrm{PCS}}$	Complex impedance of power collection system in pu	

[12] *According to IEC 60038*

2 Grid forming Capability at the Point of Connection of PPMs

In the matter of GFM capability, the draft NC RfG 2.0 stipulates the following[13] in Article Y(7) in Chapter 3:

"Where grid forming capability is specified by the relevant TSO in coordination with the relevant system operator in accordance with NC RfG 2.0 Article Y, or defined in Articles 20, 21 and 22, a power park module shall be capable of providing grid forming capability ***at the connection point*** *as listed below, considering the sub-cycle character of the physical quantities where appropriate."*

Therefore, in the draft NC RfG 2.0, all the connection requirements are evaluated for compliance (either by tests, simulations, or equipment certificates) at the PoC of the PPM with the grid. In the case of GFM capability and "*within the PPM's current and energy limits, the PPM shall be capable of behaving at the terminals of the individual unit(s) as a voltage source behind an internal impedance…"*. Therefore, **technical requirements for the voltage source behaviour shall be defined at the terminal of the individual power generating unit(s)**, while compliance shall be verified as described in Chapter 3.

As illustrated in Figure 1, a PPM and ESM typically comprises individual PGUs and Electricity Storage Units (ESUs), respectively. In this report, the term PGU is used for both power generation and ESUs. PPMs frequently include an internal grid, also known as the Power Collection System (PCS).

Consequently, the technical requirements of the voltage source behind an internal impedance (Thevenin source) shall be specified by the relevant Transmission System Operator (TSO), in coordination with the Relevant System Operators (RSOs) at the PGU terminals. The voltage source may or may not include the connection transformer(s). The terminal voltage is then respectively denoted $\underline{u}_{\mathrm{PGU,MV}}$ or $\underline{u}_{\mathrm{PGU,HV}}$ and $\underline{u}_{\mathrm{PGU,LV}}$ (see Figure 1). The facility owner needs to ensure and demonstrate that the PCS design maintains a voltage source behind an impedance behaviour at the PoC, as specified in the following sections.

Section 2.1 describes an equivalent circuit representation of the PGU. Section 2.2 elaborates the analytical expressions of the expected output currents. Section 2.3 proposes a detailed definition of GFM requirements.

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[13] [ACER_Recommendation_03-2023_Annex_1_.a_NC_RfG_TC_to_original.pdf (europa.eu)]

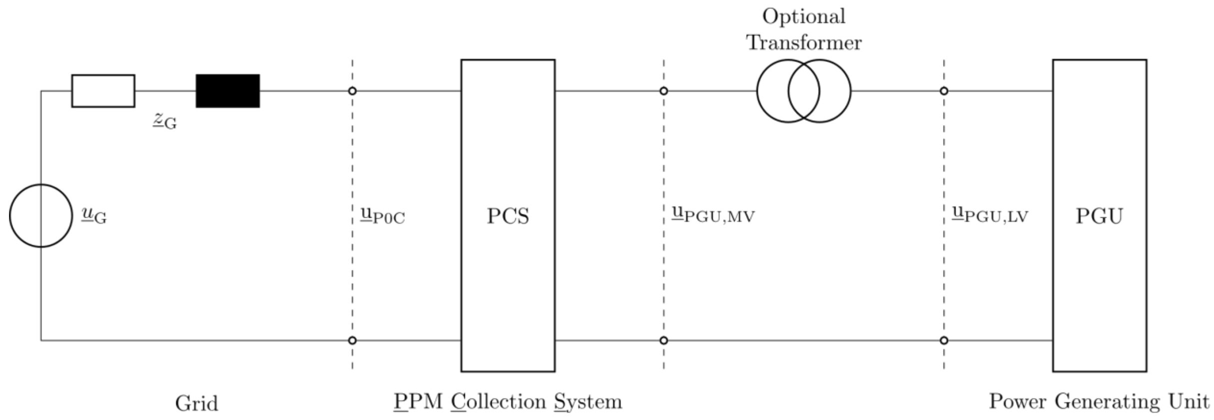

Figure 1: Example of PPM PoC and unit terminals on MV and LV for a PPM with PCS on the MV level

2.1 Power generating unit equivalent circuit representation

Figure 2 illustrates an equivalent circuit representation of a PGU connected to an infinite bus suitable for assessing its response to grid events.

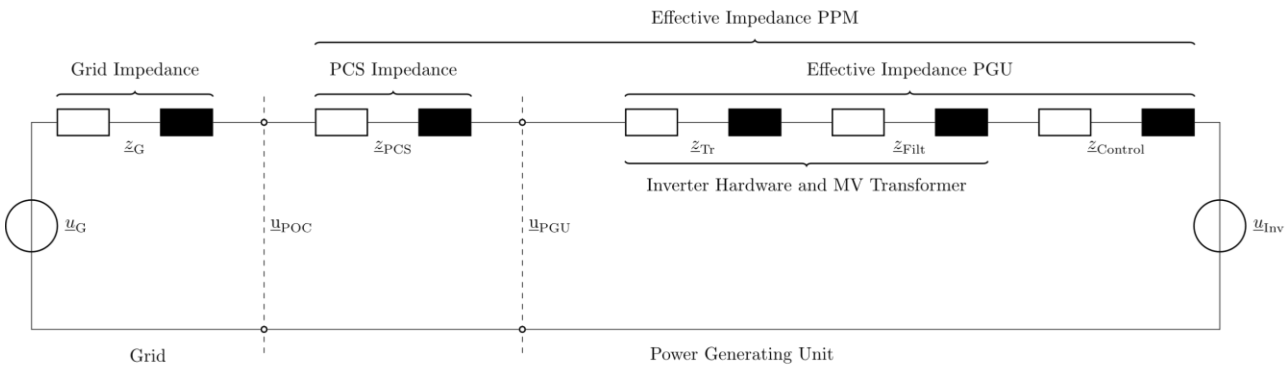

Figure 2: Equivalent representation of the PGU small signal positive sequence controller for evaluating the short-term response of the GFM PGU to variations in grid voltage magnitude and phase angle

With regard to the technical requirements for GFM capability described in Section 2.3, the following considerations are based on a simplified representation of the electrical system (Figure 2):

1. $\underline{u}_{\mathrm{inv}}$ represents the internal voltage phasor (amplitude, voltage phase angle, and frequency) of the Thevenin source of a given PGU.
2. Converter physical parameters are given as complex numbers ($\underline{z}_{\mathrm{Tr}}$ and $\underline{z}_{\mathrm{Filt}}$) and are considered fixed for a given PGU at the synchronous frequency (50 Hz).
3. The internal complex impedance of the Thevenin source is given by the equivalence of the physical impedance ($\underline{z}_{\mathrm{Tr}}$ and $\underline{z}_{\mathrm{Filt}}$) and the impedance added by the control ($\underline{z}_{\mathrm{Control}}$) of the PGU,

and will be referred to as the effective impedance $\underline{z}_{\mathrm{Eff\_PGU}}$. The effective impedance is defined at synchronous frequency (50 Hz).

4. The PCS is represented by the impedance $\underline{z}_{\mathrm{PCS}}$.
5. The network is represented by a Thevenin equivalent of the voltage $\underline{u}_{\mathrm{G}}$ and the impedance $\underline{z}_{\mathrm{G}}$.

2.2 Analytical expressions of the expected initial output current

The active ($i_{\mathrm{P,PGU}}$) and reactive ($i_{\mathrm{Q,PGU}}$) components of the positive sequence current injected by the GFM PGU at the terminals can be approximated on the assumption of $r_{\mathrm{Eff}} << x_{\mathrm{Eff}}$ (i.e. $x_{\mathrm{Eff}} \approx z_{\mathrm{Eff}}$) by equations (1) and (2) respectively, assuming steady-state conditions where all fast transients have decayed.

$$i_{\mathrm{P,PGU}} = \frac{p_{\mathrm{PGU}}}{u_{\mathrm{PGU}}} \approx -\frac{u_{Inv}}{x_{\mathrm{Eff}}} sin(\delta) \tag{1}$$

$$i_{\mathrm{Q,PGU}} = \frac{q_{\mathrm{PGU}}}{u_{\mathrm{PGU}}} \approx \frac{1}{x_{\mathrm{Eff}}} \left(u_{\mathrm{PGU}} - u_{\mathrm{Inv}} \cdot cos(\delta)\right) \tag{2}$$

where $\delta = \varphi_{U_{\mathrm{PGU}}} - \varphi_{U_{\mathrm{Inv}}}$ denotes the phase difference between the PGU terminal voltage angle $\varphi_{U_{\mathrm{PGU}}}$ and the internal voltage $\varphi_{U_{\mathrm{Inv}}}$ of the PGU (internal inverter voltage, behind the phase reactance).

Under unbalanced conditions, the negative sequence reactive current ($i_{\mathrm{Q,PGU,neg}}$) can be approximated by:

$$i_{\mathrm{Q,PGU,neg}} \approx \frac{1}{x_{\mathrm{Eff,neg}}} u_{\mathrm{PGU,neg}} \tag{3}$$

with $u_{\mathrm{PGU,neg}}$ as the negative sequence voltage at the PGU terminal.

When formulating those approximations, we assume that:

1. In accordance with the draft NC RfG 2.0, both the inverter internal voltage phasor $\underline{u}_{\mathrm{inv}}$ (and their amplitude, phase, and frequency) and effective impedance phasor $\underline{z}_{\mathrm{Eff}}$ are considered constant at the inception of grid events while current, energy, or voltage limits are not reached.
2. The ratio $r_{\mathrm{Eff}}/x_{\mathrm{Eff}}$ of PGU and PPM impedance remains small,[14] such that the impact of the resistive part of $\underline{z}_{\mathrm{Eff}}$ can be neglected for the description of the expected current response. Consequently, when this report refers to effective impedance ($\underline{z}_{\mathrm{Eff}}$), the term includes both the reactive and resistive components, even though the simplified equations include only the reactance.

[14] *A ratio of* $r_{Eff}/x_{Eff} < 0.1$ *is recommended at the PPM level*

2.3 Proposed detailed requirements

Technical requirements for GFM capability specify the response of active and/or reactive current or power to voltage variations in amplitude, phase, and frequency. The point of applicability of each requirement (i.e. at the PGU level, PPM level, or both) is described in the subsections below.

In particular, technical requirements for the following quantities are defined with respect to voltage amplitude, voltage phase angle or frequency changes:

1. The expected value of the current or power output.
2. The response times[15] of the current or power expected value.
3. The decay rate or overshoot of the current or power excursion (when relevant).
4. The damping ratio of the current or power oscillation.

2.3.1 On the voltage source behaviour within capability limits

This section details the requirement specified in Article Y(7) (a)-(c) of the draft NC RfG 2.0. These requirements are specified for PPM of type A if GFM is mandated according to Article Y(5). These requirements also apply for PPM of type B if mandated according to Article 20(4). These requirements also apply to PPM of types C and D:

"(a) Within the power park module's current and energy limits, the power park module shall be capable of behaving at the terminals of the individual unit(s) as a voltage source behind an internal impedance (Thevenin source), during normal operating conditions (non-disturbed network conditions) and upon inception of a network disturbance (including voltage, frequency, and voltage phase angle disturbance). The Thevenin source is characterized by its internal voltage amplitude, voltage phase angle, frequency, and internal impedance.

(b) Upon inception of a network disturbance and while the power park module capabilities and current limits are not exceeded, the instantaneous AC voltage characteristics of the internal Thevenin source according to paragraph (a) shall be capable of not changing its amplitude and voltage phase angle while positive sequence voltage phase angle steps or voltage magnitude steps are occurring at the connection point. The current exchanged between the power park module and the network shall flow naturally according to the main generating plant and converter impedances and the voltage difference between the internal Thevenin source and the voltage at the connection point.

(c) After inception of a network disturbance in voltage magnitude, frequency or voltage phase angle, the following shall apply within the power park module's capability, including current limits and inherent energy storage capabilities of each individual unit.

(i) The relevant system operator in coordination with the TSO shall specify the temporal parameters of the dynamic performance regarding voltage stability.

[15] *Assumed to be within one cycle for the instantaneous current response to voltage angle and magnitude changes.*

(ii) Where current limitation is necessary, the relevant system operator in coordination with the relevant TSO may specify additional requirements regarding contribution of active and reactive power at the point of connection.

(iii) The power park module shall be capable of stable operation when reaching the power park module current limits, without interruption, in a continuous manner and returning to the behaviour described in paragraph (b) as soon as the limitations are no longer active. If reaching the current limit, the grid forming behaviour must be maintained for responses as specified in paragraph (b) for disturbances that require the current to vary in the opposite direction of the current limitation."

In accordance with Article Y(7) of the draft NC RfG 2.0, both the PGU's internal voltage phasor (in amplitude, phase, and frequency) and the effective impedance should not vary *upon inception of a network disturbance at the connection point. If the PPM capabilities and current limits are exceeded, instantaneous reaction of the PGU to maintain currents limits is allowed*. Moreover, according to equations (1) and (2), the output current depends on the magnitude of the grid disturbance and the effective impedance. The grid disturbance can consist of a *voltage phase angle step and/or a voltage magnitude step*, which are external variables. The effective impedance is the only parameter defined by the PPM design. To avoid doubt, the internal Thevenin voltage source is required to change according to the temporal parameters to achieve the desired performance regarding synchronisation, the damping ratio of active power oscillations, and synthetic inertia (if specified for power generating plants of types B, C, or D).

According to Article Y (7)(c)(i), the TSO shall specify the temporal parameters of the dynamic performance. As the requirement is solution-agnostic, the TSO specifies only speed and performance duration. The requirement itself, as stated above, is solution-agnostic, defined using an equivalent circuit representation.

The temporal parameters to be defined by the TSO regarding voltage angle jump and voltage frequency are:

1. The minimum damping ratio.
2. The synthetic inertia specified in Section 2.3.2 if specified for types B, C, and D.

Regarding voltage magnitude, no additional parameter is defined. Within the normal operating range, the temporal behaviour is defined by the steady-state reactive power control requirements of the PPM. Outside the normal operating range, the magnitude of the internal voltage source is maintained at a constant unless the provisions of Section 2.3.3 apply.

To quantify the voltage phase jump power contribution, equation (4) is introduced. Based on the equivalent circuit of Section 2.1, taking into account the assumed simplifications in Section 2.2, and assuming that $\underline{u}_{\mathrm{inv}} \approx 1$, it is derived from equation (1) and (2). Equation (4) calculates the change in active current based on an angle jump γ, taking into account δ (the phase difference between $\varphi_{U_{\mathrm{PGU}}}$ and $\varphi_{U_{\mathrm{Inv}}}$ prior to the phase jump).

$$\Delta i_{\mathrm{P,PGU,Peak}} \approx -\frac{1}{x_{\mathrm{Eff}}}\big(sin(\delta + \gamma) - sin(\delta)\big) \tag{4}$$

With:

- $\Delta i_{\mathrm{P,PGU,Peak}}$ being the expected theoretical peak, which is analytically calculated.
- δ being the phase difference between the terminal voltage angle $\varphi_{U_{\mathrm{PGU}}}$ and the internal voltage $\varphi_{U_{\mathrm{Inv}}}$ of the PGU prior to the phase jump event.
- γ being the angle change applied by which the terminal voltage angle $\varphi_{U_{\mathrm{PGU}}}$ jumps from its steady-state value.

Since equation (4) assumes steady-state conditions where all fast transient effects have decayed, the resulting value of Δi only provides a theoretical analytical estimation and shall be calculated taking into account the steady-state angle δ prior to the phase jump angle γ is applied. After the phase jump γ is applied, the phase angle variation is assumed to remain stable. This theoretical steady-state value of a voltage source with infinite inertia is then taken as a reference when evaluating the first peak value measured after the voltage phase jump (see Appendix C.1 for further details).

If applied to measured data, IEC 61400-21-1 Annex C may be used to evaluate the phase angle before and after the event and to measure the current. As IEC 61400-21-1 Annex C includes an averaging over one nominal grid period, the decay of the response may already be significant during the averaging period. This must be taken into account when defining the acceptance criteria.

When the phase jump cannot be controlled at the unit terminals but is introduced in a grid location remote to the terminals, equation (5) can be applied. In this case, x_{grid} would represent the impedance between the PGU terminals and the location where the phase jump is introduced.

$$\Delta i_{\mathrm{P,PGU,Peak}} \approx -\frac{1}{x_{\mathrm{Eff}} + x_{grid}}\big(sin(\delta + \gamma) - sin(\delta)\big) \tag{5}$$

With:

- $\Delta i_{\mathrm{P,PGU,Peak}}$ being the expected theoretical peak, which is analytically calculated.
- δ being the phase difference between the grid voltage angle $\varphi_{U_{\mathrm{G}}}$ and the internal voltage $\varphi_{U_{\mathrm{Inv}}}$ of the PGU prior to the phase jump event.
- γ being the angle change applied by which the grid voltage angle $\varphi_{U_{\mathrm{G}}}$ jumps from its steady-state value.

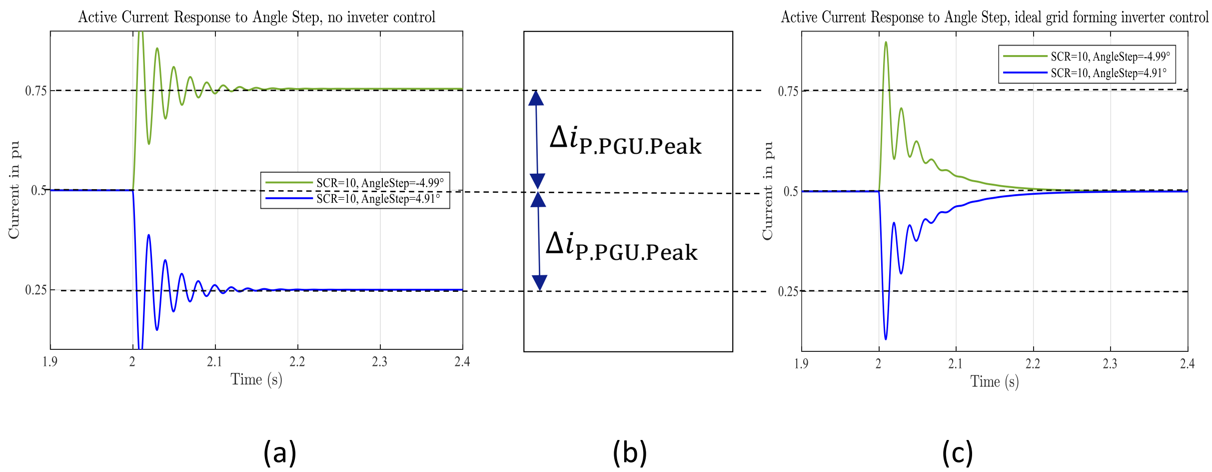

Figure 3: Result of equation (4) (subplot b) and analytical calculation of phasor values of active current for an angle step by -5° (green line) and +5° (blue line) at the PPM PoC for infinite inertia (a) or inertia of H = 5 s (c) and x_{Eff} of 0.35. (See also Appendix C)

In Figure 3(a), the blue and green curve represent active current calculated according to equation (27) (see Appendix C) with an assumed stiff voltage source (infinite inertia). Figure 3(c) represents the response to the same event with the exemplary model of Appendix B with an inertia of 5 s according to equation (34). Both subplots consider x_{Eff} of 0.35. Subplot (b) shows the result of equation (4) assuming the same phase jump and x_{Eff}.

As shown in subplot (c), the decline of the response for finite inertia starts instantaneously. To take into account additional delays in the real measurement set-up (such as calculation of the positive sequence active current component), it is proposed to define 50% of the result of equation (4) as acceptance criteria for $\Delta i_{\mathrm{P,PGU,Peak}}$.

Table 2 lists the recommended maximum values of the **positive sequence effective impedance** for different voltage levels at the PGU terminals to account for transformer physical impedance, considering typical values used across the industry.

The equivalent effective complex impedance virtually provided by the control ($\underline{z}_{\mathrm{Control}}$) shall be designed so that the PGU effective impedance ($\underline{z}_{\mathrm{Eff\_PGU}}$) is always positive.[16]

In addition, at frequencies above 100 Hz and up to a frequency threshold value specified by the TSO, in the range of 1-2.5 kHz, the frequency-dependent complex effective impedance ($\underline{z}_{\mathrm{Eff}}(f)$) of the PGU being installed in PPMs of types A-D should have a positive real part.[17] For type C and D PPMs, this recommendation should also be evaluated at the PoC.

Table 2: Proposed maximal values of the positive sequence effective impedance z_{Eff} (at 50 Hz) of the PGU at the low, medium and high voltage terminals

	z_{Eff} values (in pu)
Point of reference for evaluation	**Max value**
Low voltage PGU terminals	0.27
Medium voltage PGU terminals	0.35
High voltage PGU terminals	0.45

Table 3 lists the recommended maximum values of the **positive sequence PPM effective impedance** (defined as the total effective impedance of the PPM, including the aggregated PGU effective impedance and the PCS impedance, seen from the PoC) for PPMs connected at different voltage levels.

Table 3: Proposed maximal values of the positive sequence PPM effective impedance z_{Eff_PPM} (at 50 Hz) for a PPM connected at medium, high, and extra high voltage (usually types C and D PPM)

	z_{Eff} values (in pu)
Point of reference for evaluation	**Max value**
Medium voltage PPM PoC	0.35
High voltage PPM PoC	0.50
Extra high voltage PPM PoC	0.50[18]

It should be noted that high effective GFM PGU impedance values may reduce the sensitivity of active and reactive current injection to variation in voltage phase angle amplitude at the PGU terminal. Conversely, excessively low effective impedance may lead to the high sensitivity of the PPM output to grid disturbances, especially under strong grid conditions where this property is less

[16] *Both real and imaginary components of the impedance shall be positive*
[17] *This requirement aims to ensure that any GFM PPM provides a passive behaviour when interacting with grid resonances and do not amplify such control interactions creating harmonic stability issues.*
[18] *If it is technically justified by the power generation facility owner that an EHV-connected PPM cannot comply with 0.5 pu effective impedance at its PoC, the relevant TSO shall have the right to define higher values of the effective reactance.*

essential. Table 2 and Table 3 provide the maximum effective impedance values for the PGU and at the PPM level, respectively.

Depending on local system needs, a higher PPM contribution may be required. In this case, the RSO, in coordination with the TSO, could request a lower effective impedance threshold, typically in weak grid conditions. In such cases, the TSO and RSO may determine that certain PGU technologies are unsuitable for operation in weak grids and may therefore be excluded from connection at a specific PoC.

The **negative sequence effective impedance** $z_{\mathrm{Eff,neg}}$[19] should have a similar value to the positive sequence effective impedance and shall be below the values specified in Table 2 and Table 3 (for PGU and PPM, respectively), provided current limits are not reached. Permanent current stress from negative currents may be limited to no less than 3 %.[20]

Finally, the requirement specified in Article Y(7)(b) can be expressed in detail as follows:

Upon inception of voltage phase angle steps or voltage magnitude steps at the PoC, and provided the PPM capabilities and current limits are not exceeded, the instantaneous AC voltage characteristics of the internal Thevenin source of individual units shall remain constant and exhibit an effective impedance below the maximum values as defined in Table 2 *(at the PGU level) and Table* 3 *(at the PPM level).*

This is understood as follows:

1. The GFM requirements as specified in Article Y(7) of the draft NC RfG 2.0 must be realised in each PGU of a PPM.

2. The requirement is solution-agnostic, and all described implementation options serve solely as examples.

3. The use of a virtual (control) impedance in the control solution is neither prescribed nor forbidden, as long as performance-based requirements are achieved. The margin beyond physical impedances can be understood as a tolerance, a degree of freedom left to the Original Equipment Manufacturer (OEM) to optimise the overall performance of the solution.

4. In practice, this margin also accounts for measurement processing and damping ratio functions (see Appendix B).

5. According to equation (2), as an indicative example, the same requirement specifies the expected reactive current output following grid-side voltage amplitude variations. For instance, a voltage change of Δu_{PGU} = 5% at the PGU terminals would result in a minimal reactive current change

[19] *For wind turbines with a Doubly Fed Induction Generator (DFIG), the negative sequence effective impedance may be modified differently to form the effective positive sequence impedance if this can avoid additional hardware costs*
[20] *This current contribution is up to the inherent capability of the PGU and shall not require any increase in the PPM's permanent P/Q capability*

of $\frac{\Delta u_{\mathrm{PGU}}}{x_{\mathrm{Eff}}}$ $= 0.15$ pu for an effective reactance $x_{\mathrm{Eff}} = 0.33$. If the voltage amplitude cannot be controlled at the unit terminals, but is introduced in a grid location remote from the terminals, the reactive current contribution can be calculated using $\frac{\Delta u_{\mathrm{G}}}{x_{\mathrm{Eff}}+x_{grid}}$, where x_{grid} represents the impedance between the PGU terminals and the location where the voltage amplitude modification is introduced.

Any current response to a voltage angle change or voltage amplitude change must be instantaneous, with no delay. A physical response is expected, and no control or measurement delays are acceptable. The PGU's voltage source behaviour can be assumed if the following criteria are met:

1. Following a grid-side voltage amplitude step change, after a response time of less than 10 ms, the instantaneous[21] current shall reach 90% of the expected value. If the positive sequence[22] of the reactive current is evaluated, the reactive current shall reach 90% of the expected value within 30 ms.
2. The following two criteria need to be met. However, for testing purposes, if the PPM is compliant with one of the two criteria, then the second criterion is assumed to be compliant as well.
    a) Following a grid-side voltage phase angle step change, a peak instantaneous active current change of at least 50% of the value calculated based on equation (4) is expected[23] within 10 ms. For testing purposes, the phase jump at the PGU terminals should result in a $\Delta i_{\mathrm{P,PGU,Peak}}$ of at least 25% of the nominal active current, according to equation (4).[24]
    b) Following an islanding incident according to Section 3.5.1 (loss of last synchronous generator), the unit is capable of controlling voltage and frequency in line with the requirements defined in this section.

If the limits of the inherent energy storage or the capability of the PGUs are reached, the generating unit may limit its contribution to instantaneous active current changes in response to a phase angle jump, the requirements of Article Y(7)(c) regarding such limitations apply (see Section 2.3.3). Consequently:

[21] *Instantaneous values could be in alpha/beta or in a/b/c.*
[22] *A positive sequence evaluation according to IEC 61400-21-1 is assumed.*
[23] *The unit shall remain within its capability limits.*
[24] *The maximum effective impedance according to Table 2 and Table 3 shall be used.*

a) The PPM with no or very limited inherent energy storage is required to provide only negative power changes.

b) No power headroom needs to be reserved beyond the continuous operating points of the PPM. When operating at maximum active power or current, no positive Δi_p, as defined in equation (4), is required.

c) A PGU with no or very limited inherent energy storage is not required to absorb active power. In the case of voltage angle jumps, the PGU is not required to reduce active power below the minimum regulating level of the PGU.

In the case of a phase angle jump where the GFM response of a PPM (except ESM) results in a swing into the opposite power flow (power absorption), curtailment of the response to active power to zero is acceptable.[25] In the case of ESM, the GFM behaviour is expected to change the direction of load flow if required based on equation (4).

Regarding the dynamic response for voltage magnitude changes at the PoC, the following is expected:

- Voltage steps below ± 5% of nominal voltage: a settling time of 60 ms[26] defined as the last instant the measured value enters a tolerance band of +10%/-5% of nominal current around the end value.

- Voltage steps above ± 5% of nominal voltage: a settling time of 60 ms,[26] defined as the last instant the measured value enters a tolerance band of +20%/-10% of nominal current around the end value.

A damping ratio ξ (defined in Section 3.5.2) of at least 5% of the active power oscillations in the (0.1–10 Hz) frequency range is recommended. However, for ESMs, a much higher damping ratio value is expected.

2.3.2 On the synthetic inertia[27] contribution within capability limits

This section details the requirement for synthetic inertia as specified in Article 20 for type B and Article 21 for types C and D. In addition to synthetic inertia, contributions to limiting transient frequency deviations can be defined either as a function of the frequency deviation (Fast Frequency Control) or the Rate of Change of Frequency (RoCoF: synthetic inertia), depending on the needs of specific synchronous areas. Furthermore, the contribution can allocate the inherent or specified

[25] *There is insufficient evidence to demonstrate that following a system split, the additional effort of using a braking chopper to consume energy from the grid is justified.*
[26] *When evaluating the positive/negative sequence reactive current according to IEC 61400-21, the settling time shall be achieved within 80 ms.*
[27] *It should be noted that in this context, "synthetic inertia" follows the definition in draft NC RfG 2.0. Namely, "synthetic inertia" means a prescribed electrical dynamic performance provided by a PPM or an HVDC system at its PoC with the purpose to emulate the equivalent dynamic effect of the inertia provided by a synchronous PGM.*

energy and manage the energy balance either decoupled from synchronisation (to comply with national variation in requirements) or directly implemented in the synchronisation.[28]

The remainder of this section specifies how to limit transient frequency deviation by applying synthetic inertia.

Article 20 for type B:

"5. With regard to grid forming capability type B power park modules shall fulfil the following additional requirements in relation to grid forming capability:

(a) The relevant TSO in coordination with the relevant system operator, shall specify the contribution to synthetic inertia. The power park module shall be capable of contributing to limiting the transient frequency deviation under high frequency conditions. Additionally, the electricity storage module shall be capable of contributing to limiting the transient frequency deviation under low frequency conditions."

Article 21 for type C and D:

"5. With regard to grid forming capability type C power park modules shall fulfil the following additional requirements in relation to grid forming capability:

(a) The relevant TSO, in coordination with the relevant system operator, shall specify the contribution to synthetic inertia. The power park module shall be capable of contributing to limiting the transient frequency deviation under high and low frequency conditions.

(b) The relevant TSO may require the provision of additional energy beyond the inherent energy storage in coordination with the relevant system operator."

When specified as synthetic inertia, the change of active power due to a frequency change can be described as the mechanical starting time,[29] as defined in equation (6) and denoted as $T_{\mathrm{M,PPM}}$[30].

[28] *A non-binding example can be found in Appendix A.*
[29] *P. Kundur, Power System Stability and Control. McGraw-Hill. ISBN 0-07-035958-X.*
[30] $T_{M,PPM}$ *is equivalent to the mechanical starting time constant $T_{R,SG}$ of a conventional power plant for the control of the PGUs, whose effect on the inertia of the internal voltage angle of the inverter-based GFM unit corresponds to the effect of the start-up time constant of a conventional power plant. $T_{R,SG}$ is the time required for a conventional power plant with rated power P_{rated} to accelerate the turbine set (turbine and synchronous machine, pole pair number p) having a moment of inertia J_{SG} from standstill to rated speed or rated angular frequency ω_0, assuming that the acceleration occurs with a constant torque. The start-up time constant $T_{R,SG}$ is a measure of the inertia moment J_{SG} of the generating unit relative to rated power and rated frequency and is defined as:* $T_{R,SG} = \frac{J_{SG}\cdot\omega_0^2}{P_{rated}\, p^2}$

$$T_{\mathrm{M,PPM}} = \frac{\left(\frac{\Delta P}{P_{\mathrm{Rated}}}\right)}{\left(\frac{d(f/f_{\mathrm{Rated}}))}{dt}\right)} = \frac{\Delta p_{pu}}{\left(\frac{df_{pu}}{dt}\right)} \tag{6}$$

The mechanical starting time $T_{\mathrm{M,PPM}}$ (in s) is equal to 2H and can be used as a metric to describe the active power change of a GFM PPM for a given RoCoF. It is used to relate the energy exchanged by the PPM at its PoC with the AC network to its maximum capacity (Energy/Pmax) while the grid frequency changes. It should be noted that this metric is key for grid-planning studies as well as sizing the inertial response expected during system operation for a control area.

While the frequency changes, a PPM is expected to provide an additional active power ΔP according to equation (7):

$$\Delta P = T_{\mathrm{M,PPM}} \cdot \frac{df/f_{\mathrm{Rated}}}{dt} \cdot P_{\mathrm{Rated}} \tag{7}$$

Indicative example:

Let us assume a 2 Hz/s RoCoF (df/dt) and a $T_{\mathrm{M,PPM}}$ of 25 s. This would lead to a 1 pu active power variation from steady state. Under the assumption of a PPM with a $\cdot\, P_{\mathrm{Rated}}$ of 1MW:

$$\Delta P = 25s \cdot \frac{2\frac{Hz}{s}}{50\ Hz} \cdot 1MW = 1MW$$

Assuming a constant **df/dt** value for a given duration of Δt, then the required energy can be calculated according to (8):

$$E = T_{\mathrm{M,PPM}} \cdot \frac{df/f_{\mathrm{Rated}}}{dt} \cdot P_{\mathrm{Rated}} \cdot \Delta t = T_{M,\mathrm{PPM}} \cdot \frac{\Delta f}{f_{\mathrm{Rated}}} \cdot P_{\mathrm{Rated}} \tag{8}$$

with Δt the time during which the frequency changes (typically based on the Article 13 RoCoF requirement) and Δf the frequency change over Δt. Based on the frequency limits of **47.5 Hz or 52.5 Hz as given in the draft NC RfG 2.0,** the term $\frac{df/f_{\mathrm{Rated}}}{dt} \cdot \Delta t$ represents a maximum frequency change of ± 2.5 Hz (or pu value of ± 0.05), independently of the RoCoF. The maximum energy a PPM needs to provide or absorb is therefore:

$$E = T_{\mathrm{M,PPM}} \cdot 0.05 \cdot P_{\mathrm{Rated}} \tag{9}$$

It should be noted that equations (6)-(9) provide the necessary framework to define the synthetic inertia of GFM PPM in a harmonised manner. Therefore, national specifications shall follow this approach when applying the relevant articles of GFM synthetic inertia for PPM. Appendix E analyses the impact on needed power and energy reserve for different mechanical starting time and frequency gradient values.

Based on the above mathematical quantifications, **Article 20(5)(a)** for type B PPM can be expressed as follows:

*The relevant TSO, in coordination with the relevant system operator, shall specify the contribution to synthetic inertia. The PPM **shall** be capable of contributing to limiting the transient frequency deviation under **high frequency** conditions **by modulating active power/active current within the inherent capability of each PGU and the PPM**. In addition, the ESM shall be capable of contributing to limiting the transient frequency deviation under low frequency conditions **by modulating active power/active current within the inherent capability of each ESU.***

The requirement specified in Article 21(5)(a) for type C and D PPM can be expressed as follows:

*The PPM shall be capable of contributing to limiting the transient frequency deviation under **high and low frequency** conditions **by modulating active power/active current within the inherent capability of each PGU and the PPM**.*

Regarding Article 20(5)(a) and Article 21 (5)(a), the following applies:

1. The relevant TSO, in coordination with the RSO, shall specify the mechanical starting time $T_{\mathrm{M,PPM}}$ of PPM.

2. The requirements of **Article 20(5)(a)** and **Article 21(5)(a)** shall apply and shall be evaluated at the PoC of PPM.

3. If the limits of the inherent energy storage or the capability limits of the PGUs are reached, the generating unit may limit its contribution to synthetic inertia, the requirements of Article Y(7)(c) regarding limitations apply (see Section 2.3.3). Consequently:

    a) The PPM with no or very limited inherent energy storage is required to provide only negative power changes.[31]

    b) No power headroom shall be reserved beyond the continuous operating points of the PPM. While operating at maximum active power or current, no positive[32] ΔP, as defined in equation (7), is required.

    c) A PGU with no or very limited inherent energy storage is not required to absorb active power. In the case of voltage angle jumps, the PGU is not required to reduce active power below the minimum regulating level of the PGU.

The requirement specified in Article 21(5)(b) can be expressed as follows:

[31] Negative power change refers to a reduction of active power in response to an increasing frequency (over-frequency) or a positive phase jump.
[32] Positive power change refers to an increase of active power in response to a decreasing frequency (under-frequency).

*The relevant TSO in coordination with the relevant system operator, shall specify the contribution to synthetic inertia. The PPM shall be capable of contributing to limiting the transient frequency deviation under **high and low** frequency conditions **by modulating active power/active current within explicitly specified energy for a PPM**.*

Regarding Article 21(5)(b), the following applies:

1. No limitations of current or power shall occur for:

    a) RoCoF events while providing synthetic inertia response calculating ΔP, as in equation (7), for a RoCoF below 2 Hz/s according to Figure 4 or a lower RoCoF value specified by the relevant TSO.

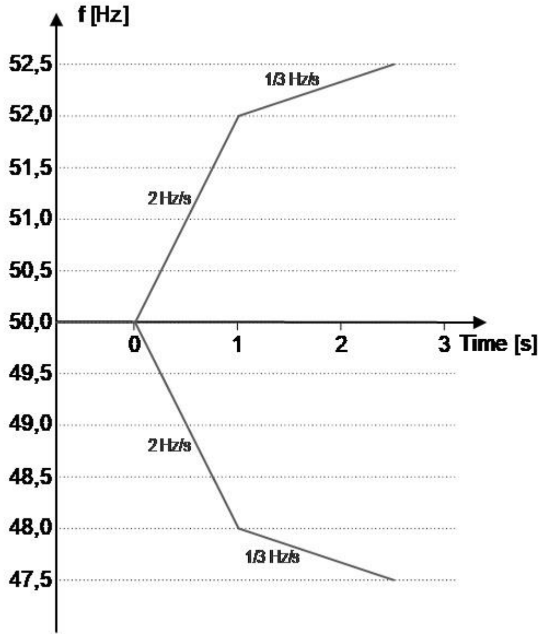

Figure 4: RoCoF events during which PPMs shall be capable of providing synthetic inertia with no current nor power limitations

b) Phase jump events, while Δi_{P} according to equation (4) or (5) remains below the current change representing the ΔP of a) above.

c) Voltage magnitude steps, while Δi_{Q} according to equation (2) remains below the current change representing the ΔP of a) above.

2. The active power change, ΔP as defined in equation (7), and its associated energy buffer Energy, E as in equation (8), shall be available at any continuous operating point of the PPM. If the energy buffer is integrated in the PGU, sufficient power head room must be reserved.[33]

3. The active power change ΔP at the PPM terminals may be provided by either all or a limited number of PGUs within the PPM, or by additional equipment installed in the PPM, behind its PoC, as long as the performance criteria at the PoC of the PPM are met.

4. The specified synthetic inertia or active power change ΔP as in equation (7), refers to the rated power of the PGUs in operation. If additional equipment installed behind the PoC is used to fulfil the synthetic inertia requirement of the PPM, this additional equipment shall be operating while the PGUs are operating.

5. The active power headroom required to provide the specified ΔP as in equation (7) is not considered when defining P_{max} of a PPM according to Article 2(16) of the draft NC RfG 2.0. If additional equipment is used to fulfil the synthetic inertia requirement of a PPM, the maximum active power of this additional equipment is not considered when defining P_{max} of a PPM according to Article 2(16) of the draft NC RfG 2.0 (see also recital 11 of the draft NC RfG 2.0).

This report does not propose any specific solution for implementing the required additional energy. Currently, both market-based solutions and mandatory connection network code requirements are potential options for applying Article 21(5)(b). According to Article 7(1) of the draft NC RfG 2.0, the approach must be determined by an entity designated by the Member State, typically the regulatory authority. However, the requirements outlined in this report may be used either for pre-qualification process for market-based synthetic inertia ancillary services or as the basis for national level connection network code mandates.

The inertial response from PPMs may depend on various technology-specific parameters such as the primary source characteristics and the control algorithm. Since the technology maturity of the GFM capability and inertia contribution of non-ESM PPMs is still low, this should be taken into account when defining acceptance criteria for tolerances of the mechanical starting time.

Regarding the dynamic response to frequency excursions within the inherent capability of the PGU, as well as in cases where energy is explicitly specified, the following applies:

[33] The specific ΔP and energy buffer shall be sufficiently justified and yield the best techno-economic solution for the grid in accordance with Articles 7(1) and 21(5)(b) of the draft NC RfG 2.0 and Article 31 and 40 of Directive (EU) 2019/944.

1. In the event of a df/dt of the grid voltage (u_{G} in Figure 2) as in equation (7), while the effect of the PPM on the grid frequency is negligible, the response time is defined by the configured synthetic inertia and damping ratio (ξ).
2. In the event of an islanding situation, the local load must be supplied instantaneously, while the resulting ΔP results in a df/dt (as in equation (7)) representing the configured $T_{\mathrm{M,PPM}}$.

2.3.3 When reaching current capability limit

Article Y(7)(c)(ii) of the draft NC RfG 2.0 sets out the following requirement:

“(ii) Where current limitation is necessary, the relevant system operator in coordination with the relevant TSO may specify additional requirements regarding contribution of active and reactive power at the point of connection.”

Regarding the requirement, the following detailed specifications shall apply:

A. If the GFM response at the PGU terminals exceeds the capability limit[34] of the PGU, the PGU may limit the response accordingly, while maintaining the behaviour of a voltage source behind an impedance. Under such conditions, the PGU shall remain connected to the grid without tripping and maintain stable operation.[35]

B. The response to changes in voltage angle and amplitude shall be equivalent to that of a voltage source (or a synchronous generator), except that the current magnitude may be limited.

C. No priority is given to any current component, whether active or reactive, positive sequence or negative sequence.[36] Upon reaching the current limit, only the magnitude of the current may be limited. The resulting current at the PGU terminals shall reflect a proportionally scaled-down vector sum of all ideal, unconstrained current components (e.g. active and reactive; positive sequence and negative sequence), such that the total magnitude complies with the current limit. If active power limits are reached, only the active current component may be reduced.

D. If the grid voltage phase angle decreases, the PGU reacts with an increase in the share of active current infeed and vice versa.

E. If the grid voltage magnitude decreases, the PGU reacts with an increase in the share of overexcited reactive current and vice versa.

[34] Active power modifications, such as damping functions in wind turbines, are not considered priorities of a current component but are considered necessary to remain within the capability limits of a wind turbine.
[35] Depending on the implementation of the synchronisation mechanism (e.g. VSM), special attention is required, as this mechanism may become non-functional during current limitation. To meet robustness requirements against phase jumps, frequency deviations, and faults, as specified in Article 13 of the draft NC RfG 2.0, appropriate measures shall be implemented to ensure that the PGU remains synchronised with the grid.
[36] For PGUs with a DFIG, the current sequence may deviate from the proportionally scaled-down value to remain within the capability limits of the PGU.

Note: This means that in the event of a voltage magnitude disturbance without relevant voltage phase angle changes, a predominantly reactive current response is expected.

F. If the grid voltage magnitude and/or voltage phase angle recovers towards the pre-disturbance grid conditions, the PGU reacts with an instantaneous reduction of current, once the unlimited voltage source behaviour results in a current below the capability limits.

G. When reaching the current limit of the PGU, current clipping[37] should be allowed to protect the PGU hardware. Up to 40 ms of current clipping is accepted after voltage angle jumps and magnitude steps. To avoid continuous current clipping, it is permissible to limit the current to 95% of the level at which current clipping would occur, but not below 100% of nominal current. It is also acceptable for a PGU to provide current above 100% of nominal current, if it is capable of doing so. To assess the impact on the grid, the manufacturer shall specify the maximum peak and RMS current and inform the RSO accordingly.

H. Regarding dynamic response of the current at PGU terminals upon reaching the capability limit:

   (a) In the event of current limitation, the expected reactive current shall remain within ± 10% of the PGU's nominal current around the expected values specified in item C above, assuming a constant inverter voltage u_{Inv} and a constant phase angle difference $\delta = \varphi_{U_{\mathrm{PGU}}} - \varphi_{U_{\mathrm{Inv}}}$. The corresponding active current is calculated based on a resulting rated value of the apparent current.

   (b) In response to a grid-side disturbance, the instantaneous active/reactive current or power variation shall reach no less than 90% of its expected value within 10 ms. When evaluating the positive sequence[38] reactive current, at least 90% of the expected value as specified in item C above shall be achieved within 30 ms.

   (c) When a steady-state value is anticipated after the disturbance in an event, a settling time of 60 ms is expected. The settling time is defined as the last instant when the measured or simulated value enters a +20%/-10% tolerance band around the expected value.

I. The requirements specified above shall apply regardless of whether the three-phase currents are balanced or unbalanced. This includes cases where current limit is reached in one, two, or all three phases due to asymmetrical loading or fault conditions.

Example

Figure 5 shows an example of the current phasor response to a voltage magnitude reduction only – with no phase jump – at the PGU terminals, for a given effective impedance. Assuming a constant internal voltage phasor within the PGU, only $i_{\mathrm{Q,PGU}}$ changes are allowed according to equation (1) and (2), before reaching its current limitation.

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[37] Limitation of the current based on sub-cycle values.
[38] A positive sequence evaluation according to IEC 61400-21 is assumed.

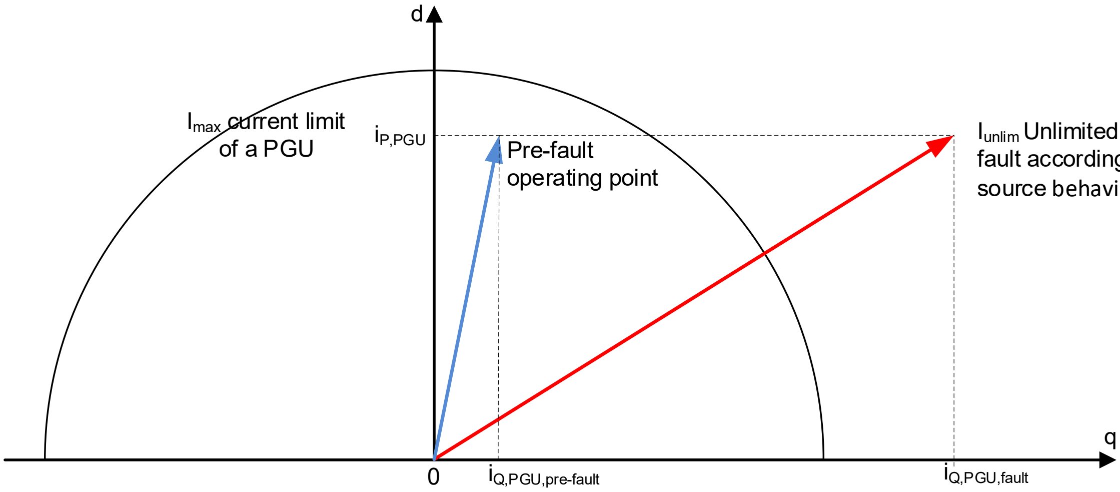

Figure 5: Example of how a grid event might increase the unlimited current phasor beyond the current limits of the PGU, a situation that is not allowed

Figure 6 shows common principles of priority by limiting the unlimited current phasor to the current limits of the PGU.

Because of what is stated above in the detailed specifications, **GFM PGU shall limit the output current only by reducing the current phasor magnitude while maintaining the current phasor angle of the unlimited phasor constant.** It should be noted that active power priority or reactive power priority is not accepted for GFM PGU.

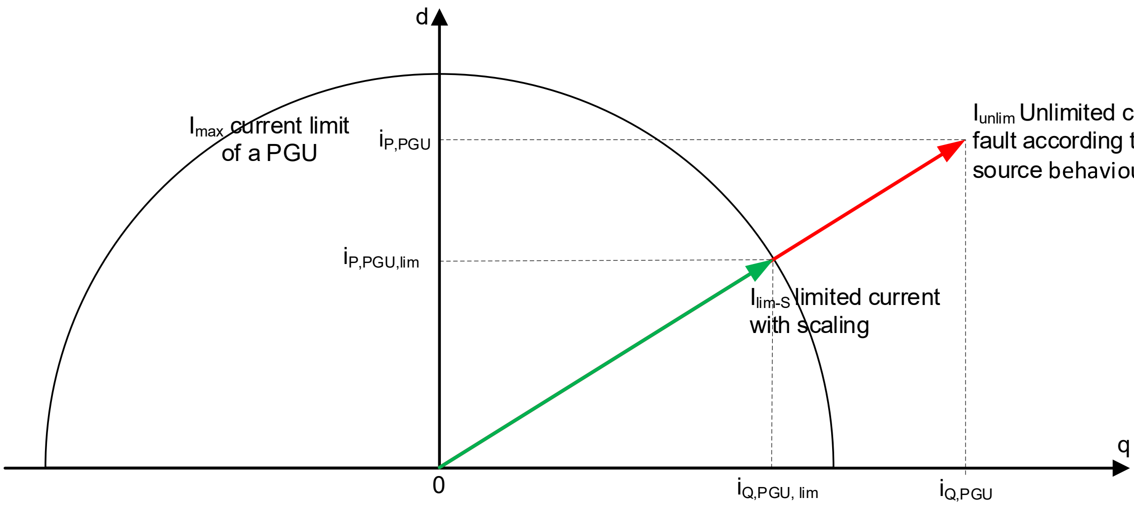

Figure 6: Current limitation requirement reducing the unlimited current phasor to a current phasor within the current capability of the PGU while maintaining the current phasor angle constant

Upon reaching current limitation, the resulting current shall reflect a proportionally scaled-down vector sum of all ideal, unconstrained current components (e.g. active and reactive, positive and negative sequence), so the total magnitude complies with the current limit. This is illustrated using Figure 6 as follows.

Ideally, unconstrained currents without limitation are:

$$I_{unlim} = \sqrt{i_{P,PGU}^2 + i_{Q,PGU}^2} \tag{10}$$

when I_{unlim} exceeds the current limit I_{max}, a scaling factor k can be defined:

$$k = \frac{I_{max}}{I_{unlim}} \tag{11}$$

Hence, currents after limitation are:

$$i_{P,PGU,lim} = k \cdot i_{P,PGU} \tag{12}$$

$$i_{Q,PGU,lim} = k \cdot i_{Q,PGU} \tag{13}$$

The proportional scaling is to be understood as a consequence of the current limitation, and characterises the external behaviour as observed from the grid side — it does not prescribe or constrain any specific internal control implementation inside the PGU.

Interpreting equation (1) and (2), **the scaling behaviour during current limitation can be achieved by modifying the term x_{Eff} while keeping all other terms of equation (2) constant**. However, this shall not prescribe any control implementation but only define the measurable response at the terminals of the PGU.

As a qualitative example, assuming pure voltage magnitude changes at the PGU terminals with no phase jump, the resulting active and reactive currents – subject to current magnitude limitation – are shown in Figure 7 as a function of the terminal voltage. In particular, both current components follow equations (12) and **Error! Reference source not found.** after the PGU reaches its current limit. The corresponding values of effective reactance x_{Eff} and inverter internal voltage angle are shown in Figure 8. Figure 9 depicts a situation where a ± 10% tolerance band is added around the expected values calculated in equations (12) and **Error! Reference source not found.**, as specified in item H(a) in the previous subsection. These figures assume a voltage drop applied by an inductive fault. For low residual voltages, the assumptions regarding R/X for equations (1) and (2) may not be valid; therefore, the figures below should be considered indicative only for low residual voltages.

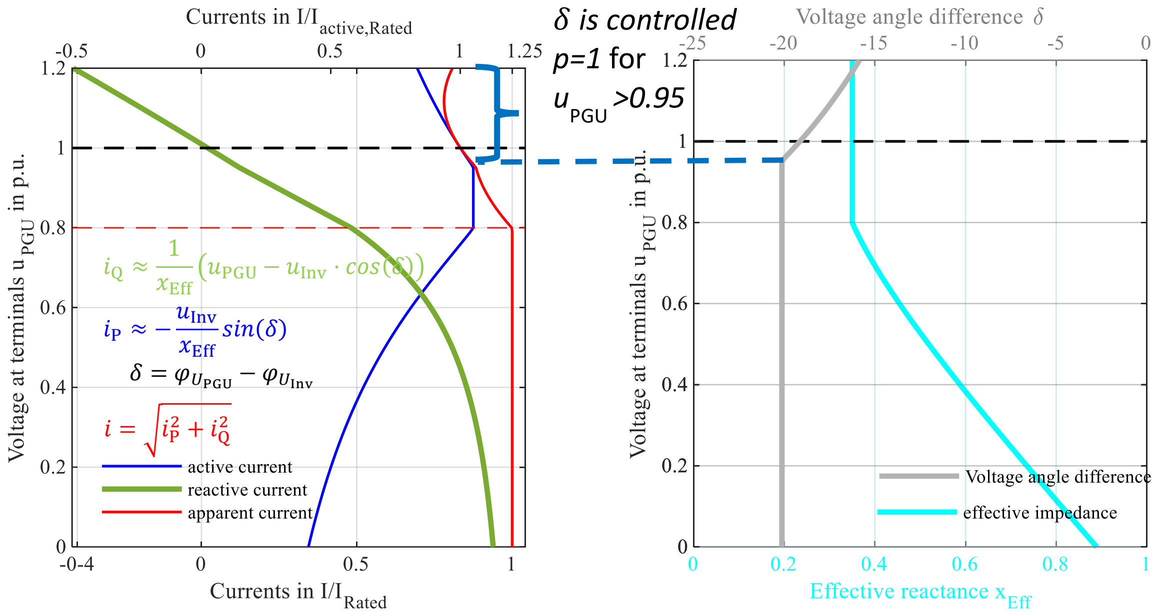

Figure 7: Active and reactive current of an inverter with current magnitude limitation

Figure 8: Corresponding values of voltage angle δ (grey line), and effective reactance x_{Eff} (blue line) for an inverter with current magnitude limitation, with the internal voltage of the inverter remaining constant

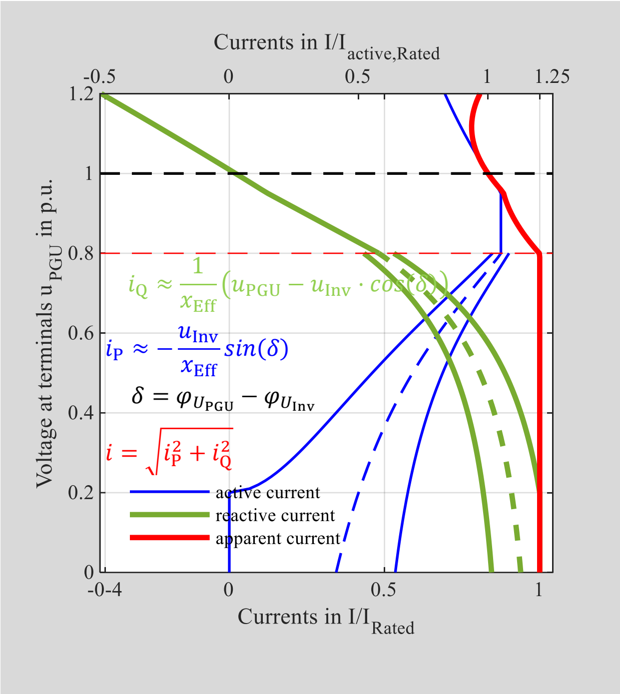

Figure 9: Active and reactive current of an inverter with current magnitude limitation, including an allowed band for the current reference of ± 10% of the theoretical value of reactive current. The red curve represents the maximum apparent current specified in G in the previous subsection to be at least 95% of the current where current clipping would occur. This graph is assuming a voltage drop applied by an inductive fault

The requirements for current limitation (by limiting the current magnitude, not active or reactive currents separately) are further discussed in Appendix C.

3 Evaluation of compliance

This chapter is organised as follows: Section 3.1 presents the regulatory background for evaluating GFM requirements, and Section 3.2 introduces the scope of the evaluation for these requirements. Section 3.3 proposes two different setups for evaluating GFM requirements. Section 3.4 proposes four test cases to assess compliance with the requirements defined in Section 2.3. Finally, Section 3.5 details the test cases described in the previous section.

3.1 General

Title IV "Compliance" of the draft NC RfG 2.0 does not provide explicit requirements for assessing compliance with GFM requirements. However, Article 42(2)(b) of the draft NC RfG 2.0 entitles the RSO to require additional tests if the tests specified in Chapter 3 of Title IV are not sufficient to demonstrate compliance with the requirements of draft NC RfG 2.0. As Chapter 3 of Title IV does not mention GFM, additional tests shall be specified by the RSO. These specifications should follow the principles described in this chapter.

Article 43(2)(b) of the draft NC RfG 2.0 entitles the RSO to require additional compliance simulation if the simulations specified in Chapter 6 of Title IV are not sufficient to demonstrate compliance with the requirements of draft NC RfG 2.0. For types C and D PPM, the RSO and the TSO may request detailed compliance simulations at the PoC. These simulations should follow the principles described in this chapter.

3.2 Scope of evaluation

As stated in Section 2.3.1, the voltage source behaviour according to Article Y(7) is specified at the terminals of the generating unit, while GFM capability is a PoC requirement. Consequently, the voltage source behaviour requirement shall be evaluated at the PGU terminals. A PPM shall be considered compliant with the GFM requirement of Article Y(7) if all PGUs within the PPM are evaluated to be GFM units and the maximum effective impedance for the PPM is not exceeded.

Similar to other requirements of draft NC RfG 2.0, the RSO shall specify whether equipment certificates will be accepted to assess the compliance at PGU terminals. The equipment certificates shall be based on type tests following the principles of this chapter.

As stated in Section 2.3.2, the synthetic inertia requirement is specified at the PoC of the PPM and may be provided by all or some of the installed PGUs or by additional assets installed in the PPM.[39] Consequently, this requirement shall be evaluated at the PPM level. The compliance verification scheme shall prove that the required ΔP (according to equation (7)) and its dynamic performance (damping ratio) are provided by the PPM. The draft NC RfG 2.0 is agnostic on the assets within the

[39] *Additional equipment providing auxiliary signals (e.g. a plant controller) may be added to improve performance. If relevant, the influence of a PPM level control shall be considered in the testing.*

PPM that provide the required ΔP of the PPM, as long as the required performance is achieved at the PoC.

The RSO shall define the compliance verification process for compliance with the GFM capability of PPMs, in the same manner as for the other requirements of the draft NC RfG 2.0. The PPM may be considered compliant with the synthetic inertia requirement if sufficient PGU or additional assets within a PPM are capable of providing the required ΔP and energy content needed to achieve the specified performance. If accepted by the RSO, equipment certificates may be applied to evaluate PPM compliance. In the latter case, it is recommended that the equipment certificates shall be based on relevant type tests following the principles described in this chapter.

As stated in Section 3.1, the RSO may require compliance using simulation models. For PPMs of types C and D, compliance simulation of synthetic inertia provided at the PoC should be conducted using the test cases described in this chapter.

3.3 Test setups

The compliance evaluation needs to be possible for different PGU technologies in a wide range of nominal power. Two possible test bench setups are presented in Figure 10 and Figure 11. The setup in Figure 10 is based on passive components that are also available for testing high power PGU up to several MW.

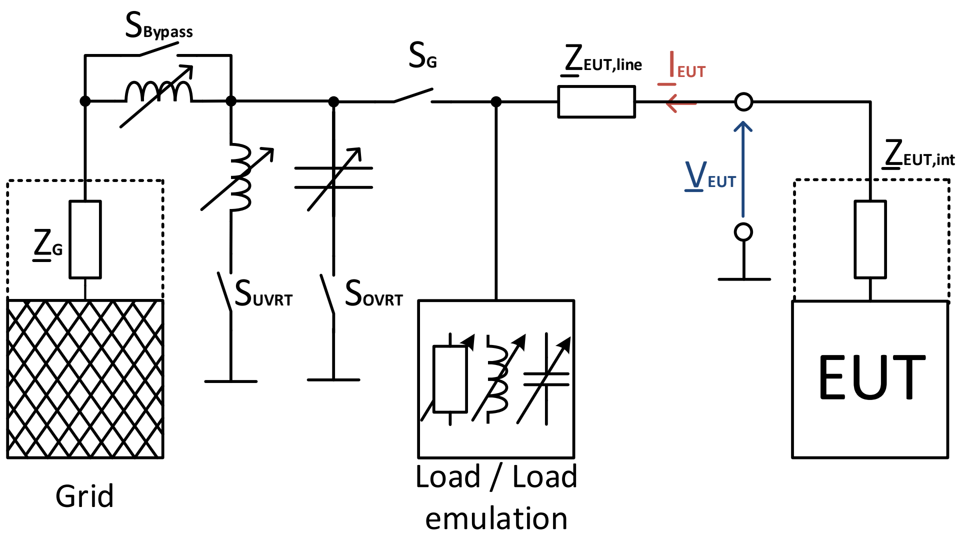

Figure 10: Example of a test setup for evaluating GFM capabilities based on a passive setup

In Figure 11, the setup is based on a grid and load emulation. As previously noted, the PGU terminals might be defined at the LV, MV, or HV side of the transformer. If the transformer is considered separately from the PGU, the impedance of the transformer may be represented as $Z_{EUT,Line}$.

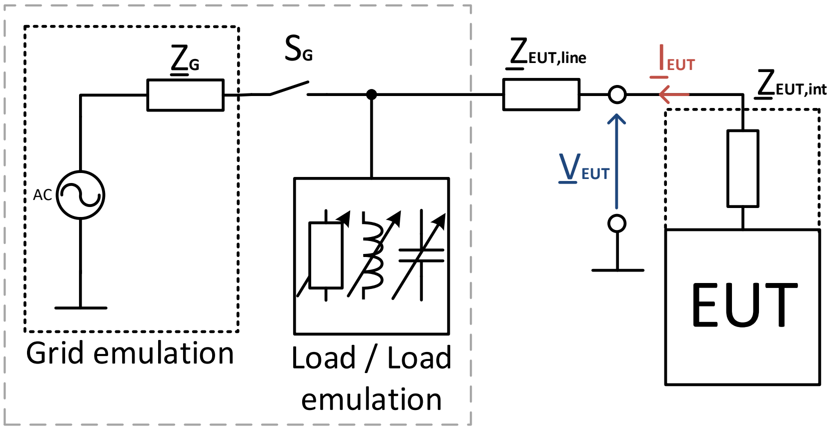

Figure 11: Example of a test setup for evaluating GFM capabilities based on grid emulation

While the compliance is ultimately being evaluated at the PGU level, the Equipment Under Test (EUT) does not necessarily need to be a complete PGU and could contain PPM-level controls if necessary. Depending on the size of the PGU, technology, and behaviour to be evaluated, relevant standards provide multiple options to conduct tests. Because the voltage source and inertia requirements affect the fundamental control and the mechanical, electromagnetic and electromechanical behaviour of a PGU, the test setup and EUT must be defined with great care. In general, test setups and tested equipment used to evaluate fault ride through requirements and, for grid-following converters, fast fault current injection, are suitable for assessing the voltage source requirement and inertia. When the EUT is simplified to a test on the drive train or converter system, the correct implementation of the primary source and the first mechanical or electrical conversion stages of the PGU along with their dynamic behaviour, must be represented with sufficient accuracy in the test set-up (e.g. in a mechanical-Hardware-in-the-Loop (mechanical-HIL) or power-HIL).

Control-HIL (C-HIL)[40] is also an option provided the primary energy source and conversion stage can be simulated with sufficient accuracy. For evaluating controller interactions, namely the impedance spectroscopy, C-HIL may be an adequate option for a large PGU.

The table below presents a description of the parameters used in Figure 10 and Figure 11.

[40] *Software-in-the-Loop (SIL) could be investigated as an alternative option.*

Table 4: Nomenclature used in Figure 10 and Figure 11

Parameter or value unit	Description
EUT	Equipment under test
$\underline{Z}_{\mathrm{G}}$	Complex impedance of grid equivalent in the test setup
$\mathrm{S}_{\mathrm{Bypass}}$	Bypass switch to bypass decoupling impedance
$\mathrm{S}_{\mathrm{UVRT}}$	Switch for Under Voltage Ride Through (UVRT) event
$\mathrm{S}_{\mathrm{OVRT}}$	Switch for Over Voltage Ride Through (OVRT) event
S_{G}	Generator switch
$\underline{z}_{\mathrm{EUT,line}}$	Complex impedance in the test setup
$\underline{\mathrm{I}}_{\mathrm{EUT}}$	Complex current of the EUT
$\underline{\mathrm{V}}_{\mathrm{EUT}}$	Complex voltage at the EUT terminals
$\underline{z}_{\mathrm{EUT,line}}$	Complex effective impedance in the EUT

3.4 Test cases

Based on the proposed detailed requirements of Section 2.3, the following four main test items for basic GFM capabilities are proposed. It should be noted that these tests aim to provide basic principles for PGU compliance verification and certification programmes, which will be established at the national level following national regulations.[41]

3.4.1 Voltage source behaviour of the PGU

In these tests, the dynamic of the voltage source itself and the effective impedance are evaluated in unlimited operation, as discussed in Section 2.3.1.

To show the voltage source behaviour of the EUT by applying phase jump events at the terminals,[42] the phase jump current contribution is evaluated, as specified in Section 2.3.1. Moreover, by applying small magnitude jumps at the terminals, the reactive current contribution in unlimited operation is evaluated. Alternatively, the EUT is switched into an island with a load difference. The test is considered successful if the EUT takes over the load and keeps the voltages stable at a new operating point. The voltage reaction time is determined, which is the time required for the EUT to restore the sinusoidal voltage. The effective impedance of the voltage source can be determined from the changing power flow during the islanding and the subsequently changing voltage amplitude and phase angle at the terminals. These tests are designed to prevent current limits from

[41] *These principles will also be further elaborated in European standardisation.*
[42] *Or by injecting a phase angle disturbance into the trajectory of the internal voltage source. This should be interpreted as an artificial angle variation in the control loop of the PGU, which would result in the equivalent grid angle variation.*

being reached. The island during the test does not need to be stabilised for long periods, as the evaluation is only performed for the first voltage cycles after the islanding.

3.4.2 Synthetic inertia behaviour of the PGU

In these tests, the behaviour of a PGU (or additional equipment) in delivering synthetic inertia is analysed in accordance with the requirements in Section 2.3.2. This includes the evaluation of the inertial constant, the available inertial power and energy, and the damping ratio.

Different procedures can be used to evaluate the inertial constant. The first is based on an islanding event. For this test, the EUT falls in an island with a load imbalance: by measuring the resulting RoCoF, the inertial constant can be determined. The second method is based on applying RoCoF at the EUT terminals[42]: by analysing the power change, the inertia constant is derived.

These tests are carried out within the current capabilities of the EUT. To test power and energy capabilities, different test cases are defined, such as determining the minimum and maximum operation power for full inertial power contribution. The behaviour of the EUT when the power and/or energy limits of the primary source are reached is also tested. Additionally, the damping ratio is tested by applying a phase jump event. The reaction to this excitation is analysed to determine the damping ratio.

3.4.3 When reaching current capability limits

These tests evaluate the behaviour when the current limitation is reached, in line with the requirements in Section 2.3.3. They analyse the behaviour during under- and over-voltage events, severe RoCoF, and phase jump events, as well as the voltage source behaviour during current limitation and the self-recovery from current limitation.

3.4.4 Controller interactions of GFM PGUs

To determine the resonance behaviour and passivity of the PGU in the frequency range (as required in Section 2.3), impedance spectroscopy is used to measure the frequency-dependent internal impedance of the PGU. This enables the analysis of harmonic stability within the PPM and/or the definition of the damping ratio of the PGU. In addition, impedance spectroscopy enables the measurements of internal harmonic sources.

Closed-loop stability according to Article 54(2)(d) is also evaluated for frequency reactions. Historically, frequency behaviour was typically evaluated at an infinite bus by changing the frequency, which overlooked several stability issues present in the closed loop control of Frequency Sensitive Mode (FSM) and Limited Frequency Sensitive Mode (LFSM). Therefore, a test is now included in which the active power response of the EUT has a defined effect on the frequency.

3.5 Description of events to test compliance

This section provides additional details on the test cases defined in Section 3.4. While this approach has been assessed on several units and testing environments, it has not yet been thoroughly validated on the full range of PGU sizes, types, and test setups. Modified or more detailed acceptance criteria may be required as more experience is gained, with further details ideally defined in future European standardisation documents.

3.5.1 Compliance evaluation for voltage source behaviour within capability limits

To evaluate voltage source behaviour (as required in Section 2.3.1), two test cases are defined alternatively.

Islanding (loss of last synchronous generator)

The first test case involves islanding the EUT with a local load. The EUT operates in parallel with a local resistive load while connected to the grid, as shown in the test setups in Figure 10 or Figure 11, with a power imbalance in the local grid. When switch S_G is opened, the EUT falls into a local island. The EUT shall instantaneously stabilise the local voltage and supply the local resistive load. The active and reactive power setpoints for both the local load and the EUT are defined by technology to ensure local load supply in all test cases. For generation technologies such as wind and Photovoltaic (PV) the load is always defined lower than the operation point of the EUT.

After the islanding, the resulting voltage sinusoid is determined as a reference. Three cycles of the voltage waveform starting 15 ms after the islanding are used to derive a tolerance band of ± 5% of nominal voltage around the ideal voltage sinusoid in the island, as shown in Figure 12. This tolerance band is extrapolated from 15 ms after islanding until the moment of islanding (i.e. when all phases are fully isolated from the grid). The basic voltage source behaviour is assessed by evaluating the response and settling time into this tolerance band. The response time shall be below 5 ms, and the settling time below 15 ms. Frequency changes after islanding may significantly impact this evaluation method and must be further addressed in future documents.

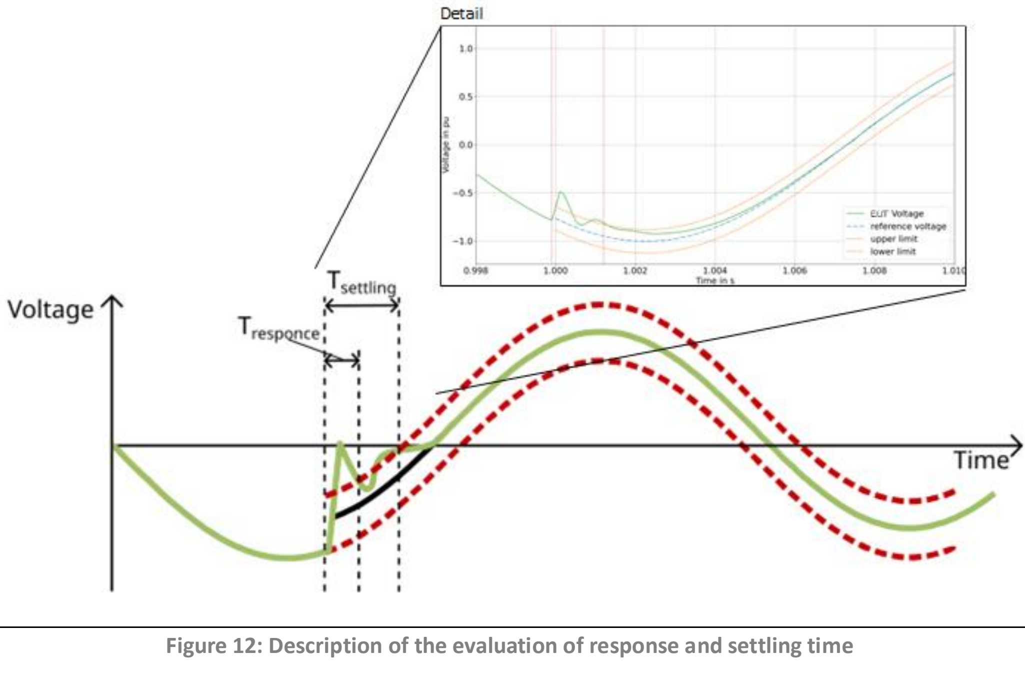

Figure 12: Description of the evaluation of response and settling time

By evaluating the voltage and current three cycles before islanding and starting at 15 ms after islanding, the effective impedance is calculated using equation (14).

The test is not intended to evaluate island operation capability. After the evaluation time of three cycles plus 15 ms, a shutdown may occur.

$$\underline{Z}_{EUT,eff} = \frac{\underline{V}_{EUT,after} - \underline{V}_{EUT,before}}{\underline{I}_{EUT,after} - \underline{I}_{EUT,before}} \quad (14)$$

Phase jump

The second test case assesses the current contribution to a phase jump. This can be done by applying small phase jumps to the EUT. Phase jumps may be introduced using a grid emulator (Figure 11) or a passive system (Figure 10) by switching a local load or grid impedance, for instance via S_{Bypass}.[42]

The current contribution is evaluated based on the measured values, as required in Section 2.3.1.

3.5.2 Compliance evaluation of the synthetic inertia contribution of a PGU within its capability limits

The aim of these tests is to assess the PGU's compliance with the requirements defined in Section 2.3.2. Although the synthetic inertia requirement is defined at the PoC of the PPM level, tests are proposed for a PGU installed within the PPM.

The final evaluation of the synthetic inertia requirement at the PPM's PoC shall be conducted using simulations with PPM models that aggregate the combined behaviour of the PGUs within the PPM. These models shall be validated using the measurements described below. The PPM facility owner shall ensure that the aggregation of the PGU models in a PPM model adequately reflects the expected aggregated performance.

Additionally, the evaluation of the damping ratio for the power frequency oscillation, as defined in Section 2.3.1, is described.

Synthetic inertia evaluation of the PGU

For evaluating a PGU's synthetic inertia contribution, both $T_{M,PPM}$ (as defined in equation (6)) and the potential power change ΔP (as defined in equation (7)) are evaluated.

Two methods can be used to assess the inertia contribution, depending on the available test setup.

If a grid emulator is available as shown in Figure 11, the RoCoF-based inertia measurement method can be used, which is based on the application of a frequency change as shown in Figure 13. By measuring the resulting settled ΔP of the EUT during the RoCoF, the mechanical starting time $T_{M,PPM}$ can be calculated using equation (6).[43]

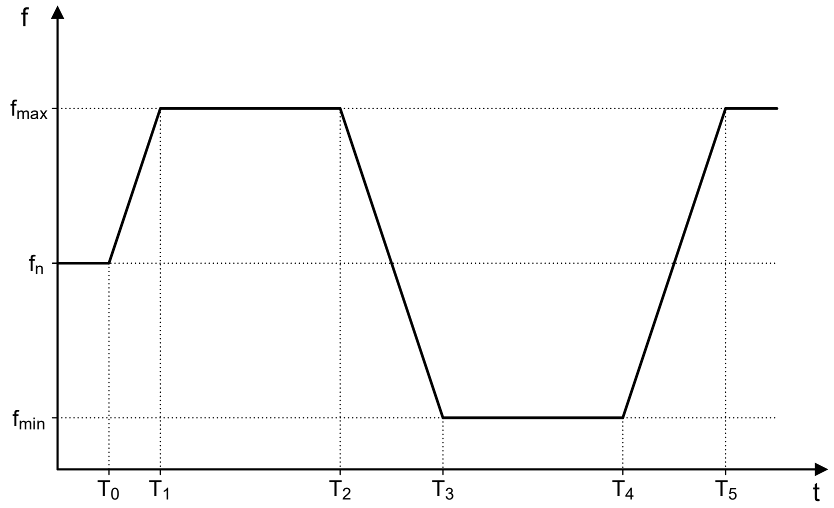

Figure 13: Example of a frequency pattern applied to a PGU to evaluate the inertia contribution using a grid emulator

If no grid emulator is available, the passive test setup shown in Figure 10 may be used with the second test method: load-based inertia measurement. In this test, the EUT is islanded with a load imbalance. Due to the load imbalance, after initial transients have decayed, the frequency in the island will constantly change, resulting in a RoCoF. By measuring this RoCoF and using the power change ΔP defined by the load imbalance, the mechanical starting time $T_{M,PPM}$ can again be calculated using equation (6).

The islanding test is not intended to evaluate island operation capability. After the evaluation period (below e.g. 1 s), a shutdown may occur. To allow sufficient time to evaluate RoCoF, the power imbalance can be set to be suitable.

For both methods, all frequency control methods (e.g. LFSM, FSM, etc.) in the EUT shall be deactivated to measure the pure inertia and damping ratio. This will lead to constant change of the frequency.

For both test methods, Appendix F presents an example to evaluate the synthetic inertia contribution of a PGU within its capability limits.

For both test methods, the first set of tests shall not lead to primary power or energy limitation, demonstrating the unlimited synthetic inertia contribution. The second set evaluates behaviour when these limits are reached, which can occur when a PV or wind PGU is operated at low power when reaching its minimum operation power.

[43] *This can alternatively be achieved by injecting a frequency disturbance into the trajectory of the internal voltage source.*

These test cases are not defined based on specific RoCoF values but on defined power changes, as some of the technologies (especially wind PGUs) are expected to have limited power changes due to mechanical limitations.

Damping ratio of active power oscillations

To determine a PGU's electromechanical damping ratio, a phase jump is used for the excitation. A phase jump can be introduced using various methods, such as a grid emulator or a passive setup.[44]

Similar to the synthetic inertia contribution test, predefined phase jumps are not applied. Instead, predefined power reactions ΔP_{GFC} are used, as these can be specified for each technology and achieve comparable excitations without depending on the PGU's effective impedance.

The damping ratio is assessed based on the damping ratio of a second-order system:

$$G(s) = \frac{K \cdot \omega_0^2}{s^2 + 2 \cdot \xi \cdot \omega_0 \cdot s + \omega_0^2} \tag{15}$$

For underdamped systems ($0 \leq \xi < 1$), the damping ratio is also defined based on the logarithmic decrement of the subsequent maximum and minimum:

$$\xi = \frac{-ln\left(\frac{|P_{n+1}|}{|P_n|}\right)}{\sqrt{\pi^2 + ln^2\left(\frac{|P_{n+1}|}{|P_n|}\right)}} = \frac{ln\left(\frac{P_n}{P_{n+2}}\right)}{\sqrt{(2\pi)^2 + ln^2\left(\frac{P_n}{P_{n+2}}\right)}} \tag{16}$$

where P_n is the subsequent maximum or minimum of the active power as shown in Figure 14. For the evaluation, the positive sequence active power of the EUT is evaluated.

[44] *Or by injecting a phase angle disturbance into the trajectory of the internal voltage source. This should be interpreted as an artificial angle variation in the control loop of the PGU, which would result in an equivalent grid angle variation.*

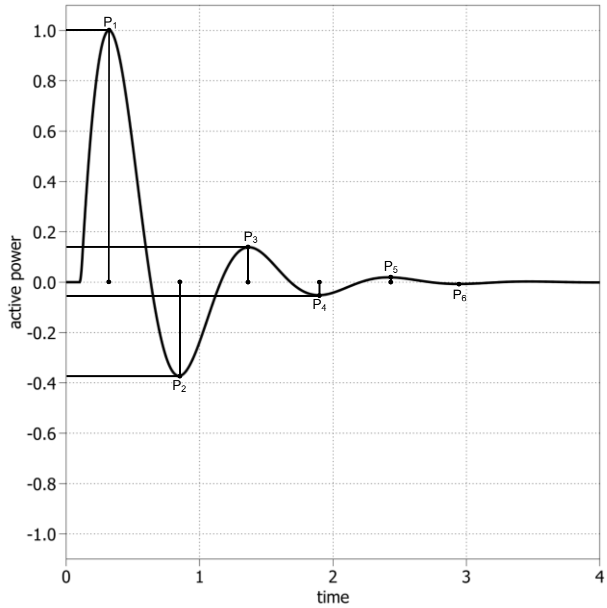

Figure 14: Example of a damped oscillation of a second-order system with the marked successive turning points

3.5.3 Compliance evaluation of PGU behaviour when reaching capability limits

These tests evaluate the PGU behaviour when reaching capability limits, according to the requirements in Section 2.3.3.

Note: This test is not intended to evaluate immunity requirements according to Article 13 of the draft NC RfG 2.0. These are evaluated based on existing principles in the Member States and European standards and are not in the scope of this IGD.

They analyse PGU behaviour during under- and over-voltage events, severe RoCoF, and phase jump events, as well as voltage source behaviour during limitation and self-recovery from current limitation.

Under- and over-voltage events

The test shall evaluate a PGU's behaviour under dynamic voltage changes, where the GFM response results in reaching capability limits. It is also used to evaluate the short-circuit current supplied during the events. The tests and test setups may be the same as those described in relevant documents representing the state-of-the-art for tests evaluating grid-following PGU.

Severe RoCoF events

The tests shall evaluate PGU's capability to withstand severe RoCoF events by applying severe RoCoF events close to the capability limits of the EUT, where the expected ΔP (according to equation (7)) reaches capability limits. The tests are conducted at active power setpoints close to the maximum and minimum operation limits.

Phase jump events

The tests shall evaluate PGU's behaviour during severe phase jump events, including:

- Phase jumps caused by changes in system impedance (such as splitting of the transmission system).
- Phase jumps caused by voltage dips.

The applied phase jumps are determined by the unit's effective impedance and its operating point prior to the event, ensuring the unit reaches its capability limits. Tests are carried out with a grid simulator or equivalent solutions.[44]

Self-recovery from current limitation

The tests shall evaluate PGU's capability during capability limitation as well as self-recovery from limitation mode.

Starting from the EUT running grid parallel, a voltage dip is applied, causing the EUT to reach capability limits. Then, the fault is cleared by creating an island with the EUT and the parallel load (see Figure 10).

The EUT shall be able to stabilise the island reaching steady-state voltage for a defined period. The test is not intended to assess island operation capability. After the evaluation period (below e.g. three cycles), a shutdown may occur. No change to control modes or internal parameter values shall be applied.

3.5.4 Test of interaction behaviour

Two tests are used to evaluate interaction behaviour and control stability:

- Impedance spectroscopy: Provides a theoretical assessment of stability across the frequency range.
- Closed loop: Evaluates the stability of the synchronisation loop and frequency control.

These tests can be carried out with the entire PGU connected to a grid emulator or using appropriate HIL according to Section 3.4.

Impedance spectroscopy

According to Section 2.3.1, the PGU control system should provide passivity within the frequency spectrum. Impedance spectroscopy is used to determine the frequency dependence of the effective impedance of an EUT.

This test can be carried out with the entire PGU connected to a grid emulator or using appropriate HIL according to Section 3.4.

The process for calculating the impedance is as follows:

1. To measure the frequency-variable effective impedance of the PGU, the EUT converter must first be set into operation by providing a voltage $v(t) = \hat{V}\sin\,(2\pi f_{fund}t)$ at fundamental frequency.

2. An excitation voltage $v_{exc}(t) = \hat{V}_{exc}\,\sin(2\pi f_{exc}t)$ is then superimposed on $v(t)$, as shown in Figure 15.

3. To improve measurement accuracy, the voltage amplitude $\hat{V}_{exc}$ of $v_{exc}(t)$ should be greater than 0.5 % of the nominal voltage $\hat{V}$, but lower than 3% to stay within the small signal range.

4. Subsequently, the frequency f_{exc} is increased to sweep the frequency range under consideration (i.e. from 100 Hz to 2,500 Hz).

5. The measured voltage and current values must be transformed into the frequency domain to get the values $\underline{V}(f_{exc})$ and the corresponding current response of the converter $\underline{I}(f_{exc})$.

6. To calculate the effective impedance $\underline{Z}_{eff}(f)$, three measurements with different excitation voltage phases with the same f_{exc} are needed.

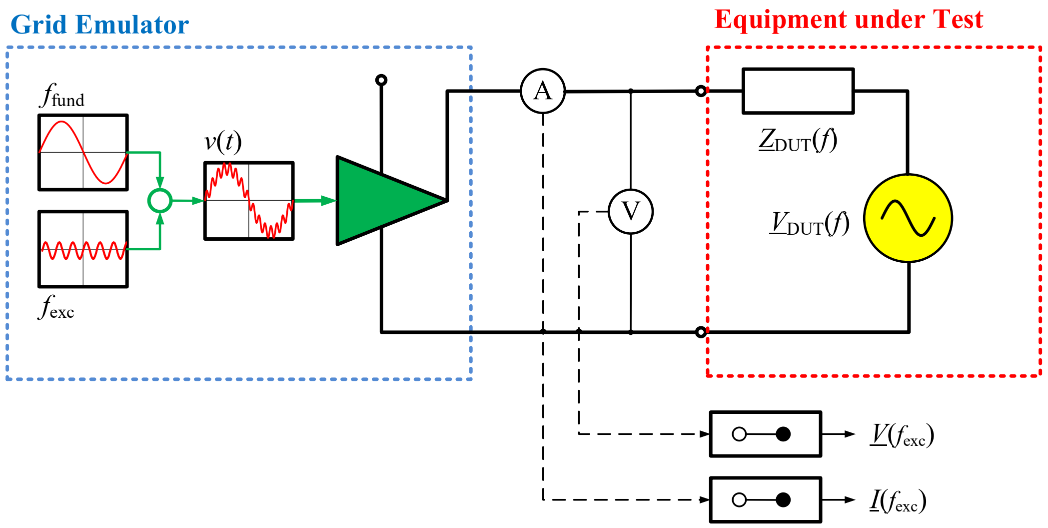

Figure 15: Principle of the impedance spectroscopy of converters (single line representation)

The test will be performed for different setpoints in active power (from 0 to 1 pu for PGU; from -1 to 1 pu for ESM). The effect of having maximum and minimum reactive power will also be analysed when the EUT is at its rated active power.

The impedances $\underline{Z}_{eff}(f)$ shall be calculated based on the voltages $\underline{V}(f_{exc})$ and currents $\underline{I}(f_{exc})$ obtained for each frequency at EUT terminals, and presented as Bode plots showing amplitude and phase separately.

Through this method, the frequency dependent harmonic impedances are obtained.

Closed loop stability

The tests shall evaluate the PGU's control stability according to Article 54(2)(d) regarding synchronisation and frequency control.

This test is conducted with a configured $T_{M,PPM}$ and with activated LFSM and FSM functions. An additional uncontrolled inertia may be included in the test setup.

The test may be performed using one of the test setups shown in Figure 10 or Figure 11. Optional appropriate HIL setups may be used. The EUT is islanded with a load imbalance (over-generation). Due to the load imbalance, the frequency in the island will start to increase. The EUT shall limit the RoCoF based on its configured $T_{M,PPM}$ and eventually stabilise the frequency based on the activated FSM and LFSM functions.

Appendix A. Separating synchronisation and frequency control (non-binding example)

Section 2.3.2 it states that the contribution to limiting the transient frequency deviation can be specified as a function of frequency deviation (Fast Frequency Control) or RoCoF (synthetic inertia), which may be necessary in some synchronous areas. Fast Frequency Control may be introduced as part of the synchronisation function or in a decoupled manner, where the frequency response is separated from the synchronisation. A non-binding example of the separation of frequency control $F(s)$ and synchronising function $K_{\text{sync}}(s)$ is presented in Figure 16. The synchronising function $K_{\text{sync}}(s)$ may be implemented in various ways, with some examples provided in Appendix B.

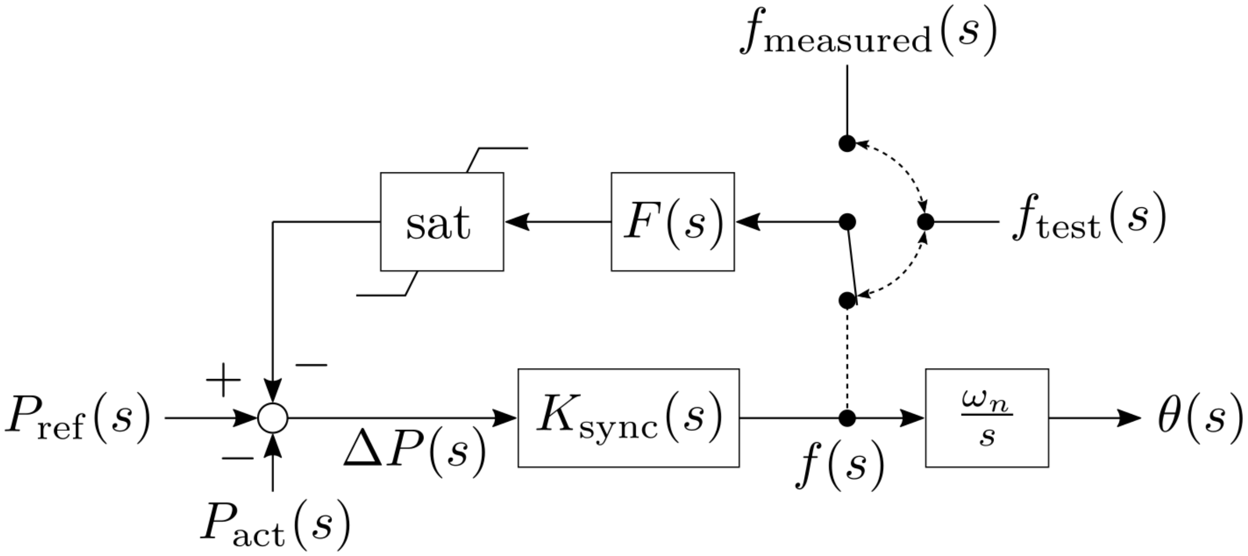

Figure 16: Block diagram showing how the synchronising and frequency control loop are defined. The test signal f_{test} is intended only for testing of the Fast Frequency Control $F(s)$, while the synchronising controller $K_{\text{sync}}(s)$ should be tested as specified in Chapter 3

The controller $F(s)$ is an additional outer control loop for Fast Frequency Control and energy management that is designed to comply with national variations in requirements for frequency behaviour and energy management. The Fast Frequency Controller is a dynamic frequency controller that uses feedback either from the characterising internal GFM frequency or measured system frequency as input. The design of the controller is decoupled from the synchronisation, enabling compliance testing by introducing a switchable test signal that bypasses the normal frequency input. The test signal f_{test} is intended only for testing of the Fast Frequency Control $F(s)$, while the synchronising controller $K_{\text{sync}}(s)$ should be tested as specified in Chapter 3.

Appendix B. Grid forming control approach (non-binding implementation examples)

Currently, numerous possible GFM control implementations are being discussed in the literature. Two relevant approaches are controls systems based on a Virtual Synchronous Machine (VSM) model and control systems based on the description of droops. The implementation used here is based on droop control and is described in [Klaes et al., 2020][45] and [Klaes et al., 2024].[46] Parameters for an equivalent implementation as a VSM are also provided.

A key requirement for any GFM control is a sufficient damping ratio for active power oscillations. The damping ratio method used (phase feed-forward damping) is well known and assumed to be free of patent restrictions.

The basic control structure of the GFM control implementation used is shown in Figure 17.

The error signal between the active power set point and the actual measured filtered active power generates an additional frequency Δf via the frequency droop gain k_f changing the voltage angle until the error is zero under stationary conditions. The calculated power is filtered with a first-order low-pass filter to ensure proper decoupling. To increase the damping ratio, the basic frequency droop control is expanded by an additional direct path, which acts as a feed-forward term from the power error Δp directly on the voltage phase θ_{Inv} via the phase feed-forward damping coefficient k_ϕ. This is generally identical to a differential action of the power error onto the frequency.

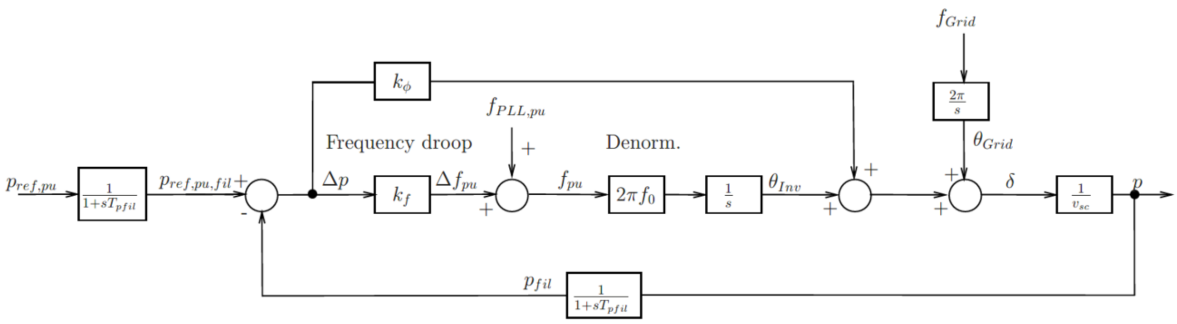

Figure 17: Reference implementation of a GFM active power control loop

The correspondence between droop-based and VSM-based GFM control is shown in Figure 18.

[45] Klaes, Norbert, Nico Goldschmidt, and Jens Fortmann. 2020. "Voltage Fed Control of Distributed Power Generation Inverters with Inherent Service to Grid Stability" Energies 13, no. 10: 2579. https://doi.org/10.3390/en13102579
[46] Klaes, Norbert and Jens Fortmann. 2024. "Immunity of grid forming control without energy storage to transient changes of grid frequency and phase" IEEE Open Journal of the Industrial Electronics Society. https://doi.org/10.1109/OJIES.2025.3532517

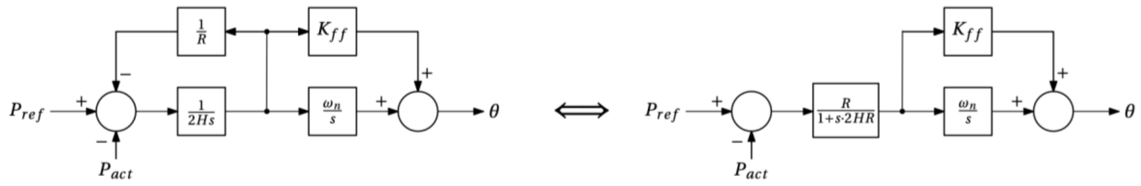

Figure 18: Corresponding VSM- and droop-based GFM control implementations

The following correspondence exists between a VSM- and a droop-based implementation if phase feed-forward damping is applied:

$$T_{pfil} = 2H \cdot R \quad (17)$$

$$k_f = R \quad (18)$$

$$k_\phi = K_{\mathrm{ff}} \cdot R \quad (19)$$

with k_ϕ as the phase feed-forward damping coefficient, K_{ff} as the phase feed-forward gain, k_f as frequency droop coefficient, T_{pfil} as the active power filter time constant, and R as the damping coefficient.

Appendix C. Physical model for the description of system disturbances

This section intends to:

1. Describe an analytical approach to specifying performance requirements.
2. Provide a generic test network for simulating these requirements.
3. Derive specific performance criteria that a single unit should be capable of providing.

If instantaneous values are used, it is assumed that they are calculated applying the Clarke transformation as shown in (20) for voltages or currents described as $y_a(t), y_b(t), y_c(t)$.

$$\begin{bmatrix} y_\alpha(t) \\ y_\beta(t) \end{bmatrix} = \frac{2}{3} \begin{bmatrix} 2 & -\frac{1}{2} & -\frac{1}{2} \\ 0 & \frac{\sqrt{3}}{2} & \frac{\sqrt{3}}{2} \end{bmatrix} \begin{bmatrix} y_a(t) \\ y_b(t) \\ y_c(t) \end{bmatrix} \tag{20}$$

The complex representation is:

$$\underline{y}(t) = y_\alpha(t) + j y_\beta(t) \tag{21}$$

And the magnitude is:

$$y = |\underline{y}| = \sqrt{y_\alpha^2 + y_\beta^2} \tag{22}$$

By applying the above to voltage and current, active and reactive power can be calculated as follows:

$$p(t) + j\, q(t) = \underline{u}(t) \cdot \underline{\imath}(t)^* \tag{23}$$

C.1 Voltage phase angle step

A phase angle step is typically the result of a sudden power change, either due to a loss of generation or a load in the system (considered a system-wide event) or from a switching operation (considered a local event). In the case of a system-wide event, the remaining units need to compensate for the power difference, which causes a change in the voltage angle. The relationship between the power change and the resulting angle change can be approximated by:

$$p \approx -\frac{(u_\mathrm{G})^2}{x_\mathrm{G}} sin(\delta) \tag{24}$$

where δ is the voltage angle difference between $\underline{u}_\mathrm{G}$ and the voltage at the load. For small angles, a proportional relationship between the angle change and power change can be assumed (with $\delta \approx sin(\delta)$).

In the model representation shown in Figure 19, opening the S_{L2} switch emulates a loss of load, while closing S_{L2} corresponds to a loss of generation, increasing the load on the remaining generators.

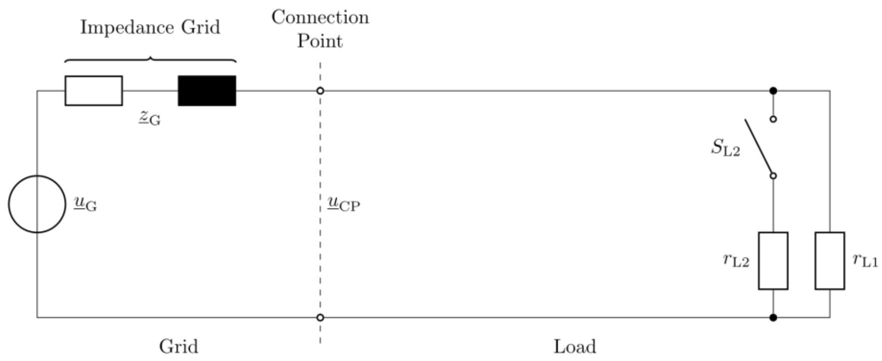

Figure 19: Simple grid and load equivalent for estimating a voltage angle change following a load change

The resulting average voltage angle change for a given change in active power is a function of the system Short-Circuit Ratio (SCR) defined by the impedance $\underline{z}_G$ .The actual angle power change (in %) experienced by a specific unit may differ from the average power difference experienced by the grid as a whole and depends on the impedance between the unit and the grid's "centre of gravity".

Therefore, the angle changes experienced by an individual PGU following a grid event depends on its location. PGUs that are close to a grid event need to withstand higher voltage angle changes than those that are more distant.

Note: In the distribution system, voltage angle changes frequently result from changes in the grid topology due to the connection or disconnection of lines and are not necessarily related to changes in system load or generation. The following calculations focus on events that affect system frequency.

C.1.1 Phase angle step with grid impedance only

A very simple grid equivalent consisting of a grid equivalent and an idealised PGU represented by an ideal voltage source (with infinite inertia H) is shown in Figure 20.

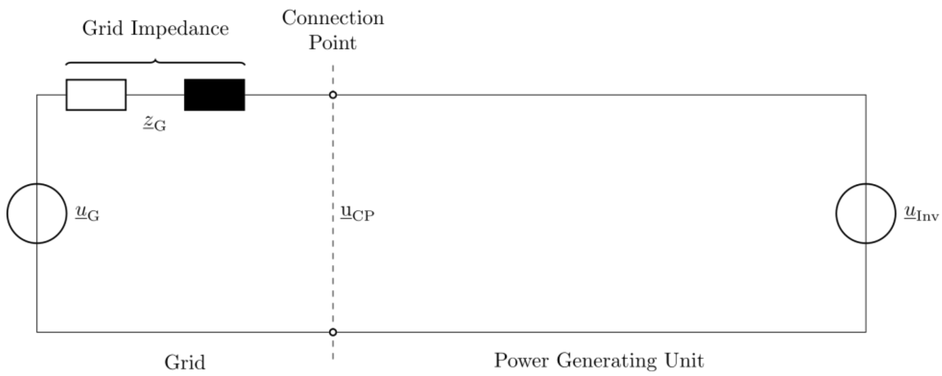

Figure 20: Simple grid equivalent consisting of a grid equivalent and an idealised PGU

For this case, the steady-state relationship between the active current and voltage angle based on equation (1) can be approximated as:

$$\delta \approx \arcsin\left(\frac{i_{\mathrm{P,PGU}} \cdot x_{\mathrm{G}}}{u_{\mathrm{Inv}}}\right) \quad (25)$$

The dynamic of the relationship between voltage angle change and power can be described as:

$$p_{Inv}(t) = p_{inv2,stat} - 3\frac{u_{\mathrm{Inv}} u_{\mathrm{G}}}{z_G} \cdot e^{-t/\tau} \cdot sin\left(\frac{\delta_2 - \delta_1}{2}\right) \cdot sin\left(\omega t + \frac{\delta_1 + \delta_2}{2} + \varphi_{\mathrm{sc}}\right) \quad (26)$$

where $\delta_1$and δ_2 are the voltage angle difference between grid and inverter voltage sources before and after the event.

For a reference parametrisation with SCR = 10 and X/R = 30.3 (r_G = 0.0033 pu and x_G = 0.1 pu), the angle change resulting from a 25% change in active power in either a positive direction (loss of load) or negative direction (loss of generation) can be calculated using equation (25) as 1.4°. The current change resulting from this change of power and voltage angle is shown in Figure 21.

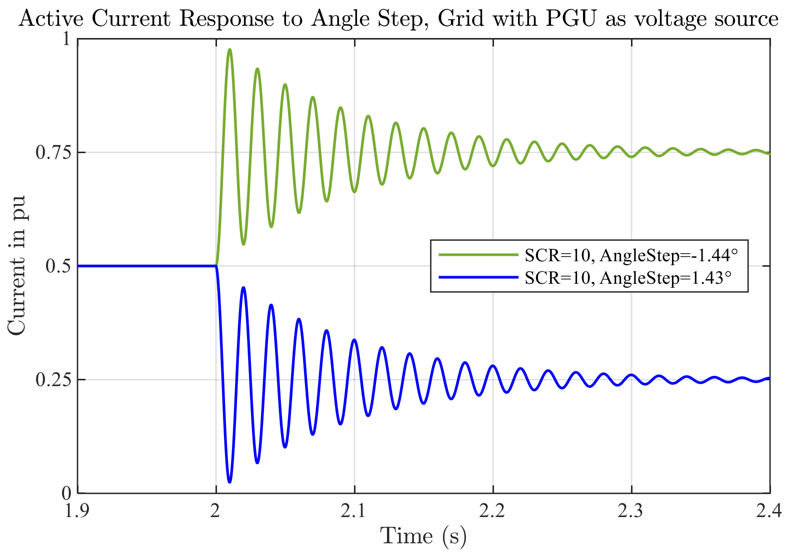

Figure 21: Active current change by ± 25% resulting from a change of grid voltage angle

The current response can be described by equation (27):

$$\begin{aligned} i_{dinv}(t) = i_{\mathrm{dinv2,stat}} - 2\frac{u}{z} \cdot e^{-(t-t_0)/\tau} \cdot sin\left(\frac{\delta_2 - \delta_1}{2}\right) \\ \cdot sin\left(\omega(t - t_0) + \frac{\delta_1 + \delta_2}{2} + \varphi_{sc}\right) \end{aligned} \quad (27)$$

with an electromagnetic decay rate of:

$$\frac{r}{x} \approx \frac{0.0033}{0.1} = 0.033 \tag{28}$$

C.1.2 Phase angle step with grid impedance and inverter hardware

Figure 22 shows an extended simple grid equivalent consisting of a grid equivalent and PGU represented by an ideal voltage source and a unit hardware equivalent consisting of an inverter filter and LV-MV transformer.

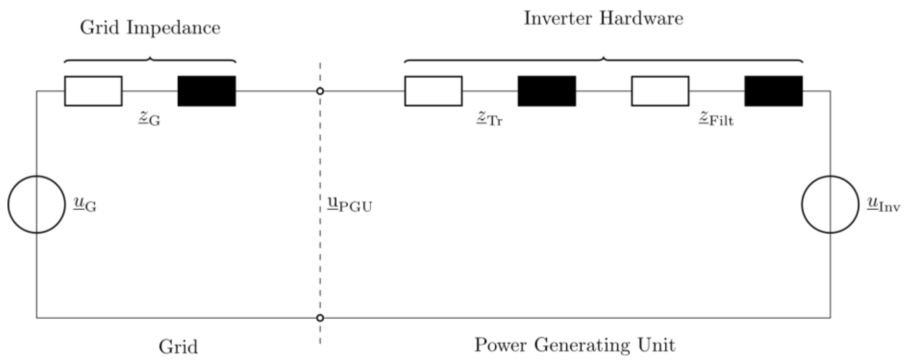

Figure 22: Simple grid equivalent consisting of a grid equivalent, unit MV transformer, and inverter filter impedance

When the unit's MV-to-LV transformer and filter impedance are added, a 25% change in active power results in an angle change of approximately 5° between the grid and inverter voltage sources. This is calculated using equation (25), with x_G replaced by $(x_G + x_{Tr} + x_{Filt} = 0.34)$, ocurring in either the positive direction (loss of load) or negative direction (loss of generation), as shown in Figure 23.

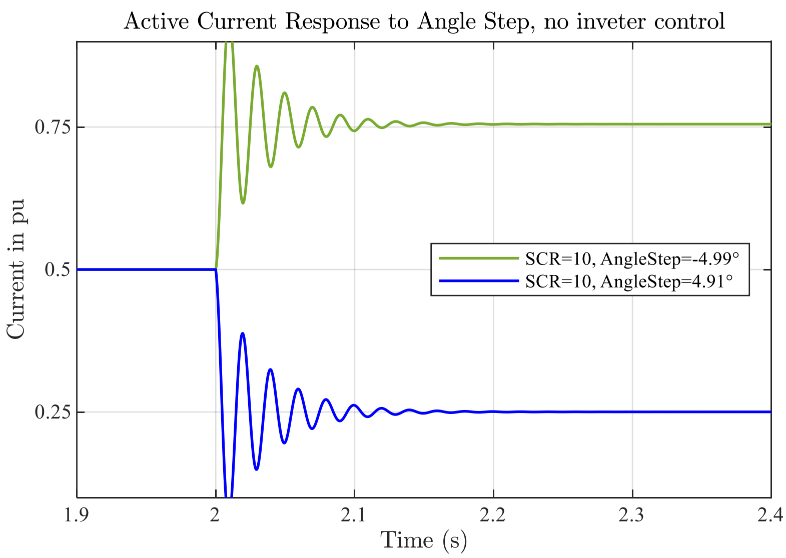

Figure 23: Active current change by ± 25% resulting from a change of grid voltage angle with electromagnetic decay rate and without inverter control

The current in a single phase is shown in Figure 24. The oscillations shown in Figure 23 are related to the transformation of the DC component of the individual phases into the three-phase magnitude domain. While the current magnitude adapts instantaneously after the phase jump, a DC transient appears in the phase currents, decaying with a time constant (τ) corresponding to X/(ω*R), which in this case this is 32 ms.

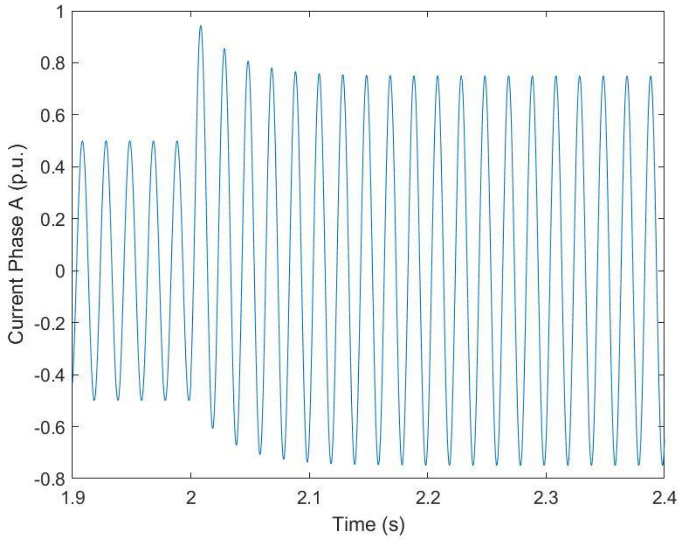

Figure 24: Single phase current throughout the phase jump

The reference parametrisation uses a grid equivalent with a SCR = 10 and X/R = 30 and a unit impedance (compromising the inverter filter impedance $\underline{z}_{\mathrm{Filt}}$ and the LV/MV transformer impedance $\underline{z}_{\mathrm{Tr}}$) of $\underline{z}_{\mathrm{PGU}}$ = 0.24/8 + j0.24. The decay rate of the electromagnetic oscillations defined by the grid and PGU parameters as:

$$\frac{r_{\mathrm{G}} + r_{\mathrm{Tr}} + r_{\mathrm{Filt}}}{x_{\mathrm{G}} + x_{\mathrm{Tr}} + x_{\mathrm{Filt}}} = \frac{0.033}{0.34} \approx 0.1 \qquad (29)$$

C.1.3 Phase angle step with grid forming control

The current response shown so far is based on an ideal system with infinite inertia. The response of a GFM-controlled unit to a voltage angle step can be described by an effective impedance $\underline{z}_{\mathrm{Eff}}$, by modelling the controller contribution using an additional impedance $\underline{z}_{\mathrm{Control}}$, as shown in Figure 25. $\underline{z}_{\mathrm{Eff}}$ defines the desired response of a GFM-controlled PGU to a voltage angle step (and a voltage amplitude step, as shown in the next section) in a method comparable to the response of a synchronous generator. $\underline{z}_{\mathrm{PCS}}$ represents the impedance of the PPM PCS.

A grid-following controller would not respond to a voltage angle change.

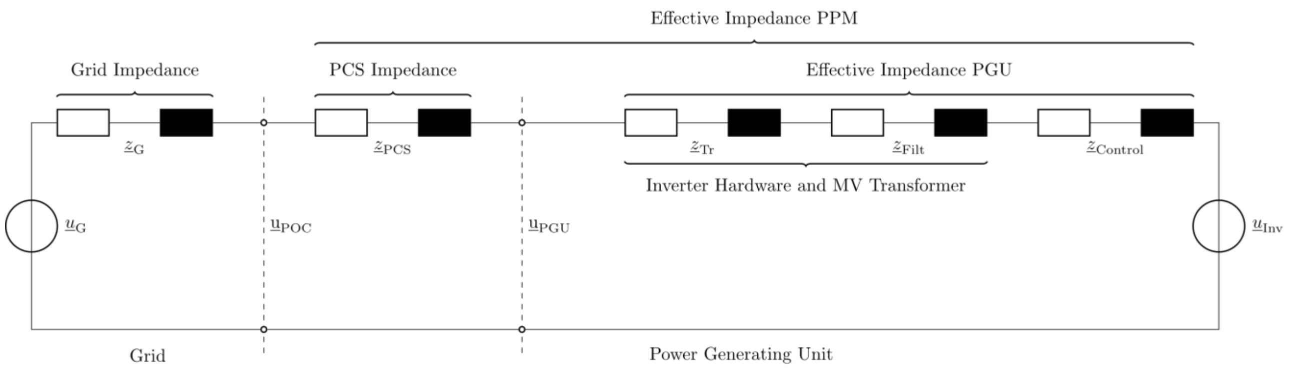

Figure 25: Simple grid equivalent consisting of a grid equivalent, PCS impedance, unit MV transformer, inverter filter, and control impedance

Based on a GFM control implementation as described in Appendix B, the currents following a voltage angle change will decay as shown in Figure 26.

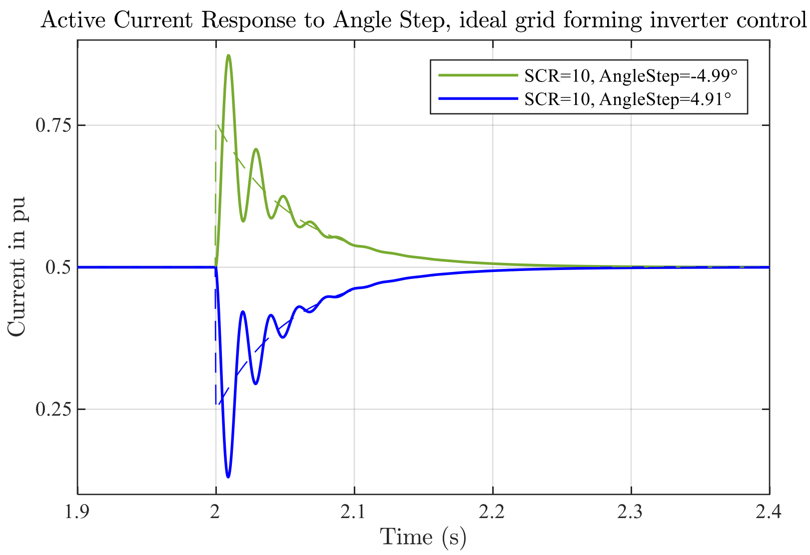

Figure 26: Active current change with angle step by ± 4.9° at the grid voltage source with simplified GFM control according to Figure 18. The dashed lines show the phasor-based calculation

The decay rate, as the "average current" depends on the internal control implementation. For the control implementations shown in Figure 17 and Figure 18, the decay function (the dashed lines in Figure 26) can be calculated as phasor values. Assuming $u_G = u_{inv} = 1$, the active power change can be described as:

$$\Delta p = \Delta p_0 \cdot e^{-t/\tau} \tag{30}$$

with:

$$\Delta p_0 = -\frac{1}{x_{\mathrm{Eff}}} \cdot (\sin\delta_1 - \sin\delta_2) \tag{31}$$

and:

$$\tau = \frac{x_{\mathrm{Eff}}}{k_{\mathrm{f}}\omega_0} \tag{32}$$

where τ is the time constant of the decay rate, x_{Eff} as the unit effective reactance, and k_f is the frequency droop coefficient (see Appendix B).

The equivalent active current response is:

$$\Delta i_P = \Delta i_{P0} \cdot e^{-t/\tau} \tag{33}$$

with:

$$\Delta i_{P0} = -\frac{1}{x_{\mathrm{Eff}}} \cdot (\sin\delta_1 - \sin\delta_2) \tag{34}$$

Inverter-based PGUs with GFM control can provide an additional decay rate independently of the value of $\underline{z}_{\mathrm{Eff}}$ by modifying the inverter voltage angle. Figure 27 shows the response of a unit with the same angle step and the same calculated power change of 25%, but an increased electromagnetic decay rate as described in equation (35).

$$\frac{r_{\mathrm{G}} + r_{\mathrm{Tr}} + r_{\mathrm{Filt}}}{x_{\mathrm{G}} + x_{\mathrm{Tr}} + x_{\mathrm{Filt}}} + D_{add} \approx \frac{0.033}{0.34} + 0.2 \approx 0.3 \tag{35}$$

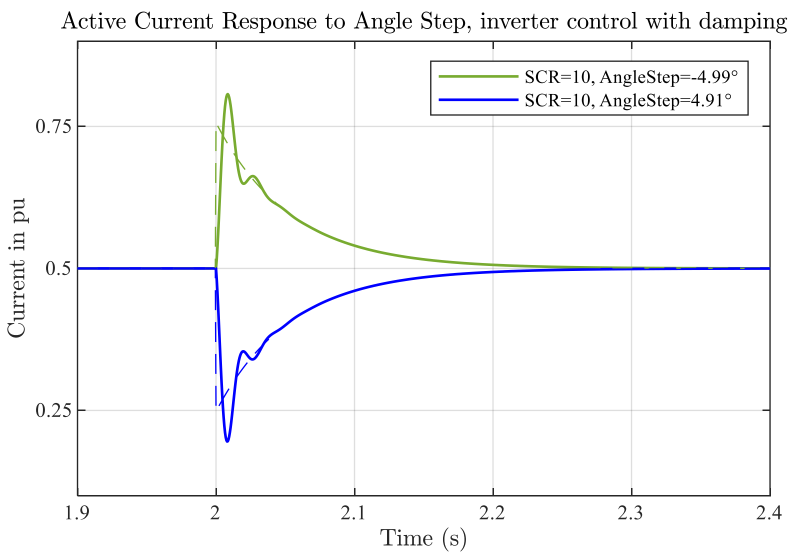

Figure 27: Active current change with angle step by ± 4.9° at the grid voltage source with inverter control and additional electromagnetic decay rate

C.1.4 Performance criteria based on ideal and simulated response to voltage angle changes

Figure 28 shows a comparison of ideal and simulated response to voltage angle changes, depicting a string correlation between the simulation results and the expected response. A close-up view directly following the angle step change is shown in Figure 29, Figure 30, and Figure 31.

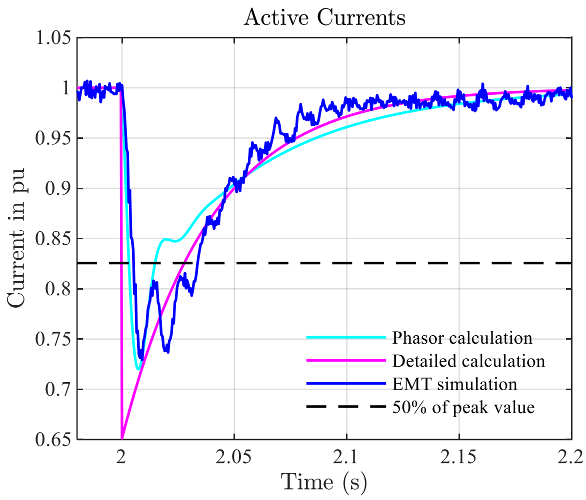

Figure 28: Active current change following voltage angle change by 5° at the terminals of the unit at rated power. Comparison of ideal and simulated response to voltage angle change

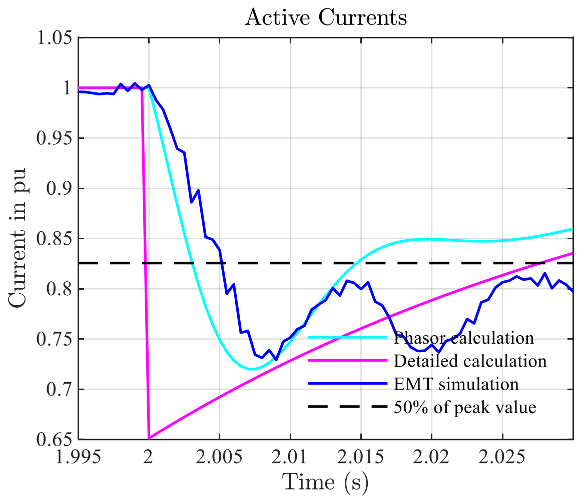

Figure 29: Detailed view of active current change following voltage angle change by 5° at rated power

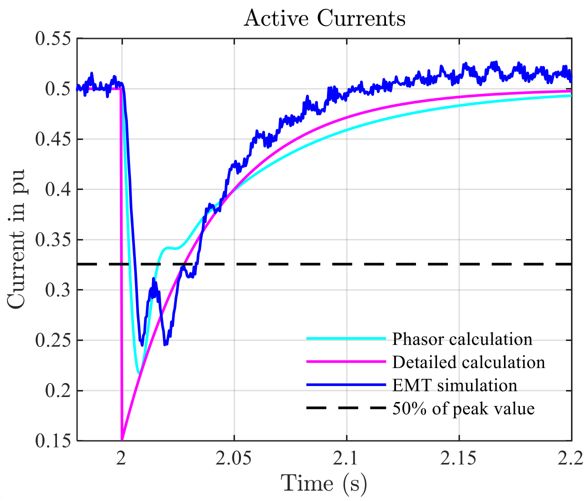

Figure 30: Active current change following voltage angle change by 5° at the terminals of the unit at 50% rated power. Comparison of ideal and simulated response to voltage angle change

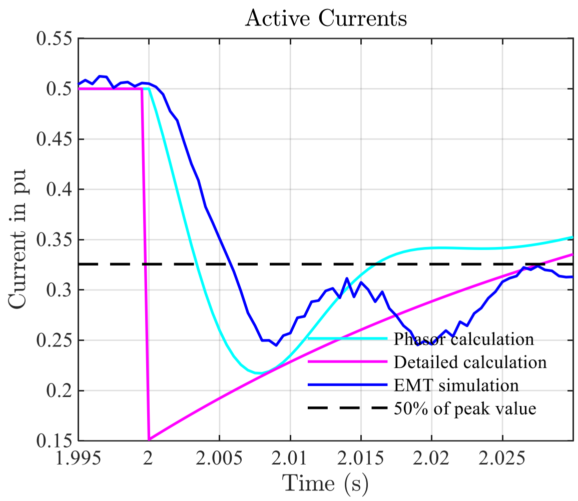

Figure 31: Detailed view of active current change following voltage angle change by 5° at 50% rated power

The pink line shows the phasor calculation, the cyan line shows the analytical solution-based instantaneous values, and the dark blue line shows the response of the Electromagnetic Transient (EMT) Simulation based on the control structure shown in Appendix B.

There is a strong correlation between the peak value of the current and the electromagnetic decay rate. The EMT simulation shows an additional time delay and a reduced peak compared to the analytical solution. The peak value of the EMT simulation is at around 10 ms, which is comparable to the expected response of a voltage source.

Recommendations

Based on the phasor calculation (equation (4)/(5)), an expected response (depending on grid and test system impedance) to any given voltage angle change can be calculated.

Units without internal storage should only provide a reduction of power due to positive voltage angle changes.

C.2 Voltage amplitude step

A simplified test setup for evaluating small and large voltage amplitude steps is shown in Figure 32.

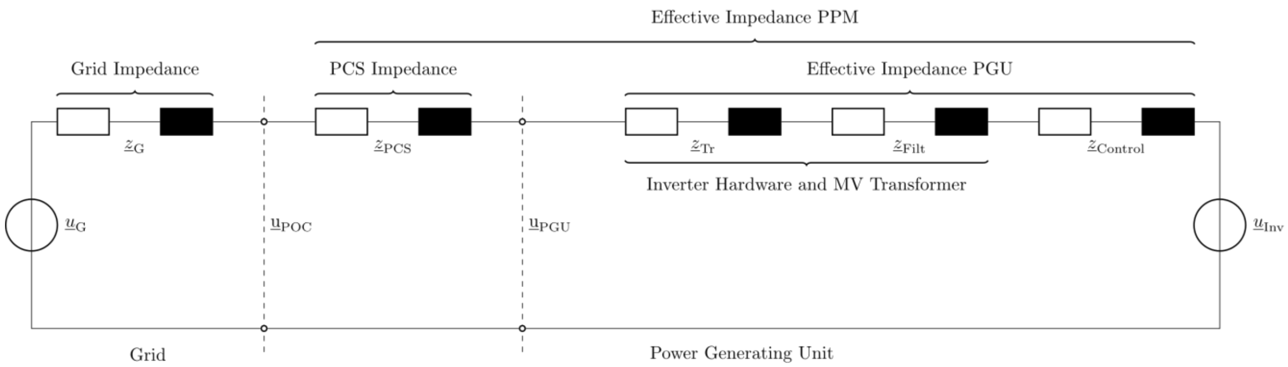

Figure 32: Simple representation of voltage amplitude changes

The response of a controlled voltage source to a voltage amplitude step change of u_{G} can be approximated by:

$$i_{\mathrm{P}} = \frac{p}{u} \approx -\frac{u_{Inv}}{(x_{\mathrm{G}} + x_{\mathrm{Eff}})} sin(\delta) \tag{36}$$

and:

$$i_{\mathrm{Q}} = \frac{q}{u} \approx \frac{1}{(x_{\mathrm{G}} + x_{\mathrm{Eff}})} \left(u_{\mathrm{G}} - u_{\mathrm{Inv}} \cdot cos(\delta)\right) \tag{37}$$

for a change in the grid voltage u_{G}.

If no current limits are reached (unconstrained operation), the reactive current i_{Q} changes with voltage changes (37). The active current i_{P} does not change as a function of grid voltage (36). The apparent current becomes very high for low voltages.

Figure 33 shows the active and reactive current response as defined by equations (36) and (37). The slight variation of active current above a voltage of 0.95 is caused by the active power control loop, which adjusts the active current based on the grid voltage to maintain a constant active power output (38). Some grid codes require PPMs to provide rated active power at voltages below 1 pu.

$$i_{\mathrm{P_{Ref}}} = \frac{p_{\mathrm{Ref}}}{u_{\mathrm{PGU}}} \tag{38}$$

Figure 34 shows the corresponding voltage angle δ (grey), which is adjusted (see equation (36)) to maintain constant active power for small voltage amplitude changes. For low residual voltages, the R/X assumptions used in equations (1) and (2) may not be valid, so the figures below should only be considered indicative for low retain voltages.

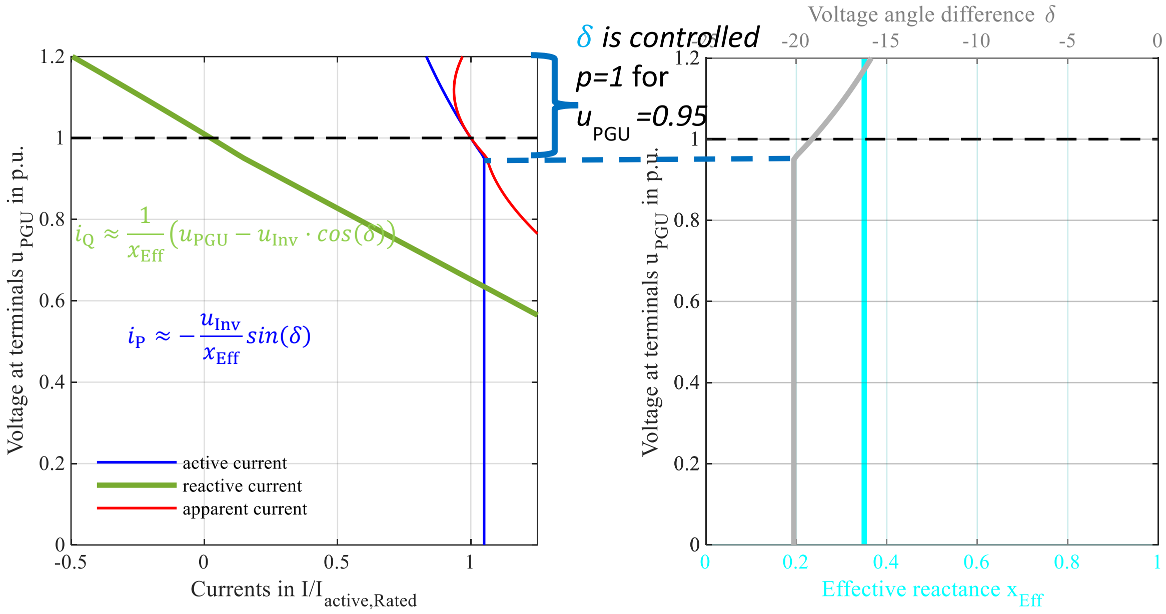

Figure 33: Active and reactive current of an inverter behaving as a voltage source if no current limits apply

Figure 34: Corresponding values of voltage angle δ (grey line). This value is commonly adopted around rated voltage to ensure constant active power. The effective reactance x_{Eff} (blue line) and the internal inverter voltage remain constant

This behaviour is comparable to that of a synchronous generator. The internal voltage of the synchronous generator remains constant, while the ratio between active and reactive current changes as the grid voltage decreases. In the case of a synchronous generator, the reactance would decrease during the fault due to saturation effects.

C.2.1 Current limitation using reactive power priority

If an effective reactance x_{Eff} value of 0.33 (in pu) is assumed, the typical current limit of an inverter (1.1-1.2 pu) is exceeded once the voltage drops by more than 33% at the PoC. For grid following inverters, it is common practice to limit active and reactive currents independently as a function of the remaining voltage. The resulting response to voltage drops can be highly nonlinear and possibly unstable.

Figure 35 shows the active and reactive current when reactive current priority is applied in a typical configuration for wind turbines. In this case, the active current is not reduced to 0. Figure 36 shows the corresponding values of voltage angle δ and the effective reactance $\mathrm{x}_{\mathrm{Eff}}$ of an equivalent voltage source as shown in Figure 25. Figure 37 shows an equivalent current priority for solar parks, where no active current is needed during voltage drops. Figure 38 shows the corresponding values of voltage angle δ and the effective reactance x_{Eff}, respectively.

Both variants behave like a current source once the reactive current limit is reached. Any additional voltage change no longer leads to any change of reactive current. This is a typical implementation of grid-following control today and does not meet the requirements of GFM behaviour. For low residual voltages, the R/X assumptions used for equations (1) and (2) may not be valid, so the figures below should only be considered indicative for low retain voltages.

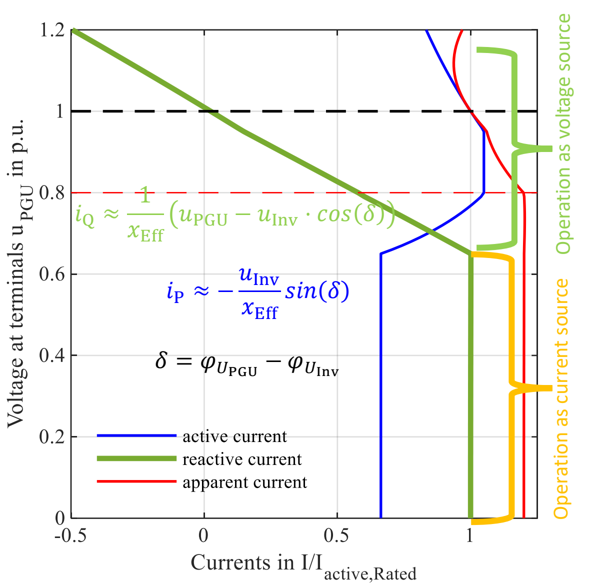

Figure 35: Active and reactive current of an inverter with voltage control and reactive current priority in a typical configuration for wind turbines when current magnitude limitation is applied

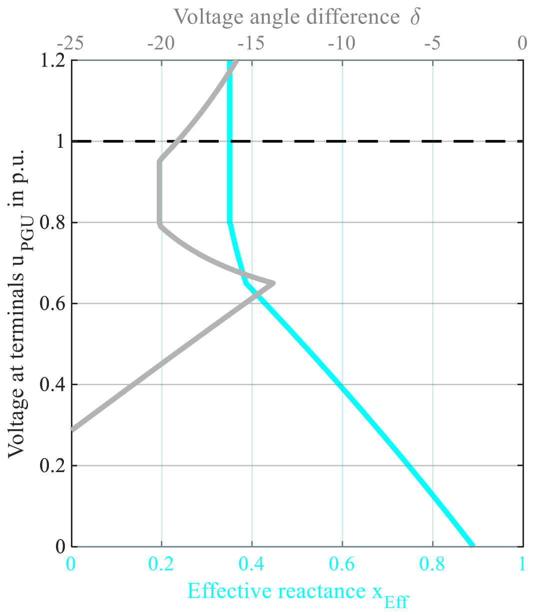

Figure 36: Corresponding values of voltage angle δ (grey line), of an inverter with reactive current priority. The effective reactance x_{Eff} (blue line) and the internal inverter voltage remain constant

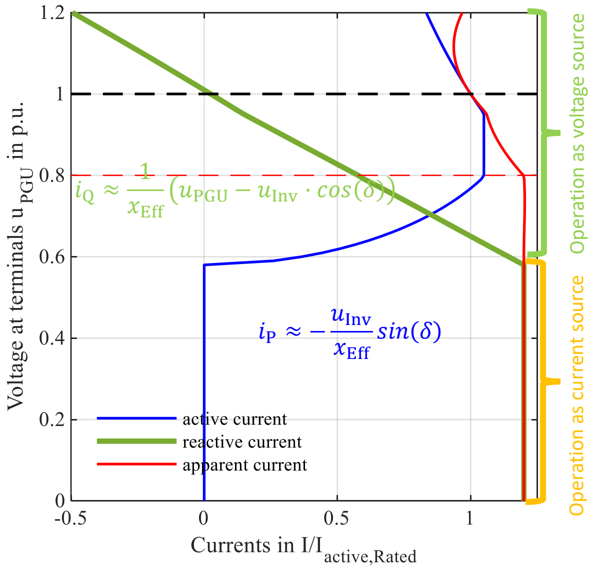

Figure 37: Active and reactive current of an inverter with voltage control and reactive current priority in a typical configuration for solar plants when current magnitude limitation is applied

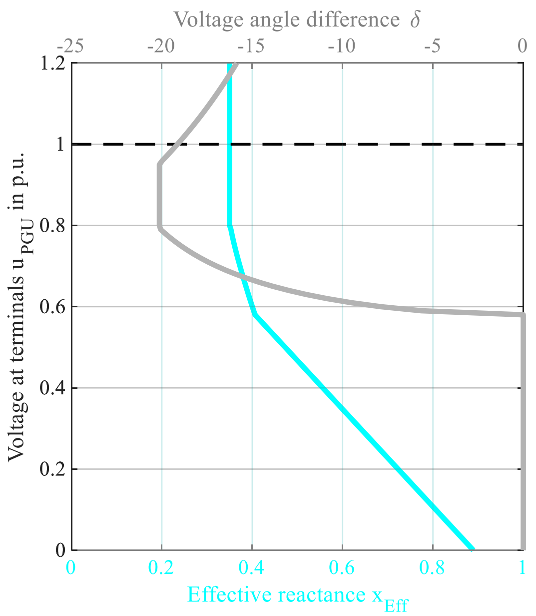

Figure 38: Corresponding values of voltage angle δ (grey line), of an inverter with reactive current priority. The effective reactance x_{Eff} (blue line) and the internal inverter voltage remain constant

C.2.2 Grid forming implementation using magnitude limitation

Figure 39 shows the response of a controlled voltage source with current magnitude limitation to changes in voltage for 100% rated power. Figure 40 shows the corresponding values of the voltage angle and the effective reactance. Figure 41, Figure 42, and Figure 43 show active and reactive current of an inverter with current magnitude limitation, including an allowed band for the current reference of ± 10% of the theoretical value of the reactive current. The starting point is reactive power at rated voltage of 0 pu for Figure 41, reactive power of -0.2 pu for Figure 42, and reactive power of 0.2 pu for Figure 43. The corresponding diagrams for 100% and 10% rated power are shown in Figure 44 and Figure 45. This can be achieved by dynamically increasing the value of $\underline{z}_{\mathrm{Control}}$ in Figure 32, resulting in a dynamic increase of the effective reactance (x_{Eff}) in equations (36) and (37), respectively. For low residual voltages, the R/X assumptions used for equations (1) and (2) may not be valid, so the figures below should be considered indicative only for low retain voltages.

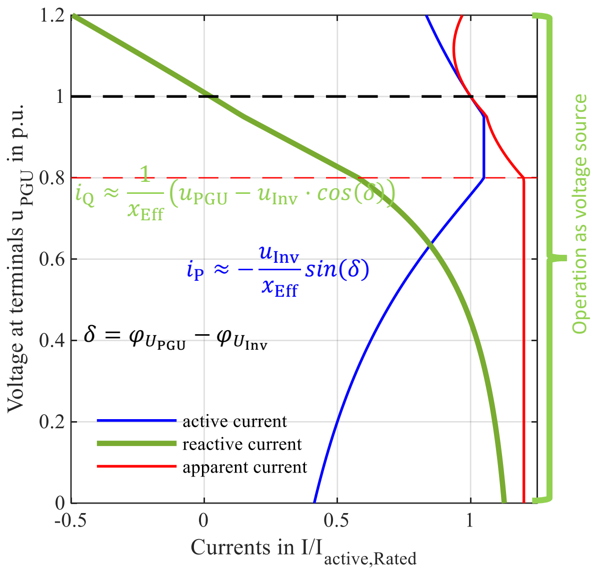

Figure 39: Active and reactive current of an inverter with current magnitude limitation

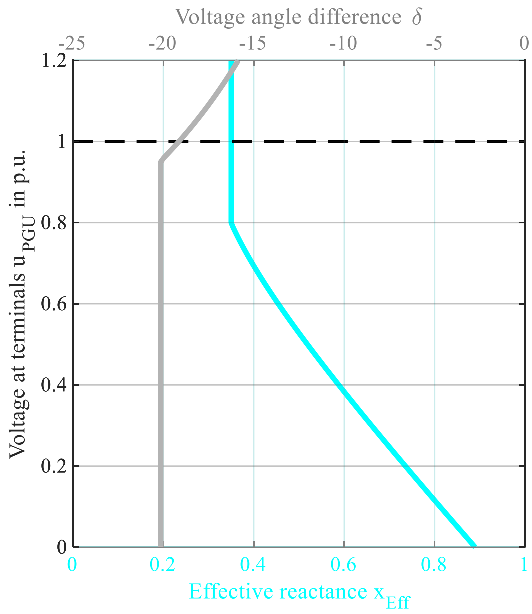

Figure 40: Corresponding values of voltage angle δ (grey line), and effective reactance x_{Eff} (blue line) for an inverter with current magnitude limitation

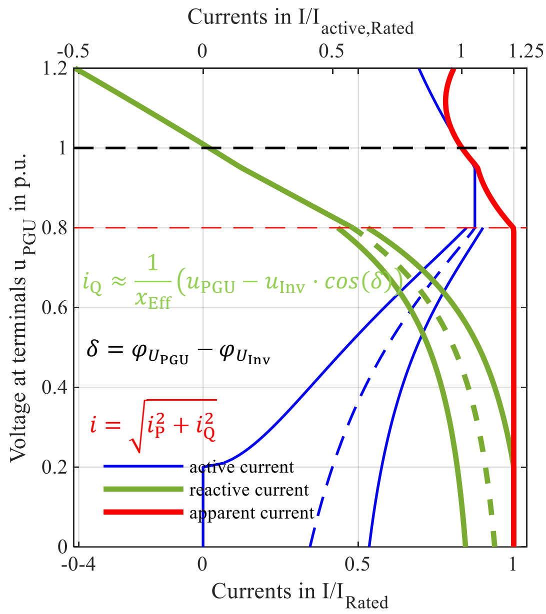

Figure 41: Active and reactive current of an inverter with current magnitude limitation, including an allowed band for the current reference of ± 10% of the theoretical value of the reactive current. This graph is assuming a voltage drop applied by an inductive fault

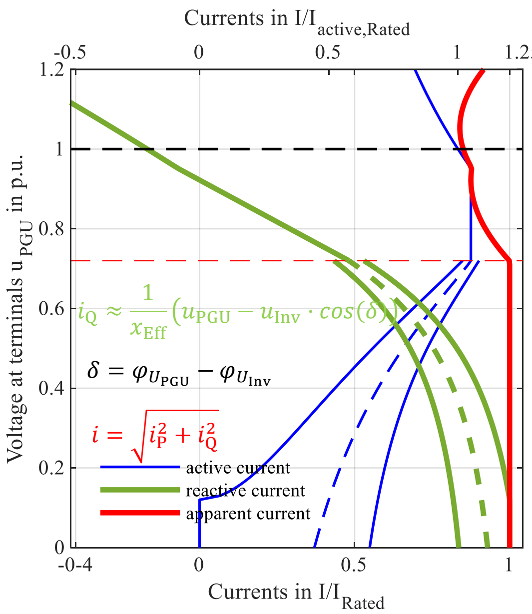

Figure 42: Active and reactive current of an inverter with current magnitude limitation, including an allowed band for the current reference of ± 10% of the theoretical value of the reactive current. The starting point is a reactive power of -0.2 pu at rated voltage

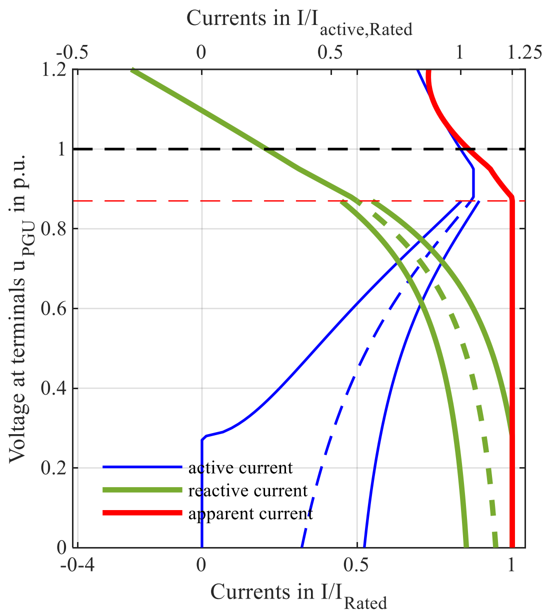

Figure 43: Active and reactive current of an inverter with current magnitude limitation, including an allowed band for the current reference of ± 10% of the theoretical value of the reactive current. The starting point is a reactive power of 0.2 pu at rated voltage

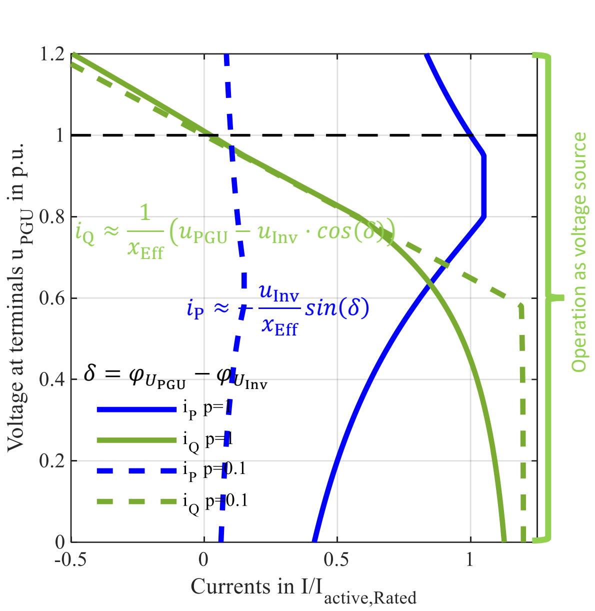

Figure 44: Active and reactive current of an inverter with current magnitude limitation at 100% and 10% active power

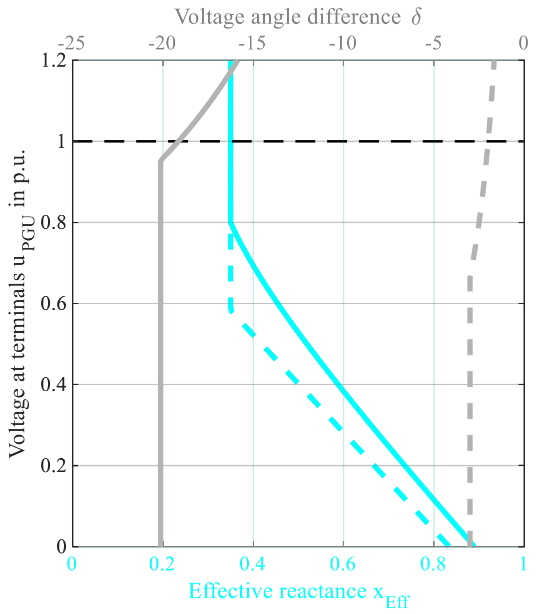

Figure 45: Corresponding values of voltage angle δ (grey line), and effective reactance x_{Eff} (blue line) for an inverter with current magnitude limitation

C.2.3 Unbalanced voltage step

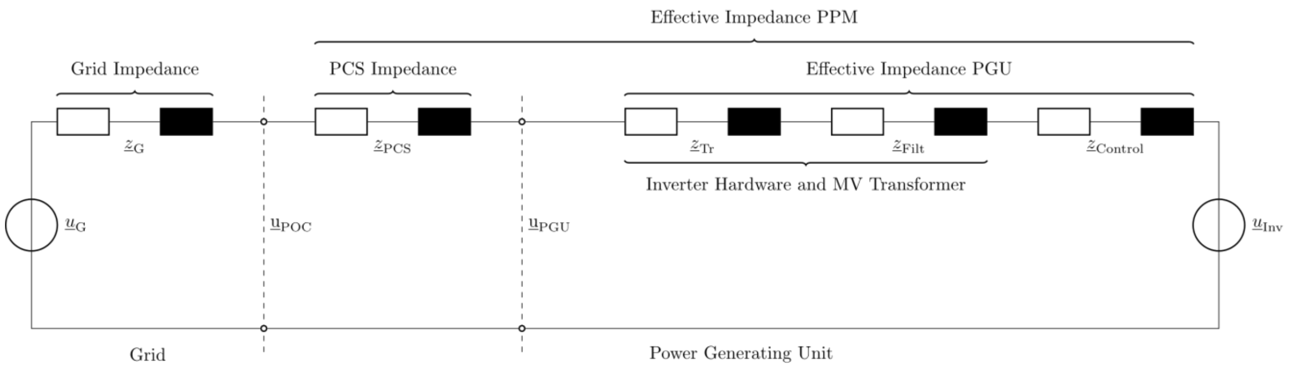

Figure 46: Test system for testing unbalanced voltage step

Under unbalanced fault conditions, the negative sequence reactive current can be described as:

$$i_{Q,neg} \approx \frac{1}{x_{Eff}} u_{PGU,neg} \tag{39}$$

where $u_{PGU,neg}$ is the negative sequence voltage at the PoC. The negative sequence effective reactance should be equal to the positive sequence reactance x_{Eff}.

If current limits are reached, x_{Eff} shall be increased dynamically to limit active and reactive currents in the positive sequence and the reactive current in the negative sequence according to equations (1)-(3).

Appendix D. Inverters with dual GFM and non-GFM capabilities

As part of the progressive introduction of GFM PPMs defined in the national roadmaps required by the draft NC RfG 2.0, some RSOs may seek the ability to change the operation of PPMs from GFM to non-GFM, or vice versa. Practically, this will mean that the GFM capability within the scope of the roadmap of Article Y(5) (i.e. capability as defined in Articles Y(7), 20(4), 20(5), 21(4), and 21(5)) of the draft NC RfG 2.0 will be enabled or disabled on the relevant PPM.

Where the ability exists to enable or disable GFM capability on a generating unit, full compliance with the draft NC RfG 2.0 requirements shall be demonstrated for both operating modes, noting that the relevant technical standards for GFM functionality are still being developed at the date of this report.

This ability to activate or deactivate GFM capability may be useful for RSOs making provisional connections, for RSOs managing and controlling unwanted power islands, and where an otherwise GFM PPM has to be connected to a LV network (for example in Member States where Type B PPMs are connected at LV).

The ability to enable or disable GFM capability may only be possible at the power generating facility by setting a specific parameter during the commissioning of the PPM, or it may be activated remotely while the PPM is running. In the latter case, the manufacturer must specify the elapsed time required to deactivate or activate GFM capability to allow the RSO to include any implications in the connection agreement and its operational rules.

Appendix E. Specification of inertia requirements

This appendix shows how the specification of the mechanical starting time $T_{\mathrm{M,PPM}}$ (as defined in Section 2.3.2) combined with the dimensioning frequency gradient and the dimensioning change in frequency, affects the required power and energy reserves.

The mechanical starting time is defined as in equation (6), where the power rather than the torque is proportional to the frequency gradient:

$$\frac{\Delta P}{P_{Rated}} = \frac{df}{dt} \cdot \frac{1}{f_{Rated}} \cdot T_{M,PPM}$$

Table 5 shows the additional power (in pu) required to emulate a given mechanical starting time without saturation for a specific frequency gradient. For example, emulating a mechanical starting time of 25 s at a 2 Hz/s frequency gradient requires an ESM capacity twice the plant's rated power to operate at rated power while providing the necessary headroom. In contrast, for a 1 s starting time, the inverter must only be overrated by 4%. When considering inertia requirements in the event of a system split, it is useful to examine the worst-case power imbalance, which shall be covered first by inertia. The extra power reserve drives extra costs for the plant. Based on the expected frequency gradient in the area, the required mechanical starting time can be adjusted.

Table 5: Power reserve required (in pu) to avoid power saturation at combinations of inertia and dimensioning frequency gradients

df/dt (Hz/s)	$T_{M,PPM}$ (s)					
	1	**2**	**10**	**12.5**	**20**	**25**
0.5	0.01	0.02	0.1	0.125	0.2	0.25
1	0.02	0.04	0.2	0.25	0.4	0.5
1.5	0.03	0.06	0.3	0.375	0.6	0.75
2	0.04	0.08	0.4	0.5	0.8	1
2.5	0.05	0.1	0.5	0.625	1	1.25
3	0.06	0.12	0.6	0.75	1.2	1.5
3.5	0.07	0.14	0.7	0.875	1.4	1.75
4	0.08	0.16	0.8	1	1.6	2

Under the same assumption as above, the necessary energy reserve can be calculated using equation (8):

$$\frac{\Delta E}{P_{Rated}} = \frac{f_{max} - f_{min}}{f_{Rated}} \cdot T_{M,PPM}$$

The energy requirement only depends on the difference between the frequencies at the beginning and end of the event as well as on the mechanical starting time.

Table 6 shows the necessary energy reserves specified as seconds of rated power for various combinations of mechanical starting time and frequency difference. For a battery, where the energy is usually measured in minutes or hours at rated power, this is not significant. But for super capacitors, the energy will impact the volume.

Table 6: Necessary energy reserve (in seconds) to provide inertia through a frequency gradient

F_{max} (Hz)	F_{min} (Hz)	$T_{M,PPM}$ (s)					
		1	2	10	12.5	20	25
50.5	49.5	0.02	0.04	0.2	0.25	0.4	0.5
51	49	0.04	0.08	0.4	0.5	0.8	1
51.5	48.5	0.06	0.12	0.6	0.75	1.2	1.5
52	48	0.08	0.16	0.8	1	1.6	2
52.5	47.5	0.1	0.2	1	1.25	2	2.5
53	47	0.12	0.24	1.2	1.5	2.4	3
53.5	46.5	0.14	0.28	1.4	1.75	2.8	3.5
54	46	0.16	0.32	1.6	2	3.2	4

Appendix F. Evaluation of synthetic inertia (example)

As stated in Section 3.5.2, two alternative options are considered when evaluating synthetic inertia contribution: a grid simulator or islanding with a local resistive load.

Figure 47 shows the results of a test with a grid simulator, applying the RoCoF profile of Figure 13:

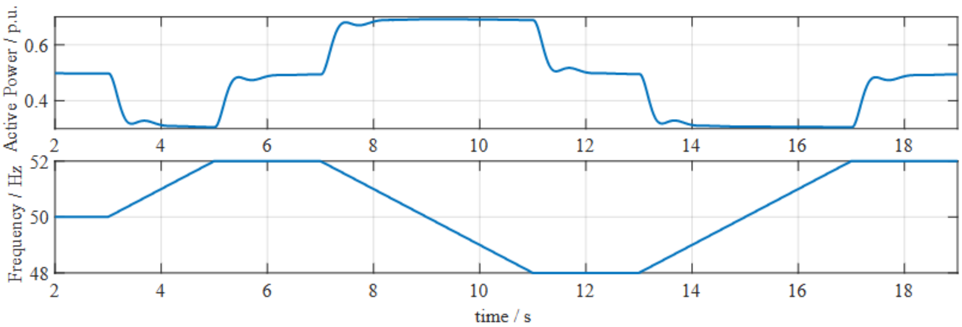

Figure 47: Virtual inertia response to RoCoF injected at the terminals of a EUT with a grid simulator

Based on the injected frequency change (lower plot), the active power of the EUT changes according to the configured $T_{M,PPM}$. As the damping ratio implemented in the GFM control results in a damped response, the $T_{M,PPM}$ is calculated according to equation (6) once the ΔP (upper plot) has stabilised. Based on Figure 47, the mechanical starting time is calculated using equation (6):

$$T_{\mathrm{M,PPM}} = \frac{\Delta p_{pu}}{\left(\frac{df_{pu}}{dt}\right)} = \frac{0{,}2}{\frac{1Hz/s}{50Hz}} = 10s$$

Figure 48 shows the results of a test with a local load. In the initial state, the EUT (green line) is supplying the load (dashed back line) and surplus generation (blue line) is fed into the grid. At 1 s, the connection to the grid is opened and only the local load is supplied by the EUT (green line), resulting in a defined ΔP.

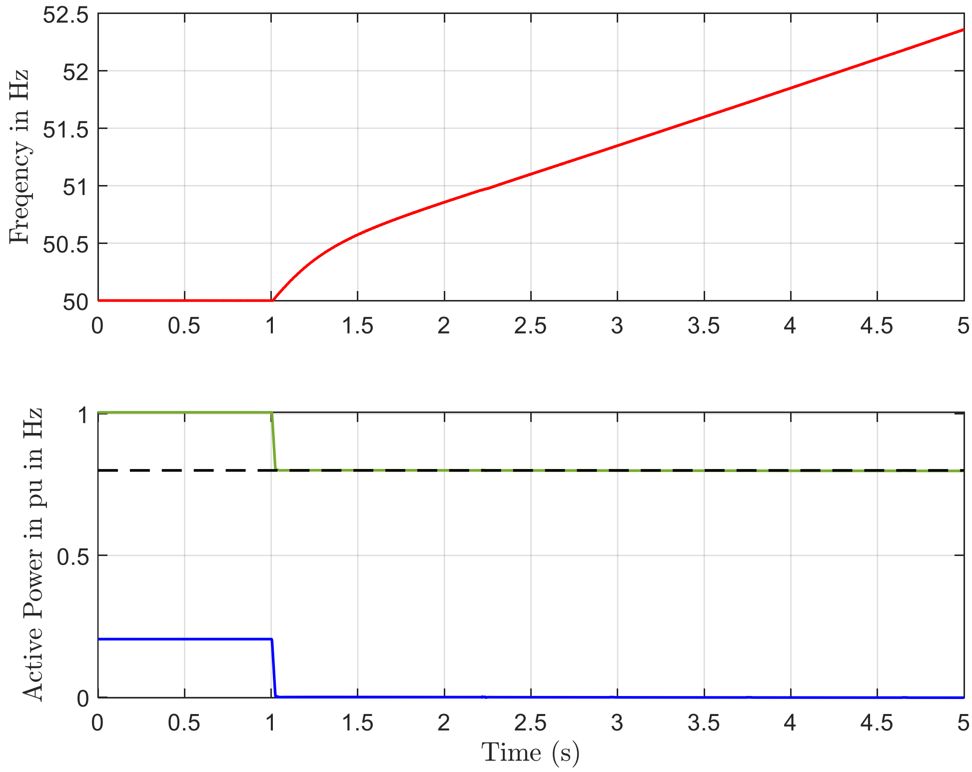

Figure 48: Virtual inertia response to a defined ΔP due to islanding with a local load

Resulting from the configured $T_{M,PPM}$,[47] the EUT continuously adapts its frequency (red line), resulting in a RoCoF. Based on Figure 48, the mechanical starting time is calculated using equation (6):

$$T_{M,PPM} = \frac{\Delta p_{pu}}{\left(\frac{df_{pu}}{dt}\right)} = \frac{0{,}2}{\frac{0{,}5Hz/s}{50Hz}} = 20s$$

[47] *For better readability, a value of $T_{M,PPM}$ = 20 s has been selected in this case.*

Appendix G. Stakeholders' deviating positions

G.1 CENELEC

TC8X WG03, appointed from CENELEC to represent it in TG GFC, agrees with the technical contents of this TG GFC report.

However, we must emphasize that the text is not able to provide the needed degree of technical details to allow an effective harmonization in Europe, as it clearly appeared during the discussion. The text as it poses the risk that national implementations deviate significantly hindering the common market of goods and requiring manufacturers to develop and certify many different control characteristics while a single development with an adequate flexibility could provide for all system needs. The approach of national implementation of the NC RfG in 2016 resulted in many national solutions and was therefore undermining harmonization and a common market and rendering it difficult to any RSO to perform the correct simulations necessary to take consequent decisions.

To avoid a further differentiation of national requirements, especially for technically challenging items such as GFM, the application of international and European standards must become the principle in all Member States and national implementations deviating from or exceeding European standards must become the exception.

WG03 is heavily involved in the GFM issue and actively contributed to the report with a huge effort, working in parallel on standards defining missing details; therefore, documents will result, at the end, completely aligned with this final report and more or less time synchronized.

WG03 working program already foresees additional documents so as to cover completely all the involved issues, features and capabilities and compliance tests, with the due level of details.

Therefore, the reference to standardization in the Article 7 of the draft NC RfG 2.0 needs to be strengthened, and standards must not only be "considered" but also must be "applied" and deviations from European standards must be reasoned and should only be accepted by National Regulatory Authorities (NRAs) if technically not avoidable.

It is already best practice in the single market of the EU that harmonized standards are used to provide presumption of conformity with EU Directives and Regulations. Close alignment between European standardisation organisations and the EC namely DG GROW ensure best support of standards to EU Directives and Regulations. To foster from the experience gained in the single market also for the grid connection regulation, CENELEC requests to invite DG GROW as permanent member into the European stakeholder committee - grid connection.

G.2 SolarPower Europe

The report is an important step toward harmonised implementation of NC RfG 2.0 and, with further clarification, can support the integration of inverter-based, renewable energy resources to strengthen grid stability across Europe. Despite the value of harmonised EU-wide requirements, SolarPower Europe's position remains unchanged: mandatory deployment of GFM inverters should not be pursued. Instead, GFM and inertia services should be procured transparently, through competitive markets, in line with the Electricity Directive (EU) 2019/944. Compliance frameworks should define only the required capabilities based on performance criteria without prescribing control architectures and consider technology readiness, while remaining technology-agnostic within the same Technology Readiness Level (TRL), ensuring cost efficiency and fostering innovation.

G.2.1 Relevant considerations

- **PV-only systems:** can provide continuous voltage control and fast LFSM-Overfrequency. However, their active power–related GFM capabilities remain limited for now and could be further explored on a voluntary, market-based basis. Acceptance criteria should be treated as development targets and updated based on operational experience.

- **BESS (Battery Energy Storage System) capabilities:** GFM batteries now compete directly with TSO-owned technologies like synchronous condensers and e-STATCOMs (Static Synchronous Compensator), requiring safeguards to ensure fair treatment. Market-based procurement of inertia offers key benefits, as demonstrated in Australia market, including fair compensation via capacity mechanisms when dedicated capacity is reserved. BESS inverters connected at all voltages, both in front of and behind the meter, should be recognised for GFM, black-start, and inertial services. With over 3 GW[48] of projects demonstrating sub-5 ms response times, TRL 9 maturity can be considered. These multi-purpose assets deliver greater societal value and can be deployed faster than single-purpose alternatives, such as synchronous condensers.

- **Hybrid PV+BESS systems (Appendix B and Appendix D):** best suited to meet GFM requirements, combining PV availability with BESS inertia and fast-response capabilities. Compliance should be assessed based on overall system performance rather than prescriptive unit level specifications. For hybrid PPMs, define maximum injection capacity and ensure plant-level voltage-source behaviour via active phase-jump current contributions is required based on this capacity value.

G.2.2 Requirements beyond the draft NC RfG 2.0

In the report, regarding Article 21(5)(b), the "additional energy" that can be required by the relevant TSO is expanded by "additional power" that has to be reserved. In combination with the RoCoF profile given (Figure 4) and without an indication, what reasonable ranges of inertia constants would be, this approach results in very large power reserves and high costs or very low realisable inertia

[48] https://www.esig.energy/working-users-groups/reliability/grid-forming/gfm-landscape/projects/

constants. Any requirement for additional storage, or for power reserves beyond the inherent capabilities, shall only be realized as part of an ancillary service in line with Directive EU 2019/944, Article 31 and 40.

G.2.3 Technical recommendations on the report

- **Technology-neutral/performance-based testing** (Section 3.5.1, Section 3.5.2 and Appendix C.1): guidance is needed for estimating internal angles from impedance and voltage. As an alternative and easier approach, the requirement could be linked to the maximum admissible effective impedance and simplified equations, following the work done in Germany under the Forum Netztechnik/Netzbetrieb (FNN).

- **Accuracy and dynamic response requirements during current limitation** (Section 2.3.3): allow flexibility under current limitation and undervoltage events. The limitation scheme implies a new kind of requirement and the associated tolerance bands are too restrictive.

- **LFSM testing** (Section 3.5.2): develop more realistic system-level methods to capture true GFM behaviour.

- **Compliance evaluation** (Chapter 3): complementary work (e.g., CENELEC) should be referenced in this report to support clearly defined test variables and success criteria to ensure consistent implementation across Europe.

- Not addressed on the report but relevant when it comes to national implementation:

    - **Active Power Overshoot (APO)** (Section 2.3.2, Section 3.4.2 and Section 3.5.2): compliance criteria should reflect natural synthetic inertia behaviour and not penalise systems that emulate inertia correctly. APO national requirements, as they are, may conflict with the new GFM requirements. One example of strict overshoot limits is Terna's laboratory tests for GFM BESS systems[49] where Test A-3.1 limits maximum overshoot to 5% of nominal power in response to 100% step changes in active power.

    - **Dynamic reactive power** (Section 2.3.1, Section 3.4.1 and Section 3.5.1): modern inverters provide faster, more flexible responses than synchronous generators. Transient behaviour of reactive power control modes in GFM will necessarily differ from traditional grid-following inverters.

[49] *https://download.terna.it/terna/Tests_guidelines_for_Grid-Forming_BESS_systems_8ddc83bc820184e.pdf*

G.3 WindEurope

GFM capabilities will be essential for contributing to power system inertia and ensuring stability in the future power system. However, changing the technical characteristics of renewables and High Voltage Direct Current (HVDC) systems is not something easily done within a few years with minor control modifications. The change will be much more profound and will need to be driven by solid industry and regulatory consensus. These upgrades will come with higher capital and operational costs, creating financial risks for developers and consumers. Full GFM capabilities from wind turbines remain several years away. Without the right market incentives to scale up clean technologies that enhance system stability, Europe risks continued reliance on fossil fuel-based systems dependent on imported gas. This would directly hinder progress toward Europe's goals of energy independence, economic competitiveness, and climate neutrality.

Effective inertia market frameworks are a way forward. System operators could build on lessons from models in Ireland, the United Kingdom, and proposals in Germany. Such frameworks would be essential to drive investment in ready-to-deploy technologies that can immediately enhance grid resilience.

WindEurope calls on the system operators to first assess and justify the need for GFM capabilities in their respective systems. Based on those assessments, they should then procure inertia services in line with EU rules rather than imposing blanket requirements on renewables. Moreover, technical parameters and rules from the ENTSO-E TG GFC report should apply only to assets participating in the market. It is also critical to ensure that harmonised EU rules are followed. Fragmenting rules across 27 countries would hinder efficient technology development.

To enable PPMs and PGUs to deliver GFM capabilities without significantly impacting the design of new generation units, supply chains, or Europe's renewable energy deployment targets, WindEurope recommends that the forthcoming IGD on GFM capabilities take the following considerations into account in context of the content of the technical report produced by TG GFC:

- **Section 2.3.1**, the technical group agreed to change "*shall have a positive real part*" to "*should have a positive real part*" in the text below. This is to read it as a recommendation and not a mandatory requirement:
  "*In addition, at frequencies above 100 Hz and up to a frequency threshold value as specified by the TSO, with the frequency threshold value being in the range of 1 kHz to 2,5kHz, the frequency dependent complex effective impedance of the PGU being installed in a type A to type D PPMs should have a positive real part. For type C and D PPMs, this recommendation should be evaluated additionally at the PoC.*"

- **Footnote 18**, for more context we suggest adding the following to the footnote: *"AC-connected offshore wind farms and large onshore wind farms connected at voltage levels of 300 kV and above may require a PCS with dual voltage levels, along with additional* *transformers. This makes it essential to ensure adequate provisions for higher effective reactance."*

- **Figure 14 on damping ratio**: Inverter Based Resources (IBR) with complex rotating machinery (like Wind Turbine Generators i.e., WTGs) may not exhibit power oscillations that follow a simple second-order system response. For this reason, it may be more practical to specify damping in terms of halving time rather than damping ratio. For example, the requirement could be defined in such a way that oscillation amplitude should have halved within 5 sec. Unlike other technologies, during a phase jump or RoCoF event, mechanical modes related to the drive train of the WTG might be excited in addition to other electrical and control modes. As a result, the shape of the active power oscillations might include different frequency components which make the damping ratio assessment more difficult.

- **Section 2.3.2 on the synthetic inertia contribution within capability limits** on the text: *"The relevant TSO, in coordination with the RSO shall specify the mechanical starting time of PPM."*

    - Suggested change: *"The relevant TSO, in coordination with the RSO shall specify the **minimum** mechanical starting time of the PPM**. This minimum capability must be available to achieve compliance; exceedance of this minimum value is allowed at any time.**"*

    - National decisions on synthetic inertia contribution should be guided by socio-economic impact. Connection requirements must clearly define the necessary capabilities, and regulations should holistically address how these capabilities are to be utilized. However, for procuring synthetic inertia services, market-based schemes should be prioritized wherever possible.

- **Section 2.3.3 when reaching current capability**: considering the theoretical framework used to explain the current response of voltage sources in this report, it seems there is no feasible alternative to the proposed variation of effective reactance to ensure constant short-circuit current angle during current limiting mode. Therefore, it is believed that the requirement is prescribing a control method. It is crucial to note that for certain PGUs, the current limiting approach may differ from the guidance provided in Section 2.3.3. This deviation may be necessary to respect other design constraints such as mechanical loads, control stability, or hardware utilisation to implement grid-forming control within the capabilities of the existing PGU design. Additionally, it may not be prudent to define such a specific way of limiting current when GFM technology and expertise has not reached a sufficient degree of maturity to be certain that this feature is a prerequisite for grid stability[50].

- **On using the term "*instantaneous*" in the report**: the paragraphs requesting an "*instantaneous*" reaction are considered as undefined requirements unless when accompanied by further criteria defining quantitatively what instantaneous means. For

[50] *For further reading, following paper can be referred: https://www.sciencedirect.com/science/article/pii/S1364032124003836*

instance, in Section 2.3.3: "*In response to a grid-side disturbance, the instantaneous active/reactive current or power variation shall reach no less than 90% of its expected value within 10 ms.*"

- **Tests on self-recovery from current limitation and closed loop stability**: the tests "*self-recovery from current limitation*" and "*closed loop stability*" are not necessary to demonstrate compliance with the GFM capabilities as defined under Article Y(7) of ACER's recommended amendment to the NC RfG, as GFM capabilities as per draft NC RfG 2.0 do not include island operation. These tests should only be required for PGMs explicitly designated for island operation, as per Article 15(4)(b).

- **Figure 13**: to avoid reaching limits during the assessment of the synthetic inertia provision under frequency events, OEMs should be allowed to propose values for the parameters defining the frequency variation profile in Figure 13: *T0, T1,T2,T3,T4,T5, fmax, fmin*.

- **Impedance spectroscopy**: testing a whole PGU using a grid emulator in a lab environment poses remarkable challenges due to the size of WTGs. Instead, it will be more suitable to only allow to include the electrical interface and controls of the PGU as EUT. This approach should also be followed in all other tests where due to practical limitations the entire WTG cannot be tested in a lab environment.

G.4 Energy Storage Europe Association

Energy Storage Europe Association, the European Association for Storage of Energy, welcomes ENTSO-E’s Technical Report on Grid Forming Capability of Power Park Modules, highly valuable for the technical challenges related to the deployment of ESUs in PPMs. The draft frames GFM requirements for PPMs, with **limited details on technical framework tailored for energy storage systems, in particular BESS**, duration limits, or cycling constraints, which critically influence inertia and stability service delivery.

The Energy Storage Europe Association therefore **endorses ENTSO-E's technical paper** as it aligns with our mission to support energy storage deployment for a cost-effective, resilient, and climate-neutral energy transition.

Generally, the Energy Storage Europe Association considers the ENTSO-E report as an insightful tool not only in identifying which GFM capabilities must be met to comply with future EU grid needs, but also in setting a framework for TSOs to account for European stakeholders, including energy storage providers, in assessing and delivering GFM capabilities.

However, the Energy Storage Europe Association sees this report as a **starting point** for further analysis **of the types of storage units that support the development of PPMs with GFM capabilities**.

More specifically, even if the ENTSO-E report acknowledges the importance of including storage module units, it does not differentiate between **batteries and other inverter-based technologies**. Consequently, the specific strengths of **different** storage solutions in providing GFM capabilities are only partially reflected.

This can be detected in the framework of the **recognition of ESMs** in contributing to limiting the transient frequency deviation under low-frequency conditions for GFM. Indeed, both BESS and other energy storage technologies have been proven to support frequency under low-frequency conditions, even if with various and different applications.

Nevertheless, **the Energy Storage Europe Association welcomes the inclusion of storage modules in providing this capability**, highlighting the role of storage in stabilising grid frequency, due to their fast response in rapidly injecting or absorbing power.

Accordingly, ENTSO-E's future IGD should take into account various characteristics related to energy storage systems, aiming to ensure that energy storage systems contribute at their best to the **future needs of PPMs**, thereby achieving European energy security.

Finally, the Energy Storage Europe Association, in its endorsement of the above-mentioned technical paper, would like to highlight the importance of including all interested stakeholders in the **drafting of IGDs**, to achieve the highest and most comprehensive possible contribution to the following implementation steps.