TECHNICAL GROUP ON FORCED OSCILLATIONS REPORT

CLARIFICATION OF DRAFT NC RFG 2.0 REQUIREMENTS

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The current report is supported by the following organisations:

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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WindEurope is the voice of the wind industry, actively promoting wind energy across Europe. We have over 600 members from across the whole value chain of wind energy: wind turbine manufacturers, component suppliers, power utilities and wind farm developers, financial institutions, research institutes and national wind energy associations.

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ENTSO-E Mission Statement

ENTSO-E – the European Network of Transmission System Operators for Electricity – brings together 40 electricity Transmission System Operators (TSOs) from 36 countries. ENTSO-E members are responsible for the secure and coordinated operation of Europe's electricity system. Together, they operate a system of around 500,000 km of power lines – **the largest interconnected electrical grid in the world** – and serve about 520 million citizens.

Electricity is not merely a market commodity, it is an essential service, and TSOs are fully regulated public service entities whose work is essential to powering Europe. The grid is the backbone of the electricity system and has extended over the whole Continent, beyond the borders of the EU. TSOs working together guarantee a functioning infrastructure that makes the trade of electricity possible, contributes to decarbonisation goals, and ensures a reliable and efficient power supply for all members of society.

These shared public service responsibilities need close cooperation beyond national borders, which led to the creation of ENTSO-E. Today, the association serves two main complementary purposes:

1. **Cooperation of European TSOs**

The foundations of this cooperation date back to the 1950s with the creation of electrical synchronous areas and interconnections, which laid the groundwork for today's interconnected European power system. TSOs established associations to work together on their own mandates and missions, that came together into what today is ENTSO-E. The European electricity system is one of the most stable and reliable grids in the world and is supported by the cooperation and coordination of TSOs both within the European Union and closely interconnected European countries. ENTSO-E strives to build consensus for decision-making amongst its member TSOs as this forms the strongest foundation for cooperation.

2. **Fulfilling EU legal mandates**

With the adoption of the Third Energy Package in 2009, ENTSO-E's role was formally recognised by European institutions. ENTSO-E was granted legally mandated tasks to further develop the European interconnected grid and to facilitate the integration of European electricity markets. These mandates cover a large spectrum of tasks, including system operation, system development, market integration, information technologies, R & D and innovation.

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Abbreviations

AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
ATD	Active Tower Damper
CE	Continental Europe
CNC	Connection Network Code
CT	Current Transformer
CWT	Continuous Wavelet Transformation
DEV	Developer
EC	European Commission
EG	Expert Group
ENTSO-E	European Network of TSOs for Electricity
EU	European Union
FACTS	Flexible AC Transmission Systems
FFCI	Fast Fault Current Injection
FON	Final Operational Notification
FRT	Fault-Ride-Through
GC ESC	Grid Connection European Stakeholder Committee
GCC	Grid Connection Compliance
GU	Grid User
HVDC	High Voltage Direct Current

IBR	Inverter-Based Resources
IGD	Implementation Guideline Document
LFSM-O/U	Limited Frequency Sensitive Mode – Overfrequency/Underfrequency
NAN	Not A Number
NC DC	Network Code on Demand Connection
NC HVDC	Network Code on requirements for the grid connection of HVDC and direct current-connected power park modules
NC RfG	Network Code on Requirements for Generators
OEM	Original Equipment Manufacturer
OFS	Offshore
ONS	Onshore
PCC	Point of Common Coupling
PMU	Phasor Measurement Unit
POD	Power Oscillation Damping
PPM	Power Park Module
PSS	Power System Stabiliser
pu	Per Unit
SO ESC	System Operation European Stakeholder Committee
SPGM	Synchronous Power-Generating Module
SSSC	Static Synchronous Series Compensator
STATCOM	Static Synchronous Compensator
STFT	Short-Time Fourier Transformation

TCSC	Thyristor-Controlled Series Capacitor
TSO	Transmission System Operator
UPFC	Unified Power Flow Controller
VT	Voltage Transformer
WTG	Wind Turbine Generator

EXECUTIVE SUMMARY

In December 2023, following an assessment of stakeholder proposals, the Agency for the Cooperation of Energy Regulators (ACER) submitted its recommendation for amending the Network Code on Requirements for Generators (NC RfG) 2.0 to the European Commission (EC). The amended version introduces two new paragraphs — 21.3 and 26.2 — which set out requirements regarding the allowable amplitude and duration of forced oscillations in grid-connected power park modules (PPMs). These provisions are designed to limit such oscillations, reflecting the evolving realities of a power grid with increasing integration of inverter-based resources (IBRs). These requirements can have a major impact on the development of wind energy projects, as the active power of these power plants is influenced by wind turbulence and wave loading and oscillations can occur due to eigenmodes of the blades and the support structure.

A technical group of 12 members — equally nominated by ENTSO-E and WindEurope — held regular biweekly meetings from June 2024 to July 2025. The group's objective was to clarify the requirements, discuss proposed ranges and default limits, and determine the appropriate measurements and tools to be used. The main deliverable of this working group is the present document.

The purpose of the present report is to provide non-binding technical guidelines regarding the forced oscillations requirements of the draft NC RfG 2.0. It contains a description of a proposed non-binding methodology to measure and detect forced oscillations in the active power of PPMs as well as a description of a proposed non-binding algorithm to quantify the amplitude and duration of these oscillations. In addition, it discusses the measurement location, which does not always need to be the point of common coupling (PCC), for example, in the case of multi-PCC connected offshore wind farms.

It also summarises the quantitative analyses performed by several members using logged data from both onshore and offshore wind farms of different sizes and with turbines from different manufacturers. Several scenarios with different limits within the proposed ranges (from most strict to least strict) have been carried out to investigate their influence on the overall compliance ratios.

Based on these assessments, the technical group has made general recommendations for limits within the proposed ranges for both offshore and onshore wind farms. The aim is to minimise forced oscillations while limiting design impacts on wind turbine generators.

Furthermore, some ENTSO-E members of the Expert Panel on the Grid Incident in Spain and Portugal on 28 April 2025 reviewed the present report to ensure consistency and alignment [16].

Afterwards, based on this technical report, ENTSO-E plans to publish a non-binding Implementation Guidance Document (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 forced oscillations requirements under national law. Even though the present report only focuses on wind turbines, the forced oscillations requirements will also apply to all other types of PPMs, such as solar PV and electricity storage modules. Consequently, further assessment on these technologies will be required in the future.

Besides, following up on the 11th recommendation of the final report of the Expert Panel on the Grid Incident in Spain and Portugal on 28 April 2025, the European Stakeholder Committees on System Operation and Grid Connection (SO ESC and GC ESC, respectively), will create a joint Expert Group (EG) in Q4 2026 to investigate the behaviour of non-observable embedded generators (in particular, the impact of solar PV).

1 Background on forced oscillations

This report provides an overview of forced oscillations phenomena in power systems, focusing on the concerns associated with power park modules (PPMs) based on wind turbines. The report is structured as follows:

- An introduction to forced oscillations is presented in Chapter 1 and Chapter 2, from a technical and regulatory perspective, respectively.
- Chapter 3 proposes a detailed non-binding methodology to assess forced oscillations.
- Chapter 4 focuses on forced oscillations from a grid code compliance perspective.
- Chapter 5 presents the performed assessment on forced oscillations for some onshore and offshore wind farms.
- To finalise the report, Chapter 6 provides some mitigation measures to reduce forced oscillations, and Chapter 7 presents conclusions.
- Chapter 8 includes the references cited throughout the report.
- Appendix A and Appendix B present the forced oscillations requirements of the draft amended Network Code on Requirements for Generators (NC RfG) in a table and graphical format, respectively.
- Appendix C investigates the contribution of normal turbulence to the exceedance of the requirements for forced oscillations.
- Finally, Appendix D includes the positions of WindEurope that deviate from what is presented in this report.

Other types of oscillations beyond forced oscillations are not covered in this report. Restrictions on other types of oscillations should be defined separately.

1.1 Definitions

Power system dynamics can be triggered by different external and internal changes, which can be periodic or non-periodic:

- Non-periodic perturbations are non-repetitive changes typically of stochastic nature corresponding to parametric fluctuations, variations in load and generation, short-circuits and switching actions, which result in transient and ambient dynamic responses.
- Contrary to non-periodic perturbations, periodic perturbations are cyclic or repetitive changes, which can be generally introduced by loads, generation, and other equipment.

Forced oscillations are the dynamic response of the power system when subjected to periodic perturbations [1]. The term “forced oscillations” is also often used to refer to the periodic perturbations themselves, and this is the definition adopted in this report.

External disturbances can trigger the numerous natural dynamic modes present in interconnected power systems. Of special interest are low-frequency electromechanical modes, covering inter-area oscillations, typically in the frequency range of 0.1–1.0 Hz and intra-area or local oscillations, typically in the frequency range of 1.0–2.0 Hz [2]. Figure 1 shows the main inter-area modes of the continental Europe (CE) grid [3]. These modes span long distances and present low damping. Although these modes are an inherent property stemming from the electromechanical nature of power systems, their damping can be modified by means of dedicated control equipment, i.e. power system stabiliser (PSS) provided by synchronous power-generating modules (SPGM) and power oscillation damping (POD) provided by PPMs [4].

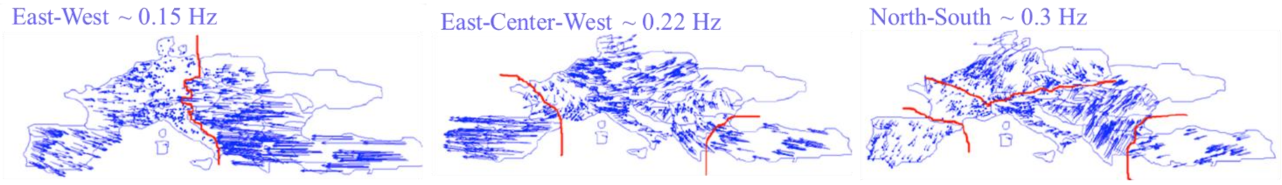

Figure 1. Main CE inter-area modes [3].

In addition, modern power systems also present oscillatory modes in the sub-synchronous range (2–50 Hz) because of higher penetration of power electronic devices. These modes can be damped (stable) or with negative or very low damping (unstable) [14]. The latter should be avoided by control design, connection studies, and/or operational measures, while the former is a consequence of the interactive nature of power systems. It is customary to emphasise that the forced oscillations to which this report refers are those originated by periodic phenomena external to the power system, and not because of interactions between devices with and/or within the system.

1.2 Main issues

Special concern is raised when the power system presents natural dynamic modes close to the frequency, or harmonics, of the forcing perturbation. In that case, the intrinsic system dynamics can amplify the periodic perturbation, resulting in much larger forced oscillation magnitudes than those of the source. This phenomenon is known as resonance, and it can be very dangerous for system integrity, as a high-amplitude oscillatory response might lead to equipment failure and cascaded tripping, which could eventually result in a system split, or even blackout [4], [5], [6].

To avoid harmonic amplification due to resonances and maintain power quality, grid codes usually limit the current injection of connected devices at frequencies higher than the fundamental. However, there is currently no limitation on the sub-synchronous range, i.e. below the fundamental frequency of 50 Hz. The draft NC RfG 2.0[1] is filling the gap by proposing a limited amount of allowed injection in the frequency range between 0.1 Hz and 20 Hz. Ideally, the requirement would cover up to 50 Hz. Nonetheless, monitoring the fulfilment of the requirement would have necessitated point-on-wave measurements, which are not a widespread practice in current power systems. The requirement is thus limited to 20 Hz to be readily assessed via existing phasor measurement units (PMU).

Forced oscillation events resulting in resonance with inter-area modes have been reported in the past for several power systems [7], [8]. Typically, the source is malfunctioning equipment, and the phenomenon is mitigated by disconnecting the faulty unit and addressing the equipment failure. However, power systems also contain several sources of forced oscillations which cannot be fully removed, such as those originating from low-speed diesel engines [9].

Similarly, wind turbines are subjected to forced oscillations stemming from wind turbulence, waves, tower shadow, wind shear effect, and blade passing frequency [10]. They also exhibit natural oscillation modes associated with the foundation-tower assembly. In particular, the side-to-side tower movements triggered by these external forces, such as wind and waves, can be minimised by the active tower damper (ATD) control in the turbines to preserve their structural integrity [10]. This ATD action, illustrated in Figure 2, usually consists of generator torque adaptation, which is an inherent part of the structural design. However, the low damping of these mechanical oscillations is translated as electrical power oscillations, and it is currently unclear how these forced oscillations affect the integrity of large-scale power systems.

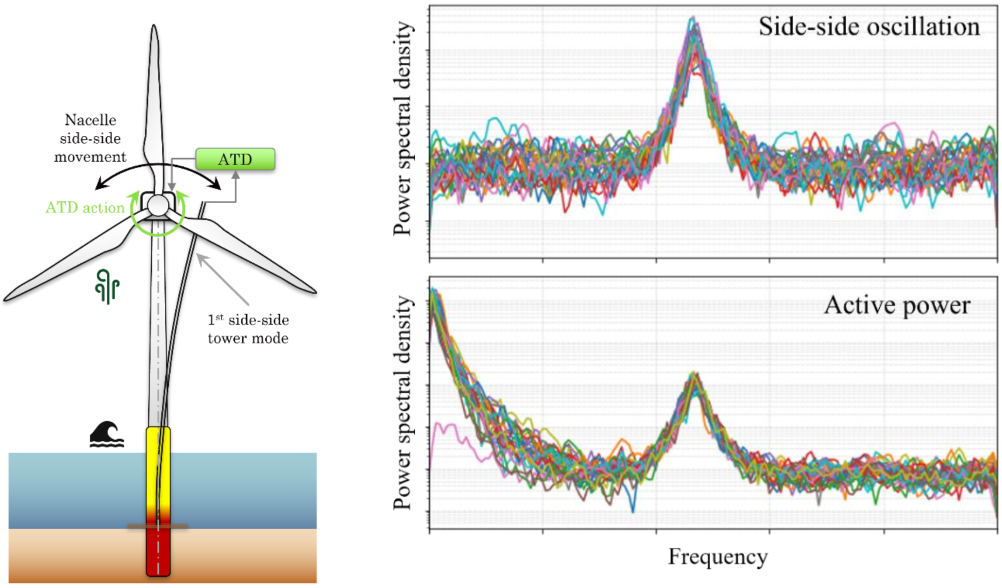

Figure 2. Working principle of the ATD and spectra of the forced oscillations in a real offshore wind farm [11].

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[1] *See Chapter 2.*

The frequencies of the turbine's side-side oscillations are site-specific, as they depend on the soil, foundation, rotor speed, tower, and other turbine properties. Figure 3 shows the range of the rotor speed (1P) and its third harmonic (3P) in purple, together with the design range of the first tower mode for several wind turbines [12]. As shown, wind, and specially wave spectrum, can heavily excite this low-damped mode, resulting in power fluctuations. In addition, the oscillatory power injection by one turbine can be partially offset by power oscillations from other wind turbines due to the phase-shift stemming from the stochastic nature of the disturbances. This compensation effect is more pronounced with an increasing number of turbines, leading to lower oscillation amplitudes relative to the active power output of the wind farm [11].

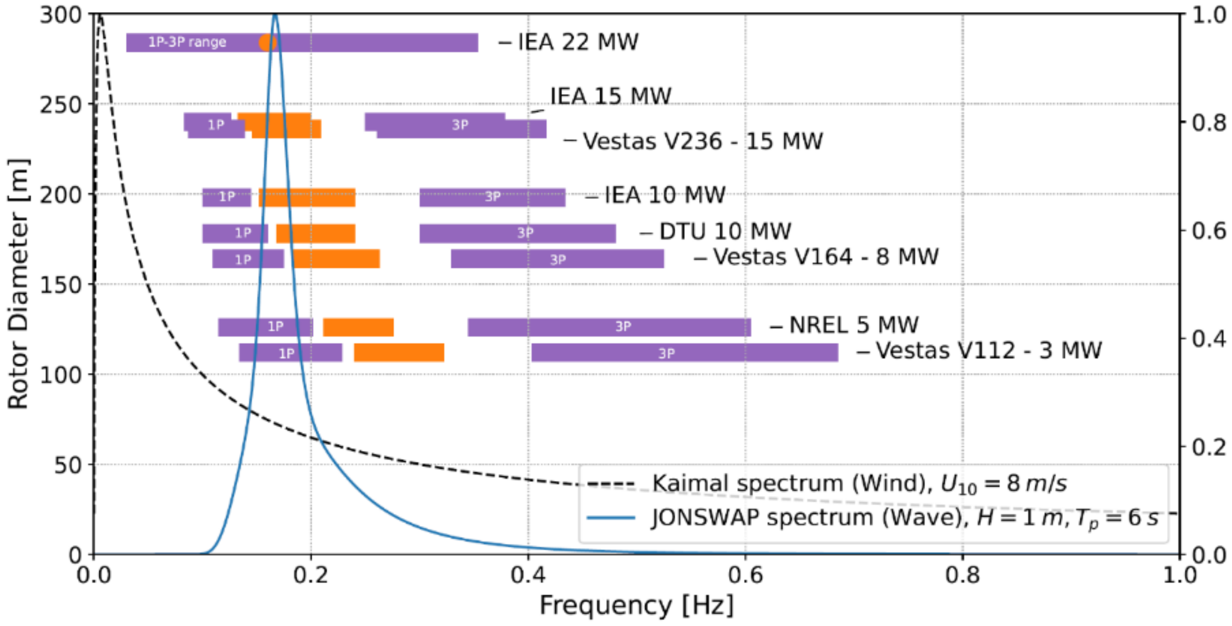

Figure 3. Horizontal axis wind turbine oscillation frequencies and external forces spectra [12].

Therefore, due to the uncertainty in forced oscillation characteristics and the potential risk for system integrity, a set of minimum requirements is needed to guarantee system integrity.

2 Background on Connection Network Codes

Three European Union (EU) Connection Network Codes (CNCs) define the technical capabilities of system users (power generating modules, demand facilities, and HVDC systems) to provide system-supportive performance under all system operation conditions. This contributes to preserving or restoring system security, especially in the event of exceptional contingencies, namely:

- Regulation (EU) 2016/1388 establishing a Network Code on Demand Connection (**NC DC**).
- Regulation (EU) 2016/631 establishing a Network Code on Requirements for grid connection of Generators (**NC RfG**).
- Regulation (EU) 2016/1447 establishing a Network Code on requirements for the grid connection of HVDC and direct current-connected PPMs (**NC HVDC**).

2.1 NC RfG amendment process

In September 2022, according to Article 60 of Regulation (EU) 2019/943, the European Commission (EC) asked the Agency for the Cooperation of Energy Regulators (ACER) to propose amendments to the three CNCs. The purpose of these amendments was to enhance the regulations by making them more future-proof and reflecting the latest developments in the electricity and transport sectors (including electricity storage, electromobility, heat-pumps, power-to-gas demand units, etc.).

In December 2023, upon stakeholders' proposals assessment, ACER submitted to the EC its recommendation for amending NC RfG [15].

At the time of writing, the process of finalising the adoption of the updated regulation is now the responsibility of the EC, and no specific deadline has been set. Nevertheless, the EC is expected to publish the amended version of the NC RfG throughout 2026. Once the code comes into force, the transmission system operators (TSOs) will have a maximum three-year national implementation period.

2.2 Motivation to limit forced oscillations in the network

To effectively manage grid stability, as explained in Section 1.2, it is crucial to minimise the forced oscillations injected into the power grid. Any increase in oscillations by PPMs over current levels poses a further risk in the context of a continuously evolving grid, which becomes increasingly dominated by inverter-based resources (IBRs). Non-compliance can have a significant impact on TSOs, potentially hindering their ability to ensure grid security.

Specific conditions in PPMs operation, such as wind gusts and ramping requirements, are recognised as exceptions for oscillations. Additionally, aligning with ENTSO-E's and WindEurope's interests, the approach avoids categorising normal operations as non-compliant activities. Section 4.2 is dedicated to outlining system support activities that are part of normal operations and are not intended to be flagged as oscillations.

2.3 Forced oscillations limitations in the Connection Network Code

As mentioned in Section 2.1, in September 2022, ACER initiated the amendment process of the NC RfG, as requested by the EC. Even though forced oscillations limitations affect all types of PPMs, this is a main concern for the wind industry. Therefore, ENTSO-E and WindEurope worked on a joint proposal to limit forced oscillations in the grid. ENTSO-E and WindEurope recognised that forced oscillations are disturbances but differed in their assessment of the level of associated risk.

These limitation requirements were introduced as a compromise between zero forced oscillations (the ideal case for grid stability) and no limit on forced oscillations (the ideal case for wind turbine design and cost). In September 2023, this proposal was shared with ACER, which was included in the NC RfG 2.0 proposal shared with the EC in December 2023.

The draft NC RfG 2.0 limits forced oscillations for type C and D PPMs in the frequency range of 0.1–20 Hz. In the frequency range of 0.1–2 Hz, less strict limits are defined for offshore-connected PPMs to provide room for flexibility, given that:

- The challenges with forced oscillations increase with turbine size.
- The costs of limiting forced oscillations also increase with turbine size.

The limitations are located in Article 21 (onshore wind farms) and Article 26 (offshore wind farms) of draft NC RfG 2.0 and can be found in Appendix A. For each requirement, a threshold and default value are defined to accommodate particular characteristics of each power grid and project in the EU. The forced oscillations are limited as follows:

- Upper power amplitude limit: a(i) and a(ii) clauses
- In case this limit is temporarily exceeded, the following applies:
    - Maximum power amplitude exceedance: b(i) clause
    - Maximum time exceedance: b(ii) clause
    - Damping factor of the oscillation: b(iii) clause
    - Maximum exceedance frequency per day and hour: c(i) and c(ii) clauses, respectively

Therefore, the present report only concerns the draft NC RfG 2.0, where limitations of forced oscillations are requested for PPMs.

2.4 Technical group on forced oscillations

When ENTSO-E and WindEurope submitted the joint legal text proposal to ACER in September 2023, both agreed that further work was required to determine the impact of the different range limits on costs and system risks. Thus, a technical group on forced oscillations was created with WindEurope and ENTSO-E in June 2024, whose goal was to:

- Provide clarifications on the requirements for forced oscillations of the ACER's proposal on NC RfG 2.0.
- Discuss the proposed ranges and default limits.
- Clarify the type of measurements and tools to be used.

The deliverable of the technical group is the present report, which will be the basis for a future Implementation Guideline Document (IGD).[2] ENTSO-E will work on this IGD and publish it once the NC RfG 2.0 enters into force.

It is also acknowledged that further work is required to determine the impact of a clause value on costs and system risks, taking into consideration the amount of wind installed in an area.

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[2] *IGDs are non-binding documents published by ENTSO-E to support TSOs and stakeholders with the implementation of the EU CNCs.*

3 Non-binding methodology for forced oscillations assessment

To assess if a measured time series complies with the requirements in the draft NC RfG 2.0, several steps must be taken to isolate forced oscillations and determine their amplitude and duration. These steps, presented in Figure 4, consist of:

1. Data processing
2. Filtering
3. Detection
4. Identifying and classifying violations

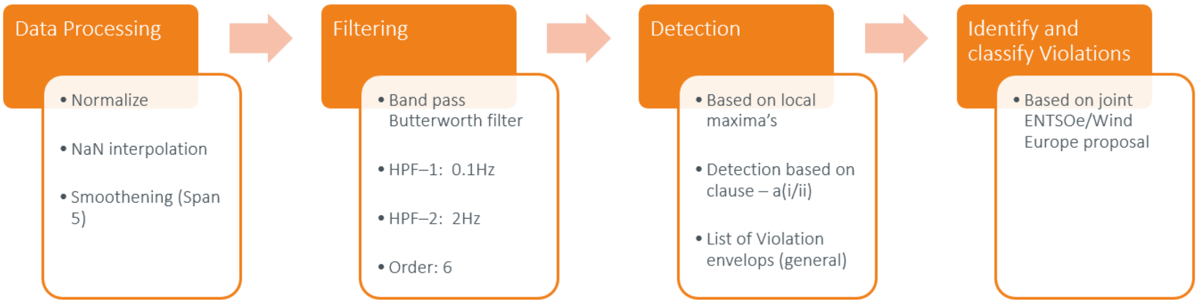

Figure 4. High-level signal post-processing procedure.

This chapter presents a detailed non-binding methodology and developed prototype tool to assess forced oscillations based on the above steps, and is structured as follows:

- Section 3.1, Section 3.2, Section 3.3, and Section 3.4 describe the four steps of the proposed methodology.
- Section 3.5 presents the outputs of the developed tool.
- Section 3.6 and Section 3.7 describe the developed tool and its limitations, respectively.
- Finally, Section 3.8 provides an alternative method to detect forced oscillations.

As presented in Section 2.3, several clauses are defined in the draft NC RfG 2.0 to limit forced oscillations: clauses a(i), a(ii), b(i), b(ii), b(iii), c(i), and c(ii). For simplicity, in the remainder of this chapter, these clauses will be directly referred to as such, without making reference to the article number in the draft NC RfG 2.0.

3.1 Data processing

The input data is typically a time series with a sample frequency of 10 Hz or higher and a duration of one week. As a first step, this input data is checked to detect potential gaps. These gaps can be filled by linear interpolation between the nearest valid samples. The data is then normalised to per unit (pu) values.

Finally, the data can be smoothed using a moving average filter to remove measurement noise. However, this is not recommended, as it attenuates possible existing forced oscillations at the high end of the frequency range.

3.2 Filtering methods and detrending techniques

As a second step, a filtering process is employed to pass the frequencies in the power oscillation range and reject the rest of the information. With this objective, a band-pass Butterworth filter is designed to allow frequencies in the specified range (for the example below, a band of 0.10–2 Hz is used). A filter order of 6, with slopes of over −100 dB/decade, is found to have sufficient selectivity, and a sampling rate of 10 Hz is employed. In case of different sampling rates, the Butterworth filter shall be adapted coherently. Figure 5 shows the magnitude response of the designed band-pass Butterworth filter.

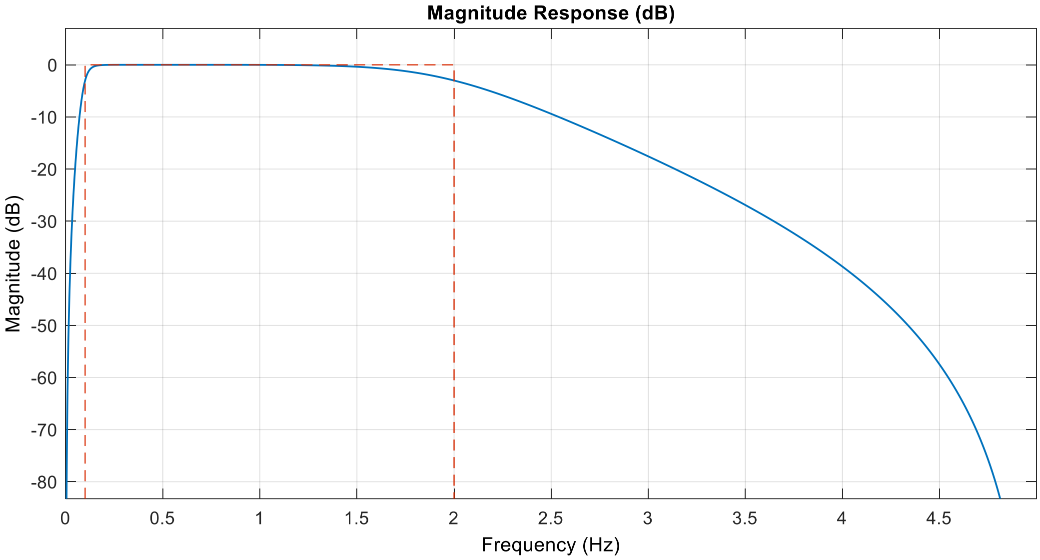

Figure 5. Frequency response of the band-pass Butterworth filter with a frequency range of 0.1–2.0 Hz and a sample frequency of 10 Hz (showing frequencies up to the Nyquist frequency of 5 Hz).

3.3 Detection

In this third step, the algorithm finds the local maxima in the filtered time series and compares them with the limits set in ACER’s NC RfG 2.0 proposal in clauses a(i) and a(ii) related to the power amplitude of the oscillations.

Firstly, at each timestamp, the limit for oscillation amplitude would be defined by the most permissive value (larger value) between clauses a(i) and a(ii). This process is exemplified by the following figure, where the red curve represents the maximum allowed oscillation amplitude per timestamp and the blue curve is the filtered power production in pu. In the example below, the default values for offshore wind farms were considered to illustrate the logic.[3]

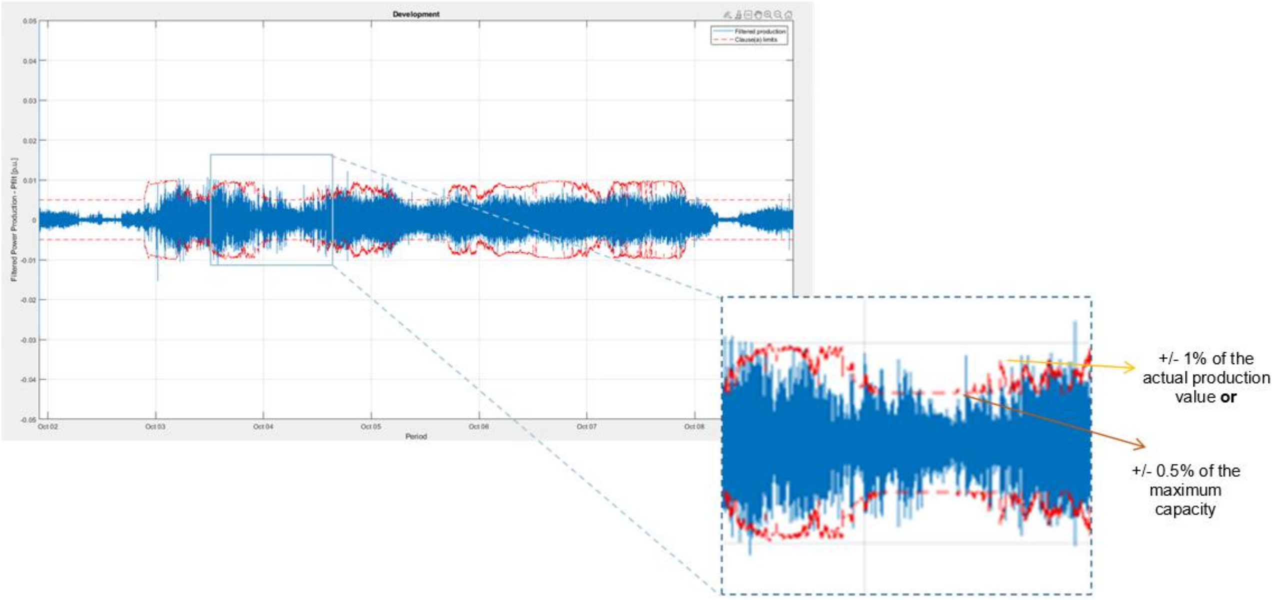

Figure 6. Maximum allowed power amplitude of forced oscillations detection.

Afterwards, the algorithm checks for adjacent maxima above the limit and groups them into envelopes while recording their length and the maximum amplitude within the envelope. This process can be illustrated in the figure below, where the green boxes represent those envelopes.

- A violation envelope is initiated as soon as the local maxima exceeds the dynamic threshold (clause a(i)/a(ii)), and the envelope ends when the local maxima return below this threshold.
- Envelope start, end, and duration, as well as the peak amplitude and behaviour within the envelope, are recorded.
- This detection proceeds serially along the data.
- A list of all envelopes is created which is the primary violation data.
- Events are then picked based on the criterion in proposal clauses b (i)/(ii)/(iii).

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[3] *In the frequency range of 0.1–2 Hz.*

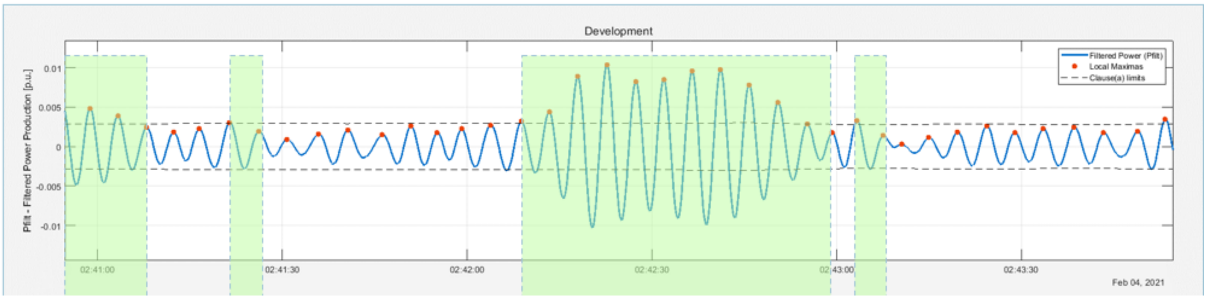

Figure 7. Oscillation envelopes detection based on local maxima.

3.4 Identify and classify violations

The tool will identify the oscillations and classify them according to ACER's proposal on NC RfG 2.0 as a pass or fail, and report those values mainly through an output table (see the following section).

3.5 Data visualisation and outputs

The following table is of interest as part of the post-processing process. The main output of the tool in order to assess the results of a specific wind farm, would have the following format (example for default limits for offshore wind farm in the range of 0.1–2 Hz).

Note that clauses a(i) and a(ii) are not reported due to their definition (see Section 2.3) of being the ones defining the initial limits. Only in cases where these clauses are not respected are the remaining clauses assessed. However, if these clauses are respected, the wind farms are also compliant with the other clauses.

Clauses	Date	Allowed Limit	Actual Value	Number of Violations	Pass (P) or Fail (F)
b(i)	1–7 January 2024	4%	No violations	0	P
b(ii)	1–7 January 2024	180 seconds	No violations	0	P
b(iii)	1–7 January 2024	2% for 90 seconds	No violations	0	P
c(i)	1 January 2024	00:14:24 (1%)	00:02:03 (0.14%)	6	P
	3 January 2024		00:00:25 (0.029%)	2	P
	4 January 2024		00:03:50 (0.27%)	13	P
	5 January 2024		00:11:47 (0.82%)	39	P
	6 January 2024		00:01:28 (0.1%)	6	P
	7 January 2024		00:00:27 (0.031%)	2	P
c(ii)	1–7 January 2024	8 hours with more than 3 violations	6 hours with more than 3 violations	-	P

Table 1. Example of the output format of the prototype tool for a single week of data.

3.6 Tool description

To properly assess forced oscillations in the context of the current work, it is relevant to have a common tool that serves as a reference point and a mechanism to unify compliance criteria.

As part of the ongoing work, a prototype of a MATLAB tool was developed, which considers different assumptions (normalisation, detrending function, NANs (not a number) interpolation, use of a Butterworth filter, etc.). This tool was used and improved as part of the current work by simulating the cases presented in Chapter 5.

Note that, at the time of writing, this tool is not publicly available, as the prototype is undergoing further development and improvement.

3.7 Tool limitations

The MATLAB tool is a prototype that can be further improved by the interested party to assess forced oscillations. The tool was initially developed to cover low frequency ranges. The increase in frequency ranges might result in a lower degree of accuracy due to the introduction of more distorted and less symmetrical waveforms. Therefore, as mentioned above, if the tool is used to process up to 20 Hz data, these limitations must be considered.

The tool is based on the detection of two continuous local maxima, which can belong to any frequency component, since ACER’s proposal for NC RfG 2.0 is intended to be applied in an aggregated time-based manner. However, in line with the technical considerations outlined in Section 1.2, treating all frequency components in aggregation, regardless of their specific value, does not reflect the varying degrees of risk posed by different frequencies. Frequencies closer to lightly damped system modes are of greater concern for system stability and may require stricter limits, whereas others may be less critical. For example, an oscillation lasting 50 s at 0.2 Hz followed by 50 s at 1 Hz would be treated as equivalent to a 100-s oscillation at 0.2 Hz, even though the system stability risk is significantly higher in the first case. Therefore, this tool limitation must be taken into consideration.

3.8 Application of other methods for the detection of forced oscillations

The tool presented in the previous sections is based on the identification of local maxima in the signal. Therefore, it cannot differentiate between oscillations that potentially occur at multiple frequencies (e.g. different structural eigenmodes of the turbine) or that are due to natural variation in wind speed (turbulence). In addition, the presence of measurement noise in the signal may lead to incorrect estimation of the duration of the forced oscillation.

Other methods may overcome this limitation by applying a time frequency–based approach, such as a short-time Fourier transformation (STFT). However, the STFT has the opposite drawback: it lacks good time resolution for all frequencies in the range under investigation (at least 0.1–2.0 Hz). An alternative approach that yields good resolution in both time and frequency is the continuous wavelet transformation (CWT), which offers time resolution that scales with frequency.

To investigate the applicability of the CWT, it was used to replace the detection function based on local maxima, while the components of the tool that detect the amplitude and duration of the events remained unaltered. Data from offshore and onshore wind farms were used (see Chapter 5 for a description of the data). This CWT-based method yielded good and reliable results. However, in terms of compliance, the outcomes were not significantly different from those obtained with the time-based algorithm. The results are similar, especially when a single forced oscillation is present in the data.

This indicates that compliance is primarily influenced by the allowable percentage of the maximum capacity, as shown in Chapter 5, and less by the method used to calculate the amplitude and duration of the forced oscillation.

A drawback of using the CWT is that it is less intuitive than the time-based approach and requires a longer processing time. Furthermore, the technology is potentially patented in the EU and the United States (the process is ongoing). All in all, the technical group recommends using the original time-based approach with local maxima for detecting forced oscillations within the scope of Articles 21.3 and 26.2 of the draft NC RfG 2.0 – at least until the status of relevant patents is clarified. This avoids giving preferential treatment to developers willing to pay for the potentially patented algorithm.

The group is open to implementing other methods in the future (a review of the existing thresholds might be necessary in this scenario).

4 Grid code compliance assessment

This chapter is focused on grid code compliance assessment for forced oscillations, and is structured as follows:

- Section 4.1 provides guidelines for the measurement location and data.
- Section 4.2 describes the compliance testing process.
- Section 4.3 and Section 4.4 conclude the chapter with recommendations for compliance simulation and monitoring, respectively.

4.1 Measurements and data collection

Measurement location

The TSO, in cooperation with the grid user (GU), defines the point(s) where the high-quality power measurements will be installed. In most cases, the measurement will be installed at the point of common coupling (PCC) or connection point, but alternatives should remain possible. On such occasions, the measurement location should be relevant in relation to the impact of the forced oscillations on the grid, and the cost and effort to install and manage such measurement system(s) should be optimised. The main reason to allow for alternative measurement locations is the trend towards multi-PCC connections of offshore wind farms.

Increasingly, TSOs install offshore transformer capacity built on platforms or an artificial island. Multiple Connection Points or PCCs are to be covered by the same grid connection agreement. Hence, the measurement point(s) for the forced oscillations should be agreed upon by the TSO and the GU.

The measurement devices will be installed by the GU, using current transformer (CT) and voltage transformer (VT) signals provided by either the TSO or the GU.

Aggregation of sites

As explained above, for newer and upcoming sites, there are a number of connection points in areas previously considered a wind farm.

To illustrate the impact this will have on the compliance evaluation, it was decided to combine two sites (Site02 and Site08) to form Site12. The power for Site12 is the sum of the active power of Site02 (Figure 8) and Site08 (Figure 9).

Each site is analysed using the default values for offshore wind farms[4]: maximum between 1% of actual production (a(i)) and 0.5% of site rated power (a(ii)). The figures show an example where two sites tend to have components in the 0.1–2 Hz range that exceed the limits. The upper subplot shows the number of hours where exceedances were observed during the week, and the lower subplot shows the number of hours during the week where more than three events per hour were observed (c(ii)). The red line is the eight hours defined by the 95th percentile (168 * 0.05 ≈ 8).

The data used to create the plots were collected from 25 November 2023 to 16 November 2024.

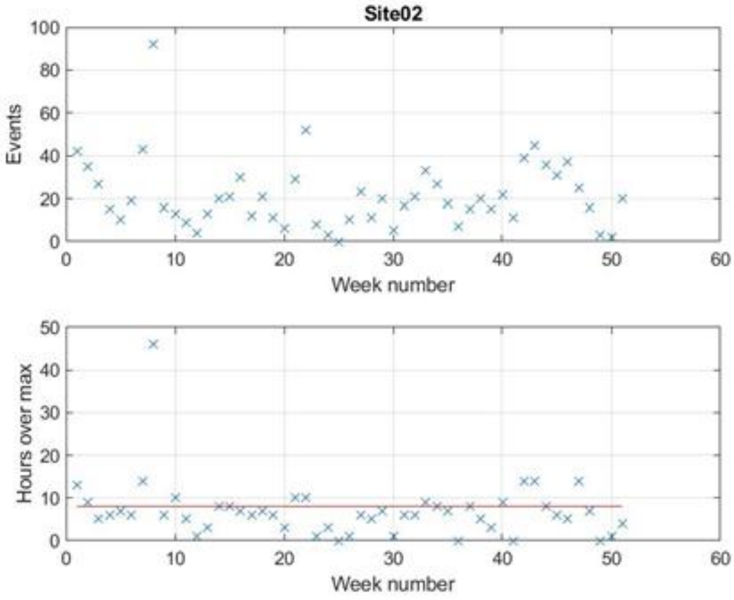

Figure 8. Weekly results for Site02.

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[4] *For the frequency range 0.1–2 Hz.*

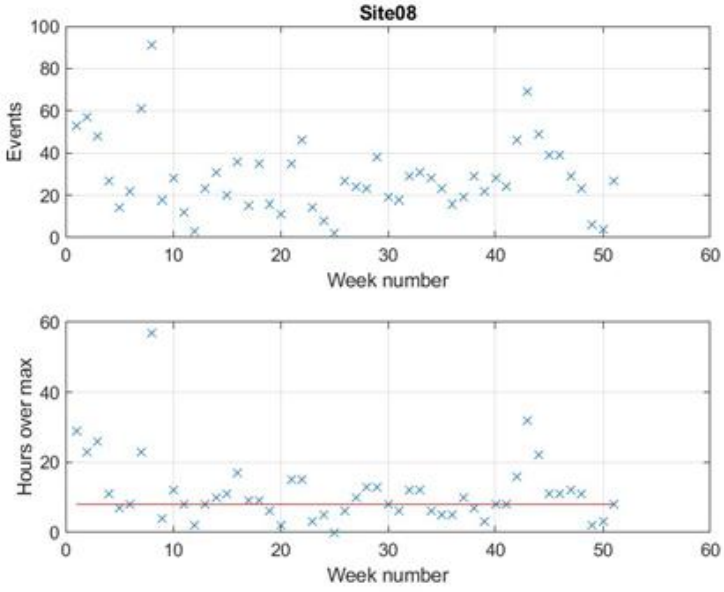


Figure 9. Weekly results for Site08.

The aggregated power time series for Site02/Site08 (Figure 10) were run through the same processing as the two individual sites. The results indicate that the aggregated site shows no compliance issues when evaluated on a weekly basis.

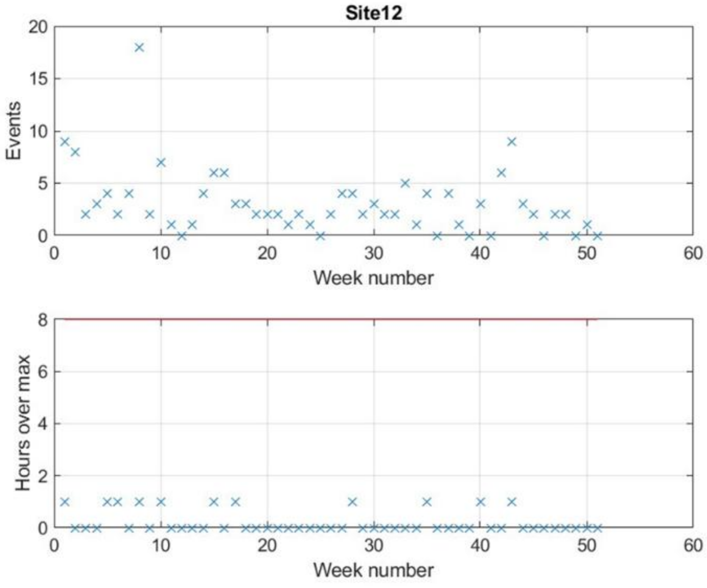


Figure 10. Weekly results for Site12.

The aggregated sites have very similar structural eigenfrequencies, so the difference in results is due to the fact that damping powers are not correlated across wind turbine generators (WTG) during the normal operation scenarios that are addressed by the requirements.

The plots show that there is variation in the excitation from week to week, so conclusions should not be drawn based on data from only one or a few weeks.

Accuracy requirements of measurement sensors (voltage and current transformers)

The accuracy of the measurement sensors used must be in line with current industry standards. Accuracy class 0,2(s) for energy measurement is advised.

Measurement device

The default measurement device to be used is a PMU following the IEC/IEEE 60255-118-1 standard. The PMU would preferably be an M-class in accordance with the above-mentioned standard to avoid aliasing.

Sample rate

A 100 ms resolution is considered sufficiently accurate for the most relevant frequency range up to 2 Hz.

As the requirement on forced oscillation is applicable up to 20 Hz, the application of the Shannon/Nyquist theorem leads to a minimum sampling rate of 40 Hz (25 ms). Due to several filtering stages inside the PMU algorithm, the usual 50 Hz (20 ms) sampling rate would be enough to achieve good accuracy at 20 Hz (based on a Nyquist frequency 25 Hz).

Hence, beyond 2 Hz, a project-specific approach is advised. The sampling rate will be arranged between the relevant system operator and the GU.

Data collection

The measurement data will be collected by the GU and made available to the TSO via secure IT/OT technology. However, the final choice will be made by the TSO and GU on a case-by-case basis. The data will be made available for a period of one year in an agreed-upon file format. The required licences will be obtained by the party that installed and maintains the measurement.

4.2 Compliance testing

The objective of compliance testing is to check the active power oscillations measured at the PCC or locations agreed upon between the TSO and the GU against the requirements set out in Articles 21 and/or 26 of the draft NC RfG 2.0. In accordance with Section 4.1, compliance testing will be conducted at the offshore wind farm level.

Testing is allowed at the single connection point level for an entire wind park, at the aggregated connection point level, at the access point level, or at any point agreed upon between the TSO and power generation facility owner.

Process

The process of verifying compliance with regard to active power oscillations can be divided into three main stages:

- The measurement data is gathered at the agreed-upon measurement location using approved measurement devices.
- The measurement data is processed and stored in an agreed-upon file format and size at a location accessible by the TSO.
- The GU and the TSO can perform and report the compliance analysis, as both parties have access to the raw data. The results of the analyses will be reported on a weekly/bi-weekly/monthly basis. No specific format is needed. However, each TSO may request to follow a specific format or template.

The Final Operation Notification (FON) is to be issued at the end of the wind park construction and after successful grid connection compliance (GCC) testing as described in the TSO compliance verification program, excluding the evaluation of forced oscillations. During wind farm construction, the measurement devices can be installed and verified. The data transfer between the GU and TSO is to be set up.

Once the wind farm is completed, the forced oscillations monitoring and assessment process to prove compliance can start:

- The first evaluation can take place after at least 2 months of full wind farm operation.
- In case of violations of the imposed limits for forced oscillations, the TSO and the GU will begin investigating mitigation measures and determining the way forward.
- After analysing further measurement data and defining the mitigation measures to respect the imposed limits for forced oscillations, the measures will be implemented, and a new measurement and assessment period starts.
- This cycle may be repeated more than once in mutual agreement between the TSO and the GU.
- Finally, if the GU fails to comply with the imposed requirements and no further mitigation measures are proposed by the GU, the TSO can decide to withdraw the FON after the last assessment.
- The FON is to be issued again when the requirements are met.

The compliance analysis shall consider the exclusion of *Operation under disturbed network conditions* and *System support requests* as per draft NC RfG 2.0, Articles 21.3 and 26.2, as summarised in Table 2:

- Legal text related to exclusion of ***Operation under disturbed network conditions***: *"...subject to the following requirements relative to the total active power and current forced oscillations, when* ***system conditions are within the frequency ranges as specified in Table 2 and voltage ranges as specified in Table (27) 10****:"*
- Legal text related to exclusion of ***System support requests***: *"(d) Forced oscillations originated from system support requests by the relevant system operator, such as power oscillation damping, are* ***excluded from this requirement****."*

Draft NC RfG 2.0 Article	**Capability**	**Normal operating conditions (non-disturbed network conditions)**	**System support request**
13(3)	Limited frequency sensitive mode – overfrequency (LFSM-O)	No	Yes
14(3), 16(3)	Fault-ride-through (FRT) capability	No	Yes
15(2)(a)	Active power controllability	Yes	No
15(2)(d)	Frequency sensitive mode (FSM)	Yes	No
15(2)(c)	Limited frequency sensitive mode – underfrequency (LFSM-U)	No	Yes
15(2)(e)	Frequency restoration control	No	Yes
15(4)(a)	Black start capability	No	Yes
15(4)(b)	Island operation	No	Yes
15(4)(c)	Quick re-synchronisation capability	No	Yes
20(2)(b)	Fast fault current injection (FFCI)	No	Yes
20(3)	Post-fault active power recovery	No	Yes
Y(7), 20(4), 21(4)	Grid forming capability	No	Yes

Draft NC RfG 2.0 Article	Capability	Normal operating conditions (non-disturbed network conditions)	System support request
20(5)	Synthetic inertia	No	Yes
21(2)(b)	Reactive power capability at maximum capacity	Yes	No
21(2)(c)	Reactive power capability below maximum capacity	Yes	No
21(2)(d)	Reactive power control modes (voltage, reactive power, and power factor control)	Yes	No
21(2)(f), 22(2)	Power oscillation damping	Yes (because it can be continuously or triggered)	Yes
21(3), 26(2)	Forced oscillations	-	-

Table 2. Draft NC RfG 2.0 Capabilities – Mapping with *Normal operating conditions* and *System support requests*.

4.3 Compliance simulation

While simulations based on electrical models are theoretically possible, they would not be required as part of the conformity process, as such simulations are lengthy and complex. Wind, waves, and damping must be considered; therefore, the reliability and accuracy of such simulations cannot be guaranteed. The electrical simulation models focus on providing an accurate representation of the hardware and control response to the events occurring in the electrical system. The components (tower + foundation) and the physics (wave height, water depth, wave/wind alignment) are not included in the simulation setup.

Instead of simulations in this regard, it is recommended to consider the ATD settings in the design phase as far as possible.

4.4 Compliance monitoring recommendations

After full wind park installation and commissioning, the forced oscillations monitoring begins, followed by regular data exchange.

As the largest oscillations are expected under certain wind and wave conditions [13], the recommended monitoring period for compliance testing is one continuously year to capture seasonal impact (e.g. wind and wave). Earlier termination can be decided by mutual agreement.

5 Assessment of data from existing wind farms

Several members of the technical group have shared data or conducted internal assessments to investigate the extent to which current wind farms comply with the proposed requirements. The results are summarised and discussed below:

- Section 5.1, Section 5.2, and Section 5.3 present the results of the forced oscillations assessments based on the data shared by two turbine manufacturers (OEM1 (Original Equipment Manufacturer) and OEM2) and by one wind developer (DEV1).
- Section 5.4 and Section 5.5 analyse additional scenarios for the strictest, default and least-strict limits.
- Section 5.6 performs a dedicated analysis of clause b(i).
- Section 5.7 focuses on the assessment of offshore wind farms for frequencies above 2 Hz.
- Finally, Section 5.8 concludes with recommendations based on the performed assessment.

5.1 Results from OEM1

OEM1 applied the algorithm to data from five different onshore wind farms, ranging from a total installed power of less than 10 MW to more than 100 MW. The data for the period from October 2024 to April 2025 was analysed. This data is characterised by a sample frequency of 10 Hz.

Only weeks with full data availability were included, which resulted in a total of 83 weeks (after combining the five analysed wind farms). Due to the sample frequency of 10 Hz, the only frequencies considered were those in the 0.1–2 Hz range, which is the default setting of the band pass filter in the MATLAB implementation of the algorithm (as mentioned in Section 3.2).

Initially, three different scenarios were investigated:

- In the first scenario, the least-strict values for all the limits were applied (***least strict***). For example, regarding clause a(i) of Article 21.3, the value on the larger end of the range was used (i.e. 1%).
- In the second scenario, the default values for all the limits were applied (***default***). For example, for clause a(i) of the same article as above, this means that the default value of 0.5% was used.
- In the third scenario, the strictest limits were applied (***most strict***). For example, for clause a(i) of the same article as above, the value of the smaller end of the range was used (i.e. 0.1%).

To produce meaningful results in this analysis, whether the wind farm meets the requirements set in b(i), b(ii), b(iii), c(i), and c(ii) is recorded for each week. Then, for each of these clauses, the percentage of weeks that pass the requirements aggregated over all wind farms is calculated. For example, a percentage of 100% for clause b(i) means that for all available weeks, the wind farms meet the requirements set in b(i).

The results are listed in Table 3:

	b(i)	b(ii)	b(iii)	c(i)	c(ii)	overall
Least strict	87%	100%	100%	100%	100%	87%
Default	87%	100%	100%	99%	99%	87%
Most strict	19%	99%	100%	75%	72%	18%

Table 3. Aggregated results of OEM1 for five onshore wind farms with three scenarios (least strict, default, most strict). Span = 5, b1_duration = 1 s. Colour scale: 100% 90% 0%

The results show that in none of the scenarios are the requirements of **clause b(i)** met for all weeks. This particular clause sets a maximum instantaneous power amplitude for forced oscillations between 0.1 Hz and 2.0 Hz (based on available sampling data). Further analysis of the weeks that failed the requirement revealed that the exceedance of b(i) was mostly caused by a sudden increase or decrease of the wind farm's grid power, originating from an external set-point change. Figure 11 shows an example where at 17:26:41, the curtailment at 0.45 pu was lifted and the wind farm's grid power was rapidly increased to the aerodynamically available power. When such a signal is passed through the band-pass filter applied in the algorithm, it results in one or two large fluctuations above the b(i) threshold.

A straightforward solution would be to limit the rate at which these set-point changes are applied in the wind farm controller. However, existing grid requirements mandate a quick response to this type of set-point change. It is therefore suggested to filter out these types of events from the analysis of forced oscillations.

See Section 5.6 for a suggested methodology to achieve this.

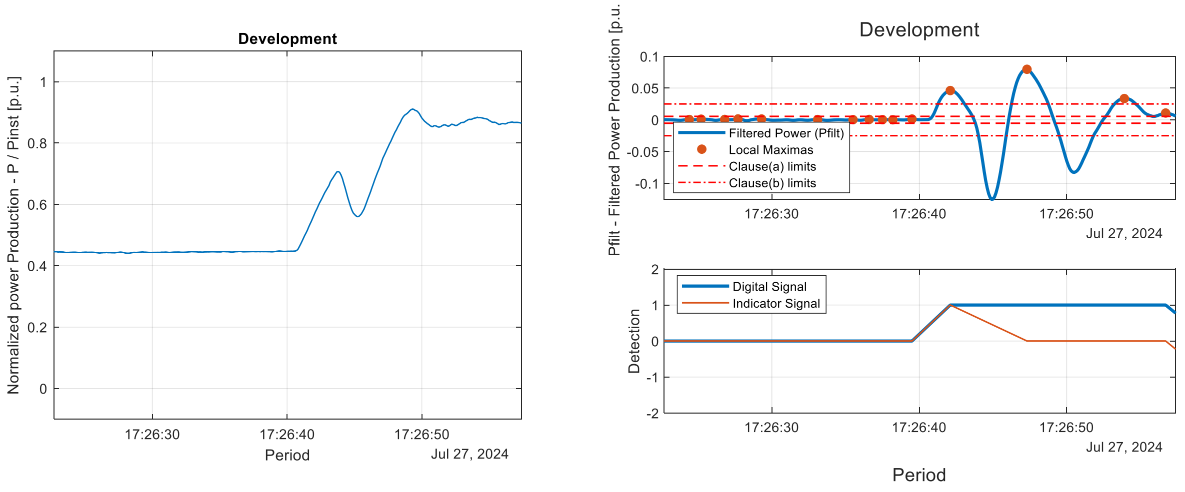


Figure 11. Example of a grid event leading to an exceedance of the b(i) limit.

Regarding the **other clauses – b(ii), b(iii), c(i), and c(ii) –** the results in the table show that all weeks meet the requirements only in the case of *least strict* limits. With *default* limits, almost all weeks meet the requirements, with only one out of 83 weeks failing.

This single week was further analysed. From the power spectral density in Figure 12 (right plot), there is no single frequency leading to non-compliance, but rather low frequency fluctuations at the lower side of the band-pass filter (near 0.1 Hz), and partly below. This aligns with the results of the analysis of synthesised wind farm data (see Appendix C): even normal turbulence levels can lead to exceedances of default limits. One could argue that, because the wind farm's output power does not exhibit a forced oscillation at a single frequency, this type of fluctuation does not increase the risk of grid instability and therefore should not lead to non-compliance. In the process of testing wind farm compliance, these weeks may be individually investigated to determine whether a forced oscillation is present in the signal. A more automated method could be to look at only one narrow frequency band at a time (instead of using one band-pass filter for the full range), by using an STFT or wavelet transform. This particular use of the wavelet transform has not been further investigated, but the general use of wavelets is described in Section 3.8.

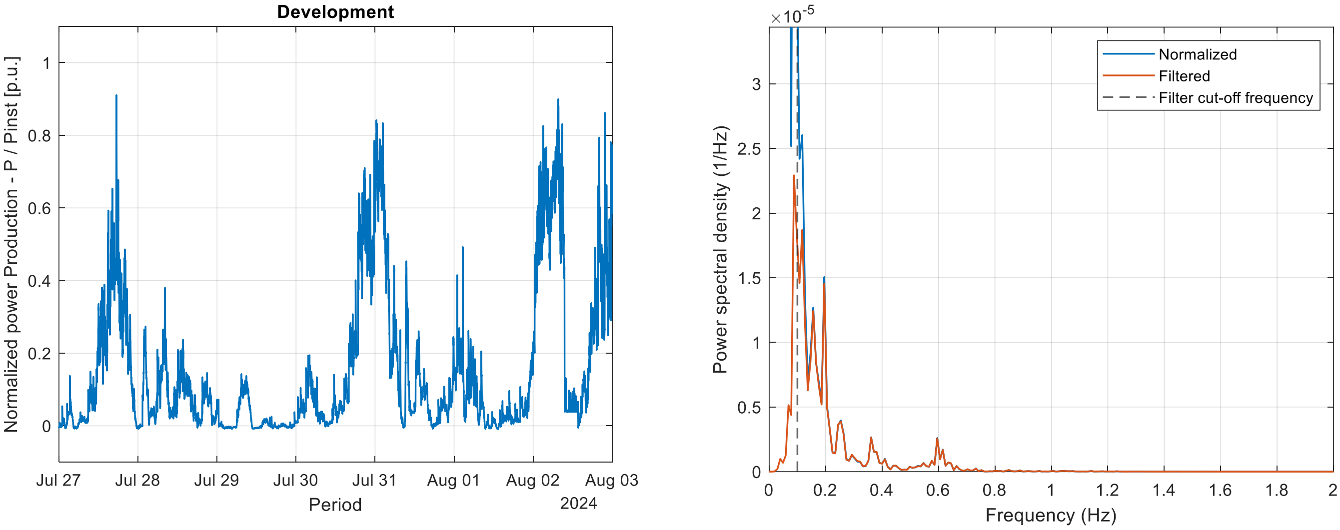


Figure 12. Example of a week with high turbulence, leading to the failure of clauses c(i) and c(ii).

With *most strict* limits, most of the weeks (99%) met the b(ii) requirements, and all weeks met those of b(iii), indicating that, in general, forced oscillations damp out relatively quickly. However, clauses c(i) and c(ii) were frequently violated, indicating that, although they damp out quickly, the forced oscillations occur too frequently. This is a clear indication that the strict limits are not feasible for onshore wind farm compliance.

5.2 Results from OEM2

The data analysis was done on data from 25 November 2023 to 1 June 2024 (27 weeks). The data was divided into one-week intervals to assess compliance with the criterion that 95% of the hours must have no more than three exceedances of the limit. The data analysis was conducted using the Butterworth filter. The limit referenced here is described in part a of the requirements in Chapter 2.

$$Filter_{limit} = max\ (a_1 \cdot P_{Exchange\ Agreement},\ a_2 \cdot P_{actual})$$

where the default value of $a_1 = 0.005$, $a_2 = 0.01$. The data analysis performed in this section does not filter out any data based on grid events. The analysis does disregard exceedances shorter than 10 s.

The principle is that the production data is normalised with the site exchange agreement. This normalised production is filtered using a sixth-order Butterworth bandpass filter to calculate the energy context in the 0.1–2 Hz range.

The analysis of one week of data for Site02 is shown in the figure below. The upper plot shows the normalised production. The middle plot shows the absolute value of the filtered production. The lower plot shows the number of times per hour where the production limit is exceeded. When the number of exceedances is higher than three, it is coloured red to show that the number of exceedances is higher than the allowed number.

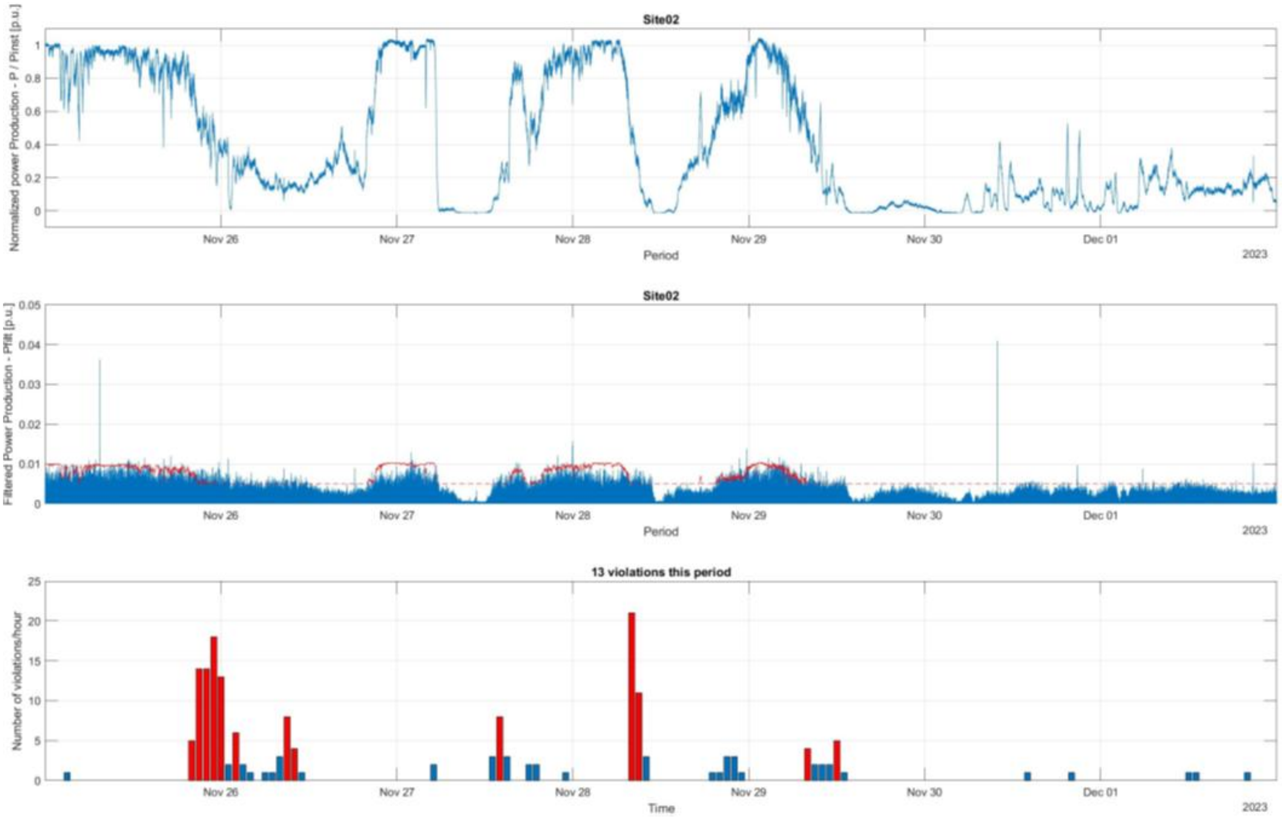


Figure 13. Example of data analysis for one week.

Instead of providing these plots for each week for each wind farm, the number of exceedances per week for each site is presented in Figure 14. The upper subplot shows the number of hours where the filtered output was above the limit. The lower subplot shows the number of hours during the week where the limit was exceeded more than three times. Eight hours per week are allowed to have more than three exceedances of the limit, so the red line indicates the accepted number of events. As shown in the subplot, this specific site has more events than allowed during the number of weeks. In other words, for the Week 1 in the figure below, the first point in the upper subplot of Figure 14 is 42 because the limit was exceeded during 42 hours in that week (the number of bars in the histogram). The number of violations (red bars) is shown by the first point in the lower subplot.

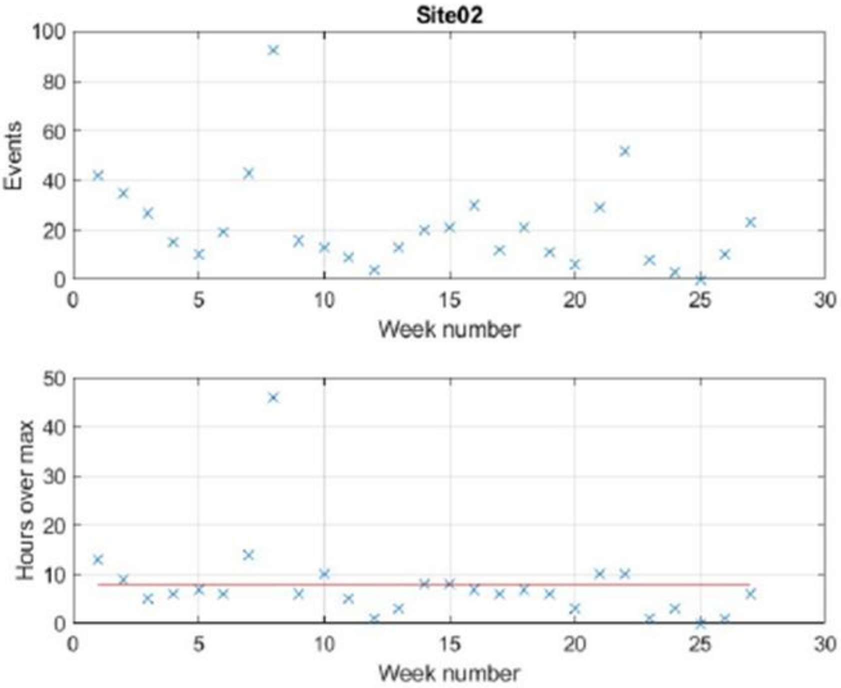


Figure 14. Weekly results for Site02.

Analysis of sites with default values

The results for the analysed sites are shown in the figure below. Site02 and Site 08 seem to have general issues with staying below the limits. The only other site with a single week where the criteria were not met is Site04.

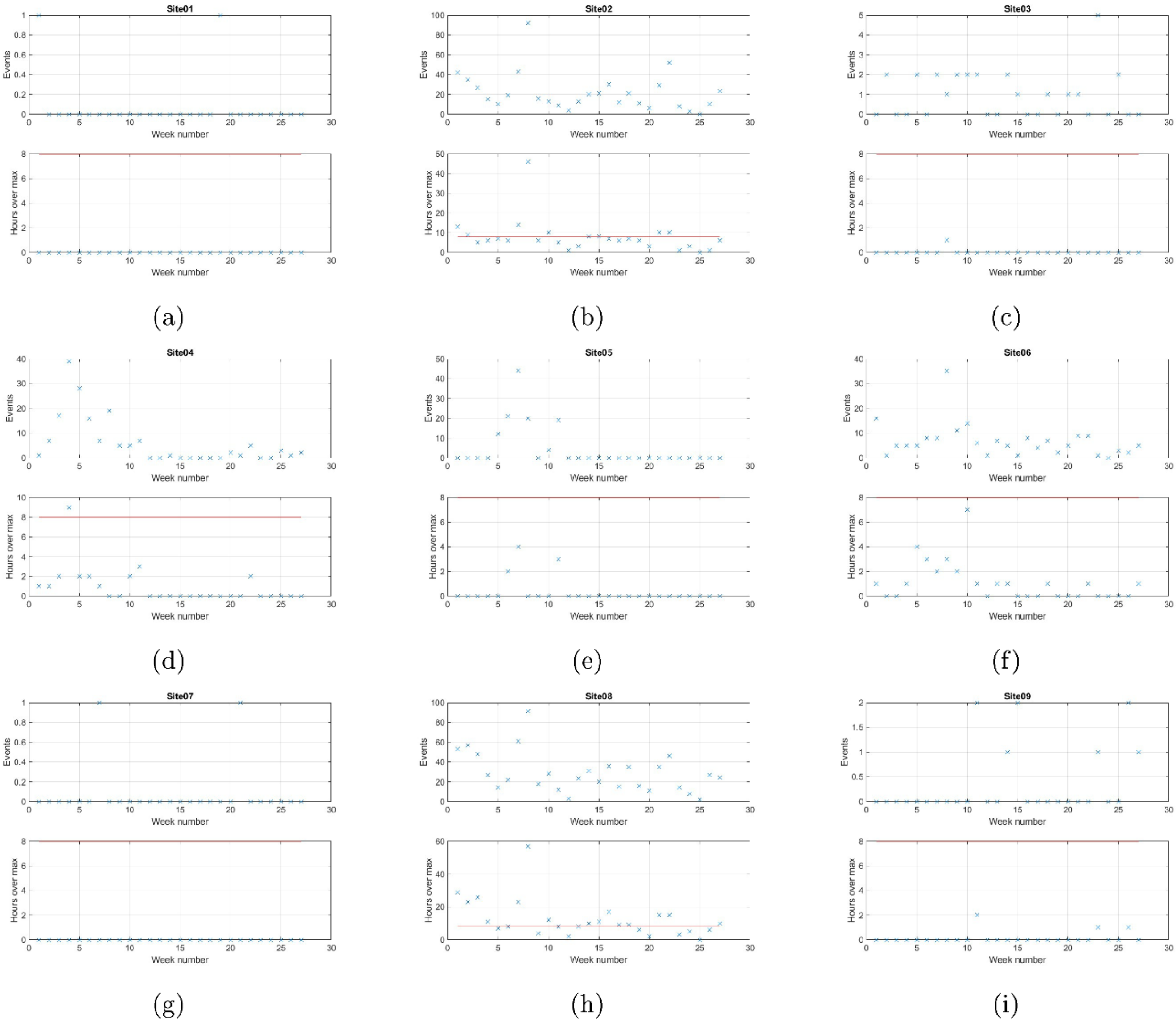
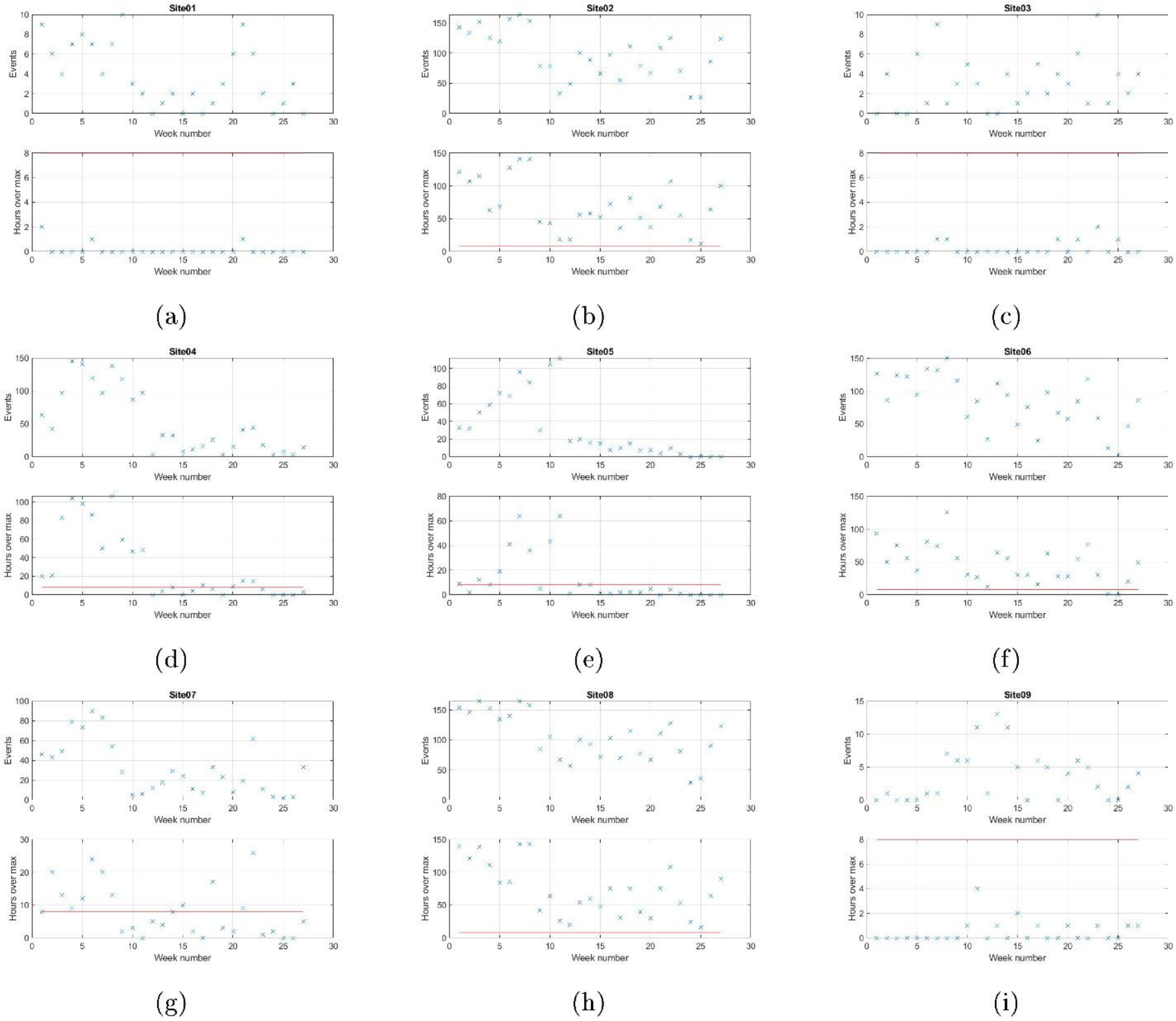


Figure 15. Site temporary exceedance using default thresholds.

The results in the previous figure show that the default limits are regularly exceeded on three of the analysed sites. Four of the other sites also have events exceeding the default thresholds, indicating that there is not a large margin to the compliance limit.

The analysis of sites with the strictest limits is shown in the figure below. Most of the sites seem to have issues with staying below the limits when the values are lower than the default values.



(a) (b) (c)

(d) (e) (f)

(g) (h) (i)

Figure 16. Site temporary exceedance using the strictest thresholds.

When the strict limits are used for the analysis, seven of the nine existing sites have values higher than those limits. This is a clear indication that the strict limits are not feasible.

5.3 Results from DEV1

DEV1 is a developer of offshore wind farms that has shared data for three large offshore wind farms (each with more than 25 turbines and more than 5 MW for the period from January 2024 to November 2024), and a sample rate of 20 Hz. This data was processed by OEM1 in the same way as explained in Section 5.1, i.e. using least strict, default, and most strict limits, but using the requirements set in Article 26.2 of the draft NC RfG 2.0. Some of the weeks were also analysed by an ENTSO-E member to cross-check the results. Only the last month was not processed, as this data were not yet available at the time of the first analysis. A total of 138 weeks were processed and analysed.

The results are presented again by showing the percentage of weeks (aggregated over all three wind farms) that pass the different clauses, as shown in Table 4:

	b(i)	b(ii)	b(iii)	c(i)	c(ii)	overall
Least strict	100%	100%	100%	100%	100%	100%
Default	100%	100%	100%	82%	85%	79%
Most strict	99%	46%	100%	28%	17%	17%

Table 4. Aggregated results of DEV1 of three offshore wind farms with three scenarios (least strict, default, most strict). Span = 5, b1_duration = 1 s. Colour scale: 100% 90% 0%

Regarding **clause b(i)**, at least 99% of the weeks were compliant for all scenarios. This is rather different compared to the results of the onshore wind farms and may be due to:

- Fewer events (set-point changes, curtailments, noise modes, etc.).
- The simple fact that, for offshore wind farms, the strictest value for clause b(i) is 2.5%, compared with just 0.5% for onshore – five times lower!

The results also show that applying the **most strict limits** leads to non-compliance for the majority of weeks, in accordance with the results from OEM2. Even when relaxing the requirements by using the default values, only 79% of the weeks are compliant. This is because the limits of c(i) and c(ii) are exceeded. However, the b(ii) and b(iii) clauses do not lead to exceedances, indicating that forced oscillations are damped out within the required time. Only when the **least strict limits** are chosen, all weeks meet the requirements for offshore wind farms.

5.4 Sensitivity analysis

The previous analyses show that when the strictest limits are chosen, wind farms that are operating normally are not compliant. This is undesirable, as normal operating wind farms should not be limited (see Section 2.2). To investigate which of the various parameters have the greatest impact on the outcome of the algorithm, several additional scenarios were run with the available data from DEV1 and OEM1. An overview of these scenarios and their respective limits is presented in Table 7 and Table 8 for offshore and onshore wind farms, respectively.

Scenarios C1–C5 are based on the default values, with the exception of a few parameters.

- **Scenario C1**: Default values, but the maximum percentage of time per day (clause c(i)) is *relaxed* from 1% to 1.5% and the percentile used to calculate the hourly exceedances is relaxed from 95% to 90%.
- **Scenario C2**: Default values, but the maximum percentage of time per day (clause c(i)) is *relaxed* from 1% to 1.75%.

- **Scenario C3**: Default values, but the maximum percentage of maximum capacity (Article 26, clause a(ii) for offshore wind farms and Article 21, clause a(i) for onshore wind farms) is *relaxed* from 0.5% to 0.75%.

- **Scenario C4**: Default values, but the maximum percentage of maximum capacity (Article 26, clause a(ii) for offshore wind farms and Article 21, clause a(i) for onshore wind farms) was *relaxed* from 0.5% to 0.65%, while the limits of clauses b(ii), b(iii), and c(i) were set to *more strict* at 150 s, 75 s, and 2/hour, respectively.

- **Scenario C5**: Default values, but the maximum percentage of maximum capacity (Article 26, clause a(ii) for offshore wind farms and Article 21, clause a(i) for onshore wind farms) was *relaxed* from 0.5% to 0.65%, while simultaneously (for offshore wind farms only) the maximum percentage of actual value (Article 26, clause a(i)) was *relaxed* from 1% to 1.25%.

The results are presented in Table 5 (offshore wind farms from DEV1) and Table 6 (onshore wind farms from OEM1).

Regarding the results for the offshore wind farms, it can be seen that:

- Only Scenario C3 (maximum percentage of maximum capacity *relaxed* from 0.5% to 0.75%) leads to full compliance.

- Scenarios C1 and C2 do not relax the maximum percentage of maximum capacity and still have a significant percentage of non-compliance (91% and 84%), even though the maximum percentage of time per day is relaxed.

- Scenarios C4 and C5 both come close to full compliance (99%). Both also relax the maximum percentage of maximum capacity to 0.65% and 0.6125%. In Scenario 4, the requirements for b(ii), b(iii), and c(ii) are also set to *stricter.*

	b(i)	b(ii)	b(iii)	c(i)	c(ii)	overall
Least strict	100%	100%	100%	100%	100%	100%
Default	100%	100%	100%	82%	85%	79%
Most strict	99%	46%	100%	28%	17%	17%
C1	100%	100%	100%	93%	95%	91%
C2	100%	100%	100%	96%	85%	84%
C3	100%	100%	100%	100%	100%	100%
C4	100%	100%	100%	100%	99%	99%
C5	100%	100%	100%	100%	99%	99%
C6	99%	100%	100%	100%	100%	99%
C7	99%	100%	100%	96%	91%	91%

Table 5. Results for scenarios C1–C7 for DEV1 of three offshore wind farms. Span = 5, b1_duration = 1 s.
Colour scale: 100% 90% 0%

The results for **onshore wind farms** show that the different scenarios do not have a significant impact on compliance with clauses b(i) and c(ii). That is because for these wind farms, the default limits already provide 99% compliance, so relaxing them does not improve the results. Out of the 83 weeks, it is the same week with high turbulence that also fails for the other scenarios.

	b(i)	b(ii)	b(iii)	c(i)	c(ii)	overall
Least strict	87%	100%	100%	100%	100%	87%
Default	87%	100%	100%	99%	99%	87%
Most strict	19%	99%	100%	75%	72%	18%
C1	87%	100%	100%	100%	99%	87%
C2	87%	100%	100%	100%	99%	87%
C3	87%	100%	100%	100%	99%	87%
C4	87%	100%	100%	100%	99%	87%
C5	87%	100%	100%	99%	99%	87%
C6	22%	100%	100%	100%	99%	22%
C7	20%	100%	100%	100%	99%	20%
C8	98%	100%	100%	99%	99%	98%

Table 6. Results for scenarios C1–C7 of OEM1 of five onshore windfarms. Span = 5, b1_duration = 1 s.
Colour scale: 100% 90% 0%

5.5 Extended sensitivity analysis

The previous results show that clause a(ii) for offshore wind farms has a large effect on the results: increasing the limit from 0.5% (default) to 0.75% (Scenario C3) increased the compliance ratio from 79% to 100%, even when the other limits were left at their default values. In addition, the other two scenarios (C4 and C5), which have a relaxed limit for clause a(ii), resulted in high compliance ratios of 99%. In contrast, the two scenarios (C1 and C2) that did not relax the limits of clause a(ii) but instead relaxed the limits of clauses c(i) and c(ii) still led to low compliance ratios (91% and 84%, respectively). This reflects the high sensitivity of clause a(ii) for offshore wind farms.

An additional analysis was subsequently carried out for both offshore and onshore wind farms to investigate whether the compliance ratio could be increased to acceptable values when the strictest limits are used for all clauses except a(ii). Therefore, two additional scenarios, C6 and C7, were investigated:

- **Scenario C6**: Most strict values, but the maximum percentage of maximum capacity (Article 26, clause a(ii) for offshore wind farms and Article 21, clause a(i) for onshore wind farms) was *relaxed* from 0.5% to 0.75%.

- **Scenario C7**: Most strict values, but the maximum percentage of maximum capacity (Article 26, clause a(ii) for offshore wind farms and Article 21.3, clause a(i) for onshore wind farms) was *relaxed* from 0.5% to 0.65%.

The results are presented in Table 5 (offshore wind farms from DEV1) and Table 6 (onshore wind farms from OEM1).

The results show that acceptable compliance ratios are indeed achieved for all clauses except b(i) for both onshore and offshore, even with the strictest limits, when the maximum percentage of maximum capacity is set to 0.75% for offshore and 0.65% for onshore (or higher).

The following tables show the different analysed combinations.

	Clause a(i)	Clause a(ii)	Clause b(i)	Clause b(ii)	Clause b(iii)	Clause c(i)	Clause c(ii) 1	Clause c(ii) 2
	max pct of actual value	max pct of max capacity	max pct of max capacity	time within limits of clause a	time within 50% limits of clause b(i)	max pct of time per day	max per hour	based on percentile
	a1_limit	a2_limit	b1_limit	b2_duration	b3_duration	c1_limit	c2_violations_per_hour	c2_limit
Least strict	2.00%	1.00%	5.0%	180 s	90 s	2.00%	4/hour	85%
Default	1.00%	0.50%	4.0%	180 s	90 s	1.00%	3/hour	95%
Most strict	0.50%	0.25%	2.5%	100 s	50 s	1.00%	2/hour	95%
C1	1.00%	0.50%	4.0%	180 s	90 s	1.50%	3/hour	90%
C2	1.00%	0.50%	4.0%	180 s	90 s	1.75%	3/hour	95%
C3	1.00%	0.75%	4.0%	180 s	90 s	1.00%	3/hour	95%
C4	1.00%	0.65%	4.0%	150 s	75 s	1.00%	2/hour	95%
C5	1.25%	0.6125%	4.0%	180 s	90 s	1.00%	3/hour	95%
C6	0.50%	0.75%	2.5%	100 s	50 s	1.00%	2/hour	95%
C7	0.50%	0.65%	2.5%	100 s	50 s	1.00%	2/hour	95%

Table 7. Additional scenarios and their respective limits for AC-connected offshore wind farms (Article 26.2). Colour scale: Least restrictive Most restrictive

Scenario	Clause a(i) max pct of max capacity a1_limit	Clause a(ii) a2_limit	Clause b(i) max pct of max capacity b1_limit	Clause b(ii) time within limits of clause a b2_duration	Clause b(iii) time within 50% limits of clause b(i) b3_duration	Clause c(i) max pct of time per day c1_limit	Clause c(ii) max per hour c2_violations_per_hour	Clause c(ii) based on quantile c2_limit
Least strict	1.00%	500 kW	3.0%	180 s	90 s	2.00%	4/hour	85%
Default	0.50%	500 kW	2.5%	180 s	90 s	1.00%	3/hour	95%
Most strict	0.10%	200 kW	0.5%	100 s	50 s	1.00%	2/hour	95%
C1	0.50%	500 kW	2.5%	180 s	90 s	1.50%	3/hour	90%
C2	0.50%	500 kW	2.5%	180 s	90 s	1.75%	3/hour	95%
C3	0.75%	500 kW	2.5%	180 s	90 s	1.00%	3/hour	95%
C4	0.65%	500 kW	2.5%	150 s	75 s	1.00%	2/hour	95%
C5	0.6125%	500 kW	2.5%	180 s	90 s	1.00%	3/hour	95%
C6	0.75%	200 kW	0.5%	100 s	50 s	1.00%	2/hour	95%
C7	0.65%	200 kW	0.5%	100 s	50 s	1.00%	2/hour	95%
C8	0.50%	500 kW	4.0%	180 s	90 s	1.00%	3/hour	95%

Table 8. Additional scenarios and their respective limits for onshore wind farms (Article 21.3). Colour scale: Least restrictive Most restrictive

5.6 Filtering out b(i) violations caused by normal events

Clause b(i) sets a maximum for the instantaneous power amplitude of a forced oscillation. The analyses in the previous sections show that the requirements set in clause b(i) are frequently violated, especially for onshore wind farms. This is because the limit for onshore wind farms is much lower (most strict limit: 0.5%) compared to offshore wind farms (most strict limit: 2.5%).

Often, exceedance of the limit is caused by set-point changes in the wind farm's active power output. See, for instance, the example in Figure 11. It is a common viewpoint in the technical group that these events are part of normal wind farm operation and should not lead to non-compliance. This can be done either through manual investigation of violations or automatically.

A simple automatic mechanism would be to not consider exceedances with a relatively short duration, in the same fashion as what is described for c(i) and c(ii) in the draft NC RfG 2.0*: "not considering oscillations that are damped to be within the limits within 10 seconds"*.

OEM1 has tried different durations (0 s, 1 s, 2 s, 5 s, and 10 s), both for the strictest and default limits, with data from five onshore wind farms (the same data described in previous sections). The results are presented in Table 9. Note that only the first and second columns are relevant, as the other columns contain data that is independent of the duration set for b(i).

	b(i)	**b(ii)**	**b(iii)**	**c(i)**	**c(ii)**	**overall**
Default, 0 s for b(i)	66%	100%	100%	99%	99%	65%
Default, 1 s for b(i)	87%	100%	100%	99%	99%	87%
Default, 2 s for b(i)	90%	100%	100%	99%	99%	90%
Default, 5 s for b(i)	93%	100%	100%	99%	99%	93%
Default, 10 s for b(i)	96%	100%	100%	99%	99%	95%
Most strict, 0 s for b(i)	10%	99%	100%	75%	72%	10%
Most strict, 1 s for b(i)	19%	99%	100%	75%	72%	18%
Most strict, 2 s for b(i)	22%	99%	100%	75%	72%	18%
Most strict, 5 s for b(i)	24%	99%	100%	75%	72%	20%
Most strict, 10 s for b(i)	40%	99%	100%	75%	72%	29%
Scenario C8 (see text)	98%	100%	100%	99%	99%	98%

Table 9. Results of using different minimum durations for b(i). Span = 5. Colour scale: 100% 90% 0%

Using a certain minimum duration for exceedance of the b(i) limit, the number of violations significantly decreases. With the default limit of 2.5% and duration of 10 s, 96% of the weeks meet the requirement. However, it has been discussed in the technical group that a duration of 10 s is not recommendable, and a maximum duration of 1 s is advisable. For the data presented, this results in 87% (default limit) or 19% (most strict limit) compliance ratios, which would be insufficient to filter out all violations.

Another OEM has shared a similar experience: turbine stops lead to exceedance of the b(i) limit, which can only be avoided by using a minimum duration of 10 s (data not presented in this report).

This proves that a duration of 1 s for b(i) is not sufficient to effectively filter out these normal events. Therefore, it was also investigated whether applying the default limit for offshore wind farms (4%) to the data from onshore wind farms would result in similar compliance ratios for onshore wind farms. This corresponds to **Scenario C8**. See Table 9, the last row for the results (and Table 8 for the definition of Scenario C8).

This shows that when the same default limit as for offshore wind farms is used (4%), most weeks meet the requirements (98%).

5.7 Frequencies above 2 Hz

The data from DEV1 has a sample frequency of 20 Hz (sample time 50 ms). This allows for the detection of forced oscillations up to approximately 4–5 Hz (half of the Nyquist frequency). An analysis was conducted with a frequency range of 2.0–4.0 Hz, applying the limits from Article 21.3 (which is applicable for offshore wind farms outside the range of 0.1–2.0 Hz).

Table 10 shows the results of the analysis, indicating that there are no violations in this range.

	b(i)	b(ii)	b(iii)	c(i)	c(ii)	overall
Least strict	100%	100%	100%	100%	100%	100%
Default	100%	100%	100%	100%	100%	100%
Most strict	100%	100%	100%	100%	100%	100%

Table 10. Results of analysis in the 2.0–4.0 Hz frequency range. Span = 5, b1_duration = 1 s. Colour scale: 100% 90% 0%

It is worth highlighting that Energinet has regularly observed oscillations at frequencies higher than 2 Hz. Below is an example from one of the power electronics integrated areas, with 20 ms resolution measurements, where oscillations at 3 Hz were observed on 4 June.

Note that the nature of these oscillations may be either control- or mechanical-driven. Thus, in case of violations, different mitigation measures should be applied depending on the oscillations' nature.

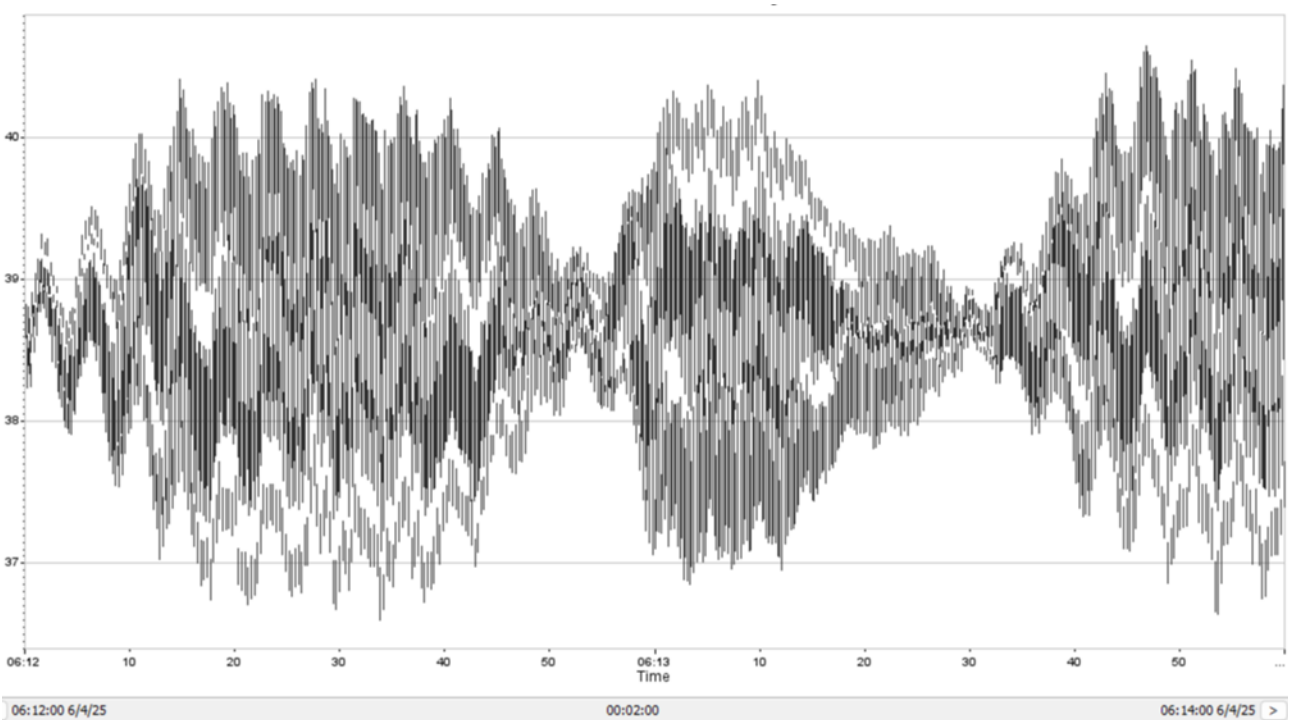


Figure 17. Measured active power.

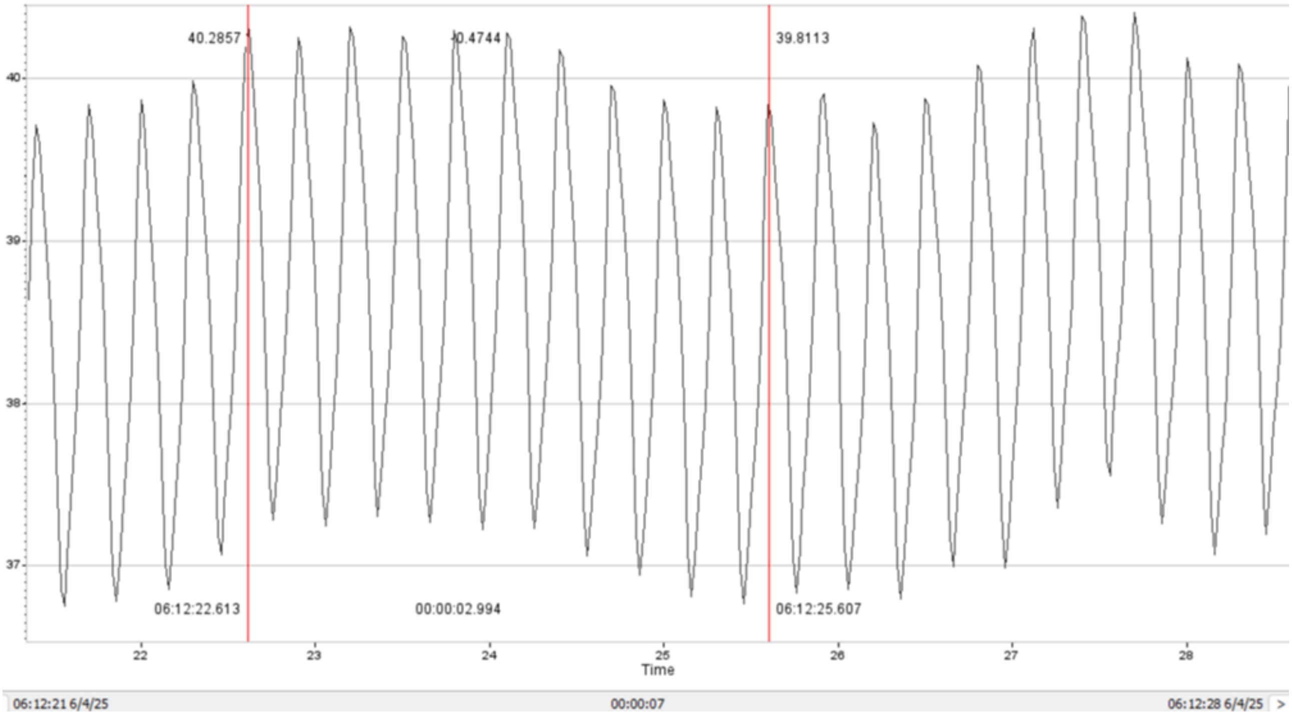


Figure 18. Zoomed-in measured active power, indicating oscillation frequency.

5.8 Outcomes of the assessment

The original default threshold values remain a solid baseline:

- For onshore wind farms in the frequency range of 0.1–20 Hz, and offshore wind farms in the frequency range of 2–20 Hz:
    - Clauses a(i) and a(ii): ±0.5% of maximum capacity and 500 kW, respectively.
    - Clauses b(i), b(ii), and b(iii): ±2.5% of maximum capacity, maximum duration of 180 s, and lower than ±1.25% of maximum capacity within 90 s, respectively.
    - Clauses c(i) and c(ii): ±1% of maximum exceedances of time per day, and maximum three times per hour based on a 95th percentile of hourly exceedances over one week.
- For offshore wind farms in the frequency range of 0.1–2 Hz:
    - Clauses a(i) and a(ii): ±1% of actual production and ±0.5% of maximum capacity, respectively.
    - Clauses b(i), b(ii), and b(iii): ±4% of maximum capacity, maximum duration of 180 s, and lower than ±2% of maximum capacity within 90 s, respectively.
    - Clauses c(i) and c(ii): ±1% of maximum exceedances of time per day, and maximum three times per hour based on a 95th percentile of hourly exceedances over one week.

However, the additional simulations confirm that there is room for refinement in some clauses to ensure adaptability to different grid conditions. These recommendations are meant to be indicative. TSOs are encouraged to adapt thresholds according to their own specific grid conditions and in the context of the evolving power system. Wind farm developers and manufacturers may also provide justifications in case of misdetection, particularly in scenarios of non-oscillatory events that are mistakenly flagged by the tool.

Clause-specific insights: Offshore wind farms

- **Clause a(ii)** has been shown to be highly sensitive. This opens the possibility to:
    - Relax (make it less strict: i.e. in a range between the default and least strict values) the threshold to allow for a more realistic compliance.
    - Simultaneously, apply stricter limits for all the other clauses, as illustrated by combination C6 in the offshore analysis.

- **Clauses b(i) and b(ii)** (maximum amplitude and oscillation duration, respectively) can be considerably reduced in comparison to default values.
- **Clauses c(i) and c(ii):**
    - The results with default values show a sufficient margin to allow further flexibilisation if the decision is made to keep clauses a(i) and a(ii) at their default levels (±1% and ±0.5% respectively).
    - This can help reduce the number of irrelevant oscillation flags and better align with offshore dynamics.

Clause-specific insights: Onshore wind farms

- The **default thresholds** are already adequately flexible for onshore wind farms.
- However, in cases where enhanced robustness is required, stricter values (in comparison to default values) may be considered for:
    - **Clauses b(ii) and b(iii)**: To address extended oscillations as the default values are considerably permissive.
    - **Clauses c(i) and c(ii)**: To ensure a reasonable number of oscillations.
    - **Clause a(i)**: To allow for realistic compliance under these stricter values, this clause may be relaxed (i.e. made less strict).
- **Clause b(i)** most strict value (±0.50% of maximum capacity) seems to be unrealistic for the purpose of wind farm compliance. It is recommended to use (at least) the default value of 2.5% of maximum capacity.

Remark: The requirement on forced oscillation applies to all PPMs. However, wind farms are considered the most sensitive PPMs to this phenomenon. Therefore, the threshold applied to these units should not constrain other technologies.

This proposition is a compromise to allow actual design to be compliant while simultaneously avoiding future design to increase the impact on the grid. The technical group proposes using them at the European level to avoid having as many requirements as there are TSOs, and help OEMs gain visibility when designing generation units. However, each TSO is free to adapt these parameters as they deem necessary based on their specific grid conditions.

The application of stricter limits for specific clauses might have a negative cost impact for the offshore wind farm or induce WTG structural lifetime reduction. Typical cost drivers/increases caused by (partially) disabling ATD are steel cost, weight increase, installation costs, pilling restrictions/limitations, foundation type changes, engineering costs and certification costs. Conversely, making thresholds less strict might jeopardise the security of the grid.

Furthermore, the relevant system operator's choice of project-specific forced oscillations limits shall take connection-point specific system risks into consideration.

Tool-related recommendations

- As the tool is a developed prototype, it is recommended to artificially set a minimum detection duration of 1 s for high-amplitude oscillations under the b(i) clause (input can already be provided in the existing tool).
    - This should not be considered a regulatory requirement, but rather a pragmatic workaround to avoid false positives in detection during post-processing.
- If this workaround still results in misdetection – especially in onshore analyses – parties are encouraged to adapt this setting on a case-by-case basis. According to the tests performed for the report, a duration in the range of 1–10 s should be enough to avoid most of the misdetection.
- Wind farms may bring justified arguments to explain potential misdetections, particularly in scenarios involving system support actions or non-oscillatory events that are mistakenly flagged by the tool.
- Interested parties are encouraged to improve and industrialise the prototype tool. A more advanced version would help reduce misdetection rates and increase confidence in compliance aspects.

6 Potential mitigations

Mitigations must be investigated on a case-by-case basis. As technology is still developing, describing or prescribing mitigating measures is not considered relevant at this stage. Room should be left for solutions that can be implemented in the longer term on the WTG, offshore wind farm, and grid level.

However, the IEC Electrical Energy Storage White Paper provides an overview of possible storage solutions. Part of the information provided is used by the Belgian FOOS study project[5] to describe and further investigate possible mitigating measures, which considers both electrical and structural solutions. The results of this study are not available at the time of writing but may be of interest when/if the results become public.

6.1 Mitigation through electrical solutions

The following technologies will be compared, including their readiness level:

- Different types of energy storage (mechanical, (electro)chemical, electrical, thermal)
- Dissipation (load bank)
- Demand side management
- Flexible AC Transmission Systems (FACTS) such as Thyristor-Controlled Series Capacitor (TCSC), Static Synchronous Compensator (STATCOM), Static Synchronous Series Compensator (SSSC), and Unified Power Flow Controller (UPFC)
- HVDC systems

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[5] *https://www.bluecluster.be/projecten/foos and https://www.sirris.be/en/joint-project/foos-forced-oscillations*

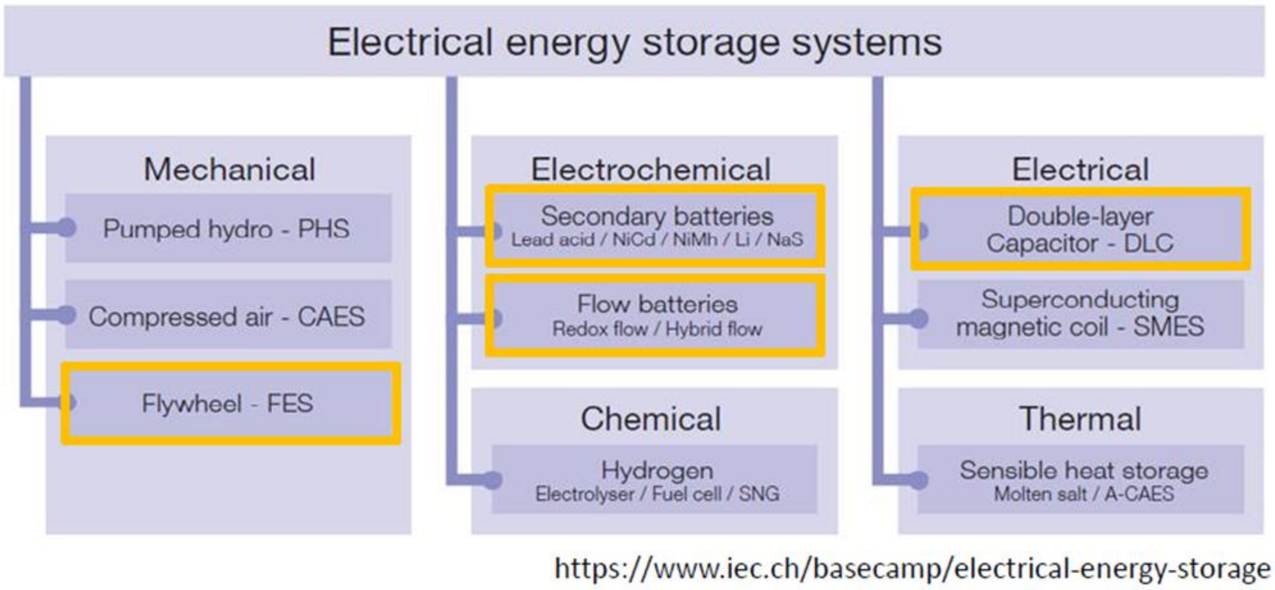

Figure 19. Electrical Energy Storage systems.

The technologies boxed in yellow are prioritised for investigation in the FOOS study project.

The level of integration of mitigating measures is considered at the WTG, wind farm or grid side.

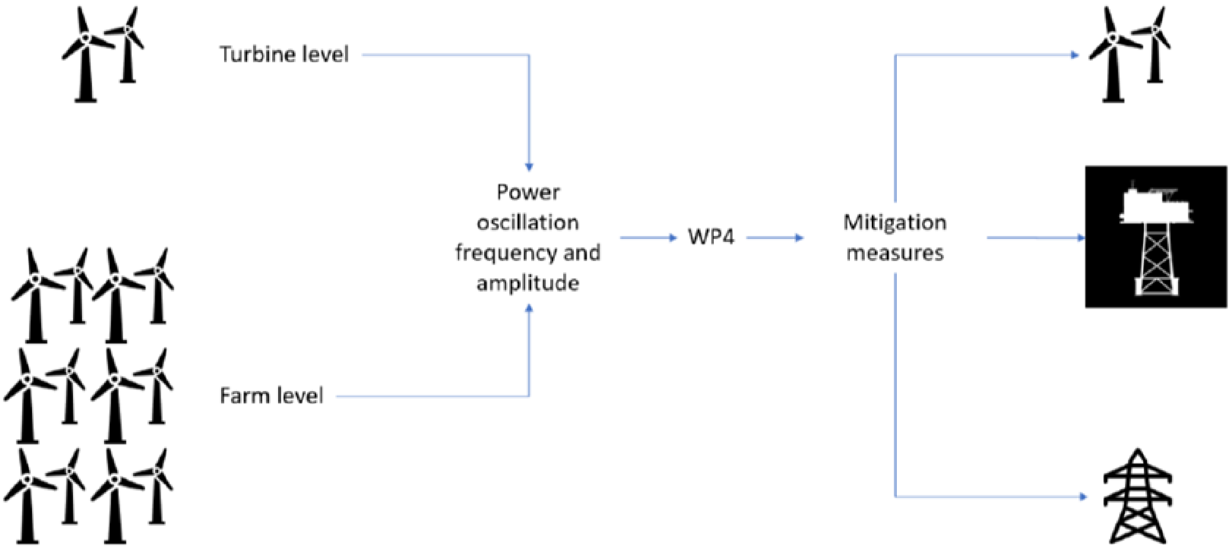

Figure 20. Mitigation measures being investigated.

6.2 Mitigation through structural solutions

Possible mitigation technologies to be further investigated in this regard are:

- Tuned mass dampers
- Slosh dampers
- Active tower damping
    a. Generator torque
    b. Pitch angle variation

7 Conclusions and remarks

The technical group has been able to quantitatively assess the requirements set out in the joint proposal.[6] Given that the available data has been limited to the frequency range of 0.1–2 Hz, it can be concluded for this range that:

1. Original default values remain a solid baseline. However, the specified ranges are sufficiently wide to leave room for adjustment when more knowledge and/or experience about forced oscillations (risks and mitigation costs) becomes available in the future.

2. These recommendations are meant to be indicative, not prescriptive. TSOs are encouraged to adapt thresholds on a case-by-case basis, considering specific system needs and local constraints.

3. In general, the observed oscillations in the available data damp out quickly: clauses b(ii) and b(iii) are also met with the strictest limits.

4. The compliance ratios are most sensitive to the limit set in clause a(ii) for offshore wind farms and a(i) for onshore wind farms. Both refer to the maximum allowable forced oscillation as a percentage of maximum capacity. It is important for wind turbine manufacturers and wind developers to start with realistic values, as it has a major impact on the effectiveness of the active damping algorithm and thus on the design loads (and cost) of the tower, substructure, and foundation.

   Once the design has been certified, and especially after commissioning, making further changes is not a trivial undertaking.

   If the default values for these clauses do not lead to realistic compliance, the technical group recommends more relaxed thresholds for these clauses (i.e. in a range between the default and least strict values) to attain realistic results. When more relaxed thresholds are used for these clauses, stricter thresholds for clauses b and c can be used for both offshore and onshore wind farms due to the need to limit forced oscillations.

5. Wind developers and manufacturers may bring justified arguments to explain potential misdetections, particularly in scenarios of non-oscillatory events that are mistakenly flagged by the tool.

6. The group is open to implementing other methods in the future (a review of the existing thresholds might be necessary in this scenario).

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[6] Although the draft NC RfG 2.0 legal text applies to all PPMs, the current report only focuses on wind turbines.

7. Obtaining data with sufficiently high sampling ratios and of sufficient uninterrupted duration might be challenging as of today. This aspect must be considered when defining more specific compliance procedures.

8. Interested parties are encouraged to improve and industrialise the prototype tool. A more advanced version would help reduce misdetection rates and increase confidence in operational decisions.

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Appendix A. Forced oscillations – most strict, default and least strict requirements

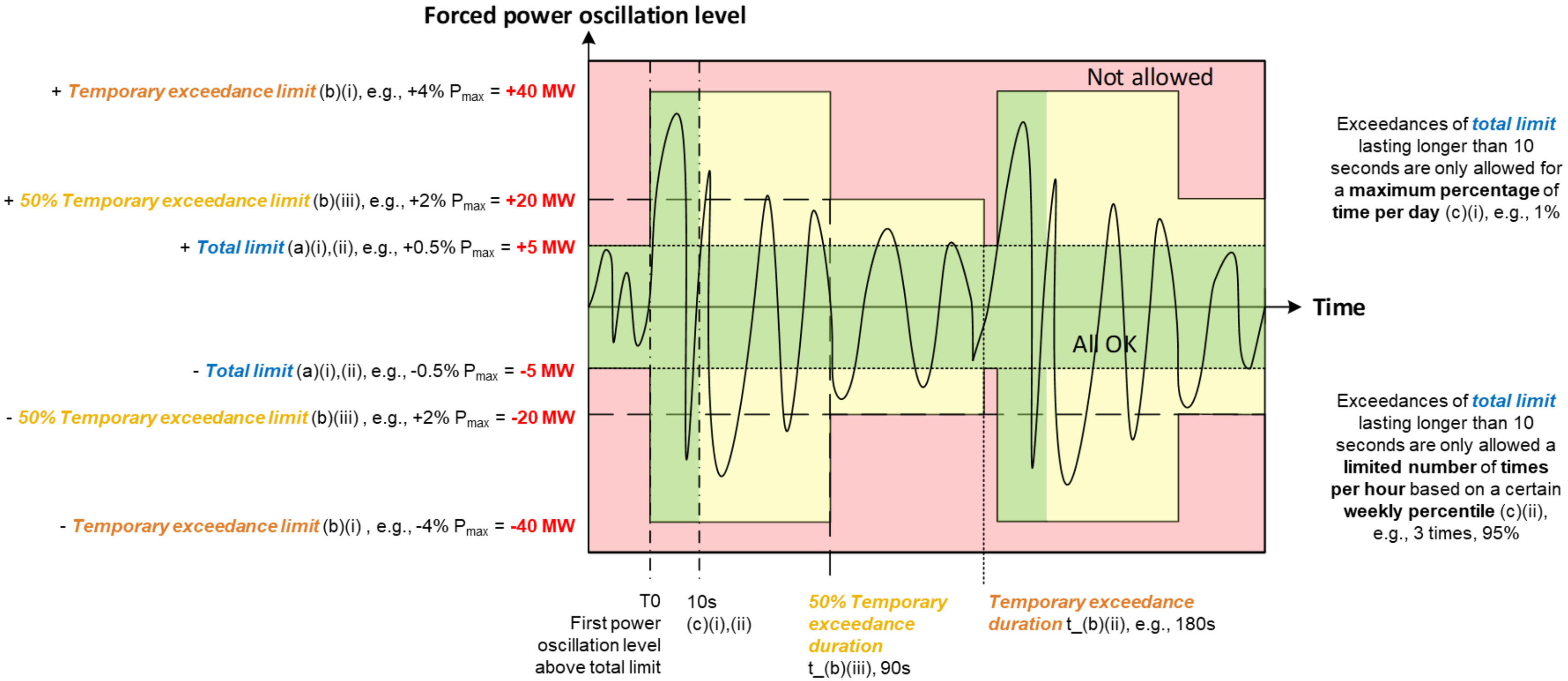
	Clause	Segment	Frequency range (Hz)	Most strict		Default		Least strict	
				Limit is the maximum of the two below		Limit is the maximum of the two below		Limit is the maximum of the two below	
Continuous limit (Total limits)	21(3)(a)(i), (ii)	ONS	0.1–20	+/- 0.1% P_{max} (a)(i)	200 kW (a)(ii)	+/- 0.5% P_{max} (a)(i)	500 kW (a)(ii)	+/- 1% P_{max} (a)(i)	500 kW (a)(ii)
	26(2) first sentence	OFS	2.0–20						
	26(2)(a)(i), (ii)	OFS	0.1–2.0	+/- 0.25% P_{max} (a)(ii)	+/- 0.5% P_{actual} (a)(i)	+/- 0.5% P_{max} (a)(ii)	+/- 1% P_{actual} (a)(i)	+/- 1% P_{max} (a)(ii)	+/- 2% P_{actual} (a)(i)
				Temporary exceedance limit	**Temporary exceedance duration**	**Temporary exceedance limit**	**Temporary exceedance duration**	**Temporary exceedance limit**	**Temporary exceedance duration**
Temporary exceedance limit	21(3)(b)(i), (ii)	ONS	0.1–20	+/- 0.5% P_{max} (b)(i)	100 s (b)(ii)	+/- 2.5% P_{max} (b)(i)	180 s (b)(ii)	+/- 3% P_{max} (b)(i)	180 s (b)(ii)
	26(2) first sentence	OFS	2.0–20						
	26(2)(b)(i), (ii)	OFS	0.1–2.0	+/- 2.5% P_{max} (b)(i)	100 s (b)(ii)	+/- 4% P_{max} (b)(i)	180 s (b)(ii)	+/- 5% P_{max} (b)(i)	180 s (b)(ii)
				Oscillation shall be below	**within**	**Oscillation shall be below**	**within**	**Oscillation shall be below**	**within**
Damping of oscillations	21(3)(b)(iii)	ONS	0.1–20	+/- 0.25% P_{max} (b)(iii)	50 s (b)(iii)	+/- 1.25% P_{max} (b)(iii)	90 s (b)(iii)	+/- 1.5% P_{max} (b)(iii)	90 s (b)(iii)

exceeding the continuous limits (a)(i), (ii)	26(2) first sentence	OFS	2.0–20						
	26(2)(b)(iii)	OFS	0.1–2.0	+/- 1.25% P_{max} (b)(iii)	50 s (b)(ii)	+/- 2% P_{max} (b)(iii)	90 s (b)(iii)	+/- 2.5% P_{max} (b)(iii)	90 s (b)(iii)

				Maximum time per day	**Maximum times per hour**	**Per-centile**	**Maximum time per day**	**Maximum times per hour**	**Per-centile**	**Maximum time per day**	**Maximum times per hour**	**Per-centile**
Exceedance of continuous limits for more than 10 s	21(3)(c)(i), (ii)	ONS	0.1–20	1% (c)(i)	2 (c)(ii)	95 (c) (ii)	1% (c)(i)	3 (c)(ii)	95 (c) (ii)	2% (c)(i)	4 (c)(ii)	85 (c)(ii)
	26(2) first sentence	OFS	2.0–20									
	26(2)(c)(i), (ii)	OFS	0.1–2.0									

Table 11. Forced oscillations requirements for the most strict, default, and least strict limits as per draft NC RfG 2.0, Article 21.3 and Article 26.2.

Appendix B. Forced oscillations – graphical representation of requirements



Exceedances of *total limit* lasting longer than 10 seconds are only allowed for a **maximum percentage** of **time per day** (c)(i), e.g., 1%

Exceedances of *total limit* lasting longer than 10 seconds are only allowed a **limited number** of **times per hour** based on a certain **weekly percentile** (c)(ii), e.g., 3 times, 95%

Figure 21. Graphical representation of forced oscillation requirements – default limits applicable to offshore PPMs[7] as per draft NC RfG 2.0, Article 26 (absolute limits in MW given as example values for Pmax = 1 GW).

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[7] *For the frequency range 0.1–2 Hz.*

Appendix C. Assessment of simulation data for virtual wind farms driven by normal turbulence

To investigate the contribution of normal turbulence to the exceedance of the requirements for forced oscillations, wind farm data was generated using a simulation model (in MATLAB) that includes:

- A simplified model of a WTG and controller, including operation in the optimal lambda region and operation in speed control.
- Turbulence based on the Kaimal spectral and exponential coherence model (one time series for each turbine in the wind farm).
- Slow-varying wind with a peak at 0.05 cycles/hour (one time series for all wind turbines in the wind farm).

Simulations were carried out for three different turbulence levels (IEC turbulence A, B, C) and an average wind speed of 8.5 m/s. Each wind turbine was simulated separately for a total of 52 weeks. The active grid power of the entire wind farm was obtained by summing all individual outputs.

The results are presented below in the same manner as before:

- The analysis shows that for a medium sized onshore wind farm of 20 wind turbines, the current requirements are only met when the least strict limits are applied, regardless of turbulence levels.

- When the default limits are used, the oscillations damp out quickly enough to avoid violating clause b with the default limits. Clause c (limiting the number of violations per hour and the total duration of all events), however, is still violated with the default limits.

- With the strictest limits, all clauses are violated, even in the case of low turbulence.

Note that aspects that normally could lead to forced oscillations like wind shear, rotational sampling, tower shadow, tower oscillations, and controller algorithms (i.e. ATD) are not modelled.

It can be concluded that normal turbulence contributes to short time oscillations in the frequency band of 0.1 Hz to 2 Hz above the allowed limits and especially leads to violations of the c clause.

Turbulence class A	b(i)	b(ii)	b(iii)	c(i)	c(ii)	overall
Least strict	100%	100%	100%	100%	100%	100%
Default	100%	100%	100%	2%	0%	0%
Most strict	0%	0%	8%	0%	0%	0%

Turbulence class B	b(i)	b(ii)	b(iii)	c(i)	c(ii)	overall
Least strict	100%	100%	100%	100%	100%	100%
Default	100%	100%	100%	6%	0%	0%
Most strict	0%	8%	23%	0%	0%	0%

Turbulence class C	b(i)	b(ii)	b(iii)	c(i)	c(ii)	overall
Least strict	100%	100%	100%	100%	100%	100%
Default	100%	100%	100%	19%	2%	2%
Most strict	0%	8%	56%	0%	0%	0%

Table 12. Aggregated results of simulated onshore wind farms with three scenarios (least strict, default, most strict) and three different turbulence classes (A, B, C). Span = 5, b1_duration = 1 s. Colour scale: 100% 90% 0%

Appendix D. WindEurope’s deviating positions

1) Articles 21 and 26 of the draft amended NC RfG, as outlined in ACER’s Recommendation No 03/2023 published 19 December 2023, introduce limits on active power forced oscillations for wind farms. These limits reflect a negotiated compromise in 2023 between ENTSO-E’s initial zero-tolerance proposal and WindEurope’s call for practical thresholds.

   We appreciate the constructive collaboration within this technical group. However, we have not yet seen sufficient evidence demonstrating the impact of forced oscillations, and no clear justification for the proposed limits.

   Unvalidated or overly strict requirements risk either frequent non-compliance or costly turbine redesigns. This could raise energy costs for consumers and delay wind energy deployment at a time when safe and stable operation of power system as well as energy security are critical for Europe.

   Therefore, we strongly recommend that:

   - The default values in the current NC RfG 2.0 draft text should represent the strictest limits
   - If a TSO wishes to apply stricter limits, the NC RfG 2.0 should require them to provide robust technical justification

2) As the technical report demonstrates, compliance assessment for forced oscillation limits requires significant effort. While such assessments may be feasible for a few very large wind plants (>300–500 MW), applying them to hundreds of small and medium-sized wind and PV plants could create a bottleneck and increase uncertainty for assets. Each project would need to factor in compliance risk during planning.

   We therefore recommend that system operators enforce this requirement only for very large PPMs, and only at grid nodes where the requirement is relevant. It should not become a blanket requirement for all type C PPMs (>10 MW in Nordics/Baltics or >50 MW in Continental Europe).

Finally, we believe continued collaboration will be valuable to improve the assessment process and refine the script and methodology for evaluating forced oscillations……