



Recommended Specification for Grid-Forming Inverters

Submitted by

Energynautics GmbH
Robert-Bosch-Straße 7
64293 Darmstadt, Germany
Phone: +49 6151 785 81 06

Authors

Daniel Masendorf, d.masendorf@energynautics.com, Energynautics GmbH

Reviewed by

Nis Martensen, n.martensen@energynautics.com, Energynautics GmbH
Jan-David Schmidt, j.d.schmidt@energynautics.com, Energynautics GmbH

Version: 1.0

27 February 2026



This report was developed in the frame of the EU4SustainableCentralAsia: Renewable Energy in Central Asia (EURECA) Regional Project through a Leveraged Partnership with GET.transform. EURECA is commissioned by the German Federal Ministry for Economic Cooperation and Development (BMZ) and co-financed by the European Union (EU).

GET.transform is a technical assistance programme supporting national and regional partners and institutions in advancing their energy sector transformations. GET.transform is part of the European multi-donor platform Global Energy Transformation Programme (GET.pro), and supported by the European Union, Germany, Norway, the Netherlands, Sweden and Austria.

Under its *Leveraged Partnerships*, GET.transform lends its advisory services to other European-funded technical assistance projects implemented by GIZ. GET.transform thereby increases its reach and capacity to mainstream and scale-up power system transformation solutions. www.get-transform.eu

Table of Contents

Preamble	5
1 Technical Requirements	6
1.1 Introduction	6
1.2 Voltage Source Behaviour	7
1.3 Inertial response	11
1.4 Weak grid operation and operation without synchronous machines	12
1.5 Damping	13
1.6 Fault Ride Through and operation when reaching current limits	15
1.7 Response to frequency deviations	17
1.8 Reactive power control	19
1.9 Operational constraints	20
1.10 Additional requirements	22
2 Modelling Requirements	23
3 Verification Tests	25
3.1 Test setup	26
3.2 Evaluation	27
3.3 Phase Angle Jumps	28
3.4 Small Voltage Disturbances	29
3.5 Response to ROCOF	31
3.6 Fault Ride Through and decreasing system strength	33
3.7 Loss of grid connection	35
4 Glossary	37
5 References	39
6 Annex	40
6.1 Determination of instantaneous values	40
6.2 Explanation of response time and damping ratio	42

List of Figures

Figure 1-1: Current limitation requirement reducing the unlimited current phasor to a current phasor within the current capability [2]	17
Figure 1-2: Illustrative example for active power during LFSM. The droops and thresholds for over- and underfrequency can be set separately [6]	19
Figure 3-1: Testbench 1 for tests in grid connected mode, source: [13]	27
Figure 3-2: Testbench 2 for tests in island mode, source: [13]	27
Figure 3-3: Illustration of the tests for inertia. The evaluation for $TA < 10s$ is shown. Source: [6]	32
Figure 6-1: Illustration of response time and relevant quantities for calculation of the damping ratio	42
Figure 6-2: Example response after which the relevant quantity settles again at the initial value	43

Preamble

This document serves as recommended technical specification for grid-forming (GFM) inverters connected to a power system. It was originally developed for the Kazakh system operator KEGOC, but it can be applied in any power system. It includes technical requirements for GFM inverters and tests for verifying the grid-forming capability. It is best applicable for application to utility-scale battery energy storage systems. However, it does not include any requirements regarding which individual facilities should be grid-forming. This has to be decided separately, e.g., through mandatory requirements or a market approach.

The chapter structure of this document can be transferred to a new document without modification. Each chapter of this document consists of two parts: First, a box with notes includes further explanations or recommendations on the chapter, including a summary of the international best practices. Then, a proposed specification text is provided, which can either be transferred to the Kazakh or any other technical grid-forming specification or used as orientation for drafting a new standard. Certain parameters such as response times and minimum current values in pu still need to be defined by the relevant authorities for their specific case. Suggested values for these parameters, based on international best practices, are included in **bold orange**.

The content of this document is based on a previously conducted review of international best practices [1], which includes further analyses of the existing specifications from other countries and recommendations on important aspects for drafting GFM requirements. Following these recommendations, the present specification includes **qualitative, quantitative and dynamic** requirements in each chapter. Clear requirements including specific numbers are beneficial for both system operators and manufacturers, because system operators are fully informed about the performance they receive and it enables manufacturers to assess by themselves if they can fulfil the requirements. The requirements as well as the verification tests have been drafted with the underlying objective that they should be as detailed as necessary, but as simple as possible.

In some of the analysed documents a description of GFM inverters in the frequency domain is included [3][13]. To communicate the GFM concept in a clear manner, the present document only includes a time domain description of the GFM behaviour.

Key messages of the proposed specification are:

- Grid-forming is what happens in the first moments after an event in the grid.
- The requirements and tests apply for inverter based units, not for power plants.
- Grid-forming requirements and verification tests are required in addition to already existing requirements and tests.
- Compliance can be verified with validated EMT simulation models or measurements.

1 Technical Requirements

1.1 Introduction

Notes

This specification assumes that there are already other technical requirements for grid-following (GFL) inverters or generators. The requirements below apply in addition to these already existing requirements. That means any existing requirements still apply to GFM inverters, together with the additional requirements described here. It could be worth including references to the relevant chapters of the existing rules in the GFM document. In some cases, the requirements of the existing rules might be overwritten. In these cases, this specification should be modified to point out which chapters of the existing requirements are superseded by this document.

The introduction should include information on the scope of this document. It should be noted that the requirements in this draft specification only apply to batteries, but other inverter-based resources can choose to fulfil them, or parts of them, on a voluntary basis. In the UNIFI document, different “tiers” of GFM inverters are defined, which also includes renewables and STATCOMs [13]. The extent of the requirements depends on the tier of the inverter. This is not included in detail in this document, since the focus is on GFM batteries.

This specification describes requirements for all grid-forming inverters connected to the **[Kazakh]** grid. Battery inverters **[with a rating above 10 MW/ that take part in the GFM market/ inertia market/ that are voluntarily grid-forming/ installed with renewable power plants with rated power above 30 MW/ in a certain region/ above a certain voltage level/ ...]** have to comply with the here described specifications. For other inverter based resources, e.g. renewable power plants or STATCOMs, there is no mandatory requirement to be grid-forming, but they can voluntarily fulfil the requirements or parts of it.

This document includes the technical requirements for GFM inverters as well as a description of tests, including success criteria to prove the compliance with the requirements. The requirements are additional requirements to the already existing requirements for all inverters. Consequently, the requirements of **[grid code, chapters 1,2,3...]** have to be fulfilled as well. In case of contradiction the requirements of the present document apply.

1.2 Voltage Source Behaviour

Notes

The first paragraph in the following text is derived from the Australian specification [3]. Similar paragraphs about voltage source behaviour, especially nearly constant voltage within a short timeframe, are found in almost all analysed documents. Compared to [3] “positive sequence” and “mainly inductive” were added. To avoid ambiguity, the “subtransient” timeframe is mentioned in addition to the transient timeframe. Definitions of “subtransient” and “transient” are provided in the Glossary. Besides, the restriction “while in normal operation” was removed. In contrast to that, in the second paragraph the requirement from Germany [6] was included, which explicitly mentions that GFM behaviour is also required when reaching current limits.

To avoid ambiguity, the text is appended with some details that are missing in other documents. A sentence for clarification of quantitative requirements that exceed the current capability is added. Another sentence is added for clarification of the dynamic requirements. Finally, it is clarified that the requirements apply to the terminals of a GFM unit and not the grid connection point of the power plant, as specified as well e.g. by ENTSOE-E and in the German specification [2][6]. In some documents, e.g. from Chile and Australia, the term “plant” is used, but no definition of the term plant is given. The UK grid code applies to grid-forming “plants” as well [7]. Typically the term “plant” refers to the whole power plant, that consists of multiple “units”, lines and transformers. It is not advised to define GFM behaviour at the terminals of a power plant, because the plant behaviour is usually determined through the coordination of multiple units. But GFM behaviour is determined through the reaction of a unit in the first moment after an event, without any coordination. Besides, there could be plants which consist of a combination of GFM and GFL units and consequently, the GFM behaviour cannot be defined at the plant terminals.

A GFM inverter behaves like a positive sequence voltage source behind a mainly inductive impedance. Its main control objective in the sub-cycle timeframe is to control its voltage waveform, as opposed to a grid-following (GFL) inverter, which controls its output current as the main objective. The magnitude and phase angle of the internal voltage source should remain nearly constant within the subtransient to beginning of transient timeframe following a disturbance. This is essential for providing the GFM inverter with capabilities like instantaneous active and reactive power response when a disturbance occurs.

The voltage source behaviour of a GFM unit is a permanent and fundamental characteristic which shall be maintained even when running into current limitation. More details on the behaviour, when reaching the current limit are described in chapter 1.6.

Each of the dynamic and quantitative requirements apply to instantaneous values in alpha beta coordinates, which are calculated with a Clarke transformation as described in annex 6.1. Since GFM behaviour happens in the subtransient timeframe, shorter than one period, requirements and evaluation of RMS quantities is not reasonable, because the determination of RMS quantities includes an inherent filter of one period.

Each of the quantitative requirements in the following chapters only applies within the current limits of the inverter. If the quantitative requirement would lead to an exceedance of the maximum inverter current, the current can be reduced accordingly.

Each of the requirements in this document applies to the terminals of a GFM unit and not to the grid connection point of a power plant.

1.2.1 Reaction to voltage phase angle steps

Notes

The inherent response of a voltage source behind a mainly inductive impedance to a voltage phase angle step is an active current step. Hence, the main objective of this chapter is to quantify how much active current is required and in which time.

Not all analysed documents include these details. In the Australian standard and its derivatives of Texas, Chile and MISO, the quantitative and dynamic requirements are given in the success criteria of the compliance tests. An active current response of 0.2 pu per 10° angle step is required [4][14][5][10]. In the German specification and in the European guideline from ENTSO-E [6][2], the requirement is based on the formula below (assuming an inductive impedance with negligible resistance):

$$\Delta i_{p1} \approx -\frac{1}{x_{eff}} (\sin(\delta_{pre}) - \sin(\delta_{post}))$$

Where Δi_{p1} is the theoretical change in positive sequence active current for a grid voltage angle step from δ_{pre} to δ_{post} , x_{eff} is the effective reactance, consisting of physical impedance and potential virtual impedance in the controls. In both documents, a minimum response of 50 % of Δi_{p1} is required [2][1][6]. With this approach, the specific response depends on the x_{eff} and hence could be different for different inverters. With a value of 0.43 pu for x_{eff} , the magnitude $0.5 \cdot \Delta i_{p1}$ is approximately 0.2 pu/10°, which is the value for power (not current!) required by [14] and others. However, at the LV terminals of a GFM inverter in the European guidelines, a maximum

inductance of 0.27 pu is allowed, which leads to higher currents. Consequently, the requirements from Germany and ENTSO-E are stricter.

For the sake of simplicity the Australian approach is suggested here. The exact value of required current can be adjusted based on the needs of the relevant power system. It should be kept in mind that this requirement assumes a linear relation between Δi_{p1} and the angle step, which is only true for small angle steps. In the Australian tests, angle steps of up to 60° are required. However, this is considered unrealistically high by Texas, MISO and UNIFI [14][10][13]. Consequently, the tested angle steps are reduced to 25°, there. Denmark requires GFM units to withstand angles steps of up to 40° [9] and Finland tests steps with 30° [12]. In the present specification a maximum voltage angle step is included, above which the requirements are less strict.

The dynamic requirements for the response time vary between 10 ms and 16.67 ms (one cycle in a 60 Hz system) in the above mentioned specifications. In the Danish document a response time of up to 30 ms is allowed, which is too high [9]. Probably this value refers to an RMS quantity, but it is not clearly stated.

The requirement for the damping ratio is discussed separately in chapter 1.5.

An angle step of the grid voltage in positive or negative direction inherently results in an active current response of a GFM inverter. The resulting additional active current peak must be at least **0.2 pu** based on the rated current per **10°** angle step for angle steps of up to **30°**. Above this value, the current should still increase with increasing steps, but no specific values are required.

The response time to **90 %** of the initial change must be **15 ms** or lower. The damping ratio for any active power oscillations following the response must be at least **0.45**, as also described in chapter 1.5.

1.2.2 Reaction to voltage magnitude steps

Notes

Just like the reaction to voltage phase angle steps, the reaction to voltage magnitude steps is an inherent property of a GFM inverter, since the reactive current follows the equation [6]:

$$i_Q \approx \frac{1}{x_w} (u_{\text{grid}} - u_{\text{int}} \cdot \cos(\delta))$$

In the equation, i_Q is the reactive current, x_w is the effective impedance, u_{grid} and u_{int} are the voltage magnitudes of the grid voltage and the internal voltage of the GFM inverter and δ is the angle between these voltages.

In the analysed specifications, the response to magnitude steps is described less detailed than the response to angle steps. In the specifications from Australia, Chile, and MISO, in which the details of the expected behaviour is only included in the tests, there is no test for small voltage steps [4][5][10]. This lack was recognised in the Texan and UNIFI specifications and a test for small voltage steps was added there, including minimum requirements for reactive current [14][13]. A reaction of 3 % rated power for a 3 % voltage step is expected with a response time of 1 cycle. Again, in these set of standards, a reaction of power is required, while the European guidelines describe the reaction of currents.

In the German specification, there are requirements for response time (10 ms) and settling time (60 ms) of the resulting currents following a voltage magnitude step, but there are no requirements for a minimum current [6]. The Finnish specification verifies the grid-forming behaviour mainly through tests of voltage magnitude steps, but the required minimum response time with 1 s is significantly too high [12].

The most detailed requirements regarding voltage magnitude steps are the Danish ones [9]. There, the response of reactive current should be double the percentage of rated current compared to the voltage step, e.g. 10 % additional reactive current for a voltage step of 5 %. However, similarly to the phase angle steps, the response time is 30 ms, which is too high. Another important aspect of the Danish requirements is that it also emphasises that negative sequence reactive currents are expected for negative sequence voltage steps.

With the above considerations, the following text is suggested, mainly based on the specifications from Texas, Denmark and Germany. The dynamic requirements are similar to the ones for phase angle steps.

The requirement for the damping ratio is discussed separately in chapter 1.5.

A magnitude step of the positive or negative sequence voltage in positive or negative direction inherently results in a reactive current response of a GFM inverter. The resulting additional reactive current peak must be at least **the same pu value** (based on rated current) like the magnitude step of voltage in pu That means e.g. a positive sequence voltage magnitude step of **0.03 pu** results in a positive sequence reactive current step of at least **0.03 pu** based on rated current. The requirement

for negative sequence reactive current to negative sequence voltage steps is equivalent. This requirement applies over the complete voltage range.

The response time to **90 %** of the initial change must be **15 ms** or lower. The damping ratio for any reactive current oscillations following the response must be at least **0.3**, as also described in chapter 1.5. The response time applies to the reactive current magnitude in alpha beta coordinates and hence can be evaluated for balanced and unbalanced faults in the same manner.

After a step of the voltage phase angle, the active power will settle at its initial value again. However, after a step of the grid voltage magnitude, the reactive power will might settle at a different value than before the event, depending on the outer control loops. The reactive power control requirements are described in chapter 1.8.

1.3 Inertial response

Notes

The inertial response is the response of a GFM inverter to a changing frequency. The higher the rate of change of frequency (ROCOF), the higher the active current response. This capability is not inherent to the voltage source behaviour as described in chapter 1.2, because this describes mainly the behaviour in the subtransient timeframe, while changing frequency happens in the subtransient and transient timeframe.

In theory it is possible to program arbitrary inertia constants in the controls of a GFM inverter. A large inertia constant is desirable because it contributes to system strengths. However, the larger the inertia constants, the larger is the current due to changing frequency. If the resulting current reference exceeds the inverter capability, it will get limited and consequently the set inertia constant will not be effective. Hence, there is a range for reasonable inertia constants.

It is important to be aware that an inertial response cannot be delivered, when the inverter is already at or close to its current limits. Consequently, the inertia constant should be determined carefully under consideration of the planned or allowed operation points.

Almost all analysed standards require inertia from GFM inverters. Texas requests a minimum constant H of 2.5 s ($H = 0.5 \cdot T$). T is the start-up time constant, which is used in most documents. Denmark requires a T between 0 and 25 s and Germany only specifies a maximum start-up time constant of 25 s and created a market for inertia [14][9][6].

The inertia is specified through the start-up time constant T , which is defined as the active power change for a given rate of change of frequency (ROCOF). In the following formula, the active power change Δp is in pu and the ROCOF df/dt is in pu/s. The unit of T is seconds:

$$T = \frac{\Delta p}{\frac{df}{dt}}$$

The maximum ROCOF that power plants are required to withstand in the grid is **+/-2 Hz/s = 0.04 pu/s**. Assuming no overcurrent capability, the maximum power that an inverter can deliver is 1 pu. Using this value for Δp and the maximum ROCOF in the above formula, the theoretical maximal inertia constant is **25 s**. However, this inertia can only be delivered for the maximal ROCOF, if the inverter is operated at zero power, prior to a frequency event.

The start-up time constant of a GFM inverter must be **between 2.5 and 25 s**. The system operator reserves the right to request project specific start-up time constants from GFM inverters. The operational constraints given in chapter 1.9 depend on the inertia constant and must be considered. GFM inverters must deliver the resulting active power corresponding to the set inertia constant for all ROCOFs below the maximum value in positive and negative direction.

The inertia constant according to above equation the start-up time constant T must be maintained at all times. The corresponding active power resulting from a frequency change shall be delivered as fast as possible, but at least fast enough to fulfil the dynamic requirements given in the verification test of chapter 3.5.

1.4 Weak grid operation and operation without synchronous machines

Notes

The capability to operate in island mode without any synchronous machines is a fundamental difference between GFM and GFL inverters. Consequently, this is mentioned in almost all GFM specifications. On the other hand GFM inverters must still be able to run in grid connected mode in parallel with other GFM inverters, GFL inverters, or synchronous machines. In most GFM specifications the operation in weak grids and island modes is emphasized. However, of course operation in strong grids is necessary as well, although not mentioned explicitly.

The following text suggestion is loosely based on the Chilean requirements [5]. The wording "short circuit level of zero MVA" stems from the British grid code [7].

GFM Inverter Based Resources (IBR) shall operate stably when connected to a grid of any short circuit ratio (SCR), including weak systems, i.e. with low SCR. The extreme case is an island grid, i.e. a short circuit ratio of zero.

GFM IBRs shall be capable of operating stably during island operation conditions or after the disconnection of the last available synchronous machine on the grid, continuing to provide the GFM capabilities required by this document, as long as the inverter limits are not exceeded. GFM IBRs shall transition smoothly and stably, without disconnection from grid operation to island operation and vice versa.

GFM inverters must be able to operate stably in stand-alone as well together with any combination of other generators, e.g. synchronous generators, GFM inverters or GFL inverters.

Caution: Since GFM inverters are able to operate in island mode, parts of the grid that are unintentionally islanded, could still be energised, when it is not expected. Staff working at the grid must be extremely cautious and strictly follow all security rules!

1.5 Damping

Notes

In most GFM specifications damping is mentioned in two contexts. On the one hand, the response to disturbances must be damped, on the other hand, GFM inverters should provide positive damping to network oscillations [3].

However, regarding the frequencies of network oscillations, for which positive damping is required, there is a discrepancy between the different documents. There is a consensus about damping of sub-synchronous oscillations, but there are different requirements for harmonic oscillations. In Germany a minimum damping for power frequency oscillation between 0.05 Hz and 10 Hz is required. For frequencies above 10 Hz and below 1 kHz, positive damping is required, but no minimum damping ratio is specified [6]. In Australia, damping of sub-synchronous frequencies is required and it is explained that damping of harmonic voltages leads to harmonic currents, which impact the load on the inverters [3]. Chile requires “non-negative” damping between 0.1 Hz and several kHz [5]. Non-negative means zero damping is acceptable as well. In the present document positive damping for sub-synchronous oscillations is required, because this is inherent to the basic GFM behaviour to maintain a constant voltage phasor in the first moments after an event. For harmonic oscillations, the two options positive or non-negative damping are included.

For damping following disturbances, some GFM specifications, e.g., from Chile and Texas, do not specify a certain value for the damping or use vague wording, such as “adequately damped” or “should not oscillate excessively” [5][14]. This approach is not recommended, since it leaves room for interpretation. Australia refers to the general grid code. There, specific damping ratios depending on the frequency are given [3].

Denmark does not consider the damping for responses to events, such as voltage angle or magnitude steps. Instead, it uses the settling time, which is also appropriate. However, they do not specify maximum numbers, but instead mention that the behaviour must be coordinated with the system operator. This is also not advised since it leads to additional effort for each project [9].

In the European document by ENTSO-E, it is recommended that the TSO specifies a damping value [2][1]. This advice has been followed by the German specifications. There, specific numbers for the minimum damping ratio are given together with an explanation how to evaluate the damping [6]. Since the German specifications include the most sophisticated approach, the recommendations of the present document are based on the German requirements. In the present document, different damping ratios for different quantities and situations are required, the same way as in Germany.

When specifying a minimum damping factor, it should be kept in mind that a high damping is contradictive to a fast and large response to events, such as voltage magnitude or angle steps. Consequently, the tuning of the GFM controls is a trade-off between a highly damped response and a large and fast response.

Positive damping must be provided for all sub-synchronous oscillations from the grid side and oscillations following disturbances. For harmonic oscillations up **[to several kHz] [non-negative damping/ positive damping]** must be provided.

For the damping ratio D_p of power frequency oscillations (as defined in Annex 6.2), without the influence of possible upstream controls, such as limited frequency sensitive mode (LFSM), e.g. following a phase angle step, the following minimum requirement applies for frequencies **below 10 Hz** and a **SCR above 3**:

$$D_p \geq 0.45$$

During island operation the frequency is stabilized through droop control as described in chapter 1.7. In this case, the damping ratio of frequency oscillations must be at least:

$$D_{f,LFSM} \geq 0.2$$

Similarly, the reactive power (current) must be damped. For the damping ratio D_{iQ} of the reactive current, e.g. following a voltage magnitude step, the following minimum requirement applies in all grid conditions:

$$D_{iQ} \geq 0.3$$

1.6 Fault Ride Through and operation when reaching current limits

Notes

Most frameworks mandate that GFM BESS must ride through grid faults (FRT), i.e., they need to stay connected to the grid. This is not a unique requirement for GFM inverters, but should be requested from all kinds of generators. The Australian specification and MISO do not mention FRT capability in the GFM requirements, but for the verification of GFM behaviour voltage dip tests are specified [3][4][10]. In the success criteria, there is no requirement except that active and reactive power are “well controlled” and the plant should not trip. This description is not advised, since it leaves a lot of room for interpretation. ERCOT and UNIFI add the requirement, that oscillations must be damped [13][14].

The active power recovery after a fault is not described in detail in most GFM specifications. The documents mentioned above mostly state that the power should not be reduced for “any extended period”. This is too vague. Consequently, UNIFI and Germany require active power recovery within 1 s after a fault [13][6]. As mentioned in chapter 1.5, a balance between a fast and a damped response must be found.

In Great Britain and Denmark an additional reactive current, proportional to the voltage dip shall be injected during the fault [9][7]. In Denmark, the proportional reaction is always required, not only during faults. In the Chilean requirements it is mentioned that the GFM inverter should maintain a balanced internal voltage source [5]. No additional requirements are specified in the Finnish Grid Code specifications [12]. In principle, it is not necessary to request reactive current contribution during FRT, since this happens inherently, as described in chapter 1.2.2. Consequently, no such requirements are specified in the German specification and European guidelines [2][6]. UNIFI does not specify a prescriptive fault current performance due to lack of experience in the industry [13].

The European, Danish and German requirements are the most detailed ones [2][6][9]. There, it is specified that no current component (neither reactive or active current nor positive or negative sequence) should be prioritised, when the current limit is reached. Instead, the magnitude of the current should be limited and the priority is to continue operating as a voltage source, when

reaching current limits. According to Annex C.2 of [2], the prioritisation of a current component resembles GFL behaviour, which is undesired. In addition, maintaining an active current component (and not reducing it to zero for the sake of more reactive current, as typical for GFL inverters) has further advantages, such as easier resynchronisation after a fault and more contribution to frequency stability.

In Germany, current clipping is only allowed for maximally 40 ms. Those are general requirements, which not only apply to FRT [6].

The requirements below are mainly based on the German and European requirements [2][6].

GFM inverters must be able to ride through balanced and unbalanced faults (Fault-Ride-Through, FRT) as specified in **[the relevant grid code]**. That means they must not trip for the same voltage dips and voltage swells for the same duration as GFL inverters.

During FRT and in all other situations GFM inverters must maintain the voltage source behaviour as specified in this document. This results in a current opposing the voltage dip or swell as described in chapter 1.2. For unbalanced faults, inherently negative sequence currents will flow, because the internal voltage source stays a positive sequence voltage.

When the current limit is reached during FRT or any other situation, which leads to reaching the current limit, the GFM inverter must maintain its voltage source behaviour. Current clipping is only permitted for up to **40 ms** after voltage angle steps and sudden changes in the voltage amplitude. In order to avoid persistent current clipping, it is permissible to regulate the current to **95 %** of the current at which current clipping would occur, however, at least to the **rated current**.

In case of limitation the GFM inverter shall limit the output current only by reducing the current phasor magnitude while maintaining the current phasor angle of the unlimited phasor constant. Active power priority or reactive power priority is not accepted for GFM inverters. Upon reaching current limitation, the resulting current shall reflect a proportionally scaled-down vector sum of all ideal, unconstrained current components (i.e. active and reactive, positive and negative sequence), so the total magnitude complies with the current limit (see Figure 1-1).

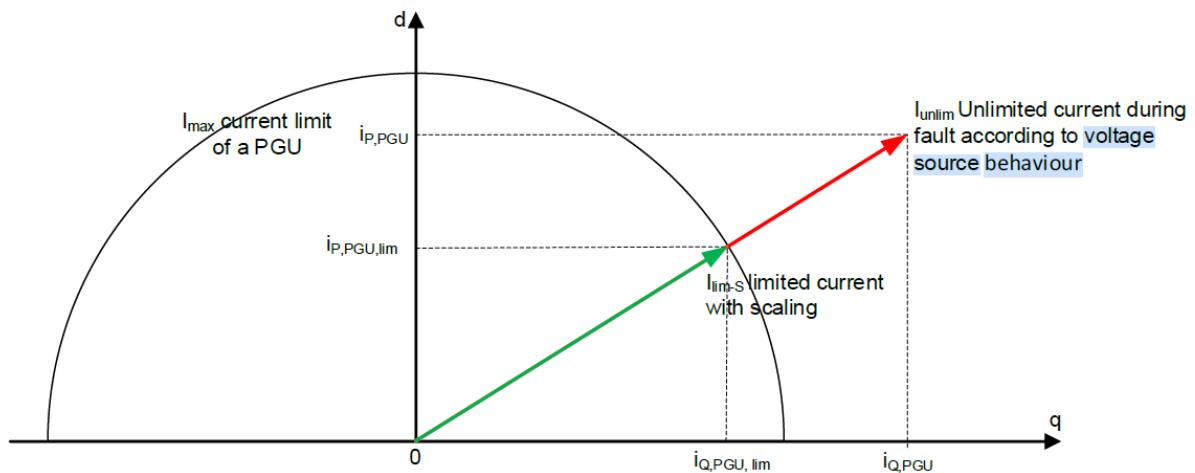


Figure 1-1: Current limitation requirement reducing the unlimited current phasor to a current phasor within the current capability [2]

If current limiting is no longer required, the grid-forming unit shall immediately switch to a new operating state without current limitation. This operating state is a result at that point in time of the respective requirements for the dynamic behaviour of the grid-forming unit. If, after a fault, the mains voltage returns to a value within the voltage range $\pm 10\%$ of the nominal voltage and the active current of the GFM inverter was reduced during the network fault, the active current shall be increased as quickly as possible immediately after the end of the fault until the pre-fault value of the active current or active power is reached (however, depending on the impact of any inertia provided). The rise time should not exceed **1 s**.

1.7 Response to frequency deviations

Notes

Through the provision of inertia, a GFM inverter inherently provides active power during changing frequency. However, without additional controls, after the frequency has settled at a different value, the active power would settle at its initial value again. Consequently, further outer control loops are required (P/f droop) to support the grid during frequency deviations and to enable island operation. In grid codes, a P/f droop is already required from GFL inverters and synchronous generators. Hence, it is no GFM specific requirement and thus not detailed in most GFM specifications. In the UNIFI specifications, it is mentioned that GFM inverters “are expected to respond to frequency adjustments by internal or external controllers to share power (droop) with other resources” [13]. The German specifications stress requirements for LFSM (limited frequency sensitive mode) most of all GFM specification documents. There, different droop settings for under

– and overfrequency are specified and an unlimited reaction speed is required, which differs from the requirements for GFL inverters [6].

Since it might be desired by the system operator to request a different LFSM behaviour than for GFL inverters and the power frequency control has significant influence on the behaviour of the GFM inverter in some of the compliance tests of chapter 3, a chapter in this report is dedicated to this requirement. The requirements are based on the German GFM specification. For determining droop values and deadbands, also the settings for GFL inverters and the needs of the grid should be taken into consideration.

Similar to GFL inverters and synchronous machines, GFM inverters have to adjust their active power to frequency deviations outside of the deadband of **+/-0.2 Hz** around nominal frequency. Outside the deadband, the active power must change linearly with changing frequency, as shown in Figure 1-2. The droop must be adjustable between **0.2 %** and **12 %**. The additional active power ΔP depending on the frequency is calculated with the formula shown in Figure 1-2. In this example, droop settings of 1.6 % and 5 % have been used. If no other values are specified, the default setting for overfrequency is **5 %** and for underfrequency is **5 %**.

The active power change due to frequency deviations has to be adapted **as fast as possible without any ramp limitation**.

The GFM inverter must stay connected to the grid for the frequency range and corresponding duration specified in **[relevant grid code]**.

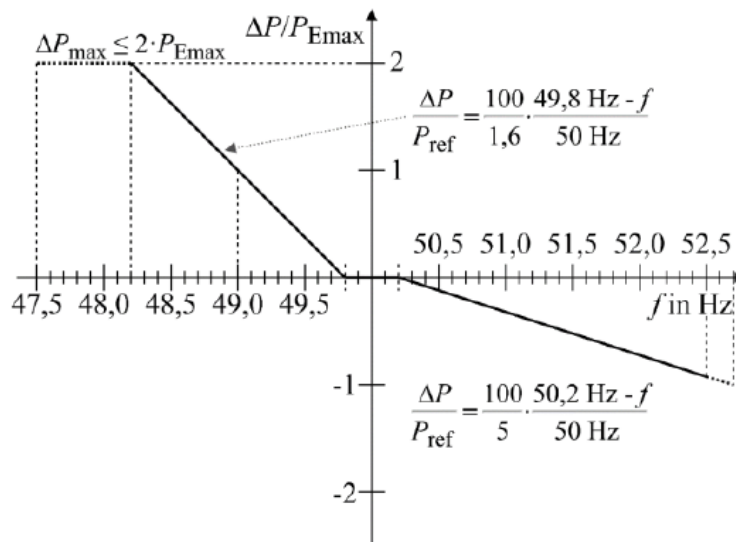


Figure 1-2: Illustrative example for active power during LFSM. The droops and thresholds for over- and underfrequency can be set separately [6]

1.8 Reactive power control

Notes

Similarly to the response to frequency deviations, described in chapter 1.7, reactive power control is no GFM specific requirement, but required from GFL inverters as well.

The requirements for reactive power control are not consistent in the different reviewed GFM specifications. The Finnish and German documents refer to the reactive power control modes of the general grid code, which also include the possibility for constant power factor or constant reactive power control [12][6]. This is not advised, because it would prevent reactive power sharing when islanded.

In all GFM specifications that build upon the test framework from AEMO [4], the Q/U droop is mentioned in the success criteria of the islanding test. In the UNIFI, MISO and Chile document, it is mentioned additionally in the requirements, that “principles of droop” should be applied[13][10][5], but no further details are specified.

The approach to require a Q/U droop is also followed in this document. Since none of the reviewed GFM specifications provides a precise specification, the following text is rather generic as well.

Similarly to the requirements for active power response to frequency deviations, a response of the reactive power reference to voltage changes is required by GFM units (Q/U droop). This is a requirement for the transient and steady state behaviour, especially relevant to achieve reactive power sharing when the grid connection is lost. For clarification: The here described requirement is not the inherent reactive power response following a voltage magnitude step in the grid (see chapter 1.2.2), but applies to outer control loops.

The system operator can request a Q control mode specified in the **[grid code]** or request a specific Q/U characteristic including requirements for slope, possible deadband, reaction time and maximum/minimum values.

1.9 Operational constraints

Notes:

The requirements on GFM behaviour can only be fulfilled, within the inverter current capabilities. I.e. if the inverter is already at its current limits it cannot increase the current in that direction to deliver the expected response described in chapter 1.2 and 1.3. However, it can still respond as required in the opposite direction of the limit. For batteries the expected limits are charging and discharging with not significantly more than rated current. Of course, it cannot always be prevented, that the inverter reaches its limits, especially not during FRT, as described in chapter 1.6.

Besides of headroom for power, the GFM device also needs to have enough energy stored and at the same time enough free storage to be able to respond to the described events in both directions. However, the required energy is significantly smaller than the required power, since for each event, power is only delivered or consumed for a short time.

Most documents do not specify allowed operation points for GFM inverters. In the Texan specification, it is mentioned that GFM inverters are not expected to operate at the limits for a notable portion of the time [14]. Similarly, the ENTSO-E guideline does not request to reserve

headroom and accepts, that in certain situations no response in the limited direction is possible [2]. This is appropriate, if the system operator is aware that the GFM service is not fully provided at all times and this does not impact the grid stability. In Australia, a discussion on the different options, (headroom, curtailment or overload capability) is included [3]. Denmark specifies that the GFM inverter must be operated in such a way that it has enough energy stored to provide inertia. This is misleading, because the provision of power is the significantly larger challenge than the provision of energy. At the same time, Denmark allows inertia constants of zero, which could lead to GFM inverters using a very small inertia constant to minimize the impact on the operation [9]. In Germany, GFM inverters are incentivised to provide headroom for inertia, because the remuneration of the inertia market increases linearly with increasing time in which the inertia is available. Below a certain threshold of availability (30 % or 90 % of the time, depending on the chosen product), no remuneration for the whole year will be paid¹.

Operational constraints should be designed carefully in conjunction with the other requirements to not achieve undesired behaviour, e.g. low inertia constants.

[By default], no operational constraints are required by GFM inverters under the assumption that the inverter will not be operated at its limits for a significant time.

However, the system operator reserves the right to request the following operational constraints from power plants. The GFM inverter must be operated at **[all times/ for 90 % of a year/ ...]** in such way that they can provide the power and energy in negative and positive directions, corresponding to the set inertia constant, for frequency changes within the frequency range and the ROCOF required by the relevant grid code **[insert numbers and references]** and chapter 1.3 of this document. GFM units can fulfil this requirement either through provision of headroom for power, overcurrent capability, oversizing of inverters and a dedicated energy buffer for GFM or through a combination of these.

In addition, the GFM plant must be capable of receiving active and reactive power setpoints from the system operator. The system operator reserves the right to request additional, project specific operation constraints.

¹ More information on the market design is available here: <https://www.netztransparenz.de/en/Ancillary-Services/Frequency-stability/Market-based-procurement-of-inertia-of-local-grid-stability>

1.10 Additional requirements

Notes

In some documents, e.g. the AEMO and UNIFI specifications [3][13], additional requirements are specified. These requirements should not be requested in general, because they imply additional constraints for the GFM batteries (see also [1]). The following text loosely orientates on the UNIFI specifications:

The system operator might ask for additional GFM capabilities to be implemented in coordination with the project developer. These requirements are no universal requirements for GFM units. If requested, they will vary from site to site and will be discussed separately. This can include (but not limited to) the following:

- Blackstart capability
- Intentional islanding
- Further mitigation of power quality issues

2 Modelling Requirements

Notes

To ensure that high quality models are submitted that are applicable for the intended use cases, a modelling guideline should exist. This is a general topic that does not only concern GFM inverters, but all kinds of generators. Models need to be capable of the simulations the system operator intends to conduct and they need to be validated with measurement data. Model validation is crucial, otherwise the simulation results are not reliable.

Since the development of the modelling guideline is out of scope of this project, only a few basic points are addressed here until a detailed guideline is drafted. Different approaches are allowed for the validation of the simulation models.

As long as the system operator has no modelling guidelines, the following rules apply:

- The system operator has the right to ask for validated RMS (Root-Mean-Square) and EMT (Electromagnetic Transient) models for the specific power plant to be connected to the system operator grid. The RMS models must be capable of unbalanced simulations. This applies to all generators, i.e. GFM and GFL inverter based generators as well as synchronous or asynchronous generators. Models of the complete **power plant** need to be delivered (including all grid elements, e.g. lines, transformers, power plant controller). The validation and compliance simulations of GFM models have to be done with a **unit** model. The system operator will potentially conduct further compliance simulations with the complete plant model or ask the manufacturer to do such simulations and document them.
- The models need to be delivered in the following software:
 - RMS models: **latest version of DigSILENT PowerFactory**
 - EMT models: **latest version of DigSILENT PowerFactory**
- To ensure high accuracy of inverter models, the real code of the unit controller has to be used and incorporated into the EMT model, as a dynamic link library (DLL). This includes as well the protections and signal processing. The DLL is recommended to be compliant with the requirements of Cigre Brochure TB 958² [16].

² The Cigre Brochure describes the usage of real controller code in simulation tools. It specifies an interface for the code to software to enable tool-independent models, that could be loaded into any simulation software. This ensures easy transferability of models between different tools and makes the models future proof for evolving software. In addition, it specifies further requirements for usability, such as the possibility to run multiple instances of the same unit in one simulation.

- The models need to be capable of dynamic simulations, such as:
 - Setpoint steps
 - Fault-Ride-Through (FRT)
 - Reaction to frequency deviations
 - Reaction to small voltage deviations
 - Models of GFM inverters need to be capable of all simulations mentioned above and the tests described in chapter 3.
- All tests described in chapter 3 have to be done with the unit models and the simulation results have to be documented in a report. All success criteria have to be evaluated and it needs to be presented if the model passes or fails.
- The models need to be validated with measurement data. Since no validation guideline for Kazakhstan exists yet, each of the following approaches is allowed:
 - For validation, the manufacturer can choose between the following options:
 - All test described in chapter 3 are done with the real equipment and replicated with the unit model. Simulation and measurement results of voltages, currents, powers and frequency of each test are plotted together and presented to the system operator for comparison. The system operator will assess the accuracy through “engineering judgment” and either accept the simulation results or ask for improvement of certain tests.
 - The models are validated according to other international standards with comparable tests, e.g. German VDE GFM specification [6] or IEEE P2800.2 [17] or others and validated as described in the used document (if described). All related documents will be provided to the system operator. Potentially, additional tests for validations will be requested.
 - Measurements for validation are done post-commissioning. In this case, only a preliminary permission for operation will be granted. Certain tests, such as setpoint steps, reaction to small voltage deviation and frequency deviation (both through manipulation of the measurement signal) have to be done during commissioning. The model needs to be validated with these tests within three months. In addition, a fault recorder needs to be installed for 5 years and a report with model validation compared with each recorded fault has to be submitted every 6 months. In case of mismatch between simulation and measurements, the model has to be improved and the compliance study needs to be repeated. In case of mismatch between model and measurements and consequently no proof of compliance, the system operator reserves the right to revoke the permission until the model is validated and compliance is proven with the validated model.
 - All documents, e.g. certificates, measurement data, simulation results, comparison of measurement and simulation data, compliance studies, etc. need to be delivered to

the system operator. The system operator will review the documents and potentially ask for additional tests or documentation.

- A comprehensive documentation is delivered, including: model description, manual, parameter settings, constraints, e.g. simulation step size, validation report as described above.

3 Verification Tests

Notes

The most popular test requirements in the analysed documents are the Australian test requirements and their derivatives [4]. The most recent and elaborated test specification of this group is the UNIFI document [13]. However, the largest deficiency of the UNIFI document is that it did not consider the European guidelines. National grid has described a series of tests, which focuses on reaction to phase jumps, ROCOF and FRT. However, no clear success criteria are formulated [8]. The Danish specification does not include verification tests, except for islanding [9]. The Finnish specification includes most relevant tests, such as small voltage step, angle steps, FRT, islanding, but no test for inertia [12]. From all European GFM specifications, the German document comprises by far the most sophisticated compliance tests [6]. Consequently, the here described verification tests are mainly based on the German and UNIFI specifications. The UNIFI tests are significantly more simple.

The proof of compliance of any grid code requirement can typically be done via simulations or measurements. As mentioned before, in case of simulations, the usage of validated models is crucial. Another small but fundamental difference is, whether the requirements are analysed at unit level or plant level. The GFM specification documents that have been used the most for drafting the present document are compared in this regard below.

	<i>ERCOT [14]</i>	<i>UNIFI [13]</i>	<i>GERMANY [6]</i>
<i>Compliance procedure</i>	<i>EMT Simulations</i>	<i>EMT Simulations</i>	<i>Measurements and simulations (RMS + EMT)</i>
<i>Model validation</i>	<i>Reference to external document</i>	<i>Reference to external document</i>	<i>Included. Tests are done in simulation and measurement and compared.</i>
<i>Point of verification</i>	<i>Plant level</i>	<i>Unit level</i>	<i>Unit level. Plant level in external document, deviation from GFL procedure described.</i>

It is remarkable that UNIFI and ERCOT require the verification at different locations, although the tests that they describe are almost identical. In the present document, the verification is done at unit level, since the requirements are also for unit level. Details about modelling and validation are out of scope of this document, some general hints are given in chapter 2. Since it is irrelevant, if the verification is done via measurements or simulations with validated models, both options are possible.

Since the technical requirements for GFM inverters apply in addition to already existing requirements for all inverters, also the verification procedure represents an addition to already existing compliance verification requirements. Consequently, the tests/ simulations of [relevant grid code, chapter 1, 2, 3...] have to be executed as well. The here described tests can be done either by simulations with validated EMT models (see chapter 2) or measurements in the laboratory or a combination of both. Since the requirements of chapter 1 refer to one generation unit, the simulations or measurements have to be done with a single unit as well. The system operator might conduct or ask for further measurements or simulations at plant level. Using measurements does not affect the system operator's right to request validated simulation models.

3.1 Test setup

Notes

Most GFM specification documents that include compliance tests feature two different test setups: one for island operation tests and one for grid-parallel tests. The figures below are taken from [13], and the description is based on the text there. The German specification includes similar test benches, with the difference that no duplicate GFM is included in the island test [6]. The advantage of including the duplicate GFM is that the capability to run in parallel with other GFMs is proven at the same time.

All tests proposed here are run using one of two simple test systems. All per-unitized quantities are defined on the basis of the IBR's rated active power. Testbench 1 (Figure 3-1) is used for all tests except for the loss of grid connection test. It uses a variable impedance $Z = R + jX$. The magnitude of Z is defined in terms of the SCR seen by the GFM unit; $|Z| = 1/SCR$, in per unit terms on the basis of the GFM unit rating. The voltage source is ideal (zero impedance) with controllable magnitude, phase and

frequency. For measurements, a grid emulator can be used. Unless otherwise specified, the frequency of the source is the nominal system frequency, and its voltage is balanced. The fault can be configured to connect two or three phases to ground through a controllable impedance. The fault can also be applied through changes of the voltage source setpoint.

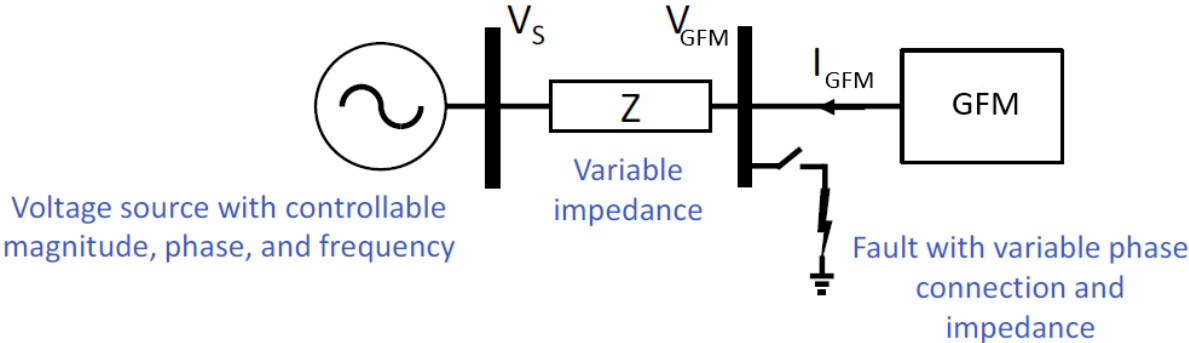


Figure 3-1: Testbench 1 for tests in grid connected mode, source: [13]

Testbench 2 (Figure 3-2) is used for the loss of grid connection test. The load has an inductive power factor of **0.95** and is a constant impedance load with an adjustable nominal power level. The duplicate GFM is a separate unit with identical controls and **same rated power** as GFM1.

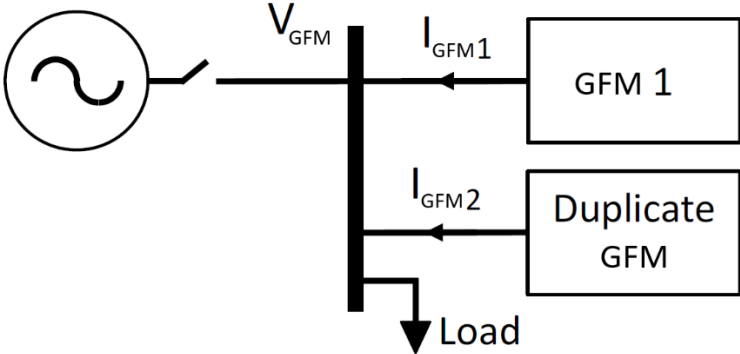


Figure 3-2: Testbench 2 for tests in island mode, source: [13]

3.2 Evaluation

For the evaluation of the success criteria, unless specified otherwise, unfiltered, instantaneous quantities have to be used, as described in 6.1.

In most of the tests, the response time and damping ratio is evaluated. The determination of these values is described in 6.2.

For the evaluation of the response time, the time at which the examined event happens is used as the reference. If this time is not clear, e.g., because the voltage first changed in one phase and then the others, the moment, when the relevant quantity in alpha beta coordinates (e.g. $|u_{\alpha\beta}|$) reaches **10 %** of the total change is used as the starting point. If measurement filtered measurement data is used for the evaluation of the response time, as described in 6.1, the acceptable response time is increased accordingly.

For each test that is done via simulation, a flat initialisation is expected.

3.3 Phase Angle Jumps

Notes

The test is copied mostly from MISO [10], which is derived from [4]. In the description by UNIFI and Texas [13][14], the tests should be initialised at maximum power, which results in reaching the current limits. This is not deemed reasonable, because the expected active power reaction cannot be seen in both direction. The initialisation at 50 % power is also in line with a similar test required by Germany [6]. Compared to [10], the evaluation is extended with an evaluation of the damping, similar to the German requirements [6].

Test bench setup:

- Using testbench 1, the short circuit ratio (SCR) at the GFM inverter connection point shall be set to **3**.
- The system equivalent X/R shall be set to **6**.
- The GFM inverter is dispatched at **50 %** of rated power and **zero** reactive power.
- The initial voltage is **1 pu**.

Test sequence:

- The angle of the voltage source behind the equivalent grid impedance is decreased instantaneously by **10** degrees.
- A few seconds later, after all oscillations have settled, the angle of the voltage source is increased by **10** degrees (back to the original value).

- A few seconds later, after all oscillations have settled, the angle of the voltage source is decreased by **30** degrees.
- A few seconds later, after all oscillations have settled, the angle of the voltage source is increased by **30** degrees (back to the original value).

Success criteria:

The reaction is in line with the requirements of chapter 1.2.1 and 1.5:

- The instantaneous active current output reaches at least **0.2 pu** on the rated active current base for each **10° angle** step, i.e. **0.2 pu** for the first two steps and **0.6 pu** for the third and fourth step. For the negative **30°** step, the theoretical active power should reach **1.1 pu**. If this is above the current limit, it is evaluated if the inverter reaches its maximum value instead of **1.1 pu**. For the positive **30°** step, it is expected that a battery inverter transitions from discharging to charging during the (sub)transient response.
- The response time of the active current to **90 %** of the initial change is **15 ms** or lower for each angle step.
- The active power settles to the pre-disturbance value shortly after all phase jumps.
- Any oscillation shall be damped. The damping ratio for any active power oscillations following the response must be at least **0.45**. The damping ratio is calculated as described in 6.2.
- Any distortion observed in phase quantities should dissipate over time.

3.4 Small Voltage Disturbances

Notes

This test did not exist in the original tests by AEMO [4], it was added by ERCOT [13] and adopted by UNIFI [14]. Voltage magnitude steps are a significant part of the Finnish GFM specifications, but no success criteria are described there [12]. In all these GFM specification documents, the initial power is supposed to be the rated power. This risks reaching the current limit during the tests. Similar tests are required as well by Germany. There the evaluation focuses on the damping and the determination of the effective impedance of the unit [6]. For the latter there is no specification in the present document. It is mentioned that no current limit should be reached during the evaluation. The approach from ERCOT and UNIFI is used here, but with lower initial power, so current limits are not reached and the evaluation of the damping is added.

Test bench setup:

- Using Testbench 1, set the impedance of the voltage source to zero. If this test is verified via measurements, a larger impedance leading to a SCR ≥ 3 , are acceptable as well.
- The GFM inverter is dispatched at **50%** of rated power, with **zero** reactive power.
- The initial voltage is **1 pu**.

Test sequence:

- The magnitude of the voltage source behind the equivalent grid impedance is decreased instantaneously by **3%** (i.e., from 1.0 pu to **0.97 pu**).
- A few seconds later, after all oscillations have settled, the magnitude of voltage source is increased by **3%** to return to 1.0 pu.
- A few seconds later, after all oscillations have settled, the magnitude of voltage source is increased by **3%** to reach to **1.03 pu**.
- A few seconds later, after all oscillations have settled, the magnitude of voltage source is decreased by **3%** to return to 1.0 pu.

Success criteria:

The reaction is in line with the requirements of chapter 1.2.2 and 1.5:

- The Instantaneous reactive current output of the plant should quickly respond to oppose the voltage step change for each of the **3 %** voltage step changes, with an initial peak reactive active change of at least **0.03 pu** on the rated power base.
- The response time to **90%** of initial change in instantaneous reactive power be **15 ms** or lower.
- Any oscillation shall be damped. The damping ratio of the reactive current should be at least **0.3**.

Note: The final reactive power depends on outer control loops of the GFM inverter. In chapter 1.8, it is referred to the general grid code and it is specified that a Q/U droop should be required. Since no exact specification for the reactive power control is made here, the evaluation of the final value is not part of the success criteria.

3.5 Response to ROCOF

Notes

While most of the other tests for verification are based on the Texan/ UNIFI procedure [15][13], the test for the inertia constant is based on the German specification [6]. This is because in the Texan specifications the evaluation of P(f) droop and inertia is mixed. Since the P(f) droop influences the active power reaction, the German specification explicitly requires the inertia test with deactivated P(f) control. The evaluation in Texas/ UNIFI is done via calculation of the average power during the first 0.5 s of a ROCOF event. The duration of the time interval is not justified and only one ROCOF is tested. In contrast to this, the German specification requires the active power to be in a certain deadband around the expected value at the end of a ROCOF event and different ROCOFs are tested.

With the above considerations, the German approach is used for verification of the inertial constant.

Test bench setup:

- Using testbench 1, the short circuit ratio (SCR) at the GFM inverter connection point shall be set to **3**.
- The system equivalent X/R shall be set to **6**.
- The GFM inverter is dispatched at **maximum/ minimum** share of rated power, that allows the provision of the full inertia (depending on the inertia constant) in the tests, without reaching current limits.
- The initial voltage is **1 pu**.
- Any P(f) control is deactivated.

Test sequence:

- The frequency curves shown in Figure 3-3 are applied to the voltage source and the active power reaction is recorded.
- Each of the two shown tests has to be done twice, once with **maximum** possible power and once with **minimum** possible power, as described above.

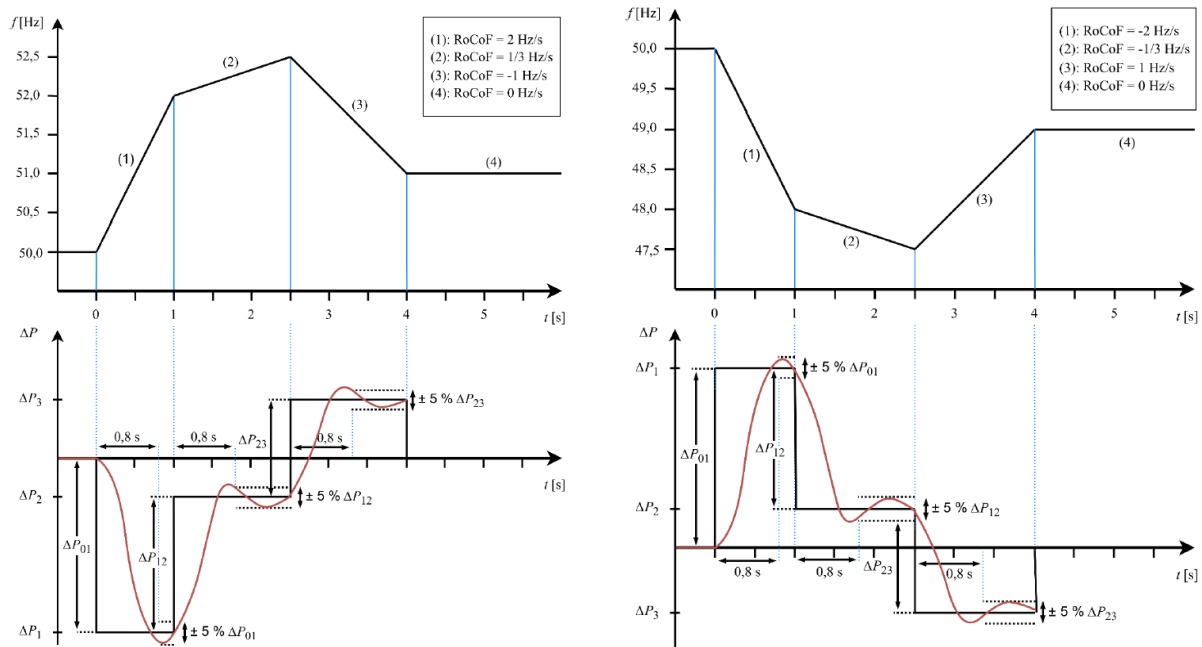


Figure 3-3: Illustration of the tests for inertia. The evaluation for $T_A < 10s$ is shown. Source: [6]

Success criteria:

For each test and each interval, the expected active Power change ΔP is calculated from the set inertia constant T_A , the nominal frequency f_n and the ROCOF $\Delta f / \Delta t$:

$$\Delta P = T_A \cdot P_n \cdot \left(\frac{\Delta f / \Delta t}{f_n} \right)$$

In each segment of the test, the measured active power change should be within a band around the expected active power change ΔP after a certain time.

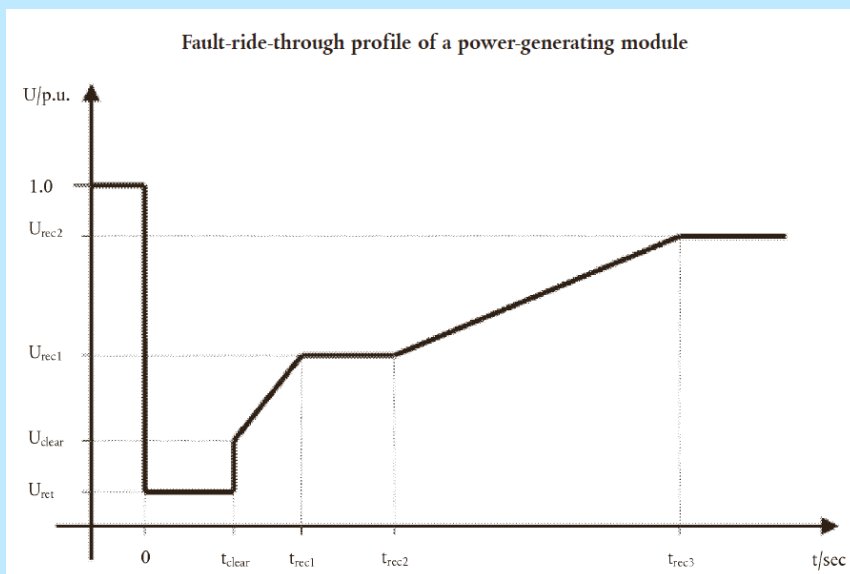
- For $T_A < 10s$: The measured active power should stay within a tolerance of **+/-5% of P_n** around ΔP , **800 ms** after the beginning of each segment.
- For $T_A > 10s$: The measured active power should stay within a tolerance of **+/-15% of P_n** around ΔP , **1 s** after the beginning of segment 1, within a tolerance of **+/-5% of P_n** around ΔP , **1.3 s** after the beginning of segment 2 and 3.

3.6 Fault Ride Through and decreasing system strength

Notes

In the original AEMO tests, there are only few FRT tests with subsequent decrease of system strength. This approach shows principle FRT capability and the ability to operate with different system strengths, but it lacks FRT tests with different durations and different residual voltages. This is adequate, because these tests for GFM capability are only meant as an addition to existing requirements, which usually already include FRT tests. The UNIFI document, which builds upon the AEMO specification includes a few FRT tests, but only for informative reasons, without success criteria [13]. Additional FRT tests are mentioned as well in the GFM specifications of Texas and Germany [14][6]. Both documents refer to the FRT tests of the general grid code framework. The difference between the two documents is that no additional evaluation is required in Texas, whereas an extensive, GFM-specific evaluation of the test results spanning several pages is described in Germany. The present document also refers to existing specifications. A GFM-specific evaluation is included, but focuses on the most relevant aspects.

An example FRT requirement from the European Grid Code “Requirements for Generators, COMMISSION REGULATION (EU) 2016/631” is shown below. For voltage dips that are above the line, the unit must stay connected to the grid for the duration indicated on the x-axis. Besides of requirements for low voltage ride through (LVRT), there might be corresponding requirements for high voltage ride through (HVRT)



In addition to these “standard” FRT tests, the test for reduced system strength, as required by AEMO [4] and all following specifications is included here. This test reduces the system strength after faults in multiple steps. In the German specification [6], the operation with different system

strengths is proven through a series of set point step simulations at different system strengths. The AEMO approach is used here because it is more demanding.

3.6.1 Verification of FRT capability curve

Test bench setup:

FRT tests are executed with testbench 1, with an a SCR ≥ 3 and an X/R ratio of 6. FRTs can be executed either through switching impedances of a FRT container or through manipulating the voltage of a grid emulator. The initial voltage is 1 pu, the active power is full or half power, as described below, and the reactive power is zero.

Test sequence:

In principle, FRT tests have to be executed in the same manner as described in [FRT test specification for GFL units/plants]. Voltage dips and swells (low voltage ride through (LVRT) and high voltage ride through (HVRT)) with different residual voltages/ voltage surges and durations according to the required FRT curve have to be executed. The FRT to each voltage level has to be executed 8 times: charging and discharging, with full rated power and half rated power, 3-phase and 2-phase fault.

Success criteria:

- The GFM unit shall not trip at any point.
- All oscillations during and after the fault must be damped. Post fault reactive current oscillations must have a damping ratio of at least 0.3 and post fault active power oscillations must have a damping ratio of at least 0.45.
- The response time of the apparent current to 90 % after the beginning of the fault is 15 ms or less.
- After the faults, the active power recovers to 90 % of the initial value in 1 second or less.
- When reaching the current limit the apparent current is at least 95 % of the rated current, there is no prioritisation of any current component. I.e. neither active nor reactive current is zero. For unbalanced faults, positive and negative sequence of active and reactive current have to be determined and none of the currents should be zero.
- Current clipping does not occur for more than 40 ms. It can be proven through calculation of the total harmonic distortion (THD), visual analysis of the current waveforms or internal control signals of the inverter.

3.6.2 Verification of operation at reduced system strength

Test bench setup:

- Using Testbench 1, the initial SCR at connection point is set to **10**. The X/R ratio is set to **6**.
- The initial voltage is **1 pu**.
- The GFM unit is dispatched at **rated active power** and **zero reactive power**.

Test sequence:

- A 3-phase, bolted (zero-impedance), 4-cycle fault is applied.
- At fault clearing time, the SCR is stepped down.
- The test is repeated in total 4 times after all oscillations have settled.
- The SCR is reduced stepwise to the following values at fault clearance: **5, 3, 1.5, 1.2**.

Success criteria:

- The GFM unit shall not trip at any point.
- All oscillations during and after the fault must be damped. Post fault reactive current oscillations must have a damping ratio of at least **0.3**. For SCRs with **3** or more post fault active power oscillations must have a damping ratio of **0.45**.
- After the faults, the active power recovers to **90 %** of the initial value in **1 second or less**.

3.7 Loss of grid connection

Notes

These tests are done through opening the switch in testbench 2. Very similar tests are described by AEMO, Chile, MISO, ERCOT and UNIFI, but they differ in details, such as the initial setpoints of the GFM inverters, size of the duplicate GFM unit, and residual load[4][5][10][13][14]. The most recent tests from [13] and [14] are used here. However, in these tests there is no test included in which the GFM inverter ends up charging. In the German specifications there is such a test [6]. Consequently one more case with this condition is added to the test series. In addition, the evaluation criteria have been extended to verify the requirements of chapter 1 regarding damping, response time and inertia, using the German specification as orientation.

Test bench setup:

- Testbench 2 is to be used. The initial voltage is **1 pu**. The initial reactive power of the GFM units is **zero**. The power factor of the load is **0.95 inductive**. The initial active power of the GFM units and the loads is as specified in Table 3.1.

Test sequence:

The switch has to be opened for the 4 scenarios described in Table 3.1 and the reaction of the 2 GFM units has to be observed.

Table 3.1: Scenarios for loss of grid connection test

SCENARIO	ACTIVE POWER GFM1	ACTIVE POWER DUPLICATE GFM	ACTIVE POWER LOAD
1: Discharging	0.3 pu discharging	0.1 pu discharging	1.3 pu
2: Charging	0.6 pu charging	0.4 pu charging	0.7 pu
3: Limit test	0 pu	1 pu discharging	1.65 pu
4. Charging in island test	0.1 pu discharging	1 pu discharging	0.2 pu

Success criteria:

- The response time of active and reactive power to **90 %** of the initial change is **15 ms** or less.
- Voltage and frequency do not reach values outside of the requirements of **[relevant grid code]** for continuous operation for a duration that is longer than required or that would trigger a protection.
- Frequency and voltage settle at expected values depending on the used P/f and Q/U characteristic.
- The damping ratio of frequency oscillations is at least **0.2**. The damping ratio of reactive current oscillations is at least **0.3**.

4 Glossary

Current clipping	A protection function that limits the current of inverters based resources based on instantaneous (sub-cycle) values to protect the hardware before the current is limited to its maximum current reference. Current clipping results in distorted current waveforms and is thus undesired.
Damping Ratio	Measure for the damping of an oscillating system, as explained in Annex 6.2.
DLL	Dynamic link library. An encrypted software piece that can be embedded in simulation tools.
Droop control	A proportional control of a quantity depending on another quantity used to stabilize the grid and share power between individual units. Typical droop controls are P(f) and Q(U).
FRT	Fault Ride Through
HVRT	High voltage ride through
IBR	Inverter Based Resource
LFSM	Limited Frequency Sensitive Mode
LVRT	Low voltage ride through
Power Plant	One or more generation unit including corresponding lines, transformers and other electrical equipment, with a point of common coupling to the system operators grid.
Response time	The response time is the time a quantity needs to reach a certain percentage of the final value after a setpoint change or a disturbance, as defined in Annex 6.2.
Subtransient	The earliest response interval during the first cycle following sudden grid changes at a generation unit. Occurs before Transients.
SCR	Short Circuit Ratio. Ratio between the short circuit power of at grid connection point and the nominal power of a connected power plant or unit

STATCOM	Static Synchronous compensator. An inverter based resource, used for provision of reactive power.
Transient	The period lasting from the end of the subtransient time frame until approximately one second following a disturbance.
THD	Total harmonic distortion
Unit	A single generation unit, e.g. one inverter based resource or one synchronous machine.

5 References

- [1] D. Masendorf, L. Rakocevic, N. Martensen: „Review of International Best Practices and Standards for Grid-forming Battery Energy Storage Systems”, Report and Presentation, December 2025
- [2] “Grid forming capability of power park modules - Report on technical requirements”, ENTSO-E, 03. October 2025
- [3] “Voluntary Specification for Grid-forming Inverters”, AEMO, May 2023
- [4] “Voluntary Specification for Grid-forming Inverters: Core Requirements Test Framework”, AEMO, January 2024
- [5] “Requisitos Técnicos Mínimos para Recursos Basados en Inversores Grid-Forming”, CEN, October 2024
- [6] “Technical requirements for grid-forming capabilities including provision of inertia, version 2.1”, VDE FNN, January 2026
- [7] “European Connection Conditions”, National Grid, 11. June 2025
- [8] “European Compliance Process”, National Grid, 19. May 2025
- [9] “Krav Til Transmissionstilsluttede Energilageranlæg Med Grid Forming Kapabilitet”, Energinet, 14. November 2025
- [10] “MISO Grid-Forming Battery Energy Storage Capabilities, Performance, and Simulation Test Requirements Proposal”, MISO, July 2024
- [11] “White Paper: Grid Forming Functional Specifications for BPS-Connected Battery Energy Storage Systems”, NERC, September 2023
- [12] “Grid Code Specifications for Grid Energy Storage Systems SJV2024”, Fingrid, 15. January 2025
- [13] “UNIFI Specifications for Grid-Forming Inverter-Based Resources Version 3”, UNIFI Consortium, 30. January 2026
- [14] “Advanced Grid Support Energy Storage Resource (AGS-ESR) - Functional Specification and Test Framework for the ERCOT Grid”, ERCOT, September 2024
- [15] “Amended RfG Regulation” (RfG 2.0), ACER, December 2023
- [16] Cigre Brochure TB 958: “Guidelines for use of real-code in EMT models for HVDC, FACTS and inverter based generators in power systems analysis”, February 2025
- [17] IEEE P2800.2 “IEEE Draft Recommended Practice for Test and Verification Procedures for Inverter-based Resources Interconnecting with Bulk Power Systems”, November 2025

6 Annex

6.1 Determination of instantaneous values

Instantaneous values are determined using $\alpha\beta$ coordinates with the aid of the Clarke transformation. The $\alpha\beta$ coordinates of the voltages are determined as follows:

$$u_{\alpha} = \frac{\sqrt{2}}{3} \cdot (u_a - 0.5 \cdot u_b - 0.5 \cdot u_c)$$
$$u_{\beta} = \frac{\sqrt{2}}{3} \cdot \left(\frac{\sqrt{3}}{2} \cdot u_b - \frac{\sqrt{3}}{2} \cdot u_c \right)$$
$$u_0 = \frac{\sqrt{2}}{3} \cdot \left(\frac{1}{\sqrt{2}} \cdot u_a + \frac{1}{\sqrt{2}} \cdot u_b + \frac{1}{\sqrt{2}} \cdot u_c \right)$$

The $\alpha\beta$ coordinates of the currents are determined as follows

$$i_{\alpha} = \frac{\sqrt{2}}{3} \cdot (i_a - 0.5 \cdot i_b - 0.5 \cdot i_c)$$
$$i_{\beta} = \frac{\sqrt{2}}{3} \cdot \left(\frac{\sqrt{3}}{2} \cdot i_b - \frac{\sqrt{3}}{2} \cdot i_c \right)$$
$$i_0 = \frac{\sqrt{2}}{3} \cdot \left(\frac{1}{\sqrt{2}} \cdot i_a + \frac{1}{\sqrt{2}} \cdot i_b + \frac{1}{\sqrt{2}} \cdot i_c \right)$$

Provided that no zero sequence components occur in the system under consideration (symmetrical three-wire system), the magnitude of the voltage and current space vector in the $\alpha\beta$ coordinate system is calculated as the RMS value using:

$$|u_{\alpha\beta}| = \sqrt{(u_{\alpha}^2 + u_{\beta}^2)}$$
$$|i_{\alpha\beta}| = \sqrt{(i_{\alpha}^2 + i_{\beta}^2)}$$

The modulus bars of $|u_{\alpha\beta}|$ and $|i_{\alpha\beta}|$ have been omitted in the following for the sake of simplicity.

The instantaneous active and reactive power in the three-phase system is defined as:

$$p = u_a \cdot i_a + u_b \cdot i_b + u_c \cdot i_c$$
$$p_{\alpha\beta} = p = 3 \cdot (u_{\alpha} \cdot i_{\alpha} + u_{\beta} \cdot i_{\beta})$$

$$q_{\alpha\beta} = 3 \cdot (-u_{\alpha} \cdot i_{\beta} + u_{\beta} \cdot i_{\alpha})$$

The magnitude of the active and reactive current vector in the $\alpha\beta$ coordinate system may be determined as the RMS value as follows:

$$|i_{p,\alpha\beta}| = \frac{p}{3 \cdot u_{\alpha\beta}}$$

$$|i_{q,\alpha\beta}| = \frac{q}{3 \cdot u_{\alpha\beta}}$$

The modulus bars of $|i_{p,\alpha\beta}|$ and $|i_{q,\alpha\beta}|$ have been omitted in the following for the sake of simplicity

To suppress measurement noise, a moving average over 5 ms is applied for the evaluation of these measurement data. For the evaluation of simulation data this is not necessary. However, if simulation and measurement results are compared, they have to be filtered the same way.

$$u_{\alpha\beta,5ms} = \frac{1}{5 \text{ ms}} \cdot \int_{t-5 \text{ ms}}^t u_{\alpha\beta} dt$$

$$i_{\alpha\beta,5ms} = \frac{1}{5 \text{ ms}} \cdot \int_{t-5 \text{ ms}}^t i_{\alpha\beta} dt$$

$$i_{p,\alpha\beta,5ms} = \frac{1}{5 \text{ ms}} \cdot \int_{t-5 \text{ ms}}^t i_{p,\alpha\beta} dt$$

$$i_{q,\alpha\beta,5ms} = \frac{1}{5 \text{ ms}} \cdot \int_{t-5 \text{ ms}}^t i_{q,\alpha\beta} dt$$

$$p_{\alpha\beta,5ms} = \frac{1}{5 \text{ ms}} \cdot \int_{t-5 \text{ ms}}^t p_{\alpha\beta} dt$$

$$q_{\alpha\beta,5ms} = \frac{1}{5 \text{ ms}} \cdot \int_{t-5 \text{ ms}}^t q_{\alpha\beta} dt$$

Source: [6]

6.2 Explanation of response time and damping ratio

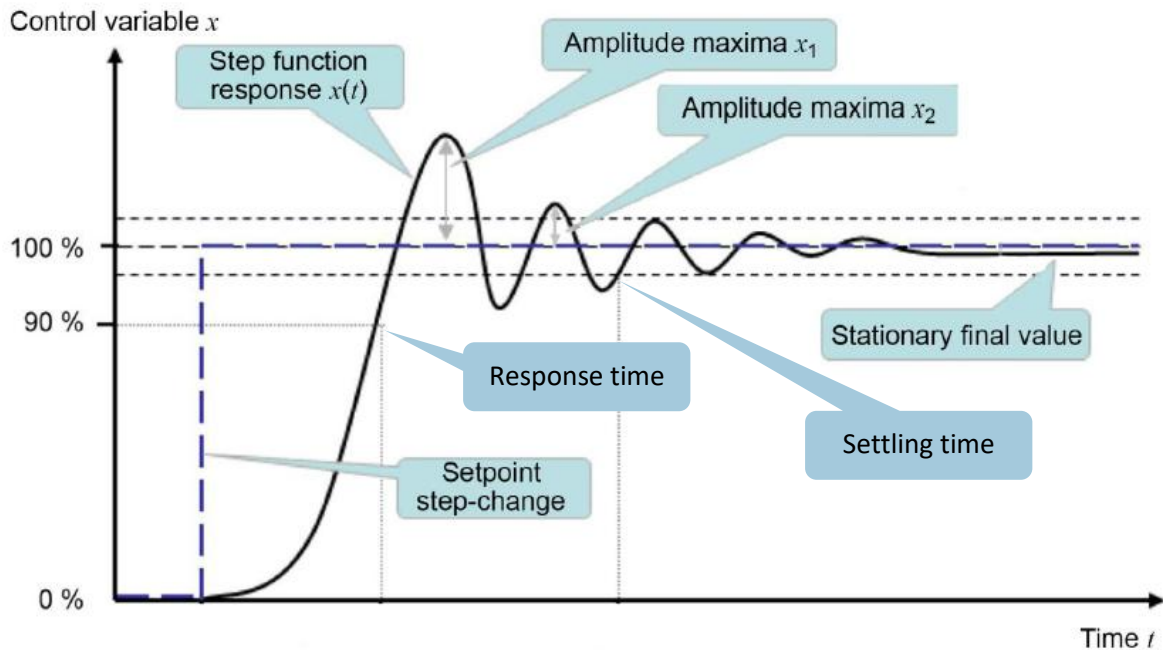


Figure 6-1: Illustration of response time and relevant quantities for calculation of the damping ratio

In this document the dynamic response to events in the grid is determined through response time and damping ratio.

The response time in Figure 6-1 is defined as the time a quantity needs to reach 90 % of the final value after a setpoint change or a disturbance. For a response after which the observed quantity settles again at the initial value Figure 6-2, the response time is defined as the time until the quantity reaches 90 % of the first peak.

The damping ratio can be calculated using the logarithmic decrement Λ of two consecutive maxima (or minima):

$$\Lambda = \ln \left(\frac{x_n}{x_{n+1}} \right)$$

The damping ratio D can be derived from the logarithmic decrement Λ :

$$D = \frac{\Lambda}{\sqrt{(2\pi)^2 + \Lambda^2}}$$

However, the evaluation of the damping ratio, using only two maxima/ minima can lead to different results, depending on the selected maxima or minima. Consequently, the first three damping ratios, using the first four amplitudes) have to be determined. If less amplitudes are observed, less damping ratios have to be determined. If the first damping ratio yields a significantly different result than the others, it can be ignored in the evaluation. For informative purposes, the amplitude ratio (not ratio of maxima/ minima(!)) is shown in Figure 6-2. The amplitude ratio for a damping ratio of 0.45, is approximately 0.2. For a damping ratio of 0.3 it is approximately 0.37.

In case oscillations around a decaying DC component are observed, i.e. not around a stationary value, this component has to be subtracted before determining the maxima or minima. This can be done by calculating the e-function of the decay and subtracting it from the measurement data.

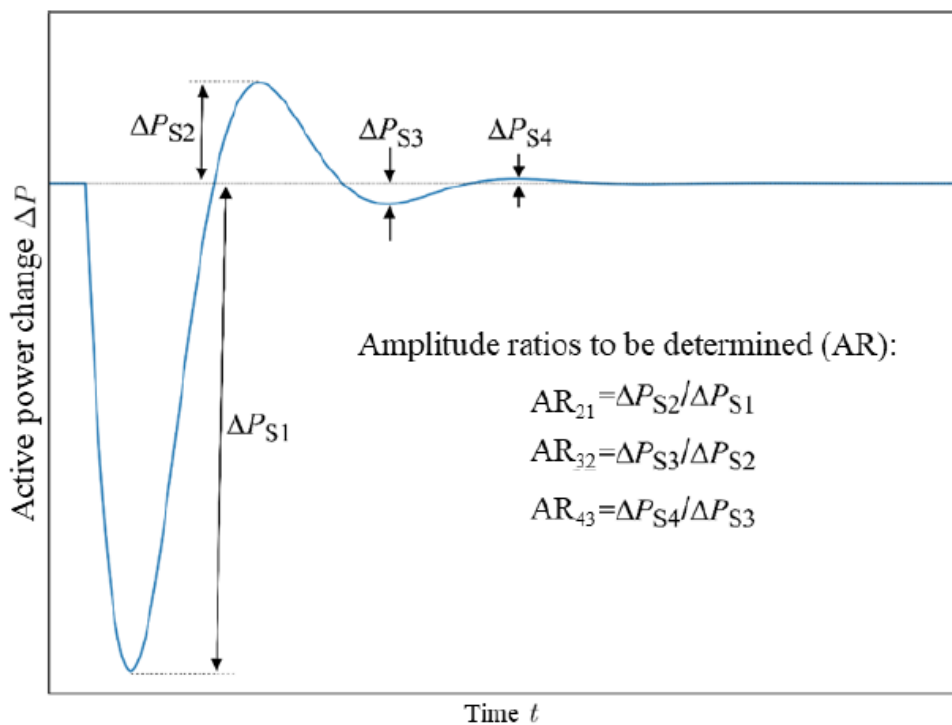


Figure 6-2: Example response after which the relevant quantity settles again at the initial value

Source: [6]